Electricity Transmission Investment in the United States: An Investigation of Adequacy

by

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Abstract

There is a prevailing sentiment that the United States is underinvested in its electric transmission infrastructure. The standard claim is that poor regulation has caused insufficient levels of capital to be devoted to the transmission system and resulted in a network that is economically inefficient and potentially unreliable. Furthermore, it has been postulated that if policy changes are not made to increase investment in the near future, the US will face a crisis within its electricity grid. This investigation assesses these claims and, where regulation or investment is found to be wanting, policy recommendations to remedy the situation are made.

Adequacy is defined here in the context of the major goals for transmission in the United States – generator interconnection, economics, reliability, and policy support – and whether the current system is achieving these goals. Adequacy is neither static nor a binary outcome, and at any point in time the system exists along some continuum between perfectly adequate and completely inadequate. This state may be affected by policies in place, the economy, the fuel prices that underlie the economics of the power system, or by other factors, and thus adequacy must be regularly revisited, as is done here.

This study begins by finding that many of the indicators traditionally used to assess adequacy of transmission investment do not actually have much utility when it comes to drawing a definitive conclusion. Additionally, data that could potentially indicate adequacy are either insufficient to support any findings on the matter or are inconclusive. As such, other avenues of research are required. Two approaches are settled on as possible ways of addressing adequacy. The first, a "regulatory rationale" approach, seeks to apply logic and experience to deduce what outcomes might result from current regulatory structures. The second, a set of interviews with professional transmission planners, serves to validate the theoretical findings of the regulatory rationale and gain insight into the actual state of the system. The interview responses are analyzed using grounded theory, a structured method for interpreting qualitative data.

Based on the two pronged qualitative assessment of system adequacy, the transmission network is found to be more adequate than is commonly claimed. Specifically, the system is quite adequate to serve the goals of generator interconnection and reliability. The conclusions for whether the system is economically efficient are the least clear, but to the extent that is possible within the current planning process, it appears that there is not cause to be concerned about underinvestment. Any major economic opportunities that are being missed are likely a result of the lack of an inter-regional planning process, which in turn means that opportunities for strengthening of economic linkages between regional jurisdictions are probably overlooked. The most concerning category where adequacy may become an issue is policy lines. While a motivating national policy is not yet in place, the type of transmission regulation that would result in transmission expansion to serve policy needs is not in place. Regulatory change is required to ensure that the system does not end up with a regulatory framework that cannot support legislative goals.

Based on these findings, a limited number of policy recommendations are forwarded. First, it is suggested that any decisions based on the conventional wisdom be reexamined based on a more rigorous assessment of more complete data on the current state of the system. Next, it is recommended that the economic criteria and planning process be revisited with a focus on ensuring that inter-regional opportunities are not overlooked. Finally, there is a need to create policy certainty about what the future goals are for the power system, which should be supported by improved regulation that will allow for the incorporation of large quantities of renewable power sources.

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Biographical Note

Jordan grew up in Southern California and attended La Canada High School. He then moved to Evanston, IL to attend the McCormack School of Engineering at Northwestern University, where he completed his Bachelor of Science degree in Materials Science and Engineering. For his senior capstone research at Northwestern, Jordan completed a project entitled "Development and Characterization of a Process for Removing Steel Placeholders from Titanium Foams." This work was recognized both by the Margaret and Muir Frey Memorial Prize for Innovation and Creativity, a McCormack-wide award, and the Hilliard Award for Undergraduate Research and Design, an award granted by the Materials Science Department. This work was also eventually published in Advanced Engineering Materials under the title "Porous Titanium by Electro-chemical Dissolution of Steel Space-holders."

After completing his BS and before moving to MIT to study Technology Policy, Jordan spent a year in Israel participating in a volunteer program called OTZMA. While in Israel, he learned Hebrew (or tried to), taught English, volunteered with holocaust survivors, and interned at a non-profit called the Perez Center for Peace.

Upon starting his Master's study at MIT, Jordan developed an intense interest in energy policy. His interests led him to participate in MIT's Energy Club, Energy Conference and Energy Education Task Force. Jordan's first year of research at MIT was as a member of MIT's "Future of Solar Energy" study. A growing curiosity about power systems regulation then led him to switch research associations so that he could participate in MIT's "Future of the Electric Grid" report. His experiences as a member of this study precipitated the questions addressed in this document.

Contents

1 Introduction

"There is growing evidence that the U.S. transmission system is in urgent need of modernization." (US Department of Energy 2002)

"Whether one considers the transmission grid adequate, 'fragile', 'antiquated', or even 'third-world', almost everyone agrees that the electricity industry and government policy makers should pay more attention to transmission, in particular construction of needed new facilities."(Hirst 2004)[1]

"Even in the Northeastern RTO/ISOs with relatively well developed transmission planning procedures, network enhancements have been slow to be realized and expansion of inter-control area transmission capacity has been virtually non-existent."(Joskow 2004)

"Further benefits to customers from restructuring are undermined by insufficient transmission investment." (National Grid 2005)

"The clear need for an increase in transmission investment exists in an investment climate that remains fragmented by different procedures, incentives, and constraints from region to region." (Energy Security Analysis 2005)

"There has been a sustained period of underinvestment in the transmission system. Notwithstanding, use of the nation's grid has more than doubled in recent years. It is clear that we need to strengthen the system to meet consumer demand... Underinvestment in the grid is a national problem." (FERC Chairman Joseph T. Kelliher, 2006)[2]

"Many electricity industry observers regard transmission capacity as inadequate." (Brennan 2006)

"This long period [1982 to 2005] of insufficient transmission investment has lead to transmission lines that are congested in several regions of the United States."(Abel 2007)

"Many analysts have identified a need to expand the national transmission system." (Kaplan 2009)

[1] Interior quotes cite Burns, Potter, and Wiotkind-Davis 2004.
[2] From FERC press release on July 20, 2006 on Docket No. RM06-4

There seems to be a prevailing sentiment that the United States is underinvested in its electric transmission infrastructure. The standard claim is that insufficient levels of capital devoted to the transmission system have resulted in a network that is economically inefficient and unreliable. Furthermore, it is postulated that if policy changes are not made to increase investment in the near future, the US will face a crisis within its electricity system (Hirst 2000). Only a few voices exist that challenge this conventional wisdom and question whether the claims being made are legitimate and reflect the true state of the network (Hogan 2008; Huntoon and Metzner 2003).

This study will attempt to take a critical and objective look at the claims on both sides of the transmission adequacy issue and make a determination of to what extent current levels of investment are adequate to serve the nation's goals. First, the document will introduce the system in question and give a brief primer on the reasons that we build transmission, including the alternatives available when deciding on investments. This will be accompanied by a preliminary framework about how to think about the concept of adequacy of investment. Then, the data will be presented that are commonly used to forward the argument that there is currently underinvestment in the transmission system. Following each presentation of the standard reasoning, a critique will be made of the metrics used to support the claim of inadequacy. From this, it will become clear that there are challenges with the data available and that it is hard to draw any conclusions based on the evidence provided; other approaches are needed in order to draw any conclusions about electric transmission adequacy.

After recognizing the need for alternative methods, two other approaches will then be taken to assess adequacy of investment. The first path will be referred to as a "regulatory rationale" approach and will strive to apply logic and knowledge of prior regulatory experiences to infer what level of adequacy should result from current regulations. Of course, without any real world backing this approach would be nothing more than an academic exercise. As such, to complement the regulatory rationale – as well as to provide a standalone and unique outlook on the issue of adequacy – the researcher will interview subject matter experts in transmission planning in order to gain insight into what is the state of the system, and what they think about current levels of transmission infrastructure investment. The regulatory rational and expert interviews will also attempt to consider how adequacy may be affected by (or affect) demands placed on the system by forthcoming environmental policies. Together, the two approaches should yield a complete story about the current state of the transmission network in the United States, and any disagreement in conclusions between the findings will be considered carefully.

The overall goal of this investigation has three parts. To arrive at a conclusion, it will first be necessary to figure out how we define a well functioning, or "adequate" system. A framework for thinking about adequacy will be presented towards the beginning of the document and then revisited as necessary. Once an approach for determining adequacy has been established, an assessment will be made using the three approaches described above. The second main objective is to determine whether there is, in fact, currently a problem with the US transmission system that requires a major policy response. This determination could take several different forms:

- It could be found that the system is currently broken and will remain so without regulatory improvements.
- It could find that the system is fine now (in whole or in part), but with anticipated changes in national policy and system goals it will become broken in the future.
- It could find that the system is functioning well and will continue to do so.

The third main objective – in the case that the system is or will become broken – is to make policy recommendations to remedy the situation. Again, an attempt will be made to assess adequacy and make recommendations for both the system as it stands today and under a scenario where carbon is constrained via broad based policy measures[3].

A note on scope: as will be described shortly, the US currently exists torn between two paradigms of power system regulation, the vertically integrated and the restructured. Because much of the concern about underinvestment pertains to restructured regions – probably as a result of the more complex administrative and investment structures – investigation of vertically integrated regions does not warrant much attention here. Furthermore, more data is available and the problems associated with network development are more compelling for liberalized power systems. As such, this project will focus primarily on these parts of the country.

[3] Under a carbon constrained scenario, it should be assumed that the goals will be at least partially achieved by incorporation of large quantities of renewable power sourced from distant locations, requiring significant new investments in transmission.

2 Transmission System Background

At its most basic level, the electric transmission is the part of the electric power system that carries electricity from power plants to demand centers (see Figure 1). In the case of high voltage transmission lines, the network is generally used to transport large amounts of power over long distances. This network consists of substations, towers, as well as the lines themselves. Though direct current (DC) transmission is used for select applications, most power lines in the US (and elsewhere) carry electric power in the form of alternating current (AC) as it has the advantage of being able to be stepped up and down in voltage level with relative ease. On a more detailed level, one may also think of the sensors, control units, information systems, and system operation functions as part of the network (Kaplan 2009).

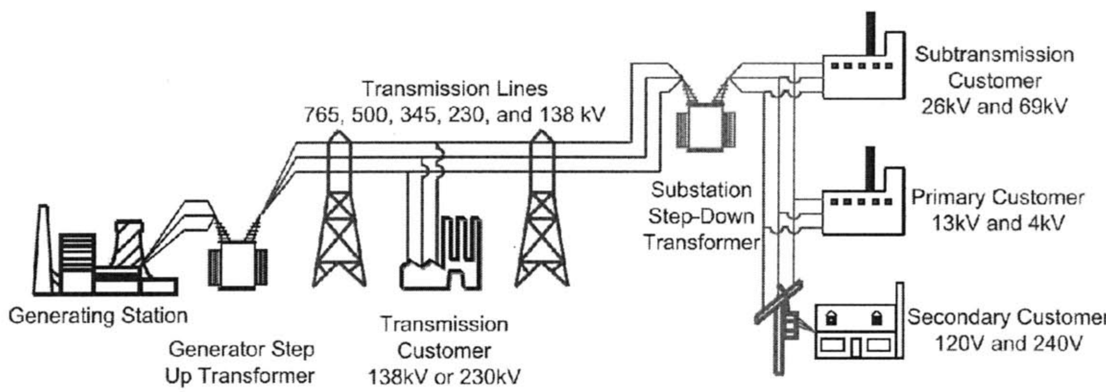

Figure 1: A schematic of the conventional power system (U.S.-Canada Power System Outage Task Force 2004).

Transmission lines may carry power at voltages as low as 22 kilovolts (kV) or as high as 765 kV[4]. Low voltage lines that are designated as such tend to be an organizational artifact; low voltage lines are actually poor at transmitting power over significant distances and thus do not fulfill the true function of transmission. The highest voltages offer advantages of diminished losses and increased capacity but require larger and more expensive equipment. High voltage lines are primarily used where there is a need for large amounts of power transfer and/or the requirement to cover long distances. As current policy discussions are mostly concerned with the high voltage, or "bulk", transmission system (200 kV+) in the US, this paper will focus exclusively on this portion of the network.

[4] What exactly constitutes high voltage transmission is arbitrary and not clearly defined. In some of the literature, it includes lines down to 100 kV or only over 230 kV. FERC and NERC define transmission as over 69 kV. For this paper, 200 kV+ was chosen as a majority of the literature on the subject uses this approximate distinction and the data on the topic lends itself to this particular division.

2.1 Why Build Transmission?

The fundamental role of transmission is to make it possible for generation to be placed where resources and economics are most favorable while still serving a stationary load. Beyond its basic function of moving power from point A to point B, transmission plays other significant roles within the modern power system. The following groupings of characteristics are by no means the only way of thinking about the services the system provides, but simply attempt at organizing the different capabilities of the transmission network:

- **Compliments the reliability and security of the existing infrastructure.** Increased transmission capacity allows for a system that can better react to contingencies in both the short and long term. In the short term, transmission capacity improves network stability, strengthens the system's ability to prevent and recover from emergencies, and increases redundancy of both it and other elements of the electric power system. In the long term, the availability of transmission capacity accommodates uncertain future growth and development (Gutman and Wilcox 2009).
- **Acts as the fundamental platform for energy markets**. A robust transmission network supports well-functioning markets for electricity by minimizing congestion and maximizing the scope of competition. Transmission allows geographically dispersed players to buy and sell power, increasing the number and diversity of competitors, decreasing prices, and reducing the potential market power of participants. Furthermore, a strong network allows supply to be brought in line with demand in the most efficient manner, whether through entry of new generation or investment in demand side or energy efficiency resources (Joskow 2005). Similarly, in regions that are vertically integrated, transmission allows utilities to plan and operate the power system efficiently.
- **Increases operational flexibility and efficiency and facilitates the coordinated use of diverse generation resources**. As renewable generators – with their variable power output – increase their penetration into the modern power system, other resources will need to be available to step in as backup when the wind is not blowing or the sun is not shining. Increased transmission capacity will allow system operators to better manage this more complex relationship between supply and demand. Similarly, in many cases transmission can also allow greater utilization of the existing generation infrastructure, reducing the need for additional investment or operating reserves. Furthermore, transmission conductors are more efficient when operating below capacity and network additions often relieve the most heavily strained lines, thus reducing system losses and decreasing the cost of using the transmission system (Brown and Sedano 2004).

- **Allows for the transfer of power over long distances.** This capability bears mentioning in the current system context for two reasons. First, most energy is consumed in urban areas that are well developed and present a challenge for sighting of new generation that could be close enough to load to connect directly to the distribution system or short transmission ties. High voltage allows the transmission of power into load centers via narrow corridors, many of which are already devoted to the transmission activity (Gutman and Wilcox 2009). Second, there is a large and growing desire to use clean, locally-sourced energy in response to concern over climate change and energy security. Increased utilization of such renewable energy resources – the highest quality of which are often far from existing population centers – is facilitated by the availability of transfer capacity in the form of long distance transmission infrastructure.

While the above traits of transmission capture the standard motivations for a well developed transmission system, some parties describe the system in different terms. American Electric Power (AEP), for example, also argues that transmission infrastructure is necessary to develop new uses of electricity. AEP's claim is that a strong Extra High Voltage (EHV)[5] network is necessary to facilitate the full realization of the potential of personal electronics and plug-in electric vehicles, along with any other unforeseen, power intensive applications that may come along. Furthermore, they posit that "a robust and well interconnected transmission system allows demand-side management techniques, such as smart meters and demand response, to have a broader geographic impact" (Gutman and Wilcox 2009).

Another example of an alternative view of transmission is presented by National Grid. National Grid's perspective on the transmission system is that it is not a market commodity, but simply a delivery mechanism and serves no function as an alternative to other resources (i.e. it does not compete with demand side or supply side options). From their point of view, the characteristics of transmission investments – in particular that such investment is lumpy[6] – and the non-rivalrous, non-excludable nature of transmission capacity make the transmission network a "public good"[7]. Because of this quality of being a public good, National Grid holds that transmission should be planned and provided by regional authorities, with the costs spread broadly among users in the service region (National Grid 2005).

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[5] This usually refers to 765 kV transmission lines.

[6] "Lumpy" refers to the fact that transmission expansions can only be made at discrete levels, based on the availability of equipment from suppliers. Often, this results in investments that are somewhat oversized to suit the need. From a system standpoint this may be desirable after the fact, but it has the unfortunately side effect of resolving any constraints to the point where it is impossible recover the costs of the line via congestion revenues. This characteristic tends to eliminate investment interest from parties who would receive anything other than regulated rates for a line they install.

[7] It is questionable whether this is actually the case from both a physical and a regulatory standpoint.

2.2 What is the Current State of the Transmission System in the US?

As it stands, the United States' electric transmission system is divided into three large, independently synchronized, alternating current (AC) networks, called interconnections (Figure 2). The two largest interconnections also include portions of Canada and Mexico. The Eastern Interconnection, the largest of the three in terms of load[8], is made up of all of the United States east of the Rocky Mountains as well as the Canadian provinces of New Brunswick, Ontario, Manitoba, and Saskatchewan. The Western Interconnection is made up of the Rocky Mountain States and the states west of the Rockies, including Alberta, British Columbia, and portions of Northern Mexico. The third interconnection, the Electric Reliability Council of Texas (ERCOT), encompasses most but not all of Texas (Kaplan 2009).

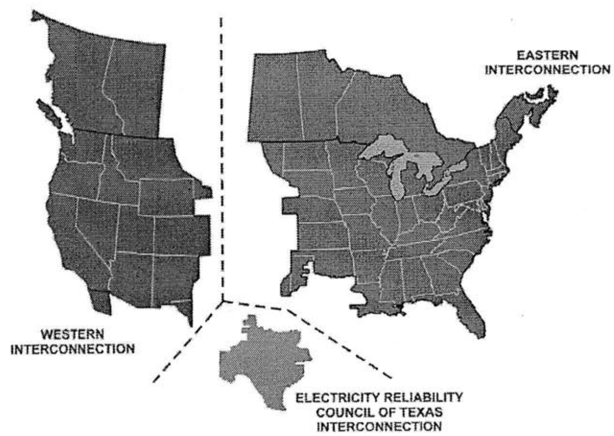

Figure 2: United States Transmission Interconnections (US Department of Energy 2010)

The three major interconnections are subdivided into ten regional reliability councils (Figure 3) and 24 sub-regional reliability organizations (map in Appendix A), which are coordinated by the North American Electric Reliability Corporation (NERC). These councils and organizations are responsible for devising criteria for reliability, including operating reserves, frequency management, scheduling, inadvertent power flows, reactive power support, contingency criteria, etc. and monitor the system in real time in order to detect and avert reliability problems. While reliability authorities do not have long term planning authority, they publish annual forecasts of investment and also evaluate impacts of new investments in generation and transmission with an eye for identifying potential shortages in capacity to serve load. Up until it was made mandatory by the Energy Policy Act of 2005 (EPACT 2005), adherence to NERC standards was voluntary (although widely followed). Adherence is now mandatory and is enforced by the authority of the Federal Energy Regulatory Commission (FERC).

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[8] The US portions of the three interconnects serve approximately 4,000 TWh of load each year. Of this amount, the Eastern Interconnect serves about 73%, the Western 19%, and ERCOT 8% (EIA form-411).

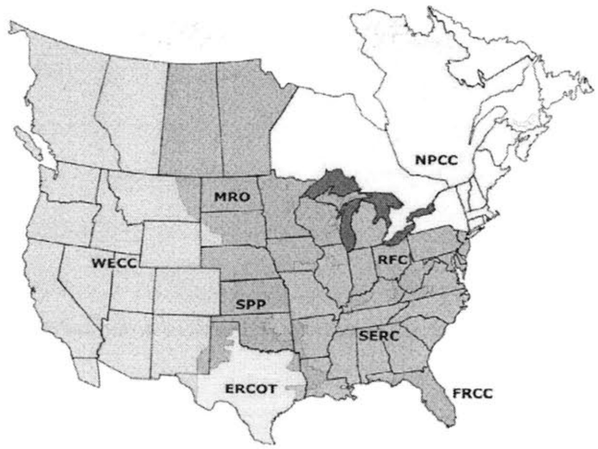

Figure 3: NERC Reliability Councils (NERC 2009)

From a physical standpoint, the US transmission system currently includes approximately[9] 670,000 miles of transmission lines of all voltages (Figure 4, full map in Appendix A) (Edison Electric Institute 2009). Of this, about 160,000 miles of line is considered high voltage, or greater than 200 kV (NERC 2009). The capital infrastructure of the network is owned by as many as 450 private companies along with a few public entities and co-ops (see Figure 5). On a day-to-day basis, 135 balancing area authorities[10] (map in Appendix A) are responsible for maintaining the balance between generation and load in their respective control areas as well as ensuring that generators under their auspices are synchronized to the frequency of the interconnection in which they reside (Wilrich 2009).

[9] Statistics throughout this report will not be exact, as there are serious issues with the availability, consistency, and accuracy of data. This problem will be addressed thoroughly later in the document.
[10] This number changes over time, there were 140 balancing area authorities in 1995 and 138 in 2008.

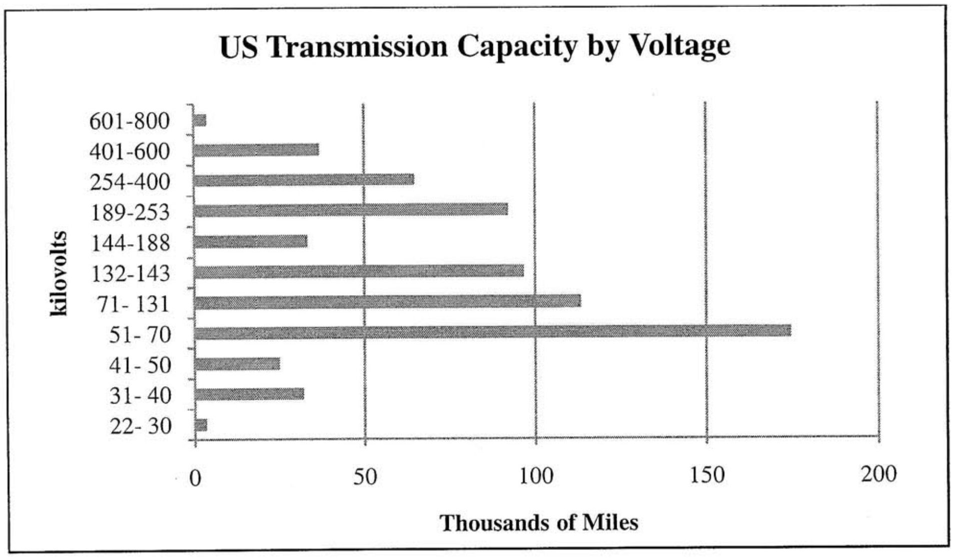

Figure 4: US Transmission Line Miles by Voltage (Edison Electric Institute 2009)[11]

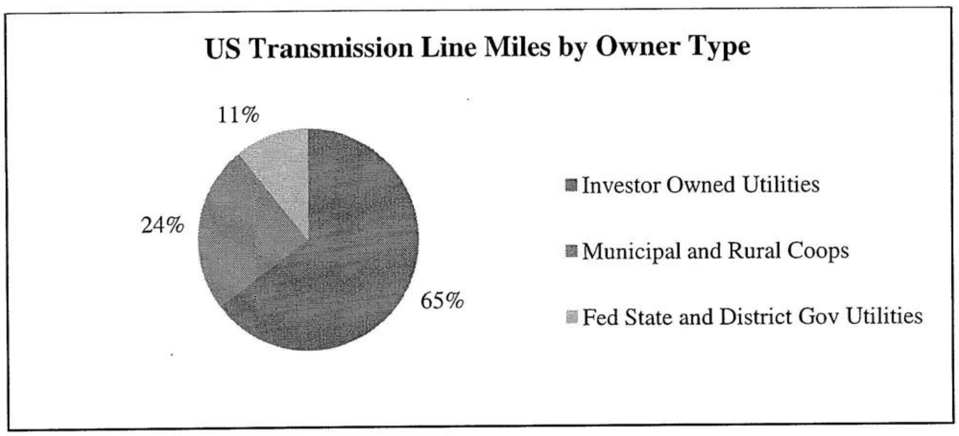

Figure 5: US Transmission Line Miles by Owner Type (Platts 2010)

It is not possible to talk about the current state of the system without addressing the movement of parts of the country away from the traditionally regulated utility structure toward a restructured[12], market-based electricity system[13]. Some areas of the US have established Independent System Operators (ISOs)[14] to run their wholesale electricity markets and manage the systems' operations, and the rules under which they exist vary greatly from state to state or region to region, although some convergence can be observed

[11] Lower voltages may seem low because of a definitional issue; most lines of those voltage levels are counted as distribution and not transmission infrastructure.

[12] The term restructured is often used interchangeably with "liberalized", "unbundled", and "deregulated" to indicate the process of moving away from a vertically integrated utility structure. Deregulated is misleading, as liberalized markets are by no means free of the auspices of a regulatory authority.

[13] A more thorough discussion of this evolution can be found in Appendix G

[14] For all intents and purposes, in the United States this term may be used interchangeably with Regional Transmission Operator, or RTO. Unlike European Transmission System Operators (TSOs), ISOs or RTOs in the US do not own transmission assets

overall. In other parts of the US, states have resisted the move towards restructured markets and retain traditional electricity service from vertically integrated utilities. Still other states have taken some of the actions associated with restructuring while hesitating to fully accept all of the changes required for an ideal (i.e. complete) shift to liberalized electricity markets. As it stands, approximately two thirds of load in the US is served by an entity that qualifies as an ISO (see Figure 6). In the context of transmission adequacy, restructuring is relevant because methods for planning and assessing transmission investments may be different between liberalized and vertically integrated regions and also across different liberalized regions.

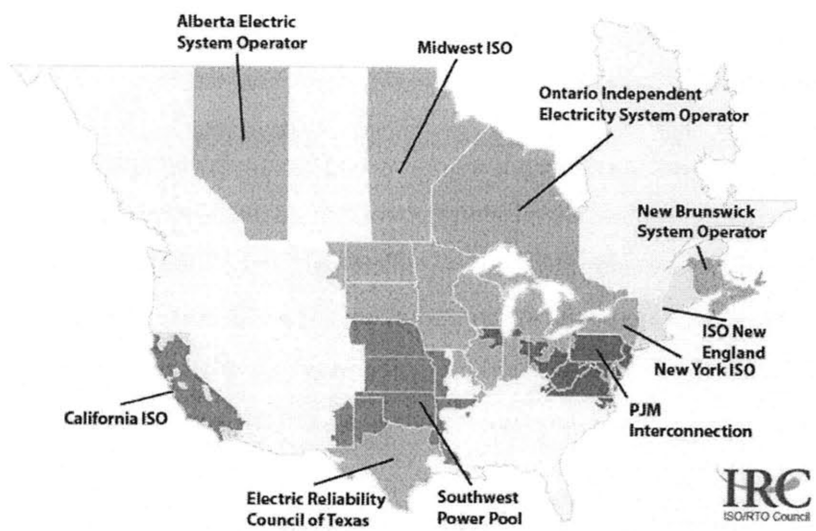

Figure 6: Current ISOs and RTOs in North America (ISO/RTO Council 2010)

2.3 Types of Investment and Alternatives to Transmission

Before moving forward, it is worth mentioning that transmission investments vary in both form and function, and that building transmission capacity is not always the only solution to any given network problem. First, though it is standard to think about building transmission as the process of constructing new lines and towers on a new right of way, it is unusual that this is actually the case. Many effective and desirable projects do not fit this commonly held vision and are not nearly as capital, real estate, and labor intensive as a green-field transmission project[15]. Specifically, projects can involve additions or replacements to the existing system with the following physical components (Joskow 2005):

- Relays and switches
- Remote monitoring and control equipment

[15] In some cases, effective capacity can even be increased with little or no cost via improved control schemes or better remedial action plans.

- Transformers
- Substation facilities
- Capacitors
- Reconductoring of existing links
- Increasing voltage of transmission links
- New transmission lines on existing corridors
- New transmission lines on new corridors

Each of these types of physical investments can be made for a number of reasons. While the specifics of transmission investments vary between regions, they can be generally classified into these six categories as laid out by (Joskow 2005)[16]:

- **Generator interconnection investments**: new or expanded generators must invest in capacity to connect their plants to the transmission network to enable them to deliver their product to the customer. At the very minimum, these interconnections must be able to support the full generating capacity of the power station. In many cases, "deeper" investments will be required to reinforce other sections of the network to the point where the generator can ensure that it will not overload other parts of the system and be able to sell power without being constrained by physical transmission capacity limitations.
- **Distribution network and large customer investments**: distribution utilities and large industrial and commercial customers also must connect directly to the transmission system. Generally speaking, these investments are the mirror of generator interconnections with a few exceptions. For example, distribution networks are tied into the transmission system at multiple points. Also, the investment decisions of individual customers are rarely sensitive to interconnection costs. While interconnections for loads do not always guarantee upstream capacity to serve demand, these investments will not be made unless sufficient capacity can be ensured one way or another.
- **Intra-RTO economic investments**: within its footprint, a TSO may make investments to reduce congestion costs[17] and increase social welfare. These investments are evaluated based on known costs of transmission hardware and benefits calculated using economic models of network

[16] The categories presented by Joskow are idealized concepts. In reality, there may be significant overlap between one type of investment and the next and in many cases it may not be possible to differentiate line types. For instance, when a system is being planned under central planning the output of a planning model will include a portfolio of lines that are recommended to achieve the system goals without indicating which kind of line is which.

[17] "Congestion *costs* are the *difference* between the cost of supplying generation services to meet demand given the scarce transmission capacity actually available on the network and what the cost of generation would be if there were no congestion to limit imports of less costly power (including the dead weight loss associated with reductions in price sensitive demand due to the higher prices) in the high price "constrained on" zone." (Joskow, 2005)

operations. Ideally, such models will consider the costs associated with location constrained dispatch of generation as well as network losses[18]. In cases where the net impact of an investment on social welfare is positive, an economic line should be built[19].

- **Inter-RTO economic investments**: if two or more RTOs participate in joint planning efforts and find that there are lines that satisfy the same criteria for economic desirability described above, they may make this type of investment. The distinction here is primarily institutional, since as long as two TSO regions fall within the same synchronous AC system there is no physical difference between this and an "intra-TSO" economic investment. The challenge with this inter-TSO investment is that differences in governance and operational structures may add significant barriers to completing such projects.
- **Interconnections to support inter-RTO links**: parallel to deep generator interconnection investments, inter-TSO economic investments will need to be connected to the existing system and may require deep system reinforcements to fully realize the economic benefits of power trades between regions (and maintain system reliability). The cost of these network reinforcements to both networks should be included in the initial cost-benefit decision analysis to determine if a line has a net positive economic effect.
- **Reliability transmission network investments**: these investments are made with the intent to maintain planning reliability criteria[20]. These criteria tend to vary by region and either match or exceed national standards set forth by NERC. In many cases TSOs have stringent reliability criteria that have been carried over from vertically integrated regimes of the past.

When considering a system need that could be satisfied with a transmission investment, there is often also the possibility of non-transmission alternatives that could serve the same purpose, in some cases at a lower cost. These alternatives take a variety of forms including but not limited to end-use efficiency, demand response, generation (including distributed generation), storage technologies, and improved capacity of the transmission system using operational schemes or more-efficient technologies within existing corridors. Each of these non-transmission alternatives (NTAs) has distinct trade-offs associated with it. For example, except in the case of centralized generation, NTAs avoid the siting, permitting, and "NIMBY" challenges that often make transmission investments so hard to execute. On the flip side, customer participation poses challenges to demand response measures, and batteries have a whole host of desirable traits but are very expensive (NCSL 2009). The point here is simply to recognize that big

[18] Many modern markets, perhaps for convenience, have neglected transmission losses in their models.
[19] This type of line is supported by general economic theory, but a more rigorous examination of the economics reveals serious problems for merchant transmission. For a more in depth discussion, see (Joskow and Tirole, 2005), "Merchant Transmission Investment."
[20] Not the same as operating reliability criteria.

transmission projects are not always the only way to achieve certain goals. Though it can make the planning process significantly more complex, it is probably also worthwhile to consider NTAs as solutions to power system needs (Kaplan 2009).

2.4 Who Builds Transmission?

In the United States investment in transmission infrastructure can take place in one of two regulatory paradigms, depending on the regional industry structure (i.e. traditionally regulated vs. restructured). In a traditionally regulated region, a vertically integrated utility will centrally plan local transmission expansion. Once the plan is approved by the relevant State Utility Commissions, the utility builds the lines that have been proposed and recovers the cost – plus a rate of return – by including them in regulated retail rates. In a restructured region on the other hand, there is far more latitude for different investment schemes because multiple parties may own, build, and operate transmission assets.

To best think about the range of possible types of transmission investment in a restructured environment, Coxe and Meeus have proposed a useful framework. Within this framework, different investment types are sorted into a matrix based on the nature of the developer/owner and how the costs are recovered:

		Cost Recovery Type	
Investor/Operator Type		ISO-Tariff Financed	Non-Tariff Financed
	Incumbent Utility	"Type 1"	"Type 3"
	New Entrant	"Type 2"	"Type 4"

Table 1: Investment types under restructuring

A brief discussion of each type of project is provided below, including a discussion of their relevance and prevalence in the US context (Coxe and Meeus 2009):

- **"Type 1", Incumbent Investor, ISO-Tariff Financed:** These projects ensure cost recovery through the regulated ISO tariff and are the most similar to transmission investments made under traditional regulation. The details of this cost recovery vary from ISO to ISO and may have different rates of return on equity and different allocation to network users. Type 1 projects are identified through the ISO planning process or through proposals from incumbent transmission utilities, and may fulfill generator interconnection, reliability, or economic needs. In particular, interconnection and reliability projects are well suited to be undertaken by incumbent investors as they require upgrades to existing capital and use of existing rights-of-ay. In restructured regions of the United States, nearly all transmission development takes place under this scheme.

- **"Type 2", New Entrant, ISO-Tariff Financed:** Like Type 1 projects, these projects recover their costs through the ISO regulated tariff. Unlike them, Type 2 projects are usually proposed by new entrants, parties who do not currently own transmission in the region in question. Type 2 investments are best suited to economic projects that involve the creation of major capacity additions on new rights-of-way. New entrants may also have technical, commercial, or financial resources that are greater than those that could be brought to bear by the incumbent. This advantage may be particularly important in cases where rapid transmission development is desirable, as may be the case if large quantities of distant renewable generation are to be brought online. In practice, this type of project is very rare as most suitable projects are undertaken by incumbent investors.
- **"Type 3", Incumbent Investor, Non-Tariff Financing:** For non-tariff financed projects, costs are recovered through contracts between specific users (i.e. beneficiaries) and the transmission owner that place a value on the rights to use a line. Network agents who finance the line then receive the incremental transmission rights. While the exact details of transmission rights vary between regions, the central idea – creating new transmission capacity to arbitrage prior locational price differences (which may be severely impacted by a new line) – holds. When an incumbent is investing in this type of line, the Type 3 structure is not unheard of in the United States. These projects are often regional or national interconnectors whose costs are recovered through contracts with specific users of inter-market projects. Also in the incumbent case, contract rates are usually tied to more traditional cost-of-service rate setting practices.
- **"Type 4", New Entrant Investor, Non-Tariff Financing:** Like Type 3 projects, investors in these projects recover costs through contracts with users. The distinction arises from the non-incumbent nature of the investor and the fact that the associated transfer of transmission rights comes in a wide variety of forms, ranging from long term contracts to direct sale on the spot market. Among the most visible Type 4 investment are "merchant" projects, for which transmission rights are sold in a negotiated or competitive process[21].

