STATE OF THE ELECTRIC UTILITY

SURVEY 2019

UTILITY DIVE

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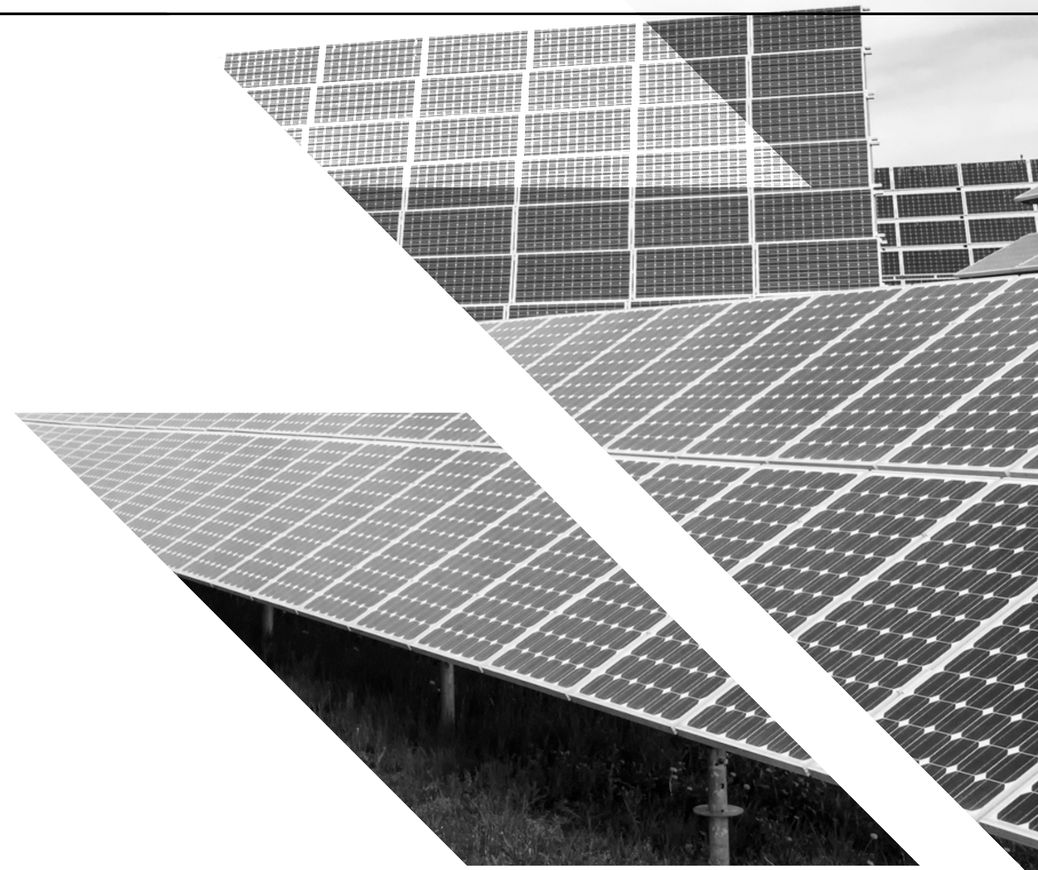
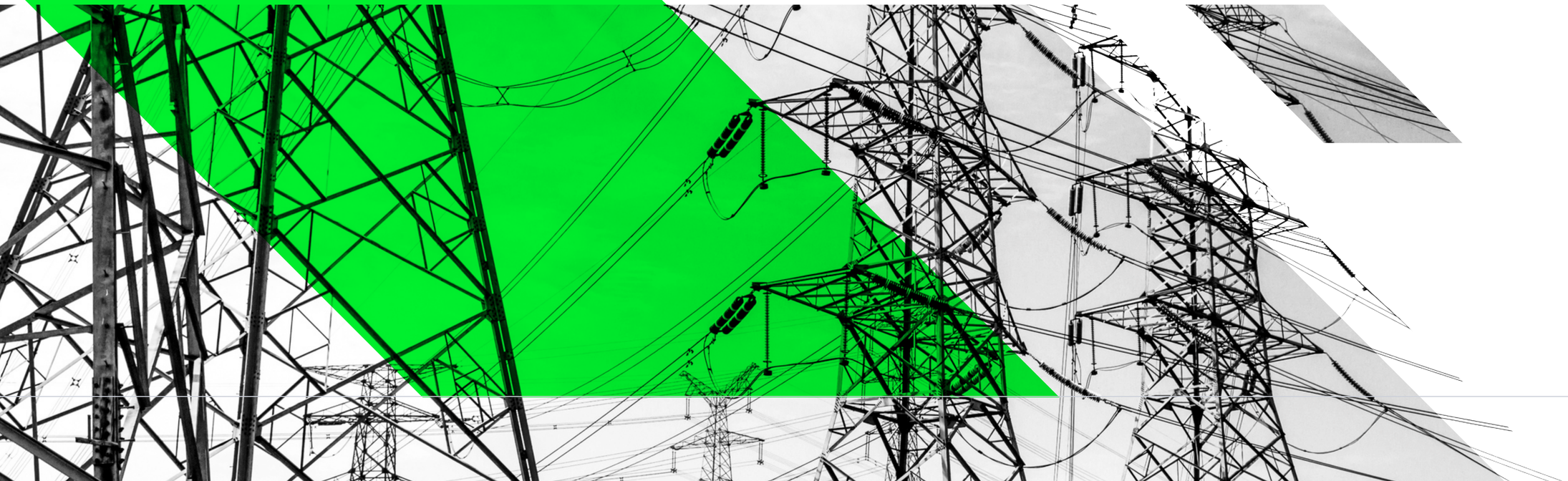


ABOUT THE SURVEY

The 2019 State of the Electric Utility Survey is based on an online questionnaire administered to Utility Dive readers in December 2018. More than 525 self-identified electric utility employees, from the U.S. and Canada, took the survey.

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



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EXECUTIVE SUMMARY

In 2019, utilities across North America are searching for clarity — from regulators, policymakers, energy markets, competitors and customers. The policy and market upheavals that characterized the industry in 2018 continue, leaving utilities uncertain about how they can fulfill their mandates and move forward as businesses.

At the same time, the nature and technologies of electric power are fundamentally transforming. In many regions, renewable energy is at cost parity with fossil fuel generation. Distributed resources are reshaping the economics of the grid. Digitalization offers vast opportunities for new efficiencies and a deeper understanding of grid management and customer service. But often, utilities struggle to justify the cost of investments in these emerging areas to their regulators.

Meanwhile, the effects of climate change are no longer looming in the future, but affect utility operations every day. From coast to coast, major utilities have been left scrambling in the aftermath of severe weather-relat-

ed events. As this report went to press, liability in several deadly wildfires had driven PG&E, California's largest utility, to file for bankruptcy.

This year's State of the Electric Utility survey highlights some key trends in these turbulent times.

2019 was the first year that, when we asked utility professionals about regulatory and market models, we explicitly offered "not sure" as an option. The results were striking, especially regarding energy markets.

1. POLICY AND MARKET UNCERTAINTY IS MOUNTING

Uncertainty was key theme in SEU 2018, especially concerning wholesale power markets and emissions regulation. This year, the scope of that uncertainty has broadened.

For the second year running, uncertainty was most prevalent when utility respondents were asked about their generation mixes. 35% of respondents indicated uncertainty over market conditions and regulations is the greatest challenge with their changing generation mixes, outpacing the reliable integration of new resources, which 24% chose.

2019 was the first year that, when we asked utility professionals about regulatory and market models, the SEU survey explicitly offered “not sure” as an option. The results were striking, especially regarding energy markets.

One in four participants were unsure what kind of wholesale power market, if any, they’d be dealing with in 10 years. About the same number don’t know what kind of market they’d prefer. This may reflect increasing anxiety among sector professionals about the multiple policy initiatives that could reshape the dynamics of wholesale markets, from FERC’s resilience docket to capacity market reforms in PJM and ISO-NE.

Similar uncertainty extends to the state regulatory model, where many jurisdictions are shifting from traditional cost-of-service regulation to performance-based standards. 11% of participants were unsure what kind of regulatory model they’ll have in 10 years, and 14% didn’t know which kind of regulatory model they might want. Yet there was one clear message from utilities about regulation: most of them want more performance-based regulation, and they expect to get it.

