The Full Cost of Electricity (FCe-)

FCe-

Executive Summary:
The Full Cost of Electricity

A SERIES OF WHITE PAPERS

THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FCe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

All authors abide by the disclosure policies of the University of Texas at Austin. The University of Texas at Austin is committed to transparency and disclosure of all potential conflicts of interest. All UT investigators involved with this research have filed their required financial disclosure forms with the university. Through this process the university has determined that there are neither conflicts of interest nor the appearance of such conflicts.

This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website:

energy.utexas.edu

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Table of Contents

Summary of the Full Cost of Electricity

The Full Cost of Electricity (FCe-) is an interdisciplinary initiative of the Energy Institute of the University of Texas at Austin to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket.

The FCe- study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy.

In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A detailed prospectus of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu.

The Full Cost of Electricity Findings Inform Stakeholders on Relevant Policy Questions within the Electricity Industry

The white papers within the FCe- study contain information and insights that are relevant to many key questions facing the electric power industry, policy makers, and electricity consumers (see Table 1). Many questions can be addressed from multiple perspectives to promote communication amongst a diverse set of stakeholders. For example:

What is the cheapest technology for power generation?

o   When full costs are included, every power generation option is more expensive than just the combination of their direct operational and capital expenditures.

o   This answer depends upon not only fuel, capital, and operating costs but also …

- where you construct the power plant, as resources, power plant utilization, and labor costs vary geographically [4],

- the health impacts from air emissions and CO_2 which depend on the magnitude of exposed population and level of pre-existing pollution [4, 9],

- requirements for new transmission interconnections to new power plants [8] and existing transmission lines [6] that connect multiple generators to load centers, and

- financial support from the government that supports overall electricity production by 3-5 $/MWh [11].

Is the cost for electricity per technology, measured in ¢/kWh or $/MWh, the only way to consider for the cost of electricity?

- o Short answer: No.

- o Longer answer: While cost per unit of electricity is important assessing policy implications, through comparisons with customer rates (via regulatory policy) and prices (via markets), it misses many important perspectives:

  - ▪ Transmission, distribution, and administration (TD&A) costs are primarily driven by fixed cost factors, and thus TD&A costs are more accurately reflected as a cost per customer rather than a cost per kWh [6].

  - ▪ From a customer's perspective, determining whether the cost of electricity is large or small depends upon total costs relative to income. That is to say, the consideration of a monthly or annual electricity bill provides a way to consider how many people are exposed to high energy costs [3].

  - ▪ Some consumers and communities do not use (lowest) cost as the sole criteria driving their desired source of electricity. The often consider "values" (such as clean, local, or resilient) and market externalities [2].

  - ▪ New technologies or categories tend to have higher per units costs (e.g., $/MWh) that decline over time as they become more prevalent [5, 11].

  - ▪ Incentives do not consistently focus on one part of the electricity supply chain. For example, the U.S. government incentivizes the extraction of fossil fuels generally, but not as much the power generation facilities that burn fossil fuels. Incentives for renewables (e.g., wind and photovoltaics) are often focused on the power generation technologies themselves (e.g., there are no fuel costs to incent) [11].

Isn't the cost of renewable electricity higher than thermal (natural gas, coal, and nuclear) because they require more investment for grid integration?

- o Short Answer: It depends.

- o Longer answer: There are a few major factors to consider:

  - ▪ Both thermal (e.g., dispatchable) and non-dispatchable renewable generation can dictate requirements for grid stability [10]

  - ▪ Operational reserve requirements of grid operators are influenced by generation technologies as well as market and non-market protocols. In ERCOT, recent protocol revisions reduced regulation reserves procurements even as installed wind capacity increased from 4 to 12 GW [10].

  - ▪ The design of the distribution grid matters. The amount of distributed (e.g., rooftop) photovoltaics that can be integrated at no additional cost varies tremendously, ranging from 15-100% of peak load [1].

  - ▪ Depending upon the existing capacity of the grid and incremental quantity of generation added, transmission interconnection costs for new generation can be negligible to significant (e.g., 0-600 $/kW in ERCOT) [8].

  - ▪ No power plant (ultimately) has zero interconnection costs. All grid-connected power plants depend upon transmission and distribution to deliver electricity to consumers. The costs of building and operating the grid are non-trivial at 700-800 $/yr per customer, or approximately 3 cents/kWh [6].

TABLE 1

Each white paper in the series for the Full Cost of Electricity discusses multiple important cost factors and impact areas along the life cycle of electricity generation.

White Paper	Cost Factors Considered within the Framework of Full Cost of Electricity								
	Generation	Connectivity	Consumers	Capital Costs	O&M Costs	Regulation, Taxes, and Subsidies	Environment	Human Health	Socio-economic
The History and Evolution of the U.S. Electricity Industry	✓	✓	✓	✓		✓			✓
New U.S. Power Costs: by County, with Environmental Externalities	✓			✓	✓		✓	✓	
Household Energy Costs for Texans			✓						✓
Integrating Community Values into the Full Cost of Electricity									✓
Integrating Photovoltaic Generation: Cost of Integrating Distributed Photovoltaic Generation to the Utility Distribution Circuits	✓	✓	✓		✓				
Market-calibrated Forecasts for Natural Gas Prices	✓				✓				✓
Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities		✓		✓	✓				
EPA's Valuation of Environmental Externalities from Electricity Production	✓		✓			✓	✓	✓	✓
Estimation of Transmission Costs for New Generation		✓		✓					
Federal Financial Support for Electricity Generation Technologies	✓			✓	✓	✓			
Impact of renewable generation on operational reserves requirements: When more could be less (forthcoming)	✓	✓			✓				
Unit-commitment, dispatch, and capacity expansion modeling of ERCOT	✓			✓	✓				
State-level Financial Support for Electricity Generation Technologies (forthcoming)	✓			✓	✓	✓			
The Past and Future of Net Metering for distributed Energy (forthcoming)	✓	✓	✓	✓		✓			✓
The Levelized Cost of Electricity in Microgrids (forthcoming)	✓	✓	✓	✓	✓				✓

Highlights from each White Paper within The Full Cost of Electricity study:

The History and Evolution of the U.S. Electricity Industry *(go to pg. 8 for summary)*

- From its beginning, the U.S. electricity industry emerged as a function of technological advancements, economies of scale, effective financial and regulatory structures that fostered capital investment, and new electric-powered loads. Over a century, there have been successive waves of changes in generation, transmission, distribution, market design and regulation of the electricity industry. While we expect electricity to continue to be an essential public good and large scale centrally generated electricity to continue to be essential, traditional utility business and regulatory models will be under stress given:

  - Continued development of more cost-competitive and lower emission centralized generation such as windfarms, utility scale solar, and natural gas-fired combined cycle power plants. The traditional thermal generation technologies such as coal and nuclear plants are being challenged by new generation technologies that are more efficient, flexible (e.g., ramping), and modular (can be built at smaller scales) while having lower emissions, shorter development times (e.g., less than 2 years for a solar farm versus 10 years for a nuclear facility), and/ or no fuel costs (e.g., renewables).

  - Advancements in distributed energy resources (DERs) such as photovoltaic (PV) generation and storage.

  - Changes in load patterns from energy efficiency, demand response, and customer self-generation.

New U.S. Power Costs: by County, with Environmental Externalities: A Geographically Resolved Method to Estimate Levelized Power Plant Costs with Environmental Externalities *(see pg. 10 for summary)*

- This paper explains a geographically-resolved method to calculate the Levelized Cost of Electricity (LCOE) of new power plants on a county-by-county basis while including estimates of key environmental externalities.

- For nominal reference conditions, the minimum cost option of a new power plant in each county varies based on local conditions and resource availability, with natural gas combined cycle, wind, and nuclear most often the lowest-cost options. Overall, natural gas combined cycle power plants are the lowest cost option for at least a third of US counties for most cases considered.

- Online interactive calculators (http://calculators.energy.utexas.edu) are available to estimate LCOE per county and technology to facilitate policy-level discussions about the costs of different electricity options

  - **Map-based LCOE calculator**: http://calculators.energy.utexas.edu/lcoe_map/#/county

  - **Side-by-side LCOE comparison calculator**: http://calculators.energy.utexas.edu/lcoe_detailed/

Household Energy Costs for Texans
(see pg. 21 for summary)

- o This paper uses data from the Energy Information Administration's Residential Energy Consumption Survey to understand how demographics describe household energy consumption.

- o Twenty-two percent of Texas households are "energy-burdened," spending more than 8% of their gross annual income on household energy.

Integrating Photovoltaic Generation: Cost of Integrating Distributed Photovoltaic Generation to the Utility Distribution Circuits *(see pg. 17 for summary)*

- o The quantity of distributed (e.g., rooftop) PV that can be integrated into distribution circuits is analyzed at three types of "hosting capacities" that assume

  - ▪ Range-1: there are no operational changes to the circuit or upgrades to the infrastructure,

  - ▪ Range-2: only operation changes can occur with existing infrastructure, and

  - ▪ Range-3: infrastructure upgrades are necessary (e.g., smart inverters).

- o The circuit topology is a very decisive factor as the "Range 1" PV hosting capacity varies greatly depending upon the circuit (e.g., from 15%-100% of peak load for three analyzed circuits). Even a circuit that necessitates smart inverters on all PV panels to enable PV to reach 100% of peak load can do so at modest cost (e.g., 0.3 $/W additional).

Market-calibrated Forecasts for Natural Gas Prices *(see pg. 20 for summary)*

- o This paper discusses a stochastic process modeling approach for developing spot price forecasts for natural gas. The forecasts include both expected future values and uncertainty bounds around the expected values.

- o The model is calibrated using market information, in the form of historical futures price data. As a result, it produces forecasts that are based upon the consensus of thousands of active market participants, rather than the subjective estimates and assumptions of individuals or small teams of forecasters. The current long-term forecast using this approach indicates that the market expects natural gas prices to remain relatively low (under $4.35 per Million Btu) through 2025.

Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities *(see pg. 12 for summary)*

- o This paper summarizes the cost trends for electricity transmission, distribution, and utility administration (TD&A) in the United States using data from the Federal Energy Regulatory Commission.

- o The number of customers in a utility's territory is the single best predictor for annual TD&A costs. Between 1994 and 2014, the average TD&A cost per customer was $119/ Customer-Year, $291/ Customer-Year, and $333/Customer-Year, respectively, for a total of $700-$800 per year for each customer.

EPA's Valuation of Environmental Externalities from Electricity Production *(see pg. 24 for summary)*

- o This white paper details how the Environmental Protection Agency (EPA) performs cost-benefit calculations for pollution regulation using three example regulations governing air emissions from fossil-fueled power plants: the Cross State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standards (MATS), and the Clean Power Plan (CPP).

