The University of Texas at Austin
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The Full Cost of Electricity (FCe-)

Executive Summary: The Full Cost of Electricity

A SERIES OF WHITE PAPERS

TEXAS
The University of Texas at Austin

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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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.

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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?

- When full costs are included, every power generation option is more expensive than just the combination of their direct operational and capital expenditures.
- 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].
  - analysis of Texas and California show that level of state support is comparable to that of the federal government [16].

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

- Short answer: No.
- 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]. The same tendencies hold at the state level for California and Texas. California generally favors renewables, and Texas generally promotes economic development relatively independently of favoring fossil fuels or renewables [16].

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

- Short Answer: It depends.
- 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.

	Cost Factors Considered within the Framework of Full Cost of Electricity								
White Paper	*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	✓	✓			✓				
Unit-commitment, dispatch, and capacity expansion modeling of ERCOT	✓			✓	✓				✓
New Utility Business Models	✓	✓	✓	✓	✓	✓		✓	✓
Quantifying Diversity of Electricity Generation in the U.S.	✓								
State-level Financial Support for Electricity Generation Technologies	✓		✓	✓	✓				✓

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. 9 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. 11 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. 22 for summary)

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

- 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).
- 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. 21 for summary)*

- 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.
- 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. 13 for summary)*

- 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.
- 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. 25 for summary)*

- 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).
- 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)*

- 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.
- 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. 27 for summary)*

- 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).
- 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. 28 for summary)*

- 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).
- 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. 24 for summary)*

- 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 *(see pg. 31 for summary)*

- Three different models were used to estimate the ERCOT generation portfolio through 2030.
- Three different models were used to estimate hourly electricity generation in ERCOT in 2030.
- Given recent coal retirements and expected wind and solar additions, the defined "Aggressive Renewables" (AR) scenario has appeared more likely than the "Current Trends" (CT) scenario. In 2030, of the total ERCOT assumed generation of 421 TWh and relative to the CT scenario, the AR scenario generates 40 TWh more from wind, 30 to 40 TWh less from coal, and up to 20 TWh less from natural gas.
- The annual cost of the AR scenario in 2030 is approximately 0.5 –1 $ billion more than the CT scenario because of larger capital costs, despite significant fuel cost savings.

Future Utility Business Models *(see pg. 34 for summary)*

- Electric utilities will need to consider alternative business models to remain viable and realize the potential benefits of DER. To facilitate the process, this report provides an analysis of six new business models for the utility. Specifically, it explores the California (CA) Proceedings, the Lawrence Berkeley National Laboratory (LBNL) model, New York's Reforming the Energy Vision (NY REV), the Rocky Mountain Institute (RMI) model, United Kingdom's Revenue = Incentives + Innovation + Outputs (UK RIIO), and the Transactive Energy (TE) model.
- These models are generally unsustainable in the scenario of low electric load growth and high DER penetration.
- While all these models cease being viable under certain conditions, they provide an important step forward for the utility. There is no one-size-fits-all solution to shifts in electric demand, generation, and efficiency.

Quantifying Diversity of Electricity Generation in the U.S. *(see pg. 36 for summary)*

- Primary Electricity Supply diversity needs to be actively considered and prioritized by policymakers across multiple levels of jurisdiction. This paper finds that increasing dispatches of wind and natural gas have impacted system diversity.
- Our analysis offers three high-level takeaways
  1. overall U.S.-level fuel source diversity is increasing, and that Primary Electricity Supply portfolios across the U.S. are changing in a context dependent fashion, not monolithically,
  2. there is wide scope of variation around the combinations of disparity, balance, and variety – different elements of what diversity entails – among states, and
  3. widespread transitions in the proportions of state-level energy generation mixes related to natural gas, coal, hydro, and wind have shifted these combination over that past 25 years.

State-level Financial Support for Electricity Generation Technologies *(see pg. 38 for summary)*

- The objective of this white paper is to identify the financial supportoffered by state governments to different technologies that provide electric power in the states of Texas and California.

- Both Texas (2-3 $ billion/year) and California (3-7 $ billion/year) offer billions of dollars annually in state-level support of energy production.
- In both states, renewables receive significantly more support than conventional technologies on a $/MWh basis, and this support via this metric declines rapidly over time.
- In 2016, we estimate that California offers more support per MWh and per capita ($150/Californian) than the Federal Government ($37/American [11]) while Texas support is similar ($60/Texan, when including transmission line costs for the Competitive Renewable Energy Zones).
- Texas generally uses its financial support for economic development while California uses it to meet environmental goals and to drive down the cost of new technologies.

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.

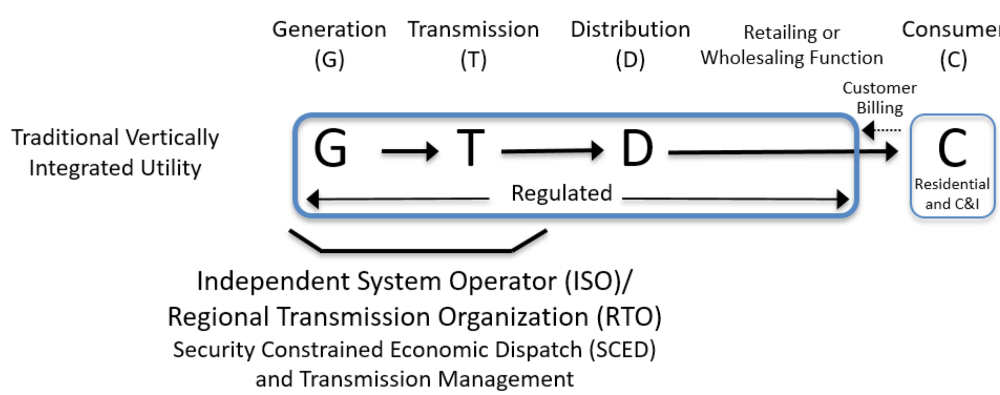
Following examples from other industries, policy makers began to rethink the notion that power generation and sales are (or should be) a natural monopoly. Policymakers were exploring means to unleash competitive and technological forces as they had observed in the telecommunications industry, for example.

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.



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.

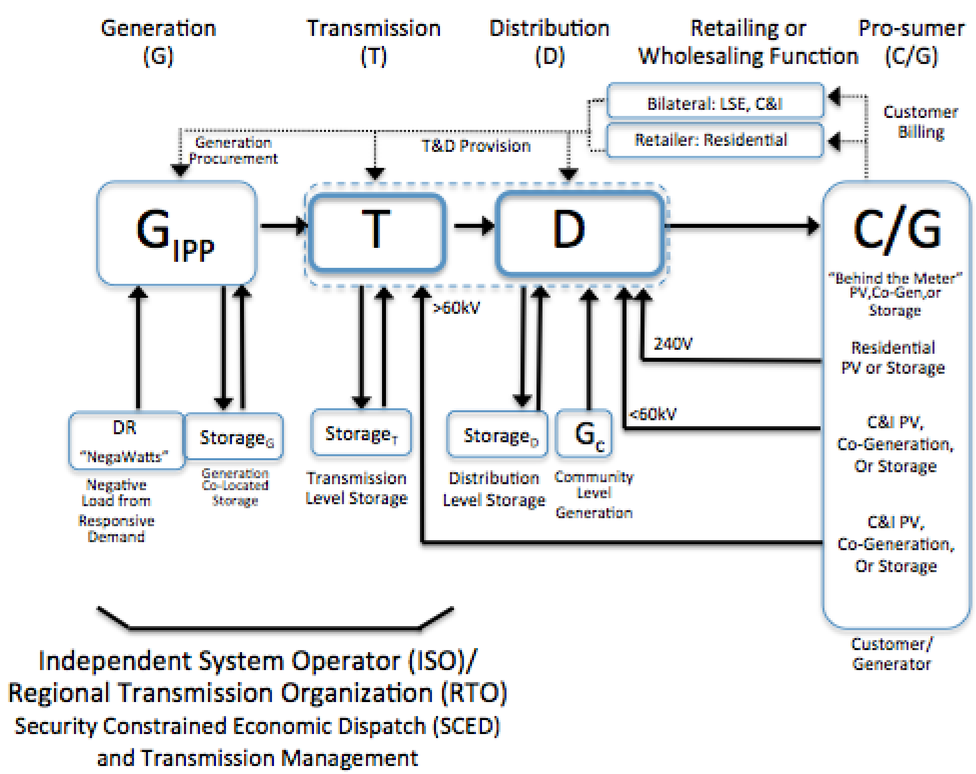
In turn, this self-generation threatens both the traditional utility business model as well as the competitive market structure as they exist today.

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.

