

## A WIRES Report

# THE TRUTH ABOUT THE NEED FOR ELECTRIC TRANSMISSION INVESTMENT: SIXTEEN MYTHS DEBUNKED



[www.WIRESgroup.com](http://www.WIRESgroup.com)

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## WIRES' PREFACE

**WIRES<sup>1</sup>** presents this excellent white paper by **London Economics International (LEI)** in response to many myths and long-held beliefs about investment in electric transmission that influence the thinking or actual decisions of policy makers, regulators, and the public about the need for, and benefits of, this critical infrastructure. For example, many people believe that lower demand for electricity means that the electric transmission system does not need to be upgraded or expanded. Others are persuaded that fixes or improvements to a facility or system in another service territory, state or region do not benefit them and are properly someone else's responsibility.

In reality, all North American economies will become more dependent on electricity as communications, banking, transportation, heating, automated manufacturing, and other developments drive our future economy and life styles and increase the need for electricity. The reliability and resilience of the electric system will consequently become more critical to us all. Despite this prospect, WIRES contends that regulators, public policy makers, industry, and the public, which stands to benefit from a robust grid, often bring outdated assumptions, misconceptions, and fallacies into their decisions about transmission investments.

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<sup>1</sup> WIRES is an international non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, independent and renewable energy developers, and engineering, environmental, and policy consultants. WIRES' principles and other information are available on its website: [www.wiresgroup.com](http://www.wiresgroup.com).

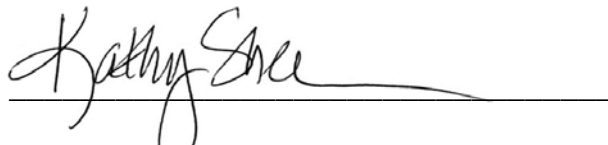
Yet, the truths about why we need to invest in the grid are not always self-evident. Therefore, WIRES has asked LEI to take a fresh look at the most fundamental misconceptions about transmission investment. These “myths” can often inflict a significant cost on investors in transmission and on customers because they contribute to protracted project delays and discount the importance of the flexibility and resilience that a robust grid provides. It is important to confront the myths that LEI identifies because they can frustrate even the most beneficial infrastructure projects. Modernization of the transmission grid that has been inherited from the last century will create an increasingly integrated and technology-driven network that binds regional power markets together and widely delivers economic, reliability, and environmental benefits. It should be accompanied by recognition that changes are needed to the regulatory system in which transmission planning and public interest determinations continue to be made under uncoordinated state and federal regulatory regimes. Those decision making processes may also require modernization.

In this paper, the LEI analysts identify the most pervasive and problematic myths from a policy-making point of view. They rebut those misconceptions and document why those myths are outdated, fallacious, or have no basis in fact. The paper then provides case studies that demonstrate why these myths about transmission investment are not supportable.

Myths can be very difficult to identify as such because they often contain an element of truth or fact. WIRES does not minimize the difficulties associated with siting major transmission infrastructure or the need for assurance that these investments will bring commensurate benefits to local, state, or regional economies and consumers of electricity. However, consideration of the benefits and burdens of such considerable investments deserve reasoned evaluation, free of ingrained misconceptions about transmission’s fundamental but changing role in the present or future electrified economy. It is time to discard mythology and instead objectively consider the benefits that grid expansions, upgrades, and reinforcements can deliver to the economy and to consumers.

\* \* \* \* \*

WIRES submits this LEI paper for our readers' consideration and solicits the readers' comments, which may be submitted to [www.wiresgroup.com](http://www.wiresgroup.com) We also acknowledge and thank the team of experts at London Economics, led by Julia Frayer, Eva Wang, and Marie Fagan and their colleagues from whose ingenuity and grasp of the industry's intricacies we all can learn.

A handwritten signature in black ink, reading "Kathleen Shea", written over a horizontal line.

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September 12, 2017

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# THE TRUTH ABOUT THE NEED FOR ELECTRIC TRANSMISSION INVESTMENT: SIXTEEN MYTHS DEBUNKED

September 2017

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## SYNOPSIS

WIRES commissioned London Economics International LLC (“LEI”) to provide a White Paper on the myths and truths about transmission investment. The views of key decision makers regarding the need for transmission investment are often governed by widely-believed but outdated or inaccurate myths regarding the key drivers for investment, such as: trends in electric demand and supply; the cost of infrastructure and who should pay for it; benefits of investment; and the interplay between transmission and various new technologies. This White Paper identifies the principal myths surrounding consideration of transmission projects in regulatory, industry, and political circles and then explains why those myths are typically baseless, false, and misleading. The paper uses real-life examples of transmission investment projects to debunk these harmful misconceptions. In order to offer a more accurate portrayal of the need to invest in transmission infrastructure, this White Paper concludes with recommendations for practical and feasible improvements to the process of evaluating transmission projects.

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**London Economics International LLC (“LEI”) is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as electricity generation and distribution, water and wastewater provision, and natural gas distribution, with a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI has offices in Boston, Chicago, and Toronto.**

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# 1 Introduction and roadmap to this report

## *Why are there myths around transmission investment?*

Myths are sprouted from small “seeds” that are grounded in reality but then grow to be “larger than life.” The factual foundations begin to fade, and the embellishments soon become the focus of the story. With respect to transmission investment, myths have arisen as a shorthand to help navigate the complexities of transmission investment decisions. Unfortunately, trying to simplify the decision of investors and system planners down to a sound bite of several words creates inaccuracies and gives rise to myths that undermine beneficial investment opportunities.

Transmission investments are complex and large-scale, and they require careful evaluation, forward-looking analysis, and long-term commitments. Key issues in the decision-making process include the following considerations:

- **Transmission investment decisions are multi-faceted.** Electric transmission investment is a highly regulated, complex undertaking which involves many decision-makers.
- **Transmission investment is large-scale.** This creates almost an immediate natural tendency to consider deferral and smaller-scale, sometimes piecemeal, options because the costs and consequences of *not* pursuing a large-scale investment are typically ignored because they are more difficult to come to grips with.
- **Transmission investment requires long-term commitments and planning.** It can take 10 to 15 years to plan, permit, and construct new transmission, and sometimes much longer. Once built, transmission projects typically have economic and operating lives that are more than 50 years.

It is tempting to tame these complexities by relying on familiar myths to guide transmission investment decisions. However, as this report shows, using outdated myths to guide investment will result in missed opportunities for benefits to the power system, transmission users, and to electricity consumers. This report uses real-life examples to debunk the myths around transmission investment.

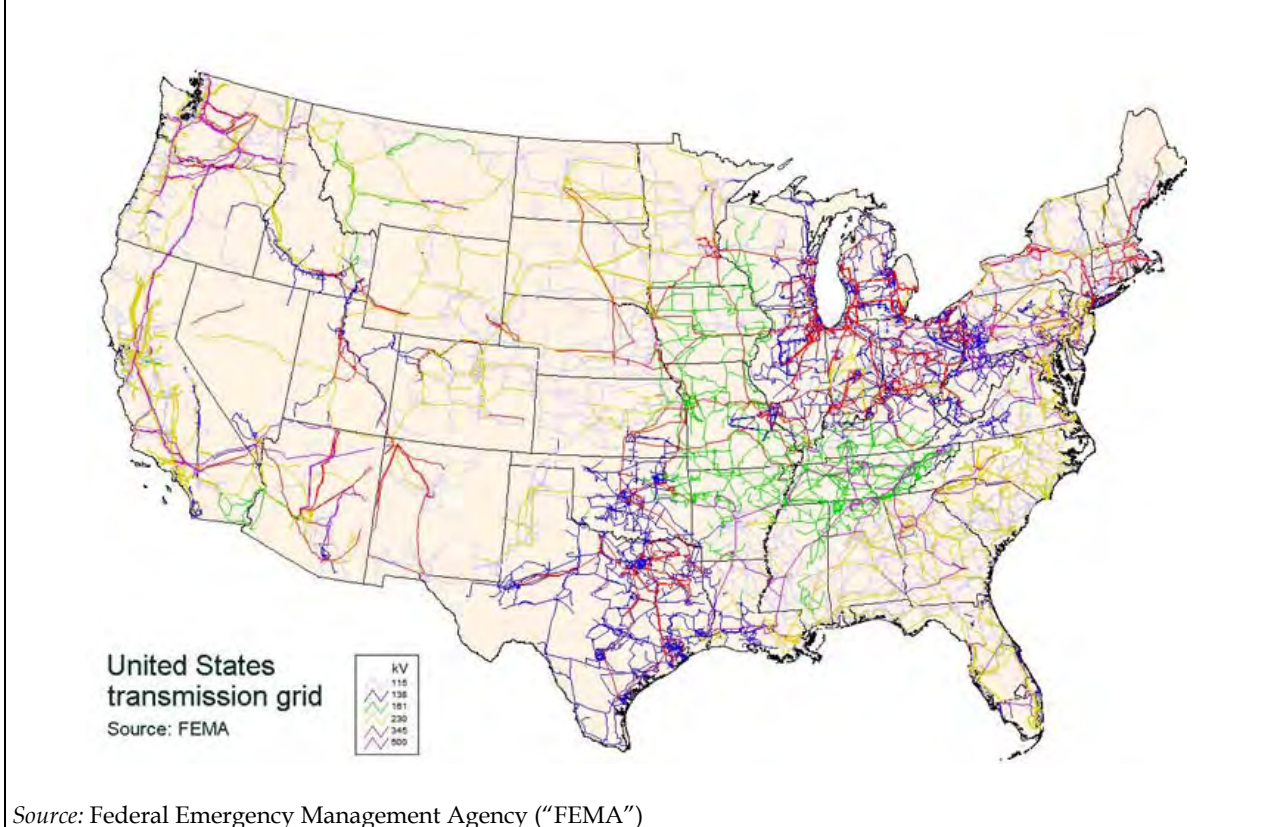
## *Roadmap*

In Section 2, we briefly explain the important changes to the transmission system over the past two decades and the new realities that have resulted for the transmission system. In sections 3-7 we identify the myths and replace them with the new realities, or truths, about transmission. In Section 8, we provide recommendations for practical and feasible improvements to the process of evaluating the need for transmission investment to reflect these new realities. Some of the recommendations are already being practiced by system planners – if other decision-makers adopt these recommendations then their decisions around investment would more truly reflect the value that transmission investment brings to consumers and the power grid.

## 2 Why do we need transmission?

Electricity service is not simply about which power plants are running. Keeping the lights on involves an integrated network of resources, including: transmission lines, substations, control equipment, and local distribution lines (see Figure 1 below). Transmission infrastructure also ensures that the system is “reliable,” meaning that the lights stay on even when power demand surges or an individual power plant goes offline.

