Envisioning the Electric Utility in 2030: “Fat” or “Skinny”?

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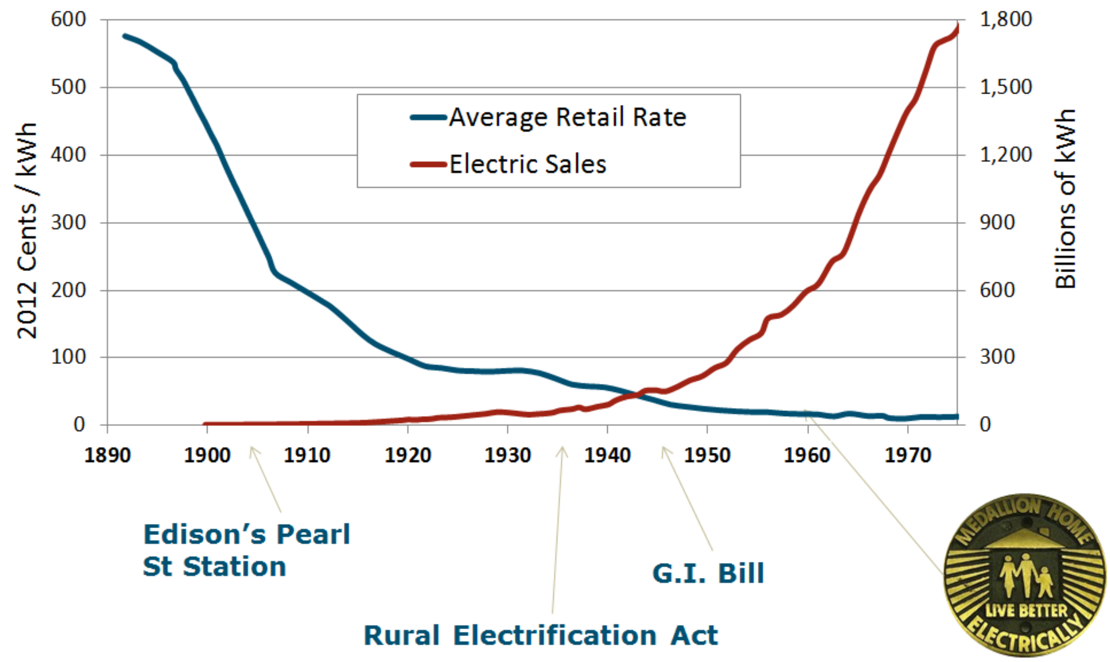
This paper describes the need for state legislators and regulators to ask themselves, and for utilities to begin to plan for, what they want the utility of 2030 to do. The paper first describes the shifting fortunes of electricity utilities, from a golden era of growth to the prospect of death spirals. It makes a case for why the electric grid, and regulated utilities, will continue to play an important role in the electricity system of the future, exploring the questions that this raises for legislators, regulators, and utilities. Drawing on recent experience in Hawai’i, California, and New York, the paper then argues that there is an inherent tension between using utilities as a vehicle for financing the implementation of public policy goals, and expanded retail-side competition and customer choice. It concludes by laying out two rational models for the utility in 2030 — fat or skinny.

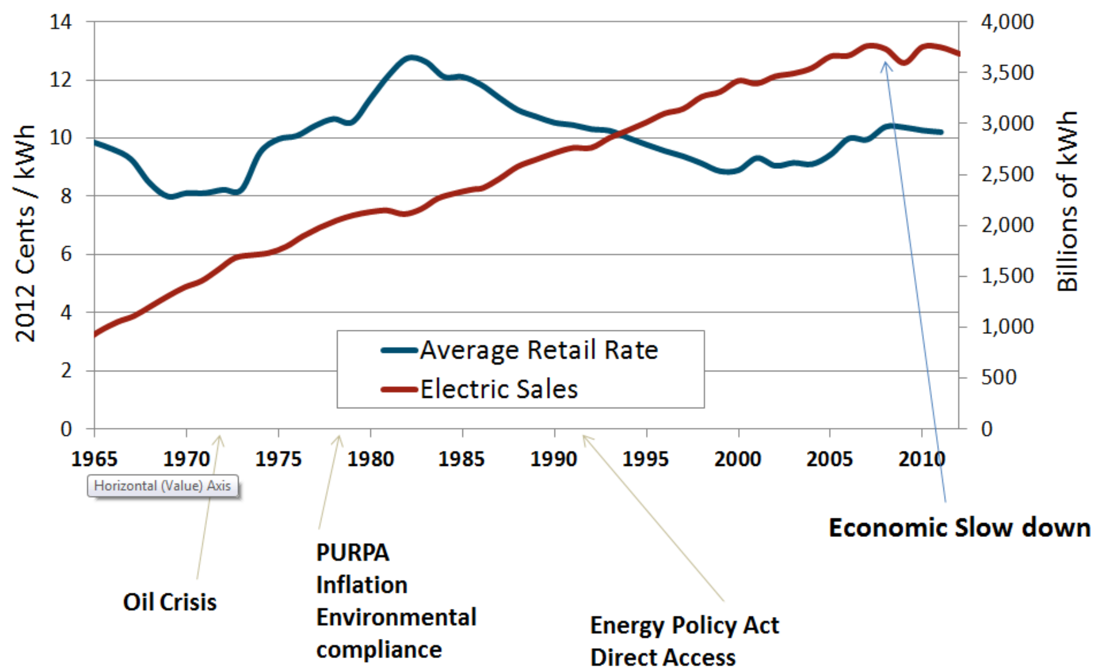
Shifting Fortunes for Electric Utilities: From a Golden Age to Death Spirals

For much of the last century, the U.S. electric industry enjoyed a virtuous cycle of growth and prosperity. Regulated electric utilities were provided a guaranteed rate of return on investment, in exchange for maintaining an obligation to serve all customers in their service area. Sales growth and economies of scale brought down prices, which in turn increased sales as a host of new electric appliances and equipment came to market (Figure 1). Lawmakers and regulators oversaw the industry with a light hand.

Figure 1. U.S. Electricity Sales and Average Prices, 1890-2014



Rate sources: Edison Electric Institute Pocketbook of Electric Utility Industry Statistics 1984 and EIA
Sales sources: Edison Electric Institute Pocketbook of Electric Utility Industry Statistics 1988 and EIA



Rate sources: Edison Electric Institute Pocketbook of Electric Utility Industry Statistics 1984 and EIA
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This golden era of the utility business model came to an abrupt end in the 1970s, as oil crises, slowing demand, inflation, environmental regulation, and slowing technological progress led to significant increases in costs (Figure 1).[1] In response, lawmakers and regulators strengthened their hand. At the federal level, Congress forced open vertically integrated utilities with the passage of the Public Utilities Regulatory Policy Act (PURPA) in 1978, requiring utilities to procure electricity from third parties as long as it was cheaper than supplying it themselves. Congress' 1992 Energy Policy Act and subsequent orders by the Federal Energy Regulatory Commission (FERC) set the stage for even greater competition in the sector, by requiring utilities to provide non-discriminatory access to their transmission systems.[2]

At a state level, regulators in many states required utilities to establish demand-side programs designed to cost-effectively reduce sales, and incorporate these into public regulatory proceedings on investment planning — an approach known as integrated resource planning. In the 1990s, some states restructured their electricity sectors, opening the generation and retail segments to competition. These federal and state regulatory developments led significant changes in the form and function of electric utilities, relative to the golden era of vertical integration and sales growth.

Despite these changes, throughout the 1970s to the early 2000s the value of the electric grid — the vast network of transmission and distribution lines that transports power from power plants to consumers — was never in question. Similarly, few questioned the role of regulated utilities in owning and maintaining the grid.

The emergence of new and lower cost distributed energy technologies — technologies like rooftop solar photovoltaics and the prospect of inexpensive home batteries — in the late 2000s and early 2010s prompted radical departures in thinking about the future of the grid and utilities. Industry pundits now warn of a "death spiral," where rapid adoption of distributed technologies leads to declining electricity sales, which requires utilities to increase retail electricity prices to recover their fixed costs, leading to further adoption of distributed energy and more lost sales. Some argue that leaving the grid altogether, through a combination of rooftop PV and battery storage, will soon be cost-effective in many areas.[3]

These prognostications raise the prospect that regulated electric utilities, and the grid along with them, might disappear.

Why Maintaining the Electric Grid is an Important Public Policy Goal

Arguments for the demise of the electric grid, and the regulated utilities that own it, are not simply premature; they also rest on analytically flawed foundations. The value of the grid is twofold: (1) it enables trade, among a diverse mix of electricity producers and consumers; and, relatedly, (2) it provides a source of low marginal cost storage for a commodity that is very expensive to store through other means.