- o For each of these three rules the estimated health benefits from the rules greatly exceed the costs of compliance. The White Paper explains the calculations in greater detail, and some of the controversial elements of the calculations.

Estimation of Transmission Costs for New Generation *(see pg. 15 for summary)*

- o There are three major transmission components to consider when connecting a new power plant to the transmission grid: spur line, point-of-interconnection, and bulk transmission expansion.

- o Bulk transmission costs required to interconnect new generation in the Electric Reliability Council of Texas (ERCOT) can vary significantly, from $0–$600/kW of generation capacity, depending on how much the bulk transmission system must be extended. The high end of that range represents ERCOT's Competitive Renewable Energy Zone (CREZ) high voltage transmission lines that cost $6.9 billion and which were designed to transmit approximately 11,000 MW of additional wind power capacity.

Federal Financial Support for Electricity Generation Technologies *(see pg. 26 for summary)*

- o Total federal financial support for electricity-generating technologies ranged between $10 and $18 billion in the 2010s. When considering total electricity-related support on a $/MWh basis, renewable technologies received 5x to 100x more support than conventional technologies. Depending on the year, fossil fuels and nuclear receive $0.5-2/MWh. Wind received $57/MWh in 2010 (falling to $15/MWh in 2019) and solar received $260/MWh in 2010 (falling to $43/MWh in 2019).

- o Renewable generation is supported by subsidies targeting R&D, electricity production, and capacity additions, while fossil fuel power plants are supported via subsidies for fuel sales, fuel production, and pollution controls. Nuclear power receives diversified support in the form of R&D funding, tax credits on electricity sales, and programs aimed at plant costs (decommissioning, insurance).

Impact of renewable generation on operational reserves requirements: When more could be less *(see pg. 27 for summary)*

- o The purpose of this report is to describe the impact of utility scale (wind) renewable generation on operational system requirements, such as procurements of particular ancillary services within the Electric Reliability Council of Texas (ERCOT).

- o The results suggest that the changes in requirements for procured reserves due to ERCOT protocol revisions performed during the transition from the zonal to a nodal market in 2010 have been more significant than the changes in requirements due to an increase in installed wind power capacity of approximately 8,000 MW from 2007 to 2013.

Integrating Community Values into the Full Cost of Electricity *(see pg. 23 for summary)*

- o   Community values are increasingly being included in decisions about future supply and delivery of electricity instead of being solely driven by market-based economic considerations.

Unit-commitment, dispatch, and capacity expansion modeling of ERCOT *(final paper forthcoming)*

The Past and Future of Net Metering for distributed Energy *(paper forthcoming)*

Levelized Cost of Electricity of Microgrids across the United States *(paper forthcoming)*

State-level Financial Support for Electricity Generation Technologies *(paper forthcoming)*

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To explore more and download all white papers, visit the following websites, or contact the Energy institute:

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1 | History of the Electric Grid

The structure of the electricity industry — of generation, delivery, and use of electricity over the past century — has evolved significantly. For decades, scale economies associated with large centralized generation technologies encouraged vertical integration and drove down the cost of electricity, fostered universal access, and provided for reliable electric service delivered by a single utility in a given region. The (now) traditional vertically integrated electric utility model that evolved from these factors is shown in Figure 1.

The combination of service area monopoly and regulatory oversight was successful at providing the surety for utilities to raise capital for large scale investments. These two factors, combined with an obligation to serve electricity as an essential public good, eventually enabled delivery of reliable, universal, and relatively low cost electric service to virtually all Americans.

Starting in the 1970s, higher fuel prices, environmental and energy security concerns, technological innovations, and a desire for more economic efficiency led to the rethinking of this traditional vertically-integrated model.

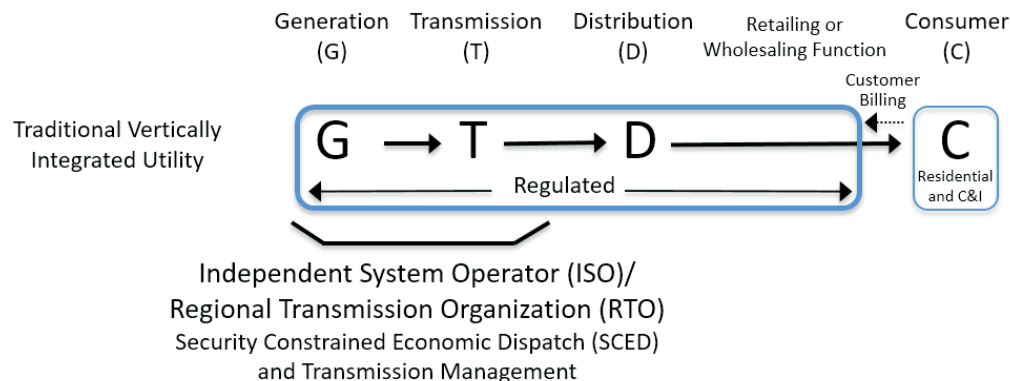Following examples from other industries, policy makers began to rethink the notion that power generation and sales are (or should be) a natural monopoly. Policymakers were exploring means to unleash competitive and technological forces as they had observed in the telecommunications industry, for example.

Also, starting in the late 1970s and 1980s a series of government decisions deregulated both wellhead natural gas prices and the pipeline industry. These regulatory changes unleashed powerful market forces in the natural gas industry that ultimately increased gas supply where it was once thought to be far more limited. Ultimately, both natural gas and gas-fired power became much less expensive. The increased competition from merchant power generators (e.g., independent and competing for power sales) had the knock-on effect of encouraging restructuring of the electric power industry in many states, helping to further break down the vertical integration model.

During the same timeframe, innovations in finance were created that complemented these new technologies to help make them more cost competitive. An important example is the Power Purchase Agreement (PPA) for independent natural gas plant electricity production and, later, wind and solar plants. These agreements played a key role in financing non-utility owned generating assets by enabling their owners, known as independent power producers (IPPs), to raise investment capital, employ tax-exempt bond financing, and capture Federal tax credits.

FIGURE 1

An example of the traditional "one-way" structure of the vertically integrated utility business model.

Traditional Vertically Integrated Utility

Generation (G) Transmission (T) Distribution (D) Retailing or Wholesaling Function Consumer (C)

Customer Billing

G → T → D → C
Regulated
Residential and C&I

Independent System Operator (ISO)/
Regional Transmission Organization (RTO)
Security Constrained Economic Dispatch (SCED)
and Transmission Management

These structures enabled IPPs to provide renewable power at attractive long-term fixed prices to utilities.

By the mid-1990s, policy makers began to restructure the electricity system, seeking to take advantage of these same technological and competitive forces in order to promote innovation and reduce electricity costs.

At the same time, policymakers incentivized alternative technologies, such as wind power. Both the federal and state governments implemented environmental regulations, tax credits, required targets for renewable generation, and other support programs for renewables. Solar technology, initially much more expensive than wind, did not benefit from these policies until the late 2000s and early 2010s when some states instituted programs that specifically supported solar installations. For both wind and solar, foreign government support for manufacturing has also been critical (e.g., Denmark for wind in its early days, and China for solar PV more recently). These technologies also enabled some customers to become "prosumers" by generating some of their own electricity such that they effectively compete with their local utility or competitive generators.

In turn, this self-generation threatens both the traditional utility business model as well as the competitive market structure as they exist today.

Several technologies are combining to drive changes in the electric industry today: increasingly cost competitive wind and solar PV, inexpensive natural gas combined with flexible and efficient combined cycle gas plants, and electricity energy storage and demand response systems with progressively lower costs. There are many new alternative combinations of markets, regulations, and technologies possible, as shown in Figure 2. The transition to a new electricity system structure can be complex and introduce considerable uncertainty in an industry that has traditionally been fairly stable and had strong incentives to be conservative over many decades.

These and other technological changes will continue to encourage the industry to adopt new technology and business models, policy makers to consider alternative regulatory and electricity market structures, and electricity customers to pursue self-generation that competes with traditional utilities in ways that may further de-stabilize the existing order. ■

FIGURE 2

The electricity system of the 21st Century has the potential to have multiple pathways for two-way flow of both money and electricity.
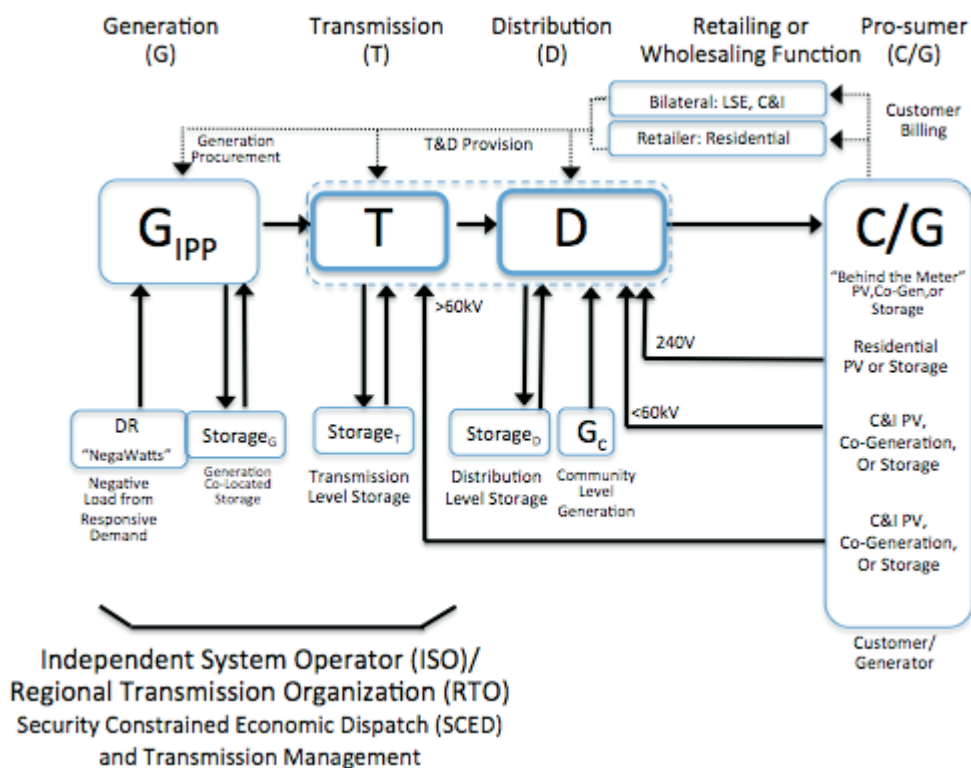
2 | LCOE: A Geographically Resolved Method to Estimate Levelized Power Plant Costs with Environmental Externalities