**Figure 1. The United States electric transmission grid**



Transmission investments are generally grouped into three categories:

- **Reliability:** Projects that are necessary to resolve a reliability issue (such as keeping the lights on);
- **Economic:** Projects that, while not necessary to resolve a reliability issue, allow cheaper generation to reach more load; and
- **Public policy:** Projects that assist in meeting public policy goals (e.g., lines built to support state renewable portfolio standards (“RPS”) by, for example, allowing new remote wind generation to access load centers).

Investing in each of these three types of transmission requires long-term planning and a coordinated effort to ensure transmission is built where and when it is needed. The “drivers” of the need for new transmission were simple and straightforward: growing demand for electricity

in a utility's service territory and the location of its power plants. The benefits of a new line were often taken for granted by the regulator, as long as the costs seemed reasonable and it was a straightforward exercise to allocate costs to consumers.

## **2.1 The evolving role of transmission**

In the past, most transmission projects were developed by “vertically integrated” utilities that served a well-defined service territory and built power lines to connect its plants with its consumers, and consumers would only take services from this utility.

Nowadays, however, many regions of the US are served by independent power generators who own only power plants, and transmission and distribution utilities who focus only on delivering electricity to consumers. Even in areas where a single utility provides all services to consumers (and owns its own generation along with its wires businesses), there are now rules and regulations that require open access of the transmission system and “arms-length” considerations between the generation and transmission businesses. Independent system operators known as Regional Transmission Operators (“RTOs”) or Independent System Operators (“ISOs”) are now operating across the North American grid, and are in charge of the system planning and evaluation of transmission projects. Meanwhile, non-traditional investors are now allowed to ‘compete’ with utilities to build and own transmission projects. The line between consumers and producers is also blurring. Not only do consumers in some states have the right to choose their own supplier, but they also have an option to invest in their own generation facilities, thanks to the evolution of technology and regulatory reforms. In addition, many states have targets for renewable investment, which often call for additional transmission facilities to connect new generations with the load centers.

Thus, over the past few decades, the simple drivers of transmission have become less relevant, and new realities are driving the sector.

## **2.2 From myths to truths**

Many common misconceptions around transmission investment have evolved from high-level generalizations about why transmission investment is needed and has led to oversimplification of the cost and benefits. These common misconceptions – “myths” – are detached from realities, or “truths,” about transmission, and impose great challenge on efficient transmission development to meet current and future transmission needs.

These myths generally fall into five different categories, namely: (i) myths about power demand; (ii) myths about power supply; (iii) myths about alternatives to transmission; (iv) myths about costs; and (v) myths about benefits of transmission investments. We have identified a total of sixteen myths (see Figure 2) that need urgently to be corrected to better help

system planners make informed decisions<sup>1</sup>—a topic which will be discussed in detail in the following sections.

**Figure 2. Common myths around transmission investment**

<b>POWER DEMAND</b>	<b>1</b>	Transmission is only built to meet current demand	●
	<b>2</b>	Demand is not likely to grow, no need for more transmission	●
<b>POWER SUPPLY</b>	<b>3</b>	Generating plants retire and new ones can use the same transmission lines	●
	<b>4</b>	No grid congestion, no need for more transmission	●
<b>ALTERNATIVES</b>	<b>5</b>	Local reliability issues can be addressed using alternatives	●
	<b>6</b>	Transmission is the most expensive option for resolving local reliability issues	●
	<b>7</b>	Customers tend to opt for new technologies and bypass the grid if they can	●
	<b>8</b>	New technologies are working well and can be easily scaled up to address grid stress	●
<b>COSTS</b>	<b>9</b>	There has already been enough investment in transmission so we don't need more	●
	<b>10</b>	Transmission projects are large and lumpy with high price tags	●
	<b>11</b>	Large transmission investment might end up underutilized	●
	<b>12</b>	Large transmission projects may be prone to overbuilding	●
	<b>13</b>	Large transmission investments involve complex cost allocation schemes that are unfair to consumers	●
<b>BENEFITS</b>	<b>14</b>	Customers on the receiving end are the only ones who benefit	●
	<b>15</b>	Transmission should only be built for resolving reliability issues -- benefits are uncertain for non-reliability projects	●
	<b>16</b>	Transmission investment is risky because the costs are certain but the benefits are not	●

<sup>1</sup> Some of the sixteen myths are bundled together in the detailed discussions in Section 3 through Section 7.

### 3 Myths and truths about electricity demand

There is more to electricity demand than what meets the eye. Even if the overall growth in traditional sectors of the economy that use electricity is not strong, electricity needs can be driven by new economic activities and new consumer uses for electric power.

#### 3.1 **Myth: Transmission is only built to meet current demand, which is not likely to grow. Constructing more transmission in anticipation of the unforeseeable future is a waste**

A common misconception is that transmission is built solely to meet current peak demand. Given that the electricity demand growth is likely to be slow or even flat thanks to a low population growth rate in the US and energy efficiency improvements, there is no need for further investment in transmission—at least not in the near future.

#### 3.2 **Truth: Transmission is not only built to meet current demand, but also to manage evolving consumer behavior and new economic activities**

Even if “top-line” growth seems slow, electricity demand growth may accelerate in the near future as new consumer uses for electricity develop in new locations. Even as the US economy becomes more energy-efficient, the economy constantly evolves, as do consumer patterns of usage. For example, electric vehicles (“EV”) sales have been emerging, and more and more homes are heating with electricity. In addition, specific local areas have experienced economic booms and therefore resulted in a large increase in electricity demand. It can take decades to plan and build a new transmission line—much longer than it takes for new uses of electricity to take hold—so it is best to plan ahead rather than waiting until transmission capacity constrains economic activity and consumer behavior.

A rapid penetration of EVs, as illustrated in Figure 3, will lead to higher demand for electricity and may require new transmission and distribution infrastructure. Although transportation electricity demand is currently very small compared with other end-uses, it is the fastest-growing aspect of electricity demand, with a compound annual growth rate of 2.4% per year, compared to the compound annual growth rate of the total load of 0.6%.<sup>2</sup> Many utilities are actively planning for these new loads by installing charging stations and other new infrastructure. For instance, in January 2017, three major investor-owned utilities in California—Pacific Gas and Electric Company (“PG&E”), Southern California Edison (“SCE”), and San Diego Gas & Electric (“SDG&E”)—submitted plans to the California Public Utilities Commission (“CPUC”) to build EV infrastructure over the next five years.<sup>3</sup>

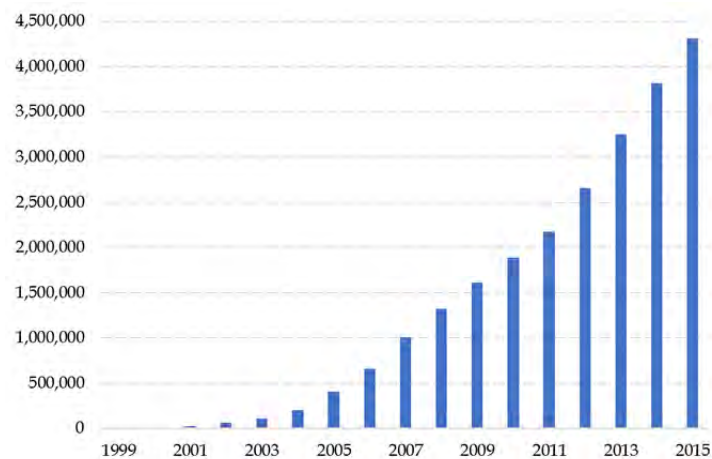
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<sup>2</sup> Energy Information Administration. “Monthly Energy Review.” July 2017. Table 7.6. Electricity End Use, data from 2000-2015.

<sup>3</sup> Greentech Media. “California Utilities Seek \$1B to Build Out Electric Vehicle Infrastructure.” January 24, 2017. <<https://www.greentechmedia.com/articles/read/california-utilities-seek-1b-to-build-out-electric-vehicle-infrastructure>>



**Figure 3. Cumulative sales of electric vehicles in the US**

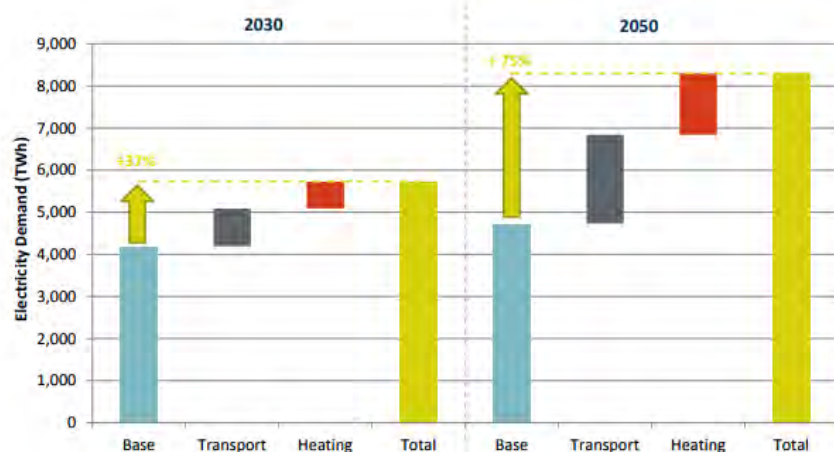


Source: Alternative Fuels Data Center. US Department of Energy. US HEV Sales by Model. January 2016.  
<<http://www.afdc.energy.gov/data/10301>>

Note: The figure shows the sales of both hybrid electric vehicles (“HEVs”) and plug-in electric vehicles (“PEVs”)

The increased popularity of electricity for home heating could also impact the seasonal and daily pattern of electricity demand and require new transmission upgrades. Figure 4 below shows an excerpt from another WIRES-commissioned analysis which demonstrates the profound implications from electrification of the transportation and heating sectors in the US. This analysis finds that by 2050, full electrification of land-based transportation could increase total electricity demand by 2,100 TWh (or 56% of 2015 electricity sales) and that full electrification of heating would increase electricity demand by about 1,500 TWh (or 40% of 2015 electricity sales).

**Figure 4. Incremental electricity sales due to electrification of heating and transportation**



Source: Brattle Group. “Electrification Emerging Opportunities for Utility Growth.” January 2017.