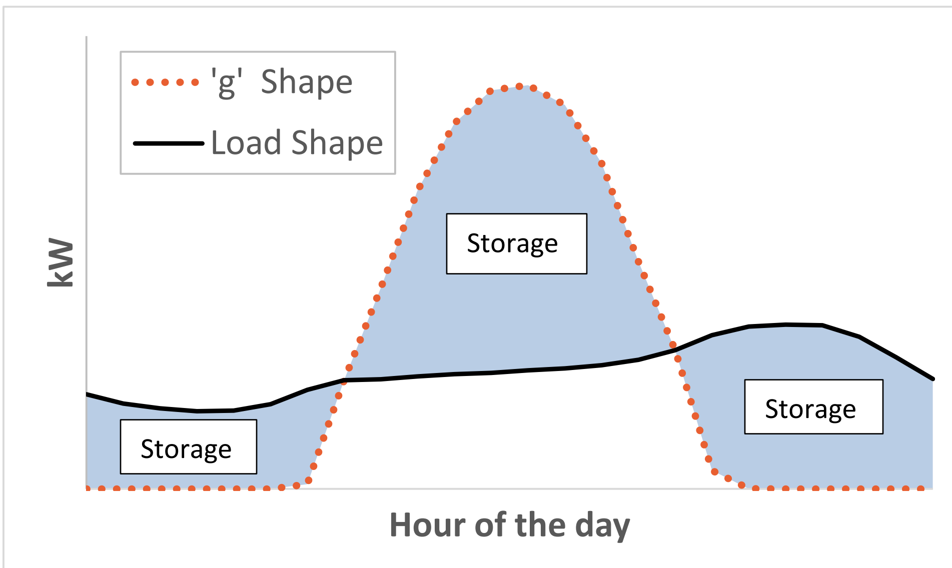
These values are best illustrated by examining the economics of leaving the grid, such as through a PV-battery system. To be entirely independent from the grid, both the PV system and the battery must be

[1] For more on the electricity sector transition during this era, see Kahn (1988) and Hirsh (2002).
[2] Fox-Penner (1997) provides a lucid history of the foundations and introduction of competition in the U.S. electricity sector.
[3] See, for instance, Abromowitz et al. (2014)

sized to meet a large portion of, or all, future electricity consumption. Doing so requires these systems to be "oversized," to account for both the energy needs of each individual customer and a range of uncertainties — consecutive cloudy days, new electric equipment, new family members, business growth. As a result, the last unit of electricity consumption from off-grid PV-battery systems, or its marginal cost, will be very expensive because most of the PV system and battery's capacity will sit idle for most of the time.

Figure 2 provides a simple illustration of the significant amount of storage that is avoided by pooling generation and loads over the grid. The figure shows a typical daily load shape for a residential customer, typical PV output, and the storage needed to meet a single customer's energy needs without the benefits of a grid. The need to maintain reliability and also provide for variation in consumption patterns would increase the storage requirements even further.

Figure 2. Illustration of Daily Storage Needed for Stand-Alone Single Customer with PV

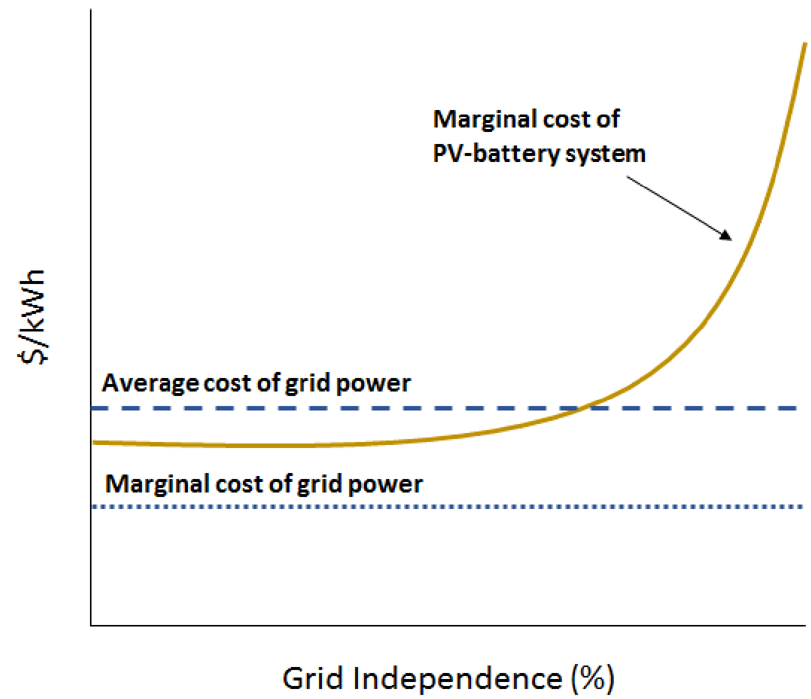


By contrast, the grid makes full use of both the substantial diversity in load shapes across different types of customers and the storage of the fuel of many of the resources connected to it. As such, the marginal cost of power delivered by the electricity grid is and will continue to be relatively inexpensive. Most of the grid has very low marginal costs, because its investment costs are largely sunk.[4] In most cases, the marginal cost of generation on the grid will either be the variable (mostly fuel) cost of thermal generation ($0.02-0.04/kWh) or the near-zero cost of hydro, nuclear, wind, or solar power.[5] The average cost of grid power depends primarily on the use of the grid — more users and more use will tend to drive down average costs.

[4] In this formulation, the marginal costs of the grid are primarily line losses and variable maintenance costs.
[5] For instance, $0.04/kWh would imply a relatively inefficient natural gas generator (10,000 Btu/kWh net heat rate) with delivered natural gas costs ($4.00/MMBtu). Nominal natural gas prices for electricity are currently (as of mid-2016) less than $3/MMBtu. See http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

The marginal cost of the PV-battery system, as opposed to its average cost, will generally be much higher than the average cost of grid power, let alone its marginal costs, as the degree of a customer's independence from the grid increases (Figure 3). This fact underscores the grid's option value in facilitating trade among and between electricity producers and consumers. The economically optimal size of a PV-battery system will almost never be large enough to cover an entire facility or home's electricity consumption. In other words, even for customers who have their own generation and storage devices, consuming some amount of power from the grid will almost always be cost-effective.

Figure 3. Illustration of PV-Battery Costs Relative to the Marginal and Average Cost of Grid Power[6]



Thus, regardless of thinking on choice and competition and the evolution of storage and other distributed energy resources, there is a clear and strong public policy case for ensuring the continued maintenance, and in some cases modernization, of the electric grid.

Critical Questions for Legislators, Regulators, and Utilities

Answering questions surrounding the future upkeep and upgrade of the electric grid requires state legislators and regulators to address three fundamental questions about the role of utilities and the framework for regulating them:

1) What do states want utilities to do?
2) What utility form and function best suits that role?

[6] Grid independence is defined as the percentage of baseline electricity consumption that is offset through own supply of electricity. This figure is intended to be illustrative. The average and marginal cost of grid power, for instance, likely change as a function of grid independence.

3) What regulatory frameworks are most consistent with that role?
4) Are the changes implied by states' answers to questions 1, 2 and 3 politically feasible over some reasonable time horizon?

As legislators and regulators consider these questions, electric utilities should also develop clear, well-reasoned responses.

What do States Want Utilities to do?

Electric utilities — private, public, and non-profit[7] — have long played a role in implementing public policy in the United States. Utilities were instrumental in expanding electricity access across rural areas in the 1930s. They played a cooperative role in the development of federal power and transmission in the 1940s and 50s. Since the 1980s, utilities have collaborated with regulators and stakeholders to expand renewable energy and improve end-use efficiency. More recently, they have partnered with federal and state agencies to safeguard the grid against cybersecurity attacks and extreme weather events.

Utilities' role in implementing public policy has persisted even as their form and function has changed. For instance, utilities in states that have introduced retail competition often continue to implement state policies for renewable energy, energy efficiency, distributed generation, electric vehicles, default electricity service, and low-income customers.

Going forward, the extent of utilities' role as implementers of public policy will be tested by state and federal climate policies. Achieving state climate goals, such as in California and New York, will likely require significant investments in energy efficiency, low- to zero-CO_2 generation, electricity storage, and electric vehicle charging infrastructure. More broadly, President Obama's signature federal climate initiative — the Clean Power Plan — will spur clean energy investments in a number of states if it is upheld in court. A key question for lawmakers and regulators is the extent to which these investments should be financed, procured, or owned by regulated utilities, by private entities, or by the public sector directly.