The Levelized Cost of Electricity (LCOE) typically expressed on a $/kWh basis, is the estimated amount of money that it takes for a particular electricity generation plant to produce a kWh of electricity over its expected lifetime. LCOE offers several advantages as a cost metric, such as its ability to normalize costs into a consistent format across decades and technology types.
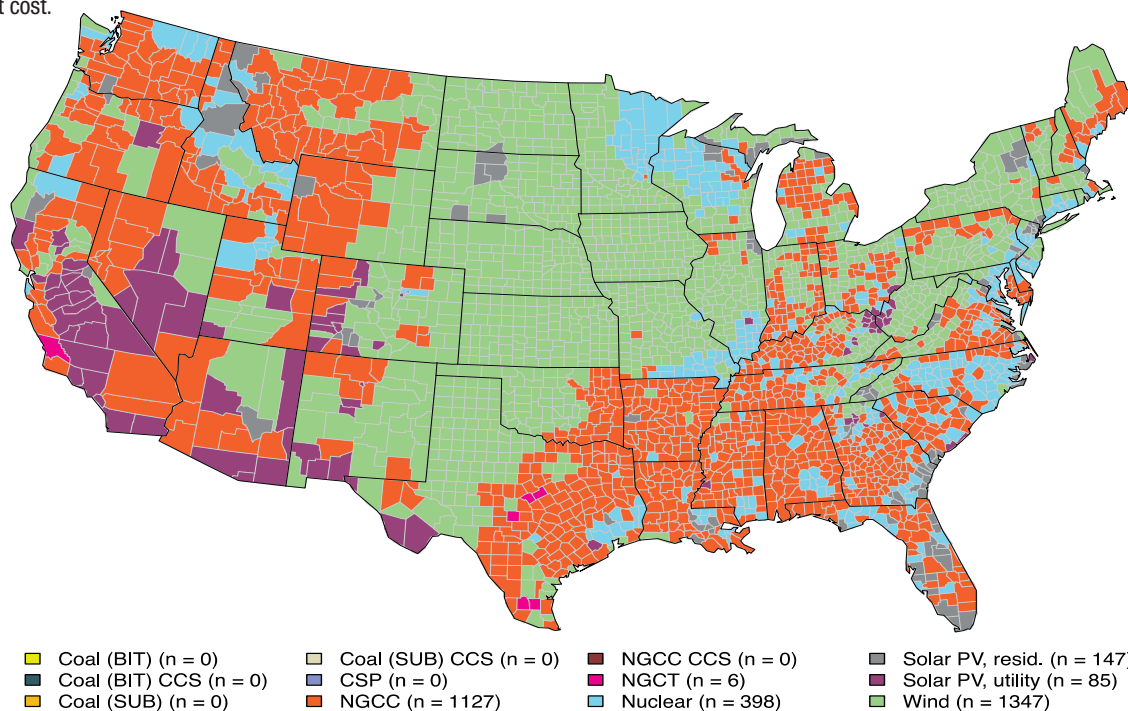
Despite its advantages and widespread use, the conventional LCOE has several shortcomings that render it spatially and temporally static. There are differences across regions that are important to take into account, including construction and operating costs, fuel delivery costs, resource availability (or quality), and capacity factors. The Full Cost of Electricity study aimed to create a framework and tools to discuss these differences to facilitate

dialogue and understanding of the input factors that affect the cost of electricity generation.

- For our reference analysis, which includes a cost of $62/tCO_2$ for CO_2 emissions as well as costs for particulate matter, NO_2, and SO_2 emissions, the technologies that most commonly have the lowest LCOE on a county basis are natural gas combined cycle (NGCC), wind, and nuclear (see Figure 3).

- The average increase in LCOE when internalizing the environmental externalities (carbon and air pollutants) is small for some technologies, but local cost differences can be as high as +$0.62/kWh for coal (e.g., under our reference analysis).

FIGURE 3

Minimum cost technology for each county, including externalities (air emissions and CO_2), restrictions via assumed availability zones, and reference case assumptions for capital and fuel costs. Numbers in legend refer to the number of counties in which that technology is the lowest cost.

- Coal (BIT) (n = 0)
- Coal (BIT) CCS (n = 0)
- Coal (SUB) (n = 0)
- Coal (SUB) CCS (n = 0)
- CSP (n = 0)
- NGCC (n = 1127)
- NGCC CCS (n = 0)
- NGCT (n = 6)
- Nuclear (n = 398)
- Solar PV, resid. (n = 147)
- Solar PV, utility (n = 85)
- Wind (n = 1347)

- There is a "dividing line" around the wind resource in the center of the country that tends to separate where wind and NGCC vie to be lowest LCOE technology. This line is heavily influenced by assumptions for natural gas price (SI-Figure 6 of [4]) and CO_2 cost (SI-Figure 8 of [4]).

- The locations where we calculate nuclear to be the cheapest technology are more sensitive to assumed CO_2 costs than natural gas costs.

These results are but a few from the analysis that can inform policy makers of the possible effects of efforts such as a carbon tax and how incentives for certain technologies might influence where they are deployed.

In order to allow many different scenarios to be considered by stakeholders, we developed two online interactive calculators for the public to utilize:

- Map-based LCOE calculator: http://calculators.energy.utexas.edu/lcoe_map/#/county/tech

- Side-by-side detailed LCOE calculator: http://calculators.energy.utexas.edu/lcoe_detailed/

The map-based calculator allows the user to change the overnight capital costs and fuel prices, and toggle on and off externalities (with the ability to change the price of CO_2) and availability zones. The map updates in real time to show the LCOE per county (e.g., in $/MWh) as well as which technology is the calculated cheapest technology in each county. The user changes the U.S. average values that are then multiplied by distribution factors that incorporate geographical diversity (for example see SI-Figure 26 of [4]).

The **side-by-side calculator** allows users to change *all input values* for the LCOE calculation. However, it limits the comparison of two different technologies in the same U.S. county or the same technology in different counties. This calculator allows a stakeholder or policy maker to understand more detail in their analysis of the effects of different factors and policies in the costs of electricity in a given location. The county input data are pre-populated with the same reference values that underlie the map-based calculator. However, we have also added the ability to include the costs of transmission lines at this level. ■

3 | Total Utility Transmission, Distribution, and Administration Costs

■ **Total transmission distribution, and administration (TD&A) costs have typically been $700–$800/Customer-Year since 1960** *(see Figure 4 and Table 2)***.**

Figure 4 summarizes the total spending by U.S. investor-owned utilities on transmission, distribution, and utility administration (TD&A) per customer per year between 1960 and 2014. Total transmission distribution, and administration (TD&A) costs have typically been $700-$800/Customer-Year ($60-$70 per month) since 1960.

■ **The number of customers in a utility's territory emerges as the single best predictor for annual transmission, distribution, and administration costs** *(see Table 1)* **[6].**

TD&A costs are recovered based upon a combination of (i) volumetric charges per kWh of energy sold, (ii) kW of peak electric demand, and (iii) a fixed connection charge. However, the number of customers found in a utility's territory is the best predictor for annual TD&A costs based on analysis of investor-owned utility costs incurred from 1994–2014 [6].

FIGURE 4

Electricity transmission, distribution, and administration costs each consist of upfront capital investments and recurring operation and maintenance costs. Total transmission, distribution, and administration costs have been $700–$800 per utility customer per year for much of the past 54 years. Figure from [6].

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Spending Category
- Transmission Capital Spending
- Distribution Capital Spending
- T&D Operation and Maintenance
- Administrative Capital Spending
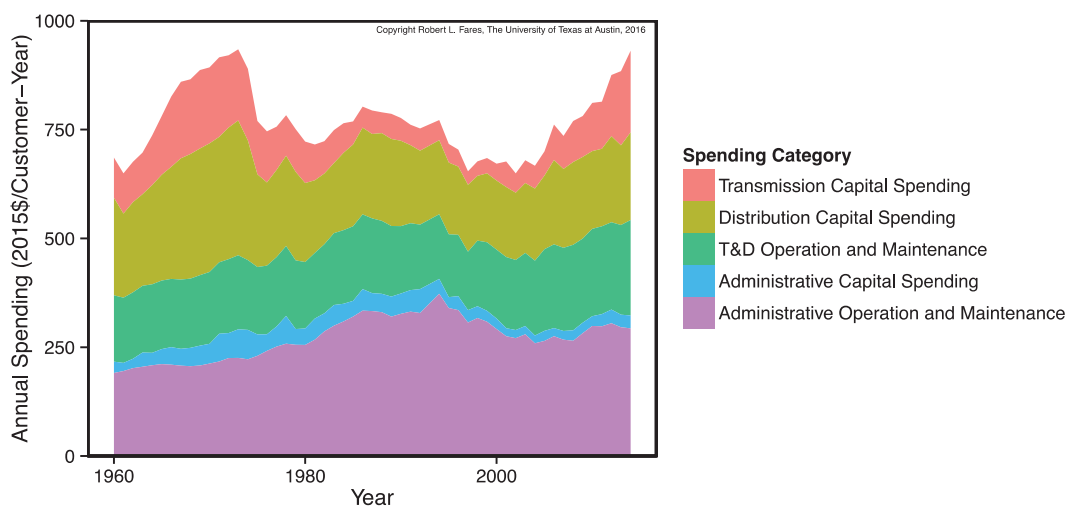- Administrative Operation and Maintenance

TABLE 2

This table summarizes the correlation between total annual transmission, distribution, and administration costs, and the number of customers in a utility's territory, annual peak demand, and annual energy sales (using FERC Form 1 data from 1994 to 2014). The value of the cost coefficient and the corresponding R^2 value are given for each regression analysis performed.

