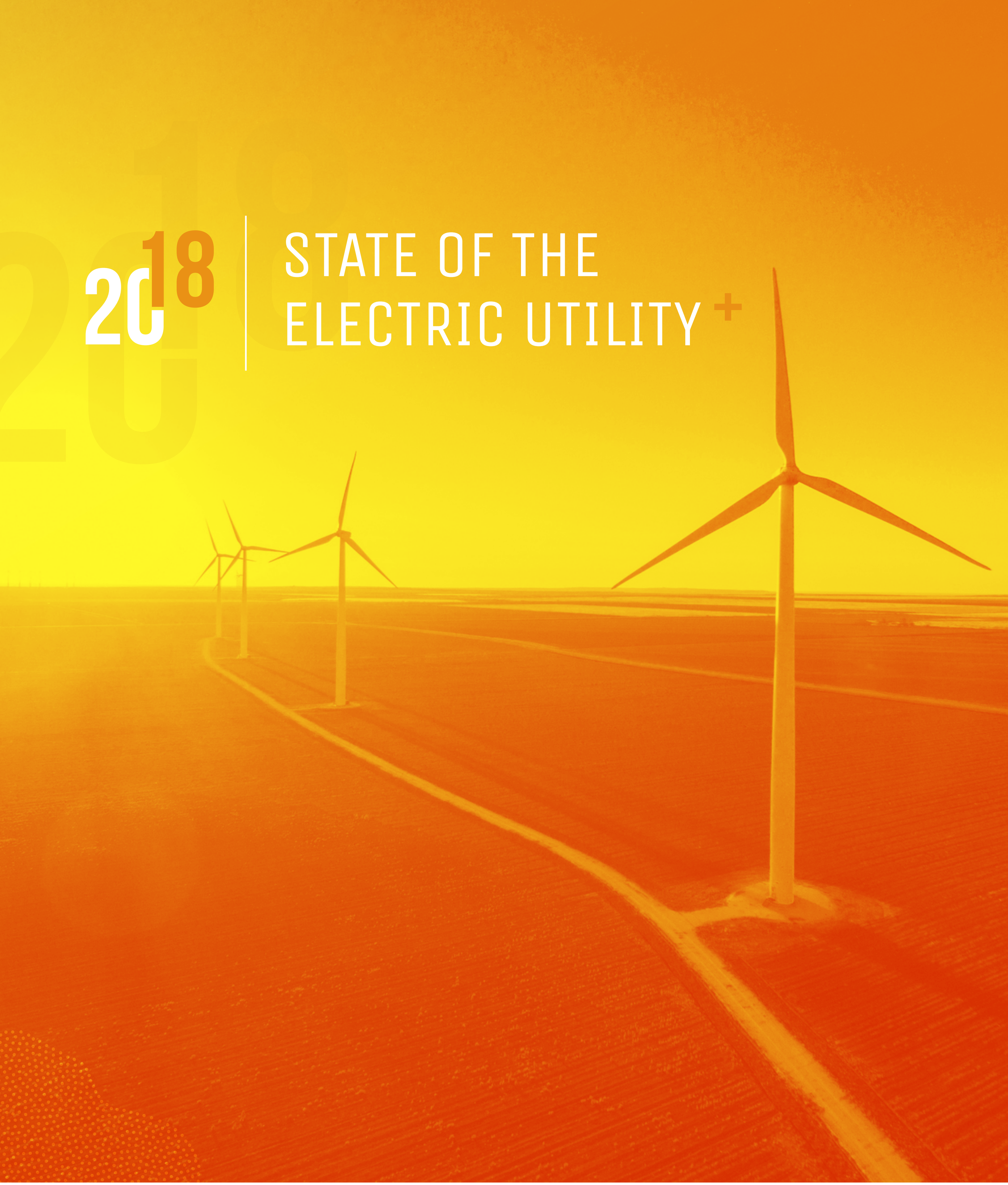
2018 STATE OF THE ELECTRIC UTILITY+



Utility DIVE

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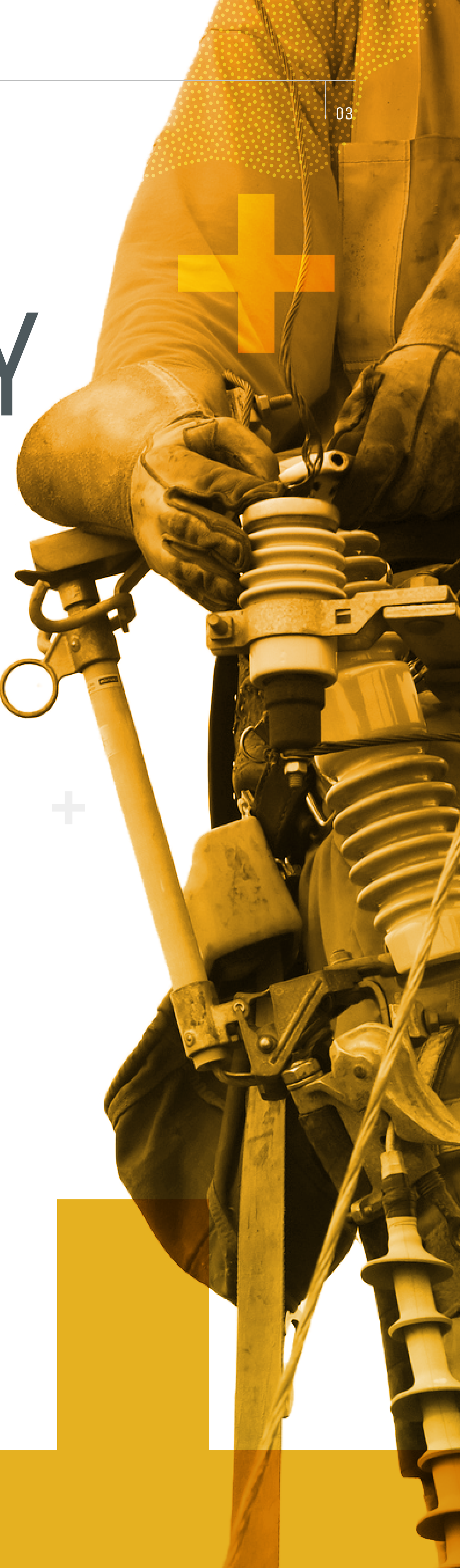

The 2018 State of the Electric Utility Survey is based on an online questionnaire administered to Utility Dive readers in December 2017. Nearly 700 self-identified electric utility employees from the U.S. and Canada took the survey.

This fifth annual survey was designed to illustrate the outlook and opinions of utility professionals. It should not be considered a scientific study.

The project was sponsored by the consulting and research firm PA Consulting; the sponsor had input in the analysis of survey data but no control over the final content of this report.

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EXECUTIVE SUMMARY

There's a reason we call electricity "power" — it's been the foundation of modern life for more than a century.

Since the establishment of the modern power industry in the early 1900s, utilities have been tasked with the dual mandate of delivering reliable and affordable power to customers. Throughout the 20th century, vertically-integrated power companies electrified virtually the entire nation through regulated investments in grid infrastructure financed by their ratepayers. In 2016, U.S. utilities supplied nearly 4 million GWh of energy, more than double what they did in 1986.

Because their systems support the economy, utilities are notoriously cautious institutions and are slow to change. In recent years, however, scientific realities, customer sentiment and regulatory initiatives have compelled the sector to add a third element to their mandate: sustainability.

Pushed by climate change and other environmental impacts of power production, regulators in the U.S., Canada and elsewhere have encouraged the development of low-emission power sources, like wind and solar, and the phasing out of the most polluting resources like coal. In the past two years, wind and solar power combined to surpass the annual contribution of hydropower to the overall utility power mix, and in 2016 natural gas-fired generation surpassed power produced by burning coal.

Along with the trend of sustainability, utilities have also had to cope with increasing competition for electricity generation and retailing. While power utilities operated as natural monopolies in their service areas for most of the 20th century, federal policymakers in the 1970s began to open up generation services to competition in hopes of securing lower prices for consumers. In the 1990s, a number of states began deregulating their power sectors, splitting competitive generation away from transmission and distribution utilities, creating the nation's first wholesale power markets.

> "UTILITIES ARE MOVING TO A CLEANER, MORE DISTRIBUTED POWER SYSTEM."
>
> + Midwestern IOU

Faced with rising power prices and the California energy crisis, many states paused or abandoned deregulation efforts. Today, the vertically-integrated model remains largely in the southern, central and northwestern regions of the U.S., while 23 states and the District of Columbia have some form of competition in generation, energy retailing or both.

At the outset of electricity competition, reforms largely affected the generation and retailing divisions of utilities, with some states forcing regulated power companies to relinquish control of those markets and compete through unregulated subsidiaries. But in this decade, the spread of distributed energy technologies has placed new demands on the poles and wires that had been relatively unchanged for decades.

Throughout the last century, economies of scale and their natural monopoly status led utilities to invest in large, centralized power generators that served big groups of customers through a one-way power system. The development of distributed energy resources (DERs) — like rooftop solar, co-generation and battery storage — changed that paradigm, allowing utility customers to control their usage and even export electricity back onto the grid. The trend has led to a litany of state debates over grid modernization to meet the needs of new DERs, as well as compensation and rate design issues for owners of customer-sited resources.

On top of all that, major federal regulatory regimes are in flux. Throughout the Obama administration, federal regulators and energy incentives pushed utilities toward a lower-carbon energy system, one that utilities came to embrace when the low cost of natural gas and declining prices for renewables cut costs for consumers.

The election of President Donald Trump in late 2016 threw that federal policy narrative into doubt. In the past year, the Trump administration has moved to review or rescind major power sector rules on carbon, methane, coal ash and other pollutants, as well as proposing new power market subsidies for coal and nuclear facilities that federal energy regulators denied.

The 2018 State of the Electric Utility Survey may indicate those actions are altering sector sentiment. Utilities list regulatory policy uncertainty as the top issue regarding their changing fuel mixes, which may reflect the uncertain future of many power sector rules. Between the dsitribution of this survey and the publication of results, for example, the Federal Energy Regulatory Commission (FERC) rejected the Trump administration's plan to lend cost recovery to merchant coal and nuclear plants.

Regulatory uncertainty is a constant in the sector, but utilities also face new threats, especially from cyberattacks and increasingly severe weather.

Most utilities understand that they need to update their assets, practices and business models to account for the changes. The results of the 2018 survey highlight both the challenges facing these companies and how many of them are rethinking the utility model to adapt.

+ PRIMARY TAKEAWAYS:

1 | Utilities are moving to a cleaner, more distributed system. As in prior years, utility professionals report their companies are moving toward a power mix that emits less carbon and features more intermittent and distributed power sources. Respondents expressed the most confidence in growth for solar, DERs, storage, wind and gas, while most expect significant decreases in coal- and oil-fired generation.

The trend to a cleaner, more distributed system is occurring despite federal efforts to support fossil fuel production and generation, and it presents a number of operational and business model challenges for utilities. Renewable energy integration, DER policy and justifying investments in emerging grid technologies all ranked high on the list of concerns for industry professionals this year, and the increasing complexity of utilities' systems can stoke cybersecurity worries as well.

2 | Utility sentiment on load growth is shifting. Since the 2008 recession, many utilities in the U.S. and Canada have faced stagnant or declining demand for electricity, fueling concerns about their ability to cover grid costs and deliver return for shareholders.

The 2018 survey indicates that utility professionals see that trend changing. This year, 46% of utility professionals foresee stagnant load growth , while 40% predict increasing load. In the commercial and residential market segments, participants who expect load to increase outnumbered those who predict stagnant load.

3 | Uncertainty abounds, particularly on federal regulations. The power of uncertainty was most clearly evident in utilities' long-term plans for their power mix. Nearly 40% of utility professionals named uncertainty as their top concern about changing their power mix — nearly twice the level of concern expressed about integrating DERs with utility systems.

Some of this uncertainty stems from policy and regulatory changes, like the Trump administration's decision to place a 30% tariff on imported solar panels in January 2018. Other concerns involve the center changing economics of energy, looming baseload generation retirement and bulk power reliability.

4 | Cybersecurity fears are stronger than ever. For the second year running, cybersecurity concerns topped the list of the sector's most pressing issues. This year, 81% of utility professionals listed cybersecurity as either important or very important -- an appreciable jump from 72% last year. Prior to 2017, security consistently ranked about fifth or sixth among overall utility concerns.

The trend reflects a growing reliance on software platforms and internet-connected devices at utilities. As utilities upgrade their systems to provide better grid intelligence and communicate more with customer devices, there are more ways than ever to launch a cyberattack against a utility. This year, almost every utility reports taking steps to improve cybersecurity, but the effectiveness of those measures remains is unclear, and the nature of cyber threats shifts on a daily basis.

5 | Utilities are focused on renewables and DERs. This year, respondents predict big increases in both central-station renewables and distributed energy technologies, posing new challenges for utility operations and finances. Power systems that feature more distributed resources often require upgrades to combat voltage and power quality fluctuations as well as to control stress on distribution assets and route power flows efficiently.

> "THE UNCLEAR REGULATORY ENVIRONMENT MAKES INNOVATION AND EXPANSION TOO UNCERTAIN TO PURSUE FOR NOW."
>
> + Large Southeastern IOU

Likely due to these concerns and others, respondents listed DER policy, bulk power system reliability and reliable integration of renewables as their second, third and fourth most pressing issues. Participants from regions that expect significant expansion of distributed generation and storage are the most concerned about reliably integrating new resources onto their systems.

6 | **How to justify emerging grid investments is a growing issue for the sector.** This year, 45% of utility professionals named justifying emerging investments as one of their top regulatory concerns — significantly more than in prior years.Utilities especially see the need for investment in grid intelligence and communications, smart metering, EV charging infrastructure, non-wires alternatives for distribution, storage, analytics and cybersecurity. However, the return on such high-tech investments is more complicated to demonstrate to regulators, ratepayers and often even within their own organizations.

7 | **Utilities want to move away from cost-of-service regulation.** This year, only 8% of utility respondents indicated they want traditional cost-of-service (COS) regulation to govern their investment decisions. Instead, 44% indicated they would prefer a hybrid model mixing traditional COS with performance-based standards, and 32% want a predominantly performance-based model.

These results and others in the survey indicate utilities are keen to adapt their business models to take advantage of new technologies and market opportunities. Only 2% of respondents indicated they did not see a need to evolve their utility business model, and 81% indicated they either have or want a regulatory proceeding in their state focused on reforming utility business and revenue models.

44%

OF UTILITIES WOULD STRONGLY PREFER TO HAVE PERFORMANCE-BASED METRICS AND INCENTIVES INTRODUCED INTO THEIR REGULATORY MODEL, AND MANY OF THEM EXPECT TO SEE THAT WITHIN A DECADE.

+DEMOGRAPHICS

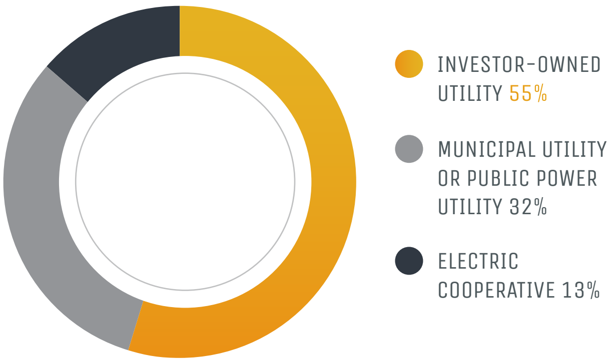
This year, a total of 686 self-identified utility industry professionals responded to our State of the Electric Utility Survey. They represent a broad diversity of locations, business models and regulatory compacts throughout the U.S. and Canada.

Over half of survey participants (55%) work for investor-owned utilities (IOUs). Municipal utilities and public power entities were the next-largest contingency, at 32%. 13% represent electric cooperatives.

This breakdown largely reflects the number of customers served by each utility type in North America. While co-ops and munis are far more numerous, IOUs serve most customers in the United States. According to the U.S. Energy Information Administration (EIA), in 2016 there were only 140 U.S. IOUs, compared to 727 co-ops and 757 municipal utilities. IOUs, however, provide power to more than two-thirds of the U.S. population.

Survey participants also represent a cross-section of utility sizes (in terms of customer base). Approximately 25% work for utilities serving 1-4 million customers. Just slightly fewer work for the largest utilities (which serve over 4 million customers). 11% of respondents represent mid-sized utilities (500,000-1 million customers). More come from the smaller end of the utility spectrum: roughly 20% each for utilities that serve 100,000-500,000 customers, and fewer than 100,000 customers.

WHAT TYPE OF UTILITY COMPANY EMPLOYS YOU?



HOW MANY CUSTOMERS DOES YOUR ELECTRIC UTILITY SERVE?

21%
FEWER THAN 100,000

19%
100,000 - 500,000

11%
500,000 - 1 MILLION

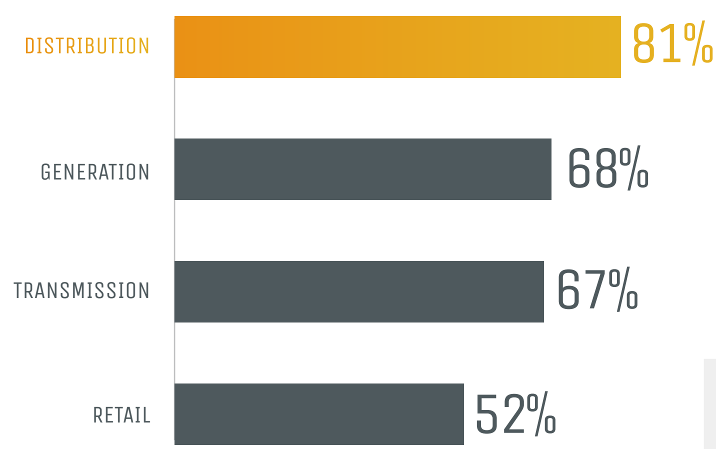
25%
1 - 4 MILLION

24%
MORE THAN 4 MILLION

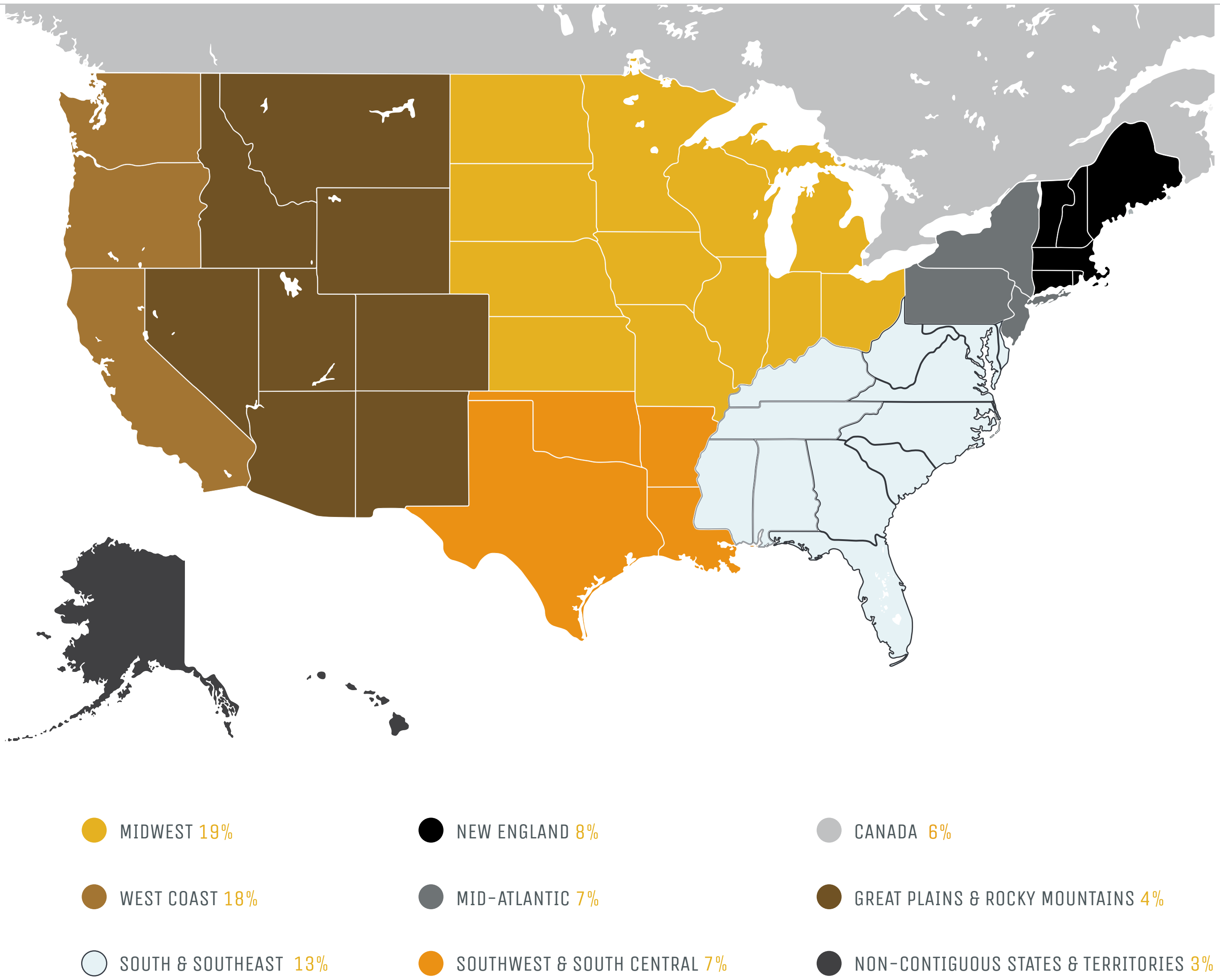
The challenges facing electric utilities vary greatly by region, and this year's survey attracted somewhat greater geographic diversity than last year. In 2017, 23% of respondents had West Coast service territories, and 21% came from the Midwest. This year, representation from both of those regions dropped to about 18% each, and more participants hailed from utilities serving the Southeast and other regions.

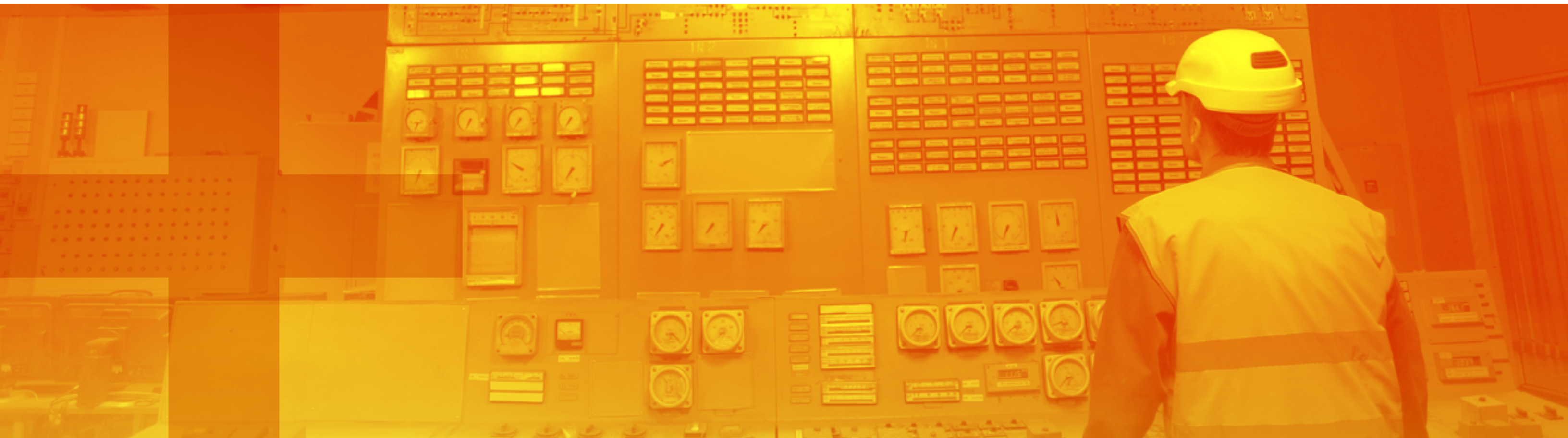
Most utilities still provide the same types of basic services, so these numbers have not substantially changed from prior years. Four-fifths of participants work for utilities that offer distribution services, about 70% each offer generation and transmission services, and only slightly more than half offer retail services.

WHICH ENERGY SERVICES DOES YOUR REGULATED UTILITY, CO-OP OR MUNI PROVIDE?