What Utility Form and Function Best Suits that Role?

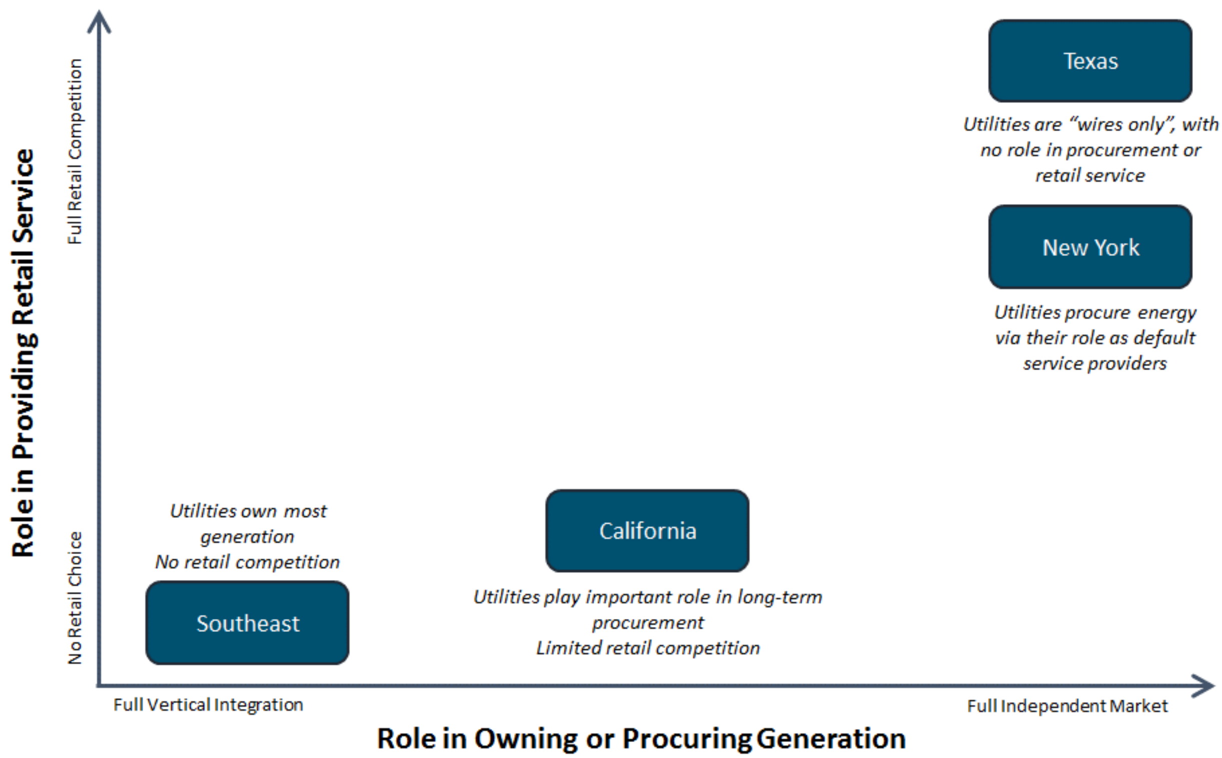
Electric utilities in the U.S. are extraordinarily diverse, ranging from more traditional, publicly- and privately-owned vertically integrated utilities that own and operate power plants, transmission lines, and distribution systems, to investor-owned distribution utilities that only build, own, plan, operate, and maintain the distribution system.

Across these different industry structures, utilities fall along a spectrum of different models, based primarily on their role in owning or buying ("procuring") generation and providing retail service (Figure

[7] Investor-owned utilities, municipally-owned utilities, and rural electric cooperatives are the three largest forms of "electric utility" in the U.S., accounting for 91% of electricity customers and 87% of electricity sales in 2014. Among these, investor-owned utilities are the largest, accounting for 65% of customers and 61% of sales. Data are from EIA, "Electricity," http://www.eia.gov/electricity/data.cfm#sales.

4). At one extreme, vertically integrated utilities typically own most of the generation in their service territory and do not have competitive retail sectors (e.g., the U.S. Southeast). California, in the middle, has limited retail competition and a competitive wholesale market for generation, though utilities continue to play an important role in long-term procurement. In jurisdictions with competitive retail sectors (e.g., New York), utilities often act as default service providers, procuring generation for customers through short-term contracts. In Texas, distribution utilities play no role in procurement or retail service.

Figure 4. Spectrum of Utility Models, Based on Utilities' Role in Providing Retail Service and Owning or Procuring Generation



Different utility models present tradeoffs for lawmakers and regulators. Competition in generation and retail are designed to wring economic inefficiencies out of formerly monopolistic market segments. However, outcomes in competitive markets are not as easily steered by public policy as the investment decisions of a regulated firm. As utility form and function tend toward vertical integration, lawmakers and regulators can generally exert a greater degree of policy and regulatory leverage over the electricity industry. Vertically integrated utilities can also exploit vertical economies, lower transaction costs, and more open internal flow of information. However, this comes at an increasing cost of regulatory effort, less competition, lower external transparency, and less retail choice. The continued plurality of utility models across the United States illustrates the lack of consensus on how these tradeoffs should be best resolved.

What Regulatory Frameworks are most Consistent with that Role?

There are, however, fundamental incompatibilities between different utility models and the regulatory frameworks governing competition and choice, on the one hand, and long-term policy-driven financial obligations on the other.

We define 'regulatory frameworks' broadly. For our purposes, we focus on five elements of a regulatory framework: (1) whether and how utilities are required to connect distributed generation to the electric grid ("network access"); (2) the extent to which utility customers are allowed to choose among electricity supply options ("retail choice"); (3) how retail electricity prices are designed and determined ("retail ratemaking"): (4) how distributed energy resources are valued, for the purposes of programs and incentives ("DER valuation"); and (5) the extent to which federal, state, or local policy goals are implemented through utilities ("policy goals").

Within each of these five categories, regulators must choose among competing approaches (Figure 5). The sum of these regulatory decisions determines the extent of competition and choice in the electricity sector, and cost recovery mechanisms, long-term financial obligations, and sources of uncertainty and risk for utilities. For example, a pro-competition open access regulatory policy designed to provide retail choice at either the wholesale or retail level brings a substantial amount of pressure on regulators to correctly unbundle rates to avoid cross subsidization between participating and non-participating customers. Conversely, if customers are not allowed to exit regulated service, retail rates can be designed to achieve policy goals, such as price stability or energy efficiency.

Figure 5. Competing Decisions for Regulatory Frameworks

Area	Options
Network Access *Connection and access to the distribution system*	a) No connection or access requirements b) Mandatory connection, but not system open access c) Mandatory connetion and open access
Retail Choice *Customers' ability to choose a provider or energy source*	a) Utility as sole retail provider b) Limited competition and distributed generation c) Fully competitive retail market
Ratemaking *Design and setting of retail prices*	a) Non-cost based (e.g., tiered pricing) b) Average cost-based c) Marginal cost-based
DER Valuation *Valuation and remuneration of distributed energy resources*	a) Policy-based (e.g., net energy metering) b) Avoided cost-based c) Competitive market-based
Policy Goals *Implementation strategies for state policy goals*	a) Utility implements broad policy goals (e.g., climate policy) b) Utility implements resource-specific goals (e.g., renewable energy) c) Utility plays limited to no role in policy implementation

Are the Changes Implied by State Priorities Politically Feasible?

The utility regulatory process has long been a venue for addressing concerns of different stakeholder groups, which also means that it is a political process. For instance, environmental advocates use the regulatory process to push for clean energy policies and programs, and stricter controls or closure of polluting plants. Consumer and low-income advocates push for rate structures that limit cost burdens on households. Producers target rents through technology subsidies and set asides, while the general business community typically prefers that electricity be provided at lowest possible cost. The preferences of these and a host of other interests, layer political constraints onto the regulatory process. These constraints shape the scope and process for making major changes to utility form and function and regulatory frameworks.

Today, interest group politics are aligning such that contradictory policies within regulatory frameworks are emerging, often with powerful interest groups behind them. As an example, some environmental advocates support both net energy metering and requirements that utilities serve as financial off-takers for clean energy contracts.[8] By taking this position, environmental advocates have created politically powerful partnerships with clean energy business groups. Regulations that increase the market share of clean energy technology firms can also increase these companies' political power.[9] For example, the political power of this clean energy coalition was evident in the extension of California's net energy metering policy, described in greater detail below.