Despite this uncertainty, utilities do not appear to be changing their strategy and investments for the future. In the face of the Trump Administration’s continued efforts to prop up coal power, utilities continue to retire those plants and replace them with renewables and natural gas. They are also preparing to handle a wave of new technologies, including electric vehicles, battery energy storage and other distributed energy resources (DERs).

While increasing uncertainty has been a hallmark of Utility Dive’s sector surveys since 2017, utilities have yet to indicate they are altering their multi-decade investment plans due to the upheavals at the state and federal level. But their 2019 responses illustrate an ever more complicated path they must navigate in the energy transition.

2. SECURITY REMAINS A TOP CONCERN

Cybersecurity has topped our list of utility industry concerns since 2017. This year, most utilities have taken care of the base basics: educating employees and developing an enterprise-wide security strategy. It's now fairly common for a Chief Information Security Officer (CISO) to be part of a utility's C-suite.

On a national level, the issues of cybersecurity and energy security have been injected into the debate over retirement of coal and nuclear assets. But in some ways, utilities are becoming less able handle some cyber-threats. This year, notably fewer participants indicated that their utility is working with cybersecurity consultants to assess and mitigate risks.

This is may be problematic, as utilities are typically challenged to attract the top tech talent to their ranks. This gap in access to skills could become considerable weakness for the industry that outside consultants and advisers could help ameliorate.

3. THE ENERGY TRANSITION IS STRESSING UTILITY BUSINESS MODELS

Utilities are facing higher standards for performance, stagnating revenues, and the need to spend more money to do what regulators require. That combination of forces explains this year's top four regulatory issues identified by respondents:

- Justifying emerging utility investments (ie: energy storage, EV chargers, microgrids)
- Recovering fixed costs through rate design
- Managing distributed resource growth and net metering/ value of solar debates
- Recovering revenue lost to efficiency and negative load growth

Meanwhile, utilities also face increasing demands from customers for clean energy and new services. If they do not meet them, customers increasingly have third-party energy options to supplant the incumbent power company.

These factors may help explain the strong call from utility respondents for more performance-based regulation, especially in conjunction with the traditional revenue model. This hybrid approach would provide utilities with some revenue security, as well as opportunities to deploy emerging technologies such as microgrids and EV charging infrastructure.

If utilities can't find a way to justify these emerging investments, other players will undoubtedly step in to fill that gap. In the long term, that competition represents one of the biggest challenges to the electric utility model.

UTILITIES FACE INCREASING DEMANDS FROM CUSTOMERS FOR CLEAN ENERGY. IF THEY DO NOT MEET THEM, CUSTOMERS HAVE THIRD-PARTY ENERGY OPTIONS TO SUPPLANT THE INCUMBENT POWER COMPANY.

DEMOGRAPHICS

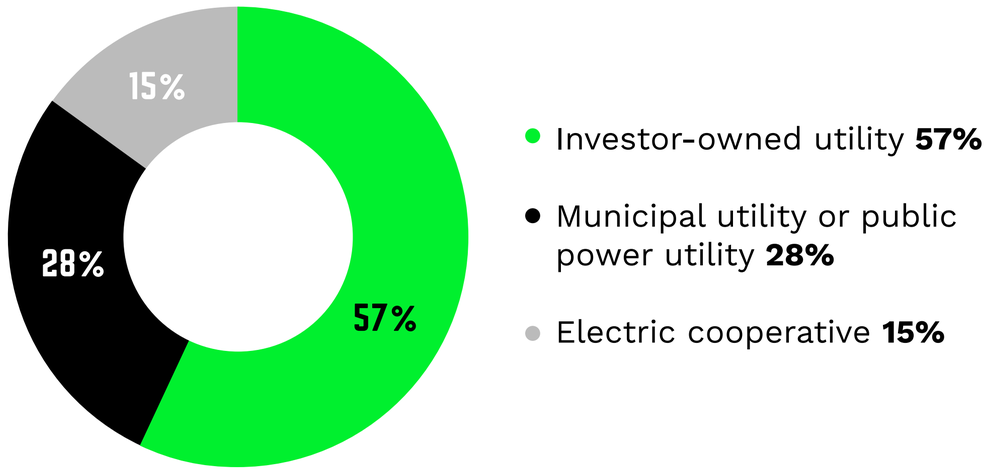
The 2019 State of the Electric Utility Industry Survey included responses from 527 utility executives and professionals.

- **Investor-owned utilities.** More than half of all participants (57%) work for IOUs. Nationally, IOUs serve approximately 2/3 of all U.S. utility customers.

- **Munis and co-ops.** 28% of participants are employed by municipal or public power utilities, and 15% work for electric cooperatives.

1

WHICH TYPE OF UTILITY COMPANY EMPLOYS YOU?



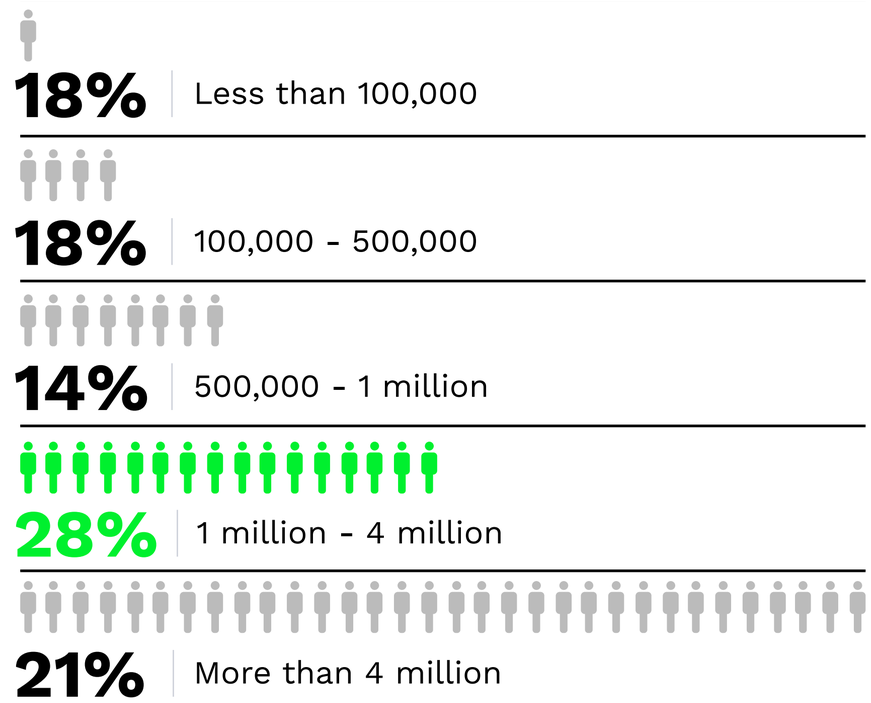
- **Utility size.** Nearly half of participants work for larger utilities (more than one million customers per utility).

- **Regions served.** Similar to prior years, our survey received the most responses from utility professionals working in the West Coast (19%) and Midwest (18%). There was moderate representation from other U.S. regions, and 5% from Canada.

- **Services provided.** Overall, 84% of participants said their utility provides distribution services. Generation and transmission services were mentioned somewhat less often. Only half work for utilities that provide retail services.

2

HOW MANY CUSTOMERS DOES YOUR ELECTRIC UTILITY SERVE?



3

IN WHICH REGIONS DOES YOUR REGULATED UTILITY HAVE SERVICE AREAS?