Cost Category	Cost Per Customer (2015$/Customer-Year)	Cost Per Peak KW (2015$/kW-Year)	Cost Per kWh (2015¢/kWh)
Transmission	119 (R^2 = 0.459)	21 (R^2 = 0.399)	0.47 (R^2 = 0.373)
Distribution	291 (R^2 = 0.901)	52 (R^2 = 0.775)	1.1 (R^2 = 0.740)
Administration	333 (R^2 = 0.853)	61 (R^2 = 0.766)	1.3 (R^2 = 0.734)
Total	727 (R^2 = 0.886)	134 (R^2 = 0.781)	2.9 (R^2 = 0.747)

FIGURE 5

Average annual TD&A costs per kWh declined between 1960 and 1980, but have been approximately 2.5–3.5 ¢/kWh since 1980. The decrease between 1960 and 1980 was likely driven by increasing energy consumption rather than decreasing service costs. Figure from [6].
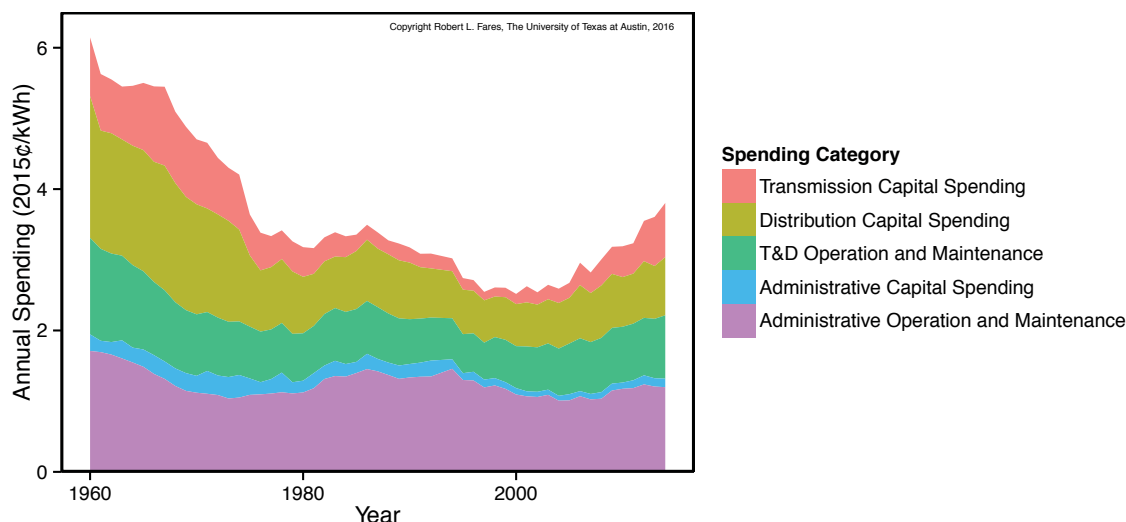
Transmission (high voltage and long-distance transport of electricity) costs are less than 20% of the total cost of TD&A.

Both distribution and administration costs are each a significant portion (~ 40%) of total TD&A costs. A relatively high fraction of TD&A costs for administration are due to the fact that administrative costs are associated with number of customer accounts, and customer services are related to the number of utility customers.

■ **Total TD&A costs per kWh have decreased significantly from 1960 to 2000, but this decrease is likely driven by an increase in energy demand per customer and not a real decline in the cost of utility service.**

When measured on a ¢/kWh basis, the average cost for transmission, distribution, and administration declined significantly from 1960 to1980, and less so from 1980 to 2000. After 2000, costs per kWh increased steadily to over 3.5 ¢/kWh by 2014, a value not seen since the late 1970s.

The decreasing trend in cost per unit of demand or energy sold from 1960 to 1980 is likely caused by the fact that the average energy consumption per customer nearly doubled from 11,700 kWh/Customer-Year in 1960 to 24,400 kWh/Customer-Year in 1980. However, the average energy consumption per customer remained roughly flat between 1980 and 2014, ranging from 23,300 kWh/Customer-Year to 26,900 kWh/Customer-Year [6]. ■

4 | Utility Annual and New Transmission Costs

■ **Transmission system costs have increased significantly since 2000 (see Figure 6)**

While transmission costs have historically represented a small portion of the overall cost of electricity (< 1 ¢/kWh), average transmission-related capital, operation, and maintenance expenses for investor-owned utilities (IOUs) have increased significantly since 2000 [6].

■ **New power plant interconnection costs consist of spur line, point-of-interconnection, and bulk transmission expansion costs**

The cost of interconnecting a new generator, or power plant, with the transmission grid consists of costs for the spur transmission line that connects the generator to the existing bulk transmission system, the point of interconnection (POI) that facilitates the flow of power between the spur line and the bulk system, and any required upgrades to the bulk transmission system itself. The way these costs are allocated varies regionally. In the Electric Reliability Council of Texas (ERCOT) region, the generator developer pays for the spur line and point of interconnection, but bulk system costs are

recovered directly from end-use customers via an adder to retail bills. In the Eastern Interconnection region, the generator developer also directly pays for part of the bulk transmission upgrade costs [8].

■ **Spur line costs are primarily driven line voltage, length, and power capacity**

Data from the Electric Reliability Council of Texas were used to derive the cost of spur transmission lines of various voltages in units of $/kW-mile [8]. Spur line costs are much lower than bulk transmission costs, typically 1-10 $/kW-mile for single circuits. Costs per kW-mile are lower for higher voltage spur lines. Typically, single-circuit spur lines are used for intermittent wind and photovoltaic generators, while double-circuit lines are used for dispatchable generators, because dispatchable generators are more important for system-wide reliability and require a second redundant circuit [8]. While the cost of a spur line is primarily driven but its voltage, length, and power capacity, the local terrain can increase the cost of a particular line. The influence of various terrain features on spur line costs are discussed in [8].

FIGURE 6

The average cost of transmission system capital infrastructure, operation, and maintenance (in real 2015 dollars) increased from 0.3 ¢/kWh in 1994 to 0.9 ¢/kWh in 2014. The cost for transmission capital infrastructure only during 1960–1992 is shown for reference, because operation and maintenance cost data are not available. Figure from [6].
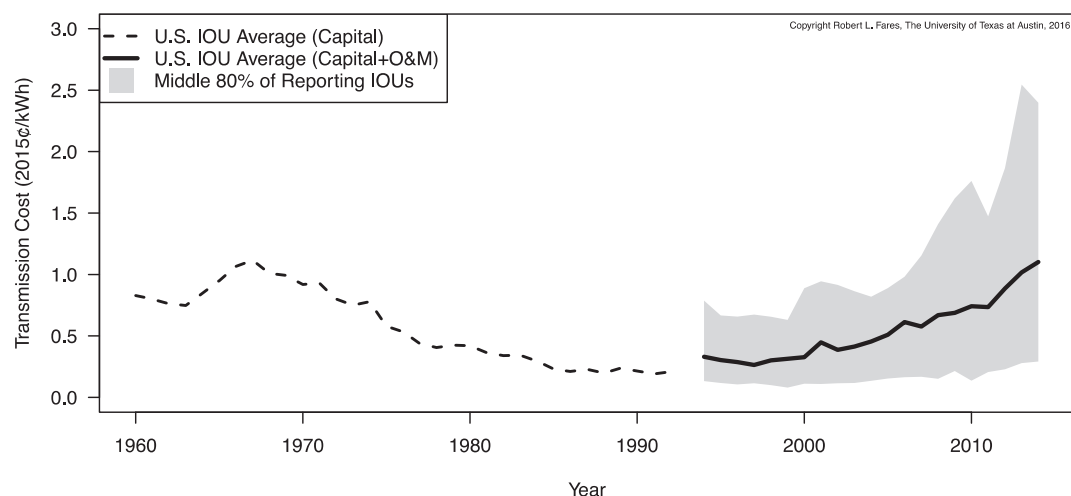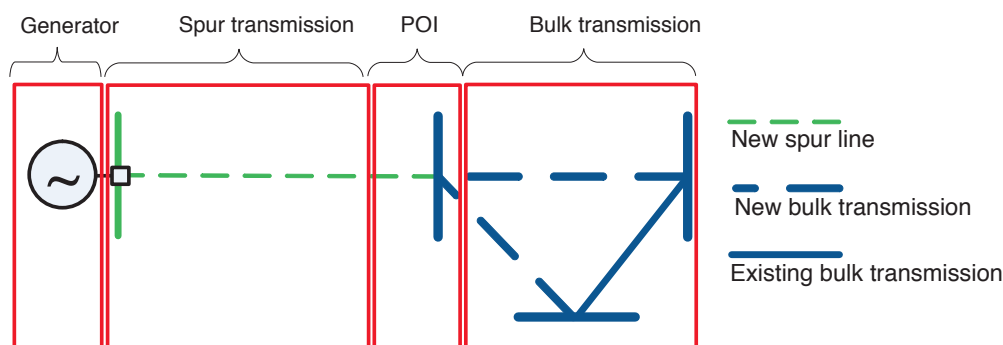
FIGURE 7

Generator interconnection costs consist of spur line costs, point-of-interconnection (POI) costs, and bulk transmission system upgrade or expansion costs (if required). Figure from [8].

■ Bulk transmission costs required to interconnect new generation in ERCOT can vary significantly ($0–$600/kW of generation capacity) depending on how much the bulk transmission system must be extended.

In general, renewable energy sources such as utility-scale solar and wind energy require more bulk transmission system expansion because the best wind and solar resources tend to be located further away from electric load (see Figure 8 and Table 4). As an example, the bulk long-distance renewable transmissions lines used to connect the Electric Reliability Council of Texas's (ERCOT) Competitive Renewable Energy Zones (CREZ) in north and west Texas costed approximately $6.9 billion in total, or $600/kW, which is more than conventional greenfield and brownfield generation projects. ■

FIGURE 8

The cost of bulk transmission expansion required to interconnect new generation depends on its distance from the existing transmission system. Figure from [8]. Sites A, B, C, and D represent candidate sites for new generation away from the existing transmission lines (blue lines).
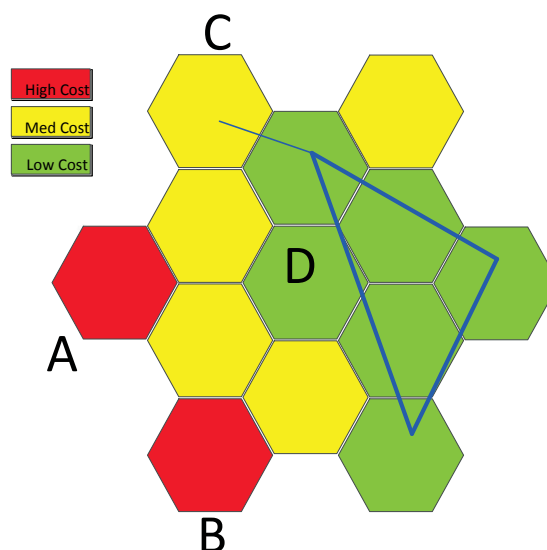

TABLE 4

Additional bulk transmission investments required to integrate new generation vary from $0–$600/kW of generation capacity, depending on where it is installed. All data based on analysis of transmission investment trends in the Electric Reliability Council of Texas (ERCOT) region [8].