Understanding the opportunities and constraints imposed by stakeholder politics will be critical for lawmakers and regulators, in order to achieve any long-term vision for utilities. Political feasibility is dynamic and can be shaped through constituency-building, but this process takes both time and effort. For instance, moving from a more competitive model for generation and retail to one that is more monopolistic requires some amount of buy-in from a variety of groups: investor-owned utilities, public utilities, competitive energy companies, consumer advocates, business groups, environmental groups, labor unions, and state and local government.

Evolving Utility Models and Regulatory Frameworks in Hawai'i, California, and New York

The evolution of policy goals, utility models, and regulatory frameworks in Hawai'i, California, and New York illustrates an emerging tension in the future of the utility, between customer choice and utilities as a vehicle for public policy. Hawai'i, California, and New York are at the forefront of state clean energy policy in the United States. All three states have combined aggressive policy goals for GHG emission reductions, renewable energy, and energy efficiency with support for distributed generation. However, each state has taken a very different approach to modifying utility models and regulatory frameworks to meet these goals, shaped by both physical realities and political constraints.

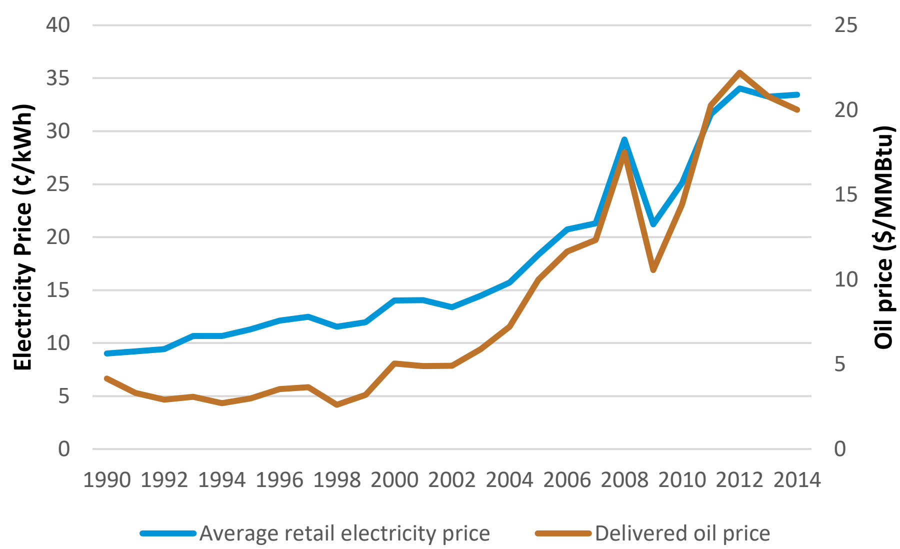
[8] Joint Commentators, 2014.
[9] Pierson, 2000.

Hawai'i

Hawai'i's electricity system consists of small, isolated grids on six main islands, with electricity service provided by three vertically integrated utilities — Hawai'ian Electric Company (HECO, Oahu), Maui Electric Company (MECO, Maui, Lanai, Molokai), and Hawai'i Electric Light Company (HELCO, Hawai'i) — and one cooperative — the Kauai Island Utility Cooperative (KIUC, Kauai). The three investor-owned utilities ("HECO Companies") are collectively owned by Hawai'ian Electric Industries, and regulated by the Hawai'i Public Utilities Commission (HPUC).

At 33¢ per kWh, Hawai'i's average retail electricity price in 2014 was more than three times the U.S. average (10¢/kWh), and nearly double the next highest state (17¢/kWh).[10] By contrast, in the early 1990s Hawai'i had lower electricity prices than seven states, including California.[11] Significant increases in Hawai'i's electricity prices over this time period were driven, in large part, by rising oil prices (Figure 6) and the state's continued reliance on imported oil as its main source of electricity generation.

Figure 6. Average nominal retail electricity price and delivered oil price, Hawai'i, 1990-2014



Source: Data are from EIA, "Hawai'i Electricity Profile 2014," https://www.eia.gov/electricity/state/Hawai'i/.

In response to high and rising electricity and oil prices, Hawai'ian legislators set renewable energy and energy efficiency goals that are the most aggressive in the U.S. Act 97, signed into law in 2015, sets a 100% renewable portfolio standard (RPS) by 2045, with interim targets for 2020 (30%), 2030 (40%), and

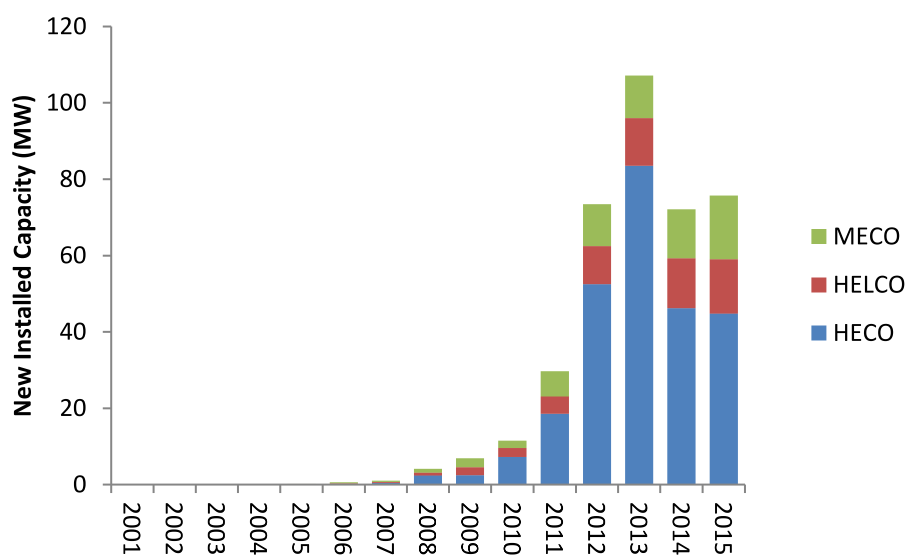
[10] Data are from the U.S. Energy Information Administration's (EIA's) EIA-826 monthly survey, http://www.eia.gov/.
[11] Ibid.

2040 (70%). Act 155, passed in 2009, establishes an energy efficiency portfolio standard of 4,300 GWh, or 45% of 2014 retail electricity sales, by 2030.[12]

Hawai'i's legislature passed legislation (SB120) in 2012 directing the HPUC to establish the incentive and regulatory framework to encourage utilities to lower retail prices while achieving the state's clean energy goals. In the same year, the HPUC initiated an IRP proceeding, instructing the three investor-owned utilities to develop an action plan for meeting state policy goals at reasonable cost, while maintaining safety and reliability.[13]

Dramatic growth in distributed generation in Hawai'i began in 2012, encouraged by a combination of high retail prices, falling prices for distributed PV, and a net energy metering, or NEM, tariff. Over the course of five years, customers in MECO, HELCO, and HECO installed 246, 54, and 58 MW, respectively, of net energy metered generation (Figure 7), equivalent to 22%, 29%, 30% of 2013 peak demand in the three systems.[14]

Figure 7. New Installed Net Energy Metered Generation Capacity in MECO, HELCO, and HECO, 2001-2015



Source: Data are from HECO Companies (2015)

Rapid adoption of rooftop PV had a significant effect on utility operations, as utilities had little ability to "see" or control generation from these systems. The utilities anticipated financial risks as well. A study supported by the HECO Companies estimated that, by 2020, they would be required to curtail a significant portion of their own renewable generation — either owned or contracted — in order to

[12] Retail sales data for 2014 are from EIA, "Hawai'i Electricity Profile 2014," https://www.eia.gov/electricity/state/Hawai'i/.
[13] HPUC, 2012.
[14] HSEO, 2015.

accommodate continued growth in distributed PV generation.[15] The HECO Companies' response to perceived risks from distributed generation was to limit grid access, restricting the amount of PV that could be interconnected to distributed feeders based on engineering rules-of-thumb. These limits led to a long queue of applications from customers wanting PV on their roofs.

Faced with mounting customer complaints and determining that the utilities were not proactively identifying strategies and new business models to lower costs, achieve state goals, and meet changing customer needs, the HPUC seized initiative. In 2014, it rejected the HECO Companies' IRP report, outlining its own vision of how the utilities' business model could be better aligned with customer interests and state policy goals.[16] The HPUC proposed that the utilities move toward a "network system integrator and operator" model: gradually divesting themselves from generation, enabling interconnection and integration for both utility-scale independent power producers and distributed energy resources, and focusing on resource planning, system operation, and grid system investment.[17]

To facilitate this new role, the HPUC required the HECO Companies to file two plans detailing: (1) how they would achieve fully renewable electricity systems, as required in Act 97, and (2) how they would improve distribution systems to proactively facilitate more distributed generation.[18] The HPUC also replaced the state's net energy metering policy with a new tariff that significantly lowers the credits given to owners of distributed generation.[19] The Commission expressed a need to enact significant changes in retail prices,[20] though it has yet to begin the proceedings to do so.