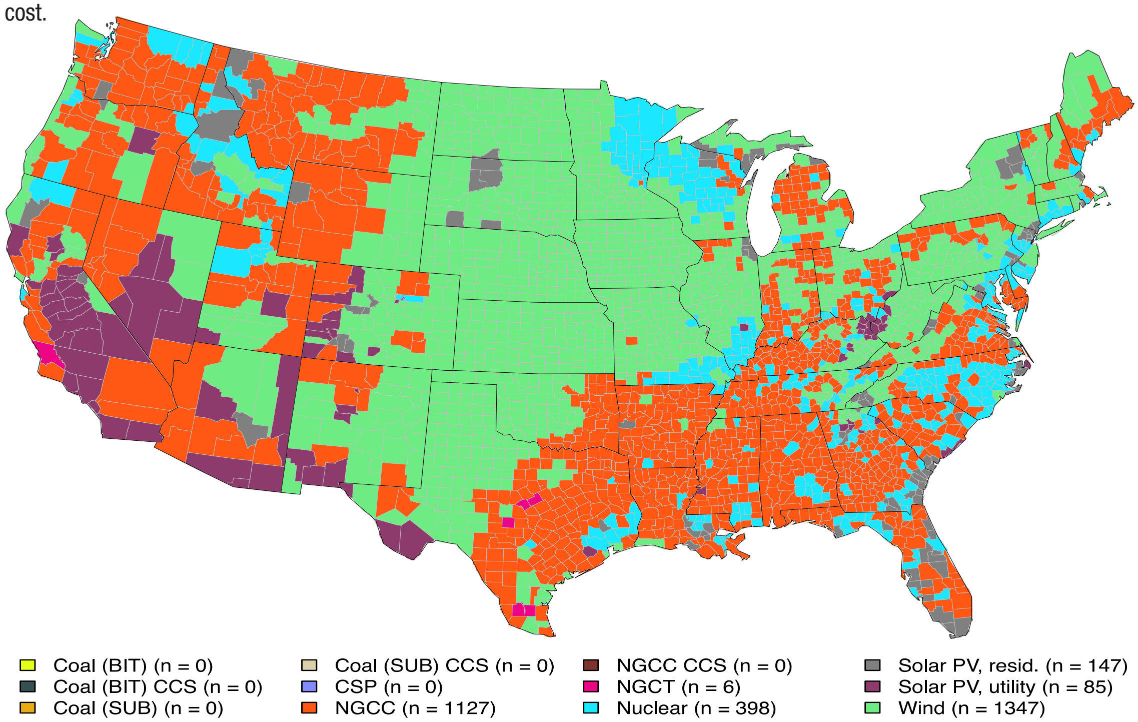
Despite its advantages and widespread use, the conventional LCOE has several shortcomings that render it spatially and temporally static. There are differences across regions that are important to take into account, including construction and operating costs, fuel delivery costs, resource availability (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.



- 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].

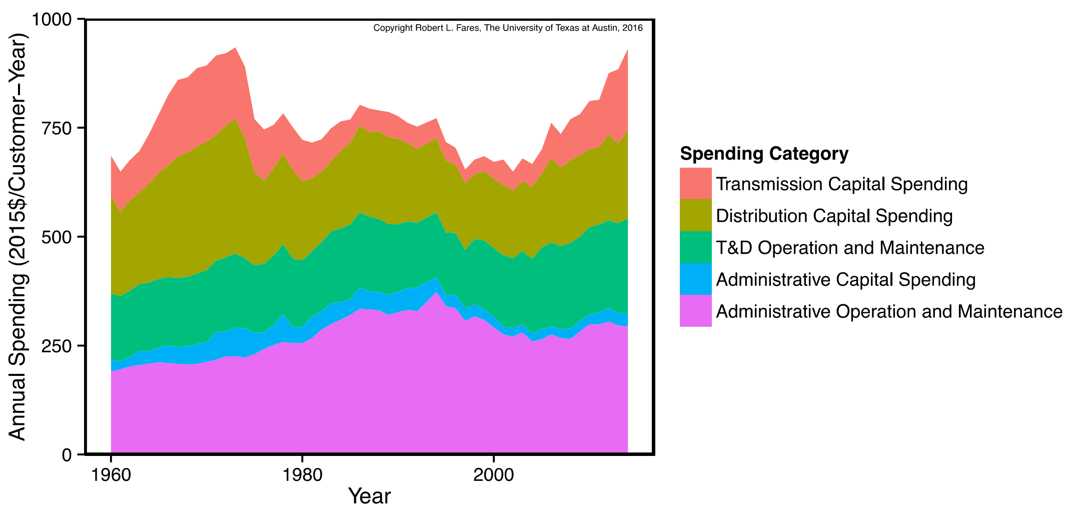


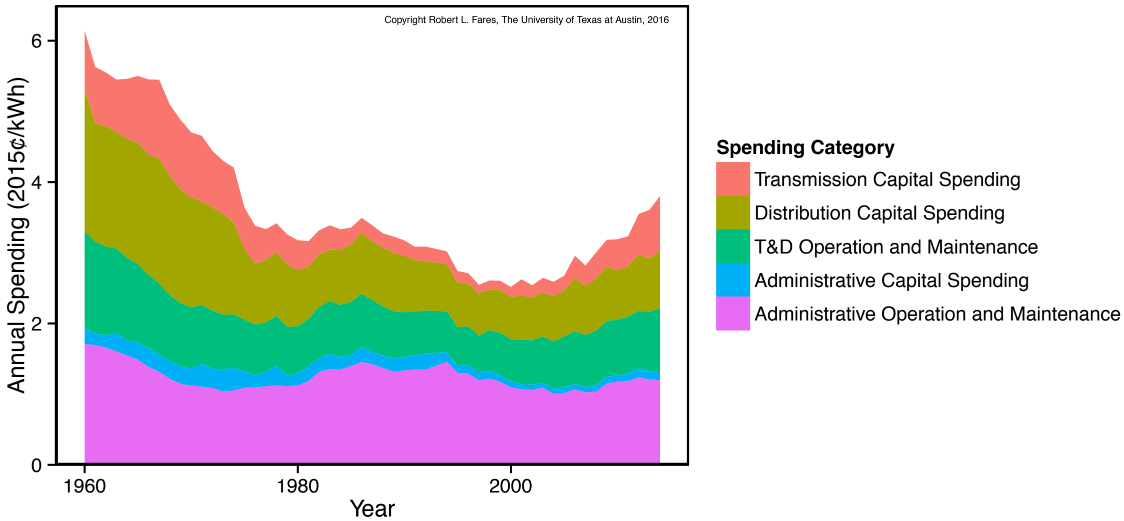
TABLE 2

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].

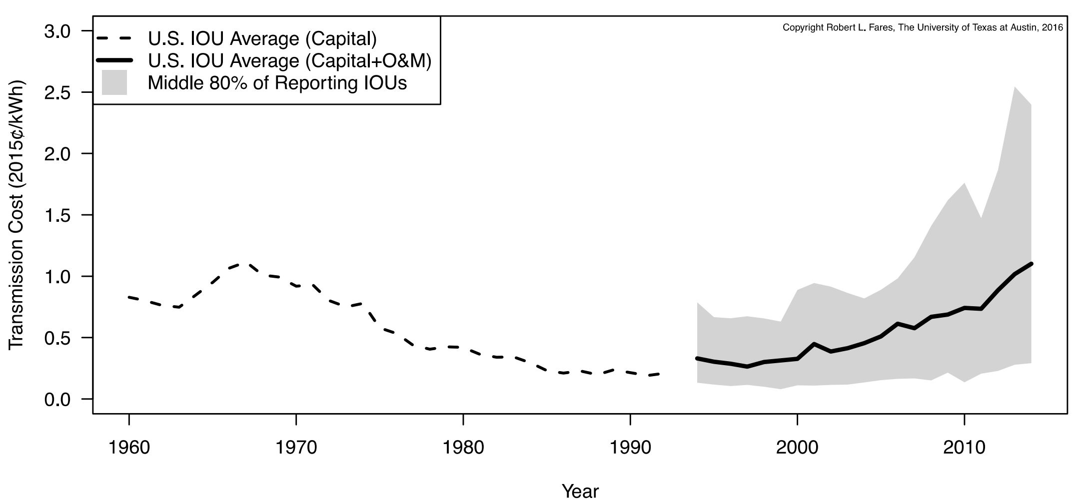
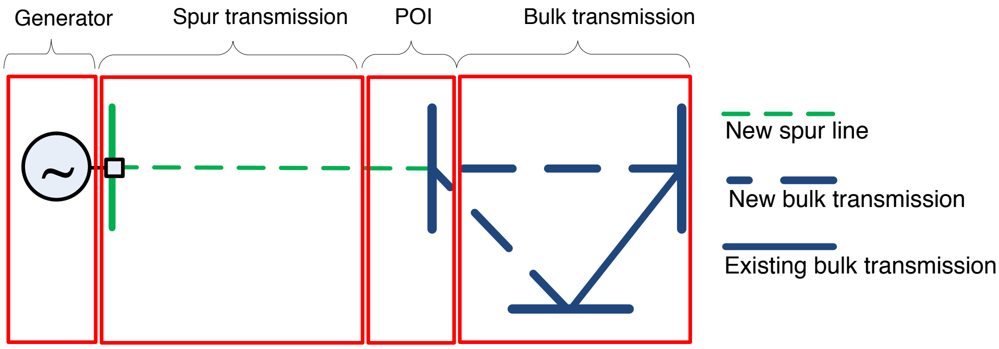


FIGURE 7

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).