West Coast **19%**

Midwest **18%**

South & Southeast **12%**

Southwest & Texas **11%**

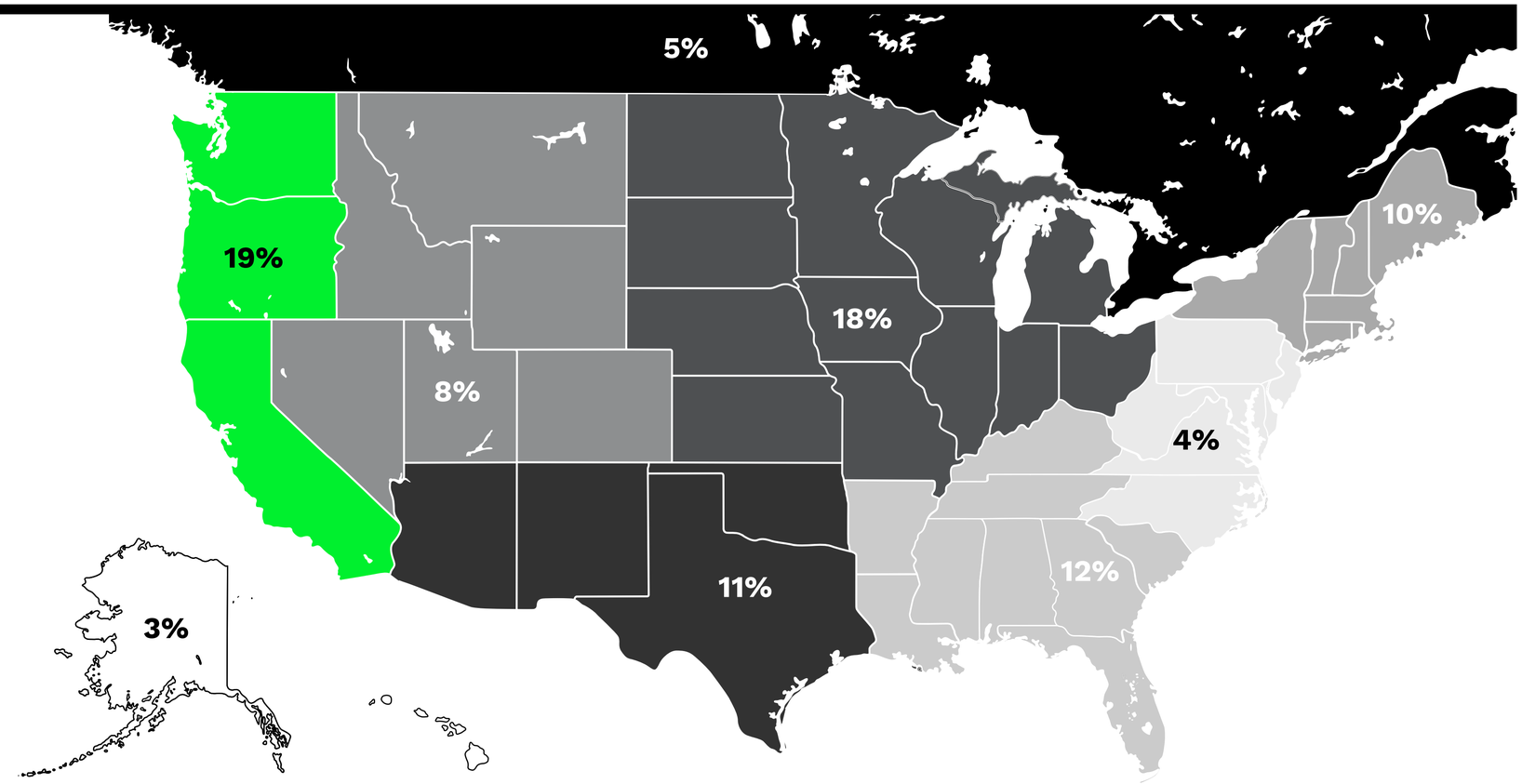
New England & Northeast **10%**

Great Plains & Rocky Mountains **8%**

Canada **5%**

Mid-Atlantic **4%**

Non-contiguous states & territories **3%**



*Other countries accounted for 8% of the utility service area

4

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

84%
DISTRIBUTION

74%
TRANSMISSION

71%
GENERATION

51%
RETAIL

TOP UTILITY INDUSTRY TRENDS AND CONCERNS

In our 2019 survey, security (both cyber and physical) continues as the #1 industry concern — cited as “very important” by 48% of participants, up slightly from 45% in 2018.

Echoing this sentiment, a recent KPMG report found that nearly half of power and utility CEOs believe that cyber-attacks against their systems are “inevitable.” This may be because the sharp increase in grid-connected technologies exponentially increases the amount of potential entry points for cyberattackers, known as the attack surface.

RATE THE FOLLOWING ISSUES ACCORDING TO IMMEDIATE IMPORTANCE

PERCENT OF RESPONDENTS WHO CALLED EACH ISSUE "IMPORTANT" OR "VERY IMPORTANT

85%	Physical and/or cyber grid security
70%	Bulk power system reliability
66%	Aging grid infrastructure
56%	Rate design reform
53%	Stagnant/negative load growth
49%	Generation retirements and/or stranded assets
48%	Compliance with state renewable and clean energy mandates
47%	State regulatory model reform
37%	Wholesale market reform
24%	Compliance with federal clean air standards

CLIMATE CHANGE INCREASES PRESSURE ON GRID MODERNIZATION BY PUTTING EVER MORE STRESS ON AGING UTILITY SYSTEMS, AS DOES COMPETITION FROM NEW THIRD-PARTY ENERGY PROVIDERS, WHICH CAN SAP REVENUE AWAY FROM INCUMBENT UTILITIES.

Other highlights from this year's ranking of utility industry concerns include:

- **Bulk power system reliability.** This concern has held steady throughout the years, cited as very important by 43% of participants in both 2019 and 2018. This reflects the utility's core mandate — the reliable delivery of power — as well as new challenges, such as wholesale market upheavals (see section 7, *Electricity Markets*) and the rise of renewable and distributed energy.

- **Aging grid infrastructure.** This perennial utility concern is gradually gaining importance as utilities face more pressure on their revenues. Upgrading infrastructure costs money, especially when deploying the advanced technologies necessary for a grid that is more sustainable, efficient and resilient.

Utilities, however, often find it difficult to justify the costs of these emerging technologies to regulators (see section 6, *Regulatory Landscape*), since they have a mandate to control customer costs. Climate change increases pressure on this issue by putting ever more stress on aging utility systems, as does competition from new third-party energy providers, which can sap revenue away from incumbent utilities.

- **Rate design reform.** Most of an electric utility's costs are fixed — related to the upkeep of grid and generation infrastructure — but the revenue they collect from customers varies depending on electricity usage. Stagnating power demand and increased competition from third-party providers put extra pressure on utility finances.

For years, utilities have attempted to move their ratepayers to rate designs that adjust for this with higher fixed fees, non-bypassable charges, or time-of-use tariffs and demand charges. Those initiatives have sparked bitter battles at state regulatory commissions, and respondents largely plan to keep pushing them (see section 5, *Load Trends and Rate Design*).

The utility sector currently exhibits a spectrum of cybersecurity preparedness. There's also considerable variation in how they are defending against cyberattacks.