In Hawai'i, the rapid emergence of distributed generation has already triggered a reconsideration of the role of utilities and the framework for regulating them. The HPUC is encouraging more competition in utility-scale generation and at the distribution system through a combination of direct mandates, more open distribution system access, and changes in wholesale and retail rate design. However, given the small size of Hawai'i's electricity systems there are practical limits to competition. The utilities will likely continue to play a role in owning or procuring generation and providing retail service, though this role remains unresolved.

California

California has a large and diverse electricity system. Electricity suppliers include three investor-owned utilities (PG&E, SCE, SDG&E), two large municipal utilities (LADWP, SMUD), and a number of other publicly-owned utilities. The state's electricity sector was partially restructured in 1999, resulting in the

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[15] See HECO filing in PSIP Update Report, April 1, 2016.
[16] HPUC, 2014.
[17] Ibid.
[18] These two plans were a Power Supply Improvement Plan (HECO Companies, 2014a) and a Distributed Generation Interconnection Plan (HECO Companies, 2014b).
[19] More specifically, the HPUC created two tariffs: (1) customer grid-supply (CGS), in which customers receive a fixed credit ($/kWh) for the lower of their net monthly consumption or their net monthly generation, and (2) customer self-supply (CSS), in which customers consume most or all of their own generation, are not compensated for net power exported to the grid, but are eligible for expedited review and approval. CGS, notably, has the effect of encouraging distributed generation owners to increase their net consumption.
[20] HPUC, 2014.

California electricity crisis of 2000 to 2001. California's electricity market survived the crisis, and much of the state's current regulatory and planning infrastructure evolved out of the crisis.[21] As a result, California is sometimes described as having a "hybrid" electricity market, combining a wholesale electricity market and procurement guidelines with extensive regulatory programs.

California's investor-owned utilities operate in a limited retail choice environment. The California legislature suspended the state's "direct access"[22] programs in 2001, in response to the electricity crisis, capping it at preexisting levels.[23] The state legislature marginally relaxed these limits in 2010 and proposed to do so again in 2015.[24] Separately, California has a growing number of "opt-out" (as opposed to "opt-in") community choice aggregation (CCA) programs, which enable cities or counties to procure electricity on behalf of their citizens, effectively replacing the investor-owned utilities' role in procurement. CCA customers must pay a power charge indifference adjustment (PCIA) — effectively an exit fee — to cover the stranded costs of past commitments the utilities had entered into on behalf of these customers.

California lawmakers implement state energy policy through technology-specific targets and programs, which are then implemented by state agencies. For instance, the state legislature recently adopted a 50% RPS target for 2030, which is implemented through the California Public Utilities Commission's (CPUC's) RPS program. California also has a goal of installing 12,000 megawatts (MW) of distributed generation by 2020, which the CPUC has implemented using a combination of utility incentive programs, net energy metering, and retail pricing. This programmatic, multi-pronged approach reflects a preference to accomplish state lawmakers' policy goals through regulated utilities. The result is a multitude of clean energy policy commitments (Table 1) and a complicated regulatory environment.

Table 1. Area-Specific Clean Energy Policy Commitments in California

Area	Goal	Legislation or Plan	Implementing Program(s)
Renewable energy	50% of retail electricity sales by 2030	Senate Bill 350	CPUC RPS Program
Distributed generation	12,000 MW of distributed generation by 2020	Clean Energy Jobs Plan (Governor goal)	CPUC California Solar Initiative, CPUC Net Energy Metering Program[25]
Energy storage	1,325 MW of energy storage by 2020	Assembly Bill 2514	CPUC Energy Storage Procurement Framework and Program

[21] For instance, the state's Resource Adequacy program began in 2006 in response to the crisis (CPUC, 2015a); its Long-term Procurement Planning proceeding was an extension of Assembly Bill 57 (2002), which allowed utilities to resume procurement after the crisis subject to the CPUC's approval of their procurement plans (CPUC, 2012).
[22] "Direct access" refers to a market where larger (usually industrial) customers are allowed to buy power directly from suppliers.
[23] CPUC, 2001.
[24] CPUC, 2010; Hertzberg, 2015.

Energy efficiency	Doubling of energy efficiency savings over current plan by 2030	Senate Bill 350	CEC building codes and standards, CPUC utility demand-side programs
Building energy	All new construction meets zero net energy (ZNE) standard by 2020	Statewide Energy Efficiency Strategic Plan	CEC building codes and standards

Within this context, conflicts between the form and function of utilities are emerging, most visibly in two highly contentious areas: net energy metering and the PCIA charge for CCAs.

The mechanics of net energy metering are important for understanding why it is so controversial. Particularly for residential customers that own rooftop PV, there may be a discrepancy between electricity generation and consumption. The PV system generates electricity during the day when, often, no one is home, "exporting" it to the grid. Households consume electricity from the grid largely in the morning and at night, when the PV system has little to no output. Under net energy metering, the distributed generation owner is compensated for exported electricity by netting the export quantity (in kilowatt-hours) from their electricity bill, effectively paying them for this electricity at their retail rate.

For larger residential customers, electricity prices in California have historically been well above average cost. Following the electricity crisis, the CPUC froze prices for smaller customers and allowed larger customers to absorb cost increases. This rate structure provided a growth platform for residential solar providers, as net metering of solar PV often lowered the electricity bills of larger electricity customers. For utilities, growth in distributed generation materialized as reduced demand, increasing their fixed costs per unit sales and leading to cost shifts across customers that owned and did not own PV.[26]

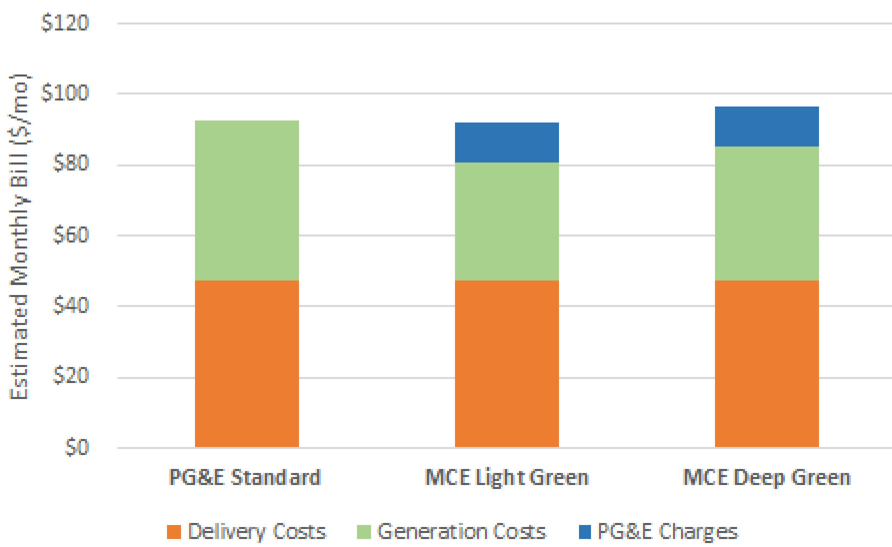
The CPUC sought to address these issues in two separate proceedings in 2014 and 2015. The first, focused on retail rates, considered revisions to tiered residential rates. The second considered revisions to the net energy metering policy. Utilities and stakeholders drew familiar battle lines. The utilities argued for marginal cost-based compensation for distributed generation, and time-of-use rates and demand charges for customers with distributed generation. Solar industry and environmental advocates opposed. The CPUC ultimately decided to make incremental changes to the tiered rate structure, though it established a plan to move all residential customers to time-of-use rates by 2019.[27] On net energy metering, it essentially decided to maintain the status quo and revisit the issue in 2019.[28]

Continued development of CCAs has elicited a similar melee. Although the primary goal of CCAs is often to be greener than the utilities, providing lower and more stable electricity bills is an additional selling point. For instance, residential customers under Marin Clean Energy's (MCE's) "Light Green" tariff typically have slightly lower monthly bills than comparable PG&E customers (Figure 8), despite the fact

[26] E3, 2013.
[27] More specifically, the CPUC flattened the tier structure, decreasing the distance between the highest and lowest tiers. CPUC, 2015b.
[28] CPUC, 2016.

that MCE's supply portfolio contains nearly twice as much renewable energy as PG&E's.[29] Customers on MCE's "Deep Green" tariff can be served entirely by renewable energy for roughly a $5 per month premium over PG&E rates.