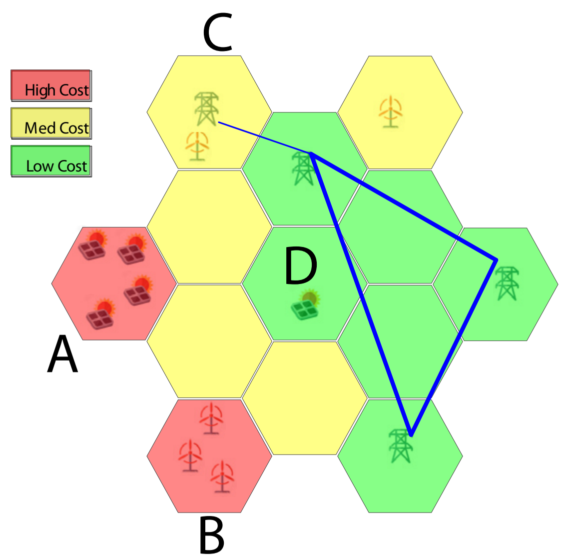


TABLE 4

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

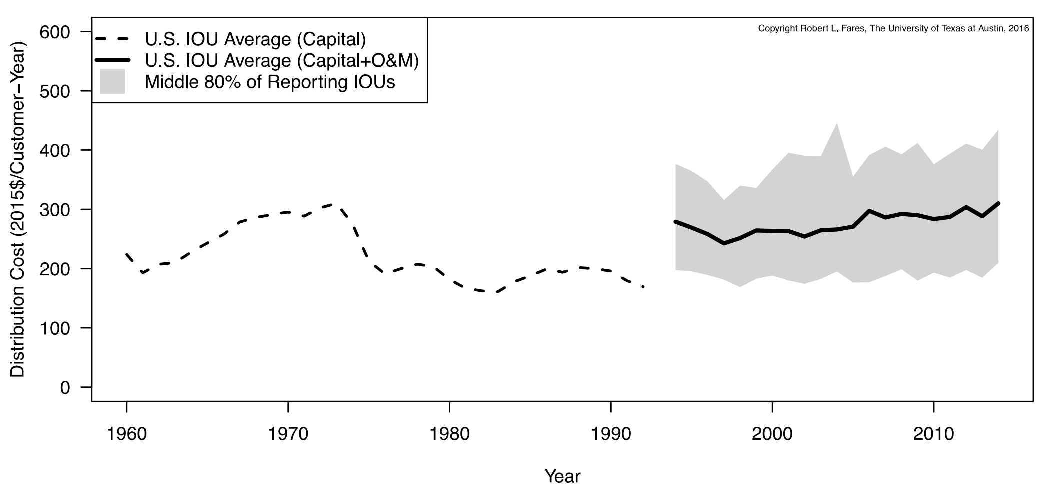
Unlike the transmission system, the distribution system does not move bulk electric power over a long distance to connect generation to customers. Rather, it distributes power from the transmission system to individual electricity customers at the level of voltage and current they require. In recent 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

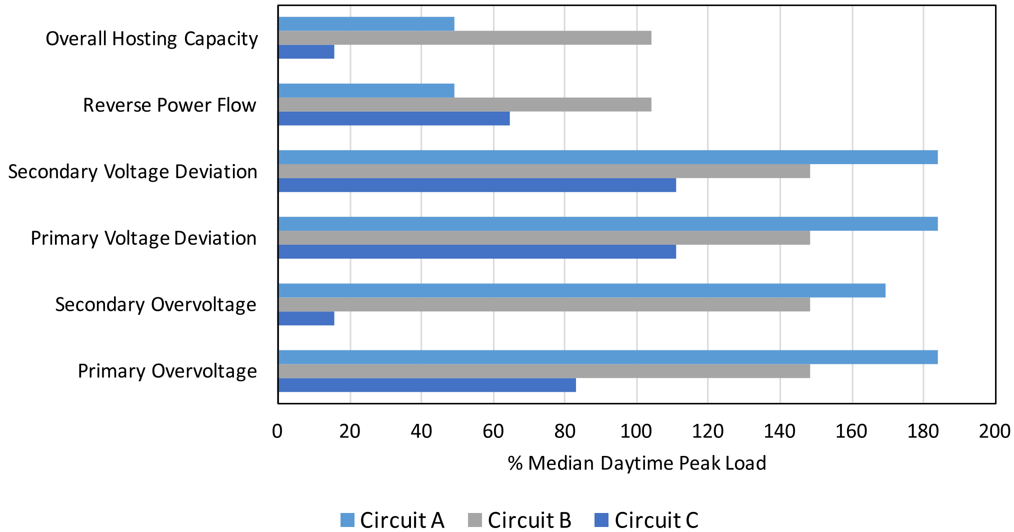
TABLE 5

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).

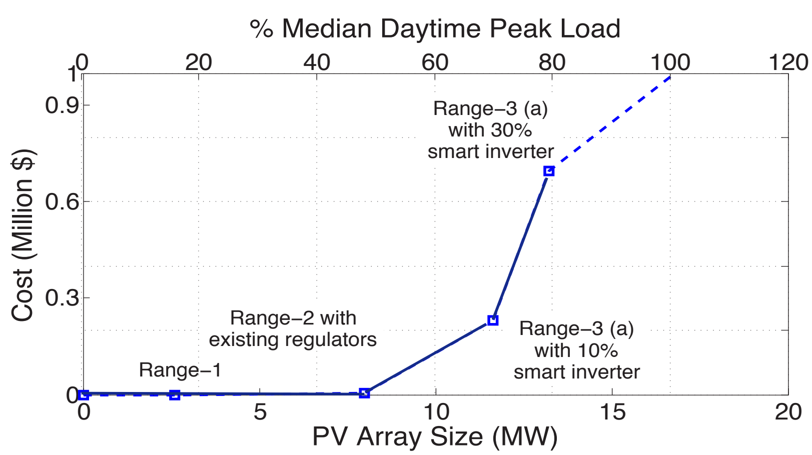


circuit peak load assuming replacement of 10% and 30% inverters at a total cost of approximately $230,000 and $700,000, respectively [1]. Note that the costs associated with adding smart inverters could be avoided if smart inverters are installed initially or as existing inverters are retired.

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].

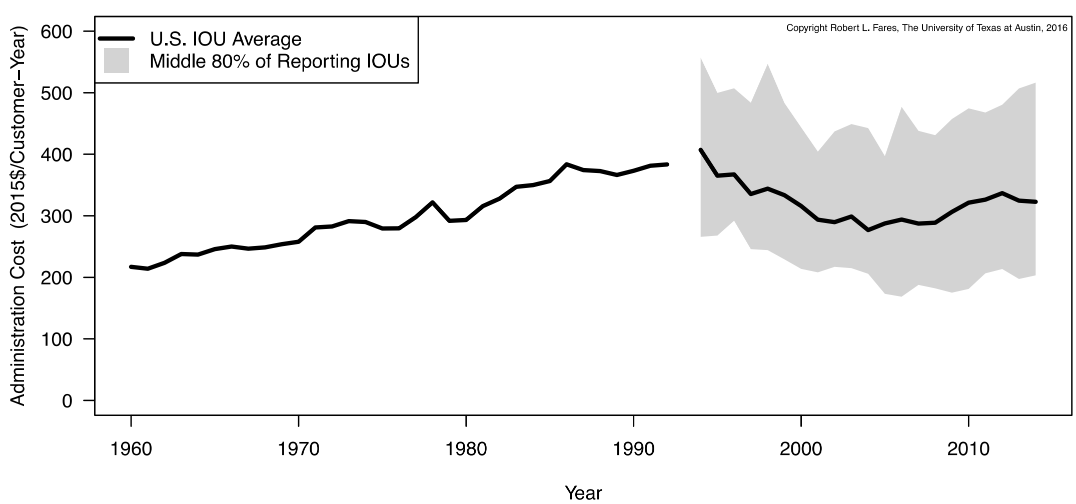
While administrative costs are often recovered at least in part through volumetric charges per kWh of energy sold or per kW of peak electric demand, the number of customers found in a utility's territory was found to be the best predictor for annual administration costs based on analysis of investor-owned 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).