### **3.2.1 Case study: Data center in Pennsylvania, New Jersey, Maryland Interconnection (“PJM”) needed new transmission service**

Data centers are a good example of a new use of electricity that has been growing rapidly driven by technology advancement. Electricity consumed in data centers in PJM increased from about 30 billion kWh per year in 2000 to 70 billion kWh per year in 2014.<sup>4</sup> In some cases, this economic activity added a brand-new end-use that required a new transmission service in affected regions. In PJM, the construction of data centers in the Dominion Virginia Power zone (“DOM”) required new transmission lines. The increasing demand in the region from this activity has also been incorporated by the ISO in their long-term resource planning, as is stated in the PJM Load Forecast Report:

*“The forecast of the DOM zone has been adjusted to account for substantial ongoing growth in data center construction, which adds 130-500 MW to the summer peak from 2017 through 2021.”<sup>5</sup>*

### **3.2.2 Case study: Shale oil and gas boom in Texas drove need for more transmission**

The need for more electricity can also arise quickly in specific locations driven by new technology. Shale oil and gas development, for example, has created a significant load on the electricity system in areas of western Texas that were previously sparsely populated and with limited consumption of electricity. Even though the significance of such type of load demand growth might be zeroed out when viewed from a national level, it is crucial for sustaining regional economic activities and growth.

The fast-growing oil and gas industry in the Permian Basin (which lies in New Mexico and West Texas) is one example of how regional fuel production activities induce investment in transmission infrastructure. By 2016, oil production has reached two million barrels per day, double the level of 2011.<sup>6</sup> This has driven up electricity demand markedly in the Electric Reliability Council of Texas (“ERCOT”)’s Far West zone, where the Permian Basin is located (see Figure 5). As a consequence of the unprecedented load growth, western Texas experienced transmission congestion, meaning that there was no available capacity on the line to transmit energy from lowest-cost plants, and thus loads had to be served by less-efficient, more-costly plants.

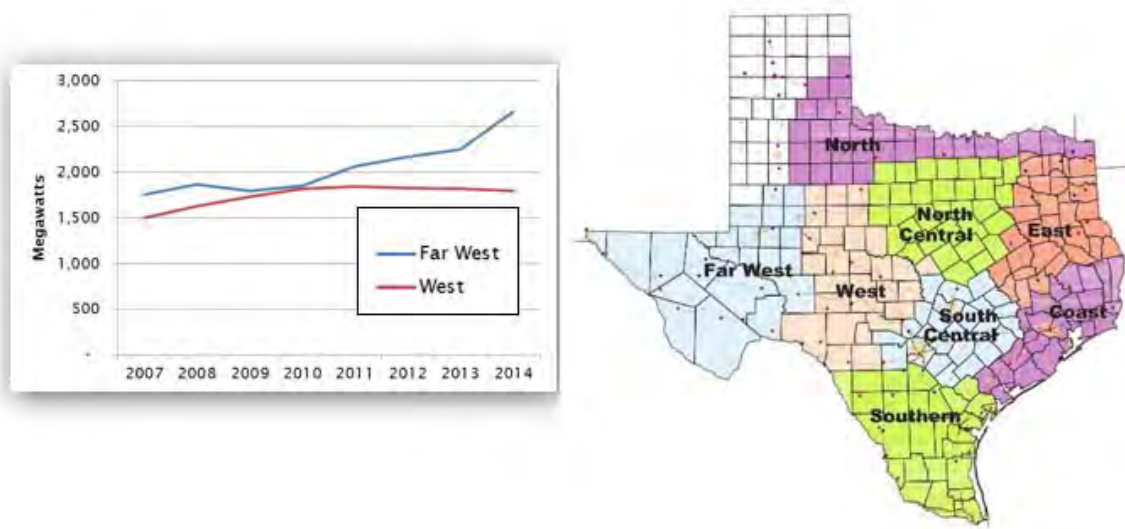
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<sup>4</sup> Lawrence Berkeley National Laboratory, LBNL-1005775. *United States Data Center Energy Usage Report*. June 2016.

<sup>5</sup> PJM Resource Adequacy Planning Department. “PJM Load Forecast Report.” January 2017.  
<<http://www.pjm.com/~media/library/reports-notice/load-forecast/2017-load-forecast-report.ashx>>

<sup>6</sup> Energy Information Administration and Texas Railroad Commission.

**Figure 5. Maximum peak-hour electric power load, ERCOT West and Far West weather zones**



Source: Energy Velocity, ERCOT

ERCOT, the transmission system operator for most of the state, noted that it was taken by surprise by the high demand for electricity triggered by the development of shale oil and gas:

*“TDSPs [Transmission/Distribution Service Providers] and ERCOT did not fully appreciate the significant increase in energy intensity that was associated with the production operations for unconventional drilled wells used for the tight oil/shale plays versus operations associated with for the historical conventional drilling.”<sup>7</sup>*

The ERCOT Board recently endorsed a transmission project that includes two new 345-kV lines to help address future reliability concerns in the growing region of Far West Texas. In the area where the project will be developed, peak electricity demand had increased from 22 MW in 2010 to more than 200 MW in 2016, and it is projected to exceed 500 MW by 2021.<sup>8</sup>

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<sup>7</sup> Energy Ventures Analysis. “West Texas Sensitivity Study Prepared ERCOT.” June 2016.

<sup>8</sup> ERCOT. “ERCOT Board approves transmission project in West Texas.” June 14, 2016. <<http://www.ercot.com/news/releases/show/126322>>

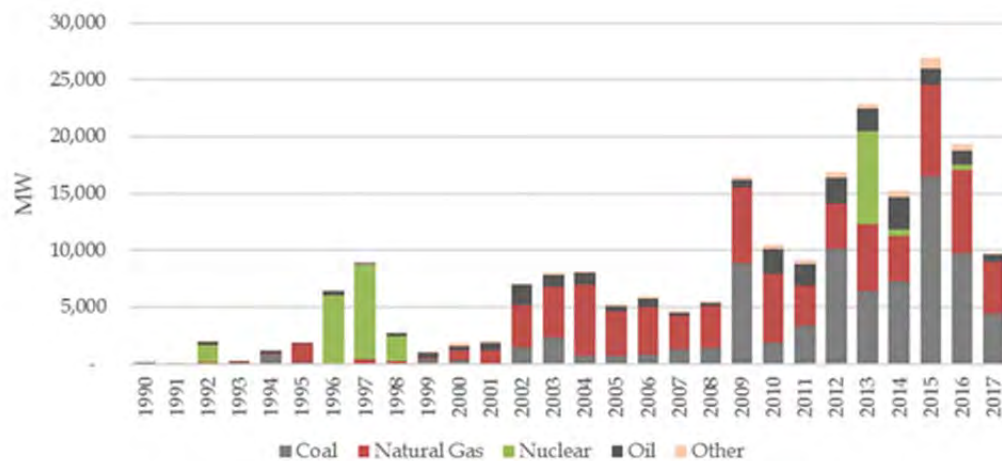
## 4 Myths and truths about electricity supply

Myths around electricity supply usually stem from misconceptions about how generation is connected with demand centers through the grid, or the idea that a transmission line can only provide one kind of benefit to the power system.

### 4.1 Myth: Retiring power plants will create room on the grid for new plants

Thousands of power plants in the US have reached the end of their useful lives in recent years (see Figure 6). As a result of the retirement of old power plants, there is a belief that there will be excessive spare transmission capacity on the system, and in sufficient quantities to interconnect new power plants. This faulty belief leads to the myth that investing in transmission to integrate new generation is not necessary.

**Figure 6. US power plant retirements through June 2017**



Source: Third party data provider

### 4.2 Truth: New power plants are not always built in the same place as retiring power plants

New power plants are not always built in the same locations as retiring power plants. New power plants are sited based on availability of fuel or other national resources needed for electricity production. For example, new wind plants are typically far from urban load areas or located where the grid is already at its performance limit. As a result, capacity freed up by retired power plants may not be utilized by new generation, without additional transmission infrastructure.

#### 4.2.1 Case study: In New England, additional transmission is needed to bring new resources to market

In New England, more than 4,200 MW of generation is expected to have retired between 2012 and 2020, equivalent to almost 15% of the region's current (2017) generation fleet. According to

the ISO-NE, an additional 5,500 MW of oil and coal capacity are at risk for retirement in coming years, and uncertainty also surrounds the continued operation of 3,300 MW of nuclear plants.<sup>9</sup>

Most of these retired or “at risk for retirement” power plants are located fairly close to load centers in central and southern New England (see Figure 7). Potential locations for new gas-fired generation are limited due to the lack of natural gas pipeline capacity and limited ability to access gas resources in many parts of the region.

**Figure 7. Major planned retirement of non-gas-fired generators in New England**



Source: ISO-NE. “2017 Regional Electricity Outlook – Retirements of Non-Gas-Fired Power Plants.”  
[https://www.iso-ne.com/static-assets/documents/2017/02/2017\\_reo.pdf](https://www.iso-ne.com/static-assets/documents/2017/02/2017_reo.pdf)

In the renewable generation sector, most of the new onshore wind power projects proposed to meet states’ renewable portfolio standards (“RPS”) targets are located in northern New England (mostly in Maine). While Maine has the best wind resources in the New England region, it is far

<sup>9</sup> ISO-NE. “Status of Non-Price Retirement Requests.” August 15, 2016.

from load centers and the transmission system there is already constrained.<sup>10</sup> The independent system operator for New England, ISO-NE, stated the need plainly: “transmission improvements are needed to interconnect more wind power.”<sup>11</sup>

### **4.3 Myth: The system is not congested so we do not need more transmission**

Historically, congestion was seen by engineers as one significant symptom of an inefficient and constrained transmission system. This outdated and simplified conception leads to another myth, which states that transmission investment is only needed where there is congestion on the transmission system, or in other words, where the grid is constrained and performing inefficiently. If there is currently no congestion, building new transmission lines or upgrading existing lines is deemed unnecessary.

### **4.4 Truth: Some transmission needs arise even in uncongested energy markets**

Although congestion relief is certainly one of the benefits of transmission, it is not the only factor that should drive investment.

Reliability problems, which could lead to voltage or thermal overloads and result in service interruptions for consumers, are not necessarily coincident with periods with congestion. Traditional transmission planning methods will consider a variety of system conditions, including various stressed transfers and generation outage profiles, that can identify key weaknesses in the transmission system even if significant congestion is not occurring on a day to day basis. In the case of the Greater Boston area in New England, for example, crucial reliability issues were identified by ISO-NE, even with full consideration of local generation. Therefore, even if there is no significant transmission related congestion under typical system conditions, there can be very critical reliability needs. In addition to reliability issues, there may be other economic or policy needs driving investment.

#### **4.4.1 Case study: Greater Boston project addressed reliability in a normally uncongested system**

In 2009, New England’s transmission system operator, ISO-NE, reported that Greater Boston and Southern New Hampshire did not have adequate transmission resources to meet future demand reliably.<sup>12</sup> However, after 2009, there were important changes to the New England

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<sup>10</sup> ISO-NE. “2017 Regional Electricity Outlook.” January 2017. *Note:* ISO-NE is conducting assessments to evaluate the potential economic effects on the regional power system resulting from different scenarios of wind integration and infrastructure improvements. The studies cover areas in Maine, as well as offshore wind development near Rhode Island and Southeast Massachusetts.