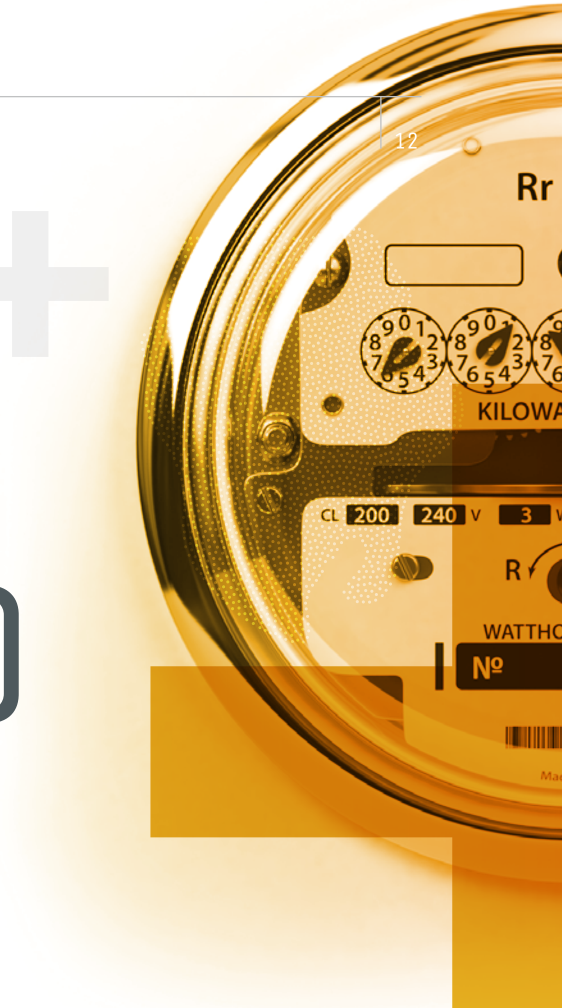


IN WHICH REGIONS DOES YOUR REGULATED UTILITY HAVE SERVICE AREAS?





UTILITY INDUSTRY TRENDS AND CONCERNS



The growth of electricity demand across the economy — "load growth" in utility parlance — is one of the most fundamental trends to shape the power sector.

For most of the last century, utilities could assume their electrical load would grow over time as the economy developed, gradually expanding their rate bases and providing need for new infrastructure projects that return equity to shareholders.

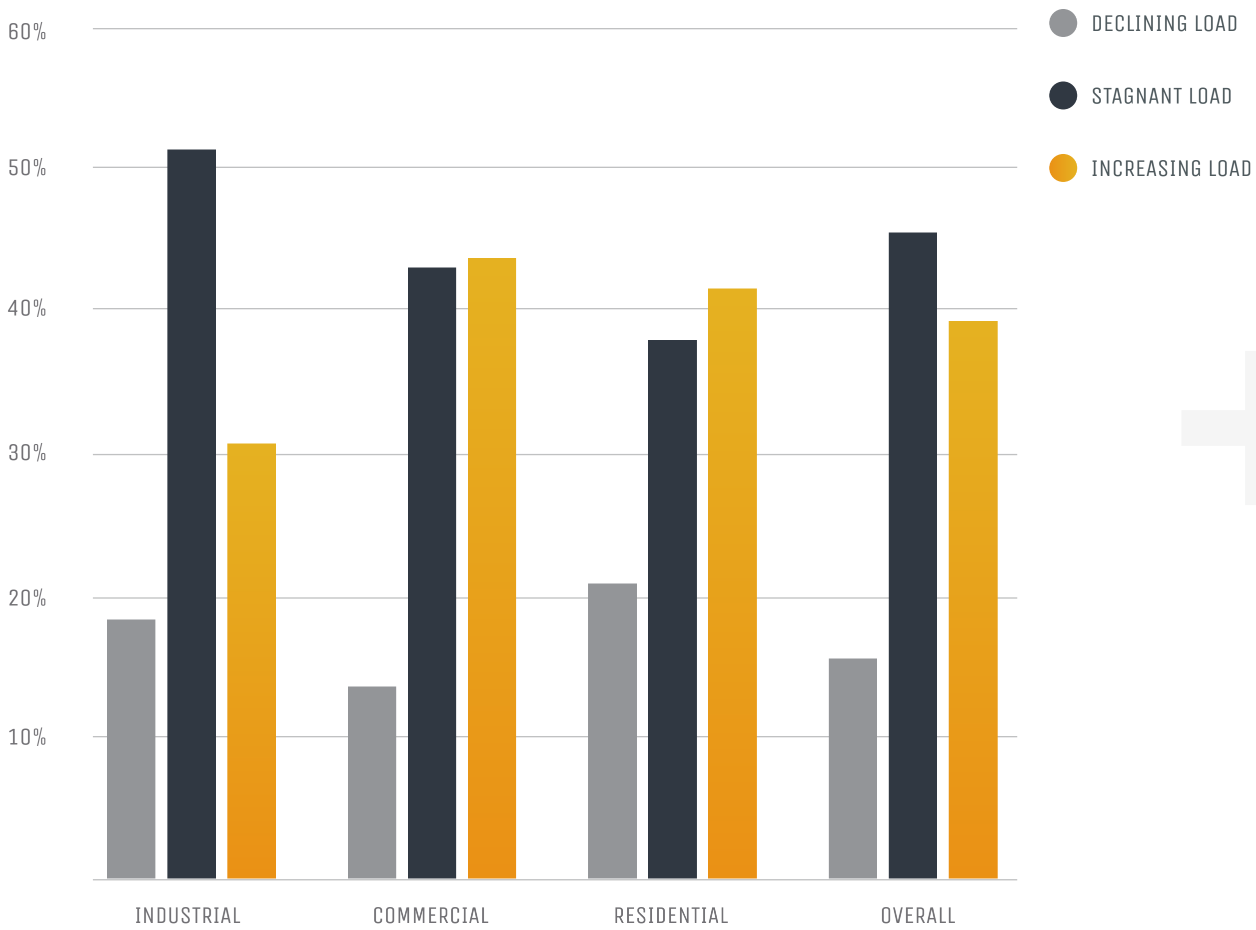
But when the Great Recession hit in 2008, that trend shifted. Electrical load growth stagnated across the country and in some places declined, at first due to lower economic activity and later due to greater energy efficiency across the economy.

That trend of stagnant load growth caused much hand-wringing in the sector for the last decade. With power demand flat and more consumers turning to distributed energy resources and alternative suppliers, some analysts worried utilities could enter a financial "death spiral" of declining revenues and increasing customer defection. In response, utilities and regulators in some states began efforts to decouple power load from utility revenues and devise new ways for utilities to make money.

This year's survey, however, indicates utilities may perceive the trend of stagnant load growth is turning. While most (45%) expect their overall load to remain stagnant, this year more utility professionals expect to see overall growth in load (39%), rather than shrinking load (15%).

Focusing on the commercial and residential customer segments, load growth looks more likely than stagnant load. And even though most utility professionals expect industrial load to stay stagnant, nearly twice as many foresee increasing rather than declining industrial load.

FOR EACH CUSTOMER SEGMENT, WHICH NET LOAD GROWTH TREND DO YOU SEE IN YOUR SERVICE AREA?

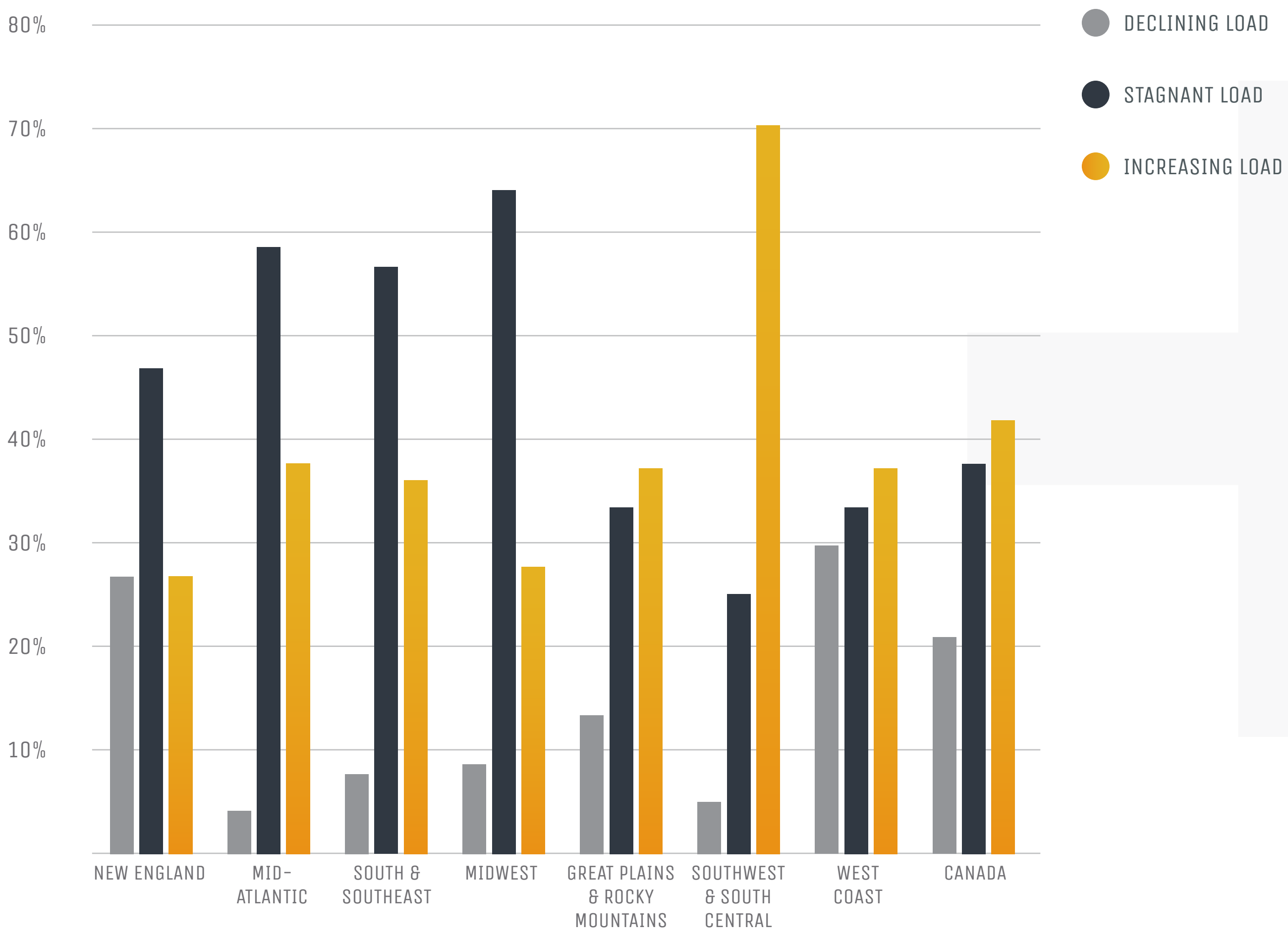


Possible reasons for this year's predicted upswing in load growth may include the overall expansion of the North American economy in the last few years. Another likely factor is anticipated strong growth in electric vehicles (EVs) in the next few years, particularly in coastal markets.

However, should the economic fortunes of the North American (especially U.S.) economies falter , the outlook on utility load growth could change. And the prolifera-tion of alternative suppliers in retail electricity markets could also affect power demand at utilities. . Regulated utilities still must supply power to customers who choose alternative suppliers or distributed resource solutions, but they typically earn less revenue for this service.

In some states, competition from these alternative suppliers is significant. In May 2017, a white paper from the California grid operator estimated that 85% of California utility consumers could be served by at least one alternative energy supplier by the mid-2020s.

WHICH OVERALL NET LOAD GROWTH TREND DO YOU SEE IN YOUR SERVICE AREA?



The overall industry prediction of stagnant/increasing load growth holds true across all utility types and sizes. However, there are some notable regional variations in this outlook.

Industrial load: Substantially more participants from New England expect to see shrinking industrial load (31%), rather than growth in this sector (12%). The West Coast and Canada report similar predictions, but with much smaller disparities. By contrast, participants from the Southwest/South Central region overwhelmingly expect increasing industrial load (58%), vs. stagnant (35%) or declining (6%).

Commercial load: All regions predict increasing rather than declining commercial load. This view is especially strong in the Southwest/South Central, South/Southeast and West Coast, where predictions of commercial load growth exceed predictions of stagnant commercial load.

Residential load: The industry outlook for residential load growth is strong in every region except New England. There, most participants predict stagnant load, and the remainder are split on growth vs. decline. More than half of participants from the Great Plains/Rockies and South/Southwest see residential load growth in their future.

Overall load: In the Great Plains/Rockies and South/Southwest, over half of utility professionals anticipate overall load growth. Population shifts from the Northeast and West Coast could contribute to load growth in these regions.

+ INDUSTRY CONCERNS IN 2018

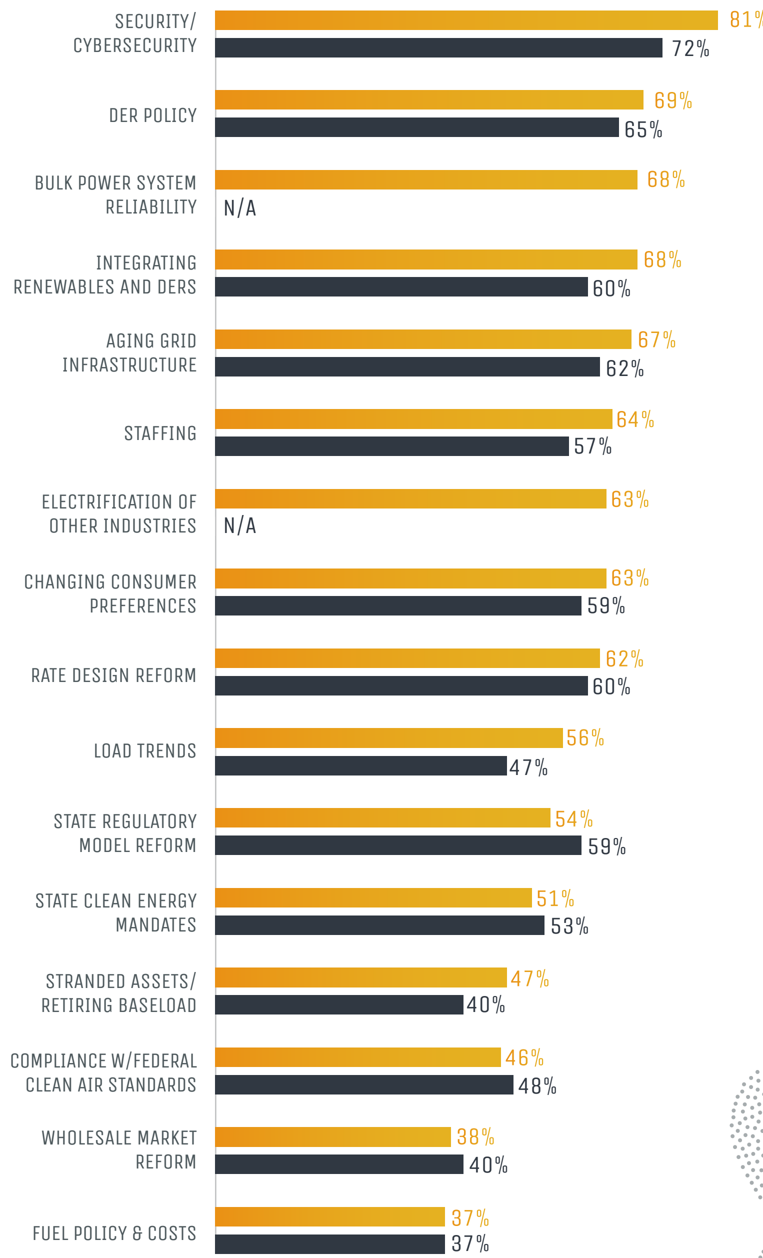
Utilities are a century-old industry dealing with disruptions from various technologies, regulations and market realities.

Our survey asked utility professionals to rank their relative level of priority or concern about several ongoing issues. Just as in 2017, utilities ranked cyber and physical security as their most pressing concern and DER policy in second place. After that, utilities listed bulk power system reliability, renewable energy integration and aging grid infrastructure as the next pressing concerns.

+ #1 concern: Physical and cyber security. This year, 82% indicated physical and cyber grid security is important or very important, up from 72% in 2017. Elevated anxiety about cybersecurity is universal across all utility types, sizes and regions.

RATE THE FOLLOWING POWER SECTOR ISSUES ACCORDING TO IMMEDIATE IMPORTANCE TO YOUR COMPANY

2018 2017 *(Percentage of respondents who indicated each option is "important" or "very important" today)*



While many utilities are taking action, there is a pervasive undercurrent of uncertainty about what cybersecurity risk really means and how utilities might respond effectively. The pace of change in cyberthreats is especially daunting to an industry that often struggles to keep its software up to date.

DER policy. Utilities across the nation indicated they are concerned with policymaking on distributed energy resources, including issues like net metering, interconnection policies, non-wire alternatives and DER ownership. Concern was most pronounced in the West Coast, New England and Great Plains/Rockies — regions where DER proliferation is greatest.

Bulk power system reliability. This year, utility professionals seem notably uneasy about the backbone of the U.S. electric power industry, with concern most pronounced in the Mid-Atlantic, South/Southeast and New England. Multiple extreme weather events in the past year, including three hurricanes and an extended cold snap, may contribute to these concerns, as well as the looming retirement of large, inflexible coal and nuclear generators struggling to compete in wholesale power markets. (Note: we did not ask about this topic in our 2017 survey.)

Integrating new power resources. A majority of participants noted significant concern about integrating renewable resources and DERs with utility systems. From solar and wind farms to storage and rooftop solar, utilities across the nation are being forced to adapt to a more variable, two-way power system. Concern about renewable energy and DER integration is highest in the Southwest/South Central, West Coast, New England and Canada.

Aging grid infrastructure. Most transmission and distribution lines in the U.S. were constructed in the 1950s and 1960s with a 50-year expected life, the American Society of Civil Engineers noted in its 2017 report. Upgrading such systems can put upward pressure on rates, and replacing certain power assets, like transformers, can be potentially disruptive to grid operations. This year, New England, Canada and the Mid-Atlantic are most concerned about aging infrastructure.

Staffing. Just as utilities are confronting the need to update their assets and systems, many are also poised to lose a vast amount of institutional expertise and memory as employees retire. Retraining employees and shifting job descriptions pose challenges the industry is likely to cope with for years to come. New England indicated the highest level of concern about the utility workforce.

Electrification of other industries, especially electric vehicles (EVs). Facing bold predictions of EV availability and adoption in the near future, utilities are pondering how to serve this demand. On one hand, EVs could represent significant new load, as well as new business opportunities. However, if utility grids are not updated and expanded soon to support networks of widely available charging stations, EV adoption might be impaired. The West Coast, Canada and Mid-Atlantic indicate especially high interest in this issue.

Changing consumer preferences. 21st-century utility customers want unprecedented levels of transparency and accountability from their utilities, including outage and billing alerts, more sustainable and efficient power and clear information from their utilities. For a utility that grew up mostly just selling kWh and mailing out monthly bills to a guaranteed customer base, the need to compete for customers and meet new consumer expectations can be challenging. The Great Plains/

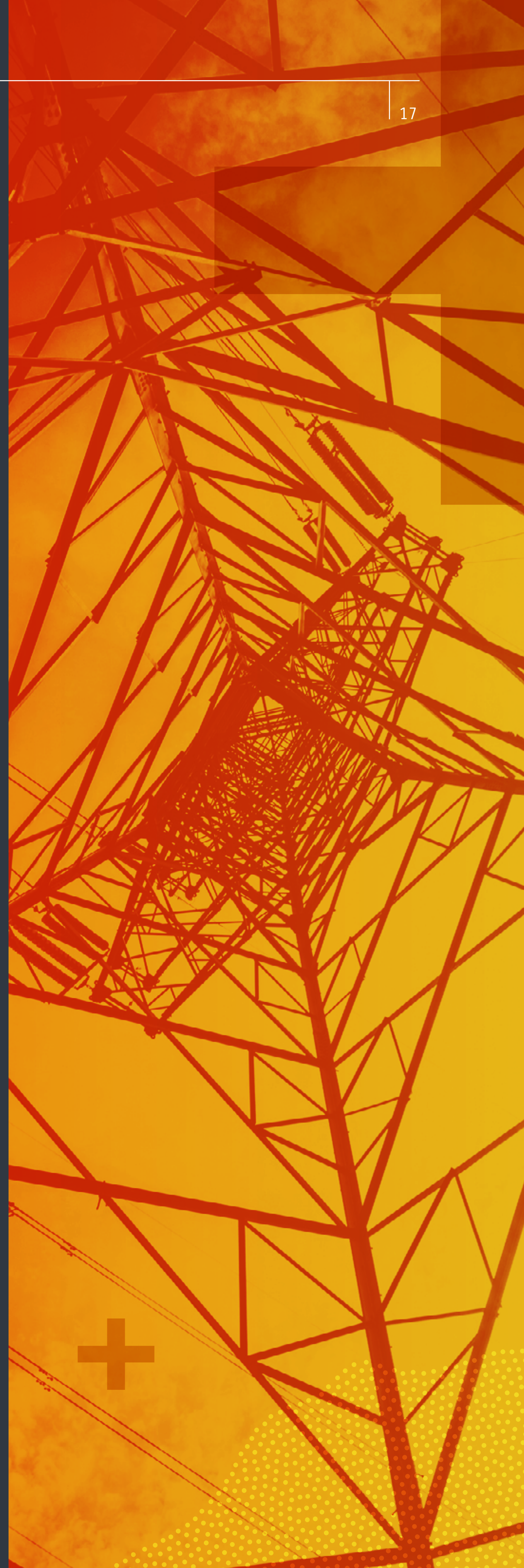
Rockies and the West Coast appear most concerned about what utility customers want today.

Rate redesign. As power demand stagnated over the last decade, utilities turned to new rate design techniques to cover the fixed costs of their grids, including higher fixed charges, time-of-use rates and a wider application of demand charges. These reforms are often controversial with consumer advocates and DER providers, and respondents from Canada, the Great Plains/Rockies and the West Coast were the most concerned about rate design — all areas with comparatively high DER growth.

Load trends, especially stagnant/declining load. Stagnating or declining load in many utility markets over the last decade has put pressure on utility revenues, but respondents to this year's survey indicate that tide may be shifting. Most utility professionals still predict stagnant load growth (46%). But nearly as many expect load growth, (40%), not decline (14%). The Midwest appears somewhat more worried about stagnant/shrinking load than other regions.

State regulatory model reform. Across the nation more than a dozen states are taking action to reform how utilities make money, shifting from full cost-of-service ratemaking to more performance-based regulations and market earnings. Nearly 60% of participants report that regulatory reform is already happening in their state, or expected shortly. A further 23% would like to see regulatory reform; only 19% are opposed to it. This issue is being watched especially closely by utility professionals in the West Coast, Southwest/South Central and Mid-Atlantic.

State clean energy mandates. While the Trump administration continues its attempt to revive coal and nuclear power, state-level mandates for renewables



> "IF WE DON'T RECRUIT AND RETAIN YOUNG, INNOVATIVE ENERGY PROFESSIONALS, THEY'LL GO TO MORE PROGRESSIVE ORGANIZATIONS, LIKE CCAS."
>
> + Small West Coast muni

remain strong. In general, the utility industry has shown a long-term trend of migrating to cleaner sources of power. However, accomplishing this transition in a reliable and affordable way is a significant challenge in many states, especially with continued low natural gas prices. Respondents on the West Coast, where states have ambitious clean energy goals, indicated they are most concerned with meeting mandates.

Stranded assets and retiring baseload generation. Increased competition from natural gas and renewables is putting financial stress on many aging coal and nuclear plants, forcing some to retire before they are fully depreciated — rendering them a "stranded asset." The Southwest/South Central and Great Plains/Rockies appear relatively more concerned about stranded assets. This topic also was second-most-likely to be voted potentially important for the future (17%).

Compliance with federal clean air standards. The Obama administration issued a number of new air regulations for the power sector during its two terms, including new or stricter rules on carbon, mercury and ground-level ozone. The Trump administration has moved to revise or rescind these standards, but most respondents indicated again this year that they are not concerned with compliance. Concern about federal clean air standards is strongest in the Southwest/South Central region, where many utilities still own coal generation.

Wholesale market reform. Wholesale power markets across North America are taking steps to reform price formation in both energy and capacity markets to better reward generators for resilience characteristics and account for state incentive policies. Additionally, the Department of Energy in September proposed a rule at FERC that would have required fuel-secure merchant power plants to be granted cost recovery, a drastic change to wholesale markets. Though the survey was conducted before that DOE proposal was rejected, respondents were largely unconcerned with wholesale market reform, with the greatest worry coming from Canada and New England.

Fuel policy and costs. Natural gas prices are likely to remain low for some time, and currently federal decarbonization policy seems stalled. Meanwhile, costs for renewables and storage generally keep dropping, but long-term federal subsidies are uncertain. Consequently, most utilities aren't terribly concerned about fuel policy today. But it is on their radar, especially in the South/Southeast. This issue is tied with wholesale market reform as being one of this year's top "potentially important for the future" issues, at 20%.

REGULATORY LANDSCAPE

For most of the last century, the electric utility sector operated under a vertically integrated business model. Utilities financed infrastructure investments by charging their ratepayers, and regulators authorized them to collect a little extra to return to their shareholders.

That utility business model electrified virtually the entire continent, but it assumed steady load growth and overall expansion. This model would keep generating new opportunities for rate recovery on infrastructure investments, as well as ever-increasing revenue from customers.

But then, the 2008 recession happened. For most of the past decade, stagnant or declining load became the utility industry norm. This was due not only to economic contraction, but also to consumers becoming more energy efficient and serving more of their own load via distributed resources — and also to increasing competition in deregulated retail markets. These fundamental changes reduced shareholder returns for IOUs, and led to calls for regulatory and market reform.

While the recent economic recovery has this year led many utilities back to predicting overall load growth, the impacts of efficiency and DERs remain. Now that utility professionals have had time to envision and plan for how regulatory and market reform might benefit their businesses, and to size up the emerging competition, they're not rushing back to vertically integrated utilities with traditional regulation and markets.