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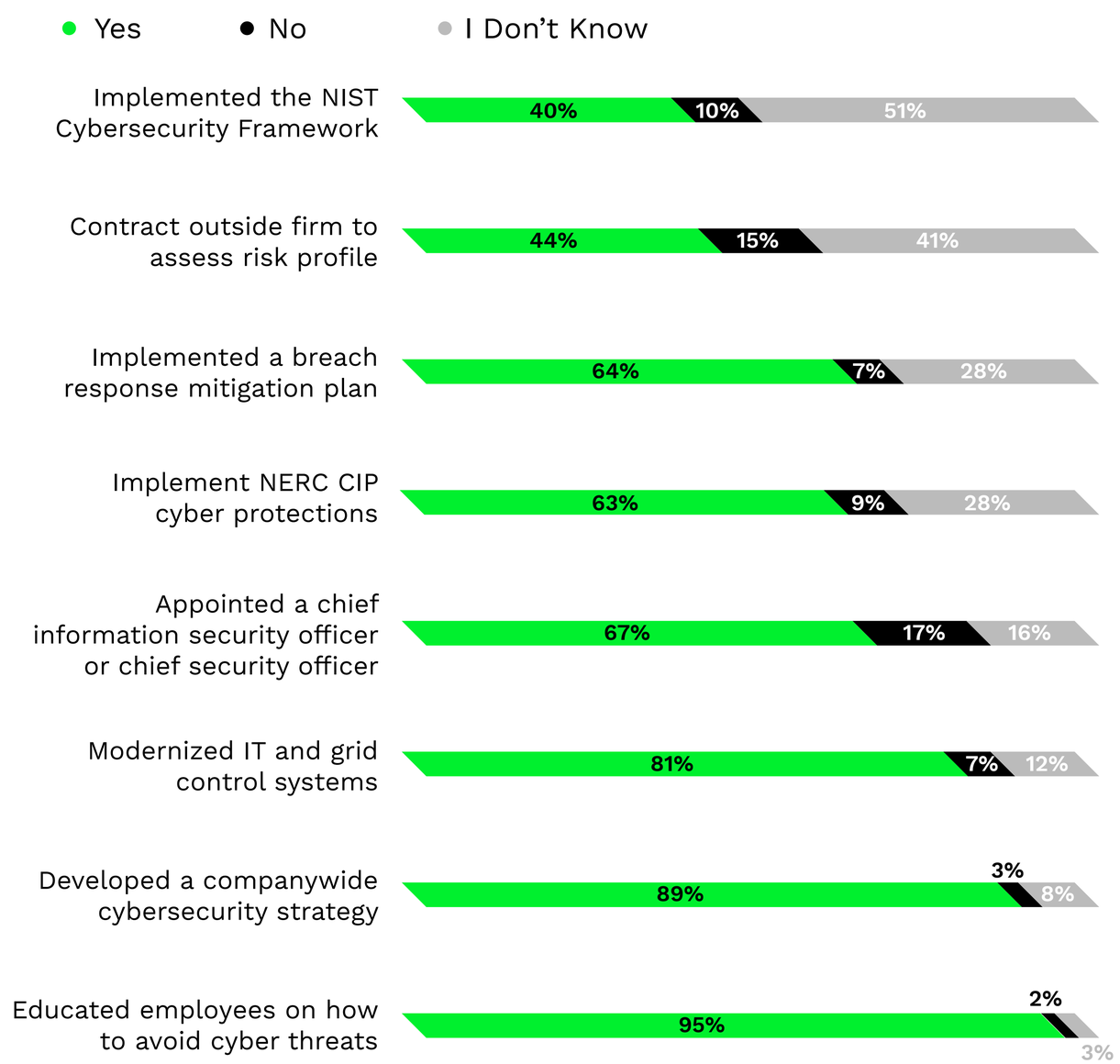
HAS YOUR UTILITY TAKEN ANY STEPS IN THE PAST TWO YEARS TO IMPROVE CYBERSECURITY?



- **Most utilities have taken care of the bare basics.** This year, nearly every participant (95%) said their utility has educated employees on how to avoid cyberthreats, up from 88% in 2018. Similarly, the vast majority (89%) said their utility has developed a companywide cybersecurity strategy, up from 82% in 2018. Unfortunately, education and strategy does not guarantee security.

- **More utility CISOs.** Many utilities have now brought cybersecurity into the C-suite. This year, 67% of participants said their utility has appointed a Chief Information Security officer — up from 61% in 2018. Leadership focus can help instill a culture of cybersecurity throughout the enterprise. In May 2018, Utility Dive noted: "New initiatives and training are often rolled out through human resources or within a corporate group, which can lead to the directives being abstract or lacking context. One way to improve the stickiness of cyber training is to have the focus come from company leadership."

- **Preparedness is dropping** on some important fronts. Most notably this year, fewer participants (44%) reported that their utility is working with outside contractors to assess its cyber risk profile, down from 50% in 2018. Utilities face considerable challenges for recruiting the best tech talent. Cybersecurity contractors can be an important — and perhaps necessary — complement to in-house resources.

LOAD TRENDS AND RATE REFORM

Variations in electricity demand — or “load,” in industry parlance — can have significant consequences for utility revenues, which can be managed via rate design.

Since the Great Recession of 2008, many North American utilities have seen stagnant or declining load due to lower economic activity and greater economy-wide

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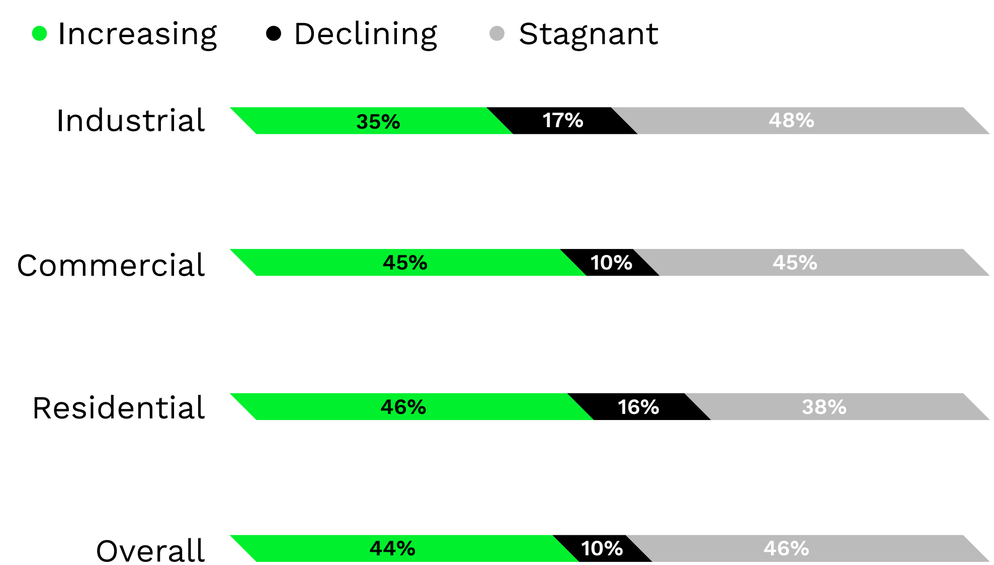
FOR EACH CUSTOMER SEGMENT, WHICH NET LOAD GROWTH TREND DO YOU SEE IN YOUR SERVICE AREA?



energy efficiency. Now that the economy has been gaining momentum, load growth is reappearing, but gradually.

- **Overall load trends.** Most participants reported that their utilities are experiencing, across all customer classes, stagnant (48%) or increasing load (44%). Only 10% reported overall declining load.

- **Residential and commercial load growth.** Increasing load is strongest for residential (46%) and commercial (45%) customers. Across much of the country, most of this growth is occurring in peak energy usage, rather than over course of the day, raising new challenges for utilities to meet periods of highest demand.