<sup>11</sup> ISO-NE. “Key Grid and Market Stats – Transmission.” Accessed June 6, 2017. <<https://www.iso-ne.com/about/key-stats/transmission>>

<sup>12</sup> ISO-NE. “Greater Boston Transmission System. Needs Assessment Review – Solution Study Initiation.” July 16, 2009. <<https://www.iso-ne.com/static->

system, which would not only reduce congestion, but were also expected to solve the reliability problem. These changes included slower load growth, plant retirements, and new generation investment. However, though these changes reduced congestion across New England, there were still reliability problems in the Greater Boston area.<sup>13</sup>

To address the reliability issues, in 2015, ISO-NE selected a transmission investment plan with various upgrades to the existing infrastructure and new construction.<sup>14</sup> As of January 2017, five projects were completed and 12 additional projects were under construction. The whole investment plan is expected to be fully completed by 2019 to address identified transmission reliability needs in New England.<sup>15</sup>

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assets/documents/2016/02/07\_16\_2009\_greater\_boston\_transmission\_system\_needs\_assessment\_review\_solution\_study\_initiation\_redacted.pdf>

<sup>13</sup> ISO-NE. "Greater Boston 2023 Solutions Study Status Update." November 20, 2013.

<sup>14</sup> ISO Newswire. "ISO-NE selects all-AC transmission solution to address grid reliability needs in Greater Boston." February 12, 2015. <<http://isonewswire.com/updates/2015/2/12/iso-ne-selects-all-ac-transmission-solution-to-address-grid.html>>

<sup>15</sup>Eversource. "Investor Call". February 22, 2017. Page 18. <<https://www.eversource.com/Content/docs/default-source/Investors/2016-q4-and-y-e-financial-results.pdf?sfvrsn=0>>

## 5 Myths and truths about alternatives to transmission

New technologies and alternatives to transmission can provide solutions to electric system needs that do not involve traditional transmission infrastructure. Alternatives to transmission come in a variety of forms and can include both demand-side (e.g. energy efficiency and demand response programs) and supply-side resources (e.g. utility-scale generation, distributed generation, energy storage, and smart grid technology).

There are several related myths about these alternatives to transmission, and they all reflect a misconception that there are cost-effective substitutes for every benefit and service that can be provided by transmission.

### 5.1 **Myth: Transmission by wire is old technology. There are new and more cost-effective substitutes for transmission**

It is widely perceived that as distributed generation, such as behind-the-meter solar PVs and energy storage, is becoming more economic and more widely installed, it allows consumers to bypass the grid to satisfy their demand. In addition, energy efficiency and demand response programs are scaling up across the country, contributing to falling electricity demand. It is widely perceived that as distributed generation, such as behind-the-meter solar PVs and energy storage, is becoming more economic and more widely installed, it allows consumers to bypass the grid to satisfy their demand. In addition, energy efficiency and demand response programs are scaling up across the country, contributing to falling electricity demand. These alternatives are sometimes deployed to alleviate pressure on the grid, making transmission no longer the only solution that addresses the need for some transmission services. However, it is a misconception that transmission solutions are the most costly and time-consuming choice, and that alternatives are perfect substitutions for transmission.

### 5.2 **Truth: Non-transmission alternatives (“NTAs”) are not always apples-to-apples substitutes for transmission**

While NTAs can meet some of the same technical needs of the system that drive transmission investment (for example, in solving certain reliability problems with system overloads or providing market efficiencies, like reducing congestion and motivating production cost savings), they are rarely a complete substitute to transmission as the benefits of NTAs (also known as market resource alternatives (“MRAs”)) and transmission will vary in terms of tenure (duration), locational dispersion, and even functional impact (in terms of reliability versus market impacts).

Figure 8 provides a comparison of services that can be provided by transmission as well as various MRAs. Although often overlooked, it is important to recognize that transmission investment and MRAs are often complements to each other rather than substitutes. Individual MRAs/NTAs typically can provide only a partial suite of the services that transmission provides, and usually can meet only very specific and local needs.



**Figure 8. Services provided by transmission lines versus MRAs**

		Transmission	Energy Efficiency	Demand Response	Distributed Generation	Energy Storage
What	Energy	●	◐	◐	◐	●
	Capacity	●	◐	◐	◐	●
	Ancillary Services	●	○	◐	◐	●
	Reduce system losses	●	◐	◐	◐	●
When	Long lifespan	●	◐	○	●	●
	Continuous basis	●	◐	○	○	●
Where	Regional	●	◐	◐	○	○
	Local	●	●	●	●	●
	Micro	●	●	●	●	●
How	System/Wholesale	●	○	○	○	●
	Customer/Retail	○	●	●	●	○
	TOTAL	●	◐	◐	◐	◐

● Provided    ○ Not provided

Source: London Economics International. *A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*. October 2014. Pg. 13.

NTAs are also not necessarily cheaper – they may even undermine reliability when viewed in the context of the larger system in the long term or require often costly solutions at the end-of-life. For example, load reductions by demand-side resources, such as energy efficiency and demand response, are difficult to measure and are not necessarily permanent, which creates additional stress and risk to the system management and planning process.

Similarly, most distributed generation resources rely on intermittent technology – solar and wind – and are not able to provide services on a continuous basis on their own (without energy storage). They also present a challenge for system planners and operators who must manage the intermittency and attendant dispatch uncertainty for these distributed resources.

While energy storage resources can provide many of the same services as transmission, they are currently more expensive and less expansive than transmission in terms of geographical reach. With the exception of pumped hydro storage, energy storage technologies have not been widely deployed to date on a commercial scale, and are generally not yet cost competitive with other MRAs and transmission per unit of electricity produced or delivered.



## 6 Myths and truths about the cost of transmission

Transmission projects can be large-scale projects, and as such their costs are high on stakeholders' radar screens. However, costs should not be evaluated in a vacuum—one should also consider benefits of transmission investment, and those benefits need to be evaluated comprehensively. Electricity cost savings, reliability improvements, and local economic benefits all contribute to the benefit side of the investment decision.

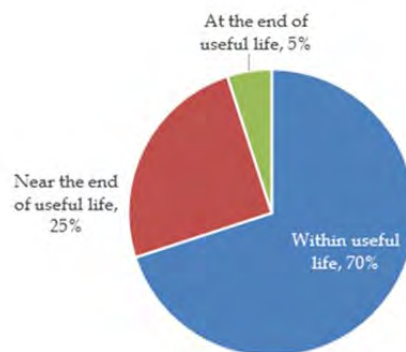
### 6.1 Myth: There has already been a substantial amount of investment in transmission, and many of the assets are fairly new so we do not need more

Investment in electric transmission has exhibited strong growth over the past few decades. From 1997 through 2012, annual US transmission investment rose \$2.7 billion to \$14.1 billion, a rate of 12% annually.<sup>16</sup> In 2015, annual transmission infrastructure investment reached a record of \$20.1 billion for the US.<sup>17</sup> This has spawned a new myth: given this great amount of past investment dollars, there is no need for new investments on the current transmission system.

### 6.2 Truth: Assets are aging and some need replacement or refurbishment

Much of the US transmission system was built in the 1950s to 1970s with the boom in the economy post-World War II. By 2014, 30% of US transmission infrastructure was at or near the end of its useful life, according to the Edison Electric Institute (see Figure 9).

**Figure 9. Current transmission infrastructure age, relative to useful life**



Source: Edison Electric Institute ("EEI") / Harris Williams Co. "Transmission & Distribution Infrastructure." Summer 2014.

<[http://www.harriswilliams.com/sites/default/files/industry\\_reports/ep\\_td\\_white\\_paper\\_06\\_10\\_14\\_final.pdf](http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf)>

<sup>16</sup> EIA. "Investment in electricity transmission infrastructure shows steady increase." August 26, 2014.  
<<https://www.eia.gov/todayinenergy/detail.php?id=17711>>

<sup>17</sup> EEI. "Transmission Projects: At a Glance." December 2016.

Many elements of the transmission system need ongoing maintenance, repair, and upgrading, or in some cases complete modernization, as exemplified by the recent experience of the Pacific Direct Current Intertie (“PDCI”).

### 6.2.1 Case study: The 45-year old Pacific Direct Current intertie (“PDCI”) needed refurbishment

The PDCI is a high-voltage direct current system (“HVDC”) 846-mile transmission line connecting the Oregon/Washington border, with Los Angeles. The transmission line carries hydroelectricity generated by the 31 dams of the federal Columbia River power system. Converter stations at the two endpoints convert the power from direct current (“DC”) to the alternating current (“AC”) used by the rest of the grid (see Figure 10).

**Figure 10. The Pacific Direct Current Intertie**



Source: Bonneville Power Administration. <<https://www.bpa.gov/news/pubs/FactSheets/fs-201604-Celilo-Converter-Station.pdf>>

The line went into service in 1970 with a capacity of 1,440 MW and has had numerous additional investments since then to meet increased capacity and reliability needs. Most recently, during 2014 to 2015, the Bonneville Power Administration (“BPA”) invested \$320 million to modernize the Celilo Converter Station at the north end of the transmission line. The project replaced vintage equipment, such as transformers, with new equipment that is faster, more reliable, and easier to maintain. It also reduced the converter station’s footprint by half. Most notable among Celilo’s new equipment are new transformers and digital controls to replace 40-year-old analog equipment. The upgrade was completed in 2016. As is demonstrated by the PDCI project, substantial investment is continuously needed to keep critical, existing

facilities in good working order. Moreover, such maintenance and incremental investment allows system operators to capture incremental capacity improvements.

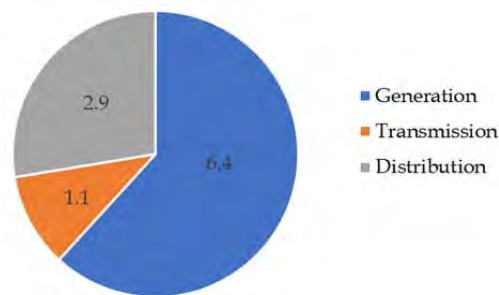
### **6.3 Myth: Transmission projects have large up-front costs which will be passed onto consumers**

Transmission projects are often big and carry high price tags. In the US, the average cost for a 'typical' transmission project can range from \$30 million to \$300 million, depending on its scale. An interregional long-distance transmission project can cost as much as \$1 billion or even more.<sup>18</sup> It is a myth that the best way to avoid high electricity bills for end-users is to avoid high price tags of large transmission projects.