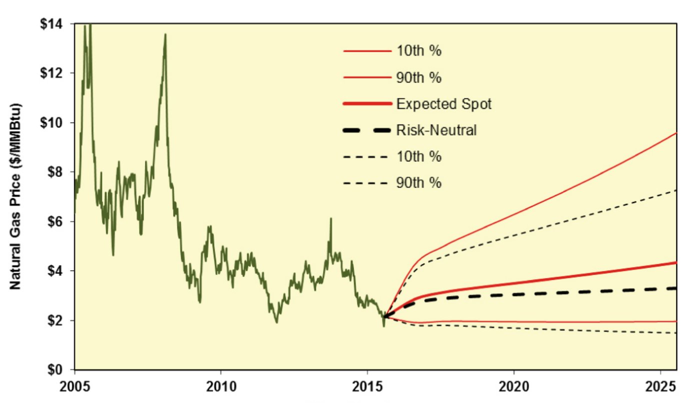
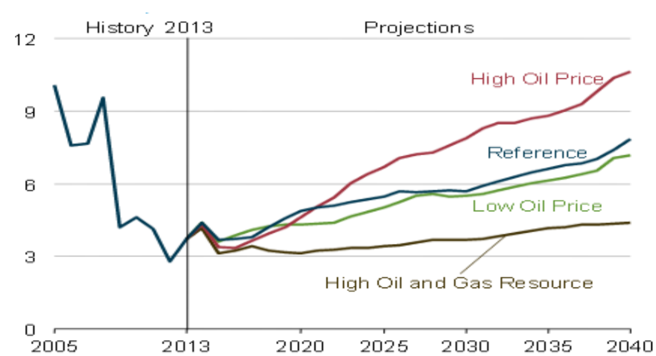


FIGURE 14

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.).

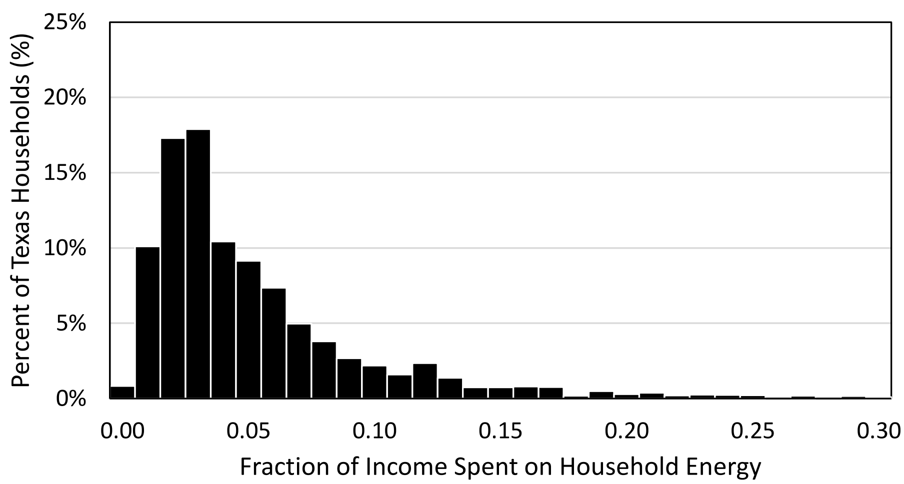


FIGURE 16

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):

- being black or of Spanish descent,
- receives SNAP benefits (household receives benefits for food from Supplemental Nutrition Program (SNAP) for Women, Infants, and Children (WIC)), or
- 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):

- having a college degree,
- being male,
- being married,
- owning your home,
- having a full-time job, or
- 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-beneift 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.

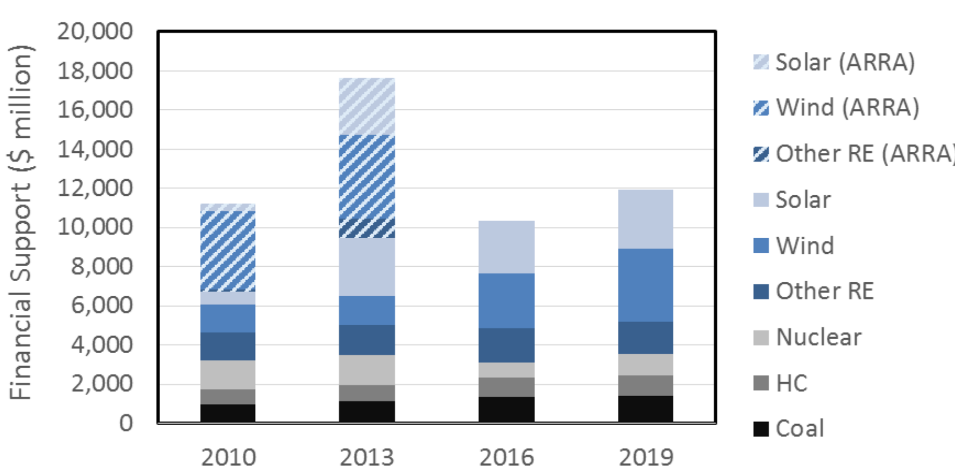
Generation from fossil fuels receive a large amount of support, but their per-MWh cost is modest due to the very large installed base and the high quantity of generation. Renewables, by contrast, receive somewhat more money but generate significantly less electricity. Depending on the year, fossil fuels 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.

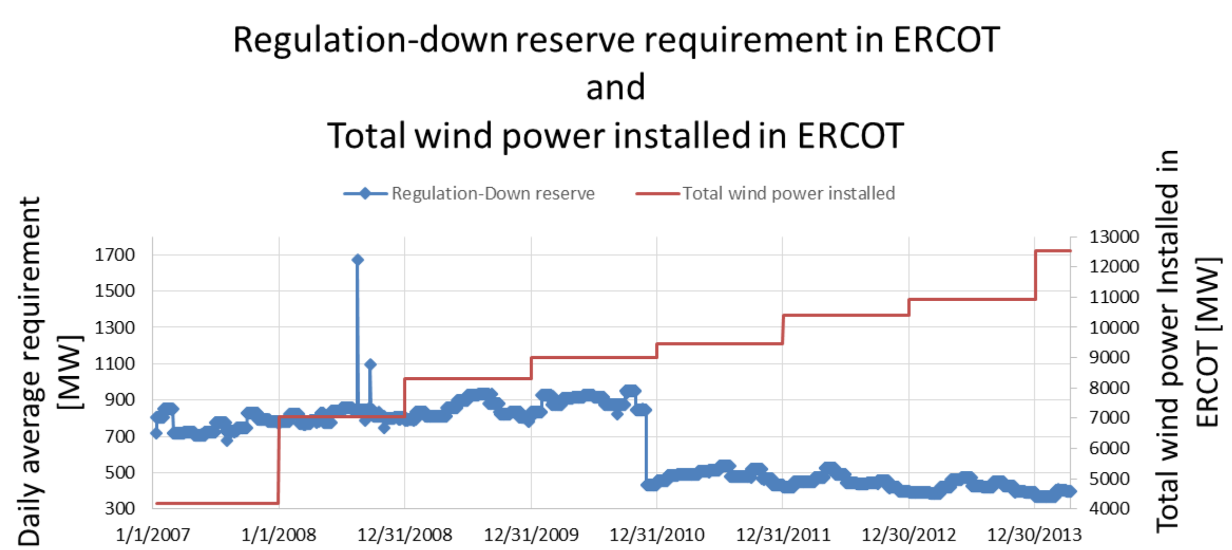
The variability of renewable generation poses several challenges to reliable operation of power systems. Additional available generation capacity, including so-called "regulating" and "spinning" (or "responsive") reserve, is necessary to compensate for variability in both load and generation. Regulating 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.

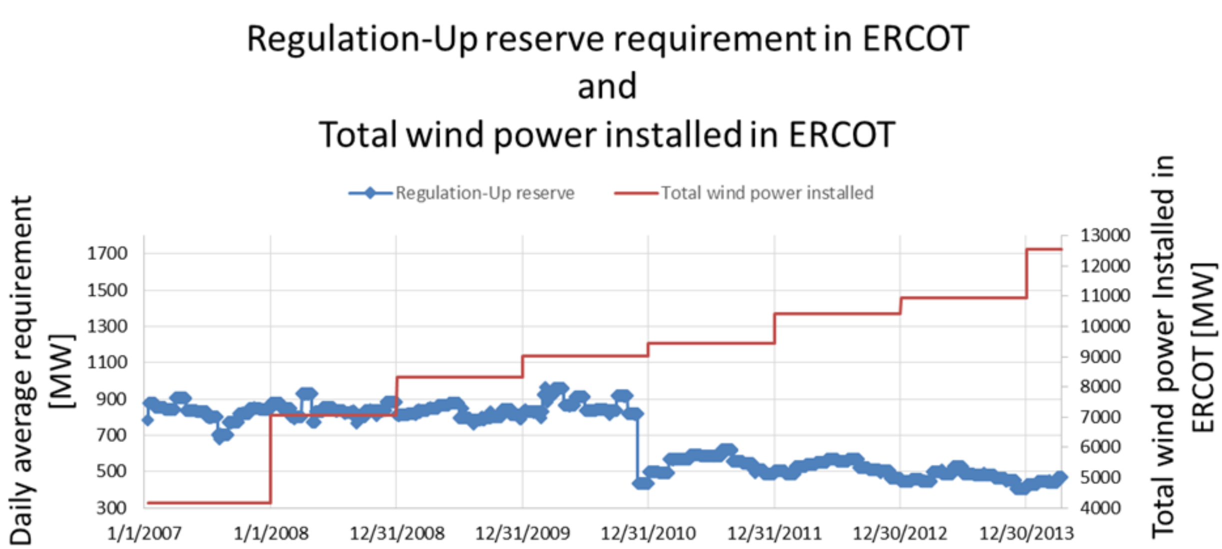


FIGURE 20

Impact of protocols revisions on Regulation-up reserve requirements.