The competition is likely to grow fierce. For instance, according to the California Public Utility Commission, by 2025, over 80% of customers of that state's three major IOUs will be served by some kind of alternate energy retailer. Customer sentiment is driving this competition, but regulators also are forcing utilities to consider new kinds of investments, such as non-wires alternatives to expand grid capacity and resilience.

Threats to the traditional regulated utility business model continue to mount. Utilities know that they must find new ways to do business, but they're divided as to the path forward. Much of this depends on the direction of regulatory evolution.

Our survey asked about these four regulatory models:

+ **Traditional cost-of-service (COS).** Under traditional COS regulation, utilities are permitted to earn a rate of return for investments made on the bulk power system.

+ **Performance-based regulation (PBR).** Under PBR, utilities are compensated for achieving well-defined performance metrics around reliability, customer service and other factors. Metrics are defined by regulators and vary by jurisdiction.

+ **Hybrid.** A state regulatory model that adds performance-based incentives on top of the utility's traditional COS model, allowing it to rate-base traditional infrastructure investments while still directing it to meet some performance standards.

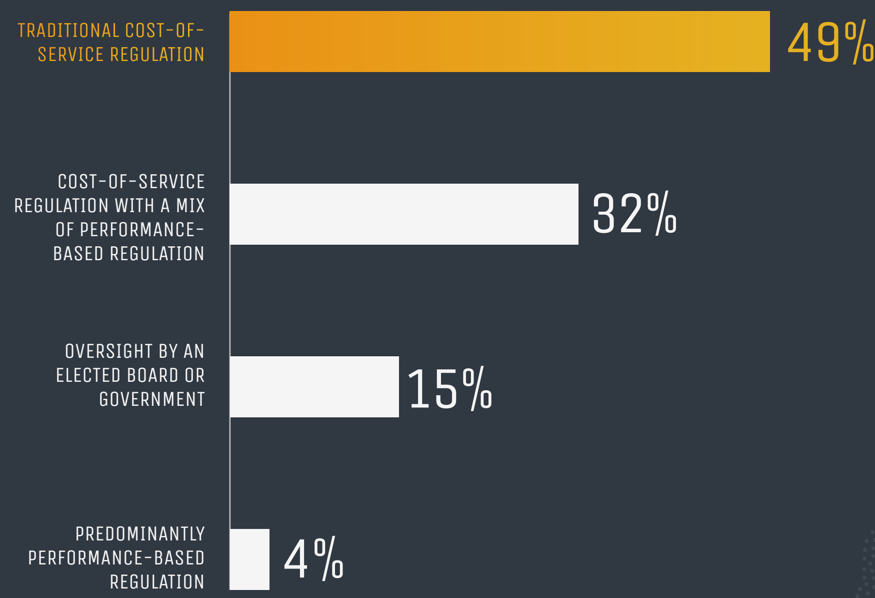
+ **Government oversight.** Most common among municipal utilities, PPAs and co-ops, this is when the utility reports directly to an elected board or government.

In addition to business model pressures on utilities, public calls for regulatory reform are also on the rise after the failure of two major utility generation projects in 2017. In June, Southern Co. announced it would abandon coal gasification operations at its Kemper plant in Mississippi after years of cost overruns and project delays, allowing the plant to run on natural gas. And in August, South Carolina utilities SCANA and Santee Cooper abandoned their bid to finish the V.C. Summer nuclear expansion, having already spent $9 billion of ratepayer cash on the project. SCANA is now looking to be sold to Dominion Energy, while Santee Cooper, a public utility, could be sold off to help pay for the project.

> "OUR REGULATOR CONTINUES TO DRIVE POLICY THROUGH RATES AND TREAT US AS A MONOPOLY. WE NEED A MARKET-BASED SYSTEM."
>
> + Mid-sized West Coast IOU

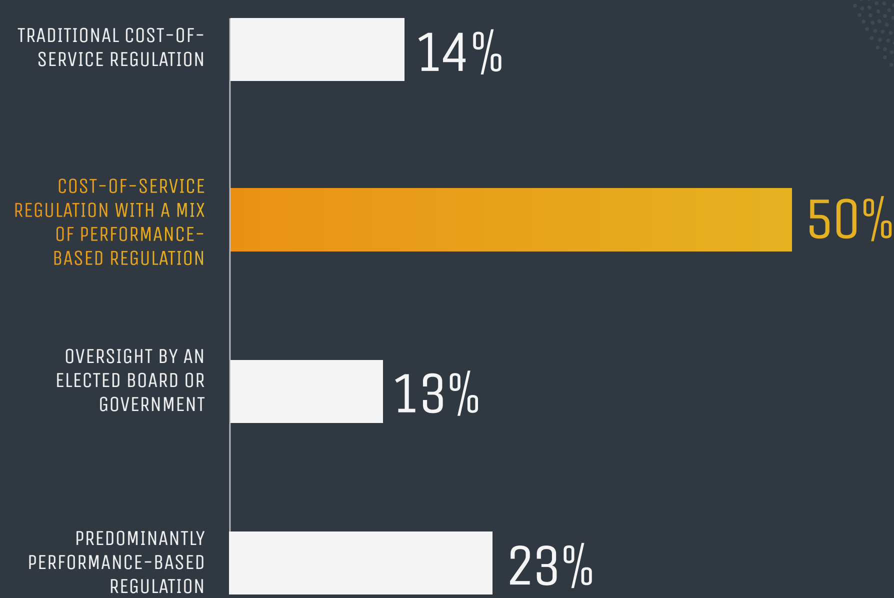
WHICH OF THE FOLLOWING BEST DESCRIBES YOUR REGULATORY ENVIRONMENT?

(IOU respondents only)

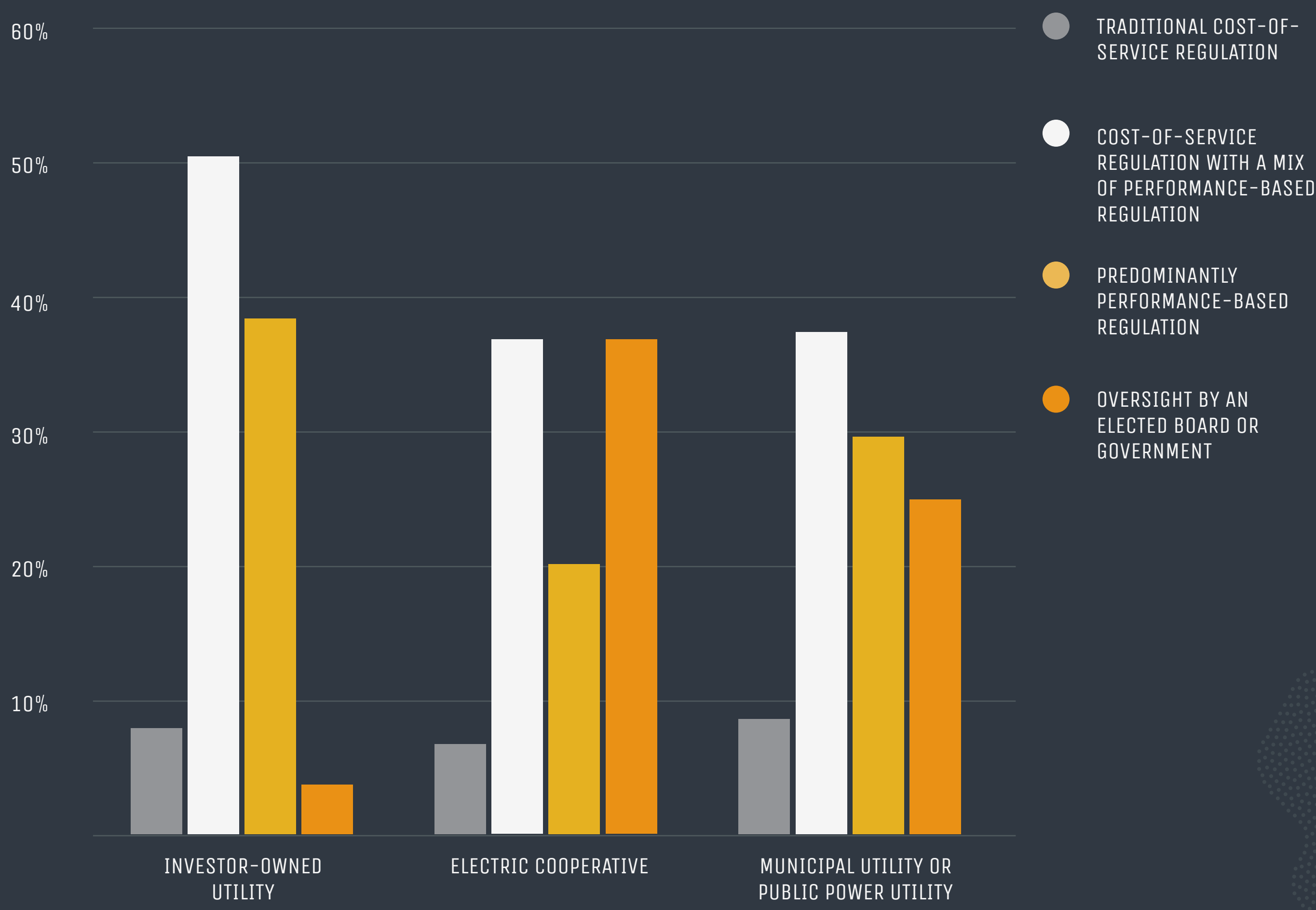


WHAT DO YOU EXPECT YOUR REGULATORY AND RATEMAKING ENVIRONMENT TO LOOK LIKE IN 10 YEARS?

(IOU respondents only)



WHAT IS THE MOST APPROPRIATE UTILITY REGULATORY MODEL IN THE 21ST CENTURY?



Direct government control of utilities is, of course, the predominant regulatory model for municipal utilities, public power agencies and electric co-ops. A greater diversity of other models exists among IOUs.

Currently, half of all IOU participants say their utility is traditionally regulated. But nearly one-third say they currently have hybrid regulation. Only 4% of IOUs indicated they have a predominantly PBR system. Regionally, there are some notable differences in how IOUs are regulated.

Hybrid regulation. New England currently leads North America in this approach. There, two-thirds of IOU professionals report hybrid regulation, vastly surpassing the traditional model (only 25%). Not far behind, 40% of West Coast IOU professionals also report hybrid IOU.

Traditional COS is currently prevalent among IOUs in the Great Plains/Rockies, Southwest/South Central, and the Midwest. By contrast, just one-fourth of New England IOUs, and one-third of IOUs in Canada and on the West Coast, currently are traditionally regulated.

PBR does not predominate anywhere yet, but so far most commonly reported by Canadian IOU professionals (17%).

As we found last year, many survey participants expect their regulatory model to evolve significantly in the coming decade. In particular, they expect to have more performance metrics to comply with as the hybrid model proliferates.

IOUs in particular foresee a big regulatory flip. In a decade, half expect to operate under hybrid regulation. Meanwhile, traditional cost-of-service regulation is expected to shrink to just 14% in this sector.

Meanwhile, the vast majority of public utilities expect to remain primarily under government control. But even this sector predicts a modest increase in hybrid regulation and PBR from their elected boards.

In the next 10 years, the greatest growth in hybrid regulation might happen in the Midwest. 48% of Midwestern participants predict a shift toward hybrid regulation within 10 years, compared to the 18% who currently report hybrid regulation. Such growth would outpace the anticipated level of hybrid regulation in New England, which (although it currently leads North America in hybrid regulation) expects no change on this front in the coming decade.

WHAT KIND OF REGULATION DO UTILITIES WANT?

As in 2017, it appears that this year many utilities still want to have their regulatory cake and eat it too via hybrid regulation.

That is, many utilities would like regulators to allow them more leeway and incentives to experiment and take technology and business risks (as is happening with performance metrics in the State of New York), while still shielding them from the worst financial consequences of risk and competition. In practical terms, utilities envision a hybrid regulation where they get to keep their ability to rate-base traditional investments, while also finding innovative revenue streams.

A big reason why U.S. utilities are bullish on hybrid regulation is that more utilities are seeing customer demand for new distributed resources. Utilities would like to capitalize on this emerging market, especially if they have low or declining load growth.

Many states are pursuing performance-based regulation or incentives, including Michigan, Oregon, Pennsylvania, Massachusetts, Minnesota, New York and Rhode Island. These state PBR initiatives and others can help spur grid modernization efforts at utilities, the North Carolina Clean Energy Technology Center noted in its first quarterly report on U.S. grid modernization efforts, released last year.

Traditional COS appears to be widely disfavored throughout the utility industry. When asked which regulatory model they believe would be most appropriate for the 21st century, fewer than 10% of professionals from any utility type mentioned traditional COS.

Across the industry, support remains strongest for the hybrid model. 44% of all utility professionals indicate a preference for hybrid regulation, while an additional third would prefer to shift to primarily PBR. Support for the traditional COS model this year dwindled to a mere 8%.

Even public utilities desire less government oversight and more performance metrics. A substantial majority of municipal utility professionals prefer the hybrid model (37%) or PBR (20%). Similarly, 37% of participants from co-ops indicated a preference for hybrid regulation going forward, equal to the percentage in that sector who continue to prefer government oversight. And one-fifth of co-op professionals would prefer PBR.

So far, only participants from Canada and the Great Plains/Rocky Mountain regions prefer performance-based regulation above any other model for the 21st century. All other regions prefer hybrid regulation — especially in the Southwest/South Central region (62%).

Participants from the Great Plains/Rockies show the weakest support for hybrid regulation (28%), and also the strongest support for government oversight (33%) This could reflect the large number of co-ops in that region.

"WE ARE READY TO GO ALL-IN ON GRID MODERNIZATION, BUT ANTICIPATE A HUGE FIGHT OVER GRID MODERNIZATION INVESTMENTS IN OUR NEXT FEW RATE CASES."

+ Large West Coast IOU

WHAT ARE THE MOST COMMONLY MENTIONED REGULATORY CHALLENGES?

1. **45%** JUSTIFYING EMERGING INVESTMENTS
2. **38%** RECOVERING REVENUE FROM DECLINING KWH SALES
3. **37%** MANAGING GROWTH OF DISTRIBUTED RESOURCES AND THE REVENUE/RATE IMPACTS OF SOLAR
4. **35%** REDESIGNING RATES TO RECOVER FIXED COSTS
5. **28%** LOSING CUSTOMERS TO COMPETITION

REGULATORY CHALLENGES

All regulatory models pose challenges for utilities. In 2017, fixed cost recovery was the most common concern noted by survey participants. But this year, the most common overall difficulty was justifying emerging utility investments in technologies like energy storage, electric vehicle chargers and microgrids. That was mentioned by 45% of all survey participants.

These issues are interrelated. For example, many utilities are experiencing relatively new problems that make it harder to recover fixed costs: new technologies, new customer demands, and stagnant or shrinking load.

Since U.S. utilities are regulated at the state level, there are profound regional differences in the types of regulatory difficulties that utilities encounter.

While one of the earliest energy policy decisions of the Trump administration was to initiate a repeal of the Clean Power Plan, this year few utilities in any region mentioned "meeting pollution mandates and/or climate standards" as a top current challenge. Those mandates are most likely to be a significant difficulty for utilities located in the Great Plains/Rockies (28%) and on the West Coast (18%). But in both regions, other more regulatory concerns appear far more pressing.

Stranded assets remain a significant concern for many utilities. Not surprisingly, utilities in the Great Plains/Rockies and Southwest/South Central states are most likely to report challenges related to stranded assets. Those regions still rely heavily on coal-fired power plants, which face increasing competition from natural gas and renewable energy resources.

REGULATORY REFORM

Efforts to move utilities from traditional cost-of-service regulation to hybrid or performance-based models are currently underway in about a dozen U.S. states. Nearly 30% of participants in this survey reported that some sort of utility regulatory reform is already happening in their state, and almost as many expect such a proceeding to commence shortly.

Many utilities welcome regulatory reform, but some do not. Of the 43% of respondents whose states are not yet pursuing regulatory reform, just over half would like to see regulatory reform, but about 45% would not.

Utilities that do not have — and do not want — regulatory reform tend to have some characteristics in common.

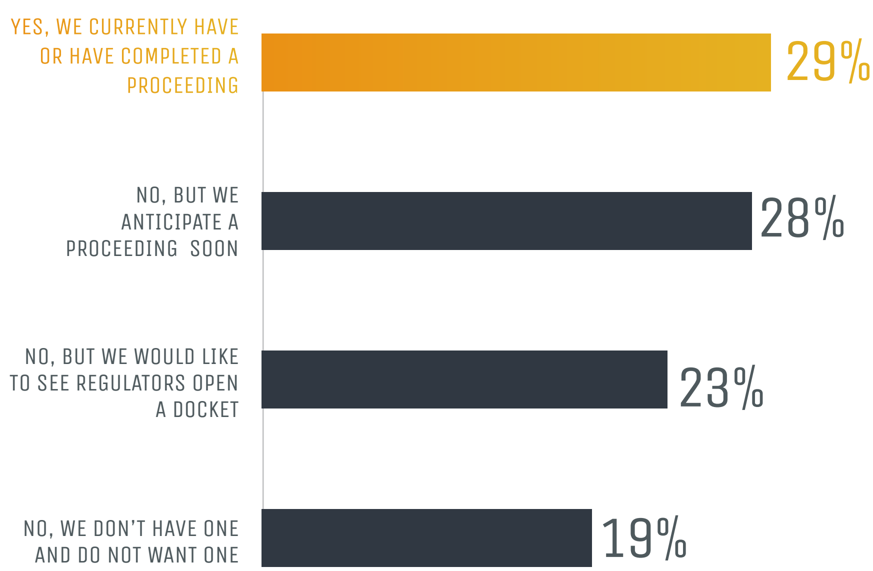
Regionally, about one-third of utilities in the Midwest, South/Southeast and Great Plains/Rockies do not want regulatory reform.

Co-ops and any utility serving fewer than 100,000 customers are especially unlikely to desire regulatory reform. Most of these utilities operate in an electricity market where they own generation assets and receive cost recovery, but generation is dispatched by regional ISO. They also anticipate little or no increase in the portion of renewable energy and new technologies (such as energy storage) in their power mix. They predict this situation will continue for at least the next decade.

Utility professionals who do not want regulatory reform also noted these top regulatory challenges:

- Recovering lost revenue due to efficiency and load decline: **46%**
- Justifying investments in emerging technologies: **44%**
- Recovering fixed costs through rate design: **37%**
- Losing revenue due to competition: **27%**
- Managing distributed resource growth and debates over net metering/value of solar: **27%**

ARE REGULATORS IN YOUR STATE CONDUCTING OR CONSIDERING A PROCEEDING TO REFORM UTILITY BUSINESS AND/OR REVENUE MODELS?



For utility professionals who do wish to see regulatory reform happen in their states, the vast majority of their companies currently operate under either traditional cost-of-service regulation (45%) or government oversight (37%). But in 10 years, these respondents expect traditional COS to decline significantly, which indicates they expect some form of performance-based regulation to be put in place eventually.

Utility professionals who desire regulatory reform expect that it will bring significant increases in hybrid regulation and, to a lesser extent, PBR. This reflects their overwhelming opinion that these two regulatory models make the most sense for the future.

Overall, survey participants who desire regulatory reform noted these top challenges related to how they are currently regulated:

- Recovering fixed costs through rate design: **44%**
- Recovering lost revenue due to efficiency and load shrinkage: **42%**
- Justifying investments in emerging tech: **41%**
- Managing distributed resource growth and debates over net metering/value of solar: **40%**
- Losing revenue due to competition: **27%**

UTILITY PROFESSIONALS WHO DESIRE REGULATORY REFORM EXPECT THAT SUCH REFORM WILL BRING SIGNIFICANT INCREASES IN HYBRID REGULATION AND, TO A LESSER EXTENT, PBR.

ELECTRICITY MARKETS

At the dawn of the utility industry, electricity was not traded in open markets. Utilities generated all the power they served to customers. In exchange for taking on the costs and risks of supplying power to their designated territories, regulators shielded them from competition.

But by the 1990s, independent generators began to proliferate and states began to deregulate their markets. Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) arose to manage the transmission system independently and to foster competition among generators in wholesale electricity market.

Today, two-thirds of U.S. electricity demand is served by these wholesale markets. The vertically-integrated model persists in the Southeast, Southwest and Northwest regions of the country. All told, 23 states and the District of Columbia have deregulated at least parts of their electricity markets.

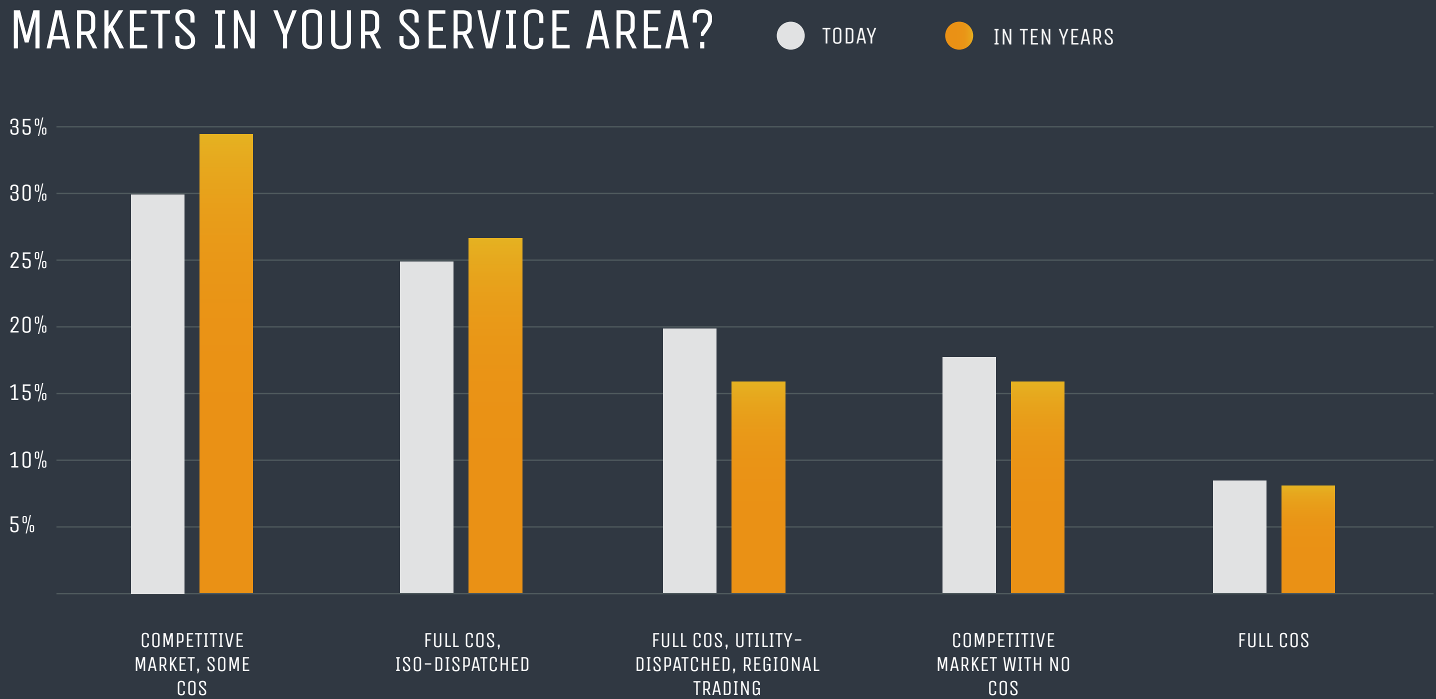
The manner in which wholesale and retail power markets work is a key consideration in both utility business/operation and regulation. This year, Utility Dive decided to delve deeper into the nuances of electricity market. We went beyond simply asking whether a market is vertically integrated or not.