### **6.4 Truth: The 'price tag' for construction of new transmission projects is recovered gradually, with only modest impacts on consumers at any given point in time**

The cost of a transmission investment is spread over many years, over hundreds or even thousands of consumers, and over millions of kilowatt hours. Transmission costs account for only a small portion of the final electricity bill – typically around one cent per kilowatt hour, or 10% of the retail price (see Figure 11).<sup>19</sup>

**Figure 11. Average retail electricity prices by service category, 2015 (cents per kilowatt hour)**



Source: Energy Information Administration, Electricity Supply, Disposition, Prices, and Emissions.  
<<https://www.eia.gov/outlooks/aeo/data/browser>>

For an individual transmission project, even a large one, the impact is even smaller. A \$2 billion project in a state the size of New York, multiplied by 18% (a rule-of-thumb for calculating annual revenue requirements), divided by an assumed 159,169 GWh of electricity consumption

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<sup>18</sup> Ibid.

<sup>19</sup> EIA. Factors affecting electricity prices. Accessed on July 11<sup>th</sup>, 2017.  
<[https://www.eia.gov/energyexplained/index.cfm?page=electricity\\_factors\\_affecting\\_prices](https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices)>

(New York state's 2016 consumption level), would cost consumers far less than a penny per kWh consumed, only around \$0.00225/kWh.<sup>20</sup>

In contrast, generation (supply-related costs) accounts for the largest share of the electricity bill in the US, generally about 60%.<sup>21</sup> Drivers that impact the cost of generation, especially drivers such as fuel prices, have by far the largest impacts on monthly electricity bills and dwarf the incremental costs from transmission projects. In addition, transmission investments for projects designed to allow lower-cost generation resources to reach demand centers and to increase market competition help to lower costs of generation for end-users.

## **6.5 Myth: Large infrastructure investments might end up underutilized**

Transmission planning is based on long-term commitments and must take into consideration potential future needs. However, failing to understand the complex evaluation process for transmission investment gives rise to the concern that the future is uncertain and that these future needs we are forecasting today may never come to fruition. These uncertainties lead to the myth that the transmission projects we are building for future need will very likely end up being underutilized.

## **6.6 Truth: Large projects are subject to detailed cost/benefit analyses, to help ensure their ultimate usefulness**

Investment uncertainties around new transmission infrastructure can be quantified and analyzed comprehensively to mitigate the chances of a “bad” decision. For instance, transmission projects between Midcontinent Independent System Operator (“MISO”) and Southwest Power Pool (“SPP”) are required to have a benefit/cost ratio of 1.25 to the entire MISO region.<sup>22</sup> Such a benefit/cost ratio calculated for a range of future scenarios provides a high degree of certainty that the transmission investment will be prudent.

### **6.6.1 Case study: MISO evaluates a wide variety of benefits and imposes a high benefit-cost threshold to mitigate risk of underutilization**

MISO gauges the value of proposed transmission projects under a variety of future policy and economic conditions across multiple quantitative benefit metrics. In its “Portfolio Economic Benefits Analysis,” MISO acknowledges and considers a variety of qualitative benefits, such as enhanced generation policy flexibility, increased system robustness, decreased natural gas risk,

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<sup>20</sup> New York state demand was 159,169 GWh in 2016, NYISO. “2017 Gold Book.” April 2017.

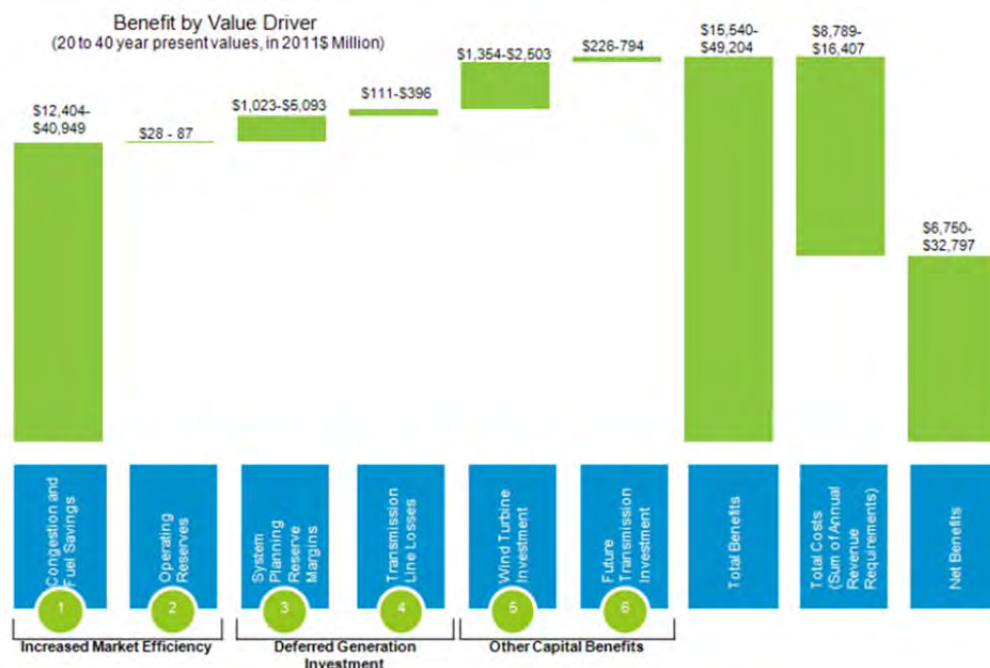
<sup>21</sup> U.S. Energy Information Administration, Annual Energy Outlook 2017, Reference case, Table 8: Electrical supply, disposition, prices, and emissions.

<sup>22</sup> FERC. Order Reject Tariff Revisions. Nov.30, 2015. Docket No. ER15-2705-000.

decreased wind generation volatility, local investment, and job creation, as well as carbon reduction (see Figure 12).<sup>23</sup>

MISO requires all its Market Efficiency Projects (“MEPs”) to have a benefit/cost ratio of at least 1.25. MISO also imposes a higher hurdle for Multi-Value Projects (“MVPs”), expecting these to have benefit/cost ratios under all scenarios ranging from at least 1.8 to 3.0. These measures help to ensure economic efficiency and necessity of transmission investments at the early planning stage and avoid undue transmission expansion that could end up being underutilized.

**Figure 12. Portfolio of economic benefits for Multi-value project in MISO’s MTEP 2016**



Source: “MISO Transmission Expansion Plan (MTEP16).” MISO. 2016.

<<https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>>

## 6.7 Myth: Transmission projects may be prone to overbuilding

A common belief is that large infrastructure investments that are paid for by consumers, like transmission projects, are prone to “gold-plating,” or in other words, over-sizing and over-spending beyond what is actually needed. Concerns that the costs of initially unused myth that will become a cost burden on consumers lead to the myth that smaller, piecemeal projects may be a better choice, because they have the appearance of lower up-front cost commitments.

<sup>23</sup> “MISO Transmission Expansion Plan (MTEP16).” MISO. 2016.

<<https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf>>

## **6.8 Truth: Transmission projects go through stringent and comprehensive cost-benefit evaluations to avoid overbuilding**

Multiple avenues for avoiding and correcting “gold-plating” exist. For large transmission projects, a stakeholder review is required by FERC, the ISOs/RTOs, and the state agencies to ensure that investments are appropriate. Other venues for ensuring projects are sized appropriately for benefits and market activities include competitive procurements, where market forces are harnessed to control costs.

“Gold-plating,” or overbuilding, is often raised as an objection to transmission projects when stakeholders do not understand the benefits and focus exclusively on costs. However, it is equally, if not more, important to support long-term grid reliability as reliable electric service will contribute to economic activity in a region. Deferring investment in transmission may result in risks of service interruption and higher costs in the future.

### **6.8.1 Case study: PJM studied many options for AP-South congestion relief as part of stakeholder review to ensure an optimal transmission investment**

In 2015, PJM began a stakeholder process and an extensive analysis process to examine efficiency, reliability, and congestion relief solutions along the AP-South corridor near the Pennsylvania-Maryland border.<sup>24</sup> The AP-South Congestion Relief Solution study analyzed 41 proposals (see Figure 13).

Based on the results of the initial study, PJM selected four projects that could each potentially solve the congestion problem and were well above the required benefit-to-cost threshold of 1.25. Of the four, Transource’s Project 9A provided the greatest congestion benefits and highest benefit-to-cost ratio. However, based on feedback from PJM stakeholders and in an effort to develop the most robust solution, PJM conducted additional sensitivity analysis studies to assess different combinations of several similar proposals in the same region. The second study again demonstrated that Project 9A consistently provided the most benefits across the scenarios studied. The PJM Board finally approved Project 9A in August 2016. The project, which is required to be in-service by 2020, has an estimated cost of \$320.19 million and an expected 15-year congestion and load payment savings of \$622 million and \$269 million, respectively.<sup>25</sup> Notably, Project 9A was one of the largest projects proposed of the 10 finalist projects, whose costs ranged from \$40 million to \$230 (except Project 9A).<sup>26</sup> Project 9A was nevertheless the most effective investment from the perspective of PJM and consumers.

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<sup>24</sup> PJM. “PJM Regional Transmission Expansion Plan 2016.” February 28, 2017.

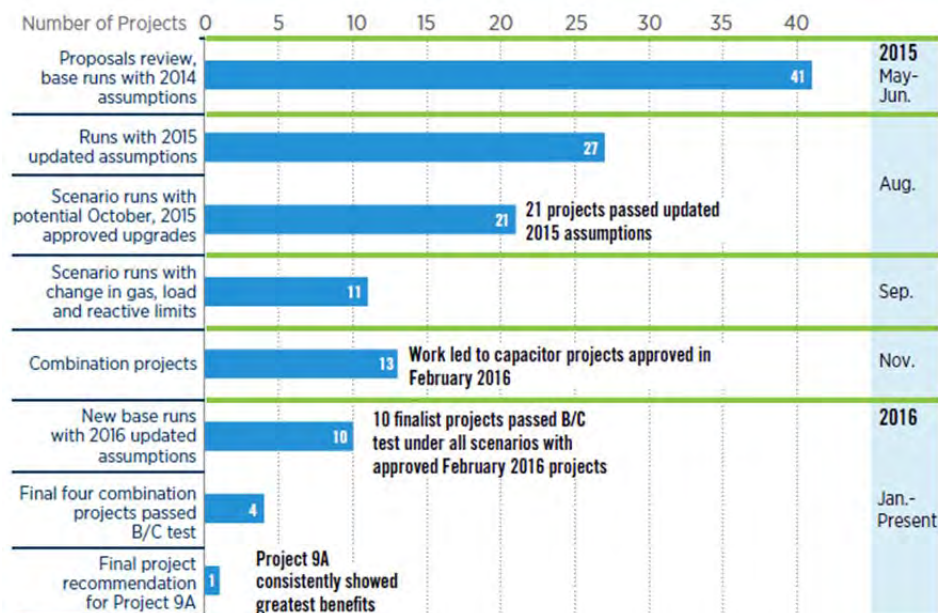
<sup>25</sup> Ibid.