Figure 8. Comparable Monthly Bills for a Residential Customer Consuming 463 kWh Per Month, under PG&E Standard Rates and MCE Light Green and Deep Green Rates[30]



CCAs have been able to lower their costs relative to the utilities for a number of reasons. Because the cost of renewable energy has fallen precipitously — by more than 50% for solar PV[31] — over the past five years, utilities' older renewable energy contracts are much higher cost than a new contract. CCAs can thus buy "new" renewable energy more cheaply than the utilities' average cost for "old" renewable energy. CCAs are also able to buy inexpensive renewable energy credits ("RECs") to green their supply portfolios. Utilities that are subject to RPS requirements can sell the RECs, or renewable energy premiums, from renewable energy that they do not need to meet RPS requirements. Because utilities over-procured to meet RPS targets, the cost of "unbundled" RECs is significantly lower than the cost of procuring new renewable generation. Additionally, CCAs have eschewed the inclining block rate structure, leading to lower rates for households with higher electricity consumption.

These price advantages are counterbalanced by the PCIA exit charge, which is typically equivalent to more than 10% of residential CCA customers' bills.[32] The PCIA has its roots in the aftermath of the

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[29] In 2014, the latest year for which power content labels are available from the California Energy Commission (CEC), MCE reported that eligible renewables accounted for 56% of its energy; for PG&E, the equivalent value was 27%. See CEC, "Utility Annual Power Content Labels for 2014," http://www.energy.ca.gov/pcl/labels/.
[30] Based on rates that are effective September 1, 2016. At previous rates, MCE's Light Green was $4.17 more expensive per month than the comparable PG&E rate. The "PG&E Standard" rates are based on the E-1 residential tariff. Example is from the MCE website, https://www.mcecleanenergy.org/residential-rates/.
[31] Bolinger and Seel, 2016.
[32] See, for instance, MCE, "The Power Charge Indifference Adjustment (PCIA) and its Impacts on CCA Customers," http://www.sandiegoenergydistrict.org/uploads/9/1/7/4/9174546/mce_pcia_overview_10.20.15.pdf.

electricity crisis. In 2004, as part of its approval of the utilities' long-term procurement plans, the CPUC noted that

> *"While we recognize that the potential CCAs want to limit the amount of cost responsibility surcharge applied to departing CCA customers for utility liabilities incurred on their behalf when the CCA customers leave utility service, Pub. Util. Code § 366.2(h) requires that the Commission authorize community choice aggregation only if the Commission imposes a cost recovery mechanism in accordance with the law."*[33]

The cost recovery mechanism was intended to "ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers"[34] — an indifference adjustment.

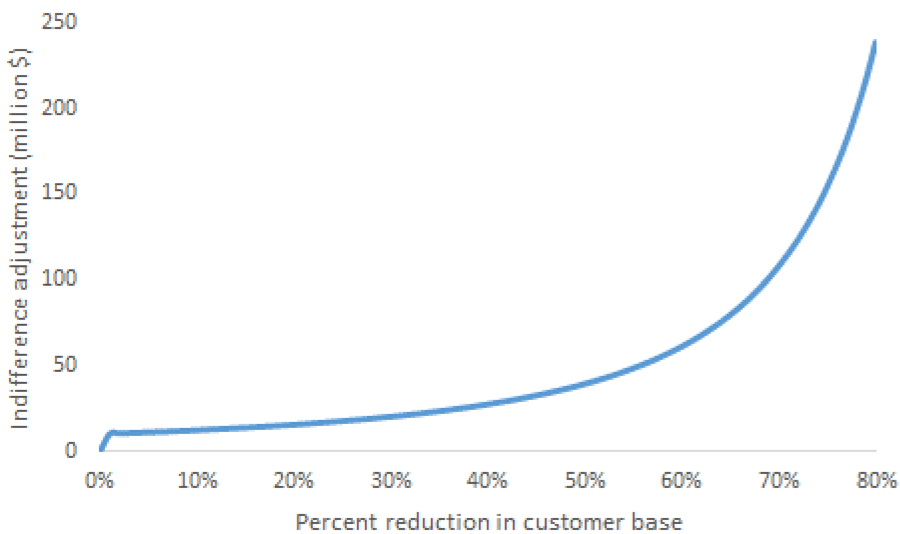
In addition to statutory requirements, the CPUC also noted concern that the lack of a recovery mechanism for stranded costs would disincentivize utilities from signing long-term contracts, both thermal contracts required to regain and maintain long-term resource adequacy and renewable contracts required to meet nascent state goals for renewable energy.[35] Consistent with these notions, the PCIA requires CCA customers and other departing loads to pay the above-market cost of long-term resource obligations that the utilities entered into on behalf of these customers. This includes recent state policy goals. For instance, the utilities are currently developing a proposal for contracts procured as part of the state's energy storage mandate to also be included in the PCIA.[36]

CCAs and local governments have strongly opposed the PCIA charge, arguing that it unfairly allocates costs to CCA customers, that utilities are unethically levying the PCIA on low-income customers, that utilities are not properly preparing for departing loads in their demand forecasts, and that utilities are incorrectly calculating the indifference adjustment.[37]

Compounding the challenge of reconciling utility and CCA interests is the PCIA's nonlinear nature. In general, exit fees increase nonlinearly as the number of departing customers increases, because a fixed quantity of costs is spread across an increasingly smaller denominator (Figure 9). This implies that the PCIA would grow significantly if the number of CCAs were to continue to increase.

[33] CPUC, 2004.
[34] Ibid.
[35] Ibid.
[36] PG&E, SDG&E, and SCE, 2016.
[37] See, for instance, MCE, "The Power Charge Indifference Adjustment (PCIA) and its Impacts on CCA Customers"; El Cerrito City Council, "Power Charge Indifference Adjustment Exit Fee Charged to Community Choice Aggregation Customers," December 2015, http://www.el-cerrito.org/documentcenter/view/5289.

Figure 9. Illustrative Example of Indifference Adjustment Required per $1 Billion in Utility Above-Market Costs as a Function of the Percent Reduction in Customer Base[38]



California's experience with net energy metering and CCAs illustrates a tension among the political momentum behind customer choice, a tendency to implement energy and climate policy through utilities, and utilities' concerns over the potential stranded costs from long-term contracts associated with energy and climate policy. How this tension will be resolved in California is still an open question.

New York

New York's electricity system combines rural, sparsely populated areas with the country's largest and densest city. The state has a fully restructured electricity sector with competitive retail, but is also home to the largest state public power organization — the New York Power Authority (NYPA). Regulated utilities act as default service providers and are responsible for distribution grid planning, construction, and maintenance. The New York Independent System Operator (NYISO) operates the state's wholesale power market, which combines independent and public power producers.

New York's energy and climate policy goals share much in common with Hawai'i and California. The state's 2015 State Energy Plan targets a 40% reduction in energy sector emissions from 1990 levels by 2030, consistent with California's goal. To achieve this goal, it set targets of meeting 50% of the state's electricity needs with renewable energy and reducing building energy use by 23% relative to 2012 levels by 2030.[39]

Despite these familiar policy goals, New York's approach to implementation has been novel. Unlike in California, in New York a state agency — the New York State Energy Research and Development Authority (NYSERDA) — has historically been responsible for implementing the state's renewable energy

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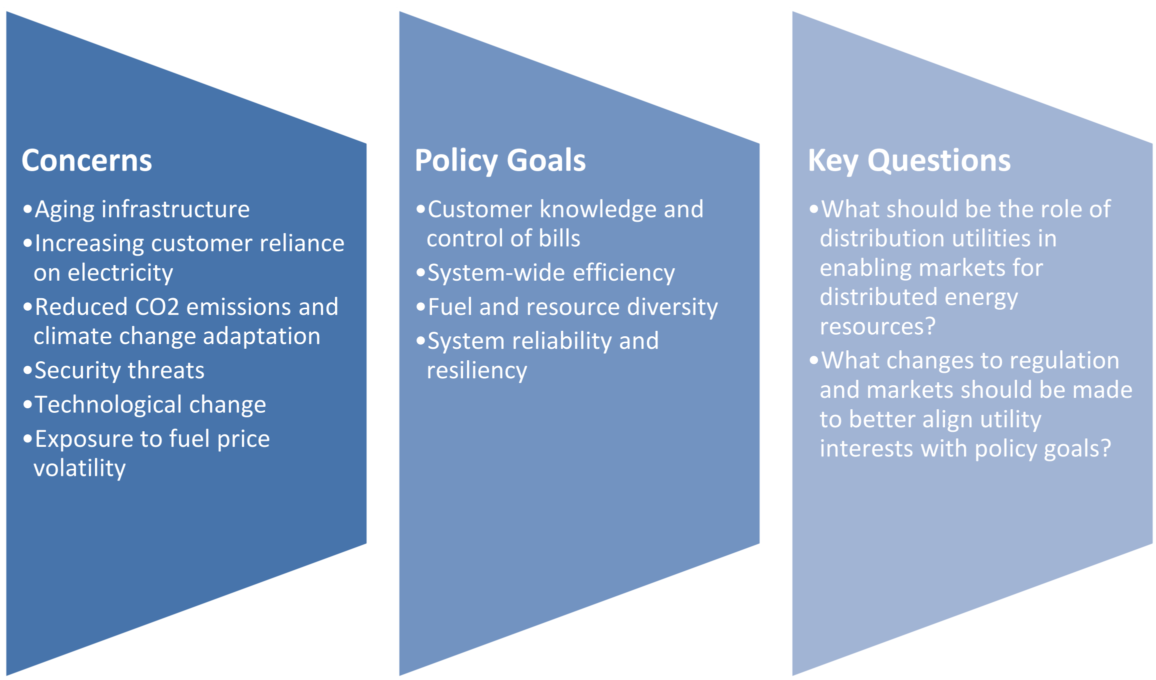
[38] In this example, the indifference adjustment is calculated to keep average rates for existing customers constant. "Percent reduction" is calculated in terms of percentage of sales rather than percentage of customers.
[39] See New York State, "New York State Energy Plan," https://energyplan.ny.gov/.