Electricity market models vary widely across North America due to variations in state laws and regional electricity market rules. In our 2018 survey, we asked utility professionals to consider five general market constructions:

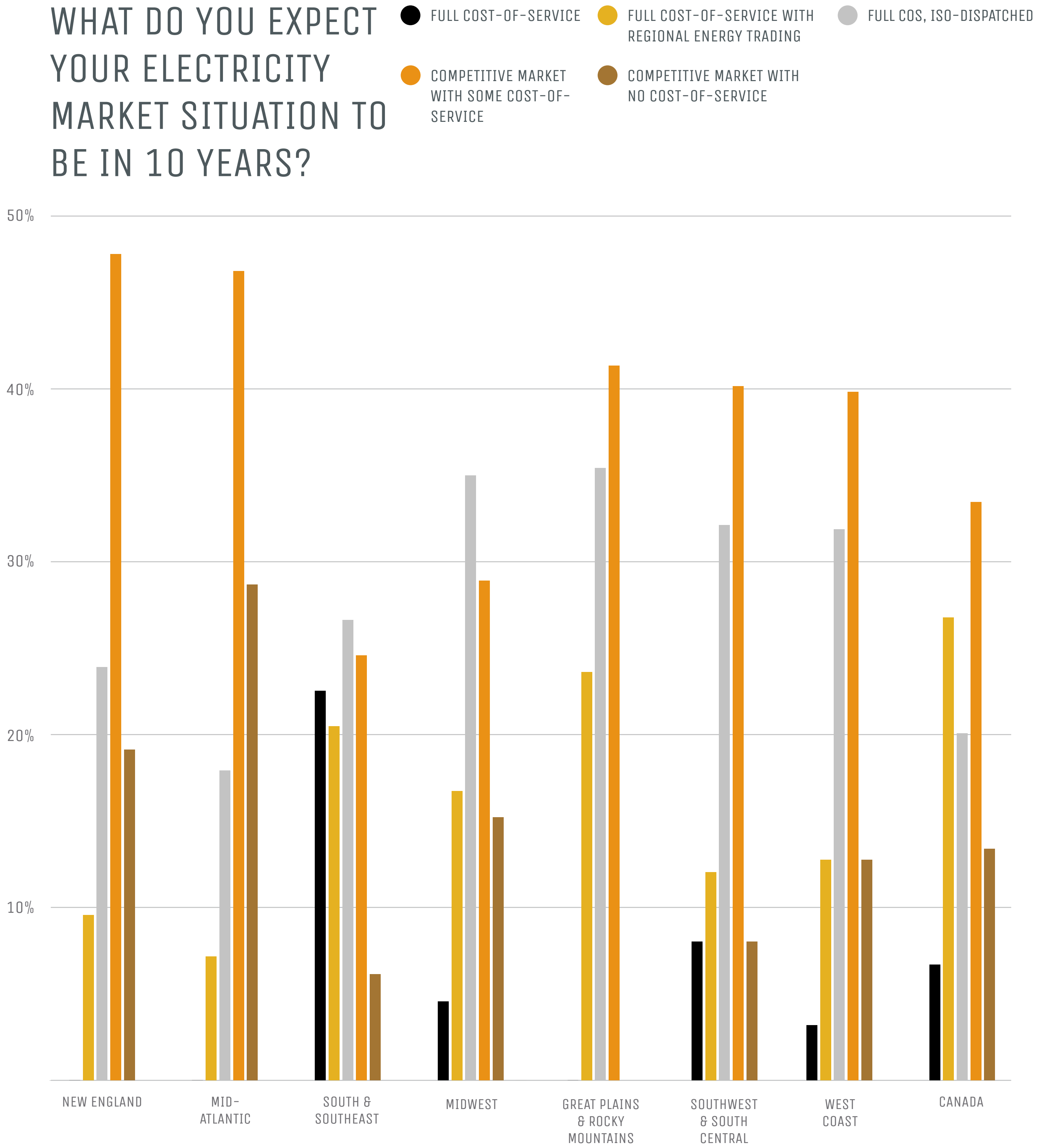
- **Full cost-of-service (COS), no regional market.** Vertically integrated utilities own and dispatch their own generation; there are no centralized wholesale or retail markets.
- **Full COS, utility-dispatched, regional trading.** Utilities own and dispatch their generation assets, and they receive cost recovery, but they trade energy with regional energy partners.
- **Full COS, ISO-dispatched.** Utilities own their own generation and receive cost recovery from the rate base, but their generation capacity is dispatched into an organized regional market by a central independent system operator (ISO) or a regional transmission organization (RTO).
- **Competitive market, some COS.** Utilities participate in a competitive market for electricity, but some generators are eligible for cost recovery.
- **Competitive market, no COS.** Utilities participate in a competitive market for electricity with no cost-of-service recovery.

Full COS, ISO-dispatched appears to be the most common electricity market model among participants: 30% report that their utility operates in this type of market. Close behind, at 25%, are regional markets with full COS and utility-dispatched generation. The least common type of North American electricity market (8%) among participants is competitive markets with no COS.

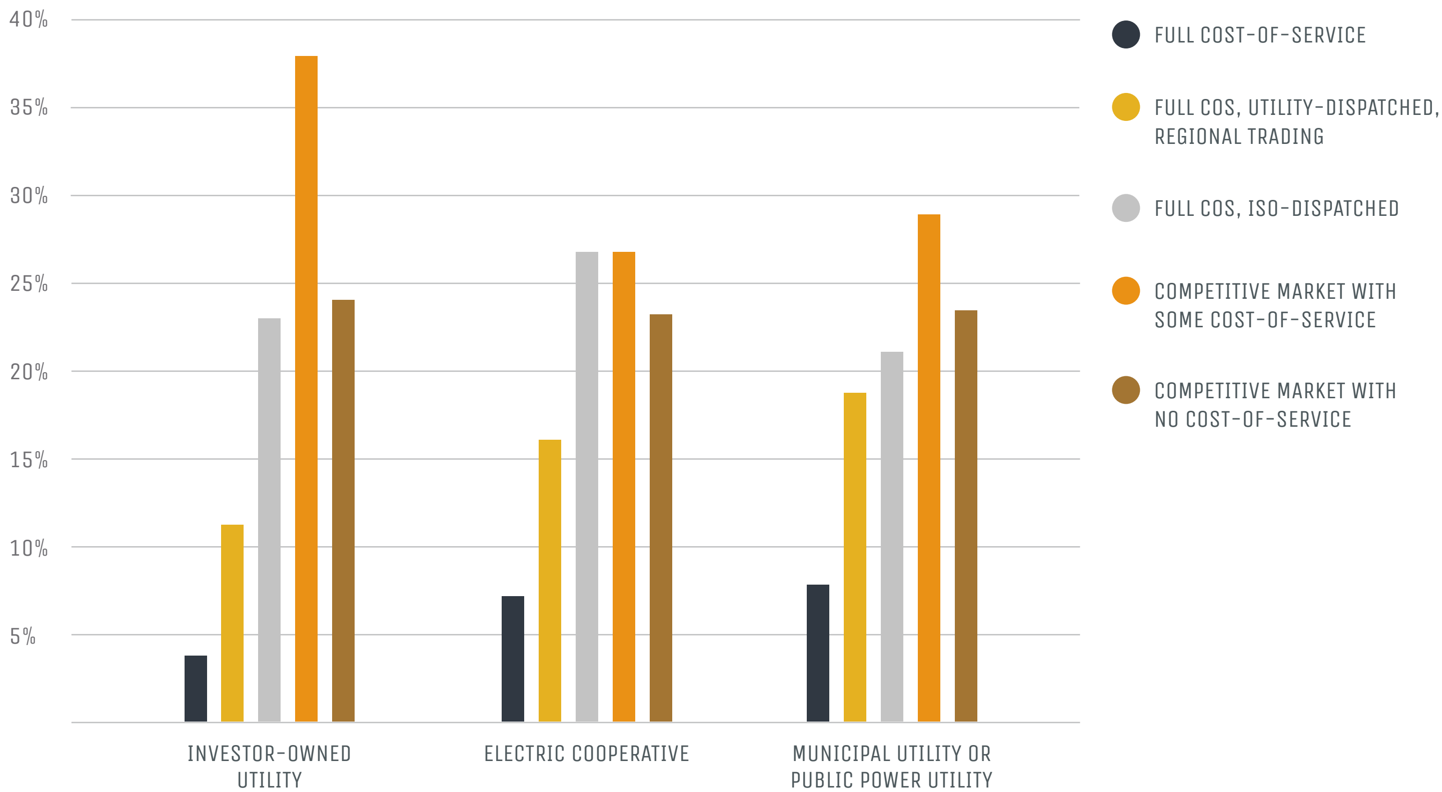
WHICH OF THE FOLLOWING BEST DESCRIBES THE ELECTRICITY MARKETS IN YOUR SERVICE AREA?



WHAT DO YOU EXPECT YOUR ELECTRICITY MARKET SITUATION TO BE IN 10 YEARS?



WHAT IS THE MOST APPROPRIATE ELECTRICITY MARKET CONSTRUCTION IN THE 21ST CENTURY?



But in 10 years, utilities expect the market landscape to look different. The most often-mentioned model is a competitive market with some COS (34%). Full COS with ISO-dispatched generation is expected to drop to second place overall (26%).

What kind of markets would utilities prefer? Overall, the model that the largest portion of survey participants believe is most appropriate is a competitive market with some COS (33%). The two next most popular models are a competitive market with no COS (24%), and full COS with ISO-dispatched generation (23%). Breakdowns by utility type and size mostly echo these overall trends.

> "FUELING RENEWABLES VIA OUT-OF-MARKET TAX SUBSIDIES SERIOUSLY ERODES THE WHOLESALE MARKET CONSTRUCT."
>
> + Small Midwestern municipal utility

REGIONAL VARIATIONS IN ELECTRICITY MARKET MODELS

There are profound regional differences in North American electricity markets. For instance, utility professionals in almost every region voiced a strong desire to move primarily toward competitive markets, usually with some cost recovery. The exceptions to this are the Midwest, Southwest and South Central states.

Canada:

- Current leading model: Full COS ISO-dispatched generation (29%), slightly leads full COS utility-dispatched generation with regional trading (26%)
- 10-year outlook, expected leading model: Competitive market, some COS (33%)
- Most preferred: Competitive market, no COS (45%)

Great Plains/Rockies:

- Current leading model: Full COS utility-dispatched generation with regional trading (67%)
- 10-year outlook leader: Competitive market, some COS (48%)
- Most preferred: Competitive market, some COS (39%)

Mid-Atlantic:

- Current leading model: Competitive market, some COS (40%)
- 10-year outlook leader: Competitive market, some COS (46%)
- Most preferred: Competitive market, some COS (36%)

Midwest:

- Current leading model: Full COS, ISO-dispatched generation (46%)
- 10-year outlook leader: Full COS, ISO-dispatched generation (35%)
- Most preferred: Full COS, ISO-dispatched generation (35%)

New England:

- Current leading model: Competitive market, some COS (38%)
- 10-year outlook leader: Competitive market, some COS (48%)
- Most preferred: Competitive market, some COS (45%)

South and Southeast:

- Current leading model: Full COS no regional trading (45%). This is only region in which the traditional electricity market model still dominates.
- 10-year outlook leaders: Full COS ISO-dispatched generation (27%), slightly leads Competitive market with some COS (25%)
- Most preferred: Competitive market, some COS (40%)

Southwest and South Central:

- Current leading models: A tie between full COS ISO-dispatched generation, and full COS utility-dispatched generation with regional trading (both 32%)
- 10-year outlook leader: Competitive market, some COS (40%)
- Most preferred: Full COS with ISO-dispatched generation (39%)

West Coast:

- Current leading model: Full COS, ISO-dispatched generation (41%)
- 10-year outlook leader: Competitive market, some COS (40%)
- Most preferred: Competitive market, some COS (38%)

PLANT RETIREMENTS AND DECARBONIZATION

Since last year's survey, the portion of utility professionals who expect to be operating under a the traditional vertically integrated market model in 10 years plummeted from 18% to 8%. But in several states, efforts are afoot to secure continued ratepayer support for aging power plants that would otherwise be retired for economic reasons. Such around-market subsidies aren't hugely popular with utility professionals this year, but they do have some support — from 12% of IOUs as well as in Canada (14%), the West Coast (13%) and in the Great Plains/Rockies (12%).

As 2017 drew to a close, FirstEnergy in Ohio was still attempting to gain cost recovery for struggling nuclear plants. Similar efforts had already passed in Illinois and New York. And a Union of Concerned Scientists report noted that 25% of remaining U.S. coal plants could be headed for retirement, largely spurred by historically low natural gas prices, which make both coal and nuclear power less competitive on wholesale markets.

But as much as the resurrection of the traditional vertical electricity market might appeal to utilities who hold considerable assets that are at risk of getting stranded, only 6% of utilities say that they desire this more than other market models.

This year, we asked utility professionals to pick their favorite option for how policymakers (regulators and lawmakers) might respond to the retirement of baseload generation (coal and nuclear plants) in the nation's organized electricity markets. Here's how they responded:

1 | **New market-based products** to value and pay grid resources for providing reliability and resilience: **30%**

2 | **Allow natural retirement** of uneconomic generation under current market rules: **27%**

3 | **Expand wholesale market rules** for reliability-must-run and capacity performance: **11%**

4 | **Impose a price on carbon** to support nuclear power, while allowing other baseload plants to retire: **11%**

5 | **Around-market subsidies** (such as New York's Zero Emission Standard) to extend the operating life of selected plants, usually nuclear: **9%**

6 | **Resurrect the vertically integrated utility** model by re-regulating state utility markets: **7%** (On a related note, vertical integration was this year's least-favored electricity market construction for the 21st century.)

7 | **Cost recovery for select plants,** as attempted by the DOE grid resilience proposal, which FERC rejected just after our 2018 survey closed: **5%**

"THE FEDERAL GOVERNMENT NEEDS TO LEAD: SET A FIRM CARBON PRICING POLICY, AND THEN LET US GET ON WITH IT."

+ Midwestern co-op

HOW SHOULD POLICYMAKERS (GRID OPERATORS AND LAWMAKERS) RESPOND TO THE RETIREMENT OF BASELOAD GENERATION IN THE NATION'S ORGANIZED MARKETS?

30%	DEVISE NEW MARKET-BASED PRODUCTS TO VALUE AND PAY GRID RESOURCES FOR THEIR RELIABILITY AND RESILIENCE ATTRIBUTES
27%	ALLOW UNECONOMIC GENERATION TO BE RETIRED UNDER CURRENT MARKET RULES
11%	EXPAND EXISTING RELIABILITY-MUST-RUN AND CAPACITY PERFORMANCE RULES IN WHOLESALE MARKETS
11%	IMPOSE A PRICE ON CARBON TO SUPPORT NUCLEAR, LET OTHER BASELOAD PLANTS RETIRE
9%	DEVISE AN AROUND-MARKET SUBSIDY MECHANISM TO KEEP SELECTED PLANTS ONLINE (E.G. NEW YORK'S ZERO EMISSION STANDARD)
7%	RE-REGULATE STATE UTILITY MARKETS TO THE VERTICALLY-INTEGRATED MODEL
5%	PROVIDE COST RECOVERY TO SELECTED PLANTS (E.G. DOE NOPR)

In 2017 the most popular option was imposing an economy-wide price on carbon and other greenhouse gas emissions (28%), such as has already been enacted in Canada. But this year, that dropped to fourth place, perhaps because utilities see a carbon price as vanishingly unlikely under the Trump administration.

Respondents appeared to align their preferred baseload solution with their preferred electricity market model. 2018's most popular option (new market-based products to value and pay grid resources for providing reliability and resilience) would mesh well with the most common type of electricity market model that survey participants expect to operate under in ten years: a competitive market with some cost-of-service recovery. Both of these were mentioned by roughly one-third of participants.

Designing new market models for large, inflexible generators is likely to be a focal point for FERC and regional grid operators in the year to come. When FERC rejected the Department of Energy's plans to subsidize coal plants it asked grid operators to respond with techniques to make the grid more resilient. Some of these operators, like PJM and ISO-New England, already have market pricing reforms in the works and those proposals are likely to take center stage in 2018.

As happened with our 2017 survey, most utility professionals desire some sort of regulation of carbon emissions. However, they are divided about how government should accomplish this. How the decarbonization question gets settled, nationally or regionally, might profoundly affect how energy markets work.

We asked about different federal policy options last year and this year, and it's worth noting that in both years the vast majority of utility professionals said they'd like to see some kind of federal decarbonization policy (75% in 2017, which swelled to 85% in 2018). This year, the chief bastions of support for no federal action on decarbonization are once again places that tend to be more politically conservative: states in the South/Southeast, Midwest, and Southwest South Central regions. But only in the South/Southeast is doing nothing the clear number one choice.

In contrast, the most popular federal policy option by far (in both years, and in most regions) is a federally imposed carbon price.

Midwestern utility professionals seem especially split on this issue. There, doing nothing and carbon price are tied for first place.

Despite the wishes of the utility industry, it's likely that U.S. federal decarbonization policies will continue to stall or backpedal at least for a few years. That inaction could increase uncertainty and risk for the sector, which utilities identified as their biggest challenge associated with their changing fuel mix (see the Power Mix section).

Despite federal inaction on carbon regulation, utilities have, for the most part, already firmly committed themselves to a future of cleaner power generation. And decarbonization policy isn't solely up to the federal government, of course. At the state level, power grid modernization, storage deployment and updates to utility business models are fast-growing policy priorities, driven primarily by aggressive state renewable energy targets.

Currently more than 30 states are considering far-reaching reforms on these fronts, including initiatives to integrate battery storage into grid planning processes. In addition, some states are adding carbon costs to their utility-planning guidelines, using a key metric calculated by the Obama Administration.

IN GENERAL, HOW DO YOU BELIEVE THE U.S. FEDERAL GOVERNMENT SHOULD APPROACH DECARBONIZATION POLICY?

30% IMPOSE A PRICE ON CARBON AND OTHER GREENHOUSE GASES

19% REINSTATE THE OBAMA ADMINISTRATION'S CLEAN POWER PLAN

17% STRENGTHEN THE CLEAN POWER PLAN'S TARGETS AND FEDERAL RENEWABLE ENERGY SUPPORTS

17% THE U.S. GOVERNMENT SHOULD NOT PURSUE A POLICY OF DECARBONIZATION

12% IMPOSE A CAP-AND-TRADE SYSTEM FOR GREENHOUSE GASES

11% SCALE BACK THE CLEAN POWER PLAN TO 'INSIDE THE FENCE'

POWER MIX

Today's power mix is a snapshot of a vast transition in generation technologies. When considering how North American utilities might change their mix of generation sources in the near future, it's important to keep the big picture of electrical power in mind.

The tale of the heyday of coal-fired power plants is told in the three decades from 1986 to 2016, the most recent year for which the Energy Information Administration (EIA) has published electric power sector data. In 1986, U.S. utilities produced 1.4 million GWh by burning coal. Nuclear was the next biggest (yet still vastly smaller) piece of the utility generation pie, at 414,000 GWh — just 30% of what coal produced that year. Much lower on the scale were hydropower and natural gas, both of which generated roughly one-fifth as much power as coal in 1986.

By comparison, solar and wind power barely existed in the 1986 U.S. utility power mix. That year, solar represented just 14 GWh, and wind a mere 4 GWh of utility power generation.

2007 was the peak of coal-fired power production in the U.S. That year, utilities generated almost 2 million GWh from coal plants. And while nuclear power had shown a slow, steady increase over two decades, 2007

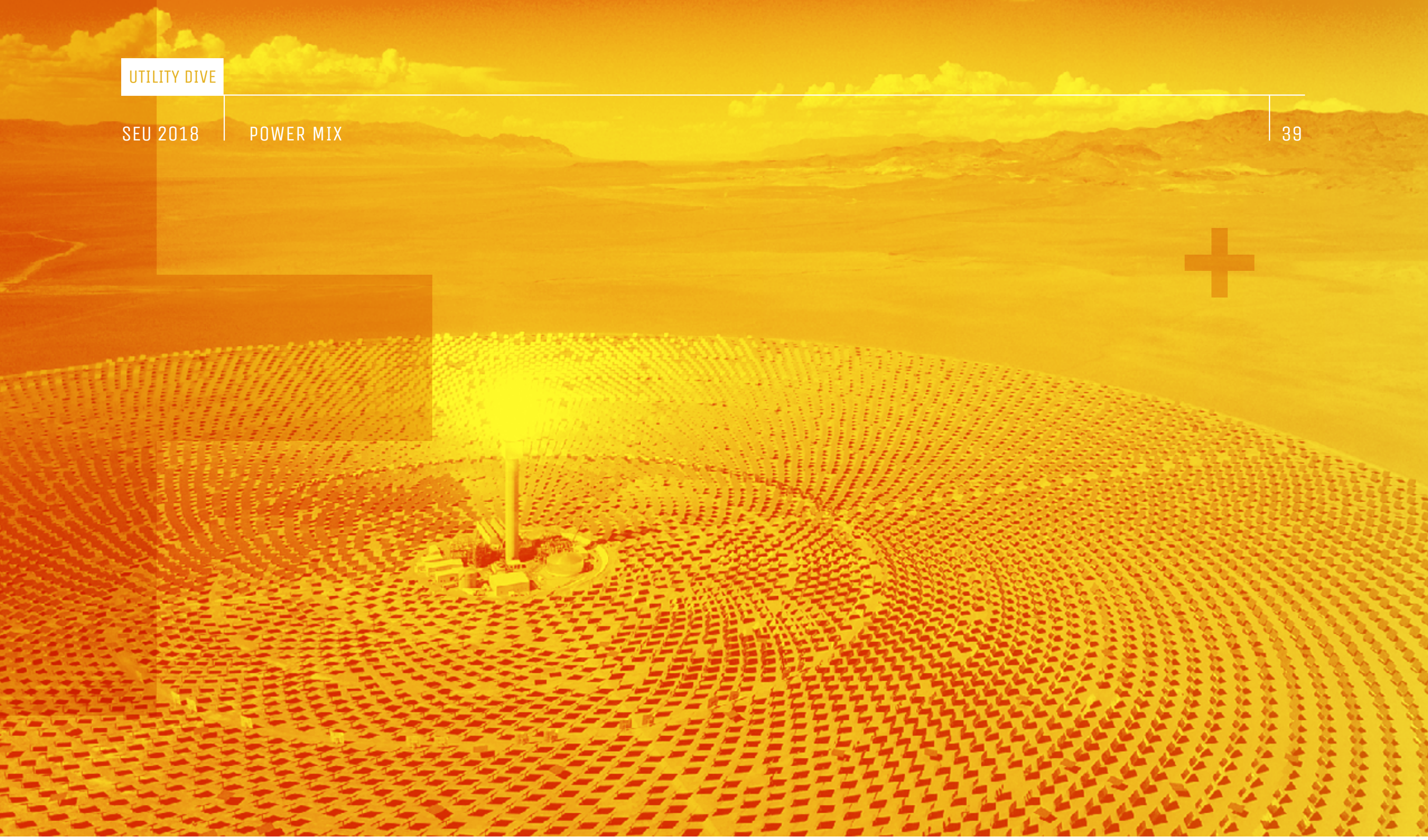
> "IF WE'RE SERIOUS ABOUT RENEWABLE ENERGY JOBS AND A SUSTAINABLE GRID, THEN GOVERNMENT INCENTIVES FOR COMMERCIAL ROOF TOPS SOLAR ARE NEEDED."
>
> + Mid-Atlantic IOU

was also the year that natural gas-fired generation reached parity with nuclear power: both generated a little over 800,000 GWh. By 2009, natural gas had pulled ahead of nuclear power output, and gas has not surrendered that lead since.

Meanwhile, by 2007 the renewables portion of the utility power mix had grown appreciably, to a total of just over 35,000 GWh (just under 2% as much energy as coal-fired power plants at that time). Prior to this, wind began to substantially surpass solar production in 1989. Then, in the early 2000s, wind power production grew in fits and starts, finally reaching over 190,000 GWh in annual production by 2016 (roughly 18% as much power as coal produced that year).

When considering renewables, it's important to keep in mind that (despite notable progress) renewable energy still produces vastly less electricity than current U.S. demand. While renewables will undoubtedly grow steadily within the U.S. energy picture, many utilities and regulators remain cautious of the challenges that renewables present, especially regarding intermittence and grid integration. Grid-scale energy storage would support renewable energy expansion and integration, as might widespread EV charging schemes, but those technologies have yet to proliferate across the nation.

Also back in 2007, coal began its steady tumble: coal power production declined by nearly 40% over a decade. This was precipitated by a revolution in gas drilling technology that led to steep declines in natural gas prices, making natural gas a far more affordable option. Utilities began shifting generation capacity from coal to natural gas, and by 2016 the two fuels represented roughly equal portions of utility power production.



EIA data indicate that by 2017 utilities were finally producing more power from natural gas than from coal. Whether this trend persists or strengthens depends mainly on economics, particularly natural gas fuel costs.

The electric power industry reached a renewable energy milestone in 2017 as well: wind and solar output may have surpassed hydro. For most of a century, hydropower has long been the largest renewable component of many utilities' power mix. But 2016 data showed that conventional hydropower output (266 million GWh) is now closely tied with the total output of wind and solar (227 million GWh). For several years, the trend has been for hydropower output to remain static, and the industry consensus is that this will not change anytime soon.

For all the rosy news about cleaner power, utilities also have substantial concerns about the future of their power mix. Our survey this year indicates that the utility professionals' biggest power mix concern, by far (at 40%), is regulatory and policy uncertainty. All types of utility organizations are highly concerned about uncertainty. However, co-ops appear slightly more concerned about reliably integrating new resources (27%), than they are about stranded assets and uncertainty (both 25%).

On the policy front, the first year of the Trump administration has cast considerable doubt on whether U.S. federal energy policy will continue reflect the consensus of utilities, states and the economy. This administration is championing a revival of coal and nuclear power while at the same time promoting natural gas development — a main competitor to the coal and nuclear sectors.

Despite the uncertainty, utilities in 2018 report that they are steadily moving to a cleaner power system more reliant on renewables, storage and gas.

10-YEAR OUTLOOK: KEY POWER MIX TRENDS

In the coming decade, utilities mostly expect to continue their evolution away from coal and nuclear power and toward renewable energy and newer technologies such as storage. These overall trends hold true across all North American regions, as well as all utility types.

Bye-bye coal. After more than a century, the utility industry appears to finally be putting this baseload workhorse fuel out to pasture. Nearly 60% of 2018 survey participants predict a significant decrease in their usage of coal in coming years, and a further 26% predict a moderate decrease. Virtually no one foresaw any increase in their coal use. The primary reason for this is the changing economics of North American energy; natural gas is plentiful and relatively cheap.

Hello, utility-scale solar. The biggest growth is expected in large-scale solar farms: nearly half of survey participants expect significant increases in this component of their power mix. This general trend is strong across all regions, but the West Coast (59%), South/South Central U.S. (55%) and Canada (50%) expect the most significant increases in utility-scale solar. However, the January 2018 announcement by the Trump administration of a 30% tax on imported solar panels could, by some estimates, reduce utility-scale solar installations by 9%.