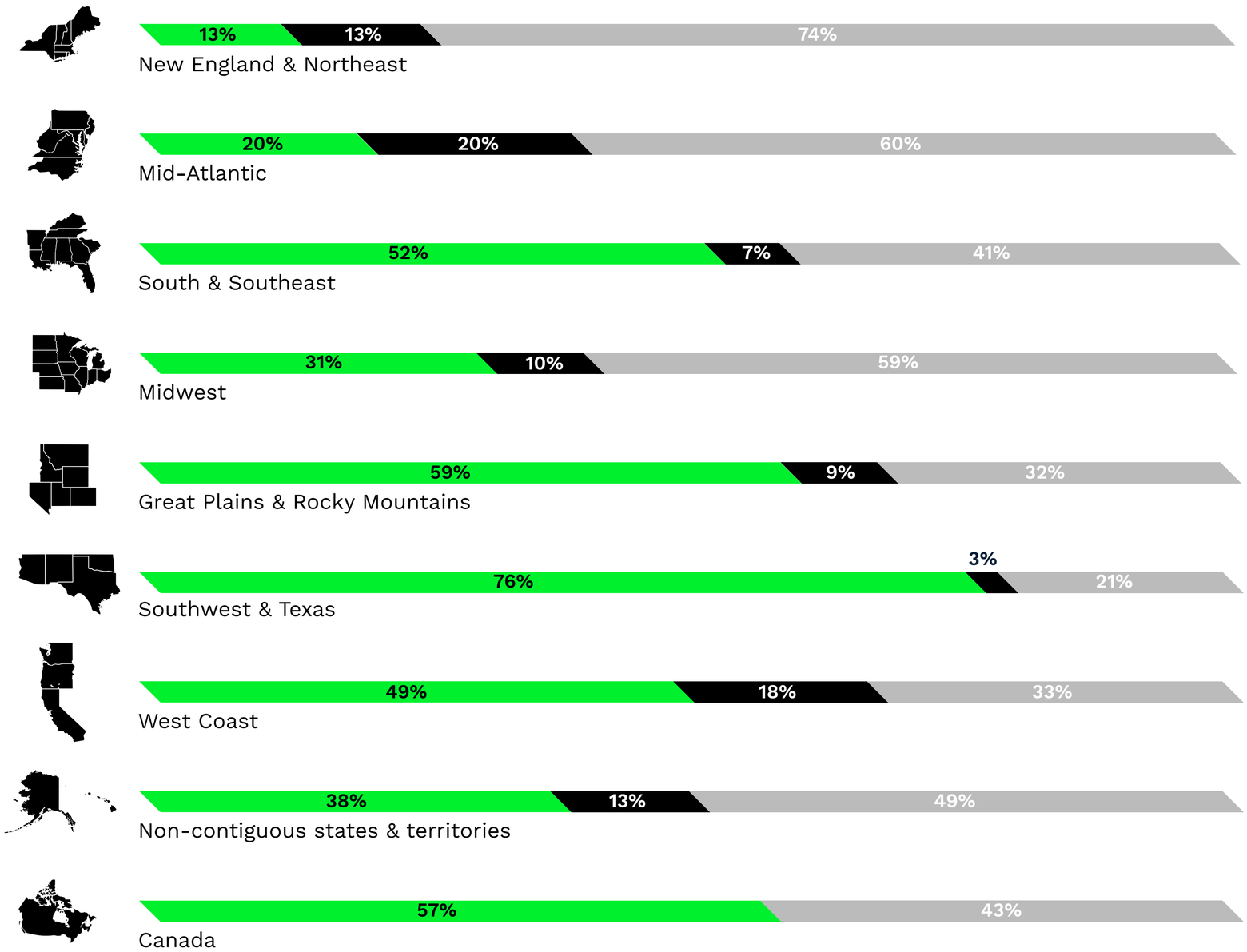
- **Business benefits of load growth.** Increasing load helps relieve the financial pressure on utilities. Pressures on the traditional utility revenue model only get more acute during times of overall shrinking load base. That's why utilities prefer rate designs with higher fixed charges; it guarantees revenues regardless of variations in consumption.

- **Losing large customers.** Industrial customers are presenting the greatest reported level of both load stagnation (48%) and load decline (17%). This likely attributable at least in part to large industrial and commercial customers installing their own generation or defecting to third-party power providers.

ONLY 10% OF PARTICIPANTS REPORTED OVERALL DECLINING LOAD.

REGIONAL LOAD TRENDS ACROSS ALL CUSTOMER CLASSES

● Increasing ● Declining ● Stagnant



- **Positive load growth** was reported the most in the Southwest and Texas (76%), Great Plains/Rockies (59%), Canada (57%) and the South and Southeast (52%).

- **Stagnant load** is the most common, by far, in New England and the Northeast (75%). After that, about 60% of participants from both the Mid-Atlantic and Midwest report overall load stagnation.

- **Declining load** is low across the U.S., but most pronounced in the Mid-Atlantic (20%) and West Coast (18%). Some states in those regions, such as Maryland, California, Oregon and Washington, have state standards for energy efficiency savings.

The continuing growth of **corporate renewable energy purchases** accounts in part for utility observations of stagnant or declining load growth. In the first 10 months of 2018, U.S. corporations contracted for 4.81 GW of renewable energy capacity, a new record. Typically, these contracts are with third-party power providers, which means the incumbent utility loses the demand served by the deal.

Corporate renewables have recently gotten a boost from the development of, **virtual PPAs,** which now account for the majority of new renewable capacity being built. VPPAs deliver contracted renewable megawatt hours into energy markets, rather than to distribution utility grid. Buyers in those markets pay contract prices to receive market prices.

This is a departure from traditional “physical” PPAs, which deliver contracted renewables onto the buyer’s local grid.

Increasingly, utilities are responding to the growth of corporate renewables purchases with their own **Green Tariff** programs, now approved in 17 states. These programs allow utilities — particularly in states without third-party energy access — to connect key customers with renewable energy.

Tthese special rates allow eligible customers to buy both the energy from a renewable energy project and the renewable energy certificates (REC). This provides customers with a more direct financial connection to renewable energy projects, which aligns with corporate sustainability initiatives. It also can offer customers greater economic benefits than unbundled RECs alone.

Once in place, a green tariff is open to a class of customers and so does not require negotiation — which makes it easier to execute than a PPA. Green tariffs allow for participating in VPPAs, which allows investment in renewable projects that might be located considerably far away from the customer’s facilities.

“WE NEED RATE RELIEF FOR NON-CAPITAL INVESTMENTS, SUCH AS SOFTWARE-AS-A-SERVICE SOLUTIONS.

Rate design refers to the prices utilities charge to different customer classes in return for electricity and other services. Particularly in times of stagnant or declining load, rate design can be a key tool to ensure utilities recover their costs. Rates can also shape customer usage, but because they affect ratepayer bills directly, are often the subject of heated public policy debates.

There are several rate design options that can help utilities continue to recover fixed costs, especially in the face of stagnant/declining load and growing amounts of distributed energy resources (DERs). These are the two most popular:

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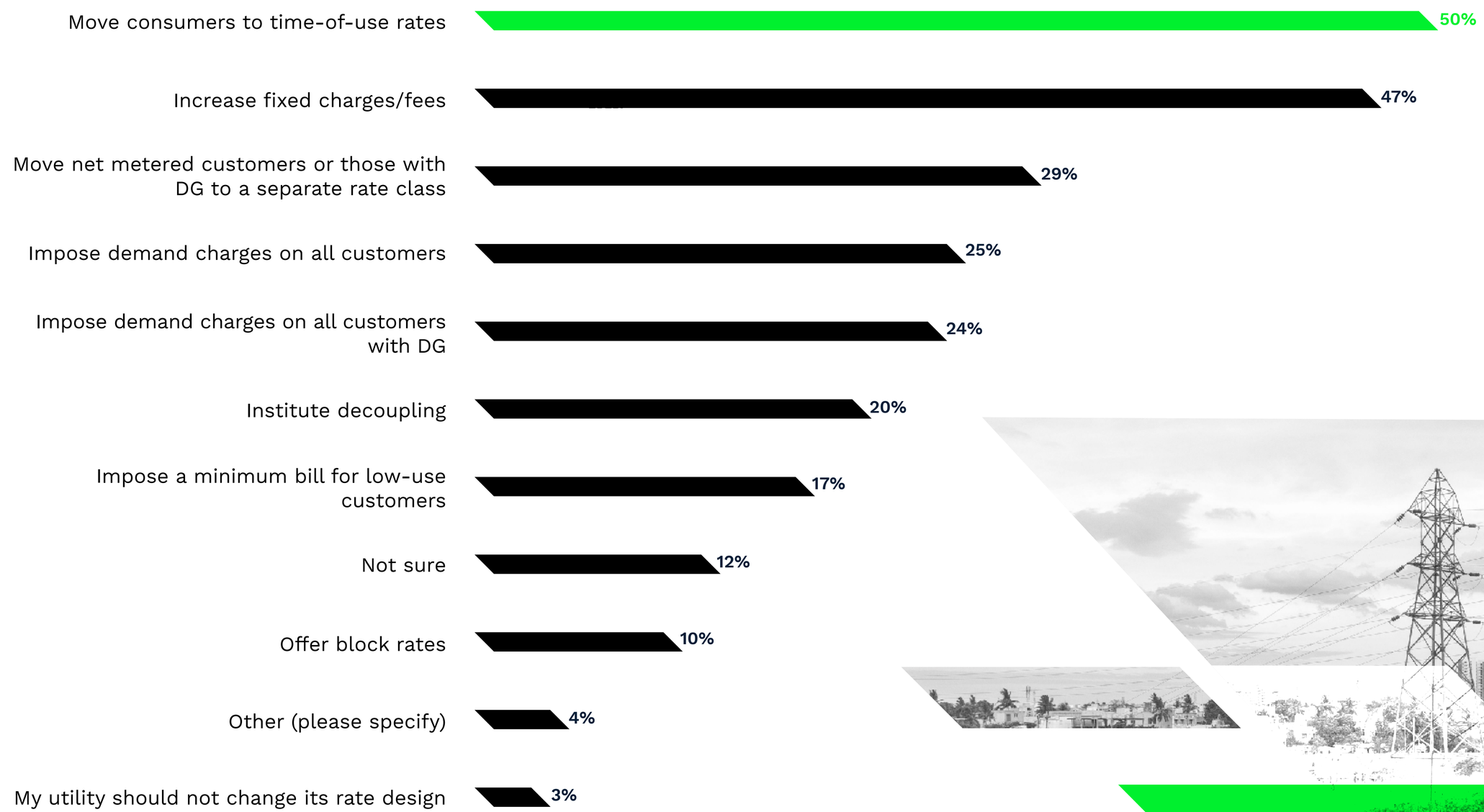
IN YOUR SERVICE AREA, WHAT IS THE MOST APPROPRIATE RATE DESIGN REFORM TO ALLOW UTILITIES TO RECOUP FIXED COSTS, PARTICULARLY IN THE FACE OF STAGNANT/DECLINING LOAD GROWTH AND THE PROLIFERATION OF DERS? CHOOSE ALL THAT APPLY.