and energy efficiency goals. NYSERDA has procured long-term contracts for renewable energy premiums via auction, subject to a maximum budget constraint and funded through a non-bypassable surcharge on customer bills. NYSERDA works with non-utility contractors to administer energy efficiency programs, which are funded through a system benefits charge. This approach is consistent with New York's retail environment, in which utility supply portfolios consist of market purchases and shorter-term (1- to 3-year) contracts. Notably, however, NYSERDA fell significantly short of its 2015 RPS target.[40]

In 2014, following Superstorm Sandy, the New York Public Service Commission (PSC) initiated the Reforming Energy Vision (REV) proceeding to consider how to develop a cleaner, more resilient electricity system. The REV process began with a broad vision. Regulators asked stakeholders to consider fundamental changes to the state's electricity system and the form and function of distribution utilities.

The NY PSC bounded the REV process with a series of motivating concerns, policy goals that followed from these concerns, and open questions. Figure 10 summarizes the PSC's initial formulation of the problems the REV proceeding is meant to address.

Figure 10. Motivating Concerns, Policy Goals, and Key Questions for the REV Proceeding



The REV process became a locus for policy entrepreneurship from the broad range of stakeholders with an interest in the future of the electricity system. Suspicious of increased costs, advocates for both large and small consumers expressed skepticism towards the notion of transforming utilities.[41] Alternatively, consultants who brought experience from bulk power markets suggested that utilities' role should be limited to owning and maintaining assets, with planning and operational decisions left to an

[40] By December 31, 2015, NYSERDA had achieved 60% of its 2015 RPS target, which aimed to procure 29% of electricity from renewable resources by 2015.
[41] Multiple Intervenors, 2014; AARP and Public Utility Law Project of New York, 2014.

independent distribution system operator.[42] Environmental advocates argued that clean energy policy leverage should remain a central consideration in any utility business model transition.[43]

In terms of utility form, the PSC ultimately elected to maintain the status quo. Regulated utilities will remain, at least in the near term, the owners, planners, and operators of the distribution system.[44] Instead, the focus of REV turned toward utility function, business models, and rate design.

A key REV goal is to transition toward more efficient retail pricing to facilitate competition on the distribution system. Having retail prices that more closely reflect time- and location-specific marginal costs of generation, transmission, and distribution would enable customers to make economically efficient decisions about how much energy to reduce, produce, and store for themselves rather than consuming from the grid. This approach to pricing would mark a radical departure from the status quo, in which retail rates are often based on average cost and, at most, only roughly reflect time- and location-specific costs. It also would change the basis upon which utilities recover their investments in the grid.

To explore utility business models in competitive distribution systems, the PSC investigated investments and incentives that would transform utilities into “platform” firms that facilitate competitive distributed energy resources.[45] In a whitepaper, PSC staff outlined a transition path to this platform firm end state, where market-based earnings supplant a large share of revenues earned through cost-of-service regulation.[46] PSC staff acknowledged that market-based earnings are likely to be modest in the near-term, and so proposed a number of projects and incentives to encourage platform-market behavior from incumbent utilities.

New York’s emphasis on competition and choice has largely headed off the conflicts between utilities and stakeholders that have occurred in Hawai’i and California. For instance, utilities and solar companies announced in a recent filing that they had come to an agreement that compensation for distributed energy resources should transition from net energy metering to a value-based approach more reflective of local marginal costs.[47] The PSC has announced its support for CCAs,[48] and stranded cost issues are less relevant in New York because of the state’s competitive retail environment.

Many of the details of REV have yet to be worked out. The details of retail rate reforms are still under discussion. Changes to utilities’ business models have focused on targeted earnings adjustment mechanisms and incentive mechanisms to encourage utilities to identify capital project deferral

[42] Wellinghoff et al., 2014.
[43] Joint Commenters, 2014.
[44] PSC 2014.
[45] PSC 2014.
[46] PSC, 2015.
[47] Solar Progress Partnership, 2016.
[48] PSC, 2016a.

opportunities.[49] The PSC issued guidance on the types of incentive mechanisms that it plans to implement, but details on their design are not yet available.

The REV proceeding began with a distribution system focus. However, in 2015 Governor Cuomo directed state agencies to enact a 50% Clean Energy Standard, leading to consideration of large-scale renewable and nuclear energy within REV. A key question in response that arose to this directive was which organizations should procure the clean energy: NYSERDA, regulated utilities, or all load serving entities?

The Department of Public Service's (DPS') proposal for implementing the Clean Energy Standard would shift responsibility for procuring renewable energy from NYSERDA back to utilities and competitive retail suppliers.[50] It argued that doing so, through long-term "bundled" power purchase agreements, would result in lower costs than the centralized NYSERDA procurement model. Recognizing the difficulties that competitive suppliers would face in supporting long-term contracts for new renewable energy projects, DPS proposed that regulated utilities procure energy required to meet the Clean Energy Standard through long-term contracts. Utilities would then sell RECs from these contracts to competitive retail providers, with any shortfalls recovered through the utilities' delivery charges. As an incentive for the utilities, DPS recommended that some portion of net revenues from the sale of RECs be allocated to utility shareholders.

DPS' proposal drew a range of responses that reverberated across familiar stakeholder lines. The utilities, for instance, were opposed to the idea of utility-backed power purchase agreements, arguing that power purchase agreements result in overpayment for renewable energy and a shift in risk from renewable energy developers to customers. Instead, they argued for incremental improvements to the status quo and a "universal renewables" model in which the utilities would own a "meaningful amount" of the renewable energy to meet clean energy standard goals. Doing so, the utilities maintained, would allow for a cost-based, rather than market-based, procurement of renewable energy, lowering overall costs.

The resolution of the REV proceeding, and its questions over retail rates, utility incentives, and renewable energy procurement, has fundamental implications for New York's electricity market and the future form and function of its utilities.