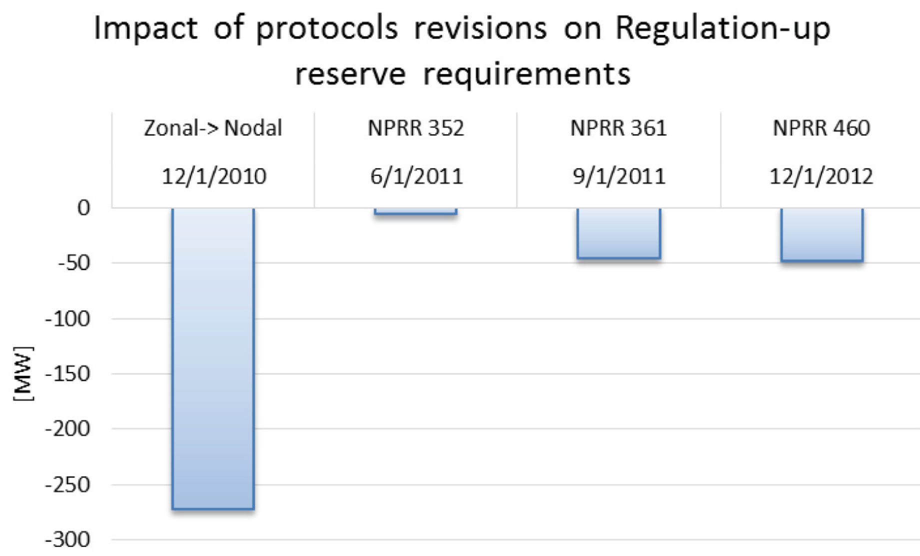
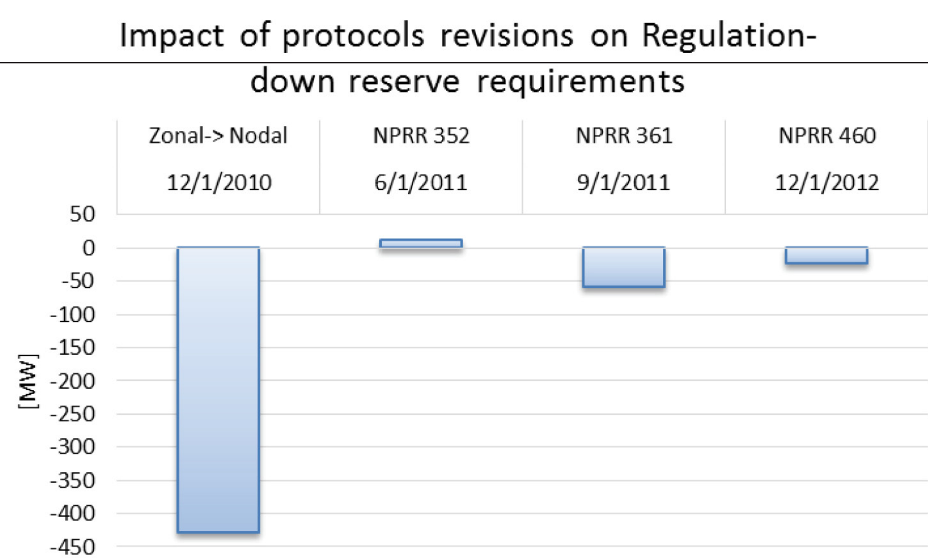


FIGURE 21

Impact of protocols revisions on Regulation-down reserve requirements.



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.

14 Four Simulations of the ERCOT Power System, Using Multiple Methods, Yield Consistent Results in System Costs and Implications of Increased Renewables

Electric grid dispatch models approximate security-constrained economic dispatch and unit commitment of electric generation units. As such, they follow economic dispatch subject to price signals (including energy, capacity and some ancillary services when applicable), operational characteristics of generation units, and transmission capacities across zones or nodes. Capacity expansion models simulate the long-run costs and revenues of a generation fleet to investigate when new capacity is needed and when uneconomic capacity should retire. Both dispatch and capacity expansion models allow users to investigate multiple scenarios in terms of generation mixes as well as policy impacts and sensitivities. The following summarize results from using dispatch and capacity expansion models, of varying detail, for the Electric Reliability Council of Texas (ERCOT).

- This report considered four computational models (listed from low to high detail) and two scenarios

Models:

- SCM ("low detail"): Screening curve model developed by UT-Austin for least-cost generation mix for a given annual load shape
- Excel ("moderate detail"): An Excel-based model developed by UT-Austin for multi-year capacity expansion estimation by generator type
- AURORAxmp and PLEXOS ("high detail"): Commercial software programs for multi-year simulation of power plant dispatch and capacity expansion by individual generation unit (including specific parameters for each unit in ERCOT)

Scenarios:

- Current Trends (CT): An expected set of power plants in-construction and continuation of electricity market and environmental regulations from 2016 as well as ERCOT regional load forecasts.

TABLE 19

Comparison of 2030 Capacities from the Three Models (GW)

	Model	Total Nuclear	Total Coal	Total NG	Total Wind	Total Solar	Total Capacity*
	AURORAxmp	5.1	18.9	60.9	20.3	0.9	106.8
CT	SCM	5.1	16.5	59.8	20.3	0.9	102.6
	Excel	5.1	18.9	56.7	20.8	0.9	103.3
	AURORAxmp	5.1	13.3	62.6	32.4	3.5	117.6
AR	SCM	5.1	16.5	56.7	32.4	3.5	114.2
	Excel	5.1	18.9	56.7	32.4	3.1	117.1

* AURORAxmp and Excel totals include other generation such as hydro and biomass.

- Aggressive Renewables (AR): Same as Current Trends, but with additional solar (2 GW) and wind (12 GW) "hardwired" into the model, including those under development and announced.
    - Multiple models with varying levels of detail show similar results for anticipated additions and retirements of power plants to 2030

All models simulating power plant capacity additions yield similar results, within 4% for the CT scenario and 3% for the AR scenario. The most noticeable differences occur for coal and gas capacities. AURORAxmp yields more gas-fired capacity than the other two models, especially in the AR scenario. The SCM gas capacity is only 1.1 GW less than that of AURORAxmp in the CT scenario, but Excel gas capacity is 4.2 GW less. Both SCM and Excel have the same gas capacity in the AR scenario, which is 5.9 GW less than that of AURORAxmp. The AR scenario results can be explained by AURORAxmp retiring 5.6 GW more coal capacity than the Excel model and 3.2 GW more than the SCM.

- The Aggressive Renewable scenario, with several GW of coal power plant retirements and solar installations, seems to be panning out

As of late 2017, more than 4 GW of coal plant retirements were approved for 2018. More coal retirements are possible in future years if wholesale prices continue to stay low due to low natural gas prices and increased renewable electricity. The AURORAxmp model calculated 6.5 GW of coal retirements by 2030, while the SCM model retired 3.3 GW of coal capacity.

Planned wind and solar resources with executed interconnection agreements indicate roughly 29 GW of wind and 2.8 GW of solar by 2020. Overall, the Aggressive Renewables scenario is closer to the actual changes in ERCOT through 2017 than the Current Trends scenario.

- Between the CT and AR scenarios estimating for 2030, natural gas and nuclear generation are relatively the same, but the AR scenario indicates declining coal and increasing renewable generation

Generation by fuel is generally consistent across all three hourly dispatch models indicating that wind and solar generation increase, nuclear generation stays roughly the same, coal generation declines significantly, and gas generation falls less than 10%.

FIGURE 40

Total Generation Output by Fuel Type in 2030 - Comparison of AURORAxmp, PLEXOS and Excel Results