New generation project type	Bulk transmission upgrade cost by line voltage ($/kW)		
	345 kV	138 kV	69 kV
Greenfield – long-distance renewable energy transmission projects (using example of Texas CREZ project)	600	0	0
Greenfield – conventional projects	78	166	49
Brownfield projects	0	0	0

5 | Utility Distribution Costs

■ **Distribution system costs have been roughly constant since the late 1970s, with typical costs near $290/Customer-Year since 1994**

While transmission costs have increased significantly since 2000 (see Figure 6), distribution costs have been roughly flat for the last 40 years (see Figure 9).

Figure 9 shows the average annual electricity distribution cost from 1960 to 2014 normalized per utility customer. The variation in costs shown for years 1994 to 2014 is caused by differences between utilities such as geographic density, underground versus aboveground cables, proportion of high-voltage versus low-voltage customers, and other factors. Cost variation is also driven by the fact that distribution system investments are inherently "lumpy," i.e. an individual utility's spending on capital infrastructure might be very high during a year where a major upgrade occurred and then return to normal levels after the upgrade is complete.

Despite differences in utility location and customer base, the level of observed cost variation over time is relatively small, illustrating the fact that annual distribution costs are approximately $200–$400/Customer-Year for U.S. investor owned utilities.

■ **Electricity distribution costs are primarily driven by load-serving requirements**

Unlike the transmission system, the distribution system does not move bulk electric power over a long distance to connect generation to customers. Rather, it distributes power from the transmission system to individual electricity customers at the level of voltage and current they require. In recent years, the distribution system has also been used to facilitate the connection of customer-sited distributed generation technologies, such as rooftop solar photovoltaic systems.

■ **The number of customers in a utility's territory is the single best predictor for its annual distribution system costs** *(see Table 2)*

Because the number of distribution substations, feeders, transformers, service lines, and meters is driven by the number of individual connections a utility must serve, the number of customers in a utility's territory was found to be the best predictor for total annual distribution system capital, operation, and maintenance costs [6]. To a lesser extent, increases in peak electric demand also drive new investments in distribution infrastructure. However, the marginal distribution capacity cost varies significantly within a utility's territory and from one utility to another. ■

FIGURE 9

The average cost of distribution system capital infrastructure, operation, and maintenance (in real 2015 dollars) was $250–$300/Customer-Year from 1994 to 2014. The average annual cost for new distribution capital infrastructure during the years 1960 to 1992 is shown for reference. Operation and maintenance costs from these years are not available. Figure from [6].
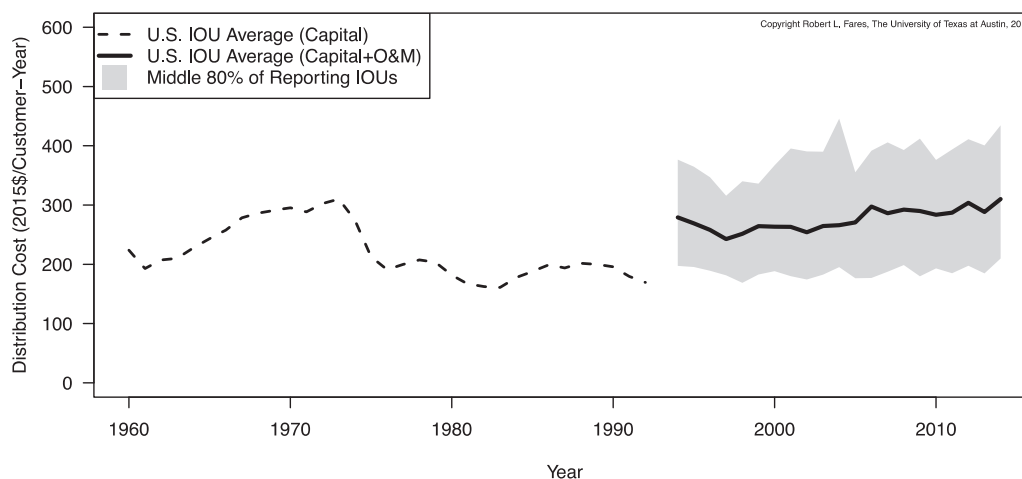
6 | Distributed Photovoltaics (PV) Integration Costs

■ **It is unlikely that there is a general "safe" limit to the amount of rooftop solar that can be added to an existing distribution circuit. Rather, the amount that can be added depends on the specific nature of the circuit.**

Three typographical distribution circuits (Circuit A, Circuit B, Circuit C) were simulated to see how much photovoltaic generation could be integrated without violating one of five distinct operational limits: 1) reverse power flow at the distribution substation caused by overgeneration, 2) deviation in the secondary voltage cause by solar intermittency, 3) deviation in the primary voltage caused by intermittency, 4) secondary overvoltage caused by overgeneration, and 5) primary overvoltage caused by overgeneration [1].

Table 5 summarizes the characteristics of each typographical circuit analyzed. The amount of solar photovoltaic capacity that can be added to each circuit without violating each of these conditions is given in Figure 10.

■ **When operational changes or equipment upgrades are required to increase a circuit's solar hosting capacity, the cost can be relatively small**

To understand the costs associated with increasing a circuit's hosting capacity for rooftop solar panels, two interventions were considered: operational changes to the existing circuit only ("Range 2"), and the installation of new equipment ("Range 3"). Because Circuit C had the lowest hosting capacity of the three circuits considered, it is used to show the cost as a function of increasing hosting capacity (see Figure 11).

The "Range 2" hosting capacity can be increased from 15% to 47% of median peak circuit load by increasing the number of substation transformer tap operations annually by 12% at a cost of approximately $4000 over ten years [1].

Adding dynamic smart inverters to some of the households in the circuit increases the "Range 3" hosting capacity to 69% and 79% of median

TABLE 5

The three typographical circuits analyzed vary in their size, voltage, proportion of residential customers, and other characteristics [1].

SYSTEM PARAMETERS	CIRCUIT A	CIRCUIT B	CIRCUIT C
System voltage (kV)	12.47	12.47	34.5
Number of customers	1379	867	3885
Service Xfmr connected kVA	16310	19320	69373
Total feeder kVar	1950	2400	3300
Subtransmission voltage (kV)	115	115	230
3ph SCC at substation	114	475	422
Circuit miles (total electrical length of all primary conductors)	48	8	74
Longest length from the substation (miles)	3	2.5	8
%residential by load	96	39	87
No. feeders on the Substation bus	1	2	2

FIGURE 10

The amount of a photovoltaic capacity (measured as % of Median Daytime Peak Load) that can be added to a distribution circuit without violating its operating constraints depends on the specific nature of the system. The overall hosting capacity (top of figure) is the minimum of the five possible constraining factors. The maximum hosting capacity with no changes to the distribution circuit is 104% of median daytime peak load (Circuit B). The minimum hosting capacity with no changes to the distribution circuit is 15% (Circuit C).
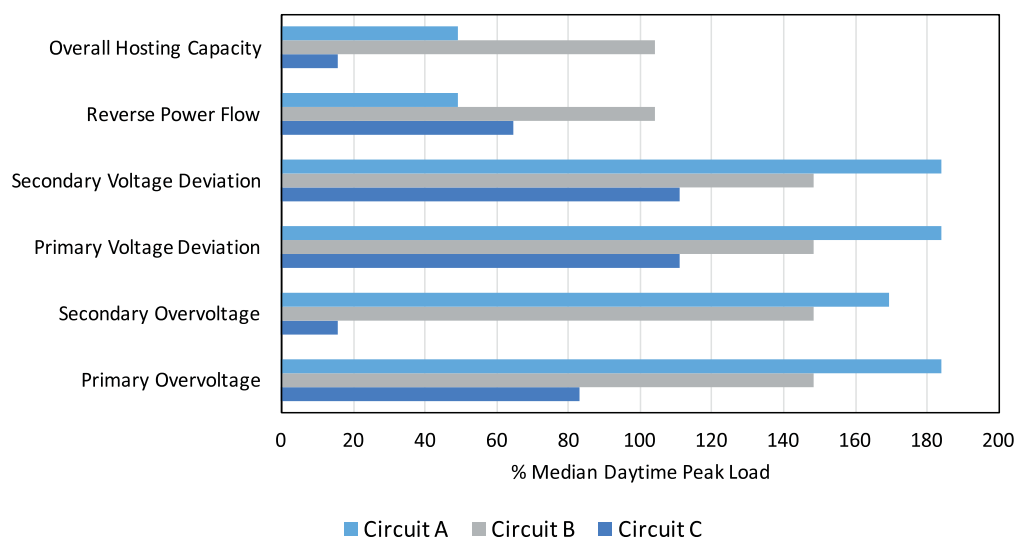

circuit peak load assuming replacement of 10% and 30% inverters at a total cost of approximately $230,000 and $700,000, respectively [1]. Note that the costs associated with adding smart inverters could be avoided if smart inverters are installed initially or as existing inverters are retired.

To contextualize the costs associated with increasing the PV hosting capacity of Circuit C illustrated in Figure 11, we calculate the investment required to increase hosting capacity on a $/W basis. Increasing the number of tap change operations at the substation transformer increased the hosting capacity by 5.4 MW (~ 30% of peak load) at a cost of $0.0007/W [1]. Replacing 10% of solar inverters with smart inverters increased hosting capacity by an additional 3.7 MW (~20%) at a cost of $0.06/W [1]. And replacing an additional 20% of solar inverters with smart inverters increased hosting capacity by an additional 1.6 MW (~ 10%) at a cost of $0.3/W [1]. All of these costs are at least an order of magnitude less than the typical 2014 cost for a residential rooftop photovoltaic system of approximately $3/W [4]. ■

FIGURE 11

The cost associated with implementing operational changes or equipment upgrades to increase the PV hosting capacity of Circuit C ranges from $4000 (Range 2 – operational changes only) to $700,000 (Range 3 - replace 30% of inverters with "smart" inverters). Figure from [1].
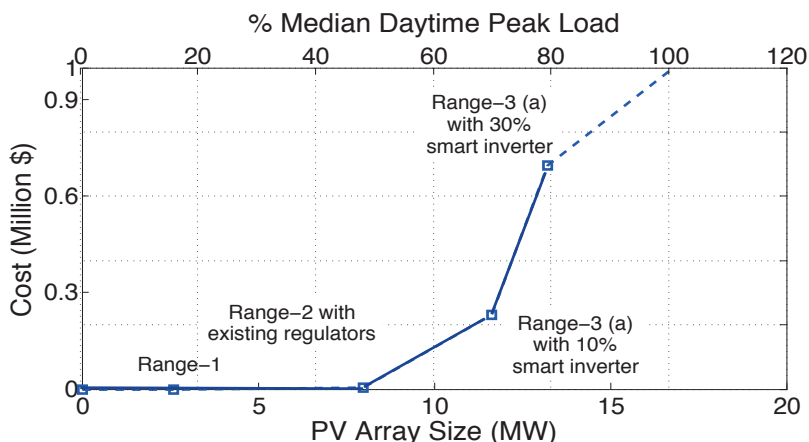
7 | Utility Administration Costs

■ **Administration costs are a requisite part of delivering electricity to end-use customers**

In addition to the costs for electricity transmission and distribution, there are also costs associated with the utility business of monitoring and controlling the grid system, managing customer accounts, customer service, etc. While these costs are not directly associated with the production or delivery of electric energy, they are a necessary component of providing electricity service to customers [6].