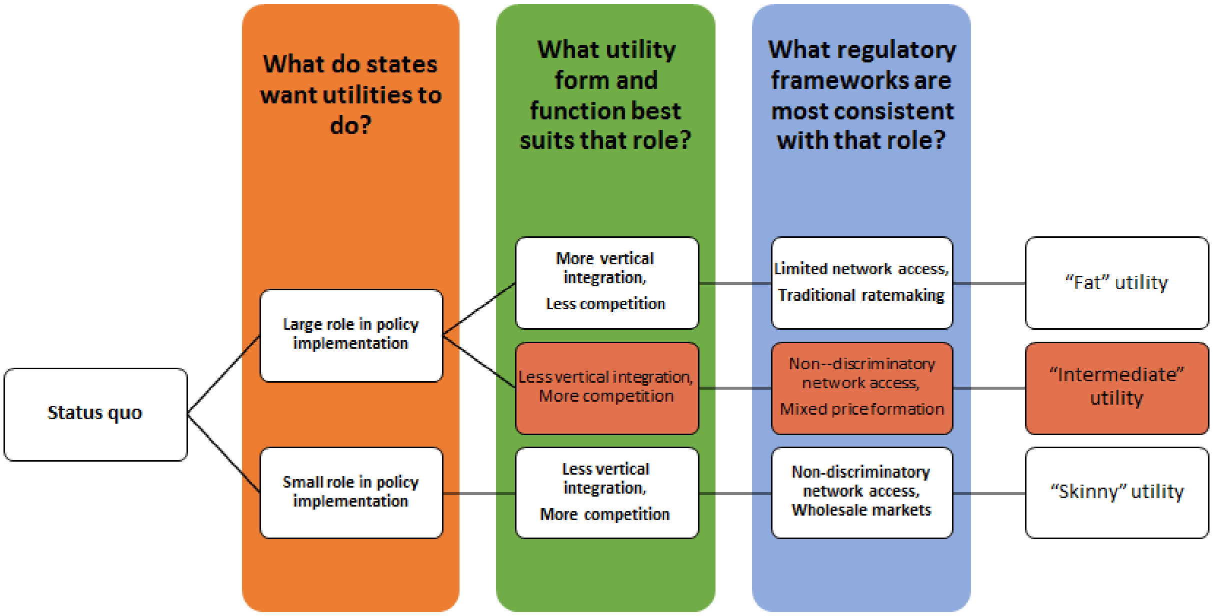
Envisioning a Utility for 2030

What do Hawai'i, California, and New York's experiences suggest about what the electric utility should look like in 2030? We argue that there are two rational end states for the utility in 2030: fat or skinny. The fat utility plays a larger role as an asset owner in policy implementation, can have a significant degree of vertical integration, is able to control interconnection of distributed energy resources, and sets wholesale and retail prices primarily through traditional, cost-of-service ratemaking. The skinny utility plays a smaller role as an asset owner in policy implementation, provides non-discriminatory access to both its transmission and distribution system, and operates in a more competitive

[49] PSC, 2016b.
[50] DPS, 2016.

environment where wholesale and retail prices are largely determined through markets (Figure 11). Which vision of the utility — fat or skinny — is preferable will depend on state political and regulatory context.

Figure 11. Fat, Skinny, and Intermediate Pathways for Utilities



However, as the Hawai'i, California, and New York examples illustrate, the “intermediate” space in between fat and skinny does not lend itself to long-term consistent and stable regulatory solutions. It mixes long-term obligations on utilities, retail and wholesale competition, and regulated and competitive pricing. The result is a perpetual back-and-forth between utilities and industry stakeholders, with utilities resisting expansion of either customer choice (e.g., as in California) or long-term policy obligations (e.g., as in New York).

Although the fat utility model is more familiar, the skinny utility model raises a number of questions that do not yet have clear answers, two of which are particularly critical. First, how are investments in new generation supported in a skinny utility model — who owns assets and who is the counterparty to contracts? New York's model, for instance, has been to have the state (NYSERDA) procure long-term contracts for renewable energy premiums. In lieu of state agency or utility procurement, the main strategy for encouraging policy goals is externality pricing, such as CO_2 prices, that is high enough to support new investment. The tradeoff, then, is between binding targets for specific generation resources and market efficiency.

Second, who plans and operates the distribution system in a skinny utility model? If distribution planning is done by the incumbent utility, state regulators face familiar incentive issues of how to ensure that new distribution infrastructure investments are cost efficient. If the incumbent utility operates the distribution system, state regulators will face the same issues with enforcing non-discriminatory access on the distribution system that FERC has faced on the bulk electricity system. An independent distribution system operator could address these issues.[51] However, it is not clear what organization would fulfill that role, or whether the benefits of an independent system operator would be higher than the costs.

Recent experiences in Hawai'i, California, and New York are suggestive of the political difficulties of transitioning to or maintaining a fat or skinny utility model. From a regulatory perspective, a compromise-seeking approach to reconciling all stakeholder interests will tend to lead to an "intermediate" model. In this sense, New York's REV process illustrates the importance of having a long-term vision to guide stakeholder discussions.

What Will Utilities in Hawai'i, California, and New York Look Like in 2030?

Hawai'i is more limited in its options than either California or New York, because the small size of its electricity sector precludes the possibility of having a competitive retail market and skinny utilities. Instead, the utilities will likely continue to be responsible for long-term procurement of large-scale renewable energy, with a de facto competitive fringe of distributed generation. The Hawai'i PUC will likely need to continue to cap the amount of distribution generation, to avoid stranding the utilities' long-term contracts and prematurely using up all of the limited hosting capacity of each island system to absorb and integrate intermittent resources. At a minimum, all new distributed generation resources will to need to be fully controllable by the utilities.

The HPUC will also need to design retail rates to ensure full cost recovery of all of the utilities' costs, including any long-term contracts for fuel, interisland cables, or grid connected renewable resources, limiting its ability to allow full choice and marginal cost-based compensation for distributed energy resources. Allocation of the utilities' longer-term costs will continue to be contentious in a quickly evolving market where distributed resources are becoming more cost-effective.

California is currently the clearest example of intermediate utilities, and is on the fence between making them fatter or making them skinnier. The breaking point for this decision is likely to hinge on future growth of CCAs and the PCIA charge. At some point the PCIA charge will either become too large for CCAs and competitive retail providers to compete, shifting customers back to utilities, or the CPUC will disallow some utility costs to be included in the PCIA charge, prompting the utilities and their shareholders to push for a skinny utility model. Ultimately, state lawmakers and the CPUC must decide whether utilities will continue to be the vehicle for state energy policy, and if so provide reasonable limits on CCAs, retail choice, and distributed generation.

New York currently has skinny utilities, and the state's REV proceeding established a path to make them even skinnier. However, the Governor's Clean Energy Standard and the PSC's proposed approach to implementation have moved New York back on the fence between fat and skinny utilities, facing a set of questions that are similar to California's. Given its starting point and the momentum of the REV process, we argue that New York is more likely to maintain its skinny utility model. Doing so, however, will

[51] For more on this concept, see Tong and Wellinghoff (2014).

require answering critical questions about how to implement aggressive energy policy goals when the resources to meet these goals are being financed by private, rather than regulated, capital.

Conclusions

The electric grid will continue to play an important role in the U.S. electricity system, regardless of whether electricity generation is more centralized or distributed. The grid enables trade — allowing electricity consumers the flexibility to use electricity when they want for what they want, and allowing large and small producers to maximize the value of their generation. From a societal perspective, preserving and upgrading the grid will be far more cost-effective than a world with either no grid or myriad isolated grids. The question then becomes, in a rapidly changing electricity industry, what is a longer-term vision for electric utilities, as owners of the grid?

Much has been recently written about changing incentives and business models for electric utilities. In this paper, we argued that, before turning their attention to incentives and business models, state lawmakers and regulators should first address four more fundamental questions: (1) what do states want utilities to do, (2) what utility form and functions best suit that role, (3) what regulatory frameworks (e.g., retail pricing, grid access) are most consistent with that role, and (4) is the ensuing vision of the utility politically feasible?

Hawai'i, California, and New York are at the forefront of questions surrounding the future of electric utilities. All three states combine aggressive state energy policies with growing political momentum behind customer choice. In Hawai'i, rapid expansion of distributed solar PV has forced the HPUC to consider a fundamental shift in the utilities' role. In California, a growing CCA movement, expanded direct access, and rising penetrations of distributed generation have created tensions between utilities' role as vehicles of state policy, on the one hand, and growing demand for choice and competition, on the other. New York has long had a competitive retail market and has already begun to consider the future of its utilities as part of the REV proceeding, but the state's Clean Energy Standard is raising new questions about the utilities' potentially expanded role in implementing state policies.

Drawing on recent developments in Hawai'i, California, and New York, we argued that there are two rational visions of the utility in 2030. In the "fat" utility model, utilities act as the financial guarantor and potentially the implementer of state energy policies, such as renewable portfolio standards, in exchange for limits on competition that ensure a stable customer base. In the "skinny" utility model, utilities do not finance and backstop state energy policies, and the retail sector and distribution systems are more fully opened to choice and competition.

We argued that the "intermediate" model, combining long-term financial commitments by utilities with greater choice and competition, does not lend itself to long-term regulatory solutions. It requires regulators to continually allocate utilities' long-term financial obligations to competitive providers — competitive LSEs, CCAs, and distributed generation owners. This will raise familiar concerns by competitive providers that utilities are making poor judgments, and familiar concerns by utilities that they will not be able to recover their costs. Tinkering with utility incentives or business models will not ameliorate this tension.

Neither the fat nor the skinny utility model is necessarily a better option. What is most practical across states will depend to a large extent on existing institutions and levels of trust among utilities, regulators, and stakeholders. However, transitioning toward or maintaining a fat or skinny model will in many cases not be easy. Interest groups will tend to drive regulators toward the intermediate model, as a point of compromise. Formulating a long-term vision of the utility will be an important strategy for both regulators and utilities, in order to better navigate the electricity industry's increasingly complex political landscape.

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