[21] "Merchant" lines are not limited to lines that arbitrage energy prices in different locations. They may also the outcome of negotiations between a promoter and a group of beneficiaries of a proposed investment, who are willing to invest in it. This applies to both "Type 3" and "Type 4" projects.

This thought framework for transmission investment presents the major ways in which transmission is built in restructured regions of the US. As the goals of the system have and continue to change over time, different levels of each type of investment may prove necessary to best serve the goals of the network. In the discussion about adequacy, it is useful to understand the mechanism by which transmission is put in place in order to gain insight into where there may be barriers to adequacy or opportunities to improve from the present situation.

3 What is Transmission Adequacy?

Before proceeding further, and for any progress to be made towards drawing conclusions, it is necessary to propose exactly what may be meant by "adequacy." Perhaps the best way to approach this challenge is to describe adequacy in the context of the goals of building transmission. Then, independent assessments can be made as to whether each goal is being met. Having laid out the specific types of transmission investment above, the four goals put forward are a reduction of those to fit a more concise framework. The proposed goals for transmission investment are: generator interconnection, reliability, economic, and policy advancement[22]. The general characteristics of each type of line are described below along with a short discussion of what is known about how they play into the adequacy argument. Any hypotheses presented will need to be revisited once data has been collected that either rejects or confirms their accuracy.

- **Generator interconnection lines**[23] simply allow for new generation to reach load. These lines may be just shallow interconnectors or include deep network reinforcements. A fair hypothesis is that, at the very least, sufficient transmission lines are built to deliver the full capacity of a new generator to the grid at the point of interconnection. Thus, adequate quantities of this line type are available. In some cases, deep reinforcements may be required for reliability or economic purposes, and those will be addressed next.
- **Economic lines** are built to increase the economic efficiency of the transmission system and enable the flow of less expensive electricity to load[24]. In theory, economic lines should be built whenever the total benefits to generators and loads are greater than the cost of the investment in new capacity. Though current transmission regulations in many regions of the United States allow economic lines to be built both as merchant facilities and as regulated cost recovery facilities, very few economic lines are actually built and labeled as such. It is unclear why this is the case. Here, there is room to explore whether or not the current system is adequately invested to achieve its economic goals. If there are economic lines that are not being built that would have a net benefit to the system, then that would be an indication of underinvestment.
- **Reliability lines** ensure that the transmission system is built to reliably serve load and are based on standards promulgated by FERC and NERC. Since these standards are mandatory and there

[22] These goals are different from the six categories of transmission investments laid out in a previous section as proposed by Joskow. Some of the prior categories have been combined as the distinctions are unnecessary for this purpose and the policy advancement category has been added as it is a relatively new idea for why to build lines that may be more common in the future.

[23] "Generator Interconnection Lines" has the same meaning in the literature as "Generator Connection Lines".

[24]The distinction between "reliability" and "economic" lines is hazy and the division is a function of reliability standards and not any analytically rigorous reasoning. This will be elaborated upon shortly.

are planning processes in place to ensure that all such lines are built, it can also be assumed that reliability goals are being met by definition. Nearly all transmission projects built in the US today are built for reliability's sake, or at least labeled as such. As described further in the following section, it is even possible that the United States is overinvested in reliability lines. Regardless, reliability is ultimately a political issue and as long as the transmission system is meeting politically established reliability standards the system may be considered reliable, independent of whether certain parties may be happy with that level of network availability. This reasoning would support the hypothesis that there is currently not a problem with adequacy in reliability investment.

- **Policy lines** enable the realization of policy goals, whether they are state or local, energy focused or environmentally focused. While policy lines may have reliability and economic impacts, they may not be necessary for achieving other system adequacy targets. For example, long transmission lines that service wind generators and carry electricity from windy plains to distant cities may not provide clear economic benefits or be necessary to satisfy system reliability – or even environmental – requirements. That said, they may be necessary to help fulfill a renewable portfolio standard or to meet a carbon emissions cap[25]. This class of lines is not yet formally recognized in most parts of the United States[26] (especially because there is not yet a national energy policy impacting the need for low carbon resource utilization), so it is not yet meaningful to discuss whether the country is adequately invested in these types of lines. Nevertheless, the proposed research may be able to provide insight onto whether the current regulation will support the installation of policy lines or if new or different policies will be required to enable such lines to be built.

It is recognized that a vast majority of potential useful reinforcements of the existing transmission network will have an impact on both economic and reliability goals. Some projects will also contribute by connecting generators to the system and helping to meet policy goals. Transmission plans consist (or should consist) of suites of lines, which together achieve a future network able to meet all four objectives. In most cases it is conceptually very questionable, strictly speaking, to isolate a line in the plan and to assess its contributions to each of the four objectives, reliability and economics in particular. However, what is done in practice and how transmission plans are publicly presented may deviate from the

[25] The chosen policy can significantly alter the nature of policy lines. For example, a sufficient carbon price could make wind the most economic form of generation, which in turn would reduce many "policy" lines to economic lines, as they would be minimizing production cost. Alternatively, and RPS could force the construction of new wind farms which, once built, could again shift transmission construction to an economic basis as zero marginal cost wind would be the cheapest energy available (assuming wind power bids into a market at marginal cost).

[26] The FERC Notice of Proposed Rulemaking of June 17, 2010 (docket number RM10-23-000) is a strong step towards formal recognition of this type of transmission project.

theoretical ideal. Having acknowledged this, but also in recognition of the fact that the partition of system goals allows for a more structured piecewise analysis, this investigation will move forward with the understanding that even if individual lines cannot theoretically be divided into buckets, the system's ability to fulfill goals can be (at least to first order).

Based on this discussion, an adequate transmission system will be defined here as one in which all of the required or justified investments are made to fill interconnection, reliability, economic, and policy goals. From the discussion above, it is reasonable to assert that interconnection and reliability lines probably exist at adequate levels; generators must connect to the grid and reach the loads and reliability lines are built to federally mandated standards. Of course, these assertions should be confirmed. At the same time, there are not yet national goals that would require the widespread construction of policy lines, so the primary goal in this respect should be to examine the ability of current regulation to support them. There also appears to be an open question about whether economic lines are being built and economic goals are being met. Since very few lines are built on economic grounds alone, data about the economic efficiency of the electric system is sparse, and there is not much clarity around whether there are additional economic lines that are studied but not built; this topic warrants further study.

3.1 Reliability of the US Transmission System

It is worth making a more general comment about the reliability of the US transmission system. While an in depth discussion of reliability is beyond the scope of this paper and quantifying reliability is challenging both within and between regions, it is safe to say that the power system (i.e. transmission, distribution and generation) in the United States is very reliable. Depending primarily on whether an area is rural or urban, electric power is available between 99.0% and 99.9999% of the time (Institute 2003). For the purposes of most system users, this is a reasonable level of reliability to expect. When something goes wrong, power interruptions can be a result of generation, transmission, or distribution level failures. While generation and transmission faults have the potential to affect many more people, most outages are caused by the distribution system (Chowdhury 2009).

For the transmission system, mandatory reliability criteria are established by NERC and incorporated into the planning and operation schemes for the network. A common goal in the US is the "1 day in 10 years" criteria, whereby transmission plans are designed to expect one day of transmission-caused outage every ten years[27]. All of this reliability comes at a price, though, and additional investments become significantly more expensive for each additional unit of reliability. Determining exactly the right level of reliability is challenging for technical, economic, and political reasons, but several experts have suggested

[27] This definition is heavily impacted by the presence of demand response resources and begins to lose meaning.

that the United States has invested in reliability at a level that is actually too high. More specifically, the price we pay for reliability in new investments – as indicated by our payments for generation capacity – may be as much as an order of magnitude greater than the implied cost of interruptions to load (Hogan 2005).

3.2 The Confounding of Reliability and Economics

What exactly constitutes the distinction between economic and reliability investments is not clear and worthy of discussion, especially when attempting to understand current patterns of transmission investment in the United States. In theory – and assuming that the optimization criterion is cost minimization subject only to some reliability constraints – optimal transmission investment would involve construction to the point where the marginal cost of new transmission capacity is equal to the marginal benefit of reducing congestion and losses while meeting the reliability constraint. Put more mathematically, for a given hypothetical generation expansion plan transmission[28] projects should be planned to simultaneously minimize the cost of transmission construction and the variable costs of generation while staying within predetermined reliability levels[29]. In the future, additional criteria may be added to satisfy policy goals (e.g. carbon reduction, renewable mandates), but such policies have not yet been enacted at a national level.

Done properly, results of such a transmission planning approach should encompass both economic and reliability concerns without a clear delineation between the two; economics being captured by the cost minimization function and reliability being captured in the form of the cost of lost load (or as an exogenous constraint). Furthermore, a line justified by an economic criterion will very often impact the reliability, and vice versa. For example, an economic line will likely make the system more reliable and a reliability line may reduce future congestion costs experienced by the network. This point may be illustrated by MISO's 2009 transmission expansion plan, which included $4B worth of exclusively reliability lines that were expected to provide nearly $3.4B in economic benefits (MISO 2009). These

[28] Under a competitive regulatory framework, there is much uncertainty regarding generation investment which both affects and is affected by transmission expansion. Still, the objective of planning is the same.
[29] An alternative approach to addressing reliability during transmission planning is to minimize the cost of lost load (i.e. the cost of unreliability) rather than planning within a set reliability constraint. Lost load, also known as unserved load, is unmet demand for electricity. Lost load may take the form of blackouts or brownouts and it is customarily given some pre-established value (e.g. $10,000/kWh). The cost of lost load is calculated by multiplying the probability of lost load (e.g. "once in ten years") by its value. When incorporated in the planning process, the objective of minimizing the cost of lost load takes the place of satisfying reliability constraints. Planning processes in the United States use the latter approach. Note that the two results do not necessarily have to coincide.

strong interdependencies make transmission investments conceptually difficult to parse and indicates an analytical flaw in the fact that there is a distinction drawn between the two (Joskow and Tirole 2005)[30].

If the theoretical distinction between reliability and economic line is so hazy, then why is it so common that transmission planning and investment make it? And what's more, why are so many lines justified under reliability considerations and so few justified by economics alone? The answer can be explained by a number of factors:

- Economic lines may be politically undesirable from the utilities' standpoint because economic lines often do not qualify for broad based – or "socialized" – cost recovery. Utilities must determine who is benefitting from an economic line and allocate the costs accordingly. This cost allocation is not simple and leaves the utility open to court challenges from parties who may not be interested in shouldering the cost of a line or who may be negatively impacted by a certain line's construction, a process that may delay construction indefinitely.
- It may be challenging to demonstrate that a line is clearly economically desirable as it can be very difficult to isolate and valuate all of the benefits of a given transmission investment (Pfeifenberger, Fox-Penner, and Hou 2009). Uncertainty about future network conditions, fuel prices, or government policy can also cloud the output of a cost-benefit calculation.
- So few economic lines may be built because the reliability standards are written in such a way that they include all investments that may be obviously economic (i.e. regardless of risk), thus leaving few lines to be built under the guise of economics.

Most likely, all of these challenges feedback on one another and lead to a system where utilities shy away from trying to justify a line as economic in order avoid the technical, financial and administrative burden or having to prove a line's worth and determine who pays. Instead, obscure rules for justifying reliability lines are created that ensure that all of the most desirable lines are built while minimizing exposure to external challenges to investment (Joskow 2005). In short, the reliability/economics distinction ensures that lines are built and the system continues to function reliably[31]. For the sake of this analysis, the distinction will be taken as given though its continued use may be challenged if the findings suggest it negatively impacts future expansion or current status.

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[30] Suggested changes to this framework may be made later, but will not be addressed here.

[31] While practical, this system also creates particular challenges for certain types of investments. For example, inter-RTO investments, which are often evaluated as economic lines, may face significant institutional hurdles in a system built to better support reliability lines.

4 A Critical Assessment of the Conventional Wisdom

This chapter will review the major metrics that are often cited as indicators of the current level of investment in the transmission system. In each case, an interpretation of the data will be presented that reflects the literature and in most cases leads industry observers to believe that there is underinvestment in the transmission system. Following each argument will be a discussion of whether the metrics presented are actually a legitimate way to assess infrastructure adequacy. The focus will be both on assessing whether certain metrics are appropriate for drawing conclusions about adequacy as well as what they may or may not indicate as a conclusion. What will be found is that many of the indicators that are traditionally used to assess the situation with transmission do not actually have much utility when it comes to drawing a definitive conclusion about adequacy. The remainder of the data is either inconclusive or – to echo earlier concerns about data availability and quality – not sufficient to support an answer on the matter.

4.1 Data Challenges

Before diving into the data presented as evidence about adequacy of investment in the transmission system, it is imperative to make a comment about the data itself. In short, the availability of data is very limited and what data does exist is often incomplete, inconsistent, or only available for time series so brief as to significantly diminish their utility. In an environment where the way the industry functions is changing rapidly, there is a need for more and better data on which to base public policy decisions. This is a serious problem that has been recognized by both industry (Energy Security Analysis 2005) and the government (US Department of Energy 2004)[32]. Ultimately, it is this lack of coherent data that makes this current discussion necessary; if there were clear metrics and quality data about transmission investment, the questions being addressed here would probably be closed.

To cope with the data quality issue, this section attempts to do the best with what is available. Each data set presented will be internally consistent and any deviations from this standard will be noted clearly. Occasionally, time series may be limited to certain years as data collection methods changed over some periods and did not exist in others. In some cases, there may be inconsistencies between two data sets reporting the same quantity, but when this happens inconsistencies are usually small and are merely an annoyance. For the most part, the general trends in the data are accurate and convey the correct message.

[32] This source, the 2004 DOE study, "Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis" provides the most thorough discussion of this issue and makes clear recommendations for improved data collection and availability.

Further, whenever possible graphs are presented that use data gathered by the author to ensure that the origins of the data are as well understood as possible.[33]

4.2 Falling Capital Investment and Failure to Hold Pace with Load Growth

In the decades leading up to the year 2000, it was clear that there were falling levels of investment in the US transmission system (Figure 7). In response to data published by the Edison Electric Institute (EEI), there was a great deal made of the fact that transmission investment had been diminishing at the rate of nearly $50M per year, on average, for some time (Hirst 2000). Since then, there has been a significant and sustained increase in the number of dollars invested annually in the transmission system on the national level. Consequently, less has been voiced recently over this statistic and concern has shifted towards other possible indicators of underinvestment.

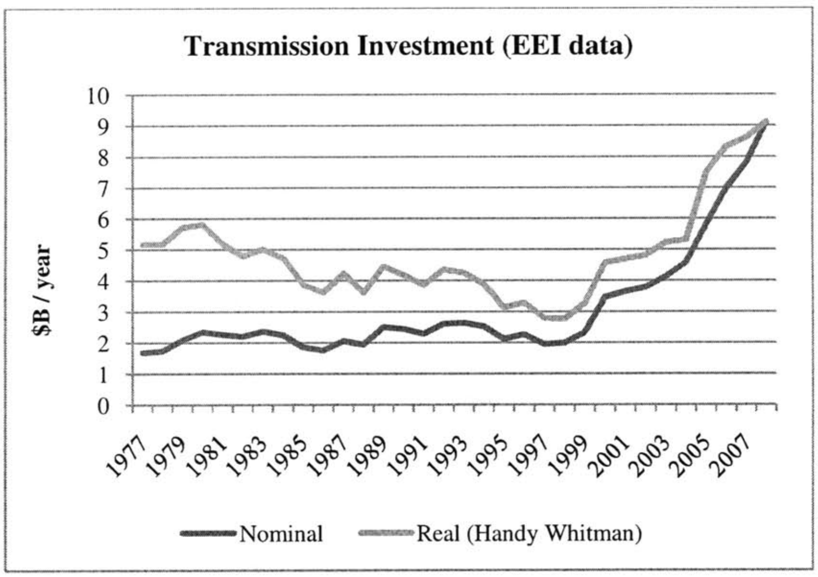

Figure 7: Transmission Investment Based on EEI Data[34]

There has been some speculation around what caused two decades of ever decreasing investment followed by a rapid upswing in the trend starting around 2000. It is likely that falling investment in the 1980s and 1990s was the result of a convergence of factors. In particular, it is possible that the Public Utility Regulatory Policies Act of 1978 (PURPA) created the concept of Qualifying Facilities (QFs) and greatly stimulated investment in cogeneration plants and renewable generators[35] (Holland and Neufeld

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[33] In the name of transparency and to further shed light on the challenges with the data, a longer discussion of specific sources and data sets can be found in the appendixes.

[34] FERC also collects this data back to 1994, and maps very closely to the EEI data. "Handy Whitman" refers to the Handy-Whitman Index of Electric-Utility Transmission Costs that is used to adjust for inflation from year-to-year in the EEI data sets.

[35] For a more detailed description of PURPA and the events leading up to and following the Act, See Appendix G

2009). Since the largest of these generators are often placed close to load – thus requiring less transmission for interconnection purposes – and since generation can act as an alternative to transmission, less transmission would have been necessary.

Investment in transmission would have been further impacted by the events of the 1970s, which included slowing load growth, growing doubts over the economic merits of nuclear power[36], and regulatory hesitancy to allow recovery for all costs[37] (US Department of Energy 1991). The declining momentum surrounding infrastructure expansions is also particularly stark as it falls in the shadow of the prosperous years for the electricity system following World War II, which were thought to end in the mid 1970s and were characterized by rapid load growth, falling energy prices, and technical innovation (Holland and Neufeld 2009). During these prosperous years, investment was further stimulated by ongoing projects by the federal government to bring cheap power to the people, including the creation of the Federal Power Authorities and rural electrification initiatives. Following the post-war period, it is also possible that prior overinvestment also diminished the actual need for new transmission as excess capacity may have been available to serve load growth needs for some time.

It is less clear what has caused the recent rise in investment[38]. It is interesting to note that the investment increase is not localized to any single region – though the Western Interconnect has seen a larger than average increase – but that a similar change has been experienced by nearly every part of the country (Figure 8). Literature on this topic is less forthcoming, but some possible explanations could include restructuring and the actions of ISOs making up for lost time, broader planning processes, or the lag between the construction of large quantities of new generation and their connection to growing load. Also, incentive based ratemaking introduced in EPACT 2005 and promulgated by FERC later that year may be responsible for the continued uptick in investment in the mid 2000s.

[36] Many nuclear power plant projects began to experience massive cost overruns and regulatory delays. Hesitancy over new nuclear construction would impact transmission investment, as nuclear plants require large transmission projects to support their significant generating capacity. They are also often sited in remote locations.

[37] With the national power crisis of the 1970s, electricity prices had risen faster than the price of inflation. Public backlash over rapidly increasing energy prices led regulators to deny recovery of some costs, making infrastructure projects less attractive to financiers.

[38] The time period corresponds with some liberalization actions, but the effect of this relationship is unclear. During the early years of restructuring (the late 90s and early 2000s), some of the lull in investment may have been a result of initial confusion about how to plan transmission under a regime where generation construction was uncertain and left to the market.

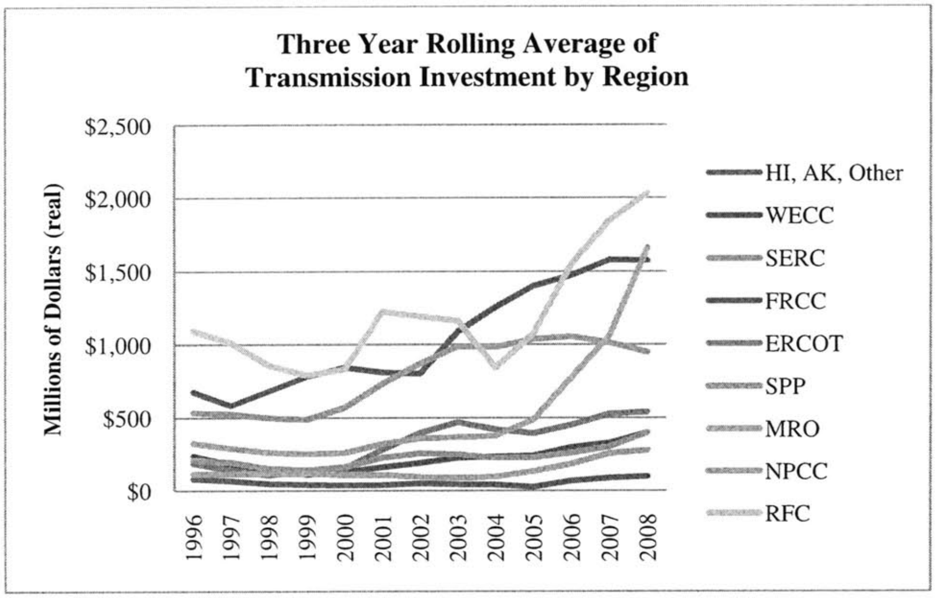

Figure 8: Three Year Rolling Average of Transmission Investment by Region, FERC Data, Adjusted for Inflation Using Handy-Whitman Index

The immediate concern associated with falling quantities of transmission investment is that transmission capacity may not have kept up with load growth on the system. The relevant curves used to illustrate this point are the number of transmission miles and the total transmission capacity[39] (Figure 9), weighted by the summer peak load (Figure 10). This curve displays a downward trend starting in 1982 (Hirst 2004) and continuing through the present, regardless of the continued growth of transmission capacity and the uptick in transmission in dollars invested. In addition, the falling level of transmission capacity relative to load is apparent not only on the national level, but also holds across every NERC region (Hirst 2000).

First, it may be nonsensical to assume that 1982, when the MW-miles per GW of peak load statistic was largest, was somehow a more desirable, more sufficient state. It is fully possible that that represented an overinvestment in system capability. In particular, if the regulatory regime at the time allowed an overly-generous rate of return on capital, firms would have been incentivized to have an above-optimal transmission to generation ratio (Brennan 2006). It is also possible that new technology and system operation schemes are better able to use available capacity to fully, efficiently, and reliably serve load. Furthermore, technical advances over time have allowed for the system to be used much closer to its theoretical limits, effectively increasing the capacity of every line in place. These improvements have been a result of the fact that understanding of the system state has shifted from an operator looking at a

[39] Details for how this calculation was done can be found in Appendix D.

frequency readout to advanced systems that provide second-by-second data on the status of the network (Moeller 2010).

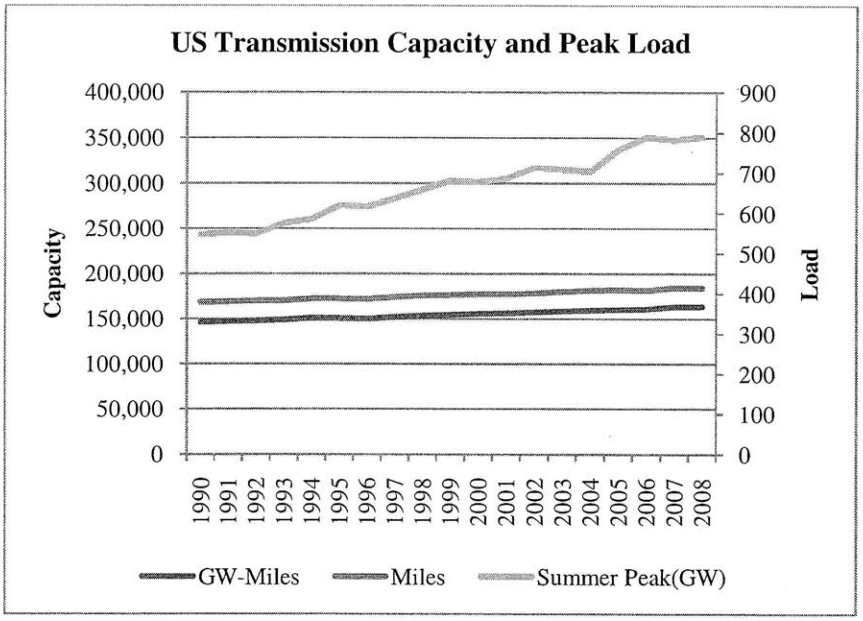

Figure 9: Transmission Capacity and Peak Load based on EIA and NERC Data

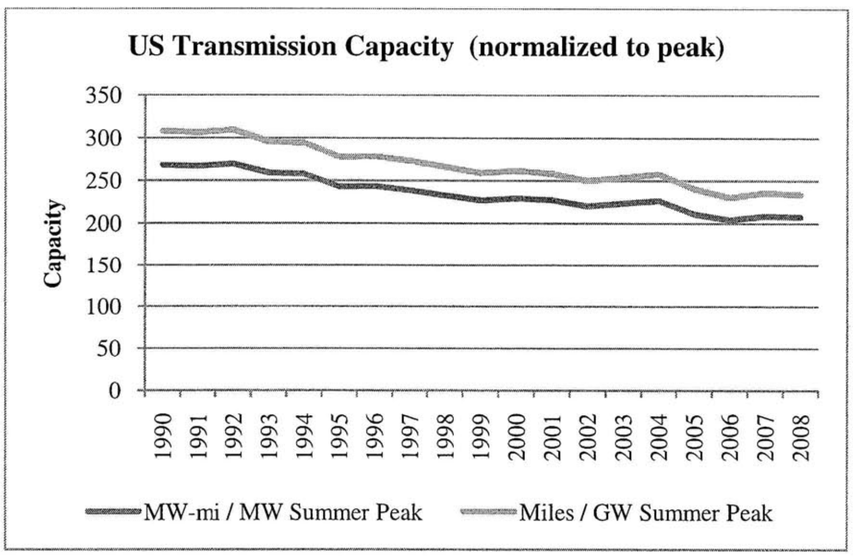

Figure 10: Normalized Transmission Capacity Based on EIA and NERC Data

There are also a number of reasons why the size of the physical transmission plant, or the dollars invested therein, is a poor proxy for making a determination about adequacy of investment in the network. For instance, examine the issue of using line length or capacity as an indicator of sufficient transmission infrastructure. As was discussed above, many hardware upgrades – relays, switches, capacitors, substations, transformers, etc – would not show up in a measure of line length. Moreover, reconductoring of lines with higher capacity cables or replacing antiquated infrastructure would also not show up in this measure. Likewise, these statistics do not consider non-transmission alternatives that may also be substituted for transmission if circumstances make such an option more desirable. In an environment where it is very difficult to plan and site new transmission lines, it makes sense that requirements for transmission capacity may have been filled using the above "zero-length" types of investments, though data to support this supposition is rarely collected and therefore scant (Joskow 2005).

In some cases, there is no choice but to build new transmission capacity on new rights-of-way (ROW). This is true when a new power plant is built on a greenfield site and must be interconnected with the existing network. Here emerges another reason that less – not more – new transmission capacity may have been required over the past few decades. In the 1960s, 1970s, and 1980s a lot of new generating capacity came online in the form of coal and nuclear plants, which tend to be located far from load centers for environmental, safety, public perception, and resource availability issues. Along with hydro and wind generators, these will be termed "long distance" generation for the sake of this discussion. On the other hand, gas fired power plants tend to be located very close to load centers as their physical footprint is significantly smaller and they may be sited more easily. Along with oil generators, these will be termed "short distance" generation. Figure 11 shows that natural gas is, in many cases, much closer to load centers than the next closest traditional source of electricity, including hydro, coal, and nuclear generating stations[40].

[40] A more detailed description of how this analysis was done can be found in Appendix D.

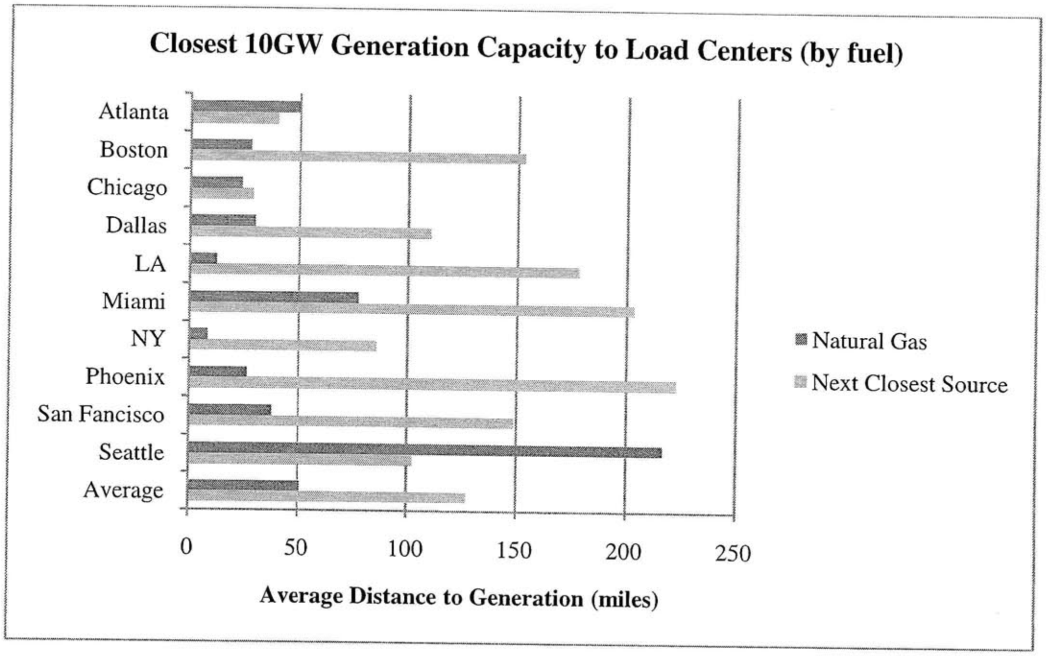

Figure 11: Proximity of Natural Gas Generators Relative to Other Traditional Electricity Sources

For both environmental and economic reasons, the 1990s and 2000s have seen gas generation capacity increase by more than 200 gigawatts (Figure 12). Meanwhile, capacity of long distance generation has remained nearly constant[41] (Figure 13). The implication of these facts for transmission is that most new generation today – and over the past two decades – does not require nearly the same magnitude of investment that coal and nuclear plants called for in previous decades. Given this decreased requirement for generator interconnections, one might expect the observed decline in both new miles of line installed and line capacity available, even relative to peak load (Huntoon and Metzner 2003).

[41] Coal is polluting and hard to permit, not to mention pending environmental legislation may make it more expensive to emit greenhouse gasses. Nuclear is contentious and expensive. Hydro resources are limited and many have already been tapped in the US.

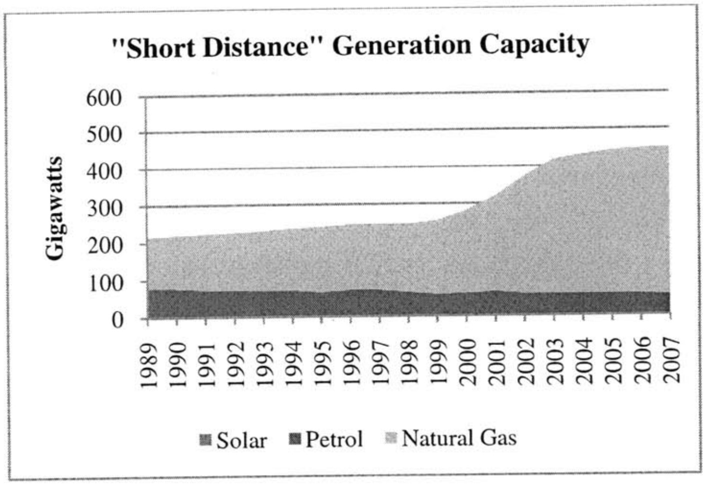

Figure 12: "Short Distance" Generation Capacity in the United States based on EIA AERs

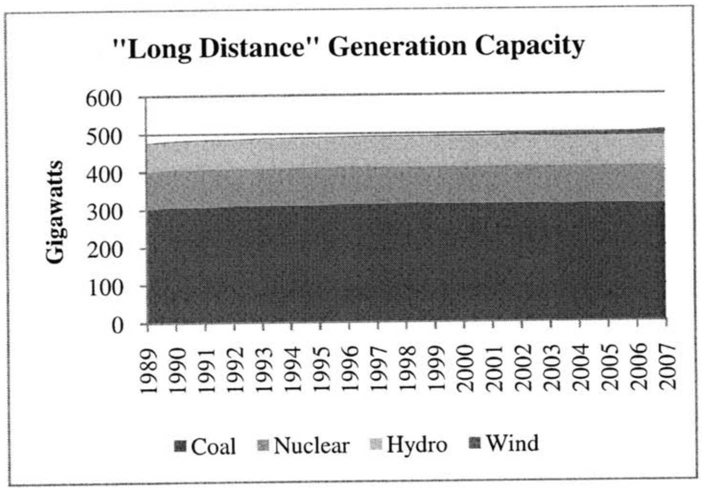

Figure 13: "Long Distance" Generation Capacity in the United States based on EIA AERs[42]

Having set aside transmission line miles and line capacity as metrics that do not lead to an answer on infrastructure adequacy, we may, in turn, do the same with capital investment in the system. As capital invested is strongly tied to capacity installed, all of the same arguments hold (though capital statistics may capture NTAs and "zero length" investments). Furthermore, there are other economic factors that change over time that additionally complicate using dollars invested as an indicator of adequacy. For example, the cost of raw materials changes over time. This may be captured by indexes used to account for inflation, but not all factors can be accounted for so easily. For instance, as regulation changes, transaction costs associated with transmission, like permitting and litigation, also change. Similarly, load growth in urban areas can exhaust the capacity of existing corridors, forcing the use of more expensive

[42] Here, wind is growing at an exponential rate relative to itself, but it is still dwarfed by conventional generation capacity. Solar is also present in the "Short Distance" plot, but its presence is vanishingly small.

technology (e.g. underground transmission lines) or the purchase of new, costly ROWs. All in all, while statistics on the physical transmission network may indicate general trends in the system, it would be difficult to reach any conclusions as to whether or not the US is adequately invested in its electricity infrastructure.

4.3 Operational Data as a Possible Indicator of Underinvestment

Moving beyond physical capacity metrics, the data have also been interpreted as suggesting that falling economic efficiencies and operational shortcomings are indicators of system underperformance. On closer examination, operational metrics lead to a similarly inconclusive result about transmission adequacy.