- **Time-of-use rates.** Half of all participants believe that moving consumers to TOU rates is one of the most effective rate design reforms. Support for this option has been increasing steadily since 2017. TOU can help utilities integrate large solar capacity, while also providing pricing signals for rooftop solar and other smaller distributed capacity. But in many states, progress toward this transition is slow.

- **Raising fixed charges and fees** follows close behind, preferred by 47% of participants. The popularity of this option is growing especially fast, up from 41% in 2017 and 36% in 2016. This year, the Great Plains/Rockies showed strongest support for this option (61%) — followed by Canada (53%), the Midwest (51%) and the Southwest and Texas (50%).

Raising fixed charges is appealing to utilities because it can insulate them from changes in customer demand and because most of their infrastructure costs are also fixed. But they also decrease customers' ability to control their bills by reducing usage or adding distributed energy, so proposed fixed charge hikes are often met by raucous opposition, and state regulators have tended to scale back utility proposals in recent years.

- **Low perceived importance of rate reform.** Despite its potential to address the erosion of utility revenues, this year fewer participants than ever (26%) ranked rate reform as one of the top concerns facing the utility industry. Even fewer (11%) ranked it as potentially important in the future. (See section 5, *Utility Trends and Concerns*)

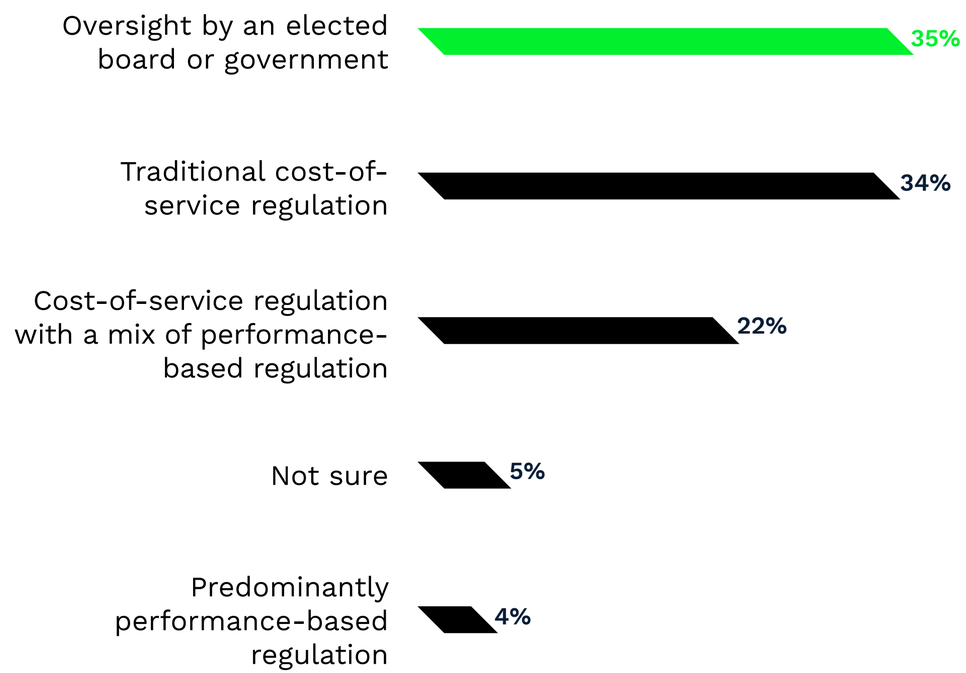
REGULATORY LANDSCAPE

Disruption is sweeping the historically slow-to-change utility regulatory landscape. The cost-of-service regulatory model that governed investor-owned utilities for a century has been challenged for years by stagnant load growth and the proliferation of distributed energy resources.

In response, regulators are increasingly proposing performance-based mandates that make part of a utility's revenue contingent on meeting targets around metrics like customer satisfaction, reliability or the ability of third-party providers to connect to their systems.

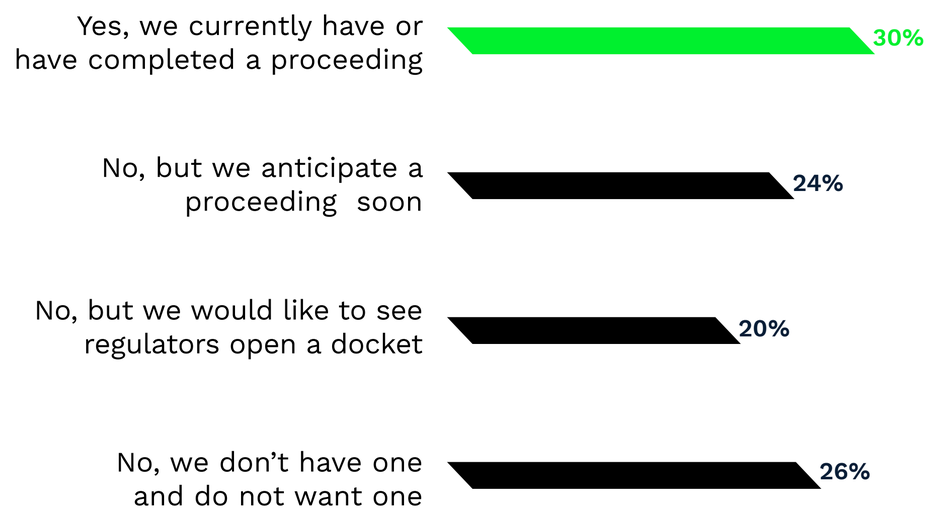
10

WHICH OF THE FOLLOWING BEST DESCRIBES YOUR CURRENT REGULATORY ENVIRONMENT?



11

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



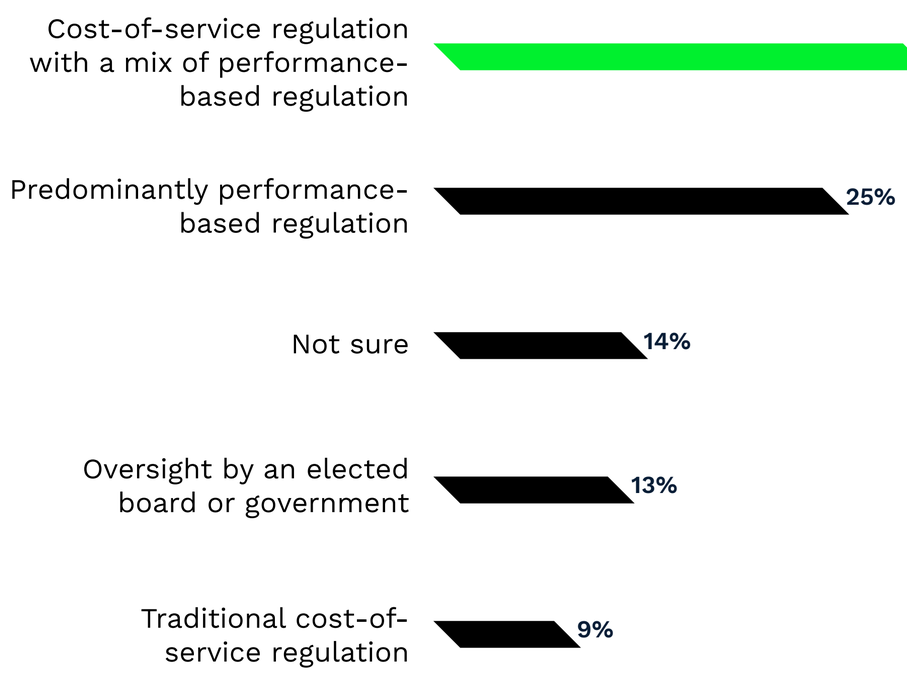
In recent years, a new regulatory paradigm appears to have taken hold among utility respondents — the hybrid model. In 2019, as in the past two years, a model that combines traditional cost-of-service regulation with performance-based metrics was the most popular regulatory model among participants.