<sup>26</sup> PJM. “Transmission Expansion Advisory Committee Market Efficiency Update.” March 10, 2016.  
<<http://www.pjm.com/~media/committees-groups/committees/teac/20160310/20160310-market-efficiency-update.ashx>>



Therefore, it is important to evaluate both the costs and benefits of a transmission investment, rather than focusing only on the costs, and a stringent and transparent evaluation process will include all the relevant costs and benefits.

**Figure 13. PJM’s review of options for AP-South congestion relief**



Source: PJM. “PJM Regional Transmission Expansion Plan 2016.” February 28, 2017.

## 6.8.2 Case study: AEP’s 765-kV transmission project was novel in 1970s – but has since served as the backbone of its system

In 1969, American Electric Company (“AEP”) developed the world’s first 765-kV transmission line, a 68-mile line between Kentucky and Ohio.<sup>27</sup>

In 1966, when AEP first proposed this interstate ultra-high voltage transmission project, it was criticized as bold and unnecessary given engineering practices at that time. However, when the project was put into service, it eventually became the backbone of the electricity network in the Midwest by efficiently enabling interconnection of 1,300 MW generating units to serve the growing regional economy. Currently, AEP has over 2,100 miles of 765-kV network.<sup>28</sup>

<sup>27</sup> AEP. “The Evolution of American Electric Power: Past, Present & Future.” February 19, 2015. <<http://energyweek.utexas.edu/files/2015/07/Crowder.pdf>>

<sup>28</sup> Heyeck, Michael. “The Next Interstate System: 765-kV Transmission.” *ELP. Electric Light & Power*. January 2007. <<http://www.elp.com/articles/print/volume-85/issue-1/sections/td/the-next-interstate-system-765-kv-transmission.html>>

Transmission investment must take into account long-term needs of the system and consider the technology that best achieves those needs. Investments perceived as “overbuilding” at one point can prove themselves as imperative to sustain a reliable and efficient grid system.

## **6.9 Myth: Project costs for interregional transmission projects are often unfairly allocated**

Cost allocation is a challenge that frequently comes up, especially for interregional transmission projects. Determination of costs and benefits of a transmission project can be very complicated and the results can vary among stakeholders and variances can also arise under different methodologies. Opponents to transmission investments claim that cost allocation settlements can take years and result in long-term suspension and delay of transmission projects, causing electricity consumers and project developers to potentially be exposed to investment risks. Hence, a myth arises that large, interregional transmission projects should be avoided when possible.

## **6.10 Truth: Cost allocation issues are not insurmountable and can be resolved with both standard and customized solutions**

Cost allocation is not a “new” issue. Transmission investment costs have been successfully allocated to different consumers since utilities first started charging for their services.

Significant progress has been made in developing and implementing standardized, widely-accepted cost allocation frameworks in recent years. ISO-NE, for example, has a default cost allocation mechanism for determining local and regional transmission costs. The MVPs in MISO are being developed based on a wide agreement of allocating the costs among benefiting states. The SPP region also uses a cost allocation mechanism for new electric transmission called “Highway/Byway” which was approved by FERC in 2010.<sup>29</sup> Meanwhile, customized tariff-based solutions, like in the case of the Tehachapi project in California described below, are possible where appropriate.

### **6.10.1 Case Study: Regional and local transmission cost allocation in ISO-NE – a standard solution**

ISO-NE has established a well-accepted cost allocation scheme which has facilitated major transmission investments. Since 2003, ISO-NE/NEPOOL has adopted a default cost allocation mechanism, approved by FERC, which allocates transmission costs among six states and many different classes of consumers.<sup>30</sup> Every year, ISO-NE conducts a Regional System Plan (“RSP”) which identifies a list of transmission projects that are expected to meet the reliability needs and

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<sup>29</sup> FERC. “Order Accepting Tariff Revisions. Southwest Power Pool, Inc. Docket No. ER10-1069-000.” June 17, 2010. <<https://www.ferc.gov/whats-new/comm-meet/2010/061710/E-7.pdf>>

<sup>30</sup> FERC Technical conference on Connecticut infrastructure. *Allocating the Cost of New Transmission in New England*. January 6, 2005. <<https://www.ferc.gov/CalendarFiles/20050124145350-Whitley,%20Cost%20Allocation.pdf>>



bring economic benefits to the New England region. ISO-NE reviews the reliability of design proposed by transmission owners and determines what costs should be regionalized and what portions should be localized.<sup>31</sup>

Specifically, projects with 115kv and above capacity identified in the RSP are categorized as regional benefit upgrades, whose costs are allocated in proportion to each ISO-NE state's peak electricity demand, and are funded through a pool-wide postage stamp rate<sup>32</sup> for their regional network service. Smaller projects (generally less than 115kv and those which do not provide regional benefits) are categorized as local benefit upgrades, whose costs are allocated through a license plate rate.<sup>33</sup>

#### **6.10.2 Case study: Tariff-based cost allocation for Tehachapi project – a customized solution**

The Tehachapi Renewable Transmission Project ("TRTP") in California provides an example of a customized tariff-based solution to cost allocation for an inter-regional transmission project.

The Tehachapi area is one of California's leading resource areas for wind energy, but there was limited transmission infrastructure in the region to bring the wind energy to market.<sup>34</sup> Southern California Edison ("SCE") developed the TRTP 500 kV transmission line to deliver the wind energy to load centers in Los Angeles and San Bernardino counties, which allowed development of the wind resources of the Tehachapi area.

Segment 3 of this project was developed under a FERC-approved Location Constrained Resources Interconnection tariff ("LCRI"). Transmission owners paid upfront, and generators must pay pro-rata shares of costs when they interconnect and come in-service.<sup>35</sup> The TRTP line was energized in 2016.

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<sup>31</sup> Fink, S. et, al. "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations." NREL. February 2011. <<http://www.nrel.gov/docs/fy11osti/49880.pdf>>

<sup>32</sup> Under a "postage-stamp" rate design, the costs of all existing transmission facilities in a large region are "rolled-in" and allocated to all consumers according to each consumer's share of the region's total load. As a result, the rate is the same for each consumer in the large region akin to a postage stamp that ensures delivery across the U.S., regardless of the distance.

<sup>33</sup> Under a "license plate" rate design, the rates for transmission vary by zone, rates can be differentiated based on distance or other metrics between zones.

<sup>34</sup> SCE. "The Tehachapi Renewable Transmission Project: Greening the Grid—Celebrating California's Progress in Renewable Energy." March 2010.

<sup>35</sup> Ibid.

## 7 Myths and truths about the benefits of transmission

The benefits of a transmission project could be geographically widespread and take various forms. One needs to take a holistic view to assess the benefits of transmission projects, which will also help decision makers and transmission consumers to better understand the costs of transmission objectively.

It is critical to recognize that the potential benefits of a transmission project go way beyond meeting regional energy demand—they could also include storm hardening, increased competition in wholesale power markets, congestion relief, deferral of new generation or other upgrades, expanded economic activity, increases in state or local property tax collections, and numerous other attributes that may impact local economies.

### 7.1 Myth: Consumers on the receiving end are the only ones who benefit

It is widely accepted that transmission projects benefit the consumers who are receiving the power, but it is a myth that consumers on the receiving end of the transmission line (where the power is "sinking") are the only ones who benefit and that it is unfair for consumers in the regions along the route to also some of bear the cost.<sup>36</sup>

### 7.2 Truth: Benefits can be geographically and demographically widespread

From a geographic perspective, a state that is a source of supply ("source") may see benefits from the construction of the transmission line, including economic benefits during construction, economic benefits from taxes or other payments once the project is complete, as well as economic opportunities in the future for the development of new generation. Transit states or regions will see benefits from property taxes collected from the transmission operator in addition to potential electricity cost savings and environmental benefits. "Sink" locations, i.e. the receiving end, will see local economic and reliability benefits from more access to electric power and could also see "knock-on" effects from local economic boom from construction activities.

#### 7.2.1 Case study: TransWest Express

The TransWest Express Transmission Project, a 600kV, 725-mile long transmission line, was proposed to provide 3,000 MW of capacity to deliver approximately 20,000 GWh/year of wind energy generated in Wyoming to Arizona, Nevada, and southern California. As of June 2017, TransWest Express has received approval from the Bureau of Land Management for its proposed right-of-way, and construction is expected to take place during 2018 to 2020.

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<sup>36</sup> Prepared by The Brattle Group, for WIRES. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*. July 2013. "WIRES Preface and Commentary." Pg. 4.

Projected benefits of the line are not limited to the availability of energy to consumers on the receiving end. Four distinct economic regions along the transmission lines were identified as benefiting from increases in direct and indirect employment (see Figure 14). According to TransWest's preliminary economic impact study, direct employment associated with the construction of each region would average approximately 203 jobs over the construction period, and secondary employment is expected to reach, on average, 89 jobs over the construction phase.<sup>37</sup> Obviously, all regions along the route, not only the "sink," will benefit from construction activities of this project in terms of local economic growth and employment increase.

**Figure 14. TransWest Express project route**



Source: TransWest Express LLC. "Delivering Wyoming wind energy to the West."  
<http://www.transwestexpress.net/index.shtml>

### 7.3 Myth: Transmission should not be built for any reason other than for resolving reliability issues

It has been argued that transmission is only needed where there are reliability issues on the grid and that, as a result, non-reliability projects are not justifiable.

<sup>37</sup> TransWest Express EIS. Section 3.17 – Social and Economic Resources. Western Energy. April 2015. Docket: DOE/EIS-0450. <<https://eplanning.blm.gov/epl-front-office/projects/nepa/65198/78887/90846/06-Chapter3.17-SocialandEconomicResources.pdf>>

#### 7.4 Truth: A transmission project initiated for reliability reasons may have other economic benefits and vice-versa

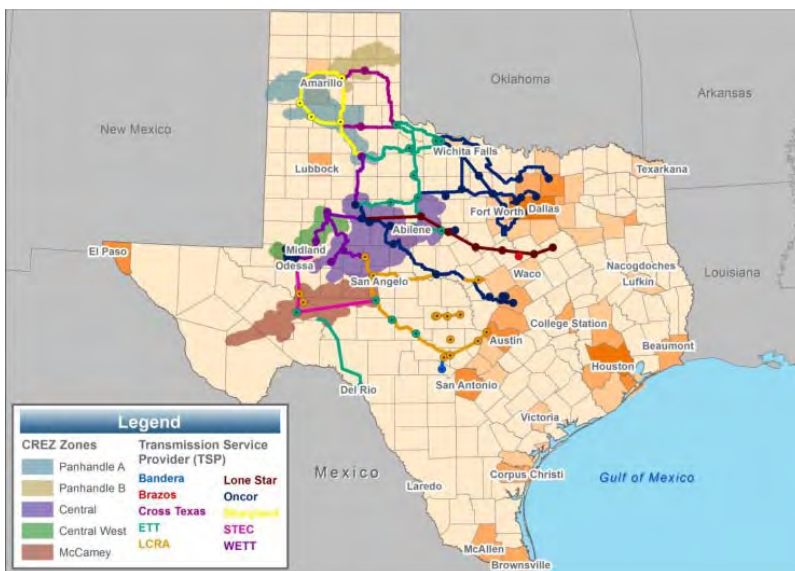
This myth overlooks the fact that transmission investment targeting reliability will naturally bring about other benefits, such as reducing system costs or providing a variety of economic benefits such as supporting local industries, and potentially motivate other investments.