4.3.1 Transmission and Distribution Losses

First, losses in the transmission and distribution system have been increasing steadily on an absolute basis (Figure 14). Rising losses are suggestive of a system that is operating closer to its thermal limits, where resistive losses are higher per unit of energy transmitted. This is usually seen as undesirable, as losses are costly and the transmission system is at higher operational risk of instability when it is operating very close to its limits. MISO, for example, cites reduced losses as a major driver for the construction of new lines in their annual Midwest Transmission Expansion Plan (MISO 2009). Note that transmission and distribution losses are not available separate from one another and it is generally understood that a large proportion of the losses take place in the distribution system, a fact that significantly reduces the value of this information.

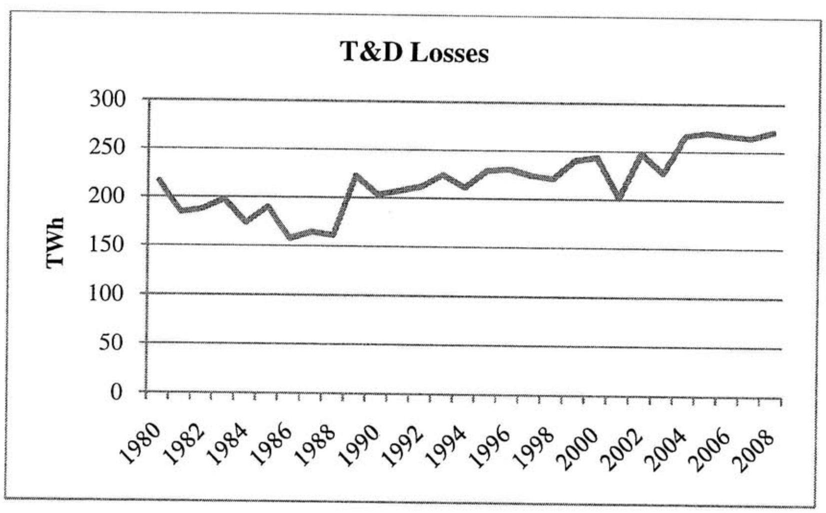

Figure 14: Transmission and Distribution Losses Based on EIA AEO Data

Looking at the data on a relative scale (Figure 15), on the other hand, leads to a different conclusion; losses are actually decreasing over time when observed relative to total electricity delivered. This may be a result of better technology in the network, more advanced operation schemes, or proximity of new generation to load. Regardless of the reason, transmission losses do not point strongly towards underinvestment. This is not to say that they indicate adequacy either, but for the purposes of this discussion they do not help us arrive at a conclusion.

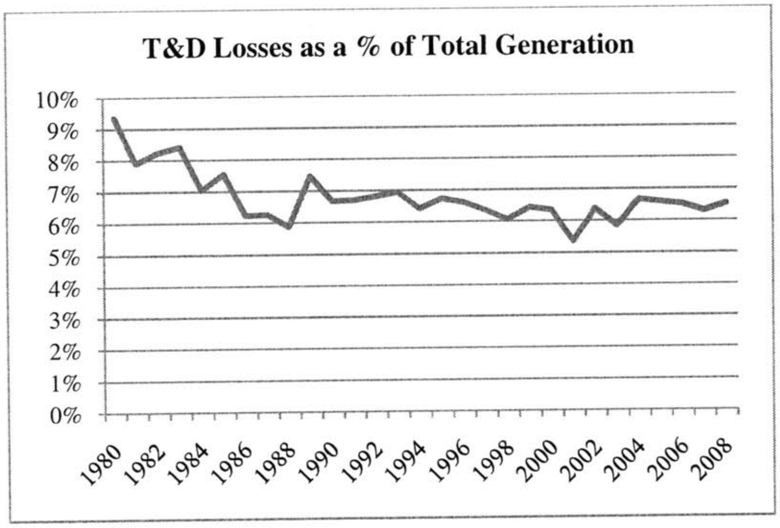

Figure 15: Transmission and Distribution Losses Normalized to Total Generation in Each Year

4.3.2 Transmission Loading Relief Events

Second among the system operation metrics, there have been a rising number of instances where transmission operators have had to reconfigure (re-dispatch) the power system to deal with congested lines (i.e. lines whose capability to carry power within reliability limits would otherwise have been exceeded). When a line is congested, NERC has a set of approved actions to deal with the situation called Transmission Loading Relief (TLR) procedures[43]. TLR events, or "calls", have six different levels, of which all calls over Level 1 (the least severe) are reported and published. The data show the number of TLR calls rising dramatically since the procedures were first formalized in 1997 (Figure 16). Concerns arise over the fact that large numbers of TLR calls interfere with market efficiency and increase consumer cost by denying access to least cost resources. The general thought is that increased transmission capacity would alleviate the congestion that creates a need for TLR calls (US Department of Energy 2002).

[43] A far more detailed description of TLR procedures can be found in Appendix B.

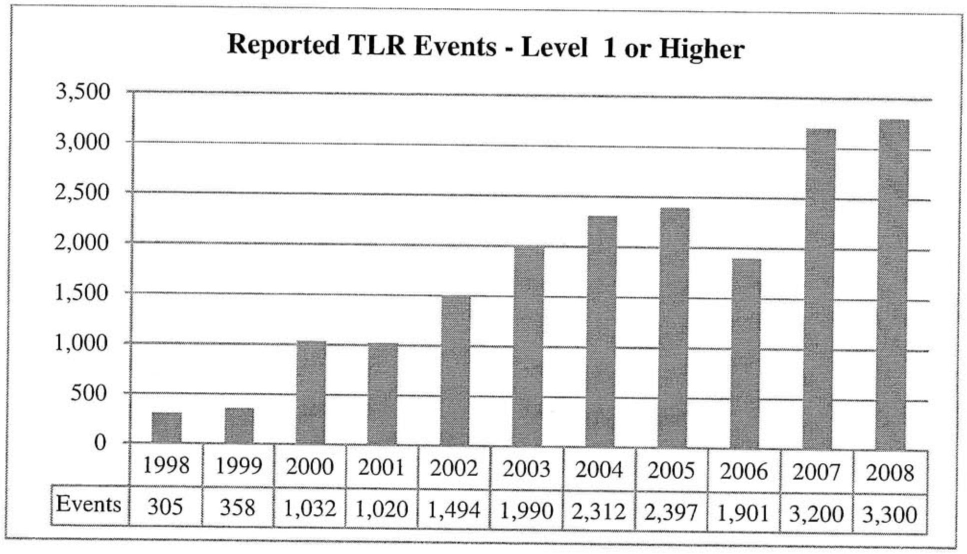

Figure 16: Transmission Loading Relief Events of Level 1 or Higher Based on NERC Records

A critical assessment of transmission loading relief (TLR) statistics involves a more complex discussion. While it is true that TLR calls have increased many times over in the years since they were first institutionalized in 1999, the frequency of events has not been evenly distributed across the country (Figure 17). As the matter of fact, the vast majority of all events have been reported by just a two authorities, the Southwest Power Pool (SPP), and the Midwest Independent System Operator (MISO). There are several significant explanations for this regional disparity as well as a few other reasons that TLR events may not be a good indicator for adequacy.

Transmission loading relief procedures may be heavily influenced by the operational structure of the power system in a region. One of the benefits of creating ISOs with wholesale markets for electricity is that the presence of markets facilitates trading and can influence the administrative need for TLRs, which are unnecessary when re-dispatch services are available. Three trends in the data evidence this point:

1. SPP's rapid rise in TLR calls started in February of 2007, when SPP implemented its Energy Imbalance Market (EIM). Under EIM's protocols, SPP as a reliability coordinator is required to issue a TLR event report every time congestion is experienced anywhere in the market footprint[44]. Because the market allows for more complete (and efficient) use of transmission capacity, more TLRs are experienced under the market regime. Prior to EIM, congestion was resolved with re-dispatch by balancing authorities and TLRs were not called (NERC 2008).

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[44] The stated goal of this decision was to publicize the presence of congestion and ensure that parties that contribute to said congestion participate in its relief.

2. PJM's increase in TLR calls before 2004 and decrease after as well as the drastic drop off of calls by MISO following 2005. The PJM curve was a result of the shift in 2005 by Midwestern utilities from operating in a pro forma open access regime to a wholesale market based regime under the PJM RTO (Chandley and Hogan 2009).
3. The MISO curve was again the result of a shift in administrative practice. In 2005, the Midwest ISO converted from operation as an RTO with an open access tariff based on contract scheduling to a centralized wholesale market. Immediately, the number of TLR calls declined and did not recover (Chandley and Hogan 2009).

Another issue surrounds which TLRs are considered analytically significant. Some would argue that the only TLR calls that are really important are those greater than Level 5. Level 5 and 6 TLRs are those that require curtailment of firm service[45], whereas all other levels entail the curtailment of non-firm service – service that was purchased from the outset with the understanding that it can be cut when necessary (Huntoon and Metzner 2003). Revisiting the data with a focus on TLR events that affect firm service, two things become apparent (see Figure 18). First, the events are yet again reported by just a few authorities, SPP (SWPP in data), MISO, and Entergy (ICTE in data). Second, the number of events is relatively small even where TLR calls are most common and "affect a minuscule percentage of all lines, curtail a miniscule percentage of all transactions, and occur a miniscule percentage of the time" (Huntoon and Metzner 2003).

The literature also suggests at least two other factors that may distort TLR statistics, weather and demand response. First, TLRs may be a function of regional weather differences. For example, north-south temperature differences can lead to unusual electricity flows. The unpredictability of weather and the resulting transmission constraints can cause congestion to shift over both short and long time periods, leading to the conclusion that "TLR calls may be affected more by trends in wholesale transactions than trends in peak demands" (Hirst 2004). Second, TLR statistics may also be distorted by demand response programs. In some NERC regions, use of demand response may be recorded as a reliability concern even if demand response is routinely used to control load (Kaplan 2009). These complicating factors make assessments of transmission capacity using TLRs even more difficult.

[45] This curtailment of service is quantifiable in the form of congestion costs, which are discussed in the next sub-section.

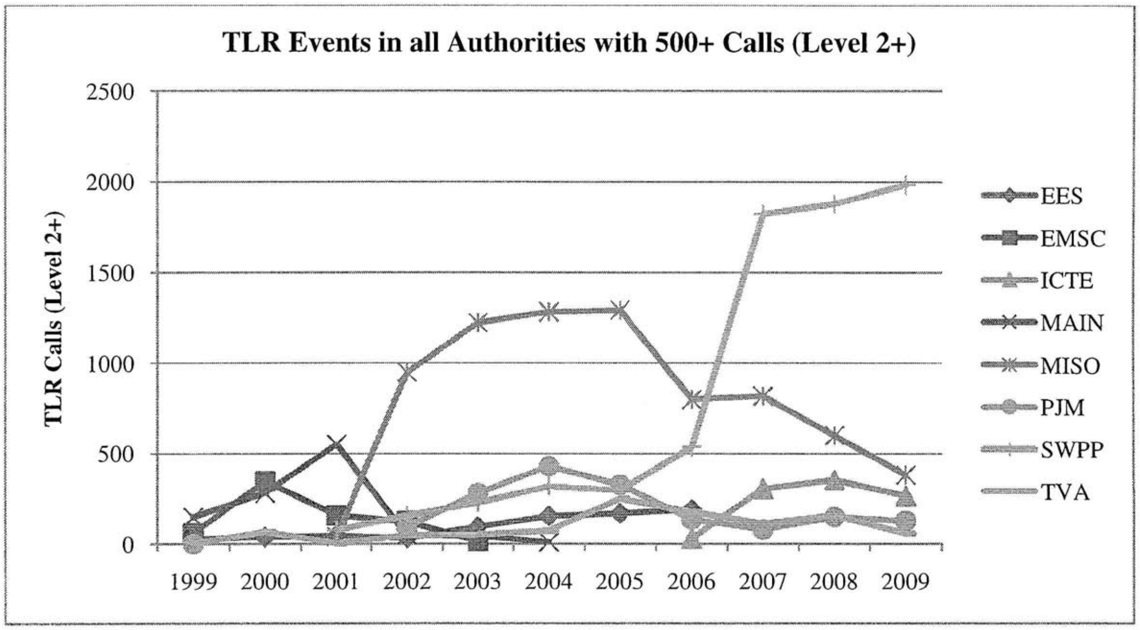


Figure 17: Transmission loading relief events in all authorities reporting more than 500 calls of level 2+

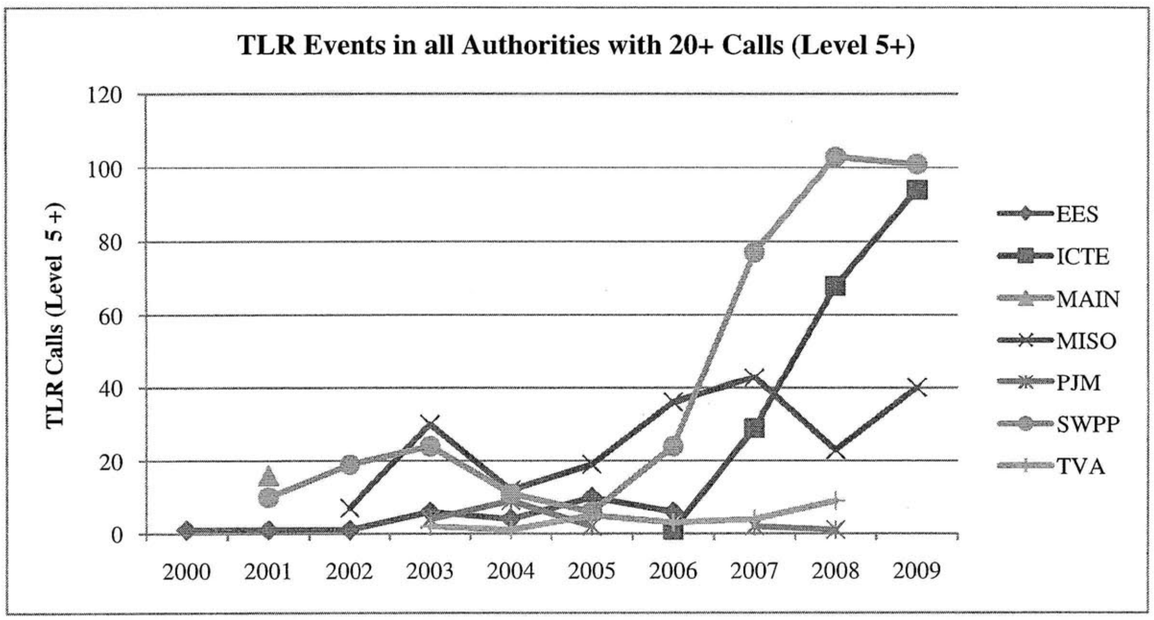


Figure 18: Transmission Loading Relief Events in all authorities reporting more than 20 calls of Level 5+

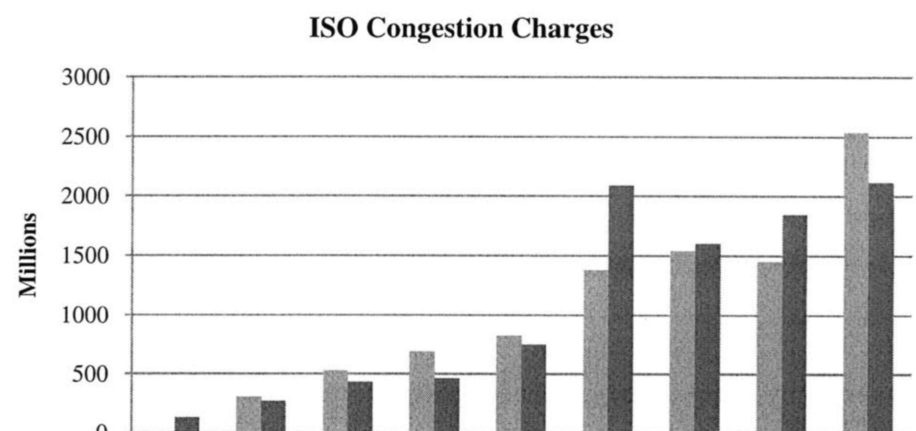
This discussion has led to the conclusions that TLRs may not indicate underinvestment, and probably are not useful in assessing adequacy[46]. The number of high-level TLRs is very low and concentrated in just a few parts of the country. In addition, it has been argued that the absolute number of TLRs holds minimal

[46] NERC's 2008 Long Term Reliability Assessment makes this point, too: "Note not all regions use TLRs to manage their electricity delivery systems and markets, and their use is neither an absolute nor a broadly applicable indicator of the need for transmission reinforcements." (NERC, 2008)

significance. Additionally, the way the system is administered can have a huge impact on whether or not TLRs manifest, it is hard to say that they do much more then tell us whether a certain operational structure is more or less prone to large numbers of curtailment events. All things held equal, increasing TLR events could indicate additional transmission constraints within a specific region, but it is rare in the current climate that regulation holds steady for long enough to arrive at such a conclusion.

4.3.3 Congestion Costs

A third indicator of decreased efficiency in system operation is congestion costs. As described above, congestion costs are a direct quantifiable measure of how far the system is from operating at its most economically efficient state. Congestion data is only available from restructured regions with wholesale markets for electricity, and PJM and NYISO are two RTOs from which the data is readily available[47] and follow the commonly cited trend: congestion costs are on the rise throughout the United States (Joskow 2005). Figure 19 shows that the past decade has seen significant costs incurred as transmission constraints have caused markets to operate far from their economic optimum.



	2000	2001	2002	2003	2004	2005	2006	2007	2008
NYISO		$310	$525	$688	$831	$1,382	$1,541	$1,451	$2,540
PJM	$132	$271	$430	$464	$750	$2,092	$1,603	$1,846	$2,117

Figure 19: Congestion Costs from NYISO and PJM Based on Market Reports

Yet again though, when the data are presented in a normalized format the rising trend disappears[48]. In this case, if congestion charges are viewed as a percent of total billing in the RTO, the trend is essentially flat (Figure 20) during the period for which PJM has run a market with locational price differences (which

[47] MISO (April 2005 market launch), CAISO (June 2009, re-designed market launch), and SPP (February 2007, launched energy imbalance service market) have not had an operating spot market for long enough to have data that is useful here.

[48] The data necessary to perform this normalization is only readily available for PJM and not for NYISO.

lead to congestion charges). Over time, PJM has grown geographically, load has increased, and electricity prices have gone up, all of which accounted for the rise in both total billing and congestion charges. Consequently, the ratio of congestion to total billing has remained constant and doesn't send any strong signal about investment adequacy[49]. It should also not be forgotten that FTRs are often used as a highly effective hedge against congestion. For example, in 2008 Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs) served as a hedge against 97.2% of the total congestions costs within PJM. So while the system was not operating free of congestion, financial instruments were able to significantly reduce uncertainty facing network users regarding price differentials (PJM 2009).

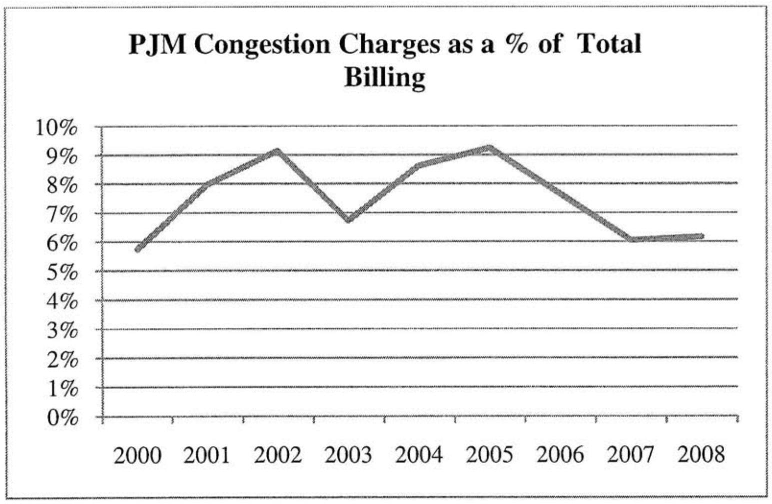


Figure 20: PJM ISO congestion costs normalized by total billing in each year

4.4 Major Network Incidents Indicate Unreliability and Underinvestment

The last of the commonly cited causes for concern over the adequacy of the US transmission network have been major events in the power system, in particular the California Energy Crisis of 2001 and the Northeast Blackout of August 14, 2003. For example, the DOE has this to say about transmission and the crisis in California:

> *"The lack of adequate transmission played an important role in exacerbating the problems created by the imbalance between California's supply and demand for electricity. Because transmission is constrained between the northern and southern portions of the state, the number of competitors able to provide electricity in each of these markets is effectively reduced thereby leading to higher prices...*

[49] Congestion costs also say nothing about the reliability of the system; they simply indicate where there is an economic opportunity that could have been realized with additional transmission capacity. Just because there are congestion charges does not mean there was a limited amount of generation available in the absolute sense, only that there was cheaper generation available elsewhere and that there was not enough transmission to allow all of the cheap generation to be accessed (Huntoon and Metzner, 2003).

transmission system upgrades remain an important element of a comprehensive, long-term solution to California's electricity system." (US Department of Energy 2002)

On the 2003 blackout, the Congressional Research Service (CRS) describes both concerns over infrastructure adequacy and the legislative response thereto:

"The blackout of 2003 in the Northeast, Midwest, and Canada highlighted the need for infrastructure improvements and greater standardization of operating rules. EPACT05 addresses some of the transmission issues by creating an electric reliability organization, establishing incentive-based rate-making for transmission, and allowing federal backstop authority for transmission siting." (Abel 2006)

The general implication is that had there been more transmission, both of these crises could have been averted. Moreover, there is a sentiment that future similar emergencies may be avoided by building a stronger transmission network. Perhaps more than anything else, these catastrophes have served to bring the perceived issues with transmission into the public psyche. Despite this, upon a closer examination of the causes, it becomes hard to argue that transmission was, in fact, the major contributing factor to the crises. For example, in 2001, California did see skyrocketing wholesale electricity prices, rolling blackouts, bankrupt utilities and widespread political and economic fallout. An array of circumstances, which are summarized below, led to this outcome:

- In the years before 2001, demand growth had outpaced supply growth. At the time of the crisis, new generation was under construction but was not yet available to serve load.
- High prices paired with low availability for natural gas and low rainfall for hydro power caused a scarcity of fuel inputs and a price increase for generation.
- The cost of fossil powered generation was particularly high at the margin because of a spike in NOx permit prices.
- An unusually large number of generators were offline for repairs and maintenance. The large number of unavailable generators further tightened demand and raised prices. It is possible that this number was artificially high as generators may have been complicit with gaming.
- The California Power Exchange's complex design inadvertently allowed for gaming and exercise of market power. At the time when markets were tightest (because of the above issues), this weakness was exploited by Enron.
- Electric distribution utilities were rigidly regulated by the California Public Utilities Commission. This regulation included a retail rate freeze so regardless of the wholesale price of electricity, these utilities were forced to sell to end consumers at a set price. Utilities had also been forced to

divest from generation assets and had not been allowed to sign long term, fixed price contracts to acquire electricity.

- When the utilities started to declare bankruptcy, they were unable to import from out of state (for lack of liquid assets) and their financial crisis became a state financial crisis which in turn affected public opinion and state politics.

This catastrophe was the result of a convergence of factors, none of which indicate that there was underinvestment in the transmission infrastructure. While this is not to say that certain stresses could have been somewhat relieved with increased transmission availability, in particular North-South transfer capacity, the California crisis was largely a combination of high generation costs, poor market structure and regulation, and unethical behavior by market players. From the literature, one cannot deduce that transmission inadequacy was one of the primary factors in this situation (Sweeney 2006).

The Northeast Blackout of 2003 was caused by a completely different set of circumstances than the crisis in California, which again do not clearly point to underinvestment in transmission as a cause. That said, some confusion seems to surround this matter. The conventional wisdom seems to have been established that the Blackout was a result of insufficient transmission infrastructure. This understanding was built up in the early rounds of talk shows and news stories following the incident, and was possibly reinforced by publications published by the certain industry groups far before the US-Canada System Outage Task Force published its official report (Huntoon and Metzner 2003). In April 2004, the Task Force published its extensive study of the Blackout and linked the following major shortcomings to the causes of the system failure, which originated in Ohio:

- Inadequate system understanding: Authorities in Ohio failed to understand vulnerabilities and instabilities in their system and did not operate it under appropriate reliability criteria.
- Inadequate situational awareness: Authorities in Ohio were not able to accurately monitor the status of their system and did not recognize the deteriorating conditions on the network.
- Inadequate tree trimming: Authorities in Ohio did not properly deal with tree growth in its transmission corridors.
- Inadequate diagnostic support: The interconnected grids surrounding Ohio were not able to diagnose the problem fast enough to respond effectively.

The Task Force report also cites a number of institutional issues centered on weaknesses with NERC standards at the time, not the least of which was that they were not mandatory. Accordingly, the Task Force recommended that NERC create standards that are "strong, clear, and unambiguous" and suggested that there be increased requirements for compliance (U.S.-Canada Power System Outage Task Force

2004). But while there were clearly a host of problems with the power system that led to the Blackout, it is not in line with the Task Force's conclusions to suggest that a lack of transmission capacity or investment was the cause of, or would have prevented, the 2003 Northeast Blackout.

4.5 Interim Conclusions and Limitations of Analysis

As has been shown, it is very difficult to draw any conclusions from the data provided. It should be clear that the issue of transmission adequacy cannot be boiled down to a single metric, or even a group of metrics, at least based on data that is commonly available. Moreover, the metrics that are commonly referenced as indicators of underinvestment in transmission capacity either are not relevant indicators of adequacy or they do not strongly show whether investment is sufficient or not. Further, what data there is, relevant or not, suffers from quality problems. Finally, all of these issues are confounded by a general disagreement on, or lack of articulation of, what exactly constitutes transmission adequacy. For the purposes of this study though, it seems reasonable to conclude that there is no reason to doubt that the US transmission system is adequate to serve both generator interconnection and reliability needs. And for policy lines, there is not yet a national policy on which to base such planning or assessment; there is only a concern about whether the system will be able to adapt to changing goals. This leaves economic lines as the primary unknown within the question of current transmission adequacy, as there don't seem to be any clear indicators that support an assertion of either sufficiency or insufficiency. As for the ability of current regulation to sustain current levels of adequacy into the future, further study is required.

5 A Prediction of Adequacy Based on Current Regulation

Having found that quantitative metrics on transmission system adequacy cannot support any definitive conclusions about the current state of the system, there is a need to explore other avenues. One possible approach is to apply logic and regulatory experience to infer what level of adequacy should result from current regulations. This chapter will attempt to take just such a "regulatory rationale" approach. First, current regulations will be described. Because of the fractured nature of jurisdiction over transmission in the US, these regulations will have to be described generally rather than giving specifics about each region[50]. If there are particularly interesting and relevant examples of region-specific regulation, they will be described in further. Once the regulatory structure has been explained for each topic, there will be a discussion on what the expected outcome should be and an indication of what findings might be revealed during the interview process, the last step of the research.

5.1 Planning Practices

Before the rise of deregulation and the move towards wholesale markets for electricity, the transmission system was planned by local utilities that were vertically integrated. These utilities were allowed a regulated rate of return on all capital investments as long as they complied with their "obligation to serve." In those days, transmission expansion was usually very moderate – generation usually was sited close to load – and any necessary expansion could be determined with a high level of confidence. Furthermore, costs were low and concerns over public and environmental acceptance were far fewer than they are today. As restructuring gained momentum in the early 1990s, the planning process became significantly more complicated. Decisions about installation of new generation became an outcome of market forces rather than centralized planning and transmission planning was exposed to unprecedented levels of uncertainty, both in where generation would locate and how power would flow around the network. The traditional model of system expansion is further stressed by new trends in generator location, as many renewable generators that seek interconnection are sited in the best resource locations, which are often far from existing loads and wires[51] (Thomas et al. 2005).

What has emerged from the period of restructuring is a system where, in most of the US, large regional RTOs are responsible for planning transmission to serve projected load. The planning processes vary significantly from RTO to RTO, but they focus on the objectives of maintaining a transmission grid that is reliable and economically efficient. The two concepts, "reliability" and "economics", remain separated, perhaps because it is easy to justify a line to avoid the specter of blackouts. And while the vast majority of

[50] A regulatory history about the US transmission system can be found in Appendix G.
[51] This is a departure from standard generator interconnection, whereby generators would usually locate close to the existing grid after requesting interconnection facilities be built to connect them to local network.

lines are built with the explicit purpose of maintaining reliability, there is no framework in place to assess the economic value of these upgrades (Baldick et al. 2007). All reliability planning is performed to adhere to mandatory criteria established by NERC, which may then be supplemented by additional constraints put forward by regional reliability authorities and the RTOs. Generally, the NERC criteria are based on the concept of "1-in-10", which suggests the system should be built to the point where one major failure[52] is expected every ten years. After reliability planning is complete, planners look for opportunities to reinforce their systems in ways that would further reduce congestion and increase the economic efficiency beyond the capability of the existing transmission capacity (Kaplan 2009). These economic planning processes are not nearly as well developed as the procedures for reliability planning, and many regions are still in the process of completing their first studies of economic opportunities[53].

Two major gaps stand out in the current planning regime. The first is that while planning on a utility or state level has gradually given way to regional planning, there is still very limited capability to perform planning on a system-wide (interconnection) level. Aside from the openness to merchant investment, there is also no systematic way to evaluate opportunities that may exist across regional boundaries (Joskow 2004). The second concern is that there are not yet procedures in place to proactively plan for large amounts of renewables (again, California and Texas are exceptions to this). This type of resource often requires long tie-lines to connect generators to the existing network, and often the generators will not be built if there is uncertainty about whether transmission will appear. In other cases, policy goals may dictate the construction of lines that don't have an obvious reliability or economics justification[54]. Most planning processes are not amenable to such projects. Accordingly, there is concern that without proactive planning for renewables, any national, regional, or state goals that require large amounts of emission-free energy will not be realized for want of transmission.

Concerns also exist over the ability of current planning methodologies (computer tools, etc.) to deal with planning over areas the size of RTOs and beyond. Generally, transmission planning is characterized by a large and highly dimensional search space, a great deal of uncertainty, optimization over multiple criteria, lumpy decision variables, and long periods over which investments must be assessed. When the desire to perform expansion planning over larger areas and over more additional criteria (i.e. policy goals), these characteristics are compounded and the challenges magnified. The current state-of-the-art in transmission

[52] What the "one" means is interpreted differently in different places. In some regions it is interpreted as "a total of 24 hours" while elsewhere it is thought of as "one single event".
[53] This may also be evidenced by the very small number of economic projects completed in restructured regions of the US (CA and TX are exceptions to this).
[54] It is worth noting that many policy goals that are currently raising alarm, like a national Renewable Portfolio Standard, do not actually exist yet. For this reason, the debate over policy lines is sometimes obscured by the fact that the policy has not yet been established.

planning is able to address power systems on the geographic scope that is demanded of it today (RTO level), including moderate levels of uncertainty on a scenario basis[55]. While this has been acceptable to date, these methods will not be effective at planning on a wider basis that may be demanded if there is to be increased transmission expansion across RTOs (Pérez-Arriaga et al. 2010, pending).

5.2 Cost Allocation Practices

Like all infrastructures, electric transmission is costly and this cost must be borne by some parties. In a restructured power system, some costs are covered by short-term locational signals that account for the losses and the differing economics of generators at different points, or nodes, on the network. The most refined pricing scheme of this type is called "nodal pricing", wherein the price at any given node is equal to the short-term marginal cost of increasing the demand at that node by one unit. This cost is dependent on transmission constraints, transmission losses, and the characteristics of available generation capacity. Each generator is paid the nodal price at its node at any given time and consumers also pay the nodal price of the node where they are connected[56]. The difference in prices at different nodes gives rise to net revenue that is paid to the transmission network. Under ideal conditions, these revenues would theoretically cover the whole cost of the network. Unfortunately, for a variety of reasons – market imperfections, economies of scale in transmission, the lumpy nature of transmission investments, non-economic reliability criteria, and planning errors – in practice they only cover about 20% of the costs to build and maintain network performance to the level customary in developed countries. The necessity to allocate costs arises from the need to cover the approximately 80% of remaining network costs that are not covered by nodal prices (Pérez-Arriaga et al. 1995).

To date, the electric transmission system in the United States has been built and been paid for primarily at the regional level. As a result of the gradual and incomplete nature of restructuring, the different values, experiences, and needs of various regions, and the lack of a federally provided method, cost allocation schemes also vary significantly from region to region. Most of them choose to use a hybrid of different cost allocation techniques, which reflects a diversity of priorities across different jurisdictions (PJM 2010). Generally, transmission built for the sake of reliability is socialized across regions or sub-regions based on peak load. Transmission projects that have an economic justification – these are rare in practice – are more likely to be allocated via flow-based network usage methodologies (which are proxies for beneficiary pays) though in some cases they may still be subject in whole or in part to cost spreading to

[55] Ideally, a probabilistic representation of the future would be used in place of a scenario-based representation.
[56] Although in most cases for small and medium consumers prices are averaged over the different nodes and the locational component is lost.

load[57]. Generator interconnection facilities, on the other hand, are usually paid for entirely by the generator that made the interconnection request. In some cases, generators may also be responsible for the costs of deep network upgrades. Another general observation about cost allocation about different regions is that the larger the cost of the line and the higher the voltage, the more likely the project is to be socialized across a large population.

Some regions have recognized that costs may need to be allocated in a different manner for interconnection lines serving renewable generators. In the past, generator interconnection charges have not been an issue because interconnection lines have been short or the interconnecting generators – as with coal and nuclear plants that are often sited far from load – have been so large that the cost of transmission was dwarfed by other expenses[58]. For renewable generators, the cost of interconnection may become a serious issue. Because of resource locations, large wind and solar installations may be sited even farther from load than their traditional counterparts and be limited in size by both high capital costs and the large quantity of real estate necessary for a high capacity plant. If these plants are responsible for 100% of their interconnection costs, they may not be built, thus making it very difficult to achieve federal or state goals for carbon reduction or renewable generation. In response to this concern, some regions have allowed for the costs of transmission that serves renewable resource zones to be partially allocated, at least in the near term, to load (WIRES 2008).