■ **Administration costs are greater than the costs for transmission or distribution**

While electric delivery costs are often referred to as "wires" costs, we found that capital, operation, and maintenance costs associated with running the utility business are higher than the costs for either transmission or distribution service, regardless of whether those costs are measured per customer, per kW of peak demand, or per kWh of energy sold [6].

While administrative costs are often recovered at least in part through volumetric charges per kWh of energy sold or per kW of peak electric demand, the number of customers found in a utility's territory was found to be the best predictor for annual administration costs based on analysis of investor-owned utility costs incurred from 1994 to 2014 [6]. This result makes sense from a fundamental perspective because administrative costs associated with customer accounts, and customer services are related to the number of utility customers.

■ **Average utility administration costs have not changed significantly in recent years**

While transmission costs have increased significantly in recent years, utility administration costs have been roughly flat or decreased slightly. Figure 12 shows the average annual cost of utility administration from 1960 to 2014 normalized per utility customer. ■

FIGURE 12

Average administrative capital, operation, and maintenance costs per customer increased gradually between 1960 and 1970, but have declined or been roughly constant since 1994. Between 1960 and 2014, average administrative operation and maintenance costs varied from approximately $200–$400/Customer-Year. Figure from [6].
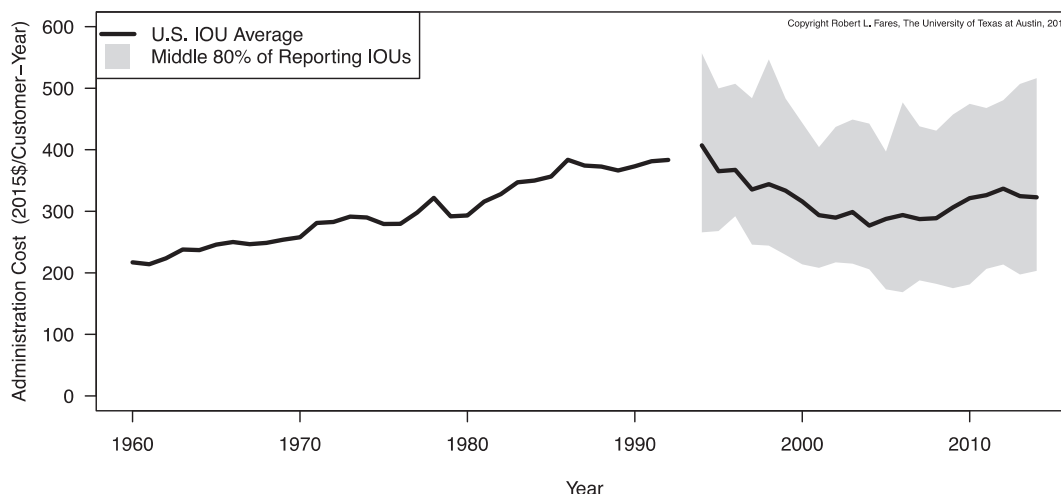
8 | Market-calibrated Forecasts for Natural Gas Prices

The White Paper on Natural Gas Price Forecasting discusses an approach that is based upon calibrating a commonly-used stochastic process model with data from the commodities markets and evaluates the performance of the model for capturing the dynamics of future spot prices [7].

■ **In this approach, the model is calibrated using market information, in the form of historical futures price data. As a result, it produces forecasts that are based upon the consensus of thousands of active market participants, rather than the subjective estimates and assumptions of individuals or small teams of forecasters.**

The futures data used in this study consisted of 969 weekly observations of natural gas futures contract prices at maturities of 1, 3, 6, 12, 18, 24 and 36 months, from the week of June 6, 1997 through the week of January 1, 2016. We also worked with a subset of these data that was selected to correspond with the approximate date when natural gas produced by hydraulic fracturing started to significantly influence market prices (set of 366 weekly observations, beginning with the week of January 2, 2009 through January 1, 2016). With the parameter estimates from calibration

to the futures price data, we used the stochastic process model to develop forecasts and confidence envelopes for both the risk neutral price (i.e., with zero risk premium) and the expected spot price.

■ **The current long-term forecast using this approach indicates that the market expects natural gas prices to remain relatively low (under $4.35 per Million Btu) through 2025.**

This research shows that the choice of the data set has some effect on the stochastic process model parameter estimates and the resulting forecast, with the longer term data set resulting in a slightly lower forecast due to the long term downward trend from the high prices realized in the middle to latter part of the 2000-2010 decade. With either data set, however, we obtain forecasts that roughly align with the High Oil and Gas Resource and Low Oil Price scenarios from the 2015 EIA Energy Outlook, two outcomes that seem increasingly likely as judged by market sentiment. This market-based forecasting model provides the added benefits of simple updating (as new futures data becomes available) and a statistical basis for uncertainty analysis, through the confidence envelope around the future expected spot prices. ■
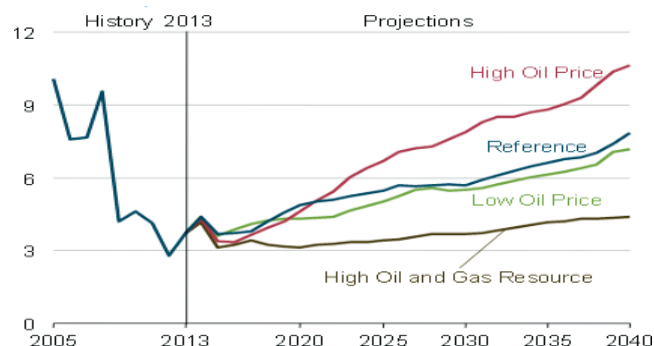
FIGURE 13

Natural gas historical and forecasted prices (calibrated to 2009–2016 futures data).

FIGURE 14

EIA scenarios and projections for Henry Hub natural gas spot prices [2015 EIA Annual Energy Outlook].

9 | Household Energy Costs for Texans

■ **Twenty-two percent (22%) of Texas households are "energy-burdened" in that they spend greater than 8% of income on household energy, and 16% of households spend more than 10% (see Figure 15)**

The average rate of electricity ($/kWh) is only one part of the story in thinking about energy costs to low income households. The average rate charged for electricity in 2009 was practically the same (at approximately 0.128 $/kWh) for Texans overall as compared to low-income (<$25K/yr) Texans and energy-burdened Texans (see Figure 1B of [3]).

■ **Higher incomes translate to higher household electricity consumption, but there are important differences between urban and rural households**

When investigating the quantity of household electricity consumption, the average Texas household consumes 14,300 kWh/yr, low-income Texans consume around 10,300 kWh/yr, and energy-burdened Texans consume 13,700 kWh/yr (see Figure 4B of [3]). Thus, energy-burdened Texans consume almost the same amount of electricity than does the average Texas household.

FIGURE 15

Probability distribution for fraction of gross household income spent on total household energy. For this calculation, income is assumed at the midpoint of the range indicated in the data. Bins are listed in increments of 1% of income (i.e., the first bin is 0-1% of income, second bin is 1%-2% of income, etc.).
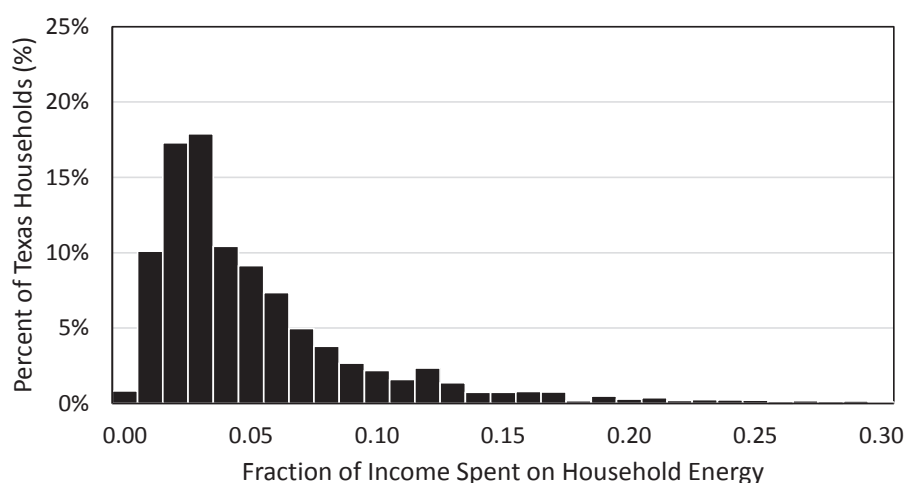

FIGURE 16

Annual electricity usage (kWh in 2009) for low-income Texas households by demographic as compared to the average for all Texans. LI = low income.

How Much Electricity Are Texans Using?			
Group	**Households**	**KiloWatt Hours**	**Kwh Standard Deviation**
All Texans	8,527,938	14277	7434
Low-Income Texans (<$25k)	2,250,512	10329	4997
Texans with Income >$25k	6,277,425	15692	7653
Texans with Income >$75k	2,244,927	18903	7874
Texans under 150% of Poverty	2,247,265	11816	6803
LI Rural Texans	207,020	12371	7123
LI Urban Texans	2,043,493	10122	4701
LI White Rural Texans	172,219	12608	7797
LI White Urban Texans	1,463,917	9932	4891
LI Black Rural Texans	7201	9455	1 Observation
LI Black Urban Texans	480,388	10632	3951
LI Hispanic Rural Texans	66,855	10440	3315
LI Hispanic Urban Texans	837,661	9191	4686

Part of the explanation is in different consumption patterns for rural versus urban households. Rural energy-burdened households consume 17,000 kWh/yr and urban energy-burdened households only 13,100 kWh/yr (see Figure 4B of [3]). The same pattern, but less severe, exists for low income Texas households — annual electricity consumption is 12,400 kWh/yr and 10,100 kWh/yr for rural and urban, respectively (see Figure 16 and Figure 3B of [3]).