New York and Texas are single-state RTOs, and thus state policy and oversight of the transmission system are easier to coordinate than in RTOs that encompass multiple states. Transmission investments in these states for purposes other than reliability are good examples of the reality of the multi-faceted nature of benefits. The Texas Competitive Renewable Energy Zones (“CREZ”) initiative was aimed at achieving renewable policy goals, but also reduced system-wide wholesale electricity prices and has other benefits. In New York, when identifying a recent “public policy” project, the state examined broad categories of transmission benefits.

##### 7.4.1 Case study: Texas built the CREZ lines based on policy drivers, with additional economic benefits to consumers

In 2008, the Public Utility Commission of Texas (“PUCT”) established CREZ to encourage the building of long-distance transmission lines to bring wind power to the grid and to consumers. The goal of the CREZ initiative was to allow the delivery of energy produced by renewable resources (primarily wind) in the West and South zones to the load centers in North, South, and Houston zones (see Figure 15).

**Figure 15. Competitive Renewable Energy Zones and transmission lines (completed)**



Source: Warren Lasher, Director of System Planning, ERCOT. *The Competitive Renewable Energy Zones Process*, August 11, 2014. <[https://energy.gov/sites/prod/files/2014/08/f18/c\\_lasher\\_qer\\_santafe\\_presentation.pdf](https://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf)>

The impetus for CREZ came from the then-governor of Texas, Rick Perry, and concerns over the high fossil fuel prices at the time (2003). However, by the time the final recommendations of Perry’s policy group, the Texas Energy Planning Council (“TEPC”) were released, renewable energy, namely wind, had gained a central role in the energy plan. As Texas’s abundant wind resources are far from load, the eventual legislation that resulted from the Governor’s committee included support for the development of high-capacity long-distance transmission lines, as well as an increase of Texas’s RPS requirements.

The CREZ transmission expansions were completed in January 2014, enabling dispatch of 18,500 MW of wind capacity.<sup>38</sup> Since the completion of the lines, wholesale energy costs system-wide (not just in ERCOT West, where most of the wind plants are located) have reflected the low cost of wind generation. Sporadic hourly negative real-time prices ERCOT-wide began after the CREZ system was energized and have persisted throughout 2015 (54 hours), 2016 (128 hours) and 2017 (35 hours as of July 2017) – even during summer months. Negative prices were seen in not only in one zone, but all across the system. These low energy prices are a concrete and measurable benefit to consumers (though they are challenging for some generators given the current market design). Thus, the CREZ lines not only helped meet renewable policy goals, but have provided electricity market benefits to consumers. An additional benefit is that CREZ lines can accommodate solar power, which tends to generate more during non-windy hours. Some of the CREZ lines have also provided system access to new consumers (see Section 3.2.2 for oil and gas developments). As such, CREZ projects have reinforced system reliability as well.

#### **7.4.2 Case study: New York examined broad categories of transmission benefits to justify transmission investment**

In 2015, New York Public Service Committee (“PSC”) identified a very precise set of transmission upgrades in its footprint that would be necessary pursuant to the state’s policy goals.<sup>39</sup> These upgrades would provide a 375 MW increase in the Central-East interface voltage transfer limit,<sup>40</sup> as well as increase by 939 MW the UPNY/SENY interface normal transfer limit.<sup>41</sup>

These upgrades are expected to reduce transmission constraints between the western and eastern regions of New York, which in turn will ease the downward pressure on western New

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<sup>38</sup> Malewitz, Jim. “\$7 Billion CREZ project near finished, aiding wind power.” October 14, 2013. <<https://www.texastribune.org/2013/10/14/7-billion-crez-project-nears-finish-aiding-wind-po/>> and ERCOT. *Competitive Renewable Energy Zones: Transmission Optimization Study*. April 2008.

<sup>39</sup> NY PSC. *Order Finding Transmission Needs Driven by Public Policy Requirements*. Case 13-E-0488. December 17, 2015.

<sup>40</sup> The C/E interface is typically voltage limited, therefore voltage limits were the focus of NYISO’s evaluations.

<sup>41</sup> NYISO. *AC Transmission Cases: Updated Powerflow Analysis*. NY PSC Case 13-E-0488. October 8, 2015 (posted October 14, 2015).

York energy prices. In addition, the New York PSC also identified significant environmental, economic, and reliability benefits that could be achieved by relieving the transmission congestion in New York. The project continues to move forward—as of July 2017, the selection process of the to-be-constructed project and transmission sponsor is under way.

### **7.5 Myth: Transmission investment is risky, because transmission benefits are uncertain, while the costs are certain**

Failing to understand the multi-faceted nature of transmission investment benefits, or evaluating a transmission investment in a short-sighted manner will inevitably bring about another myth: the benefits of transmission investments touted by developers are often intangible or “uncertain,” but consumers are required to pay for the costs regardless whether benefits materialize. Due to this uncertainty of benefits, some stakeholders argue that large and costly transmission projects should not be pursued.

### **7.6 Truth: Transmission investment risks can be managed**

Any investment involves uncertainty and risk. Yet risks can be managed through prudent analysis and decision-making. For example, some ISOs/RTOs specifically set high benefit-to-cost ratio thresholds to ensure that risky projects are not undertaken (see discussion in Section 6.6). Other ISOs/RTOs, such as CAISO and MISO, also evaluate a broad set of scenarios to test whether benefits are robust across a wide range of uncertain outcomes.<sup>42</sup>

Uncertainty is also bi-directional. In other words, the actual benefits could be larger than estimated benefits. This is especially true if the benefit analysis was conservative.

Furthermore, not all benefits of transmission investment are immediate or obvious; some may be hard to quantify and others may have different values for different stakeholders. However, as explained in-depth in Section 7.2 and Section 7.3, benefits of transmission investment take various forms, are spread extensively geographically, and last for decades (as described in other WIRES white papers, see Figure 16).

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<sup>42</sup> CAISO. *Transmission Economic Assessment Methodology*. June 2004. See also Section 6.6 for discussion of the MISO evaluation process.



**Figure 16. Potential benefits of transmission investments**

Benefit Category	Transmission Benefit
<b>1. Traditional Production Cost Savings</b>	Production cost savings as traditionally estimated
<b>1a-1i. Additional Production Cost Savings</b>	<ul style="list-style-type: none"> <li>a. Reduced transmission energy losses</li> <li>b. Reduced congestion due to transmission outages</li> <li>c. Mitigation of extreme events and system contingencies</li> <li>d. Mitigation of weather and load uncertainty</li> <li>e. Reduced cost due to imperfect foresight of real-time system conditions</li> <li>f. Reduced cost of cycling power plants</li> <li>g. Reduced amounts and costs of operating reserves and other ancillary services</li> <li>h. Mitigation of reliability-must-run (RMR) conditions</li> <li>i. More realistic representation of system utilization in "Day-1" markets</li> </ul>
<b>2. Reliability and Resource Adequacy Benefits</b>	<ul style="list-style-type: none"> <li>a. Avoided/deferred reliability projects</li> <li>b. Reduced loss of load probability <u>or</u></li> <li>c. Reduced planning reserve margin</li> </ul>
<b>3. Generation Capacity Cost Savings</b>	<ul style="list-style-type: none"> <li>a. Capacity cost benefits from reduced peak energy losses</li> <li>b. Deferred generation capacity investments</li> <li>c. Access to lower-cost generation resources</li> </ul>
<b>4. Market Benefits</b>	<ul style="list-style-type: none"> <li>a. Increased competition</li> <li>b. Increased market liquidity</li> </ul>
<b>5. Environmental Benefits</b>	<ul style="list-style-type: none"> <li>a. Reduced emissions of air pollutants</li> <li>b. Improved utilization of transmission corridors</li> </ul>
<b>6. Public Policy Benefits</b>	Reduced cost of meeting public policy goals
<b>7. Employment and Economic Development Benefits</b>	Increased employment and economic activity; Increased tax revenues
<b>8. Other Project-Specific Benefits</b>	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

Source: WIRES. "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments." July 2013.

<<http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf>>

## 8 From myths to reality: Recommendations for a change of perspectives in investment planning and decision-making

To avoid myths and to think about transmission investment realistically, decision makers need to adopt a comprehensive and consistent approach to evaluating the costs and benefits of transmission.

LEI recommends that this approach recognize a common set of evaluation criteria (or metrics) across all types of transmission projects (see Figure 17). Even if a project has been proposed for reliability, for example, it might also have benefits related to market efficiency and/or policy. Applying a broad set of metrics to every transmission investment would ensure that all potential benefits would be captured for evaluation.

**Figure 17. Evaluation metrics should be comprehensive and consistent**

Evaluation metric
Price reduction benefits
Production efficiency gains
Generation capacity cost savings
Environmental benefits
Competitive market benefits
Load diversity benefits
Public policy benefits
Macroeconomic benefits
Reliability benefits
Fuel diversity benefits

### 8.1 Costs and benefits should be evaluated as a whole package

Some benefits of a transmission project tend to increase over time with both load growth and fuel price inflation. At the same time, costs tend to leave an impression of being “front-loaded,” although in fact, the investment costs are typically spread over many years in rates to consumers, and decline over time as capital cost is depreciated. Transmission investments have benefits and cost lives that extend well beyond 40 years. In spite of this, many transmission investment decisions are made based on comparisons of costs and benefits over a much shorter period than the typical 40-year useful life of the asset, for example, for the first 10 years of a project. Requiring a comparison of the first 10 years of estimated benefits with annual transmission consumer costs for the same number of years raises the benefit-to-cost threshold that projects must overcome.<sup>43</sup> Instead, we recommend analysis of benefits over a longer period

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<sup>43</sup> The Brattle Group. *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*. July 2013. Pg. 17.



to better match the life of the investment. In addition, it is important for benefits of investments to be measured against an accurate view of the world of not doing the project. Frequently, opportunity costs are ignored even though the costs of a reliability shortfall are well recognized.<sup>44</sup>

There are many other dimensions of costs and benefits that need to be paired accurately to ensure that sound decisions are being made, as discussed below.