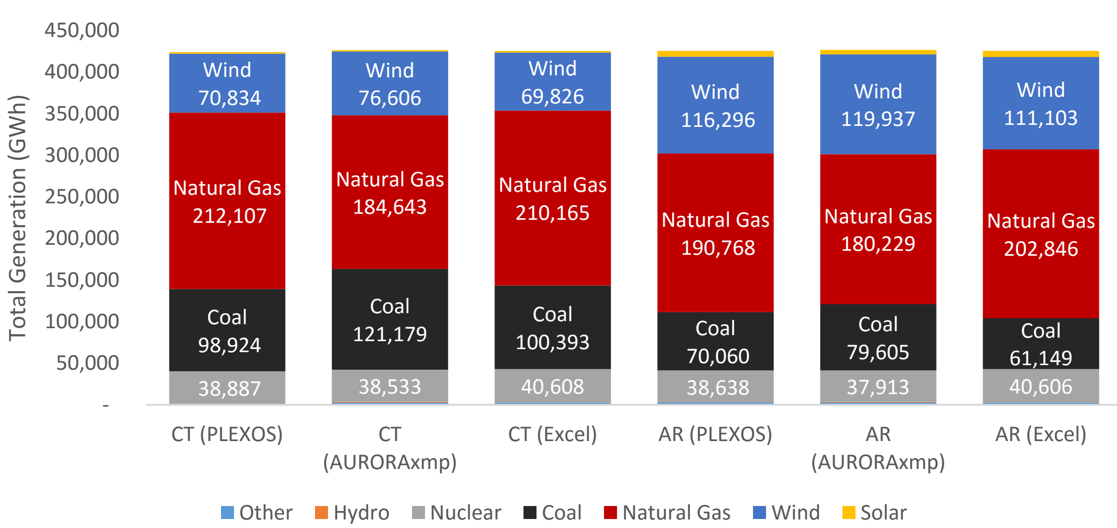
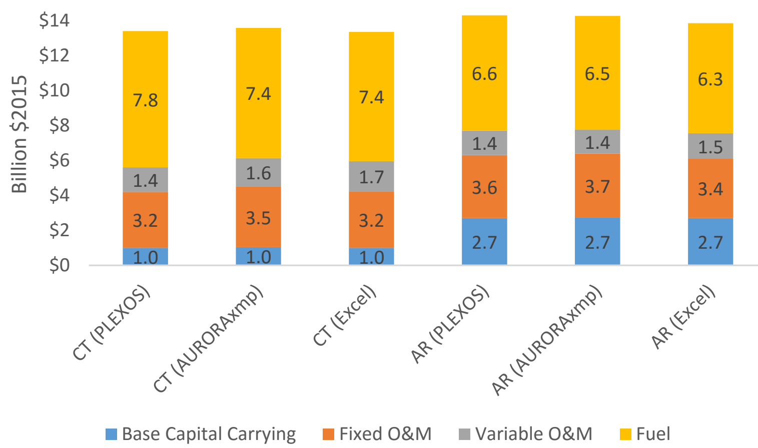


FIGURE 42

Total System Cost in 2030



In the CT scenario, the PLEXOS and Excel model results are very similar as they dispatch more natural gas generation relative to coal generation as compared to AURORAxmp that yields approximately 20,000 GWh more coal generation than the other models.

In the AR scenario, both the PLEXOS and Excel models generate more from gas plants than AURORAxmp (about 10,000 GWh and 20,000 GWh, respectively). This is at the expense of coal (9,000–18,000 GWh) and wind (4,000– 8,000 GWh). Differences in wind generation are relatively small across the models (3–8%).

- Annual costs in 2030 are approximately $13.4 Billion for CT and $13.9-$14.3 Billion for AR. The CT scenario has higher fuel and lower capital costs while the AR scenario has the opposite, lower fuel and higher capital costs.

Total system costs depict the same distribution of capital and fuel costs across all three models used for the hourly dispatch (Figure 42) as the long-term results discussed earlier (Figure 31). Capital costs, as represented by the base capital carrying cost, are larger with the AR scenario, but fuel cost savings help to compensate. As a result, total costs under the AR scenario are only slightly larger.

- Although the models had similar dispatch logic and input data, some significant differences in simulated annual generation remain. The simpler Excel and Screening Curve Models provide valuable insights into the long-term capacity mix with less computational expense.

With the key inputs matched as closely as possible, the main dispatch discrepancy between models was between coal and natural gas generators. The AURORAxmp model calculates 2030 coal generation 14–30% larger than that from the PLEXOS and Excel models. Although coal plants often have lower marginal costs than combined-cycle gas plants, they don't always get dispatched before CCGTs due to fluctuations in both fuel and non-fuel costs. For instance, AURORAxmp and PLEXOS include start-up costs, which could explain the difference from the Excel model although not the difference between the two. Also, the Excel model dispatches by aggregated categories of generators with no transmission constraint, while AURORAxmp and PLEXOS dispatch individual units subject to some transmission constraints within ERCOT.

15 | New Utility Business Models

The electricity sector in the United States is experiencing a period of significant transition. Since its inception in the late nineteenth century, the electric utility has produced electricity in power plants and supplied it to the public through the electric grid at a rate based largely on the consumer's usage. In recent years, however, Distributed Energy Resources (DER) have disrupted this model. DER adoption is ushering in an electricity system that is more dynamic, decentralized, and energy efficient. While this paradigm shift has inherent benefits for ratepayers and society at large, it threatens the traditional utility business model.

The utility will need to consider alternative business models to remain viable and realize the potential benefits of DER. To facilitate the process, this report provides an analysis of six new business models for the utility. Specifically, it explores the California (CA) Proceedings, the Lawrence Berkeley National Laboratory (LBNL) model, New York's Reforming the Energy Vision (NY REV), the Rocky Mountain Institute (RMI) model, United Kingdom's Revenue = Incentives + Innovation + Outputs (UK RIIO), and the Transactive Energy (TE) model. Our analysis identified three common themes across the six models:

- **Rate Structure Reform:** These models recognize the traditional cost of service (COS) rate structure is insufficient as the sole means of recovering fixed costs and creating adequate revenue to offset the revenue loss from DER. The models adopt a Performance-Based Ratemaking (PBR) structure that shifts the utility's focus from COS to revenues awarded for improving performance.

- **Implementation of DER:** These models prioritize integrating renewables onto the grid. The models seek to incorporate both utility-scale and distributed generation onto the electric system without penalty to the utility or ratepayers.

- **Customer Engagement:** The traditional relationship between the utility and ratepayers is replaced by one which gives the consumer greater control over their energy bill. The customer can choose energy efficiency programs that fit their needs, negotiate energy usage with the utility, and generate their own electricity through DER.

Each new business model has its own mix of incentives and revenue structures with differing consequences for stakeholders. The following chart highlights these variations.

Comparative Analysis of New Business Models

Evaluation metric	Business Model					
	NY REV	CA	RIIO	LBNL	RMI	TE
COS to PBR Transition	●	◐	●	●	●	◐
DER Encouragment	●	◐	●	●	●	●
DER as Cost Reduction Tool	◐	◐	○	◐	◐	○
Customer Engagement	●	◐	●	●	○	◐
Platform Model	●	◐	○	●	◐	●
Fixed Cost Recovery	COS + Fixed Change	COS + Min. Bill	Policy + RAV	N/A	NUC + Tariff	COS + Access Fees
Profit-Making	PER+MBR	PER+MBR	PBR	MBR	PER+MBR	MBR
Role of DSO	None	Operation	Price Settings + Regs	Operation	Operation	Operation
ESU or SIM	SIM	SIM	SIM	Both	Both	SIM

COMPARISON OF NEW BUSINESS MODELS

These models are generally unsustainable in the scenario of low electric load growth and high DER penetration. The utility's revenue declines when demand for electricity drops, and DER drives falling demand. However, the utility's costs remain unchanged, or even increase as DER becomes more widespread. If the current trend of increased DER penetration and decreased load growth continues, these models will experience the same profitability issues facing the utility today.

While all these models cease being viable under certain conditions, they provide an important step forward for the utility. There is no one-size-fits-all solution to shifts in electric demand, generation, and efficiency. However, utilities can better anticipate and respond to these trends by keeping in mind the following:

- These models will struggle in a low load growth, high DER scenario.
- The need to accommodate uneven fiscal impacts by understanding utility and market characteristics.
- The platform business model has only limited applicability to the utility industry.
- These models work best as transitional models.
- Some utilities might not survive the transition (in their current form) to high penetration of DER.
- These models will benefit participating customers and society at large.
- None of these models propose a complete move away from traditional cost of service regulation.
- A fully regulated model might be the best option for distribution utilities.
- The IDSO might be the preferable operator system. Such an operator might be a non-profit or government entity.
- The need to accommodate uneven physical impacts by using software to understand structural characteristics.
- Once a saturation point is reached, additional DER will have limited value to the overall system.
- Physical limitations of peer-to-peer transactions will ultimately hinder growth in distribution system markets, and fiscal limitations will affect distribution systems.

16 | Diversity of Electricity Generation in the U.S. has Increased Over Time

Decision makers grapple with inevitable economic, environmental, and technological challenges in good faith by sizing up impending challenges and making tradeoffs with the best information available. Yet it's common for resilience to take a back seat to near term and known system threats. Critical socioeconomic systems like our electricity system are prone to large, unanticipated infusions of critical information that turn dominant market presumptions on their head. Barely a decade ago the thought of sustained low natural gas prices in the U.S. and oil and gas exports from the U.S. would have been discarded as ludicrous. Also, just a decade ago the engineers managing operations of RTOs/ISOs would have scoffed at the idea of 50%+ instantaneous wind generation on the system. And the now famous Duck Curve for electricity demand in California didn't exist even five years ago. But each of these scenarios, with profound implications for the electricity system, did materialize and none were adequately foreseen or "priced into" earlier planning efforts.