The 2019 survey, however, reveals for the first time utility uncertainty with their changing regulatory models by allowing participants to indicate they are unsure of the models they have or how they will evolve.

- **Current regulatory landscape.** Just over one-third of participants reported working for utilities operating under traditional cost-of-service (COS) regulation. Slightly more (35%) are overseen by an elected board or government.

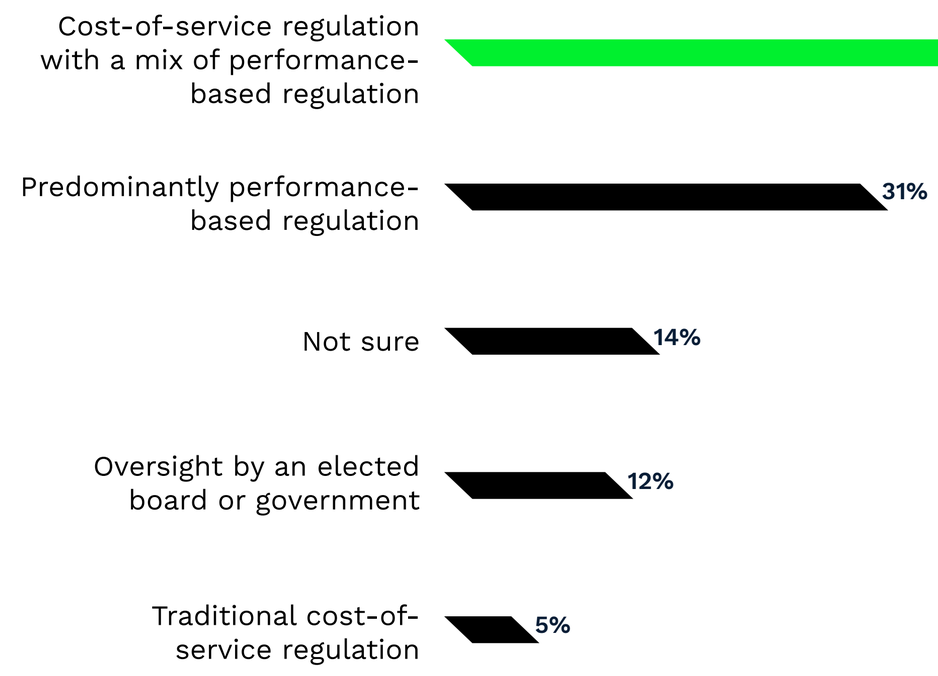
12

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



13

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



REGULATORY COMPARISON

	WHAT THEY HAVE TODAY	WHAT THEY EXPECT IN 10 YEARS	WHAT THEY WANT
Hybrid: Cost-of-service regulation with a mix of performance-based regulation	22%	35%	37%
Predominantly performance-based regulation	4%	14%	31%
Traditional cost-of-service regulation	34%	9%	5%
Oversight by an elected board or government	35%	29%	12%
Not sure	5%	13%	14%

Only 5% of participants were unsure of their current regulatory model, which probably reflects variation of awareness in different job roles.

- **Regulatory reform** is proceeding around the U.S. Over half of participants report proceedings are currently underway, completed or expected. One-fifth would like to see such a proceeding open.

- Of the 26% of participants who said they do not have, and do not want, a regulatory reform proceeding, most are in the Midwest and South/Southeast — regions where utilities still tend to be vertically integrated.

Analyzing what type of regulations utilities report today against their future expectations and desires reveals new levels of uncertainty and persistent challenges for utilities.

15

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

55% **#1**
Justifying emerging utility investments (ie: energy storage, EV chargers, microgrids)

43% **#2**
Recovering fixed costs through rate design

41% **#3**
Managing distributed resource growth and net metering/value of solar debates

**Percent of respondents who named each issue in their top three*

THE SLOW PACE OF REGULATORY CHANGE IS PLACING UTILITIES AT A COMPETITIVE DISADVANTAGE.

- **Significant future regulatory uncertainty.** Looking ahead, 13% of participants said they were unsure how they will be regulated in a decade. Furthermore, 14% weren't even sure which type of regulation they'd prefer. The utility industry is experiencing considerable flux at the state and federal level; uncertainty among industry participants is a natural response.

- **Problems justifying emerging utility investments.** This has always been one of the most commonly mentioned difficulties that utilities experience due to their current regulatory model. But year, there was a sharp jump in this problem, from 45% to 55%. It's a classic conundrum: performance-based mandates are popular with utilities and regulators, but meeting these requires new technologies. Utilities often struggle to convince regulators that those new technologies are worth the cost.

- **Recovering fixed costs is getting even harder.** Concern over paying to upgrade aging infrastructure has resurged: 43% of participants are now worried about this issue, up from 36% in 2018. Nimble third-party providers are growing more competitive, and luring away more of the rate base — especially large customers.

- **Business challenges of a cleaner, more flexible power system.** Besides costs associated with aging equipment and new technologies, this year utilities also are wrestling with managing the growth and costs of distributed resources (especially solar).

- **Wildfire risk and inverse condemnation.** While not directly surveyed, several utilities mentioned the growing business risks that utilities face as their infrastructure is implicated in causing large wildfires. PG&E, and other utilities, are facing inverse condemnation lawsuits — a legal term for when the government (or in this case,

a regulated entity) takes or destroys private property without paying compensation.

California applies inverse condemnation to utilities, which means they can be held liable for damage even if they are not found negligent. In late January, PG&E filed for bankruptcy, saying liabilities related to its role in igniting multiple deadly wildfires could reach above $30 billion.

This year's survey also drew into sharp relief the industry-wide shift toward more performance-based regulation.

- **Low performance-based regulation today.** Current regulatory models that blend traditional COS regulation with some level of performance-based regulation were mentioned this year by only 22% of participants. So far, this hybrid approach is most common in the Northeastern U.S., and to a lesser extend in the Midwest. Predominantly performance-based regulation was rarely mentioned as a current regulatory model.

- **An increasingly performance-based future.** When asked what they expect their regulatory environment to look like in 10 years, the hybrid approach leapt to top place. Overall, 35% expect hybrid regulation in the coming decade, while predominantly performance-based regulation jumped to 14%.

- **Utilities want performance-based regulation.** When asked which type of regulation is most appropriate in the 21st century, this preference was clearly apparent. Nearly 40% of participants desire hybrid regulation, while nearly one-third desire predominantly performance-based regulation.

35% EXPECT HYBRID REGULATION IN THE COMING DECADE, WHILE PREDOMINANTLY PERFORMANCE-BASED REGULATION JUMPED TO 14%.

Hybrid regulation retains some of utilities' traditional security for rate-basing fixed costs, with the potential for additional earnings through performance-based incentives. On the other hand, it is notable that while 31% desire predominantly performance-based regulation, fewer than half that amount expect that this really lies in their future.

- **Even munis and co-ops want performance-based regulation.** Among participants who work for municipal or public utilities, a mere 18% want to keep their current regulatory model. Far more (32%) want hybrid regulation, and 25% want predominantly performance-based regulation. Co-ops show an even stronger preference for predominantly performance-based regulation (29%). This may reflect a desire among employees of public or member-owned utilities for enhanced performance standards within their own organizations.