■ **Other than household income, there are several demographic variables that explain if a household spends more than 8% of income on household energy**

The following demographic variables are significantly positively correlated with Texan household energy burden (e.g., if a household has this characteristic it is more likely to be energy burdened):

- o being black or of Spanish descent,
- o receives SNAP benefits (household receives benefits for food from Supplemental Nutrition Program (SNAP) for Women, Infants, and Children (WIC)), or
- o someone is at home during the workday.

The following demographic variables are significantly negatively correlated with Texan household energy burden (e.g., if a household has this characteristic it is less likely to be energy burdened):

- o having a college degree,
- o being male,
- o being married,
- o owning your home,
- o having a full-time job, or
- o having retirement or investment income. ■

10 | Community Values Affecting the Full Cost of Electricity

■ **Just as technological advances enabled the 20th Century utility business model, so might advances in distributed energy technology enable communities to express "values" for more local and/or renewable generation.**

Viewing electricity as an undifferentiated commodity, economic rational choice theory tells us that individuals and communities will choose the lowest cost source since the utility for electricity is satisfied regardless of the source. However, there are a growing number of examples where this is not what is happening in the market place. Individuals or communities who adopt distributed energy, abandon incumbent utilities and source their own low-carbon electricity, are often making judgments that may include personal or community values before they buy.

Four common expressions of this movement are considered in this white paper are: 1) District energy utilities, 2) Community-owned renewable generation, 3) Community approved use of eminent domain, and 4) Community Choice Aggregation (CCAs) [2].

■ **An array of varied electricity market structures and regulations allow a consumers "values" to be expressed from the individual to the community level, but not necessarily in multiple ways simultaneously.**

As one example, it is important to distinguish between individual consumer choice and community choice aggregation (CCAs) as representing a community-wide decision. At a basic level, a CCA is attempting to create a new smaller municipal utility within an existing larger monopolistic utility region. The CCA might or might not own generation, transmission, and distribution assets. But CCAs are not the only method by which a consumer can express "values" in purchasing electricity. Individual consumer choice exists for some residential customers in unbundled electricity markets such as the Electric Reliability Council of Texas (ERCOT). ■

11 | EPA's Valuation of Environmental Externalities from Electricity Production

The White Paper on Valuing Externalities explains how the Environmental Protection Agency (EPA) places a dollar value on the pollution externalities associated with power production, most of which come from fossil fuel combustion. The EPA does these calculations as part of the cost-benefit analyses it is required to produce in connection with the major rules it promulgates.

■ **The EPA calculates pollution costs differently for greenhouse gases (which drive climate change) than for other pollutants from energy production like sulfur dioxide, particulate matter, or mercury (which are associated with a variety of specific environmental and health problems).**

For greenhouse gases, the federal government (including EPA) uses a time-varying schedule of costs, in $ per ton of carbon dioxide, to value climate change harm from CO_2 emissions. Both coal-fired power plants and gas-fired power plants emit carbon dioxide, the most common and plentiful greenhouse gas. The other harmful byproducts of fossil fuel combustion from electricity generation come almost entirely from coal-fired power plants.

The way the EPA calculates the benefits of reducing these pollutants is not as simple as the single figure it uses for CO_2 emissions. The agency begins by estimating the mortality (number of premature deaths) and morbidity (non-lethal health harm) effects of the pollution emissions it proposes to regulate. These estimates are based upon a toxicological and epidemiological literature estimating the magnitude of the effects associated with a ton of emissions of each of these pollutants. Next the agency estimates the number of tons of emissions its proposed regulation will avert, either through the installation of pollution controls or through the plant owner's decision to close down the plant rather than invest in pollution controls [9].

■ **According to the EPA, each premature death in the U.S. is valued at more than seven million dollars.**

In order to quantify economic benefits to pollution regulations, the EPA must attach dollar values to averted health effects of its rules. According to agency policy, *each premature death is valued at more than seven million dollars*. That figure is drawn from a range of estimates made by economists, based mostly on their examination of how much people are willing to pay to avoid risk. Morbidity impacts are estimated using this same sort of risk avoidance inference as well as other, firmer data, such as the cost of hospital visits, lost earnings, etc. To these dollar value estimates of averted deaths and other human health impacts the agency adds estimates of the value of averted environmental harm associated with its proposed rules [9].

■ **For each of three example rulemakings, the EPA concluded that the health and environmental benefits greatly exceeded compliance costs, even though in some cases compliance costs were in the billions of dollars.**

Whenever the EPA proposes a major new rule it undertakes a cost-benefit analysis, and compares the resulting benefit estimate with its estimate of the societal costs of complying with the proposed rule. The FCe- White Paper on Valuing Externalities illustrates these calculations for three recent major EPA rules targeting fossil fueled power plants: the Cross State Air Pollution Rule (regulating pollutant transport to downwind communities), the Mercury and Air Toxics Rule, and the proposed Clean Power Plan (regulating greenhouse gas emissions).

For each of these three rulemakings EPA concluded that the health and environmental benefits greatly exceeded compliance costs, even though in some cases compliance costs

were in the billions of dollars. For example, the agency estimated the environmental benefits of its Mercury and Air Toxics rule (reduced emissions from coal-fired power plants) at about $80 billion, and compliance costs at just under $10 billion. The estimated benefits are so large because coal combustion kills thousands of Americans prematurely each year and the rule would hasten the shutdown of coal-fired plants already under stress from market competition (from inexpensive natural gas and renewables) [9].

These analyses are not without controversy. Some dispute the dollar value that EPA places on a premature death, or that the U.S. government places on a ton of carbon emissions. Furthermore, the reason that the benefits of the Mercury and Air Toxics rule and the Clean Power Plan dwarf costs is because of so-called "co-benefits" — reduction of pollution other than the pollutants targeted by those rules. Critics claim that the EPA should only count those benefits associated with reducing the pollution targeted by each rule. ■

12 | Federal Financial Support for Electricity Generation Technologies

■ **Total federal financial support for the electricity-generating technologies ranged between $10 and $18 billion in the 2010s.**

Support was highest in 2013 due to one-time American Recovery and Reinvestment Act (ARRA) related funding. Excluding this temporary source of funding, electricity support totaled approximately $7 billion in 2010 and could rise to $14 billion in 2019 according to some estimates. The growth in perennial spending is attributable to renewables, especially wind. The total value of all federal financial support for the fossil fuel industry (not shown in Figure 17) is comparable to that spent on renewables. When considering only the portion of fossil fuel subsidy that relates to electric power, however, renewables receive a greater share [11].

■ **When considering total electricity-related support on a $/MWh basis, renewable technologies received 5x to 100x more support than conventional technologies.**

Generation from fossil fuels receive a large amount of support, but their per-MWh cost is modest due to the very large installed base and the high quantity of generation. Renewables, by contrast, receive somewhat more money but generate significantly less electricity. Depending on the year, fossil fuels and nuclear receive $0.5-2/MWh. Wind received $57/MWh in 2010 (falling to $15/MWh in 2019) and solar received $260/MWh in 2010 (falling to $43/MWh in 2019). Overall, electricity technologies receive financial support worth $3-5/MWh. As generation from renewables grows, the $/MWh differential between renewable and conventional technologies is forecast to decline [11].

■ **Renewable generation is supported by direct subsidies while generation from fossil fuel power plants are supported via indirect subsidies.**

That is, the government encourages the production of fossil fuels generally, but not their burning for electric power specifically. Renewables receive funding for R&D, as well as direct support for electricity production and capacity additions. There are no subsidies that directly encourage the burning of hydrocarbons for electricity production. Most financial support for coal targets externalities, either by adding pollution controls or conducting R&D on clean coal and carbon sequestration. Coal also receives approximately 3% of its support through electricity production tax credits. Nuclear power receives diversified support in the form of R&D funding, tax credits on electricity sales, and programs aimed at plant costs (decommissioning, insurance) [11]. ■

FIGURE 17

Federal financial support for Electricity by Fuel and Year ($ million, nominal). Solid shading represents perennial support; hashed shading represents one-time support via ARRA.
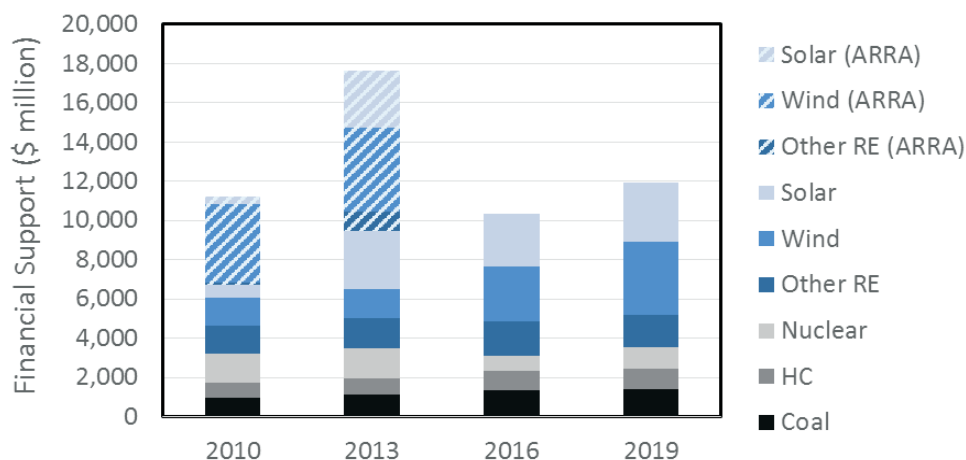
13 | Impact of Renewable Generation on Operational Reserves Requirements: When More Could be Less

◼ **This report describes concepts related with the quantification and pricing of ancillary services, with a special emphasis on renewable generation integration.**

The variability of renewable generation poses several challenges to reliable operation of power systems. Additional available generation capacity, including so-called "regulating" and "spinning" (or "responsive") reserve, is necessary to compensate for variability in both load and generation. Regulating reserve helps with moment-to-moment frequency control, while spinning reserve compensates for power plant outages. So-called "non-spinning reserve" provides additional capacity to replenish reserves if the regulating and spinning reserves are depleted. Collectively, these are "operational reserves." The report presents a description of the different concepts related to the definition,

quantification, and pricing of operational reserves with particular emphasis in the Electric Reliability Council of Texas (ERCOT).

◼ **Procured regulation declined as installed wind power capacity increased 8,000 MW from 2007 to 2013**

It is natural to think that, as the installed power of renewable generation increases, more operational reserves, and in particular more regulating reserve, will be required. However, for ERCOT, to date this intuition is incorrect. In ERCOT, regulating reserve is divided into two types: Regulation-Up and Regulation-Down. The historical procured regulating reserve data from ERCOT in Figures 18 and 19 show that, although installed wind power has significantly increased over time, regulation requirements have decreased.