Distributed generation and storage, which include grid-connected rooftop and community solar installations as well as grid-connected energy storage, are not far behind: 40% of all participants expect to see

HOW DO YOU THINK YOUR UTILITY'S POWER MIX WILL CHANGE OVER THE NEXT 10 YEARS?

UTILITY SCALE SOLAR
48% SAY INCREASE SIGNIFICANTLY

DISTRIBUTED GENERATION & STORAGE
51% SAY INCREASE MODERATELY

GRID-SCALE ENERGY STORAGE
49% SAY INCREASE MODERATELY

WIND
53% SAY INCREASE MODERATELY

NATURAL GAS
39% SAY INCREASE MODERATELY

HYDRO
74% SAY STAY ABOUT THE SAME

NUCLEAR
55% SAY STAY ABOUT THE SAME

OIL
46% SAY DECREASE SIGNIFICANTLY

COAL
58% SAY DECREASE SIGNIFICANTLY

significant growth in these technologies, while an additional 51% anticipate moderate growth. Participants in Canada (58%), New England (56%) and the West Coast (52%) expect the most significant growth in this part of their fuel mix.

Grid-scale energy storage is still in its early days, not yet widely deployed by utilities. But that could be about to change. This year, 88% of utility professionals said that they expect their companies to see significant or moderate increases in grid-scale energy storage over the coming decade. In the West Coast, 49% expect significant growth followed by Canada (46%) and New England (44%).

Wind. One-fourth of utility professionals said they expect to still see significant growth in wind power on their systems in the next 10 years, while 53% expect this growth to be moderate. In March 2017, EIA reported that wind overtook hydro as the top renewable source of U.S. power generation capacity. 33% of respondents from New England expect significant growth, followed by the Great Plains/Rockies (28%) and Midwest (27%).

Natural Gas. Low natural gas prices have played a leading role in reshaping energy markets and hastening the retirement of coal and nuclear plants. According to EIA, in 2016 gas overtook coal in the overall U.S. power mix. But the mad rush toward gas-fired generation may be waning. Just under 40% of participants predict that their utility's use of natural gas will increase only moderately in the coming decade — far more than the 17% who expect significant growth in their use of natural gas. Also, 26% expect their natural gas use to stay the same. Fewer than one in five expect any decline in their natural gas use, but in some states, especially California, aggressive renewable energy and climate targets might eventually slow or stop the growth of gas-fired generation.

Nuclear. Over half of participants noted no change in the next decade in their utility's usage of nuclear power. A handful of participants mentioned that they anticipate an increase in the nuclear portion of their fuel mix, likely reflecting the sole U.S. nuclear power project under construction in the U.S. (Southern Co.'s Vogtle project). By contrast, 19% of participants expect a significant nuclear decrease, likely due to plant retirements. An additional 21% anticipate a moderate decrease. This probably reflects jurisdictions where nuclear plants are slated to retire (Massachusetts, California, Michigan and elsewhere), primarily due to its competitive disadvantage against natural gas in wholesale markets.

Oil. For some time, oil has represented only a small portion of most North American utilities' power mix -- primarily to meet flexible generation needs during peak demand hours. But, like coal, oil appears to finally be on its way out. Of survey participants who work at utilities that currently use some oil, 46% predict a significant drop in this usage, and an additional 20% expect a moderate decrease. About one-third expect their oil usage to remain about the same, including 69% in the Great Plains/Rockies and nearly 40% in the Midwest and West Coast. Interestingly, New England and the Mid-Atlantic (where oil generation remains critical to meet winter power demands when gas is constrained), both anticipate drops in oil consumption. 100% of New England respondents expect oil to decrease in their power mix (73% significantly) and 85% of Mid-Atlantic respondents expect it to decrease (48% significantly).

Hydro holds steady, for now. This year, the vast majority of utility professionals (75%) said that they expect their hydro use to remain about the same. The big uncertainty with hydro, however, is the looming but hard-to-predict impacts of climate change, including more severe weather events. In 2015, Pacific Institute research indicated that California's drought significantly impaired hydropower production. But as the drought abated, wholesale power prices dropped, leading to greater wind and solar curtailments — which, in turn, contributed to negative pricing. Flooding events also challenge hydropower systems. For instance, in 2017, damage to California's Oroville Dam took 800 MW of generation offline.

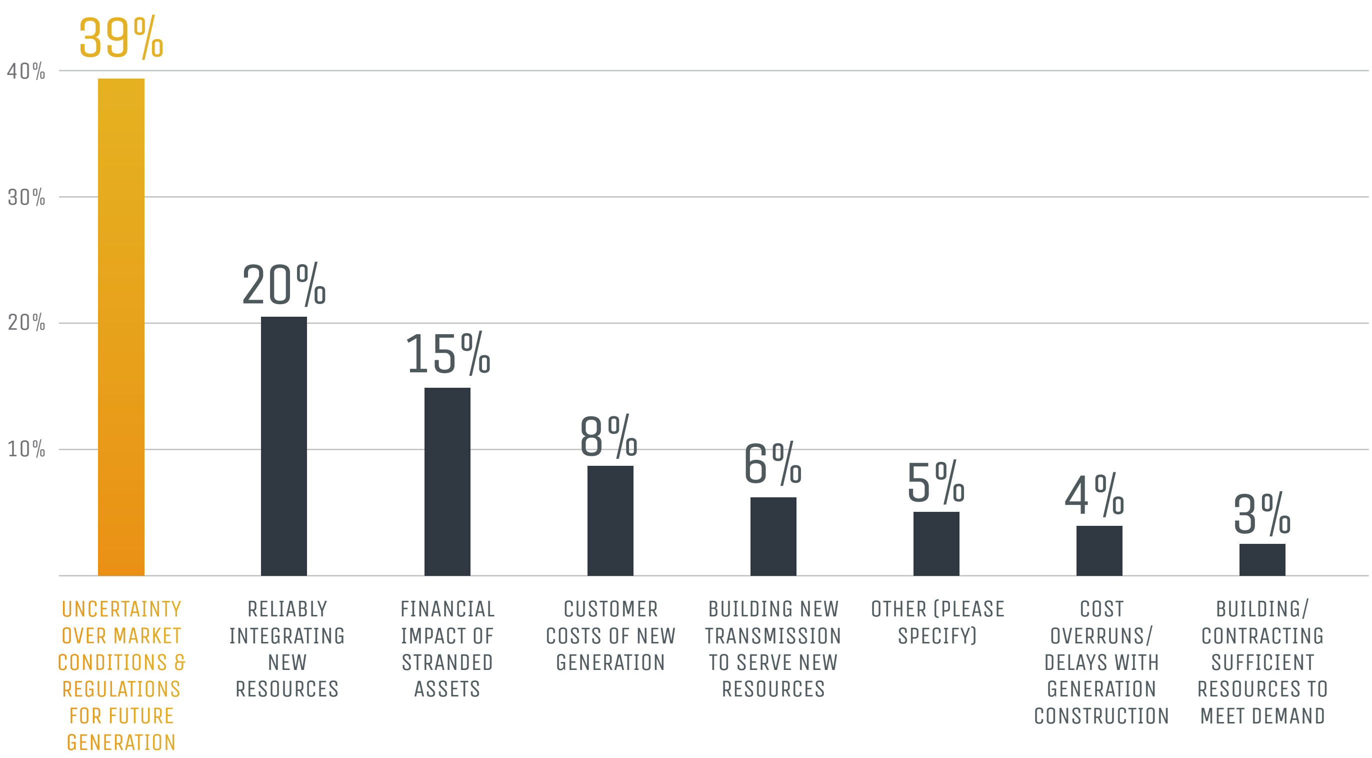
CONCERNS ABOUT POWER MIX CHANGES

Utilities know the changing fuel mix means they must change the way they operate, but the transition also presents numerous challenges.

As gas prices dropped and the Obama White House issued new emissions regulations, many utilities were faced with stranded assets — plants forced offline before they are fully depreciated.

Plant operators don't plan to strand their assets, but instead are forced into the decision by regulatory and

WHAT'S THE SINGLE GREATEST CHALLENGE ASSOCIATED WITH YOUR CHANGING FUEL MIX?



market forces. That points to the leading power mix concern among survey respondents for the second year running: uncertainty.

This year, concern about uncertainty is apparent across North America. Canadian utilities showed the most concern, at 46%. The U.S. regions reporting the highest levels of concern about uncertainty were the Mid-Atlantic (45%) and West Coast (44%).

Interestingly, only 17% of participants from the Great Plains and Rockies mentioned uncertainty as one of their top concerns. Respondents from this region indicated they were most concerned with stranded assets (39%), though market conditions and plant regulations can contribute those concerns as well.

After market and regulatory uncertainty, 20% of respondents listed reliable integration of new generation resources, making it the second-most pressing concern. That number represents an increase from 16% in 2017, but still falls well below the 32% of participants in 2016 who named reliable integration as a top concern.

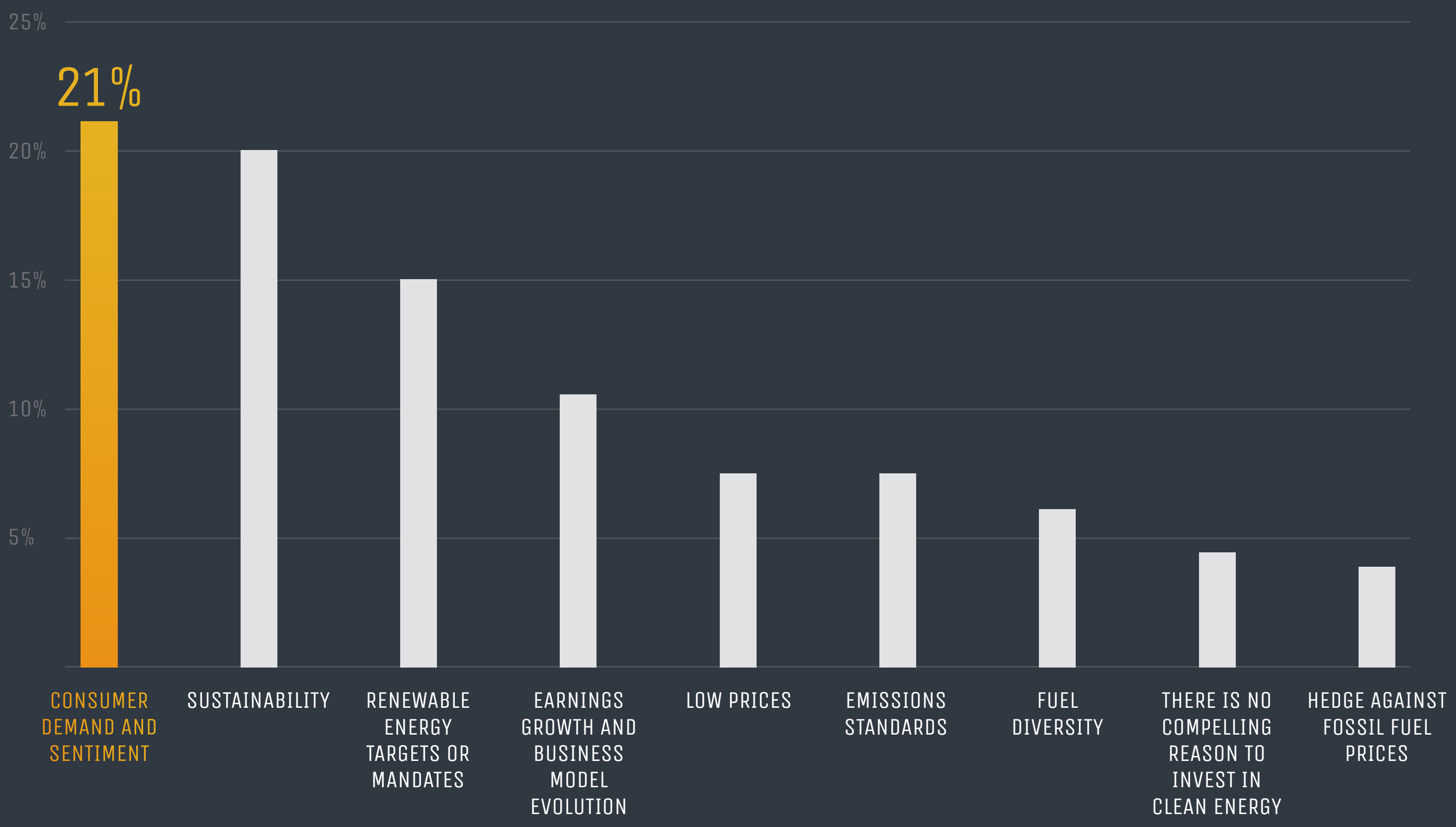
By comparison, in 2017 the #2 power mix concern (at 24%) was minimizing customer costs for new generation. But this year, a mere 9% of utility professionals mentioned this concern. This may be partially attributable to expected further price declines for renewables and energy storage, as well as continuing cheap natural gas.

In third place this year, the financial impact of stranded assets remains a significant utility concern for power mix: 15% of all participants noted this, up slightly from 2017.

There are notable regional differences in concern about each of the most pressing power mix issues of 2018:

- **Reliably integrating new resources:** New England (50%), Southwest/South Central (41%), Mid-Atlantic (21%)
- **Uncertainty over markets/regulations:** Mid-Atlantic (45%), West Coast (44%), South/Southeast (38%)
- **Stranded assets:** Great Plains/Rockies (39%), Midwest (23%), South/Southeast (19%)
- **Customer costs for new generation:** Great Plains/Rockies (17%), Mid-Atlantic (10%), Southwest/South Central (9%)
- **Building new transmission to serve new resources:** New England and Great Plains/Rockies (both 11%), Midwest (8%)
- **Construction cost overruns/delays:** Southwest/South Central (9%), Canada (7%) South/Southeast (6%)
- **Building/contracting new resources to meet demand:** Mid-Atlantic (7%), Midwest (3%), West Coast (2%). Note that these were the only regions where there was any mention of these challenges as a top concern.

+ WHAT IS THE MOST COMPELLING REASON TO INVEST IN CLEAN ENERGY TECHNOLOGIES SUCH AS RENEWABLES AND STORAGE?



BUSINESS CASE FOR CLEANER POWER

Most utilities remain strongly committed to increasing development and deployment of renewables and storage technologies, both utility-scale and distributed. Only a small minority (4%) said there is no compelling reason to invest in clean technologies, and that's declined from 7% in 2017.

Like last year, the most popular reason to invest in clean technologies (noted by 21% of participants) is that their current and future customers demand cleaner power. As energy markets become increasingly competitive, this motivation is likely to grow stronger.

Also like last year, sustainability is close behind (20%). Sustainability can be interpreted in different ways. It can be an internal organizational goal, tied to quantitative business, financial, environmental and risk management targets. It also can be a value, tied to more qualitative factors of intent and perception. Our survey did not define sustainability, but it's likely that both factors are in play at most utilities.

Renewable energy targets or mandates remained the third-place motive for 2018, mentioned by 15% of participants (down slightly from 2017).

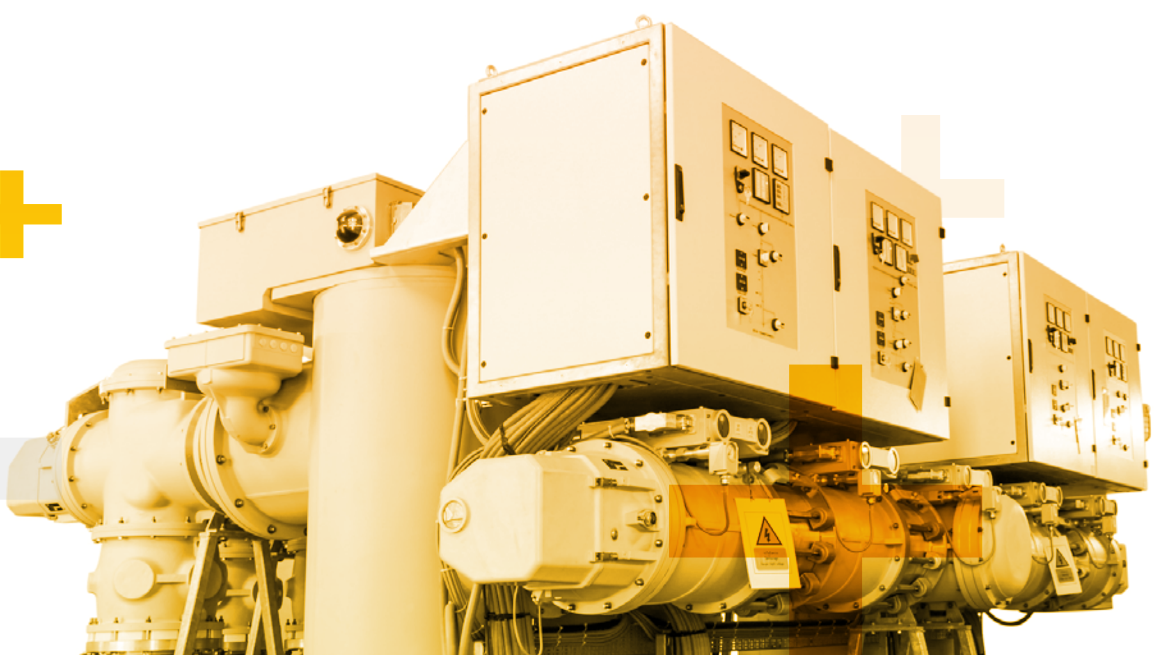
This year, earnings growth and business model evolution moved up into fourth place at 11%, although this is the same percentage as in 2017. Meanwhile, the portion of participants who named low prices as a key reason for deploying more renewables and storage declined this year to just 7% — less than half of the 15% who cited this motive in 2017.

DERS, EVS AND UTILITY BUSINESS IMPACTS

The era of decentralized energy production appears to be upon us. In this year's survey, support for distributed energy resources (DERs) is strong across all sizes and types of utilities and in every North American region.

Altogether, 91% of all participants in this year's survey expect to see moderate to significant DER expansion on their systems, slightly more than last year. And 63% report being significantly concerned about the electrification of transport and other industries.

Distributed energy resources cover a variety of power technologies. Some DERs, like combined heat and power systems, have been around for many decades. Others, like smart inverters and electric vehicle charging systems, are newer and less familiar to many utilities. And some DERs, such as demand response, distributed wind/solar, and distributed storage, involve coordinated control and strategic management of energy resources and loads, often in collaboration with the customers or third parties who own the equipment involved.



This year our survey focused on the following key types of DERs:

Combined heat and power (CHP), also known as cogeneration, has been widely deployed in municipal, industrial, and campus applications. Innovative uses that might represent new revenue opportunities for utilities include installing CHP on microgrids at customer sites to improve reliability.

Distributed wind. This can include small wind energy projects that are not grouped together as a wind farm — from a single turbine powering a building to many turbines scattered across a university campus that operate as a distributed system. This segment of wind power is defined primarily by proximity to end use and by direct interconnection either behind the meter or to the local distribution grid.

Community shared renewables and storage. Community solar is the most common type of shared DER project so far, and new business models could create more opportunity for utilities to engage profitably in this growing market sector. Some utilities are exploring similar opportunities to deploy battery storage systems under the community shared model.

Electric vehicle charging. From Florida to Canada, and from California to Virginia, utilities, states and government agencies are exploring plans to deploy large-scale electric vehicle (EV) charging station networks. This is seen as a crucial step to spur EV adoption among consumers. While so far private companies have been playing an early role in deploying public EV charging networks, utilities are well positioned to build out power delivery infrastructure upon which they might run their own charging networks, or to support private systems for a fee.

Distributed solar. So far, utilities have had a rocky relationship with photovoltaic (PV) solar that is owned by customers or third parties in grid-connected installations. In most of the nation, rooftop solar and other distributed generation is compensated with retail rate net metering, which pays solar customers the retail rate of electricity for any power exported back to the grid. Utilities say rooftop solar customers under that model do not pay their fair share of grid upkeep and shift those costs onto other consumers. The solar industry, meanwhile, says distributed systems offer benefits to the grid that utilities are unwilling or unable to recognize. The issue has led to contentious debates in key states like Arizona, Nevada and California.

Demand Response (DR) and Demand-Side Management (DSM). DSM programs engage utility customers in reducing loads during peak times, in response to utility signals and sometimes automated controls (for HVAC cycling, thermostat setpoints, pool pumps, etc.). Customers receive a financial incentive for responding to utility signals. Historically, interest in DR has mostly come from commercial and industrial customers (like Target), but the sharp increase in smart thermostats and appliances, as well as AMI rollouts, are expanding utility opportunities for residential DR. In contrast, DSM programs encompass a broad range of utility efforts to encourage customers to use energy more efficiently, or to change their patterns of energy use to better complement grid conditions.

Smart inverters and other grid communication technologies. Every distributed solar installation needs an inverter to convert DC power generated by PV solar

WHAT IS YOUR EXPECTED OUTLOOK FOR THE FOLLOWING DISTRIBUTED ENERGY RESOURCES IN YOUR SERVICE TERRITORY?

ELECTRIC VEHICLES
47% SAY INCREASE SIGNIFICANTLY

DISTRIBUTED STORAGE
56% SAY INCREASE MODERATELY

COMMUNITY SHARED RENEWABLES
54% SAY INCREASE MODERATELY

DISTRIBUTED SOLAR
53% SAY INCREASE MODERATELY

SMART INVERETERS/GRID COMMUNICATION TECHNOLOGY
52% SAY INCREASE MODERATELY

DEMAND RESPONSE
51% SAY INCREASE MODERATELY

COMBINED POWER & HEAT
56% SAY STAY ABOUT THE SAME

DISTRIBUTED WIND
50% SAY STAY ABOUT THE SAME

panels to AC power compatible with end uses and distribution grids. Ordinary inverters are designed to shut down in the event of a grid disturbance, but newer smart inverter technology can keep PV systems running through grid disturbances, and even leverage them strategically as a grid resource. For instance, they can be crucial for including distributed solar in microgrids and other applications potentially helpful to utilities. To work effectively with smart inverters and many other distributed devices, utilities need effective grid communication and intelligence — a cornerstone of most grid modernization efforts. This makes these technologies a good barometer of utilities, expectation of DER growth and need to modernize their systems and software.

Distributed storage. Battery energy storage systems that can serve a house or a neighborhood, or provide capacity and flexibility at key locations on a distribution grid, are becoming more available and affordable. These systems can operate on either side of the electric meter, and they can both release and consume power as needed, according to local demand or signals from the grid operator. A few utilities are exploring opportunities to deploy distributed storage and in coming years, utilities may deploy the resource not just for grid benefits, but as a revenue-producing service.

"OUR MEMBERS MIGHT PREFER TO BUY ENERGY ON THE OPEN MARKET, RATHER THAN BE FORCED TO PAY FOR NEW RESOURCES."

+ Large Great Plains co-op

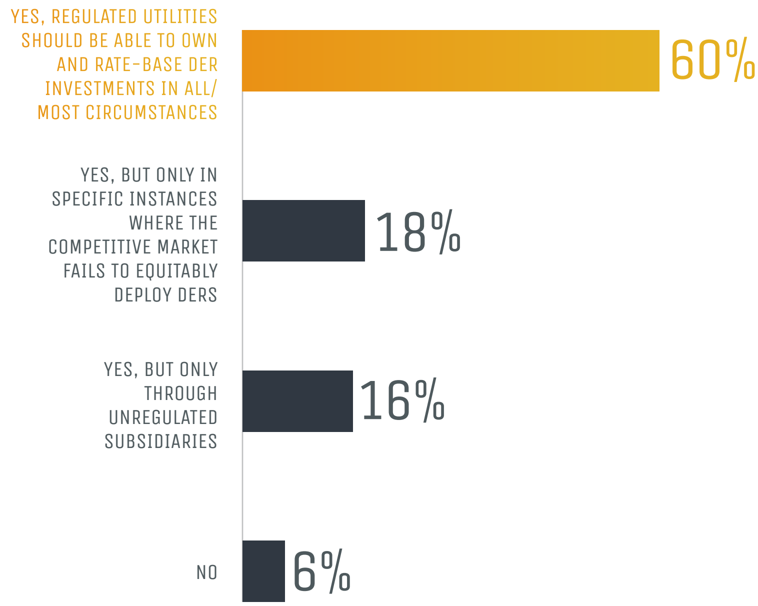
In the 2018 survey, utilities professionals were fairly bullish on all DER technologies, but the strongest overall support was for:

- **EV charging:** 90% of survey participants expect their utility to see a significant or moderate increase in their involvement with EV charging in the coming decade. Slightly more than half of these utility professionals predict a significant increase here.

- **Distributed solar:** 90% of participants also expect to see some level of increase in distributed solar on their systems — up from 78% in 2017. In contrast to the EV charging outlook, over half of these utility professionals expect distributed solar growth to be moderate, rather than significant.