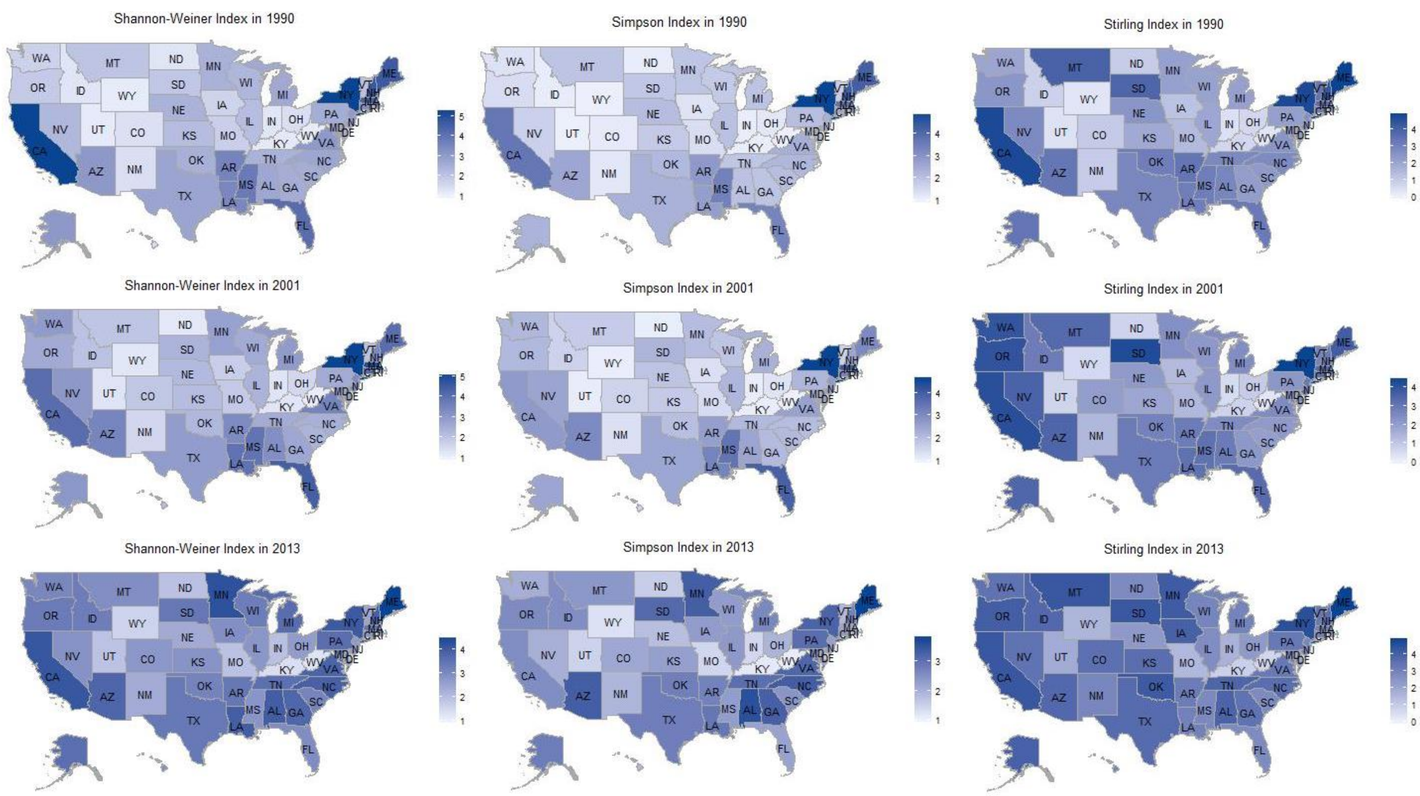
The recently announced Notice of Proposed Rulemaking (NOPR) aiming to shore up grid resiliency by pricing in an assumed value for 90-days supplies of fuels – a standard that would apply only to coal and nuclear generators. Proponents of the rule argue that system reliability has been undermined by ignoring long-term risks of reduced dependence on baseload sources like coal and nuclear, which can ramp up quickly provided sufficient fuels are accessible. The argument, though, relies on some key assumptions. First, fuel source diversity is ebbing toward historically risky or untested levels. Second, fuel source diversity is moving more or less monolithically across the U.S. in the direction of reduced fuel source diversity. Third, the impact of changes in fuel source diversity will largely play out as inadequate system readiness for acute system events, like storms and other extreme weather. Finally, resilience will improve in the short, mid, and long-term by compensating the capacity for short-run readiness. We agree with one aspect of the logic behind the NOPR – PES diversity needs to be actively considered and prioritized by policymakers across multiple levels of jurisdiction. Our analysis, however, quantifying electricity generation diversity over the last quarter century, tells a much different story for the first two of these assumptions.

System diversity is a critical element of long-term resilience, helping to mitigate unknown risks. But there are different aspects of what diversity really entails. In particular, three aspects are particularly relevant for our discussion: (1) "variety", i.e., the number of options, (2) "balance", i.e., how proportionally reliant a system is on a particular option, and (3) "disparity", i.e., how different each option is. Accounting for each of these key elements of diversity, in our recent paper Quantifying Diversify of Electricity Generation in the U.S. we explored the diversity of U.S. primary energy sources (PESs) used for electricity generation over the past 25 years, in a new paper we find that increasing dispatches of wind and natural gas have impacted system diversity, and that the ways in which the impacts are meaningful vary quite a lot, depending on the current suite of PESs, how similar they are to each other, and how many different PESs there are in total.

Our analysis offers three high-level takeaways (refer to Figure 1): (1) overall U.S.-level fuel source diversity is increasing, and that PES portfolios across the U.S. are changing in a context dependent fashion, not monolithically, (2) there is wide scope of variation around the combinations of disparity, balance, and variety – different elements of what diversity entails – among states, and (3) widespread transitions in the proportions of state-level energy generation mixes related to natural gas, coal, hydro, and wind have shifted these combination over that past 25 years.

FIGURE 1

State-wise Shannon-Wiener, Simpson, and Stirling indices (left to right) in 1990, 2001, and 2013 (top to bottom). Darker shades represent greater diversity. The shading of the state maps indicates relative diversity compared to other states: the darker states are more diverse than the lighter states.



Growth in natural gas and wind generation, along with the decline in coal-based generation, have had the most pronounced impact on PES diversity over the past 25 years. It's notable and illustrative that the main driver increasing the use of natural gas over this period (especially since the mid 2000s) relates to falling prices as a result of technological innovations on the extraction side, while federal and state policies contributed more directly to the increasing share of wind, especially initially, followed by impressive price declines.

Looking ahead, we see two new drivers on the horizon that could impact diversity in a material way. In particular, the expected explosive growth of solar PV in the coming decades will likely boost all diversity metrics. Similarly, demand-side resources like automated demand response and virtual power plants, as and when they scale up, could also significantly impact all aspects of system diversity.

Diversity alone is unlikely to be a sufficient condition for resilience. But it appears to be a necessary condition when thinking about resilience in the long run. As Andy Stirling put it profoundly: diversity can be our main response against ignorance.

17 | State Level Support for Energy and Electricity: Texas and California Comparison

This white paper on state financial support to electric power generation is a complement to the white paper on federal financial support (Griffiths et al., 2017). Both white papers are contributions to the interdisciplinary project, The Full Cost of Electricity (FCe-), managed by the Energy Institute at The University of Texas at Austin. In total there are sixteen white papers covering a wide range of cost factors from several perspectives.

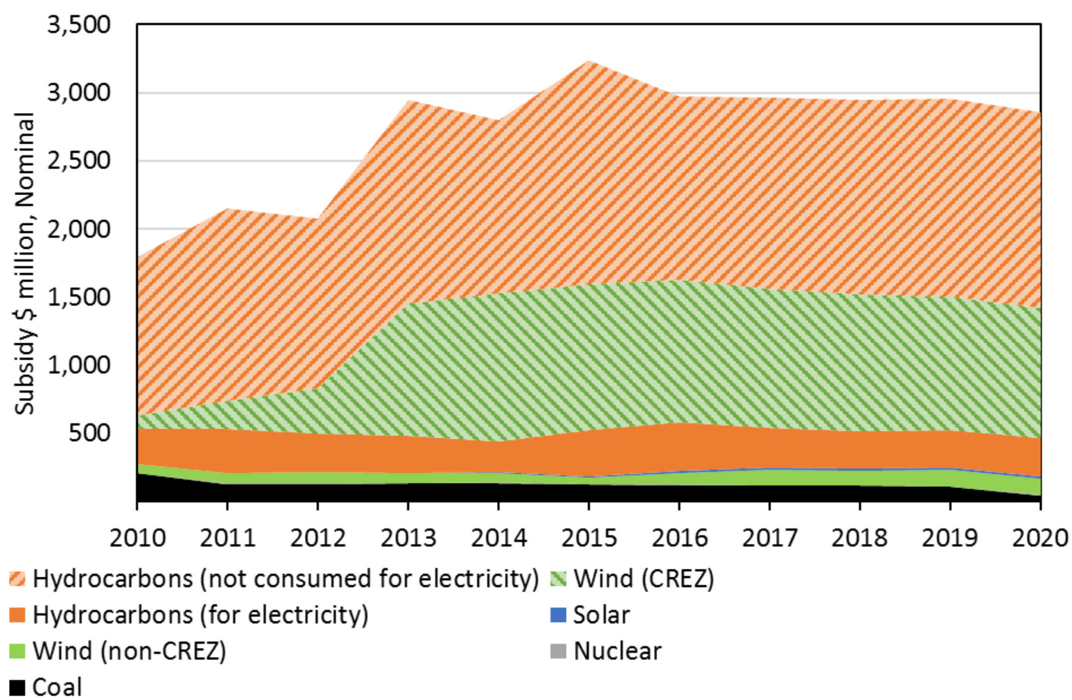
The objective of this white paper is to identify the financial support (subsidies) offered by state governments to different technologies that provide electric power in the states of Texas and California. With that objective, we provide the following points to place this white paper into the larger context of energy and electricity system assessment.