FIGURE 18

Historical procured regulation-down reserves in ERCOT and end-of-year annual wind power capacity installed in ERCOT.
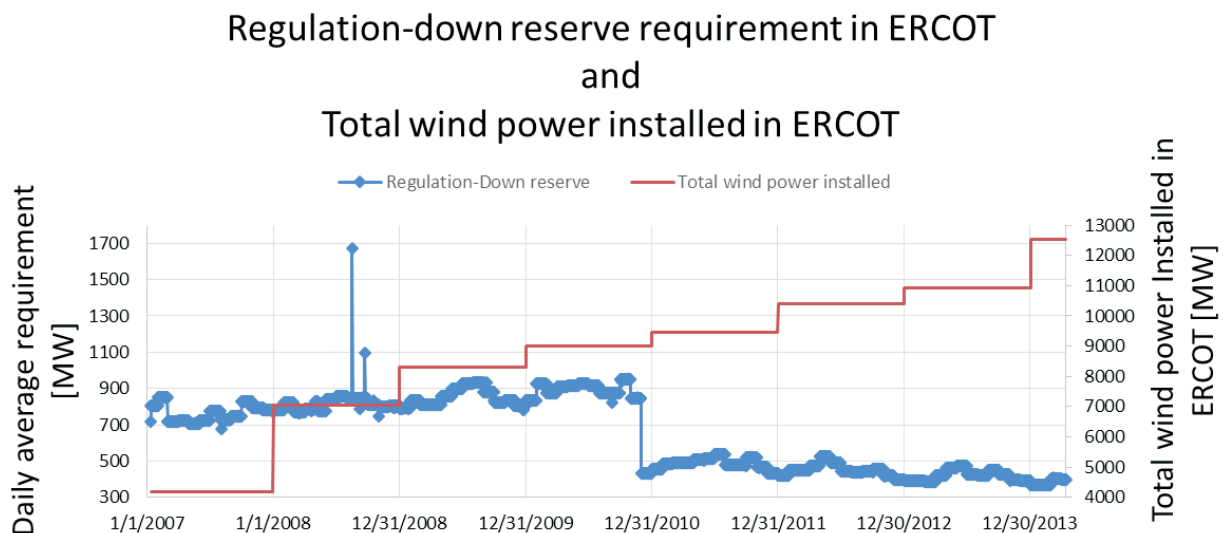
The explanation for why regulating reserves decreased while wind power increased is that several of ERCOT's operational rules have changed over time, and these changes have affected the system requirements for reserves. **The reductions in requirements for procured reserves due to ERCOT protocol revisions performed during the transition from the zonal to a nodal market (in 2010) have been more significant than the changes in requirements due to an increase in installed wind power capacity of 8,000 MW from 2007 to 2013.**

The ERCOT rules changes considered were Nodal Protocol Revision Requests (NPRRs) related to wind power production. A statistical analysis of the ERCOT historical data was performed to identify the significance of NPRRs to the market requirement for ancillary services. This analysis was performed by using regressions and Regression Discontinuity Design (RDD), which allowed quantification of the impact of installed power changes and NPRRs separately. The regression analysis considered demand and installed power of different types (e.g. Thermal generation, Coastal Wind, Non-Coastal Wind).

The following NPRRs were identified as significantly impacting procured reserves for Regulation-Up and Regulation-Down (see Figures 20 and 21):

- NPRR 352 (6/1/2011): Improvements in prediction of the maximum sustained energy production after curtailment.

- NPRR 361 (9/1/2011): Requires submission of 5-minute resolution wind generation data to assist real time market operation.

- NPRR 460 (12/1/2012): Increases the wind powered generation resource ramp rate limitation from 10% per minute of nameplate rating to five minute average of 20% per minute of nameplate rating with no individual minute exceeding 25%.

The December 1, 2010 change from a zonal to nodal market structure had the largest effect on reducing regulation reserves (see Figures 20 and 21). Several changes happened simultaneously at that time, including a change in the inter-hour dispatch interval from 15 to 5 minutes as well as dispatch by individual generation unit

FIGURE 19

Historical procured regulation-up reserves in ERCOT and end-of-year annual wind power capacity installed in ERCOT.

Regulation-down reserve requirement in ERCOT and Total wind power installed in ERCOT
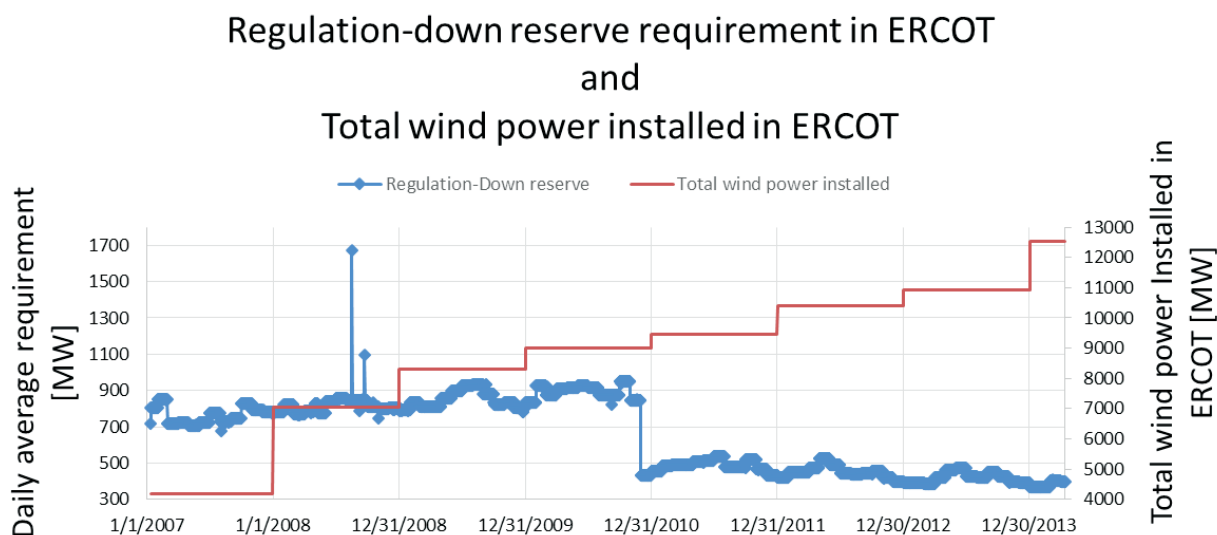
instead of by the entire power plant portfolio of a company engaged in power generation.

The analysis also discovered that installed generation capacity, regardless of its type (e.g. coastal wind, non-coastal wind, thermal), is positively correlated with procured reserves. An exception to this was the time period before the nodal market introduction, when coastal wind was negatively correlated with reserves procurement.

The observations from this study motivate the exploration of improvements in grid operate that can allow more renewable integration without significant additional cost due to its variability. ■

FIGURE 20

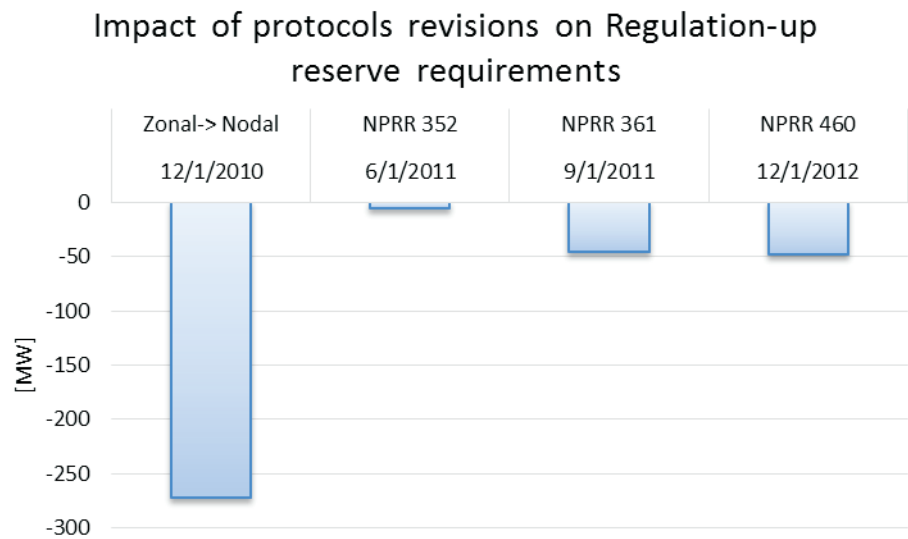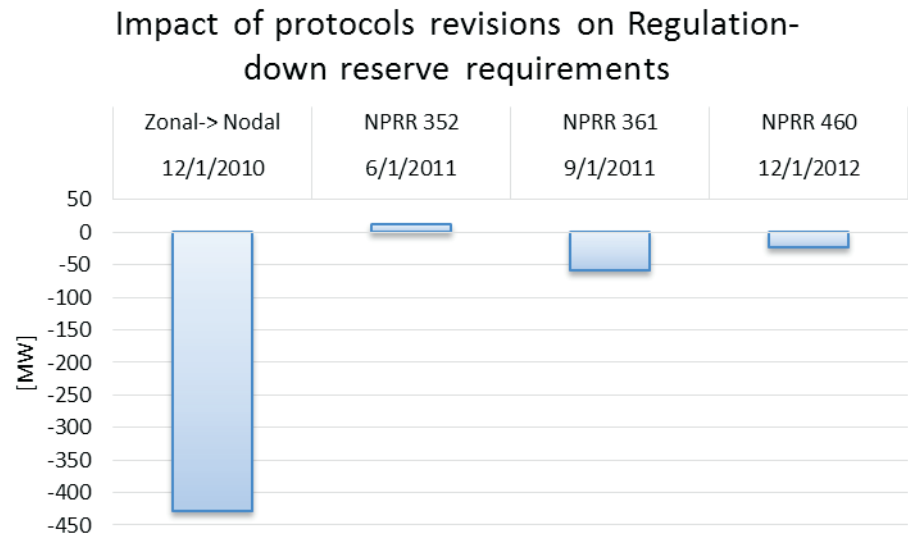Impact of protocols revisions on Regulation-up reserve requirements.

Impact of protocols revisions on Regulation-up reserve requirements

FIGURE 21

Impact of protocols revisions on Regulation-down reserve requirements.

Impact of protocols revisions on Regulation-down reserve requirements

FULL COST OF ELECTRICITY WHITE PAPER CITATIONS:

All white papers are available at: **http://energy.utexas.edu/the-full-cost-of-electricity-fce/**

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