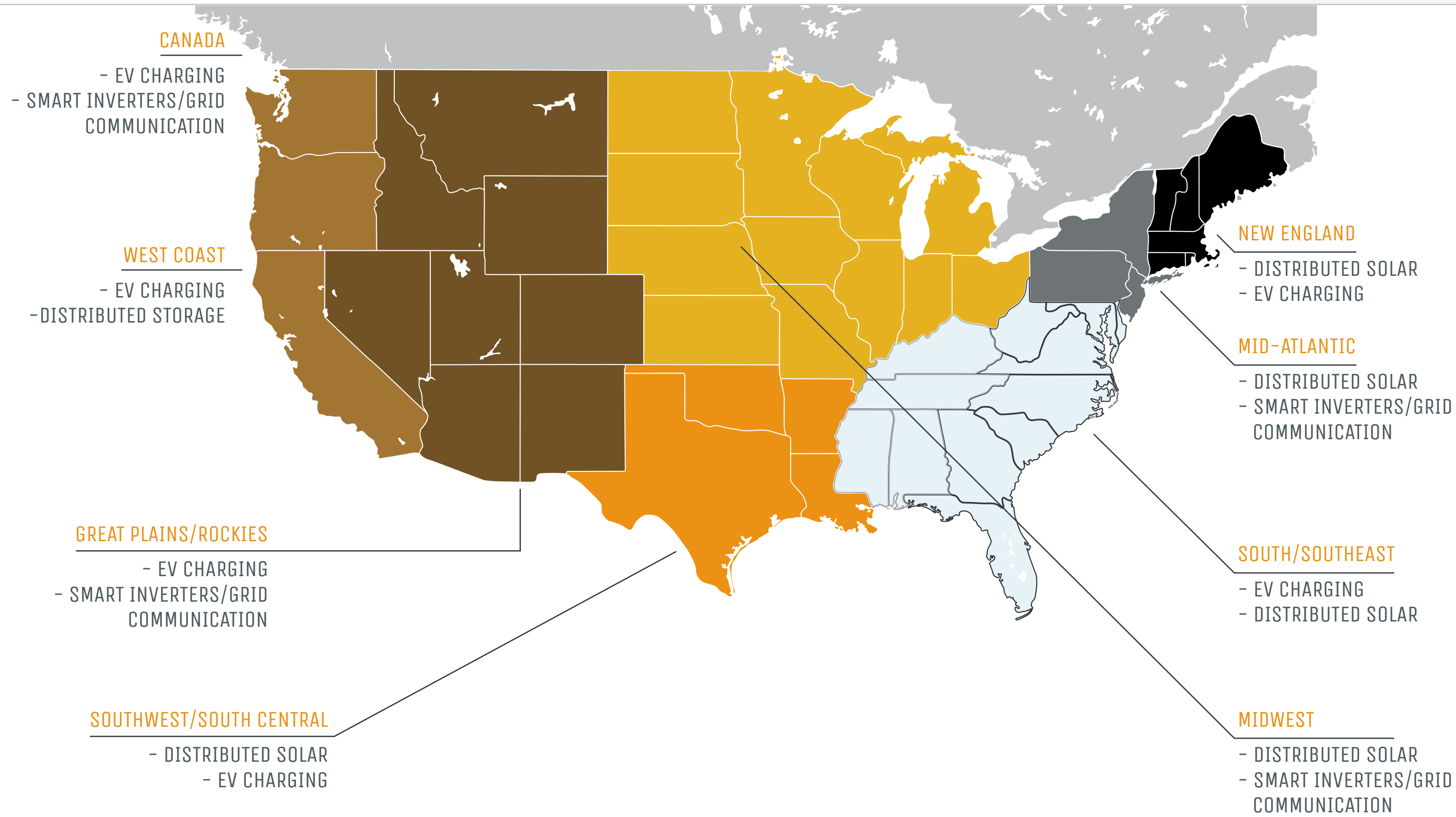
- **Smart inverters/grid communications:** 88% of participants expect their utility's involvement with these technologies to increase — up slightly from 81% in 2017.

SHOULD UTILITIES BE PERMITTED TO OWN AND OPERATE DISTRIBUTED ENERGY RESOURCES?



There are notable regional nuances regarding which DERs are expected to grow significantly in the next 10 years. Here are the two hottest up-and-coming DERs for each region.

WHAT ARE THE TWO UP-AND-COMING DERS IN YOUR REGION?



"WE WANT TO MAKE STRATEGIC BETS ON EMERGING TECHNOLOGIES, BUT ARE NOT CONFIDENT THAT STATE REGULATORS WILL ALLOW RECOVERY."

+ Large Great Plains co-op

UTILITY DER OWNERSHIP

Most utilities expect significant increases in distributed energy on their grids, but so far it's unclear whether they will (or should) own distributed generation or storage assets. DER providers say utilities may have an unfair market advantage over third party offerings due to existing customer relationships.

Few utilities have attempted to own DERs as a regulated investment. Arizona has allowed two pilot projects for utility-owned rooftop solar, while Georgia Power won approval from regulators to sell rooftop solar through an unregulated subsidiary in 2015. ConEd and other New York utilities are experimenting with new business models in the state's REV utility reform proceeding, but rules limit them to DER ownership when the private market does not provide customer access.

That inexperience with regulated DER ownership does not indicate a lack of desire. Just as in 2017, a clear majority of utility respondents think they should be able to rate-base investments in DERs.

Support for utility ownership is even strong among the few utilities that do not want regulatory reform in their region. The strongest support for this option comes from cooperative utilities. And regionally, nearly 80% of IOUs and co-ops in the Midwest believe DER ownership should be an option in all or most circumstances.

The weakest support for utility-owned DERs is in the Southwest and South Central U.S. There, only 44% of utility professionals would like to see utility-owned DERs. Nearly one-third believe this should be allowed only where the competitive market fails to equitably deploy DERs, and nearly one in five believe this should happen only via unregulated subsidiaries.

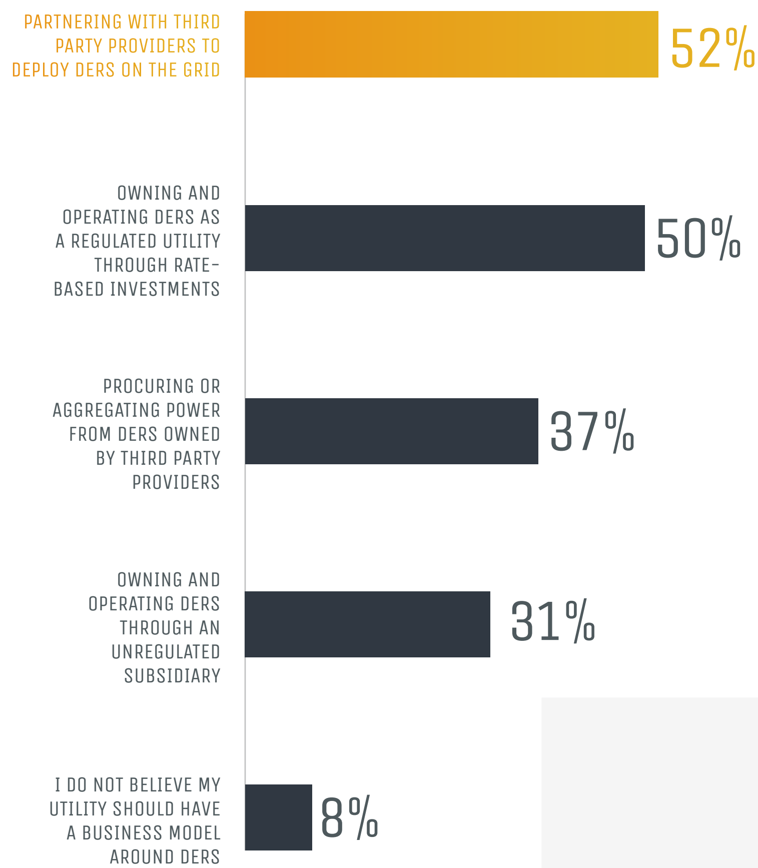
One driver of utility interest in DER ownership is likely the pressure for utilities to develop new revenue streams and position themselves to compete effectively against alternative providers, and also the need to modernize grids and replace retiring baseload generation capacity. For instance, mobile DERs could become a revenue-producing, as-needed service. Underlying this is the long-held industry assumption that load will continue to remain stagnant, or decline -- an assumption that our data this year shows might not be correct.

Other factors that are probably sparking keen utility interest in owning DERs are increasing customer demand, state renewable portfolio standard (RPS) mandates, and growing interest in (and regulatory pressure for) finding non-wires alternatives to expand grid capacity.

Resilience is another big consideration. DERs are a key component of microgrids -- an option that is gaining support as a potential reliability hedge against severe weather events, cyberattacks, and physical infrastructure attacks, as well as being useful for grid management.

From a grid management and modernization perspective, it might make sense for utilities to own battery storage units that are deployed around the grid or at substations, to smooth load curves, compensate for intermittent renewable energy inputs, enhance power quality and perform other grid services. This blurs the line between distributed and grid-scale storage. However, it's possible that in coming years, grid-deployed storage might be as common a part of grid infrastructure as transformers.

HOW DO YOU BELIEVE YOUR UTILITY SHOULD BUILD A BUSINESS MODEL AROUND DISTRIBUTED ENERGY RESOURCES?



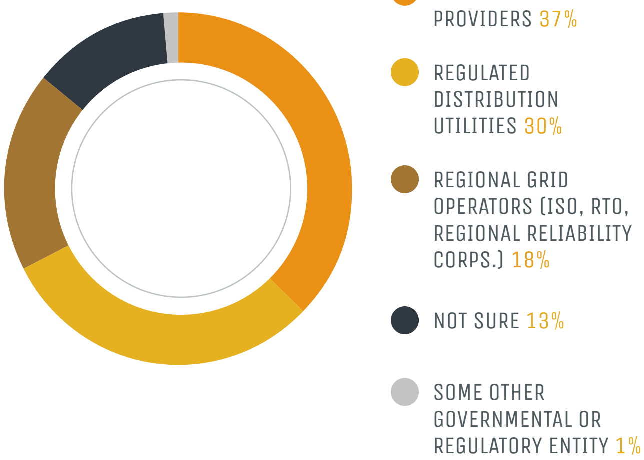
Whether utilities own DERs or not, many are working to devise business models to accommodate and support them. We asked about four utility DER business model options this year:

- **Third-party deployment:** Partnering with third party providers to deploy DERs on the grid.
- **Direct utility ownership:** Owning and operating DERs as a regulated utility, through rate-based investments.
- **Third-party aggregation:** Procuring or aggregating power from DERs owned by third party providers.
- **Subsidiary ownership:** Owning and operating DERs through an unregulated subsidiary.

Survey participants were able to choose all options that they believed might be appropriate for their utilities. Half said they would like to directly own DERs -- but slightly more (52%) would like to partner with third parties to deploy DERs on their grid. A mere 8% of participants do not believe their utility should have a business model for DERs.

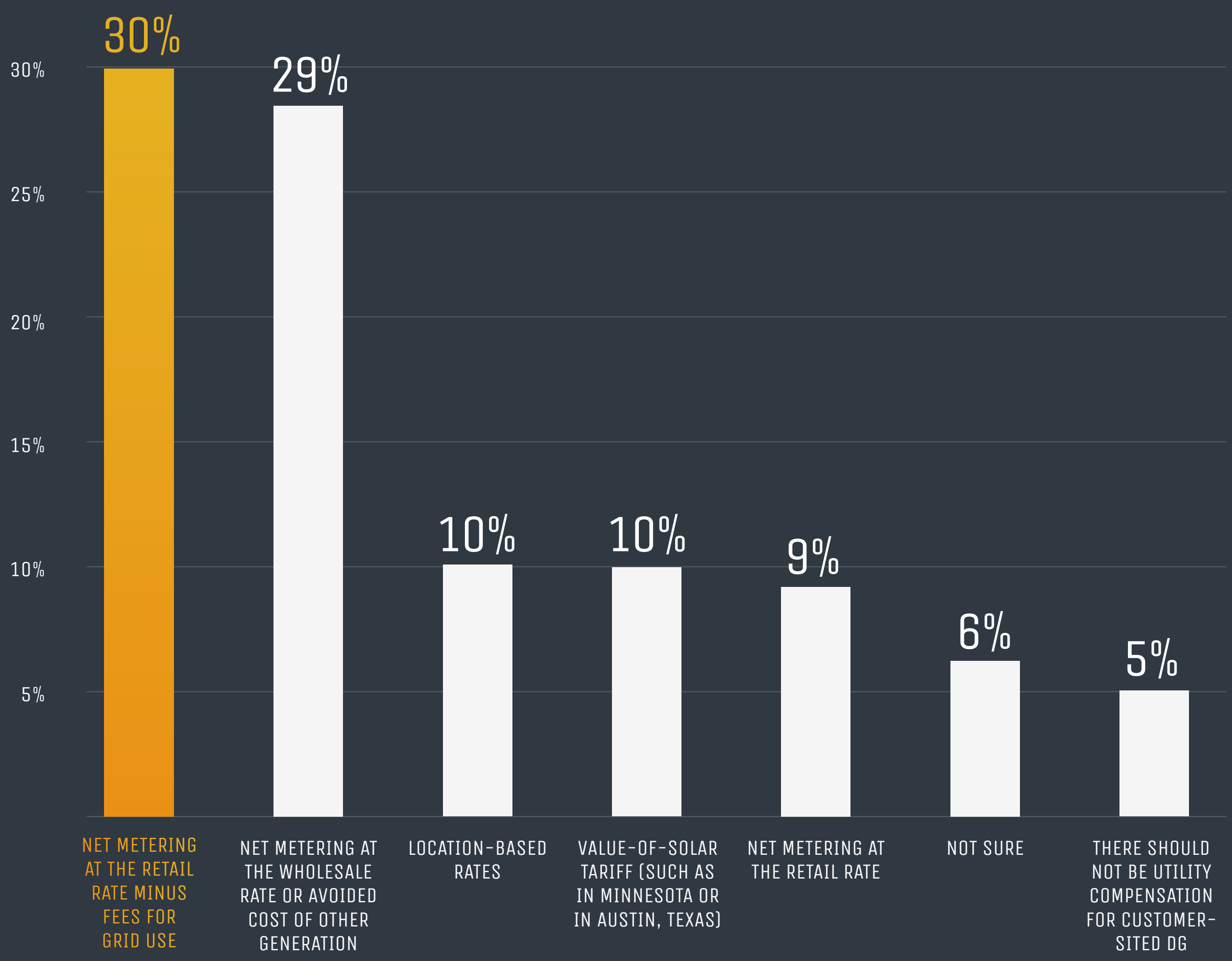
Regionally, the strongest support for regulated utilities owning and operating DERs as rate-based investments was in the South and Southeast. Canada and the Midwest showed a strong preference for doing this via unregulated subsidiaries. The West Coast and New England strongly favor partnering with third parties to deploy DERs on utility grids. Procuring aggregated DER power is most popular in the Great Plains and Rockies.

WHO WILL BE THE PRIMARY AGGREGATORS OF DISTRIBUTED ENERGY RESOURCES IN FIVE YEARS?



Over one third of participants indicated interest in procuring power from third-party DER aggregators — which makes sense, since most utility professionals believe that third parties will be the primary aggregators of DERs in five years. Only 28% believe that utilities will become the leading DER aggregators, and this view is most common in the South and Southeast.

IN YOUR SERVICE TERRITORY, WHAT IS THE MOST APPROPRIATE COMPENSATION MECHANISM FOR DISTRIBUTED GENERATION, PARTICULARLY ROOFTOP SOLAR?



WHAT IS THE MOST APPROPRIATE RATE DESIGN REFORM TO ALLOW UTILITIES TO RECOUP FIXED COSTS?

1. **46%** MOVE CONSUMERS TO TIME-OF-USE RATE
2. **41%** INCREASE FIXED CHARGES/FEE
3. **31%** MOVE NET METERED CUSTOMERS OR THOSE WITH DG TO A SEPARATE RATE CLASS
4. **24%** IMPOSE DEMAND CHARGES ON ALL CUSTOMERS
5. **21%** IMPOSE DEMAND CHARGES ON ALL CUSTOMERS WITH DG

DER COMPENSATION

So far, utilities have had a bumpy relationship with DERs. Most net energy metering (NEM) rates have allowed customers to take a credit for excess power at the full retail rate for power.

This has created favorable economics for more rooftop solar installations, cutting into utility revenues. Utilities say rooftop solar customers shift costs to other ratepayers because they do not pay their fair share for grid upkeep. Solar companies argue that distributed systems can provide benefits to the grid that utilities and regulators are often unwilling to acknowledge. Key states like Arizona, Nevada and California have played host to contentious debate on solar policy.

In recent years, in states with especially high levels of rooftop solar penetration, regulators have been revising NEM structures to help address utility concerns about finances and cross-subsidization. The 2018 survey indicates utilities are likely to continue their push for changes in NEM rules.

In our 2018 survey, nearly two-thirds of utility professionals indicated a preference for some kind of NEM that would effectively reduce the amount of the credit that customers earn for the power they contribute to the grid. More (30%) would prefer to see net metering at the retail rate, minus fees for grid use. An additional 23% would prefer NEM tariffs to reflect the wholesale price of energy, or the avoided cost of other generation. Only 11% would prefer the historic norm of NEM with credits at the full retail rate of electricity.

In contrast, alternative mechanisms that would accommodate DERs while compensating utilities for their impact drew less support. Only 11% of participants prefer value-of-solar tariffs (such as those being tried in Minnesota and Austin, Texas), and 11% prefer location-based rates.

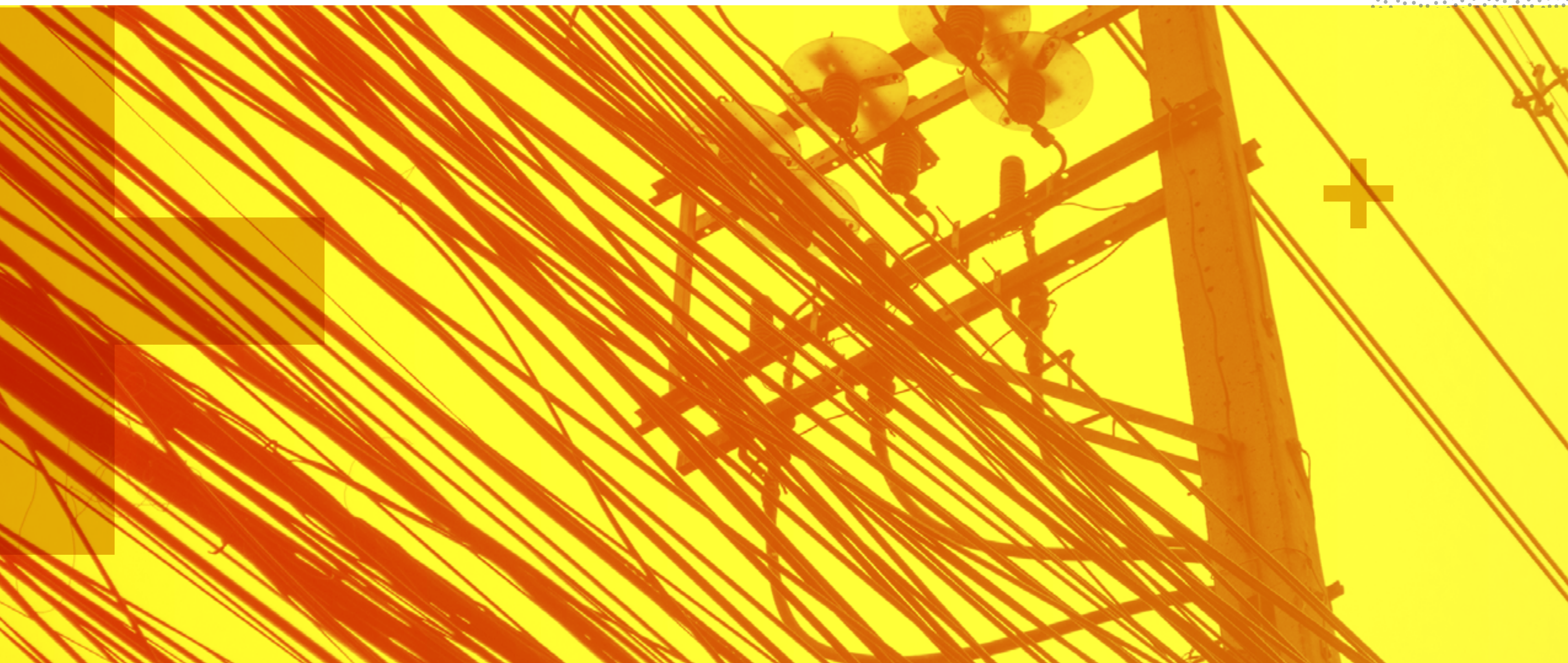
There is considerable regional variation in perspective on how utilities should do NEM. The strongest support for NEM at the full retail rate is in New England, although this region shows slightly stronger support for NEM minus grid use fees. Nationwide, the strongest support for NEM minus grid use fees is the Southwest/South Central region, supported by half of utility professionals there. The Midwest shows the strongest support for NEM at the wholesale rate or avoided cost of other generation.

Rooftop solar and NEM are early harbingers of how DERs might profoundly disrupt the traditional utility business models, and how utilities might adapt. This year we asked utility professionals which rate design reforms they'd prefer to allow utilities to recoup fixed costs, particularly in the face of load that might be stagnant/declining while DER proliferation expands.

The two most popular options, by a significant margin and across all utility types and sizes, are to move consumers to time-of-use (TOU) rates (mentioned by 46% of participants) and to increase fixed charges or fees (40%). In the West Coast and Southwest/South Central regions, over half of utility professionals supported fixed charge/fee hikes. Universal TOU rates is most strongly favored in New England (67%).

An emerging option, proposed recently by some utilities, is to separate DER-owning customers into their own rate class. This was the next most popular rate redesign option to address rooftop solar, mentioned by 30% of utility professionals overall (and 35% among the very largest utilities). So far, only Kansas has approved this measure, but the survey indicates utilities may push for this policy change.

Segregating DER customers into their own rate classes could make it easier for utilities to impose new charges or rate changes on them without affecting the rest of the rate base. However, this move could pave the way for future demand charges and fixed charges -- options that have historically drawn vocal criticism from consumers and solar installers. Support for this option appears strongest in the Southwest/South Central, New England, and the Great Plains/Rockies.



Here are some other regional nuances in utility preferences for rate reforms to address DER growth:

- **Demand charges for all customer classes.** Support for this option was strongest in the Great Plains/Rockies (44%) and the Midwest (34%). This would be a new, and potentially significant, cost for all residential customers. Thus, it would be likely to draw opposition from consumer advocates and skepticism from regulators.

- **Demand charges for all customers with distributed generation.** Beyond rooftop solar, this could include distributed wind, residential fuel cells and other emerging technologies. This might increase interest in battery storage, to avoid demand charges. There was strong support for this option in New England (47%) and the Southwest/South Central (45%).

- **Minimum bill for low-use customers.** Support for this option was moderate to minimal across North America. It attracted a maximum of 30% support in the Southwest/South Central, and no support at all in New England.

- **Decoupling utility revenue from kWh sales.** Touted as a way to solidify support for energy efficiency and other goals that run counter to selling more kWh, this option attracted moderate-to-low support across North America, with Canada being least enthusiastic (4%).

- **Block rates.** Also called "pricing tiers," block rates define electricity consumption thresholds, with lower prices as each threshold is crossed. This incentivizes increased electricity consumption. Support for this option is low-to-nil among most utility professionals, except in the South/Southeast (23%).

ELECTRIC VEHICLE CHARGING INFRASTRUCTURE

A transportation revolution is imminent: electric vehicles (EVs) are poised to hit North American streets in the coming decade. By 2021, annual U.S. EV sales could reach 800,000 -- and by 2025, the Edison Electric Institute estimates that up to 7 million zero-emission vehicles will be driving U.S. roads.

The role of utilities in keeping EVs charged and ready to roll is the topic of much industry discussion. Most utilities see providing EV charging at public parking and private lots as a potential business opportunity not just in terms of increased kWh sales, but also as a revenue-generating service.

Only 8% of this year's survey participants (mostly co-ops) believe their utility should not get involved with transport electrification.

A big reason why utilities might wish to play a leading, early role in developing EV charging infrastructure is to protect their own power systems. Charging stations will create new and different load patterns for utilities, and some are already experimenting with controlling their EV charging load to help balance the grid.

Utilities have many options for entering the EV charging business. This year, over half of utility professionals said they would like their utility to create special pricing or rates for EV charging. This would be the simplest way for utilities to participate in the EV charging market, since it would not require a separate business entity or program. It could also be used to incentivize EV charging during off-peak hours, or even by location. EV pricing enjoys broad, strong support across all utility types and U.S. regions (52% to 72%), although utility professionals in Canada are conspicuously lukewarm about it (just 30% supported).