Furthermore, current regulation does not provide a standardized framework for determining who pays for transmission projects that cross regulatory jurisdictions (including RTOs and vertically integrated utilities)[59]. Some inter-regional projects have been developed on a merchant basis or have their cost allocation arranged via an ad hoc agreement between the relevant parties. Historically, this has not been a significant issue; transmission networks were built up to use local generation to serve local load. Over time, some interconnections between regions were developed to increase reliability or arbitrage market price differences, but capacity has remained limited. With concerns that climate-focused energy legislation is pending – and with it the need to develop distant wind and solar resources – the lack of a regular procedure to allocate the costs of large, long distance transmission projects has become very relevant (Pfeifenberger, Fox-Penner, and Hou 2009). In particular, there are concerns that without an agreed-upon inter-regional cost allocation scheme, it will be impossible to build the kind of transmission lines that could connect distant renewable-powered generators to major load centers. In turn, this lack of

[57] Certain RTOs, like CAISO and ERCOT, do not make distinctions between different line types in their cost allocation; any line that is approved for construction is treated in the same manner.
[58] Only under market-based regulation has transmission cost allocation has become an issue, since only under market conditions generators may be requested to pay for transmission services.
[59] The notable exception to this lack of standardization is the arrangement that exists between PJM and MISO.

necessary transmission capacity could lead to the use of lower quality (of offshore), higher cost local renewable resources[60] (Wiser and Bolinger 2009). Or worse, transmission capacity constraints could result in a failure to achieve carbon reduction goals or renewable energy targets.

One issue that may underlie some of the ongoing challenges with cost allocation is the issue of calculating benefits. As previous chapters have described, calculation of benefits can be very challenging both because of analytical difficulties and because certain benefits are hard to quantify. In response, most regions avoid calculations of benefit whenever possible – they are not necessary to justify reliability reinforcements – and some avoid the task altogether. In regions where the calculation is done, the only benefits that are included in a meaningful way are those associated with production costs; all second order benefits are ignored or treated peripherally at best (Pfeifenberger, Fox-Penner, and Hou 2009). When trying to build a line for economic purposes, this decision may make it very difficult to gain a consensus that a line is benefit-cost positive for all but the most overwhelmingly economic lines. Furthermore, if the costs are allocated entirely to load based on beneficiaries, any benefit to generators is ignored, and thus the cost-benefit bar is further raised since only part of the production cost benefits are being included in the calculus. Alternatively, in regions where even economic lines are socialized to avoid calculating beneficiaries, there is a risk of departure from an equitable distribution of costs for new investments, which can lead to heavy opposition from local and state authorities and diminish the chances that a line is successful.

5.3 Investment Practices

The shift from a vertically integrated, centrally planned power system model to a system with competitive markets and independent system operation has the effect of increasing opportunities for alternative forms of transmission development. In particular, liberalization allows the opportunity for merchant projects to be built and enables new entrants to get involved in transmission investment. That said, merchant lines face a particular set of economic challenges. Most importantly, because of the nature of transmission investment (i.e. lumpiness, economies of scale, etc), it is extraordinarily unusual that a line will be able to recover its costs simply by arbitraging price differences between markets[61]. Recognizing this reality, a

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[60] "Local" renewables – that is to say, renewable resources that are close to major load centers – tend to be lower quality, which results in a lower capacity factor for the generators built to harness those resources. In turn this results in a higher levelized cost of generation. Still, such investments may be economically justified with respect to far away renewable resources, which incur the expense of additional transmission to deliver their power.

[61] As described before, the existence of a new line will have the effect of destroying the price differentials. In turn, the benefit of the line will not be fully reflected in the value of any transmission rights that have been created.

merchant line will more commonly be based on ex ante long term contracts with network users[62]. Of course, the old models still apply and will predominate, and incumbent transmission owners may still build transmission through the RTO planning process and receive a regulated rate of return (Coxe and Meeus 2009).

Though restructured regimes offer previously unavailable opportunities to non-incumbent investors, a concern has arisen over the fact that Order 890 grants incumbent utilities the right of first refusal on all new development. This rule may be perceived as a form of undue discrimination against non-incumbent transmission companies. In particular, it leads to the strange reality that a non-incumbent developer could propose a line, have it approved, and then lose the opportunity to construct the facility to an incumbent player. As such, this discrimination may discourage potential developers from presenting potentially beneficial transmission facilities for consideration in the larger planning processes. Of course, if discrimination is to be done away with, merchant developers will need to participate fully in the planning process and cannot simply participate peripherally and submit proposals when it is convenient to them (FERC 2010).

This point in the description of the system also deserves a discussion of risk. The type of financial risk in question pertains to which party carries the perils of building a new line, with the possibility that the infrastructure ends up un-built after sinking significant resources into a project. Generally, the tradeoff is between placing financial risk on the transmission developer or on the consumer. If the risk is to be placed on the investor, the system may face underinvestment if the risk premium is too high for potential investors. For instance, if there is a perception that siting new transmission may be a challenge that could result in unacceptably large administrative or abandoned plant costs, investors may take their money elsewhere. If the risk is to be placed on the consumers, the concern is that transmission developers will lose financial restraint and overinvest in the system. The trick is to balance the risk so as to achieve an optimal level of investment while not overburdening any party with financial hardships. In the US, this tradeoff may be a standing problem for transmission projects that are not absolutely required (e.g. everything but reliability lines). For example, utilities may shy away from building lines for economics or to serve renewables if pursuing such projects entails taking an a great deal of financial risk in light of the

[62] While practicable, this design for merchant investment is still challenging. First, because of the dispersed nature of beneficiaries who would support such a contract and, second, because those beneficiaries (once you find them) will be prone to want to free ride on others who may support the line's construction.

possibility that construction may be delayed or cancelled as a result of troubles with the siting or cost allocation processes[63].

5.4 Siting Practices

Traditionally, the transmission system was developed to ensure that supply availability was kept in line with demand. This task was performed primarily on a small scale, usually within single states. When it was determined that a new transmission line was needed, one of the responsibilities of the transmission developer was to acquire the necessary siting permits to build the facility. A developer seeking siting authorization could expect to be challenged over many issues, including land use impacts, property values, technical concerns, jurisdictional conflicts, and the allocation of costs and benefits. If one needed to build a line across multiple states or utility systems, limited provisions were in place to support the constriction of lines that would increase the reliability of neighboring systems. Over the past two decades there has been a steady movement towards regionalization of the power grid, particularly in light of restructuring and the desirability of being able to improve reliability and access inexpensive generation resources by interconnecting regions. Unfortunately, siting regimes have not been able to keep up with the increasingly regional nature of the grid. As such, the difficulties of siting a new line now tend to be compounded by the fact that expansion is being done on an interstate basis under siting regulations designed for the single state paradigm (NCEP 2008).

Over time, states have gradually taken action to ease the siting process for lines that serve interests in multiple sates. This has been facilitated by several methods, including interstate cooperatives, joint transmission studies, or multi-state compacts. While this is progress, what remains is a complex system with a large number of authorities, each with varying rules and interests. The hurdles that a transmission developer can expect to face can be divided into four categories: local objections, administrative processes, conflicting interests, and lack of timing and coordination of the above (Holdkamp and Davidson 2009).

- **Local objections** take the form of individuals or communities objecting to the aesthetic or perceived heath and environmental impacts of transmission infrastructure. Commonly called the NIMBY ("not in my back yard") problem, this obstacle has grown over concerns for fragile ecosystems, recreational land, and scenic or historic trails and parks.

[63] Some would argue that all lines that are indicated by the planning process as beneficial to a major system goal should be built, and with minimal risk to the investor. Of course, planning is imperfect and uncertain and both the identification of beneficiaries and proof of net benefit may not always be clear. Beyond lines included in the RTO planning processes, it may be acceptable to face promoters of additional transmission with a higher level or risk.

- To site a new line, developers must contend with a vast array of **administrative processes**. These include federal and state environmental reviews as well as federal land authorizations from the likes of the Bureau of Land Management, National Forest Service, the Fish and Wildlife Service, the National Park Service, etc.
- For any given line, **conflicting interests** of different parties may heavily influence siting decisions. In many cases, state and local governments are reluctant to base their decisions on the fact that a transmission project may serve regional or national interests, let alone the interests of other states. This is further complicated by inconsistent state environmental policies. For instance, some states may have greenhouse gas policies while others don't and even states that do share similar policies may be inconsistent in fundamental ways (e.g. different definitions of "renewables").
- Not only must all of the above issues be contended with, but their completion must be **timed and coordinated** in such a way that all of the necessary approvals are completed within the necessary windows. This is particularly challenging because different authorities take different amounts of time to complete their reviews and pass down their decisions. Often, things like environmental reviews will have a shelf life, and if other elements of the process take too long to complete the reviews will lapse and need to be updated or repeated. Other temporal issues include the different amounts of time required to site transmission and the accompanying renewable generation. Moreover, in many cases the determination of "need" for a line will not be completed until significant time and resources have been sunk into other parts of the siting process[64].

Taken together, all of these challenges surrounding the siting process make it very difficult to develop new transmission lines, especially over new rights of way. Perhaps more than anything else, the determination of "need" (or finding of benefit) can drive the success or failure in securing authorizations for a transmission project. The problem here is that most states do not give much priority to regional or national benefits; the concern of state or local governments tends to revolve solely around whether a project serves their interests. This has been well articulated by Hempling, who termed this balkanized, narrow-viewed condition *Interconnection Animus* (Hempling 2010). In this condition, the states erect barriers to transmission development – through the siting process and elsewhere – for fear of some (poorly articulated) ramifications of opening local power supplies to non-local loads (Krapels 2009).

[64] These temporal issues may be exploited by groups opposing transmission. Through litigation, such parties can make it exceedingly hard to site new transmission simply by using the court system to extend the process for long enough that previously obtained siting approvals start to lapse.

As the transmission system grows, becomes more strongly interconnected, and aims to achieve bulk power transfer across long distances, these parochial regulatory structures may prove to be significant impediment to investment that is adequate to serve larger system goals. In light of this, the calculation of benefit – or need, in the case of reliability - as part of the planning process also becomes essential to the siting of large, new transmission facilities and the less clear the benefits are, the harder the siting will become (Brown 2009). This also means that resolving issues surrounding the calculation of benefit and cost allocation – perhaps by way of coming to consensus about their practice – can reduce the challenge of siting by removing the number of dimensions involved in the debate.

5.5 Regulatory Rationale Discussion

This section will strive to deduce the expectation of adequacy for each system goal based on a logical argument derived from the regulation described above. The goal here is to establish a framework against which the interview responses will be tested.

First, it is again necessary to dismiss reliability and generator interconnection as transmission goals that may warrant concern regarding adequacy. With respect to generator interconnection, this goal is guaranteed to be accomplished because there are clear planning and cost allocation procedures in place. Furthermore, generators will not site where they cannot also site lines, and they will not build unless they can also finance the necessary transmission. Where there may be an exception to these statements is for generator types – like nuclear power plants and wind farms – that are usually located in distant locations. For wind generators, these concerns will be addressed as policy issues. For nuclear plants, it is possible that the cost of long interconnection lines becomes an issue[65]. Though it is hard to speculate on this because no nuclear generators have been built in the age of restructured utilities, it is possible to imagine that siting requirements (i.e. access to water and distance from populations) result in a large interconnection costs that could affect an investment decision if the generator were the sole financier. If this is the case, perhaps there reason to be concerned about the current regulation as it applies to generator interconnection. On the other hand, because the primary capital costs of nuclear generation are so high, they may dwarf the expense of transmission and make it a non-issue.

There is also no reason to suspect that reliability is an issue with the US transmission system under the current regulation. As long as one accepts the premise that the NERC reliability standards are a reasonable reflection of what the nation demands from the power system, the fact that they are mandatory suggests that the system is adequate from a reliability standpoint. As such, the cost allocation, investment,

[65] The author recognizes that a revival in construction of nuclear generating stations could very well also be viewed as a policy issue.

and siting mechanisms are all in place to ensure that all necessary lines are built to satisfy reliability goals in spite of any construction challenges. In fact, it is likely that the regulation is so supportive of reliability investment that planners may attempt to justify lines with significant other drivers, in particular economics, under the reliability heading. Furthermore, the same conclusions should hold in the future as a broader geographic scope for planning becomes the norm. This is the case because, while other types of projects must withstand scrutiny on their utility across uncertain future developments that are hard to model and open to challenge, reliability lines must only pass deterministic "bright-line" tests based on a pre-set suite of future scenarios.

Economic development is the first case where one might expect to see inadequate investment based on the current regulation. A variety of elements of the existing regulatory structure support this finding that it is likely that economically justified lines will not be built:

- Unprincipled cost allocation procedures may give rise to opposition and litigation. That is, in cases where costs are spread across large numbers of network users, many of whom do not benefit from a line, agents will have cause to protest the fact that they will be forced to pay for infrastructure from which they do not benefit.
- Uncertainty in the planning process may make it difficult to calculate not only who benefits, but how large the benefits are. Unless all of the stakeholders who are being asked to pay for a line are committed to the treatment of uncertainty in the planning process, it is likely that there will be critics of a project who do not believe that it is worth building.
- If there is no central authority that requires that all lines justified by the planning process are built[66], then challenges in the siting and cost allocation process (which in turn become banes to investment) have the potential to hamstring a line to the point where it is not completed. This situation is not eased by the numerous siting challenges described above, which are in turn magnified by cost allocation (i.e. benefit calculation) debates as siting authorities may oppose a line if they do not believe it will benefit them (i.e. the "need" determination).
- Alternative investment practices will be the exception rather than the rule, and as such will do little to remedy any economic inefficiency that arises. The major issue here is that for merchant lines, both investor and participant funded, it is hard to identify all of the beneficiaries in order to

[66] It is hard to pin down what the investment model is in all cases. For reliability lines, it is mandatory that all planned lines are built. For economic lines, it would seem that, at the very least, incumbents have the opportunity to build and recover the costs of building lines approved via the transmission planning process. For example, in PJM economic investments are opened to market participants for one year after their approval. After this period, if they are not picked up by a market player the incumbent transmission company must build the line or file with FERC that they have declined to build (this issue has not arisen to date, so how this filing process would unfold is not clear). Details on the PJM procedure can be found in the Operating Agreement, Schedule 6, Section 1.7d.

contract with them. And without contracting with all of the beneficiaries, the likelihood is high that agents will try to defer investment in order to free ride on funding provided by others. Consequently, any investment of this type will usually arrive later than is warranted (FERC 2010).

- Current planning processes do not encompass multiple regions (except for limited reliability purposes), and therefore would not expose any opportunities that exist for economic development of lines that cross regional boundaries. Merchant lines could remedy this concern, but for reasons discussed previously such investments will only be made for the most overwhelming of opportunities.
- Difficulties with planning methods and models limit the number of alternative investment scenarios that can be examined. As such, it is possible that lines that do not make it into the planning process are never studied to determine their worth. This is not to suggest that every possible permutation of lines is studied, but it is worth noting that economic opportunities may exist in the lines that go unstudied.

Although there are many reasons to expect underinvestment in lines that are indicated to increase the economic efficiency of the system, some practical considerations may reduce the severity of the situation. As it has been suggested previously, if the reliability criteria are written and executed in such a way that reliability projects eliminate most or all of the congestion on the system, such projects may eliminate the need for economic projects. Furthermore, concerns over the ability of planned economic projects to successfully make the transition from concept to reality – by completing the cost allocation and siting process – may be allayed if transmission developers are successful in gaining the cooperation of the necessary stakeholders. Finally, there is the possibility that in the future economic opportunities will be swamped not only by reliability lines, but also by policy lines. If a need develops, with the accompanying framework, to ensure that lines are built to fulfill public policy goals, the resulting investment in transmission may end up increasing the economic efficiency of the system, again without explicitly building any lines for that purpose.

Finally, there is the question of whether an examination of the regulation indicates that the current system should be able to fulfill future policy goals, namely, the incorporation of large quantities of renewable generation capacity. Two primary reasons that pervade the entire regulatory framework (i.e. planning scope and methodology, cost allocation, investment, and siting procedures and authority) suggest that the current system is probably not adequately invested to serve a system with lots of renewables, nor is the present regulation sufficient to arrive at such a state. First, there are no provisions for reinforcing the network between regions, which would be requisite if the hope is to transport lots of clean electricity from resource rich areas to load centers. Second, in most places the provisions for proactively building long distance tie lines, the type that would serve wind and solar farms, are not conducive to the expected style of development. Of course, this lack of adequate regulation is driven by the lack of a broad and clear policy mandate and, once one is in place, it will probably spur regulatory changes that will to bring about adequate investment to serve the newly established system goals.

5.6 Interim Conclusions and Limitations of Analysis

In short, the regulatory rationale approach suggests that the current regulation should lead to a system in which there is sufficient transmission for generator interconnection and reliability and inadequate investment when it comes to economic efficiency and policy goals. Economic efficiency of the transmission system is likely a victim of shortcomings in the planning and cost allocation procedures that make siting and investment a challenge to the point where some justified lines will not be built. There is some possibility that this problem is not as severe as this line of reasoning would suggest, and the hope will be to address this during the interview process. Inadequacy of the system to fulfill policy goals is, at its heart, an outcome that should be expected because said policy goals have not yet been articulated. Once they are, there will be a need to adapt the planning, cost allocation, and siting procedures to ensure that sufficient investment takes place. However, all of these conclusions are largely disconnected from the actual state of the system, and so they must be supported with findings from another approach that addresses the practice as well as the theory.

6 A Qualitative Approach to Assessing Adequacy and Regulatory Issues

Having come to no definitive conclusions about transmission adequacy via examining the data and with the conclusions from the regulatory rationale pending experimental verification, the third and final approach to assessing adequacy will involve gathering qualitative data on the state of the transmission system. As proposed, the author has interviewed a sample of professionals who are involved in transmission planning. This has allowed insight to be gleaned from experts who have the best idea of how the current regulation impacts the system and whether or not there are currently issues with investment patterns. Such an approach is particularly appropriate given circumstances where there are time limitations and where an academic exercise (e.g. system modeling) would not be as relevant as practical information about the planning and operation of the transmission system. The qualitative method proposed is further indicated enabled by the author's access to subject matter experts with years of experience.

The interview data has been analyzed using the qualitative analysis method called grounded theory. Grounded theory allows for a systematic analysis of data and the generation of a hypothesis – which in this case would be about current levels of adequacy – from qualitative sources like interview transcripts. This method has the added benefit of giving insight into whether the proposed framework is the correct way to approach the problem, as the interviews allow the interviewee to propose alternative frameworks. The process of grounded theory and its limitations are discussed in the early sections of this chapter. The later sections describe the interview findings and present any conclusions that may be drawn from this research path.

6.1 Qualitative Analysis and Grounded Theory

Grounded theory has two major principles that make it appropriate for the purposes here. First, it is suitable because it allows the researcher to deal with data that result from questions rather than measurements[67]. Since transmission adequacy can be thought of in many ways (i.e. through the lens of politics, economics, technology, etc) it is particularly hard to pin the issue to strict, objective criteria. Furthermore, there is a population who are experiencing the process of transmission investment directly. These people, many of whom are available via research and professional connections, will be able to contribute far more to the research by telling about their experience than could be achieved by culling large quantities of industry data and literature.

[67] Some data will be collected from interviewees as it is made available, but the focus of the research will be on assessment of the qualitative interview content.

Second, grounded theory has the desirable characteristic of being "hypothesis-generating" research rather than "hypothesis-testing" research. Hypothesis-testing research, which adheres to the standard scientific method, would require the creation of a hypothesis and the establishment of meaningful independent and dependent variables. Alternatively, hypothesis-generating research allows the researcher to approach the problem without having to formulate a testable hypothesis. Instead, a "grounded" hypothesis is developed by listening to what research participants have to say. This is ideal given the difficulties mentioned above and the fact that it may be difficult to properly formulate a hypothesis in such a way that both answers the relevant question and lends itself to a closed form answer. Hypothesis-generating research is also well suited to situation like this one, where there are perspectives that are left out of the current debate (i.e. the press and literature) or assumptions that need to be challenged.

6.1.1 The Grounded Theory Process

As should be expected, the experimental process for grounded theory differs significantly from what is expected by researchers familiar with the scientific method. Auerbach and Silverstein divide the process into the following steps.

1. **Identification of Issues**: The first step is to review the literature to determine where concepts are open or questions are left unanswered. Research issues are the places where there are neglected perspectives or assumptions that need to be challenged. In the context of research on transmission adequacy, this step of the grounded theory process has been the focus of Chapter 4.
2. **Research Concerns**: Following the identification of issues, the grounded theory researcher identifies research concerns and determines what type of people may be able to address said concerns. This step takes place when a hypothesis would be generated during use of standard research methods. Put simply, it is at this point that the potential pool of experts or experienced parties is identified. In this case, experts in the field of transmission planning are the parties that have been chosen as the population with the requisite experience to shed light on the question.
3. **Create a Narrative Interview**: With the interviewees in mind, the next step is to create a narrative interview. The goal of the narrative interview is to suggest important topics on which the conversation should focus, which may reveal important information. The interview plan should also be flexible, since the literature may not provide an adequate set of questions and the discussion may diverge from the expected.
4. **Select a sample and collect data**: Because of the specialized nature of the populations that are examined in grounded theory research, the field tends to reject the idea that random sampling is realistically possible for this type of work. Instead, the focus is on arriving at generalizability by sampling until responses converge on a single set of issues and additional interviews cease to add new

elements to the story. This is called "theoretical saturation". The interview process starts with convenience sampling, where researchers first recruit whomever they have access to. After convenience sampling comes "snowball" sampling, wherein other experts are elected based on recommendations by the initial interviewees, and still more are selected based on recommendations from the second round. This process stops when data analysis suggests theoretical saturation has been reached[68].

Once the interviews have begun, it is important to start the steps towards understanding what the data says. Thought of as a pyramid, these coding steps allow the researcher to build more complex levels of understanding as the raw interview text is gradually interpreted and built up to formulate a theoretical narrative (see Figure 21). The coding steps are summarized briefly below:

1. **Raw Text**: This is the raw text from the interview. It may be recorded, transcribed, or in note form.
2. **Relevant Text**: The relevant text is what remains when the raw text has been culled for sections that are related to the research concerns.
3. **Repeating Ideas**: Examining the relevant text, researchers look for similar words or phrases that express a common idea and that present themselves in multiple interviews. The set of these ideas are the repeating ideas.
4. **Themes**: Themes are groups of repeating ideas that have something in common
5. **Theoretical Constructs**: Themes can be organized into large, more abstract ideas. These theoretical constructs are the underpinnings of the eventual research findings.
6. **Theoretical Narrative**: Combining the theoretical constructs into a coherent narrative allows the researcher to summarize their findings. This last step provides the connection between the original research concerns and the participants' experiences.

The outcome of this process should be a theoretical narrative that presents a hypothesis on the original research concern. This narrative is ideally a blend of the subjects' experience and the abstract constructs built up by the researcher as the process unfolded (Auerbach and Silverstein 2003).

[68] Auerbach and Silverstein have this step split into two, one for sample selection and one for theoretical saturation. The author felt that it made more sense to combine them into a single task.

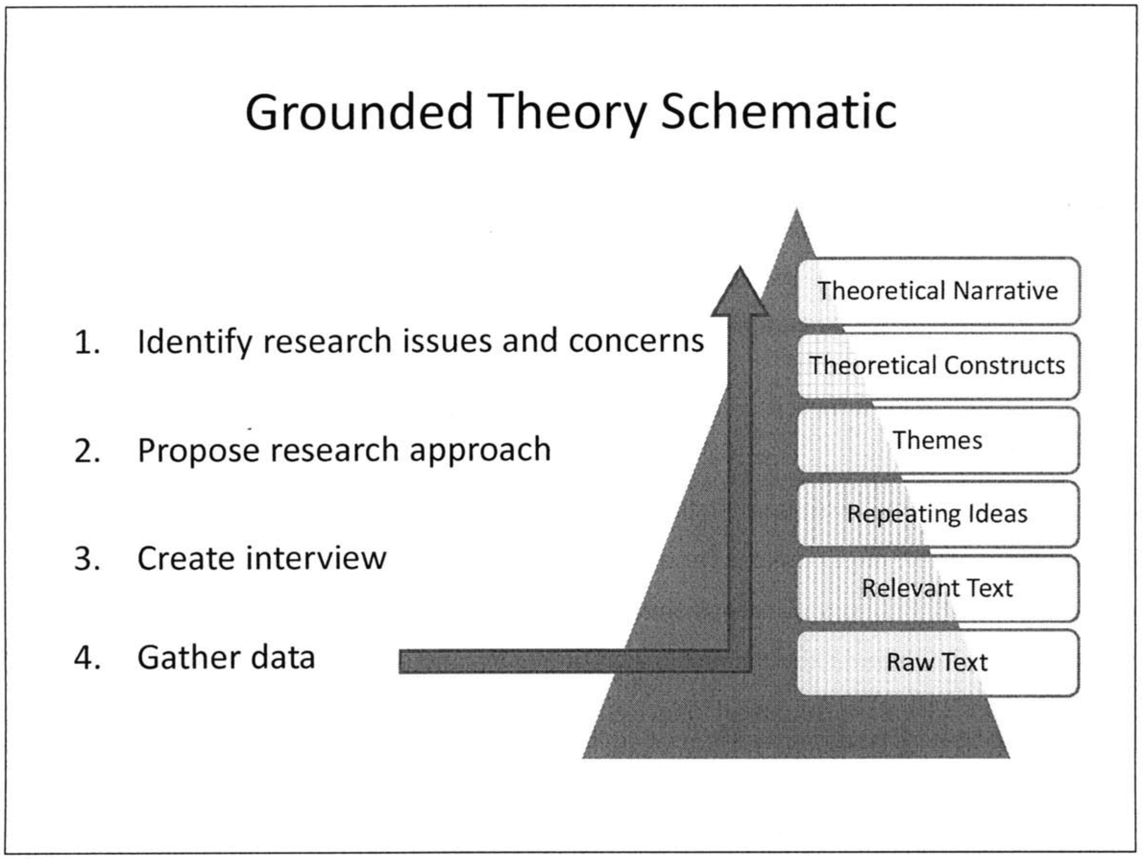

Figure 21: Schematic of Grounded Theory Research Process

6.1.2 MIT Approval

To ensure that the interview process was conducted in a lawful and ethical way, and was in line with MIT policies governing such issues, approval was obtained from MIT's Committee on the Use of Humans as Experimental Subjects (MIT COUHES 2010). COUHES governs all research that involves human subjects that takes place under the auspices of the Institute. Since an interview study like this one does not involve more than minimal risk, an "exempt" application was required. The exempt application was submitted on 5/4/2010 and included a proposed recruitment transcript, interview transcript, release form and the application itself. The application was approved on 5/11/2010. The approved interview transcript can be found in Appendix E.

6.1.3 Limitations of Methodology and Validity Issues

The method for grounded theory, presented above, represents a formalized process for moving from a research interest through the interview and coding process to a theoretical narrative. While it is possible to strictly adhere to the theory for some research, for the purposes of this investigation Grounded Theory was used as a flexible starting point rather than as a rigid technique. In light of this decision, it is important to be explicit about where departures were made from what is generally suggested. Perhaps most importantly, prior to starting the process and writing the interview transcript, the researcher had some notion of what form the answers might take. For example, a possible formulation for the definition of adequacy had already been made and there were some suspicions about which types of transmission investment might be the most interesting to discuss. For this reason, questions were formulated to confirm (or not) prior thought on these matters, and while the interviews were allowed to proceed organically, the interviewer made sure that certain topics were covered in every interview[69].

Other deviations from the ideal framework included minor departures from "snowballing" and "saturation" for practical purposes. For "snowballing", the general process was used and found to be effective, but in some cases interviewees suggested others who would not have the relevant experience to comment on some of the most important questions or whose experience lay primarily in vertically integrated regions. These suggestions were noted but not acted upon. For saturation, there was a different set of problems, though a good deal of convergence was seen by the end of the interviews. The most relevant of the issues here is the small number of organizations within which transmission planning professionals work. Even if a representative from every RTO was interviewed – and at least one from each was – that would only represent seven data points. Clearly, this would not result in saturation even when complimented with interviewees from utilities, consulting firms, and transmission developers. And while it is possible that more could have been gained from interviewing multiple people at each RTO, there was concern about exhausting the good will that was being extended by these organizations. Finally, both snowballing and saturation were limited by time constraints, though both were used to the extent that further inquiries were turning up many of the same suggestions and information.

An additional weakness to the Grounded Theory analysis was that only a single researcher was involved in the coding procedure. It is usually suggested that multiple researchers look at each transcript in an iterative process to ensure that nothing is being missed and that different views of the data are being taken. Unfortunately, this was not an option because this project was undertaken as an individual's master's thesis and there were no other people available to spend the significant time required to read through all of the transcripts and contribute to the coding process. In recognition of this weakness, extra care was taken to make sure that no important ideas were overlooked. However, there were individuals available to look over and talk through the data once it had been sorted into repeating ideas and themes, so the rationale of the author was not entirely without review and input from others[70].

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[69] This decision was discussed with a staff researcher at MIT who assured the author that this was not an uncommon departure from the idealized approach.
[70] In particular, the thesis advisor was actively involved in this process. To some extent, the MIT Grid Study team also contributed.

This leads to an important discussion on the reliability and validity of the coding process and, in turn, the research findings. Auerbach and Silverstein suggest that, for qualitative research, "justifiability" may be a reasonable alternative to "reliability" and "validity" that are demanded from quantitative researchers, in particular because it is impossible to interpret qualitative data without some degree of subjectivity. In other words, a qualitative researcher should be expected to distinguish between justified and unjustified application of subjectivity. To this end they say,

> *"We think it is justifiable, even inevitable, for a researcher to use his subjectivity in analyzing and interpreting data. However, it is not justifiable for him to impose his own subjectivity in an arbitrary manner, that is, in a way that is not grounded in data. Unjustifiable use of subjectivity is, in effect, interpreting data based on the researcher's prejudices and biases, without regard to the participants' experience."(Auerbach and Silverstein 2003)*

In response to the need to distinguishing between justifiable and unjustifiable data interpretation, they lay out three criteria that involve checks on the primary researcher's subjective data analysis. They are:

- **Transparency** is concerned with ensuring that it is clear to concerned parties how you arrived at your interpretation of the data. This is not to say that must agree with the interpretation, but simply that they know the steps by which the conclusions were reached.
- **Communicability** is concerned with the ability of the findings to be communicable. As such, the themes and theoretical constructs must be understood by, and make sense to, other researchers and to the research participants.
- **Coherence** is concerned with whether or not the theoretical constructs fit together in a rational way to tell a story. This story need not be the only possible outcome, but simply one possible way of organizing the data.

To satisfy the transparency criterion, the list of repeating text and the associated themes and theoretical constructs are provided in Appendix F. Furthermore, the following section describes the data analysis procedure and how the raw text was converted into theoretical constructs in practice. Following that, the theoretical constructs themselves are presented in a form that should create a logical narrative that leads to several hypotheses about transmission adequacy. If this presentation is successful in communicating the findings, then that should indicate the satisfaction of the communicability and coherence criteria.

6.1.4 Interview Population and Data Analysis Procedure

The researcher started with a limited number of initial leads hoping to perform 15-20 interviews over a month long period. Through online research and recommendations from initial participants, a total of 16 interviews with 21 individuals from 15 organizations were eventually conducted over the course of a month (see Table 2). All interviewees were at the management level and the majority was senior management. Most conversations took place over the phone, lasted between 30 minutes and one hour, and were recorded to later be transcribed into notes.

RTOs	Transmission Developers and Consultants	Utilities
PJM		
ISO-NE	Anbaric Transmission	Southern California Edison
NY-ISO	Mosaic Energy Insights	Exelon
CAISO	CleanLine Energy	(undisclosed utility)
ERCOT	CRA International	(undisclosed utility)
SPP		
MISO		

Table 2: List of interviewee organizations

Once the interviews were completed and transcribed into notes, the first step was to sort this "raw text" into relevant text. From each interview's note file the relevant text was copied and pasted into another file. From there, ideas that were repeated were then copied into yet another file. For this transfer, a rough system was used to keep track of how many times an idea repeated and some ad hoc measures were taken to ensure that information was lost in this transfer. First, the author thought it worthwhile to include some details about how different interviewees expressed certain repeating ideas or contributed meaningful commentary along with said ideas. Additionally, some ideas that did not necessarily repeat in the relevant text but that seemed particularly interesting or unusual were also copied to ensure that they were not lost. The same was done with relevant text that may not have been repeated but that was in line with findings from literature[71]. Once the list of repeating ideas was complete, that file was then reorganized to make the data more manageable. From the reorganization, themes started to become evident and then theoretical constructs. The contents of the last file can be found in Appendix F, which also shows from which sets of repeating ideas different themes emerged.

6.2 Theoretical Constructs

This section presents the theoretical constructs based on the themes revealed during the coding process. Each construct is supported using insight provided by interviewees, including the logic used to move from the repeating text to the themes where the progression was not clear.

[71] The author will strive to note in the following discussion where ideas are included that are not necessarily repeating and have been included in the commentary for other reasons. In cases where external documents are relevant and support the interview content, citations will be provided.

6.2.1 The Definition of Adequacy

As it was presented in Chapter 3, the definition of adequacy seems to be robust and in line with the interview responses. A reminder: adequacy was defined previously as a system "in which all of the required or justified investments are made to fill interconnection, reliability, economic, and policy goals" Similarly, interviewees tended to frame their thoughts on adequacy in light of reliability, economic efficiency ("economics"), and ability to connect and deliver renewable generation ("policy")[72]. Several mentions were also given to generator interconnection as a relevant line type, though the only place where this type of line seems to be an issue worthy of comment is in the context of renewables[73]. Also, there were several warnings against trying to treat adequacy as a binary outcome. Furthermore, there are multiple ways of approaching the issue, and regardless of how the concept is formulated it always exists on a spectrum between perfectly ideal and completely insufficient. Lastly, transmission adequacy may be a function of the energy market, and as underlying commodity prices shift, so do the perceptions of the state of the network.

It was immediately obvious that reliability was the primary driver for transmission and the most important criteria to satisfy in transmission planning; the most important task for system operators is keeping the lights on. As mentioned previously, the mandatory reliability standards are established by NERC and transmission planners do not get to focus on non-reliability issues until reliability standards have been met.

Once there is confidence in the ability of the system to consistently deliver power, other criteria can come into the picture. In most cases, the economically efficient delivery of resources seemed to follow reliability as the chief secondary concern. Some planners noted that it is important to ensure that the transmission system does not unnecessarily constrain the generation marketplace. Unlike reliability that is based on deterministic operating criteria and not cost – though there may be efforts to find the least cost solution to a reliability violation – economic projects depend on market benefits relative to the cost of relieving any network constraints. This concept was most clearly articulated by Ray Coxe (of Mosaic Energy Insights), who defined it as building until "the marginal benefits is equal to the marginal cost for the next unit of expansion".

Depending on the interviewee, the concept of policy lines took on different formulations. Generally, the labeling of lines as "policy" is a relatively new concept, and one that seems to have been solidified by the

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72 As a reminder, it has been acknowledged that many network reinforcements will contribute to multiple system objectives. While it may not be strictly reasonable to attribute a given line to a given goal, for the sake of this study it will be acceptable to address the ability of the aggregated network to achieve various system goals.