- Both Texas and California offer billions of dollars annually in state-level support of energy production.

Between 2010 and 2019, Texas offers the energy sector financial support worth a total value of approximately \$2–\$3 billion per year. Of this, we estimate that \$0.6 billion in 2010 and \$1.5–\$1.6 billion from 2013-2019 support electricity generation when including the cost of the transmission lines to the Competitive Renewable Energy Zones (CREZ) that connect wind farms to the bulk power grid. If not including CREZ transmission, Texas electricity generation support is \$0.5–\$0.6 billion annually. California offers the electricity sector \$2.5-\$7 billion annually in financial support while the state offers no material

FIGURE 1:

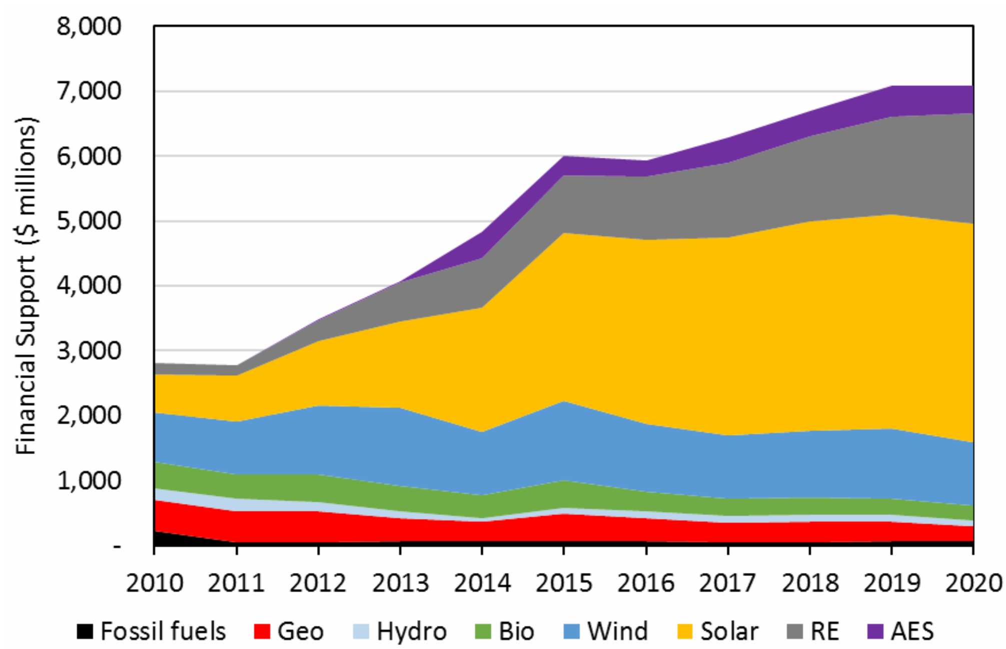
Texas Financial Support for Energy & Electricity by Fuel and Year (\$ million, nominal)



Notes: "Non-CREZ" costs for wind are those related to subsidies that are not the CREZ transmission lines.

FIGURE 2:

California Energy-Related Financial Support by Fuel and Technology ($ million, Nominal)



support to energy outside of the electricity sector. The federal government offers electricity-related support worth $11-$18 billion over the same period [Cite the federal subsidy paper].

- Renewables receive significantly more support than conventional technologies on a $/MWh basis, and $/MWh value for renewables is declining rapidly over time.

The report calculates at $/MWh value of financial support on a technology-wide basis (e.g., all generation from a technology within a state in a given year), not project-specific basis.

Depending on the year, Texas' conventional generation receives $0-$2/MWh while wind receives $16-$30/MWh (including CREZ) or $2-$3/MWh (excluding CREZ) and solar receives $257/MWh in 2010 declining to $10/MWh by 2018. California renewables receive from $56-$102/MWh while other sources receive negligible support. In California, the support for wind declines from $56/MWh to $40/MWh over the study period, the support for solar drops from $602/MWh to $96/MWh, and other renewables receive constant support at or below $50/MWh.

- California offers more support per MWh and per capita than the Federal Government while Texas support is similar, some years offering more, and some years less when including CREZ, but always less when excluding CREZ.

The total value of financial support to the electricity sector from the state of Texas in 2016 is valued at $59/Texan and $20/Texan with and without CREZ, respectively. California's support is worth $153/Californian. Federal support is worth approximately $37/American. [11]

- Texas and California differ in distribution of financial support for energy and electricity technologies
    - Texas generally uses its financial

FIGURE 3:

Texas $/MWh Financial Support by Type & Fuel (annual $ nominal divided by annual generation per fuel)

Note: that per-MWh costs of Solar and Wind (with CREZ $) are much higher than the vertical scale of the inset graphic.

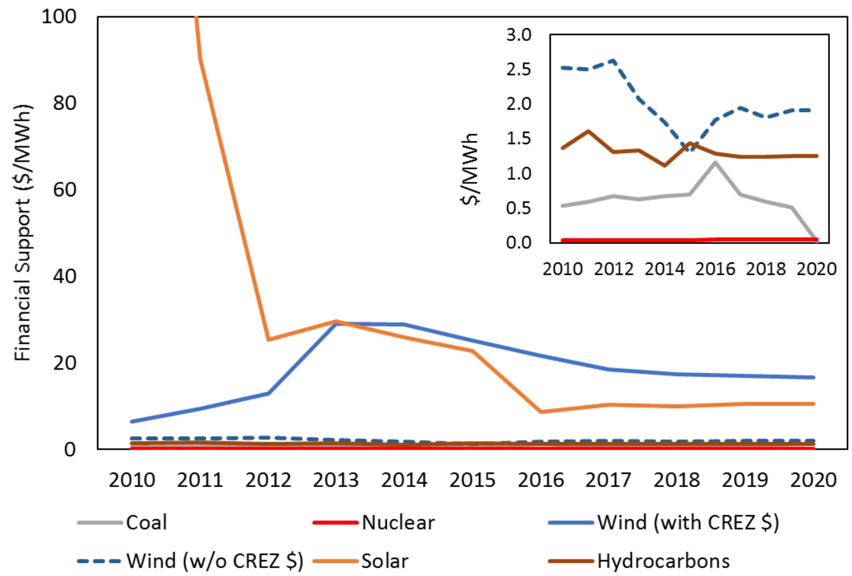
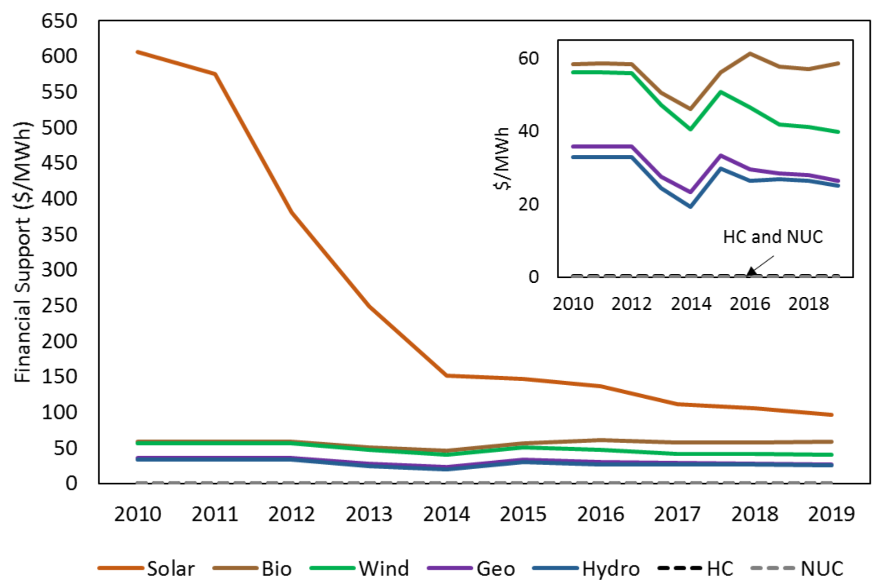


FIGURE 4:

California Volumetric Financial Support for Electricity ($/MWh)



support for economic development while California uses it to meet environmental goals and to drive down the cost of new technologies.

- California directs all of its financial support to a diversified portfolio of renewable electricity technologies while Texas splits its support between hydrocarbon extraction (leading to natural gas-fired electricity) and wind capacity additions.

- Texas offers support using a mixture of direct expenditures, mandates, and tax expenditures. California offers more than 90% of its support through mandates.

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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