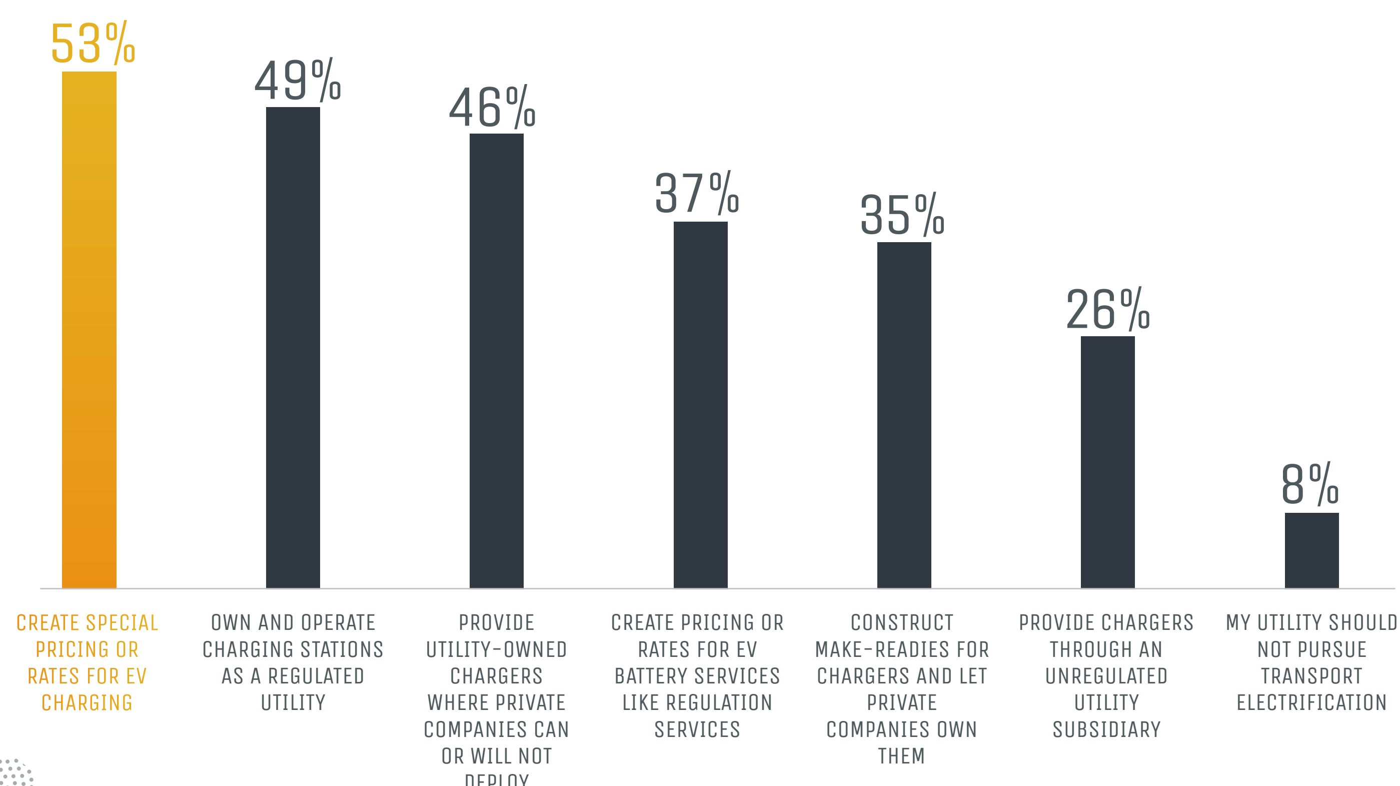
A beneficial side effect of special EV rates might be that additional revenue from EV owners could help fund grid-related expenses and investments. That could reduce bills for all customers, or help fund needed grid modernization and expansion.

Close behind, 44% of participants said they would like to see their regulated utility directly own and operate public charging stations. Support for this option is especially strong in Canada and the West Coast, while the Midwest and co-ops in general are least enthusiastic about it.

Utility owned and operated charging networks could be a daunting challenge, depending on the scale. Most analysts watching the EV market say that public charging stations need to be nearly ubiquitous, at least in urban and suburban areas and along highways, to quell consumers' notorious range anxiety. But if utilities build EV charging, will consumers really come? Meeting that need up front represents a considerable investment, with a delayed and as-yet highly speculative return. If EVs end up not being as popular as hoped, charging networks could become a stranded asset.

However, utilities wouldn't have to be alone in providing ubiquitous EV charging in public parking and private lots. Private companies like ChargePoint might deploy broader charging networks. Then, utilities might supply their own charging stations only where private

HOW SHOULD UTILITIES APPROACH THE ELECTRIFICATION OF THE TRANSPORTATION SECTOR?



companies can or will not deploy. This year, 43% of all participants liked this option, and it's especially popular in the Midwest and West Coast. IOUs also favor this approach most strongly.

Alternately, 27% of all utility professionals said they'd like to see charging stations deployed by unregulated utility subsidiaries. This option is most strongly favored in New England.

Already, most jurisdictions allow utilities to build and own make-ready infrastructure. This equipment delivers electricity to a point where a charging station can be installed; at a minimum, upgrading transformers and service capacity and/or running new service drops. In several states, regulators have allowed cost recovery for make-ready expenditures, as well as costs to interconnect make-readies with the power grid.

This year, 33% of survey participants said they'd like their utility to construct make-readies, and allow private companies to add charging stations to this infrastructure. Support for supplying make-readies is strongest in New England, the Midwest and the West Coast. Public utilities and co-ops favor this option slightly more than IOUs. While private companies, or owners of commercial or public real estate or parking facilities, might opt to build these necessary upgrades, utilities are well-positioned to offer make-readies as a service. Doing so might help ensure easier, more consistent integration of charging stations with power grids.

Another way that utilities might build a revenue-producing business from EVs is to develop pricing or rates for EV battery services, such as regulation services. 36% of all survey participants like this option, with the West Coast being especially bullish.

+CYBERSECURITY

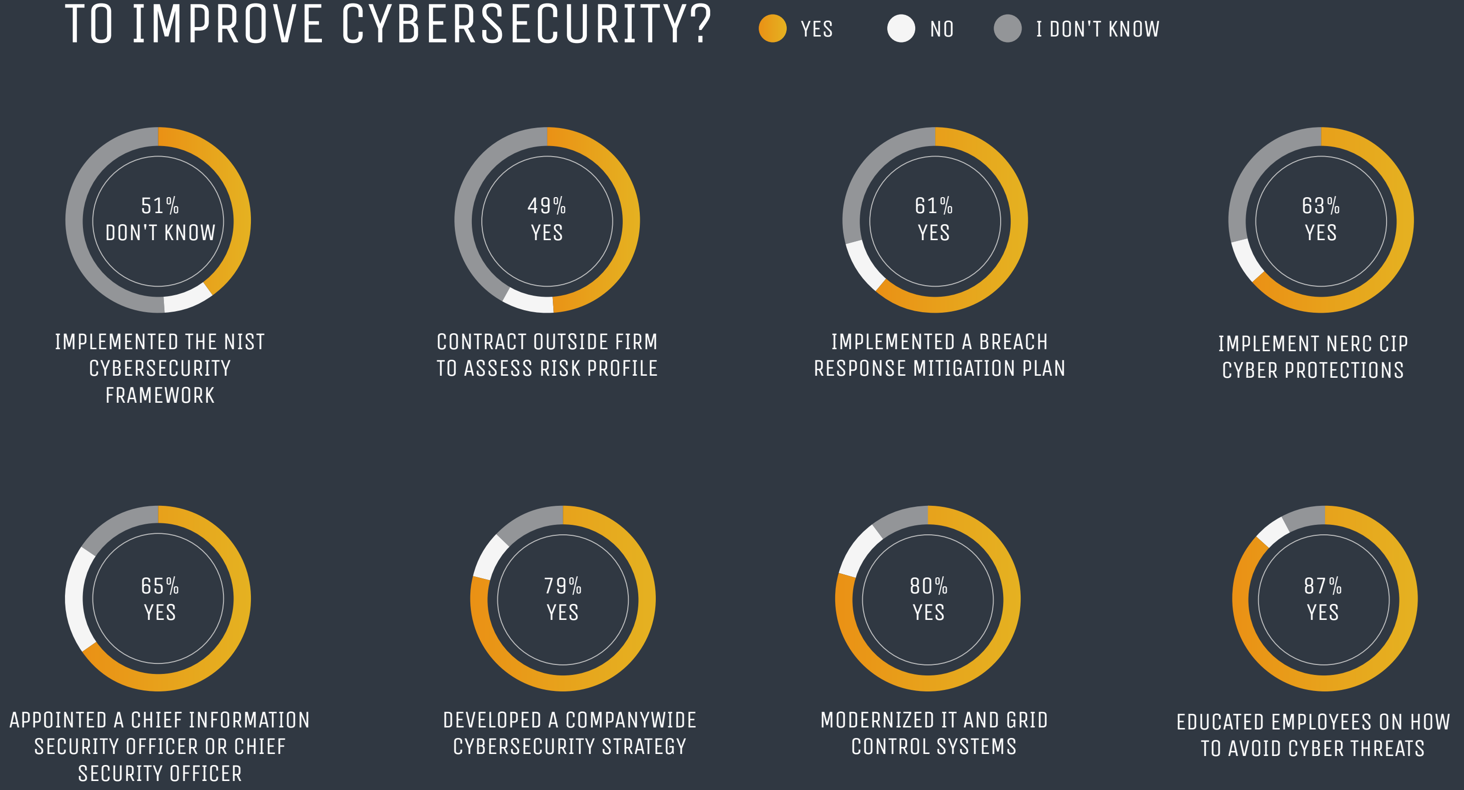
Utilities have good reason to feel anxious about cybersecurity — they are uniquely attractive targets.

Electric generation assets and distribution networks are some of the most critical infrastructure in any nation. Utility distribution networks are geographically dispersed, fairly exposed and deeply interconnected. Also, widespread deployment of new grid-edge technologies and has multiplied digital vulnerabilities. Solar inverters were recently identified as being especially at risk regarding two cyber vulnerabilities identified in late 2017: Spectre and Meltdown.

This year, 81% of utility professionals listed cybersecurity as either an important or very important concern -- an appreciable jump from 72% in 2017, and the second year in a row that this has been the #1 concern of utility professionals.

Meanwhile, the legacy information technology (IT) used in many core utility systems and processes and embedded programming (firmware) for many utility devices are often outdated and vulnerable to cyberattack. The risks lie not just in generation and distribution systems and controls, but every digital system within a utility. A cyberattack might begin with an email to the marketing department, or a thumb drive in the financial office.

HAS YOUR UTILITY TAKEN ANY STEPS IN THE PAST TWO YEARS TO IMPROVE CYBERSECURITY?



At the same time, deployment of smart thermostats, appliances and other internet-connected devices, has sharply increased among all customer classes and consumer demand is rising for utilities to make use of data and control opportunities that IoT devices enable.

"This spectrum of connected devices will increase digital complexity and attack surfaces, and therefore require more intensive cybersecurity protection," a 2016 MIT white paper on utility cybersecurity noted. "A multi-pronged approach to cybersecurity preparedness is required. System operators must have the capacity to operate, maintain and recover a system that will never be fully protected from cyberattacks."

Despite industry-wide urgency about cybersecurity, there's a conspicuous lack of clarity on this topic. For instance, the North American Energy Reliability Council (NERC, charged with implementing cybersecurity standards on FERC's behalf) until recently had a threshold for mandatory cyberattack reporting that was unreasonably high, leading to no incidents at all being reported. FERC moved to correct this in December 2017 with a notice of proposed rulemaking. The new rule would require reporting whenever a cyberintrusion breaches a utility's electronic security perimeter or control or monitoring systems, even if service is not disrupted. Expect reported cyberattacks against utilities to increase substantially in 2018.

There are many ways for utilities to address cybersecurity, and the 2018 survey shows respondents believe their utilities are making progress. This year, we asked about several measures commonly recommended for utilities that seek to harden themselves against electronic intrusions or interference, or increase their resilience to such problems:

1 | **Educating employees on avoiding cyberthreats.** This includes skills to resist time-tested infiltration techniques such as phishing and spearphishing (attacks targeted at specific individuals in an organization), as well as learning to recognize and respond to the potential warnings and effects of cyberattacks (such as unusual device operation, traffic on communication networks, access privilege problems and more).

2 | **Developing a companywide cyber strategy.** Ideally this includes proactive measures for IT planning and procurement, as well as cybersecurity standards and practices adopted throughout the organization. This entails both dismantling the organizational silos which historically have been prevalent in utilities and creating newer and more versatile firewalls to sequester threats or attacks.

3 | **Modernized grid and IT control systems.** Aging grid infrastructure is one of this year's top overall utility concerns, and cybersecurity is a big reason why. As generation becomes less centralized and AMI and IoT devices become more ubiquitous, utilities have been forced to step up their IT capabilities. Updating utility IT and communications, and keeping them up to date and secure, are not just an operational imperative; they are also a business imperative in an increasingly competitive utility landscape.

4 | **Implementing NERC CIP.** NERC has developed Critical Infrastructure Protection (CIP) standards — a set of security requirements with which all North American bulk power systems must comply. Utility distribution systems are not required to comply with NERC CIP, although some utilities may voluntarily do so. Of the 70% of this year's survey participants whose utilities offer transmission services, nearly three-fourths report that they are working to comply with current NERC CIP recommendations -- but most of the remaining one fourth are not sure about their NERC CIP compliance. The catch with any security mandate, especially for cybersecurity, is that compliance does not equal security. Utilities can comply with requirements and still be quite vulnerable to penetration, or unable to mount a successful response.

5 | **Executive leadership.** Specifically, we asked whether utilities have designated a C-suite position to take point on security — generally a Chief Information Security Officer, or a Chief Security Officer.

6 | **Breach response/mitigation plan.** Similar to procedures to contain and investigate any potential crime scene, this is a step-by-step plan to secure affected systems, preserve all data and records of the incident (especially log files), assess the causes and impact of the breach, involve insurers as needed, and manage communications with affected customers or partners, government agencies, and the media/public.

7 | **Independent risk profile assessment.** This would be performed by outside security consultants. This should go beyond a traditional network assessment to address the intricacies of embedded industrial control systems. Traditional utility security assessments usually fail to account for the rapid expansion of wireless networks and embedded intelligence.

8 **NIST cybersecurity framework.** Compiled by the National Institute of Standards and Technology with widespread input from many sectors, this voluntary guidance is intended for all critical infrastructure industries. Based on existing standards, it includes guidelines and practices to better manage and reduce cybersecurity risk. In 2015, NIST published specific guidance for energy sector on how to apply the framework; it's unclear whether or when this energy context might be updated.

The vast majority of utility professionals report that they've made progress on implementing measures 1-6.

For measures 7-8, the portion of participants who said "no" or "I don't know" rivalled or surpassed the "yes" answers. Furthermore, utility professionals indicated a markedly higher level of uncertainty about measures 5-8 (26-45%, compared to 6-15% for measures 1-4). These trends hold true across most utility types, sizes and regions.

Our survey only asked whether utilities have taken any of these steps in the last two years. But these steps may or may not have been substantial or effective. For instance, a "yes" for "educating employees on cybersecurity" might mean anything from a memo reminding personnel not to click links in email messages, to extensive department-specific training, updated frequently.

All major utility associations (the Edison Electric Institute, American Public Power Association, and the National Rural Electric Cooperative Association) offer ample cybersecurity resources; and the National Association of Regulatory Utility Commissioners (NARUC) offers a cybersecurity guide for utility regulators. In 2016, the U.N.'s World Energy Council published a report on managing energy-sector cybersecurity risks, which strongly recommended cross-sector cooperation, and especially attention to cybersecurity in the supply chain. NERC is also focusing attention on supply chain cybersecurity. Most recently, in January 2018, the National Cybersecurity Center for Excellence released a description of its new Energy Sector Asset Management project, and is accepting comments on this through Feb. 16, 2018.

THE WAY FORWARD: TRANSFORMING UTILITIES

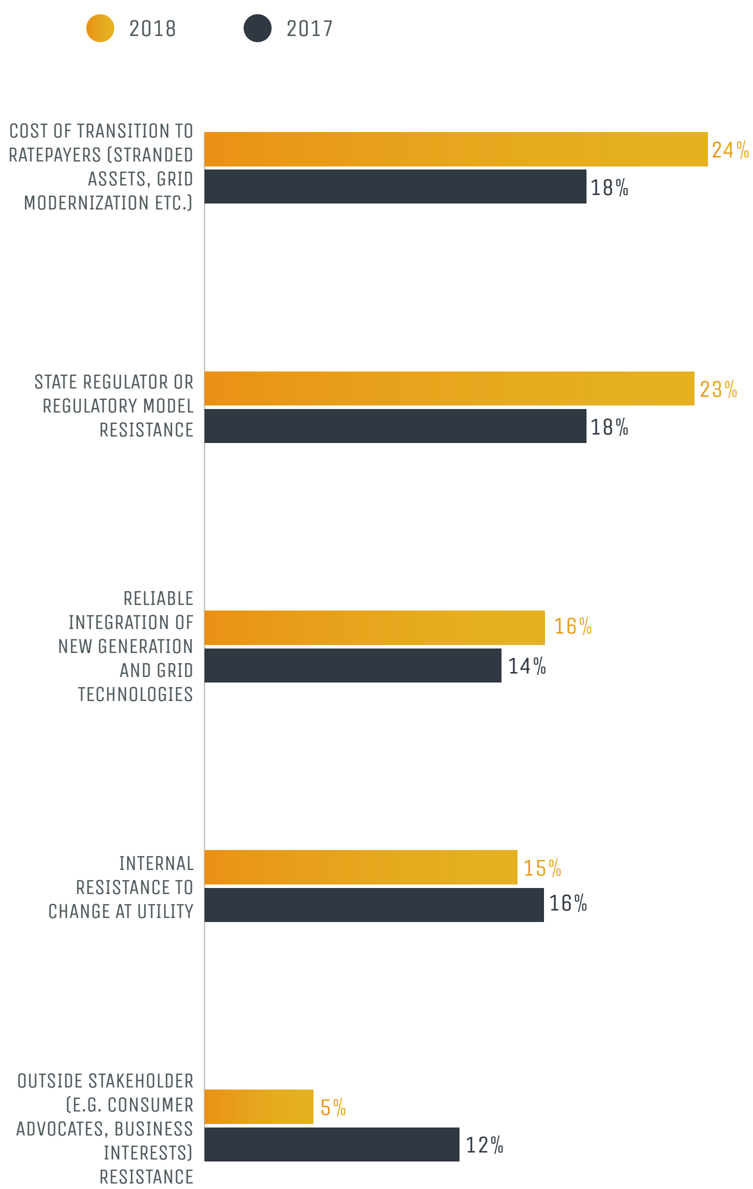
One of the most significant challenges facing electric utilities today is how to transform from the traditional model of a regulated, cost-of-service utility to a business model that is more flexible and responsive to performance incentives and market forces.

The urge to transform is nearly universal across the utility industry. This year, a mere 2% of participants contended there is no need for their utility business model to change.

Updating the utility business model requires tackling thorny issues like internal company culture, changing regulatory priorities and growing customer sentiment for clean energy.

One survey participant connected these dots: "The cost and consequences of new technologies on customers and moderating the impact of changing customer preferences are our two biggest issues going

WHAT IS THE GREATEST OBSTACLE TO THE EVOLUTION OF YOUR UTILITY'S BUSINESS MODEL?



forward. The biggest obstacles to tackling these issues are the cost to transition to a new business model, and internal resistance to change."

The attitude of utility leadership can significantly influence the pace of change. One participant observed, "Our current generation of senior leaders generally don't see changes that need to be made based on consumer preferences and technology."

This dilemma can be frustrating for the many utility professionals who advocate for change in their organizations — as well as for customers and markets that often seem to be waiting for utilities to catch up with them. Meanwhile, new competitors, especially new energy retailers and independent power producers, are attempting to capitalize on the relatively slower pace of change in utilities.

Fortunately, some progressive utility leaders view the prospect of major business model transformation and industry disruption as an opportunity, not a problem. In 2017, the CEO of Canadian utility Alectra quipped, "If someone's going to cannibalize our business, it may as well be us."

As in prior years, this year we asked utility professionals to name the single biggest obstacle to business model transformation at their utility. By far, this year's most popular response (cited by 25% of survey participants) is how utility transformation might financially impact customers.

Specifically, utility professionals expressed concern about how much ratepayers might be asked to pay for stranded assets, grid modernization and the like. For instance, one utility professional wrote, "The need to modernize the grid, integrate more renewables and DERS into the system, and also to expand customer offerings (often through new technology investments) in order to meet increasing customer expectations, all create financial pressures on the utility to continue to provide affordable service to customers."

One IOU professional observed, "Grid modernization costs are tremendous and will not likely yield a noticeable difference in power reliability or quality for our customers. A lot of our grid modernization involves simply replacing a lot of old infrastructure (poles) with new infrastructure (newer poles with sensors attached)."

"The customer won't really experience a noticeable change in service quality," this professional noted. "Explaining why their bills are increasing is tough. The value of grid modernization investments (which will cost billions across a distribution system like ours), is difficult to articulate. Cost recovery is going to be a real challenge."

Meanwhile, a co-op executive wrote, "As a not-for-profit, affordability is a key tenet of our business model. The evolution of our business model depends on our ability to maintain affordability for our members."

This risk of rising costs for utility customers gets more troubling as most utilities face a far more competitive future. Newer retailers with fewer capital investments could hold a financial advantage with potential investors as well as customers.

This year's second-most-common chief obstacle is internal resistance to change within utilities (17%), up just slightly from last year. Because they face legal mandates to deliver safe and affordable power, utilities

"SENIOR MANAGEMENT IS TOO LOCKED INTO OLD WAYS AND UNABLE TO THINK CREATIVELY FOR BUSINESS SUCCESS."

+ Large Mid-Atlantic IOU

often fear major changes to their operations. That can discourage innovation, including for business models.

When utilities resist change, that can slow the pace of technology adoption and ultimately impair a utility's ability to compete. One utility professional wrote, "Nothing that has not worked for five decades will get a fair shake here. We are reliably 2+ technologies behind the curve."

Regulatory resistance to new utility business models is this year's third most popular obstacle, cited by 15% of participants. One municipal utility employee observed, "We want to make strategic bets on emerging technologies (microgrids, storage), but we are not confident that the state regulators will allow recovery."

Utilities and regulators can also slow each other down. For instance, one participant shared, "Our local utility holds strong influence on lawmakers and regulators. Thus changes to the utility business model are slow and not transparent." Conversely, another observed: "Our Commission seems willing to change regulation, but the speed at which utilities can change is hindered by the lengthy regulatory approval process."

Consequently, more utilities and their competitors are now exploring ways to talk to regulators about the changing energy landscape — especially the technology, economics, and environmental impacts of generating and distributing electricity.

The challenge with enhancing mutual understanding between utilities and regulators is that such efforts may risk the perception, or the reality, of "getting too cozy" with regulators. This can undermine the market position of utilities, as well as consumer and regulator confidence. Supporting understanding between regulators and utilities is where nonprofits such as the Regulatory Assistance Project and Rocky Mountain Institute can play a helpful role.

Different types of utilities hold different views on the obstacles they face regarding transformation.

+ **IOUs.** This year, IOUs are especially concerned about saddling their ratepayers with stranded asset costs — and they also are nearly equally worried about state/regulator resistance.

+ **Co-ops.** In 2018, co-ops are even more worried than IOUs about sticking their ratepayers with the bill for stranded costs. All of their other fears about business model transformation pale in comparison to this.

+ **Municipal utilities** are also strongly concerned with ratepayer impacts, but equally concerned about internal resistance to change.

Throughout North America, each region has a somewhat different perspective on the top obstacles to utility transformation. This list shows where each chief obstacle is most frequently cited:

- **Internal resistance to change at utility:** Great Plains/Rockies (38%), New England (27%), South/Southeast (26%)
- **Costs to ratepayers:** Midwest (36%), West Coast (32%), Great Plains/Rockies (31%)
- **Resistance from state regulators or regulatory model:** Canada (28%), Southwest/South Central (25%), Mid-Atlantic (25%)

- **Reliable integration of new generation and grid technologies:** Great Plains/Rockies (19%), South/Southeast (18%), Mid-Atlantic (17%)

- **Political resistance (state legislature, governor, other):** Canada (16%), New England (13%), 10% or less elsewhere.

- **No obstacles, there is general consensus:** New England (13%), negligible elsewhere.

- **Wholesale market construction and regulation:** Mid-Atlantic (13%), negligible elsewhere

- **Federal environmental or emissions regulations:** Negligible (under 10%) in all regions

- **Outside stakeholder resistance (consumer advocates, etc.):** Negligible (5% or less) in all regions

- **Finance resistance (from capital markets, banks and Wall Street):** Negligible. 2% on the West Coast, zero elsewhere.

Despite all of these daunting issues, utilities are changing every day. Most of this change is incremental, but some especially disruptive influences on the electric power industry could trigger faster-than-usual change at utilities.

In just five years, there might be nearly three million EVs on U.S. roads. Utilities can do more than merely support this transportation revolution. They could lead it by working to reform their rate designs and infrastructure planning to accommodate fast EV growth.

The same can be said for other distributed resources. If utilities embrace planning for these technologies today, they can be prepared for the operational and financial challenges that come with their growth. If they do not, they could find their balance sheets and grids increasingly stressed.

Regulatory initiatives are also likely to play a role. Today a number of states have proceedings to reform utility revenue models. New York's Reforming the Energy Vision docket is the most well-known of these, but California had been implementing performance-based standards since the mid-aughts, and investigations

into PBR are active in Ohio, Rhode Island, Minnesota, D.C. and elsewhere.

Each state's initiatives differ, but the aim is the same: devise ways to reward utilities for new energy services, like efficiency or DER deployment, that do not fit into the traditional model. In places like New York, regulators are devising new markets for utility services and incentives for customer outcomes, while in California regulators rely more on mandates and enforcement.

"WITH OR WITHOUT FEDERAL HELP, OUR PATH FORWARD IS THROUGH MARKET-DRIVEN DECISIONS."

+ Large Midwestern co-op

In the year ahead, technology advances and continued regulatory efforts are likely to step up pressure on utilities to transform. As more states look to enhance the resilience and sustainability of their power systems, utilities could well be pushed into new performance mandates and and see new business opportunities open for resources like microgrids.