73 Interviewees from PJM also noted that they have a type of transmission investment for operational issues. This was not repeated elsewhere and is apparently exceedingly rare even in PJM.

recent FERC NOPR of June 2010 (docket number RM10-23-000). In several cases, policy lines were described in concept rather than name as lines that are needed to connect distant renewables to the network, and then to deliver renewable power from interconnection points to load centers (often over long distances and across jurisdictional boundaries). Such lines were recognized as a major paradigm change, the likes of which is seen very rarely and perhaps has not been experienced since the nuclear build-out of the 60s and 70s. Consequently, it is likely that once the concept of policy lines has been fully incorporated into the planning processes, the system goals and definition of adequacy will probably not change again in the foreseeable future.

6.2.2 Reliability and Generator Interconnection Adequacy

Both transmission investment for reliability and transmission investment for generator interconnection – at least in the traditional sense – seem to be perfectly adequate. As described above, reliability is the primary concern of transmission planners and they adhere to strict criteria to ensure that power is nearly always available to load. A great deal of time and effort is put into maintaining system reliability, and the vast majority of all transmission projects are driven by reliability criteria. The planners feel that they are very good at keeping the system in line with load growth changes and, while they may not be far ahead of today's needs, they are certainly on top of the situation. As it stands, the system is very reliable to the point where some suggested in may be too reliable (i.e. we are paying for levels of reliability beyond what we might actually demand). One respondent went so far as to say that in his 30 years of experience, he has never known the system to actually be at the minimum reliability level; it is always more reliable than required[74].

Some reasons were given for why adequacy for reliability lines is not a problem. The most obvious explanation is that once a potential reliability violation has been recognized, there is a federal mandate that action be taken to remedy the violation. Moreover, regulatory authorities and stakeholder groups respond well to being told that a line is justified on reliability grounds, which eases the project financing process. Finally, siting is still challenging and tough questions are asked at siting hearings, but once people are convinced that a line is needed because of reliability reasons, they are good about ensuring that it is built.

No interviewees stated any concern about interconnection lines and the ability of the system under current regulation to deliver the capacity of traditional generators to the network. Network interconnection is usually considered part of the capital cost of a new plant, and generators pay to connect to the system at

[74] This may be a result of the fact that NERC does not define the critical system conditions under which reliability tests are performed. These tests are dictated by local reliability councils and RTOs, and may be overly conservative in their assumptions.

the closest node. This should not be mistaken with the efficient delivery of power to load, which is an economic issue, or interconnection of distant renewable generators, which will be addressed as a policy issue. Based on the qualitative data, there is no need for additional concern about generator interconnection adequacy.

6.2.3 Economic Adequacy and the Search for Un-built Lines

Of the questions asked of the interviewees, several were focused on trying to support some sort of conclusions about the current adequacy of lines built to increase the economic efficiency of the transmission system. Among the questions focused on shedding light on the economics issue, perhaps the most important was the question of whether or not they were familiar with any lines that were justified on economic grounds – that is to say: lines with a calculated benefit greater than cost – that had not been built for some regulatory reason or otherwise. The thought behind asking this question was that such justified but un-built projects would be an indicator of some deeper problem with the adequacy of the transmission system to serve economic goals. In essence, these lines would be a smoking gun for underinvestment and support a strong argument for inadequacy. The existence of such lines would also help explain why so few lines are built on the basis of economics alone.

The responses of planners from across the country to the inquiry about un-built economic lines yielded no concrete examples of a line that fit the given description. For some interviewees the answer was a resounding, "No. I know of no such lines." Others conveyed the sentiment that "such lines must be out there but nothing jumps to mind." Still others thought that they may have heard stories of projects that fit this bill, but could not point to specific examples. Perhaps Ray Coxe best captured the flavor of the responses when he said, "There almost certainly are lines in the set, but your challenge may be to figure out is the perception greater than the reality. The popular perception is that there are a large number of highly attractive transmission projects that aren't being built for a variety of easily solvable regulatory reasons." To the extent that the combined body of interviews indicated anything, they showed that the perception is certainly much greater than the reality, and lines that could be a smoking gun are simply not forthcoming.

So if there are no evident economic opportunities in transmission that are left unrealized, then why are so few transmission lines – no more than two economic lines have been built in any single RTO, and some have built none[75] – justified by their economic value proposition? This phenomenon could be explained in one of three ways: 1) on an objective basis, economic opportunities for transmission investment simply do not exist once all reliability requirements have been met, 2) proponents of transmission investments

[75] This statement excludes CAISO and ERCOT, where the distinction between economics and reliability is not as meaningful, as all approved lines are treated in the same manner as part of the rate base.

prefer to stress the reliability component (rather than the economic component, however large) of proposed projects because of existing regulatory difficulties surrounding economic lines, or 3) there is a problem with the search function, the process by which transmission planners and developers seek out economic opportunities. As it turns out, the interviews would suggest that the answer is probably a little bit of all three.

First, the fact that a huge amount of investment is undertaken in the name of reliability almost certainly quashes many economic opportunities. Because the reliability planning process is completed first, and reliability projects take precedence, potential economic projects are only studied after reliability reinforcements have been added into the system and the models thereof[76]. As reliability investments have the effect of reducing congestion and relieving constraints on the system[77], many projects that would have been built for economics' sake are already justified based on reliability[78]. Also, in many cases, transmission planners like Jay Caspary (from SPP) find that "tomorrow's reliability project is today's economic project" and there is a general feeling that at some point all lines are needed for reliability. To demonstrate this point, cases were described both In California (with the Sunrise line) and in PJM (a transformer in Virginia) where a project was initially developed with an economic justification but by the time it came time to build the project it was required to resolve a reliability violation. So while systems may gain a lot in the way of economics from reliability investments, these investments also significantly reduce the need for economic development for its own sake.

Second, and reliability aside, the odds are stacked against finding economic lines in the planning process for any number of reasons. Among other things, it is very hard to prove that a line has a positive benefit-cost ratio and the economic criteria are set up to ensure that only the most beneficial lines are built. Often, a huge benefit-cost ratio is required to justify the large cost of a line and it must be proved that all parties come out ahead after a line is installed; a line that raises consumer prices one place without massively reducing them elsewhere will face strong opposition[79] (the number of consumers harmed and helped will also be a factor). Moreover, any calculation of benefit is complicated by uncertainty (which will be

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[76] As policy lines become a part of planning processes, they may have the same effect. The result may be that economic opportunities end up being eliminated by both reliability and policy investments.

[77] Though not all processes fully incorporate this fact, most transmission investments also reduce network losses and constitute an economic improvement for the system.

[78] Some interviewees commented that this might be less true in the western interconnect than it is in the east, as the network topology in the two regions differs significantly. Because the load in the west is concentrated in geographically dispersed locations, the west sees a lot of long lines that are absolutely necessary to move power from place to place and economics might not be as confounded with reliability in this case.

[79] One interviewee noted that he sees the future of economic investment revolving around smaller projects that only affect a single load pocket and do not have to deal with broader market impacts. For these lines, the beneficiaries are easier to show and the burden the proof is not as high, nor is the uncertainty. There also may be merit to developing lines in "baskets" of lines rather than one at a time.

discussed more later), which in some cases makes planners hesitant to make any strong claims about whether an investment truly is benefit positive. In addition to these difficulties, several interviewees noted that because of limited resources and analytic capacity, less time and effort is spent looking for economically justifiable projects than might be necessary to seek out all opportunities[80].

It is worth exploring the possibility that the problem is not on the planning side but on the investment side. This concern can be dispatched quickly: because the process of building transmission is very long and involved, it is true that many times investors will take their money elsewhere (like generation) in order to ensure more rapid returns. That said, it was made very clear by interviewees that, generally speaking, the problem is not the availability of investment dollars or insufficient returns. The regulated returns are actually very high and attractive to investors who have the patience to work their way through the process and who are willing to accept the risk that a line does not get built. While not all investors are willing to endure the wait and complete the process, it would seem that there are sufficient resources available such that financing for projects should not be a problem.

Interviewees also suggested that economic transmission opportunities may also be elusive because nobody is particularly good at looking for them. For RTOs, planning for economics is challenging because the need arises to examine demand side and supply side alternatives when choosing the lowest cost project[81]. As demand and supply considerations are worked into the analysis, so too do all of the associated uncertainties and the need for RTOs to not only be experts in transmission planning, but also in predicting the future. Compared to the bright line reliability criteria, the uncertainty associated with planning for economics is very challenging. Furthermore, this process requires transmission entities to be reactive and not proactive – their traditional role – as they try to affect changes in the market rather than reacting to them. Utilities are the other major type of organization that is involved in transmission planning, and they face a different set of problems with searching for transmission opportunities. Most importantly, they do not have access to proprietary market data that is required to do a complete economic assessment of a transmission project. Consequently, utilities can only perform screening analysis of potential economic projects before submitting project proposals to the RTO for further study.

[80] One interviewee maintained that the problems was not a shortage of time or resources devoted to economics, but more the fact that policy and renewable development swamped economic opportunities.

[81] Several interviewees commented on the importance of considering non-transmission alternatives (NTAs, e.g. distributed generation, demand response, traditional generation, etc.) as possible network solutions. Their feeling is that people tend to forget there are other ways of achieving system goals and the industry tends to have a culture of bigger is better, leading them to preferentially consider large transmission solutions. And while lip service is paid to NTAs, planners do not do a very good job of looking for these opportunities. In part, this is understandable because of the fact that transmission tariffs can only be used to pay for transmission investments, and there is no mechanism for RTOs to exercise NTA solutions.

Aside from the fact that seeking economic opportunities is a challenging process that nobody particularly excels in, one shortcoming with the search function may be with the lines that no organization is tasked with looking for, namely, lines that cross RTO boundaries[82]. While most intra-RTO opportunities are examined via current planning methods, inter-RTO economic opportunities might exist notionally to connect high price load pockets to low price generation pockets. For example, there is cheap, coal-fired generation capacity available in western PJM while expensive, gas-fired generation is being used to serve load in New England. Unfortunately, there is not currently any planning body that is able to assess such opportunities[83]. A line like this would also face cost allocation and siting issues – RTOs and utilities have historically acted to only approve projects that directly served native load – but the concept still holds. These other challenges will be addressed later in this chapter.

In theory, merchant investors are a party that has the means and interest to examine possibilities for economic transmission expansion both within and between RTOs. It was suggested during at least one interview that if there were obvious economic opportunities out there, they would be realized by merchant developments. As a proof by absence, the lack of merchant development[84] could be seen as indicating that there are no big ticket transmission items that are being missed by the RTO planning process. Examination of other interviewee comments supports this idea to some extent, but limits how much can be inferred by the lack of merchant investment. The biggest concern with using this approach is that it relies on the assumption that merchant investments exist on an even playing field with regulated investments. All of the experts in merchant development who were interviewed were emphatic that this is not the case. They argued that where regulated transmission investment takes on regulated (read: low) risk and is shielded from situations where the investment has less value than expected, merchant investors are at the mercy of the market. Furthermore, the current regulatory environment adds additional risk for merchant investors; conservative transmission planning practices often result in action that purposefully eliminates price differentials[85], which in turn makes it impossible for merchants to arbitrage price differences across markets[86]. Moreover, difficulties with the inability of financial instruments (FTRs,

[82] This was well articulated by an interviewee who noted that the flow gates that might have the most potential for economic opportunities are the flow gates that do not yet exist (i.e. cross-seam connections).
[83] The new planning collaboratives in the different interconnections, funded by ARRA, may be a step towards performing this type of broad-viewed planning. Furthermore, FERC's June 2010 NOPR also strongly suggests coordination and inter-RTO planning.
[84] Only a few large merchant projects have been developed in the US and they tend to be the exception rather than the rule in transmission expansion. Each example of successful merchant projects included a significant economic benefit and the interest of all of the relevant parties.
[85] This conservatism may take the form of confusing scarcity rents with monopoly rents. If the authorities perceive monopoly rents, they will not allow them to persist and add transmission capacity to eliminate the economic opportunity. Actions like this have trained merchant developers to stay away from most transmission investment.
[86] This point demands elaboration, as it is one of the fundamental principles of transmission regulation. That is: transmission investment for economic purposes – if it is of the right magnitude – destroys the business opportunity

CRRs, etc) to sustain most merchant investments also add to the challenges for such projects. So while the small number of merchant investments may be an indicator that economic projects are not being missed, they are only a signal that can provide information about the most glaring of opportunities.

6.2.4 Policy Lines and Network Support for Renewables

The last class of transmission adequacy that the interviewees were asked to reflect on was the ability of the system to support large quantities of renewable generation. This type of generator, usually powered by wind or solar energy, would likely be located far from load centers and be called for by policy initiatives. The response was clear: the current system does not have the kind of spare capacity that would be required to serve significant penetrations of renewables and share the resulting power across regions. This assertion was supported by evidence including curtailment of existing wind capacity, the fact that some of the best wind resource areas are not currently serviced with transmission, and the limited transfer capacity that currently exists between regions. Furthermore, the system is not proactively preparing to deliver lots of wind. Across the country very different approaches are being taken to begin planning and building for renewables, and many regions' plans are either nascent or non-existent. To sum up, the system is inadequately invested if it hopes to accommodate lots of clean energy sourced from distant locations. More importantly, the necessary investment will not take place – in adequate volume or in time – to meet these needs under the current regulatory framework. Therefore, a significant regulatory and policy response will be necessary if this concern is to be addressed.

6.2.5 Planning and Cost Allocation Regulation for Policy Development

The major areas where interviewees felt regulation would need to be improved in order to deal with the integration of renewables – and to increase the possibility of building more economic lines – were generally agreed to be planning and cost allocation. In the face of clean energy requirements and needing to expand the system to meet policy goals, the current planning processes are not adequate to deal with the changing criteria. As it stands, the available planning tools are not capable of dealing with policy, economics, and reliability, especially because policy lines depart from economic criteria. What results is a situation where planners attempt to optimize against multiple objective functions, which is very challenging. Planning models are also claimed to be somewhat ineffective at predicting the operation of the system in the future; interviewees claimed that the current approaches are bad at finding problems and volatility in the system end up muted, which in turn results in an understated need for more transmission.

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of arbitraging regional price differences. Without understanding this, the mistake could be made of believing that all transmission projects could be executed as either merchant (i.e. based on price differentials, not contracts) of regulated investments.

Any existing planning problems are magnified by uncertainty. This uncertainty comes in two forms, one as policy uncertainty and the other as uncertainty on the impacts of transmission investment. The policy uncertainty derives from the imperfect view on how to promote renewables development and the lack of a clear articulation of what needs to be planned for in the present. Consequently, planners today end up doing what they call "faith based planning", which requires them to make predictions about what future policy will require. The concern is that if they wait for policy certainty, it will be impossible to build the necessary transmission capacity fast enough to fulfill near-term goals (once they are established). Investment uncertainty is one of the great challenges associated with restructuring – RTOs only plan transmission and cannot perfectly predict supply or demand side responses – that becomes even more complex when paired with renewables[87]. As the resource mix shifts, transmission planners must try to forecast when, where, and how much renewable capacity will be added to the system. And when this involves a task like trying to service forthcoming wind capacity in the Midwest, which is a very big place, it is impossible to build a grid to cover all possible wind projects.

The parallel regulatory issue in transmission that interviewees considered a major barrier was cost allocation. Nearly all of the comments revolved around the understanding that transmission development to serve renewables would likely require large lines that crossed state and regional boundaries, across which the costs would need to be divided. Transmission cost allocation has yet to be tested for a large interstate project[88] and stakeholders tend to withhold their support for a line until they know who is going to pay for it. The distinct challenge for long lines ties back into the economic issues since these lines will usually cause energy prices to rise in one region and fall in another region. A line may even have zero impact on some they traverse between their origin and destination. As such, it is hard to show all of the involved parties that their interests are not harmed, let alone forwarded, in the process of convincing them that they should bear some part of the cost and allow siting through their jurisdiction[89]. Furthermore, as projects grow in size, the more expensive they become and the more overwhelming the justification or

[87] Investment uncertainty is also complicated by other types of environmental policy actions. For example, new laws in California will require the retirement or repowering of all one-through water cooling of generation facilities. As a result, some plants may be shut down, others will be repowered using other cooling approaches, and more plants will be brought online to replace old plants that have been shut down. All of these actions create unpredictable changes in the resource mix that are very hard to properly plan transmission for.

[88] Large interstate projects have been built and paid for, but under the justification of reliability, which in most places allows the cost to be socialized. As described, reliability lines rarely face much opposition.

[89] The advent of LMP markets make it very clear for all to see if they benefit or are harmed.

requirement for that line must become. Because lines to serve renewables will likely be both large and long, cost allocation will clearly be a major hurdle[90].

The challenge of quantifying benefit, which in part underlies the problem with cost allocation, was repeatedly mentioned in interviews as an area in need of attention. As much an issue for economic as for policy development, they saw the incomplete investment calculus as a major unsolved problem that influences the outcome of transmission system. As it stands, most calculations of transmission's benefits are focused primarily on production cost indicators[91] and leave out other secondary benefits. There have been no successful attempts to quantify and incorporate in the calculus the worth of advantages like reliability, fuel market impacts, or the option value that transmission allows in terms of making the system flexible to alternative future demands. Additionally, many planning processes do not consider reduced losses through increased physical efficiency in the calculation of benefit. What's more, the fact that any benefits that are included must be calculated out into the future to show that they are sustainable, which brings in the difficulty of uncertainty again. As a result of these shortcomings, there is still a struggle to create a transmission assessment framework that is durable and that stakeholders are willing to accept as the basis for a cost allocation scheme.

Up to this point, planning and cost allocation have been discussed as separate concerns. In reality, the two issues are intricately interwoven and cannot be separated; in a transparent and participative process of transmission planning, where all interested stakeholders can be involved, it is impossible to get very far in planning and execution of a project if there is not already agreement and understanding on who will pay. Together, planning and cost allocation become even more difficult to resolve when multiple regions are involved. The multi-regional aspect complicates the modeling exercises, which are necessary to determine both who is benefiting (and therefore paying) and how new lines will impact the system operation and efficiency. When performing large area planning and cost allocation, uncertainties are again magnified by the scope of the process and seams issues become a major stumbling block; modeling two regions with different pricing schemes is challenging and modeling the impact of a line that passes through both restructured and vertically integrated regions is currently intractable. These complications underlie the current inability to turn conceptual large overlay or inter-regional transmission plans into a reality; there is no agreement on who will pay or consensus on the practicality of the plans. On a more fundamental

[90] Where construction of large lines has been, and may continue to be, successful is when a large number of parties decides to act on what all perceive to be an overwhelming economic opportunity. Most such projects end up being executed by merchant investors.
[91] Even production cost benefits indicated by changes in congestion can present a problem in cases where a significant amount of the congestion has been hedged against. Should the calculation of benefits include theoretical congestion charges or actual congestion charges (where much of the theoretical charges have been hedged away)?

basis, these challenges also underlie the shortage of any substantial inter-regional transmission development.

Finally, there is the need to reconcile the temporal issues associated with developing transmission capacity to serve clean generators. The obstacle here is that a new wind farm can be developed in approximately two years (in cases without unusual difficulties) while a new transmission line can easily take a decade or more to complete. One interviewee called transmission a "slow moving train", and described the fact that usually by the time a transmission project is completed the world is quite different from what it was when originally planned. What results is an exacerbated version of the classic problem about which comes first, the wind farm or the requisite transmission, or the "chicken and egg" problem[92]. As the transmission planning must lead the generation interconnection by such a large amount of time, there needs to be a way to coordinate both the transmission and generation so that one step does not hold up the others. Some successful approaches to this problem, which include both planning and cost allocation solutions, have been demonstrated in California and Texas with their Competitive Renewable Energy Zone (CREZ) processes.

6.2.6 The Need for Policy Changes to Support Future Adequacy

To drive the proper regulatory improvements that will allow the system to develop to support renewables and policy goals, there is a need for high level policy action to provide both certainty and direction to transmission planners. The interviewees felt that a large part of the current problem is a lack of clarity on high-level energy policy, without which progress towards large deployment of renewables will be substantially hampered. Establishment of a national energy policy will have the combined effect of providing planners certainty about what to plan for and bringing the goals of states and regions in line with one another.

First, well-articulated energy and environmental policy will allow planners to move forward with plans that support the realization of policy goals. It is easier for stakeholders to agree on projects when analysis shows that the resulting transmission capacity clearly advances to objectives of the policy in place. Furthermore, policy will remove some of the uncertainty and need for "faith based planning". Instead, utilities and RTOs will be able to respond to a more certain generator interconnection queue. Of course, interviewees made it very clear that policies need to be carefully crafted so that they may be converted to hard criteria. The more general and ambiguous any legislation is, the harder it is to plan against. For

[92] One interviewee described a second sub- "chicken and egg" problem that arises between filing interconnection requests to an RTO and having an RTO do the analysis necessary to build a new line. Essentially, if a transmission developer wants to build a line to serve wind, the RTO may turn down the request for analysis if there is not yet wind in the generation queue. On the other side, generators will not file requests and pay to get in the queue because the transmission has not yet been studied.

example, significantly different planning criteria result from a policy that strives to minimize carbon output compared to a policy that has the stated goal of a certain amount of generation from renewable resources (and which renewable resources). However, well crafted policy mandates allow planners to work towards specific objectives and measure the ability of the system to support their goals.

Second, a high-level energy policy will move the nation closer to a "one world" view of the power system. Currently, many state policies do not correlate well with national policies. For instance, states utility commissions are usually unwilling to approve lines that only accrue benefits to other states. In some cases, states are more interested in economic development agendas than any larger energy policy goals. Perhaps worse, some states have their own energy policies, which requires regional planning based on state criteria; a situation that is both technically meaningless and complicates the planning process. Interviewees felt that without the political will and a regulatory push from a higher power, there would not be any organic agreement on how to plan in a multi-state or -region environment. The codification of a national energy policy will serve just that purpose, and allow different jurisdictional areas to come together to work towards common goals, and enable the decision making process that is requisite for the construction of the transmission infrastructure necessary to build out lots of renewables.

6.2.7 Other Issues in Investment Adequacy

Most of the investigation in this chapter has revolved around transmission lines, and neglected the fact that there are other elements in the transmission system that might face different difficulties or adequacy issues. Accordingly, in the interviews participants were asked if they had any thoughts on substation investments. They responded that substation investments tend to be easier because such projects are relatively inexpensive and driven by reliability. Most of the economic opportunities have been realized over the past several decades as more advanced monitoring and control technologies were added to the system, which have significantly improved the efficient functioning of the network. That said, in new cases where economics are involved, the cost-benefit calculus is simpler. Of the problems that do arise, most are related to siting and land use expansion. Fortunately, siting issues are not as pronounced as they are with new lines, as substation expansions require less area and involve fewer stakeholders with NIMBY concerns. In light of these responses, there doesn't seem to be any reason to be worried about transmission adequacy as it relates to substation investments.

Last but not least, siting was discussed as a perpetual problem when building new transmission. At its heart, siting is an issue because people do not like the way transmission lines look. And because any state, county, town or individual landowner can hold up a whole transmission project if they do not approve the transmission siting permits, the siting of lines can be a huge factor in the success of a project.

Interviewees suggested improvements to the siting process that revolved around the importance of the coordination of goals across states. Especially in light of goals for renewables and long distance transmission, there is a need to be able to take a regional or inter-regional perspective when assessing whether a line benefits a state enough to warrant siting approval through it. Particularly when it is time consuming and expensive to site a line – and there may only be one chance to site through a particular area – there is a need to manage diverse stakeholder interests and work together to ensure that a line is built. Coordination is also required to deal with federal land authorities (in particular in the West). In conclusion, siting will continue to be an issue and it will likely also need to be addressed in order to adequately develop the transmission system to fulfill policy goals.

6.3 Interim Conclusions

This previous section attempted to weave the repeating ideas and themes from the interviews into a coherent story about the current adequacy of the transmission system and the ability of the regulation to maintain or improve on that state. As much commentary from the interview texts was added as possible to back up the theoretical constructs from the coding analysis. To sum up, the major findings are as follows:

- The definition of adequacy presented earlier in this study holds up under scrutiny. It is valid to approach the investigation of adequacy by dividing the objectives of the system into four buckets (generator interconnection, reliability, economics, and policy), which may in turn be found to be sufficient or insufficient to achieve the network goals.
- The generator interconnection goals of the system are being adequately met. This conclusion applies to interconnection of traditional generation sources, and connection of large, distant renewables (and the associated reinforcements) is treated under the "policy" citatory.
- The way the system is planned today is very focused on maintaining its reliability. As such, the system is reliable and the current levels of investment are adequate for this purpose.
- The economic efficiency of the system is not conclusive, and it is not clear how adequate the system is to achieve this goal. That said, there does not seem to be hard evidence – a smoking gun - to find that the system is inadequate. The explanation for the lack of evidence may be driven not by the realization of all potential opportunities but by regulatory and organizational shortcomings with how lines are planned and built. Such shortcomings could lead to underinvestment but also hide the symptoms thereof. More discussion here is warranted and will follow.
- The transmission system is not currently able to support expected policy goals that will likely require large amounts of renewable generation. Remedying this problem will require a regulatory response.

- Policy certainty is vital to ensuring transmission adequacy in the future. It should not be forgotten that sweeping environmental and energy policies have not yet been enacted by Federal authorities. If/when they are, they will allow for regulation to be crafted that addresses current shortcomings with planning, cost allocation, and siting procedures.

In the final conclusion chapter, these findings will be reconciled with the expected outcome based on the regulatory rationale. After that, some conclusions should become apparent and point towards a set of policy recommendations on how to achieve and preserve electricity transmission adequacy.

7 Conclusions

There has been a long standing belief that transmission infrastructure in the United States is inadequate to serve the country's needs. This sentiment has been forwarded through academic literature, the press, and by a limited amount of governmental action. This investigation sought to reassess the accuracy of this belief via several investigative approaches. First, the primary data sources supporting this assertion were presented, including arguments about falling levels of physical capacity and financial investment, poor technical and economic efficiency, and anecdotes on system unreliability. In turn, each of these arguments was refuted as either not useful for assessing adequacy or not actually showing what they are commonly thought to show.

Having found a data-centric assessment method to be inconclusive, two more avenues were chosen through which to explore adequacy of investment. One, a "regulatory rational" approach, aimed to deduce the levels of investment that might result from current regulatory structures across the US. The other approach, a collection of qualitative data through interviews, strove to gather information from transmission planners about their thoughts and experience on the state of the transmission network. The goal was to determine if the current regulatory regime for transmission investment is resulting in sufficient levels of transmission infrastructure now and if it will continue to do so in the future. These two paths of exploration yielded similar, although not identical, findings.

This chapter will describe the findings of this research project. It will lead with a discussion on the definition of adequacy that took shape during the investigation. Then, the findings on current levels of adequacy will be discussed, focusing on generator interconnection and reliability investments. The particularly complicated issue of economic lines will be addressed subsequently with a focus on attempting to reconcile the differences in findings between the regulatory rationale and interviews, and trying to determine what conclusions about economic adequacy can be made. The discussion of adequacy will be wrapped up with the research results on the ability of the regulatory framework to support adequacy in the future, including policy recommendations on how to ensure that the system will continue to serve the nation's goals. The two final sections will address possible future work and closing thoughts on adequacy.

7.1 Discussion on the Concept of Adequacy

Adequacy is a tricky concept. It is not easy to pin down a single definition of the idea, nor is there really any one right way of thinking about it. Here, a proposal for adequacy was presented based on four primary system goals, generator interconnection, reliability, economic efficiency, and policy realization. For each goal, the system may be considered adequate if the goal is achieved. Of course, this is somewhat challenging when the goals' definitions are hazy (i.e. for economic efficiency) or not yet defined (i.e. policy realization). For the most part, this framework held up through the interview process. Some important contributions from interviewees included the notion that adequacy must be thought of on a continuum and not as a static value, and the fact that transmission adequacy may be a function of the energy market, and as underlying commodity prices shift, so will the perceptions of the status of the network. Furthermore, it is important to think about adequacy on a systems level and not at a line-by-line level, as any given line will contribute to the advancement of many, if not all, of the system goals.

It is also interesting to note that the concept of adequacy is currently in a state of flux. Such change is a result of the recent recognition that new paradigms for transmission regulation and investment will almost certainly be needed to ensure that the system can incorporate large quantities of renewables in order to fulfill forthcoming national energy policies. This idea has recently stimulated discussion in a fundamentally new type of transmission project (and class of adequacy) called "policy lines." Even as this research was being completed, a FERC Notice of Public Rulemaking was issued that codified this new category of investment. A fundamental alteration in transmission thought such as this one is a rare event that will change the regulatory model for the foreseeable future and that is not likely to be repeated soon.

7.2 Findings on Current Levels of Adequacy in the United States

On at least two counts, the transmission system in the United States is completely adequate to accomplish the nation's goals. First, generation interconnection for traditional generators is not currently an issue. These transmission investments are made out of necessity to the generation owner and by requirement of the transmission planning process. For all intents and purposes, interconnection lines may be seen as part of the capital expenses and siting concerns of a new generator that are dealt with during its construction. During the interview process, little was made of this adequacy target and there was no mention of any problem with it. That said, this issue may need to be revisited in the context of nuclear power – or perhaps coal fired generation with carbon capture – if new plants of these types, with the accompanying need for long transmission interties, become prevalent.

Second, transmission system reliability is very good, to the point where reliability levels may even be high enough as to raise the question of whether or not too much is being paid for reliability. Moreover, general system reliability is maintained by force of law – in the form of mandatory deterministic reliability criteria provided by NERC – and as such the only way that the system could depart from a reliable state is if transmission planners were negligent in their responsibilities. This finding was reinforced through the interview process, and nearly every participant commented on the centrality of reliability in the current planning process. In essence, system planning today is chiefly focused on maintaining a reliable system and all other concerns are secondary. As such, the transmission system is adequate for reliability purposes.

The conclusions about the other two system objectives are less definitive. From a policy realization standpoint, the current state of the system is not adequate to deliver large quantities of renewables the long distance between resource-rich regions to load centers. To be fair though, until now national policy goals have not been put in place, and as such the network should not be considered inadequate in this sense...yet. On the other hand, there is the question of whether the current regulatory structure supports the type of system development that will be required to maintain a clean power system. It almost certainly does not. The shortcomings of the regulatory structure will be addressed in a subsequent section.

In the case of economic efficiency, which was probably the most complex topic examined here, it is difficult to come to a clear conclusion. While there are no glaring opportunities that present themselves as smoking guns of economic inadequacy – that is to say, cases where overwhelmingly benefit-cost positive lines were not built – this is a situation where absence of proof may not be proof of absence. For example, there may be reason to believe that issues with the structure or process of transmission planning tend to systematically overlook certain types of opportunities. As this is the only case where the regulatory rationale is not in line with the interview responses, this topic also warrants further discussion, which will be found in the following section.

7.3 The Question of Economic Lines

Perhaps the most interesting and challenging question in this exploration has been the issue of economic lines and the adequacy of the transmission system to support the goal of economic efficiency. If it turns out that the system is clearly underinvested in lines to serve economic objectives, then there may be merit to the arguments that investment in the transmission system is inadequate. On one side, the regulatory rationale would suggest that the US would systematically under-invest in lines that are justified primarily on economic grounds. On the other hand, interviews with expert transmission planners failed to uncover any instances where an economic line was left on the drawing table after the planning process revealed it to be a justified investment. Here, this discrepancy will be addressed along with a discussion of what conclusions can reasonably be drawn.

In favor of a conclusion of adequacy, interviews revealed some characteristics of the planning process for economic lines that were hypothesized in the regulatory rationale chapter. Foremost, it was evident that because of how strict the reliability standards are many lines with significant economic impacts are built under the requirements of the NERC criteria. Also, while it was acknowledged that very few lines have been built explicitly for economics' sake[93], those lines that have been produced by the planning processes have successfully been paid for, sited, and financed. Interviewees indicate that this success has been a result of rigorous stakeholder processes that create general acceptance and support of the output of the planning processes. These characteristics serve to somewhat diminish the concern of economic underinvestment.

Unfortunately, practical considerations may also complicate any assessment of the situation, especially one that indicates adequate levels of investment. Specifically, without performing extensive modeling work, the only way to assess economic failures is by attempting to find lines that have been studied, shown to be beneficial, and then not built for one reason or another (as was attempted with the interview process). The problem is that this assessment technique is only useful for lines that are revealed during the planning process[94]. Accordingly, certain types of lines will elude this method of assessing adequacy, including the following (many of which are problems with the planning search function):

- Lines that are benefit-cost positive in net, but that are abandoned during the planning process because they have a negative impact on a region whose participation – fiscal and otherwise – would be necessary for successful development.
- Lines that are benefit-cost positive in net, but where uncertainty puts them close enough to the boundary with being benefit-cost negative (or close enough to a preset, and perhaps conservative, threshold set before the planning exercise) that they are not proposed as realistic economic opportunities[95].
- Lines that might be benefit-cost positive in net, but where some of the benefits are not quantified in the modeling process, thus keeping the project away from a necessary threshold of benefit.
- Lines that would realize economic opportunities between regions that are not studied for lack of an inter-regional planning process.

To reconcile the information that is available with the goal of coming to a conclusion about adequacy of investment for transmission system economics, the author suggests proposing a series of hypothesis about inadequacy until one can be plausibly shown to be false, as follows:

Hypothesis One: There exist economic projects that are not being built.

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[93] As a reminder: aside from CA and TX – where the distinction between economic and reliability lines is less meaningful – no RTO has seen more than a couple of economic projects built since restructuring.

[94] An exception to this may be lines that are not considered in the RTO planning process but that are studied and built by merchant companies. Again, these will only be the built to realize the most overwhelming economic opportunities.

[95] For example, PJM requires a line to have a benefit-cost ratio of 1.25:1 before it can be considered for remuneration as an economic line.

Response: This is certainly the case. At the very least, this may be evidenced by the fact that it is impossible to model and assess every possible transmission line. This hypothesis cannot be rejected.

Hypothesis Two: There exist moderately economic projects that are not being built on an inter-RTO level.

Response: This is probably the case. Such projects would not have a sufficient value proposition to attract merchant investment and would not be revealed through other means for lack of an inter-regional planning scheme. This hypothesis cannot be rejected.

Hypothesis Three: There exist moderately economic projects that are not being built on an intra-RTO level.

Response: This is probably the case. For the reasons described above, it is very possible that such lines would not make it past vetting through the current planning process. While this hypothesis cannot be rejected, the fact that uncertainty plays so heavily into future economic propositions, this may be an appropriate outcome. It would be undesirable for questionably benefit-cost positive projects to receive too much support for concern that the public may be forced to pay for lines that may not be justified (due to uncertain future conditions). Also, based on the current practice and the stringency of reliability criteria, this set of lines is probably quite small.

Hypothesis Four: There exist overwhelmingly economic projects that are not being built on an inter-RTO level.