## **8.2 Transmission alternatives need to be examined comprehensively**

As noted previously, alternatives to transmission (NTAs and MRAs) and transmission investment offer a range of different types of benefits. While it is true that MRAs can provide valuable services, transmission infrastructure tends to provide a broader array of benefits that accrue to a wider variety of parties over a larger geographical dimension (as well as to local areas). Thus, an optimal process is not one that poses an either/or decision (treating transmission and MRAs as substitutes), but one which treats them as potential complements, and asks “how much of each should we use in this circumstance?” When considering the costs, the cost of subsidies provided to some distributed generation such as behind-the-meter solar PV should also be included as an indirect cost. In addition, positive and negative externalities should be considered, thereby evaluating indirect benefits or costs on various stakeholders.

## **8.3 Recognize that certainty of costs and uncertainty of benefits can be an illusion**

It is easier to perceive the costs of an investment than to envision its benefits. The cost of an investment is up-front (at least when described in capital spending terms) and “known” while benefits can be of varying magnitudes over time and will depend upon how the future unfolds. In addition, it is difficult for most stakeholders to perceive the cost of not taking action. However, there are real costs to inaction—system reliability can hamper local economic activities (for example, if there is simply insufficient electricity to meet demand, some economic activities will need to be interrupted). Inaction can also increase the cost of electricity (due to the lack of efficient resources and rising congestion when existing transmission capacity is “used up”).

## **8.4 Plan for the future**

Not only is transmission a long-lived asset, its required siting, permitting and construction time frames are also lengthy, as noted previously. Thus, investors need to project drivers for transmission investment many years into the future, so that when the transmission development project is finally completed and energized, it will be the right size, and in the right place. For example, the timing of many nuclear license expirations (for the 2030s and early

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<sup>44</sup> Frayer, Julia, et al. *Estimating the Value of Lost Load—Electric Reliability Council of Texas*. LEI. June 2013.  
<[http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT\\_ValueofLostLoad\\_LiteratureReviewandMacroeconomic.pdf](http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf)>

2040s) seems far into the future right now; but a transmission development process that begins in 2018 and takes 10-15 years to complete will result in a project that will serve the market for many years *after* those nuclear plants retire.

## 8.5 Overcome the natural human tendency to over-rely on recent experience

Looking out over the long term, developing realistic assumptions for forward-looking investment analysis and system planning is not straight forward. The use of scenario analysis to understand and quantify some of the uncertainties in long-term investment can be valuable. Scenarios should include a “business as usual” scenario, as well as alternative scenarios that contain various transmission solutions and technically-suitable alternatives, or alternative values for drivers (such as varying assumptions for future natural gas prices, economic activities and consumer behavior patterns around electricity use).

Scenario analysis is built on plausible futures that are intended to envelop the range of outcomes, not just outcomes that mirror recent experience. If all the scenarios were to identify meaningful benefits, that suggests that even if one were uncertain about the future, there would be benefits to the investment regardless of which scenario was actually realized.

## 8.6 Plan for the unexpected

A “most-likely” analysis cannot capture the impact of unlikely but extreme events. These events can have expensive consequences for consumers. For example, during the winter of 2013/14, the coldest winter in 20 years in many places,<sup>45</sup> there were in fact three “Polar Vortexes” that extended across the Eastern seaboard of the US. Many ISOs/RTOs saw unprecedentedly high winter peak loads and experienced very high energy prices (see Figure 18). For instance, the NYISO set a new record winter peak load of 25,738 MW, and requested voluntary reduction from about 900 MW of its demand resources.<sup>46</sup> ISO-NE reached a peak just short of its all-time historic peak and also called for demand response resources to be ready for deployment.<sup>47</sup> PJM and some providers in South Carolina had to cut voltage in their areas by 5%, while South Carolina Electric & Gas was forced to disconnect some consumers to ensure that the power grid could remain within safe operating limits and could withstand a worsening of the emergency.<sup>48</sup>

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<sup>45</sup> NERC. *Polar Vortex Review*. September 2014.

<[http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar\\_Vortex\\_Review\\_29\\_Sept\\_2014\\_Final.pdf](http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf)>

<sup>46</sup> NYISO. *Winter 2013-2014 Cold Weather Operating Performance*. March 2014.

<[http://www.nyiso.com/public/webdocs/markets\\_operations/committees/bic\\_miwg/meeting\\_materials/2014-03-13/Winter%202013-1014%20NYISO%20Cold%20Snap%20Operations%20EGCW-MIWG.pdf](http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2014-03-13/Winter%202013-1014%20NYISO%20Cold%20Snap%20Operations%20EGCW-MIWG.pdf)>

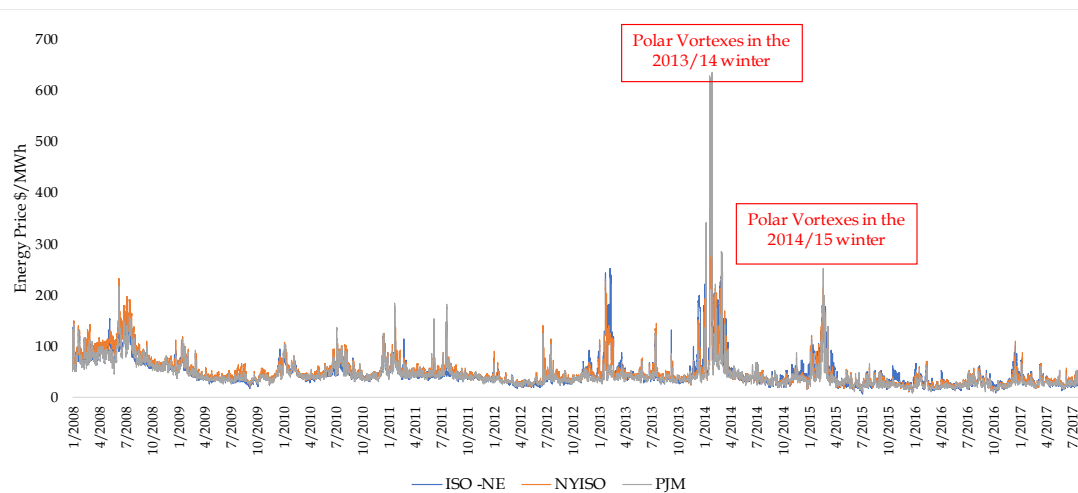
<sup>47</sup> FERC. *Winter 2013-2014 operations and market performance in RTOs and ISOs*. April 1, 2014.

<<https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf>>

<sup>48</sup> Kemp, John. “U.S. power grid survived polar vortex, but only just: Kemp.” *Reuters*. October 3, 2014.

<<http://www.reuters.com/article/us-usa-power-weather-kemp-idUSKCN0HQ4TB20141003>>

**Figure 18. Energy price hikes in New England, New York, and PJM during Polar Vortexes**



Note: The figure presents rolling hourly LMPs for the Internal Hub in ISO-NE, New York City (Zone J) in NYISO, and PSEG zone in PJM, from January 2008 to July 2017.

Source: Third-part data provider.

A system-wide blackout can amount to billions of dollars of economic losses. For example, the total cost of a 12-hour system-wide outage in MISO, which has an outage cost of \$3,500/MWh and an average hourly load of 76,850 MWs, would amount to \$3.2 billion.<sup>49</sup> Prior economic studies have pinpointed economic losses from the blackout of 2003 to as much as \$4-\$10 billion.<sup>50</sup> A transmission line can help moderate consumer rate hikes due to weather driven events and could in some circumstances make the system more resilient and insure against an expensive system-wide blackout.

## 8.7 Conclusion

Decision-making around transmission investment is complex and multi-faceted, and each transmission project is unique to some degree in the mix of benefits it can provide to consumers and the electric system. As we have shown, relying on outdated myths can handicap the decision-making process, mistakenly reject valuable transmission investment, and result in missed opportunities to benefit consumers. We must strive to correct the myths in our thinking about transmission investment and must also move the investment analysis in a direction which will allow us to avoid the trap of making more “myths.” In doing so, we can thereby ultimately support more informed transmission investment decision-making in the future.

<sup>49</sup> MISO Market Subcommittee. “Evaluating Energy Offer Cap Policy Market Roadmap.” May 3, 2016 and Energy Velocity (data for average hourly load in 2016).

<sup>50</sup> U.S. Department of Energy, U.S.-Canada Power System Outage Task Force. “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.” April 2004. <<https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf>>

## 9. Appendix: Acronyms

<b>AC</b>	Alternating Current
<b>BPA</b>	Bonneville Power Administration
<b>CPUC</b>	California Public Utilities Commission
<b>CREZ</b>	Texas Competitive Renewable Energy Zones
<b>DC</b>	Direct Current
<b>DOE</b>	US Department of Energy
<b>DOM</b>	PJM Dominion Virginia Power Zone
<b>EEI</b>	Edison Electric Institute
<b>EIA</b>	US Energy Information Administration
<b>ERCOT</b>	Electric Reliability Council of Texas
<b>EV</b>	Electric Vehicles
<b>FEMA</b>	Federal Emergency Management Agency
<b>FERC</b>	Federal Energy Regulatory Commission
<b>IPP</b>	Independent Power Producer
<b>ISO</b>	Independent System Operator
<b>ISO-NE</b>	Independent System Operator of New England
<b>LCRI</b>	Location Constrained Resources Interconnection
<b>LEI</b>	London Economics International LLC
<b>MEP</b>	Market Efficiency Project
<b>MISO</b>	Midcontinent Independent System Operator
<b>MRAs</b>	Market Resource Alternatives
<b>MVP</b>	Multi-Value Project
<b>NERC</b>	North American Electric Reliability Corporation
<b>NTAs</b>	Non-transmission Alternatives
<b>NYISO</b>	New York Independent System Operator
<b>PDCI</b>	Pacific Direct Current Intertie
<b>PEVs</b>	Plug-in Electric Vehicles
<b>PG&amp;E</b>	Pacific Gas and Electric Company
<b>PJM</b>	Pennsylvania-New Jersey-Maryland Interconnection
<b>PSC</b>	Public Service Committee
<b>PUCT</b>	Public Utility Commission of Texas
<b>PV</b>	Photo Voltaic
<b>RPS</b>	Renewable Portfolio Standard
<b>RSP</b>	Regional System Plan
<b>RTO</b>	Regional Transmission Organization
<b>SCE</b>	Southern California Edison
<b>SDG&amp;E</b>	San Diego Gas & Electric
<b>SPP</b>	Southwest Power Pool
<b>TEPC</b>	Texas Energy Planning Council
<b>TRTP</b>	Tehachapi Renewable Transmission Project