If that happens, utilities could see their traditional rate-based revenues decline over time, replaced by new revenues from market-based activities and performance incentives. That could leave the utility with a much different revenue model than it has today.

+APPENDIX

WHICH TYPE OF UTILITY COMPANY EMPLOYS YOU?

Answer Choices	Responses
Investor-owned utility	37.48%
Electric cooperative	9.15%
Municipal utility or public power utility	21.57%
Other (please specify)	31.81%

WHICH ENERGY SERVICES DOES YOUR REGULATED UTILITY, CO-OP OR MUNI PROVIDE? CHOOSE ALL THAT APPLY.

Answer Choices	Responses
Generation	69.12%
Transmission	63.55%
Distribution	75.00%
Retail	50.63%

IN WHICH REGIONS DOES YOUR REGULATED UTILITY HAVE SERVICE AREAS?

Answer Choices	Responses
New England	8.05%
Mid-Atlantic	6.60%
South & Southeast	11.15%
Midwest	17.13%
Great Plains & Rocky Mountains	3.82%
Southwest and South Central	6.60%
West Coast	16.00%
Non-contiguous states & territories	2.48%
Mexico	0.62%
Canada	5.57%
Other (please specify)	21.98%

HOW MANY CUSTOMERS DOES YOUR ELECTRIC UTILITY SERVE?

Answer Choices	Responses
Fewer than 100,000	22.27%
100,000-500,000	18.03%
500,000-1 million	10.71%
1-4 million	22.48%
More than 4 million	26.51%

WHICH OF THE FOLLOWING BEST DESCRIBES YOUR REGULATORY ENVIRONMENT?

Answer Choices	Responses
Traditional cost-of-service regulation	33.64%
Cost-of-service regulation with a mix of performance-based regulation	23.77%
Predominantly performance-based regulation	6.22%
Oversight by an elected board or government	36.38%

WHAT DO YOU EXPECT YOUR REGULATORY AND RATEMAKING ENVIRONMENT TO LOOK LIKE IN 10 YEARS?

Answer Choices	Responses
Traditional cost-of-service regulation	10.68%
Cost-of-service regulation with a mix of performance-based regulation	34.62%
Predominantly performance-based regulation	21.73%
Oversight by an elected board or government	32.97%

WHAT IS THE MOST APPROPRIATE UTILITY REGULATORY MODEL IN THE 21ST CENTURY?

Answer Choices	Responses
Traditional cost-of-service regulation	7.00%
Cost-of-service regulation with a mix of performance-based regulation	42.54%
Predominantly performance-based regulation	35.17%
Oversight by an elected board or government	15.29%

PLEASE IDENTIFY THE TOP THREE DIFFICULTIES ASSOCIATED WITH YOUR STATE REGULATORY MODEL.

Answer Choices	Responses
Recovering fixed costs through rate design	34.33%
Recovering revenue lost to efficiency and negative load growth	33.98%
Potential loss of revenue due to customer choice (e.g. CCAs, utility defection, etc.)	27.99%
Justifying traditional utility investments (wires, poles etc.) to regulators	18.66%
Justifying emerging utility investments (energy storage, EV chargers, microgrids etc.)	43.49%
Meeting renewable and other clean energy mandates	26.41%
Meeting pollution mandates and/or climate standards	15.14%
Managing distributed resource growth and net metering/value of solar debates	38.56%
Obtaining adequate capacity through wholesale power markets	8.63%
Recovering costs from stranded utility assets	20.25%
Meeting performance mandates for efficiency, customer engagement etc.	13.20%
Resolving waste issues related to nuclear decommissioning, coal ash etc.	7.39%
Other (please specify)	11.97%

ARE REGULATORS IN YOUR STATE CONDUCTING OR CONSIDERING A PROCEEDING TO REFORM UTILITY BUSINESS AND/OR REVENUE MODELS?

Answer Choices	Responses
Yes, we currently have or have completed a proceeding	31.81%
No, but we anticipate a proceeding soon	27.43%
No, but we would like to see regulators open a docket	24.19%
No, we don't have one and do not want one	16.57%

WHICH OF THE FOLLOWING BEST DESCRIBES THE ELECTRICITY MARKETS IN YOUR SERVICE AREA?

Answer Choices	Responses
Full cost-of-service: vertically integrated utilities own and dispatch their own generation with no centralized wholesale or retail markets	17.35%
Full cost-of-service with regional energy trading: utilities own and dispatch their own generation but trade energy with regional partners	21.83%
Full cost-of service within a regional electricity market: utilities own their own generation and receive cost recovery but are dispatched by a central ISO	26.68%
Competitive market with some cost-of-service: utilities participate in a competitive market for electricity, with some generators eligible for cost recovery	24.07%
Competitive market with no cost-of-service: utilities participate in a competitive market for electricity with no cost-of-service recovery	10.07%

WHAT DO YOU EXPECT YOUR ELECTRICITY MARKET SITUATION TO BE IN 10 YEARS?

Answer Choices	Responses
Full cost-of-service: vertically integrated utilities own and dispatch their own generation with no centralized wholesale or retail markets	8.65%
Full cost-of-service with regional energy trading: utilities own and dispatch their own generation but trade energy with regional partners	14.66%
Full cost-of service within a regional electricity market: utilities own their own generation and receive cost recovery but are dispatched by a central ISO	23.68%
Competitive market with some cost-of-service: utilities participate in a competitive market for electricity, with some generators eligible for cost recovery	34.59%
Competitive market with no cost-of-service: utilities participate in a competitive market for electricity with no cost-of-service recovery	18.42%

WHAT IS THE MOST APPROPRIATE ELECTRICITY MARKET CONSTRUCTION IN THE 21ST CENTURY?

Answer Choices	Responses
Full cost-of-service: vertically integrated utilities own and dispatch their own generation with no centralized wholesale or retail markets	5.46%
Full cost-of-service with regional energy trading: utilities own and dispatch their own generation but trade energy with regional partners	14.12%
Full cost-of service within a regional electricity market: utilities own their own generation and receive cost recovery but are dispatched by a central ISO	19.96%
Competitive market with some cost-of-service: utilities participate in a competitive market for electricity, with some generators eligible for cost recovery	34.84%
Competitive market with no cost-of-service: utilities participate in a competitive market for electricity with no cost-of-service recovery	25.61%

HOW DO YOU THINK YOUR UTILITY'S POWER MIX WILL CHANGE OVER THE NEXT 10 YEARS?

NATURAL GAS

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	5.56%	5.56%	27.78%	33.33%	27.78%	6.16%
Mid-Atlantic	0.00%	3.70%	25.93%	51.85%	18.52%	9.25%
South & Southeast	2.13%	0.00%	25.53%	42.55%	29.79%	16.10%
Midwest	0.00%	15.87%	22.22%	39.68%	22.22%	21.58%
Great Plains & Rocky Mountains	5.56%	11.11%	16.67%	66.67%	0.00%	6.16%
Southwest and South Central	4.76%	9.52%	19.05%	42.86%	23.81%	7.19%
West Coast	11.29%	30.65%	33.87%	14.52%	9.68%	21.23%
Canada	4.00%	20.00%	16.00%	44.00%	16.00%	8.56%
Total	4.11%	13.70%	23.97%	36.30%	18.15%	100.00%

NUCLEAR

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	12.50%	62.50%	25.00%	0.00%	0.00%	5.48%
Mid-Atlantic	23.08%	30.77%	46.15%	0.00%	0.00%	8.90%
South & Southeast	14.58%	18.75%	52.08%	12.50%	2.08%	16.44%
Midwest	18.03%	22.95%	59.02%	0.00%	0.00%	20.89%
Great Plains & Rocky Mountains	11.76%	5.88%	82.35%	0.00%	0.00%	5.82%
Southwest and South Central	9.52%	19.05%	71.43%	0.00%	0.00%	7.19%
West Coast	32.20%	15.25%	50.85%	0.00%	1.69%	20.21%
Canada	12.50%	12.50%	66.67%	8.33%	0.00%	8.22%
Total	17.81%	19.86%	52.05%	2.74%	0.68%	100.00%

COAL

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	77.78%	16.67%	5.56%	0.00%	0.00%	6.16%
Mid-Atlantic	59.26%	29.63%	11.11%	0.00%	0.00%	9.25%
South & Southeast	41.30%	50.00%	6.52%	2.17%	0.00%	15.75%
Midwest	52.31%	38.46%	9.23%	0.00%	0.00%	22.26%
Great Plains & Rocky Mountains	66.67%	27.78%	5.56%	0.00%	0.00%	6.16%
Southwest and South Central	68.18%	18.18%	13.64%	0.00%	0.00%	7.53%
West Coast	66.67%	6.67%	25.00%	0.00%	1.67%	20.55%
Canada	75.00%	4.17%	20.83%	0.00%	0.00%	8.22%
Total	57.53%	25.00%	12.67%	0.34%	0.34%	100.00%

OIL

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	72.22%	27.78%	0.00%	0.00%	0.00%	6.16%
Mid-Atlantic	48.15%	37.04%	14.81%	0.00%	0.00%	9.25%
South & Southeast	31.82%	31.82%	36.36%	0.00%	0.00%	15.07%
Midwest	44.07%	13.56%	38.98%	3.39%	0.00%	20.21%
Great Plains & Rocky Mountains	25.00%	6.25%	68.75%	0.00%	0.00%	5.48%
Southwest and South Central	61.90%	4.76%	28.57%	4.76%	0.00%	7.19%
West Coast	51.79%	7.14%	39.29%	0.00%	1.79%	19.18%
Canada	50.00%	16.67%	29.17%	4.17%	0.00%	8.22%
Total	42.47%	16.10%	30.48%	1.37%	0.34%	100.00%

WIND

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	0.00%	0.00%	5.56%	61.11%	33.33%	6.16%
Mid-Atlantic	0.00%	3.70%	25.93%	51.85%	18.52%	9.25%
South & Southeast	2.22%	4.44%	44.44%	37.78%	11.11%	15.41%
Midwest	0.00%	0.00%	12.50%	60.94%	26.56%	21.92%
Great Plains & Rocky Mountains	0.00%	0.00%	5.56%	66.67%	27.78%	6.16%
Southwest and South Central	0.00%	0.00%	45.45%	40.91%	13.64%	7.53%
West Coast	1.61%	0.00%	14.52%	59.68%	24.19%	21.23%
Canada	0.00%	7.69%	23.08%	50.00%	19.23%	8.90%
Total	0.68%	1.71%	21.23%	52.05%	20.89%	100.00%

SOLAR (UTILITY-SCALE)

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	0.00%	0.00%	0.00%	55.56%	44.44%	6.16%
Mid-Atlantic	0.00%	3.57%	10.71%	46.43%	39.29%	9.59%
South & Southeast	2.17%	0.00%	6.52%	43.48%	47.83%	15.75%
Midwest	0.00%	0.00%	6.35%	47.62%	46.03%	21.58%
Great Plains & Rocky Mountains	0.00%	0.00%	0.00%	66.67%	33.33%	6.16%
Southwest and South Central	0.00%	0.00%	18.18%	27.27%	54.55%	7.53%
West Coast	1.59%	0.00%	7.94%	31.75%	58.73%	21.58%
Canada	0.00%	0.00%	0.00%	50.00%	50.00%	8.90%
Total	0.68%	0.34%	6.51%	42.47%	47.26%	100.00%

HYDRO

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	0.00%	0.00%	66.67%	27.78%	5.56%	6.16%
Mid-Atlantic	0.00%	3.70%	81.48%	14.81%	0.00%	9.25%
South & Southeast	2.17%	6.52%	80.43%	4.35%	6.52%	15.75%
Midwest	0.00%	6.67%	81.67%	11.67%	0.00%	20.55%
Great Plains & Rocky Mountains	0.00%	6.25%	93.75%	0.00%	0.00%	5.48%
Southwest and South Central	0.00%	4.55%	86.36%	9.09%	0.00%	7.53%
West Coast	0.00%	3.39%	71.19%	22.03%	3.39%	20.21%
Canada	0.00%	0.00%	69.23%	15.38%	15.38%	8.90%
Total	0.34%	4.11%	73.29%	12.67%	3.42%	100.00%

GRID-SCALE ENERGY STORAGE

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	0.00%	0.00%	5.56%	50.00%	44.44%	6.16%
Mid-Atlantic	0.00%	0.00%	25.00%	57.14%	17.86%	9.59%
South & Southeast	0.00%	0.00%	26.09%	45.65%	28.26%	15.75%
Midwest	0.00%	0.00%	16.13%	50.00%	33.87%	21.23%
Great Plains & Rocky Mountains	0.00%	0.00%	11.76%	58.82%	29.41%	5.82%
Southwest and South Central	0.00%	0.00%	0.00%	59.09%	40.91%	7.53%
West Coast	0.00%	0.00%	9.84%	40.98%	49.18%	20.89%
Canada	0.00%	0.00%	7.69%	46.15%	46.15%	8.90%
Total	0.00%	0.00%	13.70%	46.92%	35.27%	100.00%

DISTRIBUTED GENERATION & STORAGE

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly	Total
New England	0.00%	0.00%	5.56%	38.89%	55.56%	6.16%
Mid-Atlantic	0.00%	0.00%	3.45%	65.52%	31.03%	9.93%
South & Southeast	0.00%	0.00%	10.64%	68.09%	21.28%	16.10%
Midwest	0.00%	1.59%	12.70%	53.97%	31.75%	21.58%
Great Plains & Rocky Mountains	0.00%	0.00%	0.00%	50.00%	50.00%	6.16%
Southwest and South Central	0.00%	0.00%	0.00%	57.14%	42.86%	7.19%
West Coast	0.00%	0.00%	6.35%	41.27%	52.38%	21.58%
Canada	0.00%	0.00%	3.85%	38.46%	57.69%	8.90%
Total	0.00%	0.34%	6.85%	51.03%	39.38%	100.00%

HOW DO YOU THINK YOUR UTILITY'S POWER MIX WILL CHANGE OVER THE NEXT 10 YEARS?

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly
Natural gas	4.06%	14.49%	25.51%	39.13%	16.81%
Nuclear	18.84%	20.67%	55.02%	4.86%	0.61%
Coal	58.65%	26.10%	13.20%	1.47%	0.59%
Oil	46.20%	18.54%	32.22%	2.74%	0.30%
Wind	1.45%	2.03%	20.35%	52.62%	23.55%
Solar (utility-scale)	1.14%	0.85%	6.27%	43.59%	48.15%
Hydro	0.60%	4.78%	74.03%	16.12%	4.48%
Grid-scale energy storage	0.29%	0.58%	13.95%	48.55%	36.63%
Distributed generation & storage	0.28%	0.57%	8.24%	51.42%	39.49%

WHAT'S THE SINGLE GREATEST CHALLENGE ASSOCIATED WITH YOUR CHANGING FUEL MIX?

Answer Choices	Responses
Uncertainty over market conditions & regulations for future generation	38.63%
Customer costs of new generation	7.65%
Financial impact of stranded assets	14.12%
Cost overruns/delays with generation construction	3.73%
Reliably integrating new resources	19.41%
Building new transmission to serve new resources	6.27%
Building/contracting sufficient resources to meet demand	2.75%
Other (please specify)	7.45%

WHAT IS THE MOST COMPELLING REASON TO INVEST IN CLEAN ENERGY TECHNOLOGIES SUCH AS RENEWABLES AND STORAGE?

Answer Choices	Responses
Sustainability	21.25%
Low prices	8.38%
Emissions standards	7.99%
Fuel diversity	7.21%
Renewable energy targets or mandates	14.04%
Consumer demand and sentiment	17.15%
Hedge against fossil fuel prices	4.09%
Earnings growth and business model evolution	9.94%
There is no compelling reason to invest in clean energy	4.87%
Other (please specify)	5.07%

IN YOUR OPINION, HOW SHOULD POLICYMAKERS (GRID OPERATORS AND LAWMAKERS) RESPOND TO THE RETIREMENT OF BASELOAD GENERATION IN THE NATION'S ORGANIZED MARKETS?

Answer Choices	Responses
Allow uneconomic generation to be retired under current market rules	30.66%
Expand existing reliability-must-run and capacity performance rules in wholesale markets	9.82%
Devise an around-market subsidy mechanism to keep selected plants online (e.g. New York's Zero Emission Standard)	7.41%
Provide cost recovery to selected plants (e.g. DOE NOPR)	5.41%
Devise new market-based products to value and pay grid resources for their reliability and resilience attributes	29.26%
Impose a price on carbon to support nuclear, let other baseload plants retire	10.82%
Re-regulate state utility markets to the vertically-integrated model	6.61%

IN GENERAL, HOW DO YOU BELIEVE THE U.S. FEDERAL GOVERNMENT SHOULD APPROACH DECARBONIZATION POLICY?

Answer Choices	Responses
Reinstate the Obama administration's Clean Power Plan and new source performance standards for power plants	20.00%
Scale back the Clean Power Plan to cover only emissions "inside the fenceline" of existing power plants	9.80%
Strengthen the Clean Power Plan's targets and federal renewable energy supports	17.00%
Impose a cap-and-trade system for greenhouse gases	12.00%
Impose a price on carbon and other greenhouse gases	26.20%
The U.S. government should not pursue a policy of decarbonization	15.00%

PLEASE INDICATE YOUR EXPECTED OUTLOOK FOR THE FOLLOWING DISTRIBUTED ENERGY RESOURCES IN YOUR SERVICE TERRITORY, DEPLOYED BOTH BY PRIVATE PARTIES AND UTILITIES.

	Decrease significantly	Decrease moderately	Stay about the same	Increase moderately	Increase significantly
Distributed solar	0.21%	0.63%	9.87%	49.58%	39.71%
Distributed storage	0.63%	0.00%	12.05%	53.28%	34.04%
Distributed wind	0.65%	2.59%	46.65%	36.93%	13.17%
Demand response and demand-side management	0.63%	0.63%	22.83%	50.95%	24.95%
Combined heat & power	1.71%	3.43%	50.96%	36.19%	7.71%
Community shared renewables & storage	0.42%	1.70%	21.87%	54.14%	21.87%
Smart inverters and other grid communication technologies	0.63%	0.21%	11.21%	50.53%	37.42%
Electric vehicles	0.42%	0.84%	8.81%	43.82%	46.12%

SHOULD UTILITIES BE PERMITTED TO OWN AND OPERATE DISTRIBUTED ENERGY RESOURCES?

Answer Choices	Responses
Yes, regulated utilities should be able to own and rate-base DER investments in all/most circumstances	60.29%
Yes, but only through unregulated subsidiaries	15.97%
Yes, but only in specific instances where the competitive market fails to equitably deploy DERs	17.65%
No	6.09%

HOW DO YOU BELIEVE YOUR UTILITY SHOULD BUILD A BUSINESS MODEL AROUND DISTRIBUTED ENERGY RESOURCES? CHOOSE ALL THAT APPLY.

Answer Choices	Responses
Owning and operating DERs as a regulated utility through rate-based investments	49.79%
Owning and operating DERs through an unregulated subsidiary	30.56%
Partnering with third party providers to deploy DERs on the grid	51.50%
Procuring or aggregating power from DERs owned by third party providers	36.54%
I do not believe my utility should have a business model around DERs	8.33%

WHO WILL BE THE PRIMARY AGGREGATORS OF DISTRIBUTED ENERGY RESOURCES IN FIVE YEARS?

Answer Choices	Responses
Regulated distribution utilities	27.52%
Third-party DER providers	39.92%
Regional grid operators (ISO, RTO, regional reliability corps.)	17.02%
Some other governmental or regulatory entity	1.89%
Not sure	13.66%

IN YOUR SERVICE TERRITORY, WHAT IS THE MOST APPROPRIATE COMPENSATION MECHANISM FOR DISTRIBUTED GENERATION, PARTICULARLY ROOFTOP SOLAR?

Answer Choices	Responses
Net metering at the retail rate	10.55%
Net metering at the retail rate minus fees for grid use	30.17%
Net metering at the wholesale rate or avoided cost of other generation	23.21%
Value-of-solar tariff (such as in Minnesota or in Austin, Texas)	11.18%
Location-based rates	10.97%
Not sure	8.65%
There should not be utility compensation for customer-sited DG	5.27%

HOW SHOULD UTILITIES APPROACH THE ELECTRIFICATION OF THE TRANSPORTATION SECTOR? CHOOSE ALL THAT APPLY.

Answer Choices	Responses
Own and operate charging stations as a regulated utility	44.23%
Construct make-readies for chargers and let private companies own them	32.70%
Provide utility-owned chargers where private companies can or will not deploy	42.35%
Provide chargers through an unregulated utility subsidiary	27.46%
Create special pricing or rates for EV charging	51.78%
Create pricing or rates for EV battery services like regulation services	36.06%
My utility should not pursue transport electrification	8.18%

FOR EACH CUSTOMER SEGMENT, WHICH NET LOAD GROWTH TREND DO YOU SEE IN YOUR SERVICE AREA?

	Declining load	Stagnant load	Increasing load
Industrial	18.20%	51.24%	30.56%
Commercial	13.48%	42.92%	43.60%
Residential	20.72%	37.84%	41.44%
Overall	15.44%	45.39%	39.17%

IN YOUR SERVICE AREA, WHAT IS THE MOST APPROPRIATE RATE DESIGN REFORM TO ALLOW UTILITIES TO RECOUP FIXED COSTS, PARTICULARLY IN THE FACE OF STAGNANT/ DECLINING LOAD GROWTH AND THE PROLIFERATION OF DERS? CHOOSE ALL THAT APPLY.

Answer Choices	Responses
Increase fixed charges/fees	35.27%
Move consumers to time-of-use rates	47.99%
Impose demand charges on all customers with DG	18.30%
Impose demand charges on all customers	23.66%
Impose a minimum bill for low-use customers	18.75%
Institute decoupling	18.30%
Offer block rates	6.47%
Move net metered customers or those with DG to a separate rate class	27.90%
Not sure	11.16%
My utility should not change its rate design	6.25%
Other (please specify)	6.47%

HAS YOUR UTILITY TAKEN ANY STEPS IN THE PAST TWO YEARS TO IMPROVE CYBERSECURITY?

	Yes	No	I don't know
Developed a companywide cybersecurity strategy	72.87%	7.13%	20.00%
Modernized IT and grid control systems	71.59%	9.70%	18.71%
Implemented a breach response mitigation plan	54.67%	9.35%	35.98%
Appointed a chief information security officer or chief security officer	55.79%	21.06%	23.15%
Implement NERC CIP cyber protections	55.81%	10.70%	33.49%
Implemented the NIST Cybersecurity Framework	36.79%	12.97%	50.24%
Contract outside firm to assess risk profile	43.40%	14.39%	42.22%
Educated employees on how to avoid cyber threats	79.54%	6.21%	14.25%

RATE THE FOLLOWING POWER SECTOR ISSUES ACCORDING TO IMMEDIATE IMPORTANCE TO YOUR COMPANY — 1 (NOT IMPORTANT AT ALL), 2 (POTENTIALLY IMPORTANT IN THE FUTURE), 3 (SOMEWHAT IMPORTANT TODAY), 4 (IMPORTANT TODAY), 5 (VERY IMPORTANT TODAY)

	1	2	3	4	5
Bulk power system reliability	5.56%	7.41%	18.75%	25.69%	42.59%
State regulatory model reform	7.87%	14.12%	23.38%	31.02%	23.61%
Wholesale market reform	8.67%	17.56%	32.32%	27.87%	13.58%
Rate design reform	4.66%	10.72%	25.17%	32.87%	26.57%
Compliance with federal clean air standards	7.42%	13.23%	32.02%	24.13%	23.20%
Compliance with state renewable and clean energy mandates	8.76%	11.75%	25.81%	26.27%	27.42%
Aging grid infrastructure	2.78%	9.51%	21.58%	35.03%	31.09%
Physical and/or cyber grid security	1.63%	4.19%	15.35%	34.42%	44.42%
Stagnant/negative load growth	7.19%	13.23%	28.31%	32.48%	18.79%
Generation retirements and/or stranded assets	8.76%	17.74%	29.03%	27.42%	17.05%
Aging workforce and worker transition to new technologies	3.67%	10.09%	24.54%	38.99%	22.71%
Reliable integration of renewable and distributed resources	2.52%	6.86%	19.91%	37.53%	33.18%
Fuel policy and costs	7.11%	18.01%	36.73%	24.64%	13.51%
Distributed resource policy (net metering, microgrids, rate basing DERs etc.)	2.76%	8.76%	20.05%	38.25%	30.18%
Changing consumer preferences	3.70%	9.24%	26.33%	37.18%	23.56%
Electrification of other industries, such as transport	3.93%	9.47%	26.33%	31.64%	28.64%

WHAT IS THE GREATEST OBSTACLE TO THE EVOLUTION OF YOUR UTILITY'S BUSINESS MODEL?

Answer Choices	Responses
Reliable integration of new generation and grid technologies	14.35%
Cost of transition to ratepayers (stranded assets, grid modernization etc.)	22.78%
Internal resistance to change at utility	17.54%
State regulator or regulatory model resistance	13.44%
Outside stakeholder (e.g. consumer advocates, business interests) resistance	5.69%
Wholesale market constructs and regulation	4.78%
Federal emissions and environmental regulations	3.64%
Resistance from capital markets, banks, and wall street	0.91%
Political pressure (from legislature, governor, or others)	8.20%
Nothing — my utility is not transitioning or does not need to transition from our current model	2.73%
Nothing — there is general consensus in my jurisdiction over the path and process of utility evolution	3.64%
Other (see next question)	2.28%

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