Response: This is the most unclear outcome of the hypotheses that will be presented. While some such projects will be built by merchant investors (and have been) who can operate in the inter-RTO space, other opportunities may not be realized if they are not recognized or not quite definitive enough to provide ample certainty to a merchant-type investor. Remember, the standard RTO planning processes will not recognize these opportunities. As such, there is a probably not sufficient ground on which to reject this hypothesis.

Hypothesis Five: There exist overwhelmingly economic projects that are not being built on an intra-RTO level.

Response: This is probably not the case. It has been shown that clear economic opportunities – those that are not already realized based on reliability – will be built. From the interview process, it appears that there is no reason to believe, nor any evidence to suggest, that the current regulation is sufficiently obstructionist to keep lines that are proven to have manifest economic value from being built. This hypothesis can be rejected.

While the above conclusions may seem dire at first glance, further examination may indicate otherwise. Hypotheses one through three represent minor concerns. Especially in the face of uncertainty, it would be hard to argue that every last line that is moderately economic and that would provide marginal economic efficiency improvements should be built. As one interviewee suggested, the barriers that keep such lines from being built may be appropriate manifestations of a competitive industry environment that ought to be allowed to work. The author would add that they are also probably manifestations of a conservative regulatory regime that is structured to minimize conflict where possible and avoid burdening ratepayers with unnecessary costs. However, transmission underinvestment tends to be more costly to network users than transmission overinvestment, a fact that should not be overlooked when formulating regulation and planning new projects (Joskow 1999)[96].

The larger concerns are with hypotheses four and five. Any overwhelmingly economic opportunities that are missed create serious concerns over the adequacy of the system to meet economic goals. Given the conclusions on these hypotheses, the significant concern that arises over economic adequacy of the US transmission system is that major inter-regional opportunities that are not realized. This is a somewhat expected conclusion based on the generally balkanized nature of the power system and the lack of a structured method of performing inter-RTO planning. Also, it is probably the largest current problem regarding the adequacy of the transmission system. However, it is very reassuring that the current regulatory structure does not seem to be missing any major opportunities where it is looking for them.

The above conclusions demand a discussion of why the situation is not worse than it is, as the regulatory rationale might have suggested. The author would posit that while there are conceptual shortcomings in the current regulation – in particular surrounding lines justified primarily by economics – the impact of these weaknesses has been minimized in practice (i.e. through extensive building for reliability's sake). Because the reliability-focused regulatory framework seems to have effectively been stretched by transmission planners to the point where it has resulted in the building of nearly all of the justifiable lines, there is little cause for concern at the moment. How these regulatory faults come into play in the context of renewables is less clear. It is possible that current failings become exposed as the need to build policy lines grows, thus leading to more severe underinvestment. Alternatively, it is possible that policy lines

[96] This can also be deduced through reasoning. A thought experiment: starting from equilibrium at an ideal level of investment, additional transmission capacity continues to reduce losses and congestion (to a point) while only incurring the additional cost of transmission capacity. On the other hand, reduction in transmission capacity saves the cost of transmission but incurs increased losses, congestion costs, and eventually unserved load (the latter two quickly become very expensive).

could have the same effect as reliability lines; they may be planned and built based on legislative requirements and further swamp economic opportunities while maintaining transmission adequacy.

7.4 Findings on Ability of Regulation to Support Future Policy Goals

As it stands, one clear conclusion is that the current transmission network cannot support the kind of bulk inter-regional transfers of power that are thought to be a characteristic of a power system that has incorporated lots of renewables. More importantly – since such a policy is not yet in place, at least not on the national level – there is lack of support for the development of the transmission policy that would result in the kind of transmission development that will be necessary to both connect renewable generators to the grid and to facilitate the long-distance transfer of the power they generate. Consequently, while the grid may not yet be actually inadequate to serve policy goals (as they have not yet been established), the regulation is inadequate. Changes that will be required to remedy this include updates to all of the facets of regulation discussed in this document. Of course, it is also important that clear policy is put in place to drive the necessary regulatory adjustments and to provide strong planning criteria.

7.5 Policy Recommendations

Based on findings of the current adequacy of the transmission infrastructure in the US, and on the ability of the current regulation to support future adequacy, the author presents the following recommendations to policymakers who are concerned about maintaining a transmission system that fulfills the current goals of generator interconnection, reliable power delivery and economic efficiency and that will support future policies that may necessitate large quantities of clean power generation:

- Current conclusions on transmission inadequacy, the need for policy change, and the need for additional investment may be founded on metrics that are not relevant or indicative of this conclusion and should be questioned. Any policymaking efforts based on such arguments should demand more in terms of proof that there is call for regulatory change.
- An effort should be made to improve the breadth and quality of information available on the state of the transmission system. This will facilitate the ongoing assessment of the adequacy of the network in a more precise and efficient manner.
- To fully realize all prospects for increased economic efficiency, it is necessary to have some process through which inter-regional planning can recognize major opportunities. There may also be cause for clarification of the economic criteria used to address intra-regional economic efficiency.

- In expectation of a federal environmental policy, procedures should be put in place to perform inter-regional planning and facilitate cost allocation across RTOs. Similarly, regulatory changes should be made to support the long generator interconnection lines that will be needed to connect wind and solar plants to the grid. These improvements will also support goals related to economic efficiency.
- To properly motivate regulatory changes and provide the guiding criteria for future planning, there is a need for policy certainty. Of course, this requires action on the part of Congress in the form of definitive energy and climate legislation. Care should be taken to word legislative language such that it may be incorporated into the regulatory framework with minimal ambiguity as to the desired outcome. This demonstration of political will would have the effect of providing the framework necessary to make the appropriate changes to transmission regulation and promote the construction of an "adequate" transmission system.

A particular challenge associated with several of these recommendations is the required shift in scope of several transmission functions from a regional to an inter-regional (or interconnection) level. Given the evolution of transmission regulation to date and the current administrative structure, seams problems between regions are both to be expected and hard to remedy. Under today's system, regional interests prevail and there is significant opposition to bodies with broader geographic authority and decision-making processes that take a more "one world" view of benefits. That said, history suggests that over long periods of time it is possible to expand the scale at which the transmission system is planned and paid for, especially if policy is put in place that requires a high level of coordination across regions whose interests are increasingly aligned.

7.6 Future Work

This investigation has attempted to create a framework for thinking about adequacy and has taken a novel and multi-pronged approach toward assessing the current system status. Although these methods combined to create a case that the author hopes is compelling, they are certainly not the only way of approaching the problem of adequacy. More analytic investigations could make an attempt to collect more quantitative data on system utilization, economic efficiency, and reliability. Alternatively, modeling exercises – paired with proper databases and tools – could be used to assess the system's ability to operate within the chosen criteria. Furthermore, sufficiency in transmission investment is certainly not a static condition. Both the definition of adequacy and the state of the network change with time and are impacted by external factors like policy, fuel prices, the quantity and nature of demand, and weather patterns. As such, adequacy should be constantly addressed as the power system evolves.

Throughout the course of the research described herein, other issues associated with transmission regulation became apparent. These open questions could be fodder for future study. For example, it is not clear whether reliability standards are too stringent (i.e. the US may pay more for reliability than it is worth). It is also not clear that the application of standards is in line with their intent or if their application is overly conservative. Furthermore, it could be worth establishing a planning method that eliminates the theoretically shaky distinction between reliability and economics. Another pair of issues that are wanting of more attention is planning and cost allocation, on both an intra- and inter-regional level. It is clear that these two issues may be major roadblocks to future transmission adequacy, and proposals for improved practices would be useful. Finally, it would be useful to have an elegant and effective way of ensuring that policy lines are built into the system in an efficient manner that allows national goals to be fulfilled. Any of these topics would make for great research projects in the future.

7.7 Final Remarks

This investigation set out to address the prevailing wisdom that holds that the electricity transmission network is inadequate to meet the goals of the United States' power system. With a focus on restructured regions, it was first made clear that such claims of inadequacy were often based on quantitative data that did not clearly support the conclusions that were being drawn from it. The investigation that followed – using a regulatory rational approach paired with interview data from professional transmission planners – revealed that while claims of inadequacy may not be completely inaccurate, the specific concerns are probably misplaced. In fact, as it stands the transmission network in the United States is both reliable and quite economically efficient, at least on a regional basis. Moreover, major opportunities for system improvement lie not in areas where current development processes try and fail, but where they do not look, namely, between regions. Setting aside specific shortcomings in the narrow scope of the existing planning processes, the most pressing concern for maintaining an adequate transmission system is how we expect the definition of adequacy to change in the future. If energy and environmental polices demand a system that must incorporate large amounts of renewable power, likely from distant resource locations, there is a critical need to adjust the regulatory structure so that the transmission system may evolve and continue to serve the goals of the nation.

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Appendix A: Maps

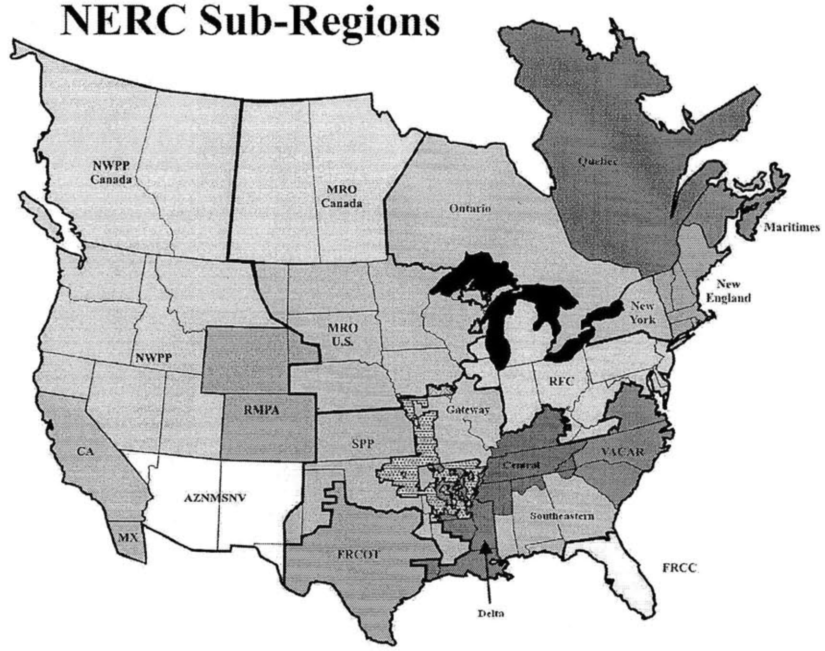

Figure 22: NERC Sub-regional reliability organizations (NERC 2009)

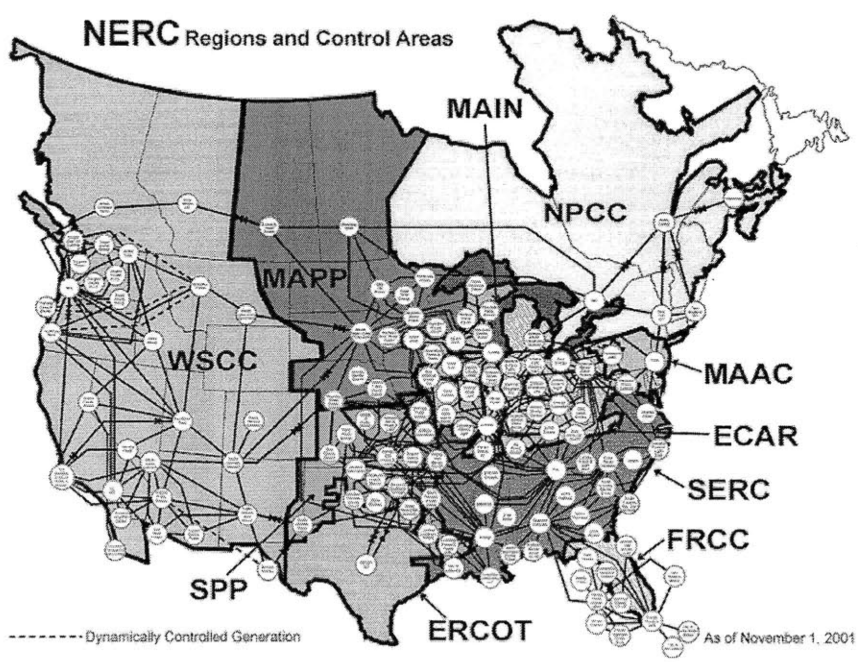

Figure 23: NERC Regions and Control Areas (US Department of Energy 2001)

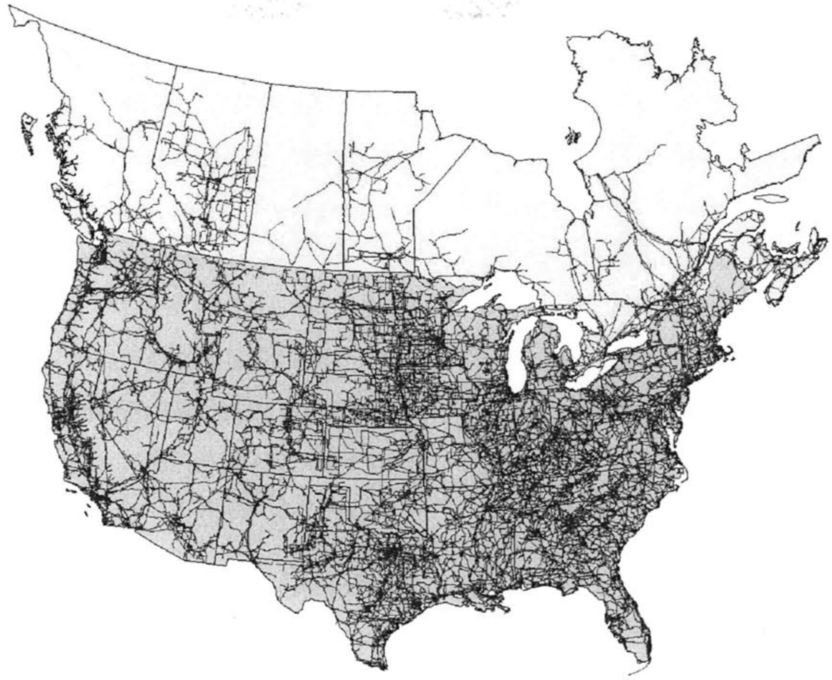

Figure 24: The US and Canadian High Voltage Transmission Network[97]

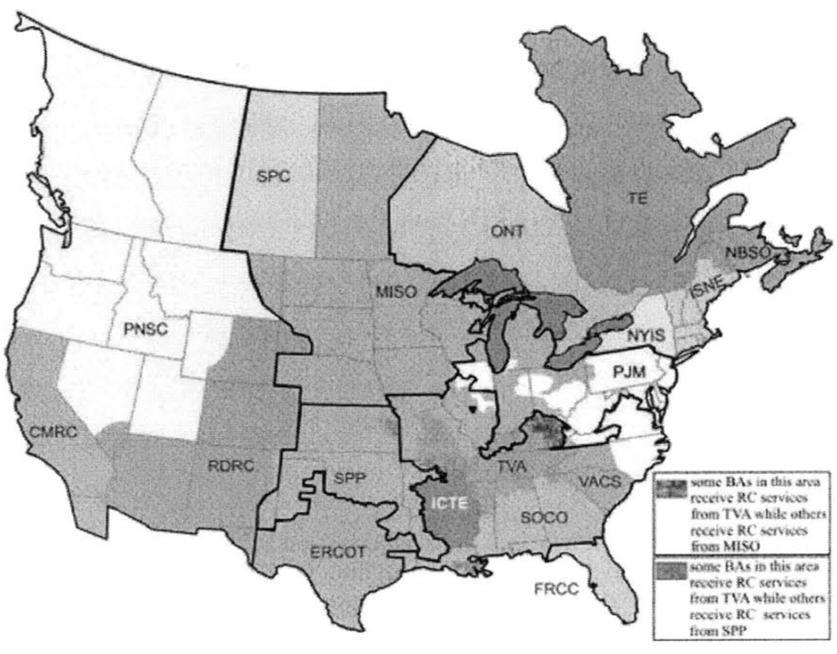

Figure 25: Reliability coordinators in the US and Canada (map from NERC)

[97] Generated using the Platts transmission line overlay in ArcGIS.

Appendix B: Transmission Loading Relief

Transmission Loading Relief (TLR) is a reliability standard laid out by NERC that establishes procedures by which a network authority may act in real time to manage events in the case that operating limits or reliability limits face violation. During a TLR event, or call, the NERC rules require certain parties to adjust their generation or consumption schedules until excess flows over congested lines are once again within predetermined safe limits. The particular limits that the standard pertains to are Interconnection Reliability Operating Limits (IROL)[98] and System Operating Limits (SOL)[99]. The TLR standard applies to reliability coordinators, transmission operators, and balancing authorities in the Eastern Interconnection[100]. TLR standards were first put in place in 1999 and the most recent iteration of the standard, IRO-006-4.1, became effective on December 10, 2009 (North American Electric Reliability Corporation 2007).

TLR events are divided into seven levels (see Table 3) based on the severity of the violations and the priority of the service that must be curtailed to bring the system back within acceptable limits. Transaction priority is lowest for short term non-firm service and increases through different time scales, where long term firm service has the highest priority (see Table 4). At each TLR level, the reliability coordinator must take certain actions which gradually affect higher and higher priority transactions are affected. At the lowest levels of TLR, the coordinator may only need to hold transactions at the present level or reallocate low priority non-firm transactions. At the highest levels, the coordinator must take more drastic action and change the schedules for high priority firm transactions(FERC 2010). All TLR events of level 2 and higher are reported to NERC and available to the public.

[98] According to the NERC Glossary of Terms Used in Reliability Standards, IROLs are "A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System" (http://www.nerc.com/files/Glossary_12Feb08.pdf).

[99] According to the NERC Glossary of Terms Used in Reliability Standards, SOLs are "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria." These values may include facility ratings, transient stability ratings, voltage stability ratings, and system voltage limits (http://www.nerc.com/files/Glossary_12Feb08.pdf).

[100] The Western Interconnect and ERCOT have different interconnection-wide loading relief standards which are not cited often in literature about transmission adequacy. The WECC standard is IRO-STD-006-0 and is called the Qualified Path Unscheduled Flow Relief (http://www.nerc.com/docs/standards/rrs/IRO-STD-006-0_17Jan07.pdf). The ERCOT standard is provided in section 7 of the ERCOT protocols which discuss congestion management issues (http://www.ercot.com/mktrules/protocols/current).

TLR Level	Coordinator Action
1	***Notify*** reliability coordinator of potential SOL or IROL violation.
2	***Hold*** Transfers at current level to prevent SOL or IROL violations. This does not apply to transfers using firm transmission service.
3a	***Reallocate*** transmission service by curtailing transactions using non-firm service to allow transactions with higher priority. This action follows service priorities.
3b	***Curtail*** transactions using non-firm service to mitigate a SOL or IROL violation. This action follows service priorities
4	***Reconfigure*** the transmission system to allow transactions using firm service to continue. Here, there may or may not be a SOL or IROL violation.
5a	***Reallocate*** transmission service by curtailing transactions using firm service on a pro rated basis. Goal is to accommodate all firm transactions but at a reduced level.
5b	***Curtail*** transactions using firm service to mitigate a SOL or IROL violation. Curtailment takes place on a pro rated basis.
6	***Emergency procedures***. This process may include demand side management, re-dispatch, voltage reductions, and load shedding.
0	***Conclude*** TRL event. System state is returned to normal.

Table 3: NERC TLR Levels and corresponding coordinator actions

Service Priority	Name
0	Next-hour market service
1	Service over secondary receipt and delivery points
2	Hourly Service
3	Daily Service
4	Weekly Service
5	Monthly Service
6	Network Integration Transmission Service from sources not designated as network resources
7	Firm Point-to-Point Transmission
7	Network Integration Transmission Service from Designated Resources

Table 4: NERC transmission service reservation priorities.

The set of specific entities responsible for managing and reporting TLR events is different from any other regional structure discussed in this paper thus far. Figure 25 (Appendix A) shows the regional breakout of the different reliability coordinators. The reporting is made somewhat more complicated by the fact that some areas are subdivided into smaller territories where local transmission operators or balancing authorities may also be managing TLR calls, not to mention the fact that these jurisdictions have changed over time. Also, as mentioned in the body text, the operational structure can affect TLR reporting and regions that establish central operators with re-dispatch ability (namely: RTOs) will use this capability in place of the need for TLR calls. This fact is most evident in restructured regions that have put in place location constrained wholesale electricity markets, which have the function of incorporating reliability constraints and causing TLR curtailments to become less necessary and widespread.

Reliability Coordinators	Code
American Electric Power	AEP
Allegheny Power	AP
California Mexico Reliability Coordinator	CMRC
Entergy Services, Inc.	EES
Cinergy	EMSC
Florida Power & Light	FRCC
Hydro Quebec, TransEnergie	TE
Independent Coordinator Transmission - Entergy	ICTE
Independent Electricity Market Operator (Ontario)	IMO
ISO New England Inc.	ISNE
Mid-America Connected Network	MAIN
Mid-Continent Area Power Pool	MAPP
Michigan Electric Coordinated ystems	MECS
Midwest ISO	MISO
New Brunswick System Operator	NBSO
New York Independent System Operator	NYISO
Ontario - Independent Electricity System Operator	ONT
Pacific Northwest Reliability Coordinator	PNSC
PJM Interconnection	PJM
Rocky Desert Reliability Coordinator	RDRC
Saskatchewan Power Corporation	SPC
Southern Company Services, Inc.	SOCO
Southwest Power Pool	SWPP
Tennessee Valley Authority	TVA
VACAR-South	VACS
VACAR-North	VACN

Table 5: Reliability coordinators and other parties who have reported more than 10 TLRs since the standard was first approved

For the sake of the analysis provided in this paper, all available TLR data was gathered from the NERC database and aggregated into a single worksheet. An attempt was made to make all of the data internally coherent, as some parts of the data reported events slightly differently (e.g. SPP and SWPP were used interchangeably over the years). For ease of comparison and data handling, TLR levels with sublevels (i.e. 3a and 3b. 5a and 5b) were combined to represent just the numbered level. Statistics were then gathered to generate the plots provided in the body text and the table of all recorded events found in Table 6 (with the exception of regions with less than 10 events over the decade of reporting). It should be noted that this data set is more thorough than what is usually presented in the literature, as the standard data provided by NERC only parses TLR calls by Level 2+ and Level 5+.

Authority	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
AEP	12											12
AP	12	43	82	25								162
EES	29	38	48	34	95	154	170	190				758
EMSC	59	346	159	124	16							704
ICTE								32	305	353	266	956
IMO	22	7	26	8	45	35	59	1				203
MAIN	148	283	551	49	46	11						1088
MAPP	9	32	61									102
MECS	12		25									37
MISO			40	950	1221	1281	1291	800	819	599	381	7382
NYISO											109	109
ONT								30	52	161	169	412
PJM	1			95	281	429	326	136	80	150	129	1627
SWPP	30	142	86	157	228	317	296	535	1824	1879	1983	7477
TVA	3	68	3	49	52	74	250	176	114	158	59	1006
VACN	14	2	3	3	5	9	3					39
VACS	1	1					5	1	5		1	14
Total	**358**	**964**	**1084**	**1494**	**1990**	**2312**	**2400**	**1901**	**3199**	**3300**	**3097**	**22099**

Table 6: Count of TLR calls by authority (excludes authorities with less than 10 calls for the decade)

Appendix C: Generation-Load Proximity Analysis

The goal of this exercise was to show that natural gas fired power plants are, in fact, located closer to load centers than other traditional forms of generation. The chosen method was to us Geographic Information System (GIS) software to map the linear distance from select load centers to power plants of each type. For each of the cities selected, the distance to every power plant in the US was computed. Using this output, the closest 10 gigawatts (GW) of generation capacity for each major plant type (hydro, coal, nuclear, oil, gas, wind, solar) were determined and the average distance to each type of plant was calculated (Figure 26). Oil, wind, and solar plants all turned out to be so diffuse and/or so small that the average distances skewed the results. For this reason, and because they provide a very small percentage of total power consumed in the US, they have been left off the plots below. Since many parts of the US do not rely on all of the power sources analyzed, conclusions about relative distance to load from generation where based on a comparison with the next closest type of generation, rather than all of the other forms of generation (as seen in Figure 11 above). Finally, to verify that the generating capacity choice of 10 GW was not giving a misleading result, the process was repeated for 5 GW (Figure 27) and 2 GW (Figure 28). If anything, the smaller capacity calculations showed more extreme results (see Table 7). Calculations were not repeated for larger capacities, as this would start to exceed capacity required by certain cities.

Software: ESRI ArcGIS, licensed by MIT for affiliates

Data Layers: Provided by Platts, licensed by MIT for affiliates. Specific layers used included a generic layer of major American cities and a Platts layer of all US power plants.

Load Centers: Cities were chosen not with any quantitative characteristics in mind. Rather, a geographically diverse mix of large, well known cities was chosen. The objective was to include all major populated areas (Midwest, West Coast, Gulf Coast, Atlantic Coast, New England) in such a way that a variety of fuel mixes would be represented.

Limitations: It should be reiterated that the goal of this analysis was to confirm the oft repeated statement that gas generation is closer to load than most other major types of power plants. In the context of this paper, this statement was used to make the point that less transmission capacity is needed to interconnect gas generation capacity, which was prevalent among new installations during the 1990s and 2000s. There is certainly room for improvement with this analysis and it is far from rigorous. Some apparent flaws include that fact that there are significant capacity factor differences between different types of plants, there is no way to know for sure where any given kWh originates, and small gas turbines may even hook directly into the distribution system, bypassing the transmission system entirely. Despite these imperfections, the point of the analysis shines through: natural gas power plants are much closer to load than other major types of power plants.

Generation Capacity	Ave. Distance to NG Capacity (miles)	Next Closest Ave. Distance (miles)	Relative closeness of NG plants
10 GW	51	255	40%
5 GW	26	84	31%
2 GW	16	45	35

Table 7: Relative closeness of Natural Gas generation capacity to next closest generation type

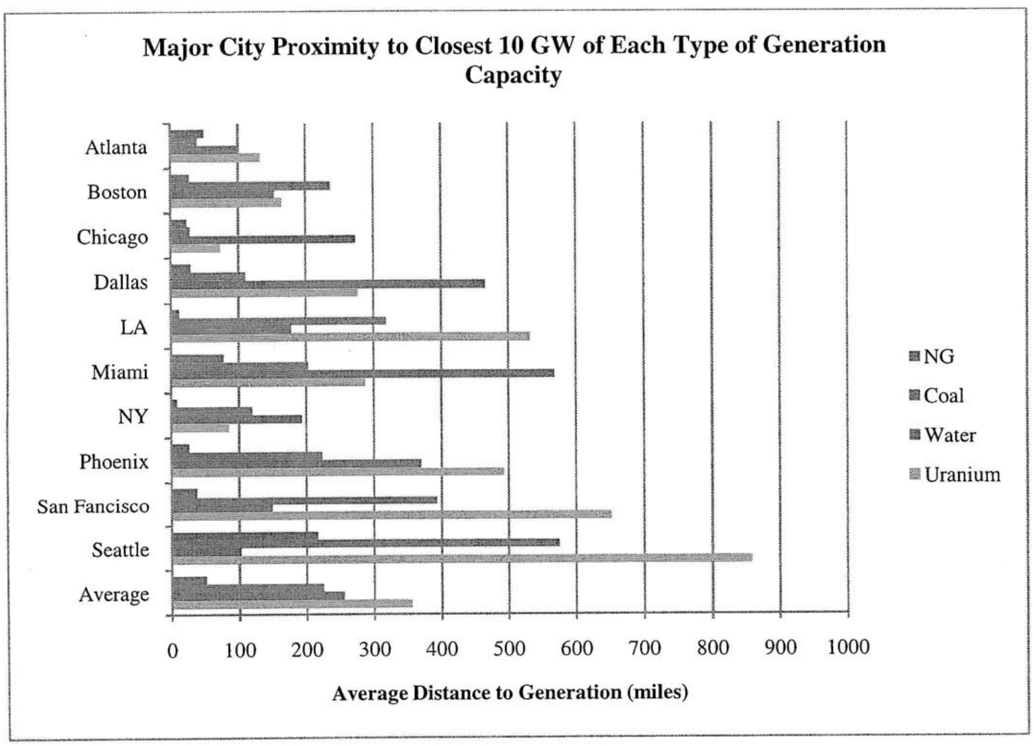

Figure 26: Proximity of closest 10 GW of generating capacity to major load centers, by fuel type

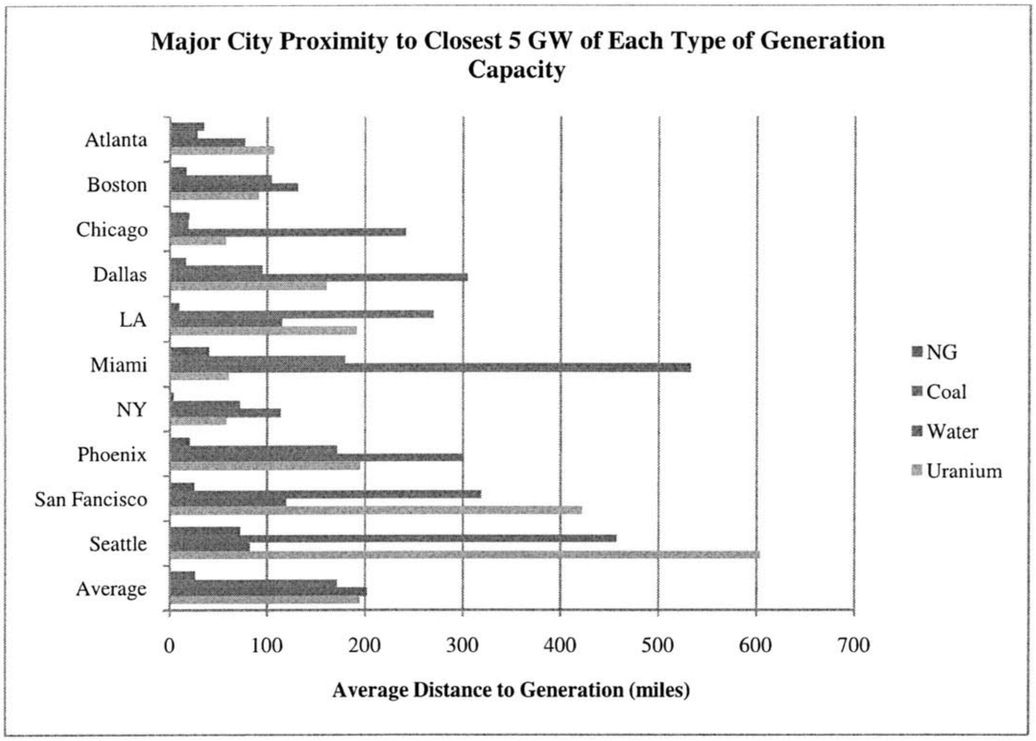

Figure 27: Proximity of closest 5 GW of generating capacity to major load centers, by fuel type

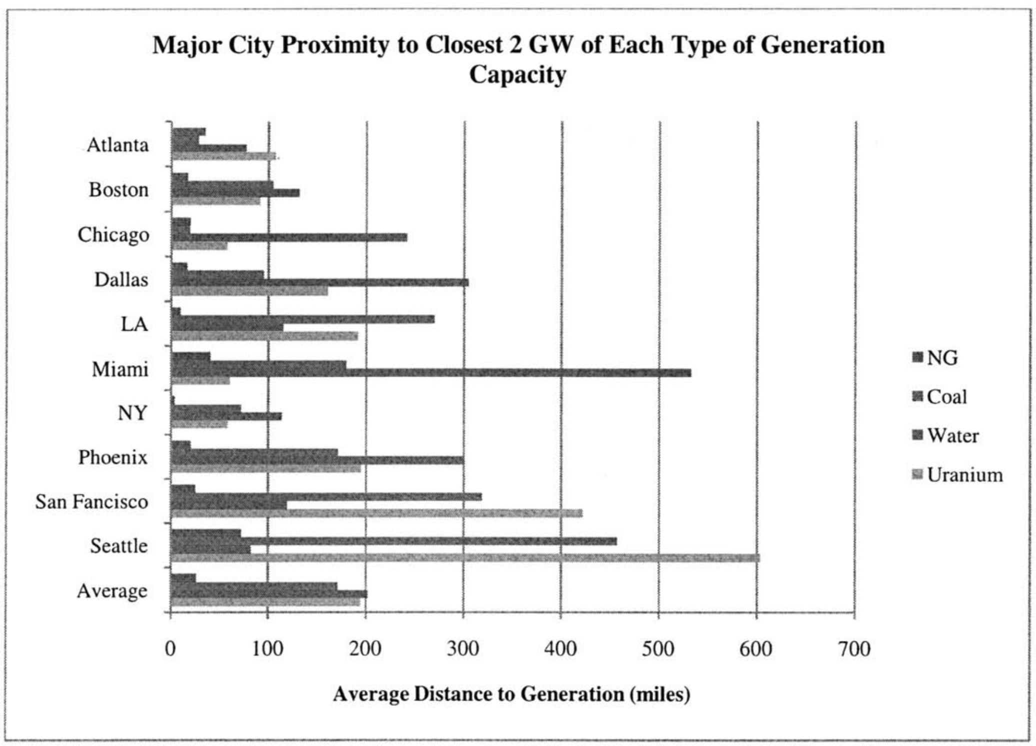

Figure 28: Proximity of closest 2 GW of generating capacity to major load centers, by fuel type

Appendix D: Weighted Line Capacity Calculations (MW-miles)

Though plots are available in the literature, transmission capacity calculations were repeated for the sake of this study. This process allowed for both a greater understanding of the data and increased analytical flexibility. The NERC ES&D dataset was used for line miles installed, which reports high voltage installations after 1990. Though this collection of statistics reports line lengths sorted into buckets (e.g. 200 kV – 300 kV), all lines in each bucket were assumed to be the most common voltage within the range (see Figure 29).

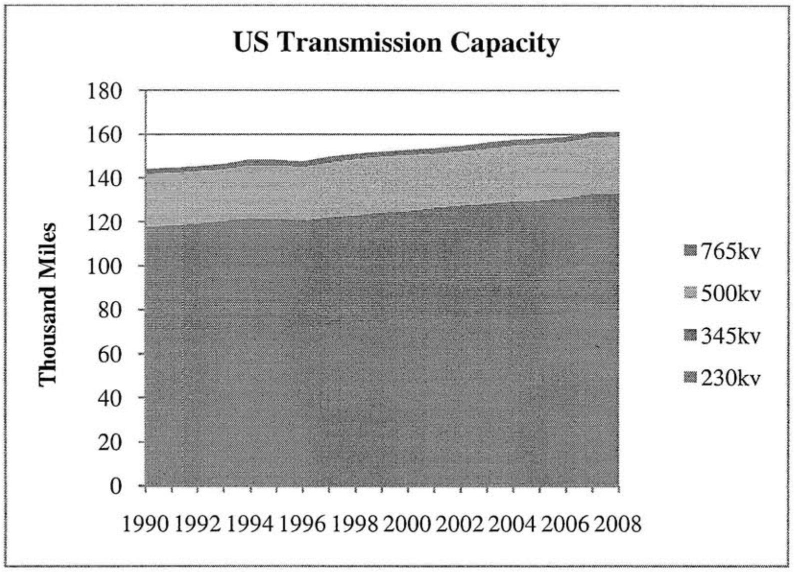

Figure 29: US transmission capacity (miles) by line voltage based on NERC data

Once the lines had been divided into discrete voltages, they were then weighted by the capacity and the average circuit count of all lines of each voltage (see Equation 1). Capacity specifications were available from several sources, but AEP's quoted numbers were used (see (Table 8). This choice affects the results, but should not make a huge difference in the outcome and will certainly not change any conclusions. Circuit scaling factors were derived from the Platts 2008 GIS data layer, which details the length, voltage rating, and number of circuits of every transmission line in the United States. While this data set is not complete – it does not match NERC or EEI data on total transmission invested – it is the best source of detailed information on individual transmission lines. For this reason, it should serve the purpose for which it is used here: determining how many circuits[101] are used, on average, for each level of transmission (see Equation 2). It was further assumed that transmission capacity scaled linearly with circuit count. The results of these analyses can be seen in Figure 30.

[101] A transmission circuit can be thought of as a single set of conductors of a specific voltage. Multiple circuits are simply additional sets of conductors strung along a single transmission corridor.

$$\text{Weighted Transmission Capacity} = \text{Miles} \times \text{Line Capacity} \times \text{Circuit Scaling Factor} \qquad \text{(eq.1)}$$

$$\text{Circuit Scaling Factor} = \frac{\sum \text{Individual Line Length} \times \#\,\text{Circuits}}{\sum \text{Individual Line Length}} \qquad \text{(eq.2)}$$

Voltage, kV	Capacity, MW (AEP)	Capacity, MW (Hirst and Kirby)	Circuit Scaling Factor, circuits/line
230	500	350	1.21
345	967	900	1.20
500	2040	2000	1.11
765	5000	4000	1.36

Table 8: Capacity by line voltage

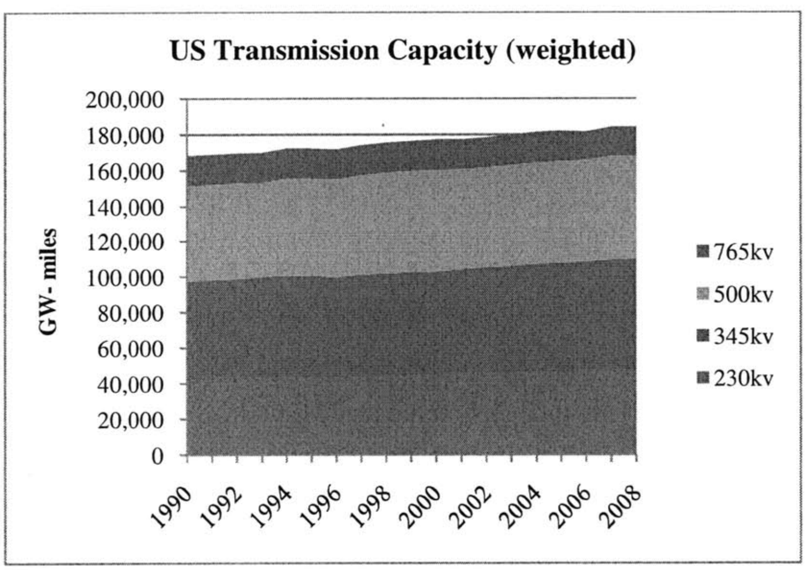

Figure 30: Weighted US transmission capacity (MW-miles) by line voltage based on adjusted NERC data

Appendix E: The Interview Transcript

What follows is the transcript used during the interviews for the qualitative investigation component of this study. The list of questions was primarily intended as a guide for each conversation, and not all questions were asked in every interview depending on the organic path that each discussion followed.

Introduction

Before we start the interview, have you read and understood the consent form that was provided? Do you have any questions to that end? If you have not yet faxed or emailed the form back to me, would you do so as soon as this interview concludes?

I am going to start recording now.

So as a brief reminder, my current research position is with MIT's Future of the Electric Grid Study, a faculty-led, interdisciplinary project that seeks to examine the substantial issues surrounding the national initiative to enhance the functionality and reliability of the electric grid in the United States. Within the broader study, my focus is on the electric transmission system and my goal is to assess to what extent current levels of investment are allowing the goals for the network to be achieved. The output of this work will be a subset of the MIT study findings and the basis for my Master's thesis.

To address the issue of transmission infrastructure sufficiency, I plan to take an approach that is perhaps outside the norm. Rather than simply looking at traditional quantitative indicators of transmission investment and infrastructure performance, I plan to interview people like you who are involved in the transmission development process. In these interviews, I hope to hear from transmission professionals about their thoughts on transmission adequacy (e.g. How should we think about it? Do we have it?) and gather anecdotal and empirical evidence that will help me arrive at a conclusion about the state of the current system. Based on my findings, I will attempt to both lay out a framework for thinking about transmission sufficiency, including a determination of whether we have it, and formulate policy recommendations about how the US should proceed with any changes to transmission regulation.

I am happy to tell you more about my thoughts on the matter and the results of the work I have done thus far, but I'd like to save that discussion for after the body of the interview. This will allow me to better ensure that I am not introducing personal bias into the research process and that my findings from this interview are not unduly influenced by other aspects of my work. Also, any products of my research will be publically available – with the exception of non-released identification information, of course – so you will have access to the full body of my work and recommendations upon the completion of my thesis.

And to establish some expectations, I hope for this conversation to take between one half and one hour. I have 11 initial questions, so you can scope your answers accordingly, and I may ask some follow up or clarification questions as we go.

Do you have any questions of clarification before we begin?

Questions

1. Can you explain your personal role at *organization name* as well as any other experience you may have in this sector? This will help me to categorize and interpret your answers during my analysis.

2. How do you think about adequacy of investment in the electric transmission system? In addition to this, what do you think would be the best indicators of whether or not we were investing in the network at appropriate levels?

3. Have you observed any change in the definition of adequacy over time? Do you see it changing in the future (e.g. under a carbon constrained national energy policy that could lead to large scale deployment of renewable/ variable generation concentrated in specific locations)?

4. Based on your experience, do you think that current levels of transmission investment are adequate to serve our short term needs? Long term needs? Based on what? And what are the major obstacles to arriving at this state?

5. Does the procedure you use rely on comparisons of cost and benefit? If so, how do you define or think about benefits and costs with regard to the transmission system? What procedures do you follow or recommend when measuring benefits and costs? What are the outputs of your processes and how does that impact the investment decisions you make?

6. What has been your experience with lines that have a greater benefit than cost but where uncertainty makes the advantage less clear? Could you provide me with some data about such lines?

7. Do you know of any planned transmission lines (either by you or other parties) that have not been built but that have clear economic benefits that outweigh the associated costs? Would you be willing to provide data about these lines, or point me in the direction of the right materials to find the information?

8. Similarly, have you ever heard of a line being built for which the costs clearly outweigh the benefits?

9. In general terms, what is your answer to the same questions concerning transmission-related investments other than lines, such as synchronous condensers, reactances or capacitors to control

voltage or reduce losses, FACTS devices, phasor measurement units, enhanced control or protection systems, etc.? In response to which types of engineering problems (e.g. low voltages, instabilities, etc) do you see these types of investments being made?

10. Going forward, what do you think about the ability of current regulation to result in adequate transmission investment under scenario where no new regulations are created (i.e. no carbon price/RPS)? What about under a carbon constrained scenario with potentially large volumes of renewable generation?

11. Is there anyone else you would recommend talking to on this issue (either in your organization or at another organization)?

12. Do you mind if I contact you with follow up questions?

Appendix F: Sorted Relevant Text from Interviews and Proposed Themes

As described in the text, in the name of transparency it is important to provide the documentation from which the theoretical constructs and narrative evolved. This appendix strives to provide such documentation and includes much of the relevant text, repeating ideas, themes, and theoretical constructs. It is organized in such a way as to be accessible and keep similar topics together. The primary layer of bullets represents what the author sees as repeating ideas, and listed below those – on sub-bullets – are the relevant text that supports the repeating idea. The relevant text has been maintained because it provides useful color to the final theoretical narrative in addition to forwarding the goal of transparency. "Potential Themes", while they may be supported further in later sections of the text, are presented above the topic where they originated from repeating idea. Theoretical constructs are listed first (though they were formulated last). Finally, The particular interviewee (or his/her organization) who provided a comment is only noted if it is particularly relevant to understanding the text.

Potential Theoretical Constructs (based on themes)

- The definition of adequacy as presented is relevant
- The state of reliability investment is adequate, at the least
- The state of traditional generator interconnection is adequate
- The state of economic investment is not conclusive, but there is no reason to suspect a major problem with adequacy
- The ability of transmission to support policy goals is poor and in need of improvement if policy requires such development, which will require major regulatory action
- Policy certainty is vital to ensuring transmission adequacy in the future

Repeating Ideas and Potential Themes

Adequacy Definitional Issues

Potential Theme: The original proposed definition of adequacy holds with some minor changes
Potential Theme: Reliability is the prime objective and, for now, others are secondary
Potential Theme: The definition of adequacy will probably not be changing again soon

- Adequacy is not a binary outcome
- Transmission adequacy is a function of the energy market today, and as the underlying commodity prices shift the perception of the market shifts
- Generator interconnection as an issue for adequacy

- (Renewable) generator interconnection is now dominating the interconnection queue
- The linkage between resource adequacy and transmission adequacy is not yet well defined and has no set standards (this could be useful with more renewables)
- Policy lines can be thought of as a slant on the traditional generator interconnection framework, where lines are planned , financed or allocated differently in a special case – new proposals are coming to address this

- Reliability standards take precedence over everything, need to keep the lights on
  - Planners don't get to focus on other issues until reliability standards have been met
  - Conditions are defined so that we're not looking at naïve or overly catastrophic situations, but ones that are pragmatic and may actually occur
- Economics as an indicator of adequacy, want to efficiently deliver resources
  - "the marginal benefits is equal to the marginal cost for the next unit of expansion" (the classical definition) (Coxe)
  - Ensure that transmission does not constrain the generation marketplace
  - Can you do something to the system (transmission, generation, demand response) to make it operate more efficiently (improve operation, efficient use, wise use)?
  - Customers may not care as much because they do not see the market price of electricity
  - This can be looked at as carrying cost relative to yearly efficiency savings (ERCOT)
- Not much is going to change in the definition of adequacy going forward
  - The recent addition of policy lines and renewables is an unusual and major change
  - There could be small changes by alterations in NERC criteria or specific criteria used to evaluate economic projects
  - Clarification and codification of energy policy will be important to solidifying this change, including the FERC NOPR and pending climate and energy legislation
- Operational issues may also be a justification for upgrades
  - These are brought up by PJM interviewees only and are apparently very rare

Reliability Lines

Potential Theme: Building for reliability purposes is relatively easy
Potential Theme: The system is adequately invested, if not over-invested in reliability

- The system is very reliable
  - Trying to stay in line with need and load growth changes and we are pretty good at this
  - We may not be ahead of today's needs, but we are usually pretty on top of the situation

- Some places are seeing less of a need for these lines now given the slow in load growth after the recession
- NERC standards are strict, and perhaps too strict – and any requirements that result in deviation from and idealized investment framework should at least be explicitly recognized
- The vast, vast majority of projects are driven by reliability criteria
- Based on requirements in place, the grid is very adequate for reliability purposes
- Even LMP markets enable signals about reliability, and chronic congestion and operation of older inefficient units tend to be indicative that there is a problem from a reliability standpoint (ISO-NE)
- The system is probably always more reliable than is actually required

- For reliability, the economics concept has a different meaning
  - In this case, it is the tradeoff between the different ways of relieving a reliability constraint
  - The economics tend to advance the need in terms of reliability (Exelon)
- People respond well to being told a line is for reliability, it is easy to sell
- Reliability standards can get muddy because transmission authority is responsible for defining the critical system conditions under which reliability tests are performed, and there is more than one such authority
- Tough questions are asked during siting hearings, but as soon as people are convinced that a line is needed they are good at ensuring that a line is built

Adequacy of Economic Lines

Potential Theme: To the extent that entities are able to seek out economic opportunities, there is no reason to suspect that there us underinvestment in economic lines
Potential Theme: The odds are stacked against economic lines, both by design and by merit of the fact that there are no entities that are very good at or devoted to looking for them
Potential Theme: Many economic opportunities are swamped by reliability projects (and in the future they may be swamped by renewables development)
Potential Theme: Inter-regional economic opportunities may exist notionally, but they are not being looked for, and thus not being exposed and not being built

- Unbuilt economic lines are not forthcoming
  - SCE - Thinks they must be out there but nothing jumps to mind

- Coxe - could probably give more examples of lines that should not have been built than lines that were not built that should have been – it may be worth looking at lines that were materially delayed
- "There almost certainly lines are lines in the set, but your challenge may be to figure out is the perception greater than the reality. The popular perception is that there are a large number of highly attractive transmission projects that aren't being built for a variety of easily solvable regulatory reasons." (Coxe)
- Exelon - there are just not that many real economic opportunities on an objective basis that would justify the construction of high voltage lines – while people may say these lines exist, the evidence is not forthcoming (beyond just having congestion)
- PJM - Has heard stories in the industry, but right now cannot point to specific projects – anecdotally hear about lines that cross state boundaries that one state stops from being sited
- PJM – these lines may not exist because they don't spend much time looking
- A lot of the press may not be about short term economic issues, but instead is about the flexibility of the system to respond to opportunities
- its not that we don't have adequate [transmission to serve the load] it's that we don't have adequate [transmission] to serve a highly flexible energy resource type of market
- Finding economic opportunities is easier said than done
- Most of the opportunities within RTOs are handled and realized – what may be missed is the inter-RTO (cross-seam) opportunities (more below)
- Can't imagine that there are opportunities within markets and within regions, the problem is between regions
- Haven't seen anything that jumps off the page that says that a big opportunity is being missed but they haven't been able to fund

* Third party (interstate) projects often show desirable economics, but not convincingly
* Many projects that could be built for economics are already justified based on reliability
    - TOs in MISO tend to make about $500M in reliability investments that have as much as $1B per year in congestion relief
    - once you plan a reliable system, you end up with a little excess capacity that might hurt economic opportunities – as such, reliability development might end up reducing economic investments - there is not enough congestion remaining to drive new investment
    - "tomorrows reliability project is today's economic project" (caspary)
    - ISO-NE has had a great deal of success in building reliability lines, and from these successes, have gained a lot in terms of economics

    - Reliability lines may not wipe out economic opportunities in the west as they do in the east - The east has solid population while the west has pockets of load in desert oceans – so the west sees a lot of long lines to move power from place to place
- Some lines start out as justified by economics and are finally built for other reasons
    - PDV 2 is an example of a line that started out for economics (power import from AZ) and ended up being a project to serve renewable development, changes in price differentials between CA and AZ caused the line not to be extended into AZ
    - Sunrise as an example of a project that started as an economic project and ended up being a reliability project, primarily – reliability drove the timing and economics drove the project selection
    - At some point all projects are needed for reliability (Exelon)
    - There are probably not as many economic lines built as they expected when they started the TEAM process – very few purely economic lines (most have a reliability or policy use)
- The economic criteria are set up to ensure that only the most beneficial lines are built
    - This may cause people to invest preferentially in generation
    - CARIS, for example, is very stringent
    - need to have very high prices in some places and very cheap power elsewhere or a constrained interface where you must pay for RMR units
    - takes a huge benefit to justify transmission because it is so expensive
- Very little time is spent out looking for economic opportunities (maybe)
    - In CA, this is at least in part because of uncertainty challenges
    - Only recently has PJM spent much time looking for opportunities (esp low voltage)
    - Tend to end up with a reliable system that is efficient but not as efficient as it could be if you had infinite time and infinite analysts (technical and process problem that will result in a good but not the best solution, try to get better at every year)
    - AEP rep doesn't think that transmission is being short changed from a time and resources point of view (the problem is more with the fact that policy and reliability lines swamp the opportunity)
    - For economics, doing nothing (or the cost of doing nothing) is often acceptable
- The economic test may be most useful for local lines where you are only concerned with a single load pocket and don't have to deal with broader market impacts
- Nobody is particularly good at looking for economic opportunities

- For RTOs, planning for economics is challenging because there is a need to expand to demand and supply considerations and all of the associated uncertainties -Now not only need to be a transmission expert, but also an expert at predicting the future
- It is easier to develop for reliability with bright lines rules, and economic development is harder because there are lots of subjective elements and uncertainty involved – there is much more to be challenged
- Transmission entities are traditionally reactive and not proactive, they have in the past responded to changes in the market and have not tried to affect changes in the market (like deciding where the best renewable resources are)
- For utilities, analysis of economic opportunities is challenging because of a lack of market data - Utility analysis is primarily for screening purposes before proposed projects are sent to the ISO for validation

- There may be economic opportunities that are not being looked for but exist notionally
    - you might argue that there is not enough transmission in place to allow for cheaper generation in the west to get to load in the east, which could lead to lower prices in the east – this is economically good but not possible today
    - These projects don't get far in the process because flyover states do not want to pay because they might not benefit
    - The historical mindset is that transmission in RTO's jurisdictional boundaries will be approved because it benefits native load
    - Bigger picture planning has not been traditional view of electric utility companies, this is a new way of looking at the system
    - The biggest missed opportunities may be over flow gates that do not exist (e.g. cross seam opportunities)
    - Most of the opportunities within RTOs are handled and realized – what may be missed is the inter-RTO (cross-seam) opportunities (more below)
- If there were glaring and obvious opportunities out there (and they have had some opportunities to explore them, merchants have looked at these) they would be realized via merchant developments – this could be a way of showing that we are not currently missing big ticket items
- Barriers to transmission may be appropriate manifestations of a competitive market environment that ought to be allowed to work
- The regulatory problem is not a problem of money or insufficient returns
    - The regulated returns are very, very high

- The ability to get a high rate of return on transmission built privately under regulated rate of return makes transmission a very attractive investment (FERC gives great rates)

- The stakeholder process is effective but also significantly influences the outcomes
    - all of the opinions are heard and factored into the final decision, but slow process
    - The natural consequence is that financial implications to every member have to be heard and rolled into the solution, delicate balance
    - Adds to the technical and engineering aspects to fining a good, defendable solution – extra work to make sure that people understand the locational financial impacts
    - The right answer may be a function of what people can/will build rather than what is actually best

Merchant Investment and NTAs

Potential Theme: The current regulation is not friendly to merchant investments (which includes NTAs), nor do they exist on an even playing field

Potential Theme: It is important to consider NTAs, but there is not currently a good mechanism or perhaps the will and interest

- It is important to consider other all options to serving a need
    - This includes DG, conventional generation, etc.
    - People tend to forget that other things can be competitive with transmission and there is more than one way of achieving network goals
    - The industry has a management/structural culture such that bigger is always better (and with good reason for a while because of economies of scale)
    - We don't do a good job of looking for these opportunities (we do a little bit of it and a lot of lip service, but very little action)
- Merchant investments do not exist on an even playing field
    - This includes NTAs
    - the transmission investment takes a regulated risk which is much lower and guards against situations where investment is less valuable than expected – merchant investor is at the mercy of the market
    - There is also regulatory issues (another barrier) with the fact that scarcity rents may be confused with monopoly rents by regulators (they do not allow price differentials to persist) - markets have now been trained to realize that regulators are going to step in anyway so merchant investors stay away

- Transmission tariffs can only be used to pay for transmission investments
- No mechanism for RTOs to exercise NTA solutions, which creates bias towards transmission and causes some groups to be anti-transmission for this reason
- While financial instruments for transmission rights are interesting, they will not sustain most merchant investments, thus PPAs are vital to merchant development

Policy Lines

Potential Theme: The network requires expansion if it hopes to serve lots of renewables
Potential Theme: The current system is not prepared to plan for and deliver lots of wind, policy changes will be required
Potential Theme: Policy changes add uncertainty and increased the difficulty of planning

- The system is tapped out in terms of having the kind of spare capacity that would be required to serve lots of renewables and share resources
  - This can be evidenced by curtailment of wind in some areas
  - Areas with lots of wind are not well serviced with transmission at the present
  - We also might be planning too small to accommodate national policies
- The current system is not in a proactive way prepared to deliver lots of wind
  - Some places (e.g. PJM) do not have a plan for dealing with policy lines
  - MISO is still in the "embryonic" stages of planning for dealing with new resources
  - Don't know how to deal with operational requirements of renewables
  - The system is also not set up to do any sort of long lines
  - New proposals are being made to start to plan proactively (field of dreams)
- Very different approaches are being taken to planning and building for renewables at the present
- Dealing with contingency for long distance capacity is a large cost
  - Especially when compared with a local solution
- Transmission development (for renewables) cannot be left to generator developers
  - They are bad at transmission development
  - generators cannot be expected to front all of the funds
- Abandoned plant assurances are important for building lines to renewables
  - don't want to put all the risk on the shareholders
- Many states are content to harvest in-state renewable potential
  - CA is not looking elsewhere because there is lots of in state renewable potential, and building big long distance lines is both challenging and expensive

- TX will be similar until they run into barriers with having to incorporate massive amounts of wind

Planning

Potential Theme: Planning is a major issue with transmission development
Potential Theme: We may currently lack the necessary tools to continue to plan effectively
Potential Theme: Various uncertainties make planning in the new environment very hard

- We don't have to tools today to do the planning right and deal with policy and reliability
  - this information is not available or not fully studied today, and certainly not with agreed upon input of the stakeholders (NY)
  - the tools are not very well developed to do a good job of predicting the operation of the system in the future
  - tools are bad at finding problems and volatility ends up muted and the need for transmission is understated
  - Tools do not consider all of the reliability requirements and the data is not that great for how generation really operates – also, tools have perfect foresight and assume a perfect load forecast and do not capture a lot of the extreme events
  - is also challenging that operating criteria and planning criteria are different things
- Policy uncertainty makes it even harder
  - There is an imperfect view on how to promote renewables development in general
  - The biggest challenge is for the regulator to make clear what needs to be planned for now
  - Planners end up doing "faith based planning" based on predictions of future policy w
  - Challenges with establishing scenarios may make it very hard to show economic potential of a project
- Uncertainty makes it very hard to predict impact of transmission investments
  - CAISO does not have a good way of forecasting the future price of congestion
  - In CA, other changes in population and weather patterns change the way power is shipped around the SW and NW at different times of year, further complicating the situation
  - This is one of the great challenges of restructuring, don't know what the generation market is going to do and you don't want to distort it – don't know where generation is going to be
  - Know that there will be wind in the mid-west, but the mid west is a very big place and to built a grid to catch any project would be extremely expensive

- Also don't know how DG, DR or RECs are going to play into the system and how pervasive they will be
- Policy changes shift the resource mix and make it hard to plan
- CA, for example, has both requirements for renewables and a requirement to shut down once through cooling plants
- separate processes where you try to acquire generation and guess the price of the associated transmission and try to minimize cost, all of which is very hard

* Modeling the competitive, profit seeking behavior of generators is challenging
* Policy lines may depart from economic criteria
    - Cape Wind energy price given as an example
    - Hard to deal with paradigm shifts and how they play into the economic planning process
    - and it is hard to optimize for multiple criteria
    - As you have more zero bid projects, you may have more economic projects that look like policy projects as long distance wind is connected for import

Cost Allocation

Potential Theme: Cost allocation is a major issue with transmission development
Potential Theme: Unless all parties benefit, it is very hard to allocate the cost of a line (this is particularly troublesome in a multi-state approval process)
Potential Theme: The larger the line, the more clear the benefits must be

* Cost allocation is a challenge, maybe the biggest challenge
    - Has yet to be tested for a large interstate project
    - People cannot decide how they feel about a line until they know who is going to pay for it
* Cost allocation is particularly difficult when there are any parties that are hurt or whose interests are not forwarded
    - LMP markets make it very transparent for everyone to see if they benefit or are harmed
    - people in NE do not want to play for big, long lines and so if they don't want to pay for them, they don't want them to be built or planned for
* For large lines, success requires the involvement of lots of parties acting on a clear (overwhelming) economic opportunity
    - success in North-South projects along the Pacific Seaboard (PATH projects) were based on value proposition of the hydro resources and gas resources that could be traded

- when the business case is clear (or a line is required by deterministic criteria) there will be many fewer troubles with siting and cost allocation
- in this case, often merchant investors will take action (like Neptune and VFT projects)
- when there is clear benefit, things have a very high likelihood of happening
- The bigger the project, the more overwhelming the project's economics needs to be
- The bigger and more expensive a line is, the longer the lead time and payback period, and the longer the prediction time required, and thus the larger the uncertainty, etc.
- The proof is much easier with smaller lines and shorter lead times
- Larger projects will probably be driven by reliability criteria

Planning AND Cost Allocation

Potential Theme: Planning and cost allocation are intricately interwoven issues
Potential Theme: The long life of transmission investments complicates transmission projects
Potential Theme: The (relatively) long development process complicates transmission projects

- Cannot separate issues of planning and cost allocation
    - Can't get very far in planning and construction of a project if there isn't agreement and understanding on who would pay
    - A lot of the overlay and conceptual plans are based on assumptions of future, but it is also important to figure out who is going to pay
- the situation is made more complex when looking at it on an inter-regional basis
    - seams between restructured regions and between restructured regions and vertically integrated regions - no good way to model this
    - "the degree of difficulty in building inter-regional transmission projects is tremendous" because of different process speeds (getting through the interconnection process, the requirement for local upgrades to be supported at a high price, etc) and general hostility from source-area transmission providers
    - Uncertainty problems are magnified when broadening the scope of the study, as larger scopes lead to more uncertainties and more players that have to agree on scenarios
    - And all of the other issues identified above
- Temporal issues associated with building transmission must be overcome
    - needs to be a way to get through the interconnection queue, secure transmission arrangements, get contracts from the utilities, and gather financing in a feasible way so that one step does not hold up the others

  - In the end, the deliberative nature (and long life) makes it hard to gain closure on new projects
- Transmission is slow to build
  - SCE calls it a "slow moving train"
  - Process is so long that by the time you finish a project the world has changed
- The chicken and egg issue with transmission and generation poses a challenge
  - Especially because of the large time difference between the two project types
  - It also makes it hard to determine if good opportunities for economic lines are being passed up because transmission Is not in place to serve high quality renewable resources
  - There is also a secondary chicken-egg problem with for example, if you said to the ISO that you wanted to build an economic project from N. Maine into NE and do the analysis, they would say that there isn't enough wind to justify a line even for analysis. Then, potential generators are not filing interconnection requests because the transmission does not exist and it costs money to get in the queue

Calculating benefit and the investment calculus

Potential Theme: The incomplete investment calculus is a major problem that underlies the challenges with cost allocation

- The incomplete investment calculus (calculation of benefit) is a major unsolved problem that significantly influences the outcome
  - Don't know how to deal with generator revenue
  - Also hard to deal with calculating benefit when a lot of the congestion is hedged against
  - Also need to be able to calculate first and try to calculate second order benefits
  - There is still a struggle to create a transmission assessment framework that is durable and that people buy into that includes things like uncertainty, NTAs, etc
  - We don't look enough at the value of more transmission in reducing losses and increasing efficiency
  - This is generally a very complicated problem
  - People are very hesitant to give credit to enabling infrastructure in the face of uncertainty, even though you know it is going to provide value (option value and flexibility) – and it is nearly always going to be there

- someday there may be more cost benefit analysis on what it is worth to keep the lights on, but right now that is not even an option (as old system components are replaced, it will be very valuable to replace them with infrastructure that is flexible to many futures)
- This calculation of benefit is the big challenge underlying cost allocation
- If people doubt how benefits were calculated, they will doubt the cost allocation
- Benefits must be sustainable over the lifetime of a project, failed projects often happen when the costs are high and the benefits are not sustainable

- Most calculations of benefit will be focused primarily on production cost and leave out other benefits
  - People will agree on things that are readily quantifiable and others will be left out
  - Texas, for example, may also use some things like consumer benefit also
  - MISO is going to try to submit a way to incorporate more benefits (July 15 filing)
  - ISO-NE sees very little in the way of a dialogue about including other factors
- There is value in thinking about the option value of transmission and what the best plan is to serve alternative possible futures
  - This is especially true for large lines, which makes people uncomfortable

The need for policy certainty and action

Potential Theme: There is a need for high level regulatory and policy action to provide both certainty and direction

Potential Theme: Policies and regulation need to be written in a way that they can effectively be incorporated into planning processes

- There is a need for high level regulatory and policy action
  - Clarity of energy policy makes it much easier to agree on projects, then analysis can show that transmission projects clearly advance the policy in place
  - Political will to construct is very important – and people will need to be willing to consider alternate proposals like wind to the NE from the plains)
  - The biggest issue seems to be uncertainty in what the future holds in terms of GHG legislation, it would help to have some indication of which way that is going to go
  - Policy certainty would make the job of the utility much easier, as they will be able to respond to generator construction
  - policy needs to be developed to determine how new required transmission is going to be identified, planned, built and paid for

- Once commitment is articulated, plans can be made and the policy will be accommodated – right now nobody knows what the transmission is for
- Public policy mandates are very hard to establish criteria against
    - Policies need to be crafted carefully so that they may be converted into hard criteria
    - so the problem becomes to be able to measure the ability of the system to support the goals (and the goals must be very carefully defined to do this, like what kind of renewables
- Regulatory framework is not set up to support assessment on a one-world basis
    - Need a one world view to successfully develop larger, longer transmission lines
    - Need to get the eastern states on board and willing to consider other options
- Don't even have a common definition of renewables
- jurisdictional issue between FERC and the states can be a real mess when federal policies do not correlate well with state policies
    - There will never be organic agreement on how to plan in a multi-state environment – will only happen with push down from the regulator
    - NG rep thinks the planning capability is there, but what is missing is a central authority that has the power to commit to a certain set of investments to serve a certain set of goals – after that, need to deal with the fact that jurisdictional areas are going to be crossed and the cost allocation issues arise
    - Don't have the kind of political planning process, approval process, ROW process required to make decisions that involve multiple states
    - The federal state conflict over transmission construction and renewables integration is beyond the current willingness (this is the magic word) to build
    - FERC should be the entity that has the ability to plan for or approve the plans for transmission investment across states (without interference from the states)
    - Getting stuff out of the states is going to be a big deal, need cooperation as if we were a country
    - It is also very hard to plan a regional grid using criteria established on a state basis, may have to be on a larger basis
- State commissions are not willing to approve lines that only accrue benefits to other states
    - good transmission from other regions may not go forward because of conflicting interests and objectives
    - states also have economic development agendas they are trying to forward
- "need a lot of dumb wires to have a smart grid" (Caspary)

- Current actions with ARRA funded planning organizations and the NOPR are steps in the right direction and many are hopeful

Siting

Potential Theme: Siting is a challenge on a local level that can have significant impacts on the development of even large projects

- Siting is challenging because people do not want to look at transmission, etc
    - Eminent domain is a must have for completing all lines (though it should be avoided if possible)
    - A single county or landowner can undermine a whole line and block a project
- Siting regulation could be updated to have a broader perspective
    - State examiners need to look at benefits to a state which can be harder to show when we are looking at broader regional projects. How should benefit to crossover states be addressed?
    - Coordination with neighbors is important, especially if you only have one chance to route transmission through a certain area (need to manage interests and work together)
    - Need to figure out how to deal with the federal land authorities in the west
    - States can now torpedo a whole project if they don't like it for some reason
    - A single siting hang-up on a line can cause the whole project to go back to the drawing board, even if the planning is very good
    - Some states may even have criteria that require them to propose line (e.g. if a line must have benefits in a state to be approved for siting through the state)
    - Needs to include federal authorities like BLM and the park service

Substation Investments

Potential Theme: Substation investments tend to be more straightforward and justified by reliability, as most economic opportunities have already been realized

- Substation investments tend to be easier
    - Now Driven primarily by reliability, though also some by economics
    - Tend to be relatively inexpensive
    - Much simpler cost benefit analysis
- Substation investment challenges are usually associated with siting and land use expansion , but these issues are not as pronounced as with new lines (fewer back yards and less total area)
- Many of the big opportunities have already been realized and there are not many tricks left

- But these investments have significantly improved the functioning of the system
- In PJM, most of these investments are SVCs or transformers

Appendix G: A History of Transmission Regulation in the United States

To attempt to understand the regulatory and functional structure of the United States electric transmission as it stands today, it is necessary to look back on the regulatory environment through which the system evolved. This appendix attempts to trace US regulation – as it pertains to the transmission system – through time in order to gain perspective on what series of developments led to the current state. To achieve this, it will work from the early origins of the electric transmission system and the Federal Power Act through the major developments of the 2000s. Finally, there will be a discussion of current energy bills and how they may affect the US transmission network. As necessary, sections covering more recent activities will also address the development of markets for electricity, as this evolution has immediate effects on the development and operation of the transmission system.

It is important to note that this section will not attempt to comprehensively describe current US transmission policy and regulation. Such a task is complicated by several issues, not the least of which is that the regulatory structure is still in a constant state of change as it has been in over the past several decades, as will become apparent. More importantly perhaps, describing the regulation completely requires one to examine rules at the federal level as well as those at state and regional decision-making levels. Because the regulatory institutions have developed differently over time and federal authorities often deferred to local decision makers, the resulting structures now vary dramatically and the current state cannot easily be generalized even into a few basic categories (Joskow 2004).

Early Development of the US Electricity Grid

By the end of the 1890s, the electricity system in the US had expanded from Edison's first power system in Manhattan to urban areas across the country. These systems were entirely isolated from one another, and by 1896 alternating current had become the functional paradigm, replacing earlier direct current systems[102]. Privately owned utilities created franchises with the local municipalities in order to make use of public rights of way needed to run their transmission and distribution systems. Utilities had to incur large fixed costs in infrastructure before they could expect to make any return, a situation which led to a great deal of corruption. In many cases, the need to maintain their franchises and raise the necessary capital led utilities to both overcharge their customers and fall victim to extortion by local authorities, who controlled public rights of way (Holland and Neufeld 2009).

Following an 1899 investigation of corruption, two methods were suggested to eliminate the unwanted behavior: public ownership or protected private monopoly with state regulated rates for electricity. This finding, paired with an 1898 Supreme Court decision (United States Supreme Court 1898), which held

[102] At this point in time, these systems would be considered distribution networks.

that utilities under rate regulation had the right to a "fair return" on their investment, essentially reduced the likelihood of foul play by eliminating the need for extortion on the part of utilities trying to cover their costs. To manage the necessary rate making, 30 states had established electricity regulatory commissions by 1914. The effect of this shift to regulated electricity rates was twofold. First, it reinforced the idea that electricity generally – and generation specifically – was a natural monopoly and thus competition was discouraged[103] by the regulatory commissions to protect ratepayers from having to pay for redundant capital. Second, it made investments in electricity infrastructure predictable and safe, which facilitated access to capital borrowing (Holland and Neufeld 2009).

The Early 1900s and the Rise of Utility Holding Companies

Nonetheless, some were disappointed in the performance of the state regulators, which helped sustain the feeling that government ownership might be preferable. This sentiment would take decades to come to fruition, and sweeping change would not be realized without the contribution of a variety of other challenges that would arise over time. The first major problem that resulted from the authority of state commissions was that it made the industry very resistant to change. Over the first two decades of the 1920s[104], transmission technology had improved to the point that larger, interconnected grids were feasible. Despite the economic efficiencies that could be realized with such consolidation, the regulatory construct made utilities hesitant to expand and most continued to serve small urban areas without developing physical or economic ties to neighboring grids.

The second major problem that arose in the electricity industry in the 1920s was related to the growth in demand for electricity. Electric service had become the cornerstone for economic activity, and massive new construction projects – both plants and wires – were required to serve the growing load. To meet this need, the concept of Utility Holding Companies was born. Holding companies purchased common stock in multiple operating companies, thus granting the holding company control over multiple utilities. Along with providing a mechanism for gathering the necessary capital for infrastructure investments, holding companies also represented a shift towards larger systems.

Trouble came with the fact that holding companies' services were not regulated; they owned but were not themselves utilities . Holding companies were able to abuse their subsidiaries by charging exorbitant prices for their services, allowing them to post enormous profits. Over time, these profits led holding

[103] This belief has changed over time and may seem somewhat foreign now, but the understanding that generation infrastructure is a natural monopoly was held until late in the 20th century.

[104] In 1925, Pennsylvania governor Gifford Pinchot even went to far as to suggest a radical reorganization of the utilities in his state to separate generation, transmission, and distribution utilities, with transmission utilities operating common-carrier lines. This forward looking proposal was met with strong opposition from incumbent utilities.

companies and their stocks to grow at alarming rates. By 1929, the top three holding companies operated 45% of all generation in the US and nearly every utility was owned by a holding company. Complex financial relationships and large amounts of leveraging resulted in a bubble that was exceedingly sensitive to any reduction in its rapid rate of growth. These frailties were exposed at the onset of the Great Depression, when many holdings companies collapsed in some of the largest business failures in the history of the country.

The Depression and New Deal, combined with investigatory findings by the Federal Trade Commission (FTC)[105], led the federal government to get involved. In 1930, the Federal Power Commission (FPC), FERC's predecessor, was reorganized into an independent regulatory agency[106]. The FPC was tasked, first and foremost, with regulation of wholesale electricity sales. This increased federal jurisdiction led state commissioners to start to worry about their ability to exert authority; a fear that has remained an issue ever since and still colors the national debate over regulation of the electricity industry.

Also during this time, direct federal ownership of electric utilities increased. The general concept was to have government owned and operated utilities, like the Tennessee Valley Authority (TVA), act as benchmarks for both rates and quality of service of private utilities. TVA holds as a particularly strong example, as it became a massive utility that could offer low rates, effectively demonstrating the value of hydropower and the desirability of inexpensive electricity. The TVA example also highlighted to the American public the inequity of the service offered by the holding companies, further fueling negative public sentiment towards these large private institutions. Public anger came to a head in 1935, resulting in the Public Utility Holding Company Act (PUHCA)[107] and the mandated breakup of all interstate holding companies. Any remaining holding companies – those that had existed previously within a single state – were heavily regulated under the newly formed Securities and Exchange Commission (SEC). Though the first experiment with utility holding companies was not sustainable, it did lay the groundwork, both theoretically and through wide area infrastructure investment that was made, for the expansion of utility systems across wider geographic expanses (Holland and Neufeld 2009).

[105] The Federal Trade Commission (FTC) had undertaken a massive investigation of the American utility industry in 1928 in response to fears that the industry was evolving towards a natural monopoly and was immune to state regulation.

[106] The FPC had originally been created as part of the Federal Water Power Act (US Code Ch. 12, Title 16) passed in 1920. Its original charter had been to coordinate hydroelectric projects.

[107] "In its original form, PUHCA offered a possible alternative by substantially increasing the regulatory powers of the FPC to create regional grids and to compel utilities to transmit or "wheel" power from other utilities. This extension of FPC authority was stripped from the act after intense opposition from state commissions, which argued that electric energy was a local commodity (!) and not interstate in character." (Holland and Neufeld, 2009)

The "Golden Age" of Electric Utilities

Following the events leading up to PUHCA, the decades after were filled with relative peace and prosperity for the electric utility industry. The federal government promoted the growth of rural electricity service by passing the Rural Electrification Act of 1936 and establishing the Rural Electrification Administration to provide loans and support to rural communities. The federal government also expanded its involvement with electricity generation, with the goal of providing less expensive electricity to municipals and cooperatives. The Bureau of Reclamation began building large hydroelectric dams across the West and the Bonneville Project Act of 1937 created the Bonneville Power Authority, the first of the Federal Power Marketing Administrations (PMAs)[108]. During World War II and the years that followed, the electric power industry remained calm – in part thanks to a steady state regulatory regime – and experienced large growth, steadily falling energy prices, and significant technological improvement including the advent of nuclear generating stations in the 1950s (US Department of Energy 1991).

Crisis in the 1970s and PURPA

Peace in the electricity industry was disrupted by a convergence of factors that began to emerge towards the end of the 1960s and became significant issues in the 1970s. They were as follows:

- Improvements in generation efficiencies began to slow as technologies began to approach natural limits for thermal conversion of energy.
- A major power blackout in the Northeast in 1965 threw into question the wisdom of large interconnected power networks.
- Growing concerns about sulfur dioxide emissions and other pollution from coal plants led to federal policies, including the Clean Air Act, to discourage the use of coal for power generation and require environmental impact statements as part of their permitting process.
- Fuel switching from coal to oil became common, but had immediate negative consequences due to the 1973 Arab oil embargo. The Energy Supply and Environmental Coordination Act of 1974 effectively barred the use of natural gas or petroleum as fuels for electricity generation, at least for a time.
- Construction of huge nuclear plants at a massive scale was undertaken and immediately followed by massive cost overruns and delays caused by complex regulation and public concern over safety.

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[108] There are now 4 PMAs, the Bonneville Power Administration, the Southeastern Power Administration, the Western Area Power Administration, and the Southwestern Power Administration. The PMAs' mission is to market the power produced at federal water projects at the lowest possible rates to consumers while still adhering to sound business principles (http://www.energy.gov/organization/powermarketingadmin.htm)

- Demand growth slowed and failed to meet projections, causing plant cancellations and enormous sunk costs.
- Electricity rates began to rise to cover costs at a rate faster than inflation but sometimes not fast enough. Regulators initially allowed the complete recovery of incurred costs but faced public criticism for this action. Regulators then moved to deny recovery of some costs, in turn making utilities increasingly risk averse and slowing new investment(US Department of Energy 1991).

As a reaction to this disruption of the electricity industry, President Carter's 1977 National Energy Plan had numerous provisions that affected electric utilities. Most notably, utilities were to bear the cost of switching back from liquid fuels to coal, they were to help instigate energy efficiency programs, nuclear plant licensing was streamlined, and the structure of retail electricity rates was reformed. As proposed, new rates would do away with antiquated pricing practices and would strive to better reflect the marginal cost of generating electricity. Yet again though, fears of federal authority on the part of state regulators and fears of losing price advantages by industrial users forced many of the proposed changes to be abandoned.

Of the provisions that survived Congress's deliberations over the National Energy Plan, the Public Utility Regulatory Policies Act (PURPA) stands out as the one that most impacted future policy. PURPA required utilities to purchase power from Qualifying Facilities (QFs)[109] at a price determined by state regulators and based on avoided cost, rather than cost of production. As some state regulators set the price for such generation very high, QFs quickly became very profitable, spurring a new wave of utility construction. This act also signaled the first time that independent power producers had access to the public grid and laid the groundwork for a system where competing generators could sell electricity onto a common transmission and distribution system.

The Advent of Power Pools

Power Pools, precursors to the modern ISO, evolved in the early 1980s when it became evident that there were benefits to be had when two or more utilities reached agreements to coordinate operation and planning of their power systems. With the goal of minimizing operational costs, as many as 30 pools came into existence during the 1970s and1980s and, during some periods, accounted for as much as 38% of total generated electricity. In many cases, utilities entered into pools with the understanding that they might have clashing competitive positions with other pool members, but the advantage gained through coordination outweighed the competitive risk. For these reasons, establishing set procedures for realizing

[109] Qualifying Facilities were generally small scale cogeneration plants or renewable generators, though some expensive and advanced combined cycle natural gas plants were enabled by the favorable rates offered to QFs

the benefits of pooling was important. Rules had to provide an agreed upon distribution of costs and benefits, shared use of transmission facilities, coordinated operation of the power pool, and establishment of transaction prices. In a tightly organized power pool[110], coordination would include:

- Reduction of operating costs for the whole pool via the use of a single control center
- Reduction of required independent operating reserves, as capacity required to deal with contingencies could be shared
- Exploitation of differences in load curves to mutual benefit (e.g. use of hydro power)
- More effective response to emergencies via coordinated action
- Coordinated maintenance programs, reducing the need for substitute plants
- Lower long term reserve capacity, increased transmission reliability, economies of scale in new facility construction (all via coordinated planning)

Though many of the aspects of a tightly coordinated pool were understood, there was a diversity of actual structures put in place and most pools realized only a subset of the full potential gains. Furthermore, the types of agreements that were reached in pools across the US varied from informal inter-utility arrangements to very formal agreements among a group of companies. Formal bilateral and multilateral agreements would involve wholesale energy sales, which were subject to approval by FERC. Following the formal agreements and approval, each utility in a pool would offer separate rates to their customers that reflected the benefits from coordinated operations and planning. Like much of the rest of this chapter though, there was enormous diversity in the degree of integration of power pools and the types of agreements they reached, so it is hard to do anything but generalize about common characteristics.

The 1990s and Restructuring

The 1990s saw a dramatic move towards restructuring of the US electric power sector to support and even promote the creation of wholesale markets for electricity[111]. This shift gained significant momentum with the passage of the Energy Policy Act of 1992 which, among other things, created a new classification of power producers called Exempt Wholesale Generators (EWGs)[112]. A generating unit that qualified as a EWG could contract with a wholesale customer to provide electricity at agreed upon prices. On a case by

[110] Examples of tightly organized pools include NEPOOL (New England) or NYPOOL (New York). Rarely were all of these aspects of coordination realized in a single pool.

[111] During this same period, the natural gas, airline, telephone, and trucking industries were also undergoing the process of restructuring and moving away from regulated rates.

[112] "Exempt" refers to the exemption from some requirements of PUHCA, allowing an EWG to sell to whomever it chose at whatever rate was agreed upon (though transactions were still subject to regulatory approval)

case basis, local utilities would then be required to "wheel"[113], or transmit through their system, the power that had been contracted with the EWG and would otherwise have been served by the utility's generation capacity (examples of wheeling are shown in Appendix B). Falling natural gas prices (and the ability to build gas turbines quickly), cost overruns by incumbent utilities, and the expense of paying QFs all gave EWGs a competitive edge in the marketplace.

The experience with EWGs and their low electricity prices created vocal support for the easing of access to transmission in order to increase the availability of cheap power from independent power producers (IPPs). Industrial users in particular, who were not wholesale customers, were outspoken about wanting access to "retail wheeling"[114]. If IPPs were to flourish though, the regulation and operation of the electric system as a whole would have to change. This reality is a direct result of the characteristics of electricity: it can be neither traced nor stored; every generator can impact the whole network and sources and sinks must be kept in balance at all times. Traditionally, tracing electric transactions was unimportant – all power was generated by a single entity – and balancing, or "dispatch", was executed by a vertically integrated utility with full information about all of its generators[115]. To enable the system to continue to function reliably while many IPPs injected power into the system, a new mechanism would be required.

In addition to the desire by customers for access to less expensive electricity, the process of restructuring – separating generation from transmission – has several other important benefits. First, it places the risk of investment on utilities rather than on ratepayers who pay into tariffs designed to ensure cost recovery by generators. Second, it provides generators with a strong incentive to increase the efficiency of their plant operations. Improved efficiency results in lower prices; fuel savings accrued to generators, and decreased emissions. Finally, restructuring eliminates the aversion of utilities to expansion of the geographic scope of their transmission networks. Larger transmission networks then offer the advantage of more efficient dispatch, reduced requirements for reserve capacity, and the ability to better cope with the variable nature of some renewable energy sources(Joskow 2003).

[113] "Wheeling" existed prior to EPACT 1992 and the creation of EWGs simply introduced a new form of wheeling. During the 1980s the MIT group led by Fred Schweppe proposed the use of "wheeling rates" based on spot prices of electricity (what we now call locational marginal prices or LMPs). At the time, pancaking was rampant and FERC had to approve these wheeling rates by the thousand.

[114] "Retail wheeling" is, in effect, the same thing as "retail competition". Retail competition is not discussed further in this memo. Suffice to say, while wholesale competition has had a good amount of success, in very few places has retail competition thrived. Texas is perhaps the only state with a well functioning competitive retail market.

[115] Understanding the different technical and cost characteristics of different generators allows the system operator to dispatch generation to balance load in an efficient manner.

Open Access and Orders 888 and 889

Early implementation of Energy Policy Act of 1992 provisions for transmission access took place on a case-by-case basis. This was institutionally challenging for utilities and prevented widespread wholesale transactions. Responding to these facts, FERC issued two major orders in 1996 to impose – from a federal level – the requirement that transmission owners provide unbundled transmission service to third parties. The hope was that access to the transmission system would eliminate discrimination and encourage merchant generating companies to enter and compete in the market, eventually facilitating a full shift to bulk power markets.

Order 888, called the "Open Access Rule", forced transmission owners to offer transmission services to third parties under terms similar to what they offered to themselves. Incumbent transmission facilities would file an open access tariff to be approved by FERC that must meet minimum standards. The Order also specified additional services that were to be made available (e.g. ancillary services), defined "available transfer capacity" (ATC)[116] and stated how it was to be managed in the case of congestion. Furthermore, the rule allowed incumbent utilities – who had made significant investments under old regulatory regimes – the right to recover any stranded costs as part of their regulated rates. Notably, while Order 888 encouraged the formation of ISOs, it did not provide further guidance on the organization of wholesale markets, locational prices, capacity mechanisms, etc.

Order 889 established the Open Access Same-time Information System (OASIS) as a mechanism for creating a level playing field for market participants. Each incumbent utility was required to set up or participate in an OASIS, which provides in real time the necessary information about the state of the system, including ATC and prices. If utilities choose to continue to own transmission, distribution and generation facilities, they could do so but they were mandated to keep separate books and records for each activity. One important issue that was unaddressed by both Orders 888 and 889 was the pancaking[117] of transmission tariffs, which would be left untouched until the end of the 1990s.

Voluntary RTOs and Order 2000

Orders 888 and 889 assumed that the existing structure of the power industry would not change; priority access to the transmission network was retained by the incumbent utilities in any case of shortage.

[116] "A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin." (http://www.eia.doe.gov/cneaf/electricity/page/eia411/nercterms.html)

[117] Pancaked rates historically resulted from transactions where sellers of electricity were separated from buyers by more than one transmission system. The resulting transactions became prohibitively expensive because the contracting parties were forced to pay the transmission tariffs of multiple networks, thus "pancaking" the rates.

Movement in the late 1990s by 3 Northeastern power pools (PJM[118], New England, and New York) as well as California to create ISOs[119] suggested there was a trend turning the country towards systems where multiple transmission and generation operators would all participate in centrally operated markets. To support this movement, in December of 1999 FERC issued Order 2000, describing the minimum characteristics[120] and functions[121] of an RTO. The Order did not require participation in RTOs[122], nor did it set any boundaries or mandate structure, but was aimed at creating a framework – within the legacy structure of the system – that would result in effective operation of the transmission grid and support efficient competitive wholesale markets (Abel and Parker 2004).

The largest challenge addressed by Order 2000 was that existing transmission networks were not well connected and standard practices by vertically integrated utilities were discriminatory against merchant generators and did not result in optimal asset operation. The first step to relieving this problem was to require all transmission owning utilities who wished to join an ISO/RTO to transfer operational authority of their assets to the system operator[123]. The thought was that over time this action would allow an increase in the regional scope of network operations and assign the RTO with all tasks related to short-term reliability. To further promote performance of the market and its actors (many of whom were not used to competing for service), the Order eliminated pancaked rates within an RTO's territory, created market based congestion management protocols, and encouraged performance based ratemaking of transmission owners.

The California Energy Crisis and FERC's Standard Market Design

Starting in the spring of 2000 and continuing into the summer of 2001, a combination of low rainfall (and thus a shortage of hydropower), high natural gas prices, high prices for NOx emissions permits, market manipulation, and a flawed regulatory design with frozen retail rates and suppliers forced to buy at

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[118] PJM is an abbreviation for Pennsylvania – Jersey – Maryland, an ISO that has grown over time and now stretches as far west as Chicago.

[119] The Midwest ISO (MISO) and ERCOT would follow in the early 2000s.

[120] "The required characteristics of an RTO are: the RTO must be independent from market participants; it must serve a region of sufficient size to permit the RTO to perform effectively; an RTO will be responsible for operational control; and it will be responsible for maintaining the short-term reliability of the grid." (Abel and Parker, 2004)

[121] "The required functions of an RTO outlined in Order 2000 are: it must administer its own transmission tariff; it must ensure the development and operation of market mechanisms to manage congestion; it must address parallel flow issues both within and outside its region; it will serve as supplier of last resort for all ancillary services; it must administer an Open Access Same-time Information System; it must monitor markets to identify design flaws and market power and propose appropriate remedial actions; it must provide for interregional coordination; and an RTO must plan necessary transmission additions and upgrades." (Abel and Parker, 2004)

[122] It is not clear that FERC would have the power to do this even if it decided to

[123] RTOs do not own transmission infrastructure nor are they responsible for its maintenance and physical operation. The RTO simply makes operational decisions about how to utilize the assets and the transmission owner is obliged to abide by the operators decision.

wholesale market spot prices resulted in the California Energy Crisis. Specifically, the first four factors listed caused prices to spike while utilities had to continue to sell the expensive power they were buying to their customers at fixed rates. This bankrupted many utilities and forced the state to purchase power on behalf of consumers at astronomical prices. As the prices shock spread to other states in the West, the general perception emerged that the crisis was a result of failed regulation and, more generally, a failure of the idea of wholesale markets for electricity. Restructuring plans in progress in other parts of the country were set aside and momentum towards liberalization of the electricity system halted nationwide.

Motivated by the crisis in California, the seams[124] problems between existing ISOs, and the failure of additional ISOs to form, FERC proposed the Standard Market Design (SMD) in July of 2002. There were also concerns of inefficiencies in existing markets, which would result in underinvestment in transmission infrastructure and could result in further energy crises like California. The overall goal of the SMD was to aggregate the best practices of existing ISOs into a single standard design, which could then be adopted by ISOs across the country.

In its original form, the SMD was a bold assertion of regulatory authority on the part of FERC. In its initial form, FERC asserted its jurisdiction over all transmission facilities, including those providing bundled service to retail customers, and required that they all be operated by an Independent Transmission Provider (ITP)[125]. Complete unbundling of transmission service from generation was to be completed by September 2004 (as under Order 888) and each region was to submit a service tariff using the "license plate" approach[126]. From a market standpoint, the SMD drew heavily from the PJM model and included LMP based day-ahead and retail markets, a congestion management system with financial transmission rights (FTRs), strong market power mitigation mechanisms, and generation adequacy requirements. Finally, transmission planning was to be executed regionally by each ITP (with input from local parties) with investment decisions for nonessential lines coming from private initiative (Abel 2003).

Though many parties from industry lauded the SMD proposal, it met with heavy opposition from some industry groups (who were concerned about implementation) and from the states (Joskow 2004). State regulators in particular were a loud opposition voice, claiming that FERC was overreaching its

[124] When discussing markets for electricity, "seams" issues refer to incompatibilities between the markets of two adjacent transmission grids caused by differences in market rules. For example, it becomes difficult to resolve trades between neighboring regions if markets close at different times or with different frequencies.

[125] ITPs were a construct created by Order 2000 and could be existing RTOs or some other unspecified type of organization that do not own, but operate, transmission assets

[126] A "license plate" tariff is one that charges each transmission user a set price to system utilization based on the location from which the user accesses the system. This rate is determined for each location based on the benefit that the user derives from the network (the method for determining this benefit is beyond the scope of this paper). "License plate" tariffs can be compared to "postage stamp" tariffs, which charge all users the same fee to use the system.

jurisdiction and treading on state authority. Concern about liberalization also lingered after California and public enthusiasm for competitive energy markets had waned substantially. FERC responded to concerns in a White Paper issued in April 2003. The Commission withdrew the ITC requirement, reversed its position on the applicability of SMD to bundled retail sales, and removed the requirements for auctioned FTRs and for a minimum resource adequacy requirement for generation. The White Paper also allowed for phased implementation and regional differences in the ultimate determination of participant funding rules. After lengthy debate and continued resistance from traditionally regulated states, FERC formally withdrew its proposal in 2005.

Energy Policy Act of 2005 and Piedmont v. FERC

EPACT 2005[127] was the first omnibus energy legislation in more than a decade. Though it addressed energy considerations across the board, it had serious ramifications to the electricity industry which were, in large part, a response to the ongoing debate and experimentation in liberalization[128]. Major provisions included:

- Required FERC to certify an Electric Reliability Organization (ERO) to oversee the reliability of the bulk power system. The ERO, which would end up being NERC[129], was granted enforcement authority and could levy penalties on system participants who violated an approved reliability standard.
- Repealed PURPA section 210, which dictated the terms by which utilities were compelled to purchase power from QFs. The impetus for this change was that such an advantage was no longer necessary in a restructured environment because all generators have access to markets.
- Repealed PUHCA, which made it possible for the FERC and state regulators to access the records and books of utilities. The repeal was intended to allow for utilities to diversify their assets (and in doing so reduce their risk profile) while ensuring that abuses were not taking place.
- Directed FERC to take action to ensure price transparency in markets. Where the commission found inadequacies, it was allowed to establish information systems to further facilitate transparency.
- Required the Secretary of Energy to execute a study of the electric transmission system in order to isolate areas of heavy congestion. Once areas had been isolated, they could be designated

[127] Formally P.L. 109-58, Title XII contains provisions for electricity and is also referred to as the "Electricity Reliability Act of 2005."
[128] The complete list of provisions relevant to electricity in EPACT 2005 is longer than can be described here, and in some cases the actual wording has had lasting significance. A good thorough summary of the bill has been written by the Congressional Research Service and is cited in this section.
[129] NERC, the North American Electricity Reliability Council, had existed for decades but without any enforceable authority. For years, NERC had proposed voluntary standards to which many utilities adhered by choice.

National Interest Electricity Transmission Corridors (NIETCs), essentially a recognition of the fact that transmission in that area was in need of modernization for the sake of continued overall system reliability.

- Granted FERC the ability to issue construction permits in NIETCs, which could then be used to acquire rights of eminent domain on behalf of a transmission investor. Though the original legislative wording was somewhat vague, it appeared that this authority could be used to override permit denials by both state and federal authorities (Abel 2006).

Perhaps the most contentious outcome of EPACT 2005 has been FERC's authority to override, or "backstop", siting of transmission in NIETCs. The first National Electric Transmission Congestion Study was completed in 2006. It found that large regions of both the Southwest and the Northeast were heavily congested and designated them as NIETCs. In an early attempt to exercise their backstopping authority and override a state permit denial, FERC was challenged in the US 4th Circuit Court of Appeals by the Piedmont (Virginia) Environmental Council. On February 18, 2009, the Court ruled that FERC's interpretation of its authority to act as a backstop when a state has "withheld approval [of an application] for more than one year"[130] was incorrect. It was determined that "withheld approval" was only the failure to issue any decision within the required period of one year and not the same thing as explicit denial of approval – which had been the decision issued by Virginia. To date, this interpretation of FERC's authority to exercise its backstop siting authority stands; FERC may only override a state if the state fails to act on a permit application within one year of its submission[131].

FERC Order 890

After a decade of the "Open Access Transmission Tariff" created in Orders 888 and 889, FERC issued Order 890 with the core objective of remedying undue discrimination in transmission service. The Order, issued February 2007, requires more transparent planning processes that are based on predefined principles[132] and open to all transmission users, neighboring transmission systems, and any other interested party. Transparent and open planning requirements were included because FERC had determined that prior rules did not sufficiently relieve the disincentive of the incumbent utility to relieve congestion. Order 890 also clarifies a methodology and ensures transparency for the calculation of

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[130] Section 216(b)(1)(C)(i) of the Federal Power Act

[131] There are other situations in which FERC may exercise siting authority, but they are not relevant to this case. They are: 1) The state where a line is planned lacks siting authority or state law prohibits siting to achieve interstate benefits; 2)The permit applicant is not eligible for site approval because it does not provide retail service in the state; 3) The state siting body attaches conditions that will prevent congestion reduction or make new line economically infeasible

[132] FERC's planning principles include coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

available transfer capacity, which historically had varied between transmission providers. Additional changes included a shift in the way that imbalances are priced, how firm point to point service is addressed, and the details of rollover rights for transmission customers who wish to renew contracts. Order 890 was amended three times between the end of 2007 and 2009. In each case, the amendments were primarily affirmations of the original Order that provided clarification of ambiguities in the primary text[133] (Commission 2007).

EISA 2007 and ARRA

While the Energy Independence and Security Act of 2007 (EISA 2007) was not focused on major changes to transmission regulation or even electricity specifically, electricity related provisions aimed to support modernization of the transmission and distribution infrastructures in a way that would facilitate a shift towards a "smart grid." As defined, the smart grid refers to a distribution system that allows flows from the customers' meter both into the house and back to the distribution utility. Improved communication and use of new technologies promise to change the way that consumers use power in a way that relieves the load on an increasingly overloaded network, reduces the need for additional expensive and hard to site infrastructure (e.g. generation and transmission), and increases the efficiency, reliability, and flexibility of the electric grid. In particular, these improvements could be realized with increased participation of the demand side in the form of demand response programs, which are heavily promoted in EISA 2007. Annual funding was established to assess and plan for demand response, NIST was directed to establish interoperability standards[134] for smart grid equipment, and DOE was to issue a report on the status of smart grid technology and deployment (Abel 2007).

Following the worldwide recession of 2008, and building on many of the goals of EISA 2007, American Recovery and Reinvestment Act of 2009 (ARRA 2009) appropriated major funding to the DOE for grid modernization and infrastructure expansion activities. DOE was granted $4.5B to cover investigation of smart grid and grid storage technologies and subsidize modernization expenses[135]. An additional $6B was allocated to cover costs of loan guarantees made under EPACT 2005 that could be used for short-term construction projects, including upgrades and expansion of the electric transmission system. Furthermore, BPA and WAPA each received $3.25B in borrowing authority for the purposes of managing the hardware

[133] Order 890 was amended in December 2007 (Order 890-A), June 2008 (Order 890-B), and March 2009 (Order 890-C). Clarifications included such things as more precise definitions of certain terms, explicit requirements for method and frequency of certain calculations, and data release terms for transparency.

[134] Interoperability standards, to be established by NIST in cooperation with FERC and the DOE, are intended to increase the flexibility and utility of smart grid devices by creating standardized communication protocols that should result in a more seamless and effective overall system.

[135] The "smart grid" was defined using language from EISA 2007, and funds could be used to match private investments. The breakdown of Smart Gird Investment Grant Awards ($3.4M) can be found at http://www.energy.gov/recovery/smartgrid_maps/SGIGSelections_Category.pdf.

and operations of the transmission lines in their service territories, including construction, upgrades, planning, system studies, operation, and maintenance. Finally, ARRA required the Secretary of Energy to include a study of renewable energy related transmission issues in the 2009 study on transmission congestion(Sutherland 2009).

Pending Legislation

With growing concern over global warming and the 2008 election of Barak Obama, a president who vowed to make energy and climate change one of his top priorities, sweeping legislative packages aimed at cutting greenhouse gas (GHG) emissions have been introduced in congress. An expected result of such legislation is the widespread installation of renewable generators, in particular wind turbines but also solar photovoltaic, concentrating solar and geothermal generators. Aside from being low carbon, each of these sources shares a characteristic: the best places to harvest these renewable energies are almost always far from population centers. For this reason, prevailing wisdom holds that massive new transmission projects will have to be undertaken to serve renewable generators if, and when, climate change legislation is enacted (Joskow 2008).

In order to build large-scale, long-distance transmission projects, three major issues may have to be addressed and are currently receiving lots of attention: planning, siting, and cost allocation[136]. Planning on an unprecedented (national, or interconnection wide) scale could be required in order to site renewable generators and then connect them to load in a way that best utilizes resources and serves demand. Once lines have been planned, it may be necessary to have protocols in place to ensure that the rights-of-way for their construction are made available. Finally, an equitable and practicable method of allocating the new infrastructure costs would likely need to be determined and then put into practice. As should be apparent from the discussion above, each of these elements represents a major friction with the current paradigm where local interests dominate and state and regional[137] authorities hold most of the power (Brown 2009).

Since the beginning of the Obama Administration, two major sets of transmission provisions have been drafted, one in the House of Representatives and one in the Senate. The House's provisions are within Title 7 of H.R. 2454, the American Clean Energy and Security (ACES) Act of 2009, or "Waxman-Markey". ACES first overrules the 4th Circuit's Piedmont decision and authorizes FERC to override state decisions on transmission projects – regardless of whether the state delays or denies a proposal.

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[136] Each of these issues demands (and will receive) further treatment than will be provided here. Future memos will be written by this study to explore the details of each of these challenges.

[137] "Regional" authorities are usually ISO/RTOs but can also be PMAs or NERC regions – anything larger than a state but not as large as an interconnection.

Furthermore, rather than limit FERC's jurisdiction to within NIETCs, ACES extends federal jurisdiction to the whole Western Interconnection[138]. For planning, ACES proposes the creation of regional planning entities that would be reviewed by FERC to ensure consistency with set planning principles[139]. Any planning would take into account all demand-side and supply-side options, including energy efficiency, distributed generation, demand response, and storage. ACES was passed through the House in June 2009, and awaits the passing of a Senate version (Commerce 2009).

On the Senate side, multiple bills have been proposed though none has yet been passed. The primary bill that addresses transmission issues is S.1463, the American Clean Energy Leadership Act (ACELA) of 2009, sponsored by Senator Jeff Bingaman and originally introduced on July 16, 2009[140]. ACELA states its intent about transmission as follows:

> *"...transmission infrastructure should be guided by the following goals: support for development of renewable generation; opportunities for reduced emissions; cost savings resulting from reduced congestion, enhanced opportunities for trades, reduced line losses, generation sharing; enhanced fuel diversity; reliability benefits; diversification of risk; enhancement of competition and mitigation of market power; ability to collocate facilities on existing rights-of-way; competing land use priorities; the needs of load-serving entities; and the contribution of demand response, energy efficiency and distributed generation."*(United States Senate Committee on Energy and Natural Resources 2009)

To achieve these goals, ACELA tasks FERC with overseeing the development of interconnection wide transmission plans, including taking appropriate action to relieve any obstacles that it sees as hindering the achievement of policy goals. Like ACES, states are granted one year to grant permits for high priority transmission projects, after which FERC has the power to take independent action towards siting (this only applies for lines over 345kV). ACELA also addresses cost allocation and calls on FERC to establish

[138] From an objective point of view, one could argue that not extending authority to the Eastern Interconnection makes sense because the Eastern infrastructure is already well developed; the East is more concerned with capacity expansion of transmission rather than placement of new transmission. Others would argue that this is a far more political decision promoted in the West by those who seek to build transmission so that they may export renewable resources and on the East Coast by those who fear the import of wind from the Plains States and wish to build offshore wind farms using local resources.

[139] These principles would be written with the express purpose to "facilitate the deployment of renewable and other zero-carbon and low-carbon energy sources for generating electricity to reduce greenhouse gas emissions while ensuring reliability, reducing congestion, ensuring cyber-security, minimizing environmental harm, and providing for cost-effective electricity services throughout the United States ..." (EISA 2007).

[140] While S.1463 will not likely pass as written, it is generally understood that whatever energy bill does come out of the senate will include the transmission language from this bill. This includes S.1733, the American Clean Energy Leadership Act of 2009 ("Kerry-Boxer"), introduced September 30, 2009 and the forthcoming Kerry-Lieberman-Graham Senate energy bill.

appropriate methodologies of cost allocation for high priority projects, though methods must be "just and reasonable and not unduly discriminatory or preferential." However, FERC is prohibited from spreading the costs of new transmission broadly across large regions unless specific economic and reliability benefits can be demonstrated.

Pending FERC Rulemaking

On June 17, 2010, as the final stages of this investigation were taking place, FERC issued a Notice of Proposed Rulemaking (NOPR) focused on "Transmission planning and Cost Allocation by Transmission Owning and Operating Public Utilities." Though this manuscript must be submitted prior to the end of the 60-day comment period, and certainly before the issuance of the final rule, the content of the NOPR is noteworthy in the context of long term transmission adequacy. The NOPR aims to improve upon order 890 and support the development of transmission facilities necessary to maintain reliability, reduce congestion, and "enable compliance with public policy requirements established by state or federal laws or regulations." To this end, FERC recognizes several shortcomings with the current 890 proceedings:

- The lack of a requirement for regional transmission plans.
- An absence of provision for transmission needs driven by public policy requirements.
- Significant obstacles to non-incumbent transmission developers' participation in the regional planning processes, including their ability to invest.
- The shortage of coordination between planning regions.
- The fact that existing cost allocation schemes may not be just and reasonable, that cost allocation should be more tightly linked with planning, and that there are no standard methods for the allocation of cost of lines that cross more than one planning region.

In light of recognizing these current deficiencies, FERC proposes a set of rules to remedy the situation. Briefly, there is a call for establishment of inter-regional planning and cost allocation procedures, improvement of intra-regional planning and cost allocation recognizing the close relationship between the two, action to lower barriers to non-incumbent participation, and recognition of the need to plan for lines that will enable the realization of public policy goals. The findings and proposed rules of FERC are in line with the findings and recommendations of this study, and the author sees this NOPR as a strong step in the right direction.