ELECTRICITY MARKETS

2018 was a year of significant upheaval in U.S. electricity markets — and utility executives and professionals are profoundly unsure of how this will affect their companies, and their industry.

- **States' power grab on generation.** After decades of deregulation in most of the nation, several states have begun to reassert their authority to determine the sources of electricity produced and consumed within their borders.

MARKET TYPE COMPARISON

	WHAT THEY HAVE TODAY	WHAT THEY EXPECT IN 10 YEARS	WHAT THEY THINK IS BEST
Restructured wholesale and retail markets	18%	28%	28%
Not sure	14%	25%	27%
Restructured wholesale market with some vertically-integrated utilities	18%	20%	20%
Vertically-integrated utilities with sub-ISO energy trading (i.e. Western EIM)	24%	18%	14%
Vertically-integrated utilities — no wholesale or retail markets	21%	6%	5%
Restructured wholesale market, no vertically-integrated utilities, no retail choice	4%	3%	6%

- **FERC intrigue.** Last year, FERC opened a controversial long-term proceeding on grid resilience after rejecting a DOE effort to prop up coal and nuclear power, spearheaded in part by Bernard McNamee, who has since left DOE to become a FERC Commissioner.

  So far, McNamee has refused to recuse himself from this proceeding, despite protests from Democrats and environmental groups about his apparent conflict of interest. The outcomes of this proceeding could determine not only what plants are built today, but how the U.S. power sector will evolve in coming decades.

- **Capacity markets unraveling?** In July 2018, FERC ordered changes to the capacity market rules for PJM, the largest US energy market. This will likely reshape the grid operator's relationship with its state participants.

CAISO WANTS OUR CAPACITY, BUT IS NOT WILLING TO PAY FAIR MARKET VALUE FOR IT.

Large, West Coast public power agency

- In November, PJM CEO Andy Ott told Utility Dive in a podcast interview, "What I'm hearing from the states is maybe least cost isn't the only answer. Maybe it's least-cost green power, or least-cost locally generated power, or they want to save a particular plant. So the game has changed, and if it's changed to the point that a capacity market is not the best way, fine. But our mandate is to operate reliably at least cost."

- **McIntyre absence.** As if this wasn't sufficiently chaotic, FERC Commissioner (and former Chairman) Kevin McIntyre died on Jan. 2. In December, Utility Dive named McIntyre Policymaker of the Year for 2018, notably for leading FERC to unanimously reject the Trump administration's coal and nuclear support plan, and for pushing for a rewrite of capacity rules for PJM.

These complex events color how utilities view their electricity market future: which outcomes they expect to see, and the kind of electricity market landscape they desire.

- **Current market landscape.** This year, nearly one-fourth of survey participants said that their utility is vertically integrated, with sub-ISO energy trading (such as Western EIM). Nearly as many (21%) work for straightforward vertically integrated utilities, with no wholesale or retail markets. Restructured wholesale markets were somewhat less common, and those with no vertically integrated utilities or retail choice were the least common, by far (4%).

That is to be expected, as only one state — Vermont — cleanly fits into this model today.

- **Drastic change expected.** In 10 years, many utilities expect to see a very different market landscape. Nearly 30% expect to be operating in restructured wholesale and retail markets. But even more notably, one-fourth of participants are not sure what to expect. Many utilities may be wondering whether they will remain in an organized market, or whether their state lawmakers will attempt to leave the market or re-regulate their utility systems.

- **What kind of markets do utilities want?** Many of them (27%) — aren't sure which kind of electricity market would be most appropriate for the 21st century. That's nearly the same number of participants who'd prefer to see restructured wholesale and retail markets.

- **Despite chaos, utilities still do want markets.** 2018 brought mixed news about U.S. energy markets. Yet the vast majority of survey participants (73%) still prefer to have some kind of market, rather than dismantle energy markets altogether.

Many also want those markets to change. Today, only 18% operate in fully restructured wholesale and retail markets — but in 10 years, 28% expect their market tobe restructure.

POWER MIX

As utilities look ahead to the sources of their power in the next decade, the industry-wide shift away from coal continues to gain momentum, while renewables continue to rise.

- **Coal definitely declining, again.** This year, 67% of survey participants said they expect to see a significant decline in their utility's use of coal in the coming years — up from 60% in 2018, and 51% in 2017.

  The current sentiment is edging back to what we saw during the Obama administration, before the repeal of the Clean Power Plan. In 2015, 77% of participants expected a significant decline in coal use. This year, the regions with the largest predicted declines in coal

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

Solar (utility scale)
51% say increase moderately

Distributed generation & storage
52% say increase moderately

Grid-scale energy storage
52% say increase moderately

Wind
52% say increase moderately

Natural Gas
41% say increase moderately

Hydro
79% say stay about the same

Nuclear
55% say stay about the same

Oil
43% say decrease significantly

COAL
67% say decrease significantly

power are the Mid-Atlantic, Southwest/Texas and New England/Northeast (71% each). No region anticipates any increase in coal usage.

- **Natural gas still reigns** as the dominant U.S. fuel source. With natural gas prices projected to remain relatively low for the next decade, utilities anticipate adding more gas plants. 51% predict moderate or significant increase in gas generation, while 28% think it will stay the same.

  Overall, 14% expect a moderate decrease in natural gas use, and only 7% expect any significant decrease. Even if natural gas prices were to start climbing, that might not make utilities return to coal. In late November 2018, while gas spot prices were peaking, many generators refrained from switching back to coal.

- **Nuclear mostly holding steady.** Like last year, 55% percent of participants said they expect their utility's use of nuclear power to stay the same, while 38% expect some moderate or significant decrease. Only the Northeast/New England and the West Coast predict any significant nuclear decrease, reflecting expected plant retirements in those regions.

  Back in 2015, the industry outlook for nuclear was quite different: just 35% expected their nuclear use to stay the same, while 21% predicted a significant decline. The more bullish attitude may be due to some generators going offline already, along with state regulatory efforts in New York, Illinois, New Jersey and Connecticut to save nuclear plants.

- **Everybody loves solar and storage.** Overall, 93% of participants predict their use of utility-scale solar to increase moderately or significantly. Almost exactly as many foresee a rise in their use of distributed generation and storage, and slightly fewer (87%) expect moderate or significant growth in their use of grid-scale energy storage. Interest in storage, both distributed and grid-scale, has been steadily rising in the last few years.

- **Regional growth spurts in distributed generation and storage.** A sizable majority (71%) of participants from the Mid-Atlantic region predict a significant increase in these technologies — well beyond other U.S. regions. Canadian participants are similarly bullish on this front: 47% expect a significant increase, and 41% a moderate one.

- **Stronger gusts of wind power growth** are predicted by participants in New England/Northeast, where 91% predicted moderate or significant increase, the Midwest (90%), the Great Plains/Rockies (88%) and the West Coast (84%).

All utilities must adapt their fuel mix over time, but executing this shift is daunting. Companies must take into account expectations of future regulations, fuel prices, market conditions and environmental risks like climate change. As in the past two years, uncertainty over market conditions and regulations appears to spark the most anxiety.

- **Uncertainty rising.** In 2019, “uncertainty over market conditions and regulations for future generation” once again tops the list of utilities’ top challenges associated with changing their fuel mix — cited by 35% of this year’s participants.

This has been true every year since 2017, when concern over uncertainty doubled. In our 2016 survey, only 16% listed uncertainty as a top concern.

This year, sentiment of uncertainty was strongest in the South/Southeast (62%), Mid-Atlantic (57%) and Canada (53%). On the bright side, this angst has eased slightly; last year, it peaked at an overall 39% of participants.

- **Integrating new resources** remains another high-level concern, this year noted by 24% of participants, up from 20% in 2018 and 18% in 2017. That's still not as high as it was in 2016 (32%), likely a reflection of increasing utility experience with renewable and distributed resources.

- **Financial jitters.** Utilities remain somewhat concerned this year about the financial impacts of stranded assets (13%, down two points from last year) and the cost to consumers for new generation (11%, up two points from last year).

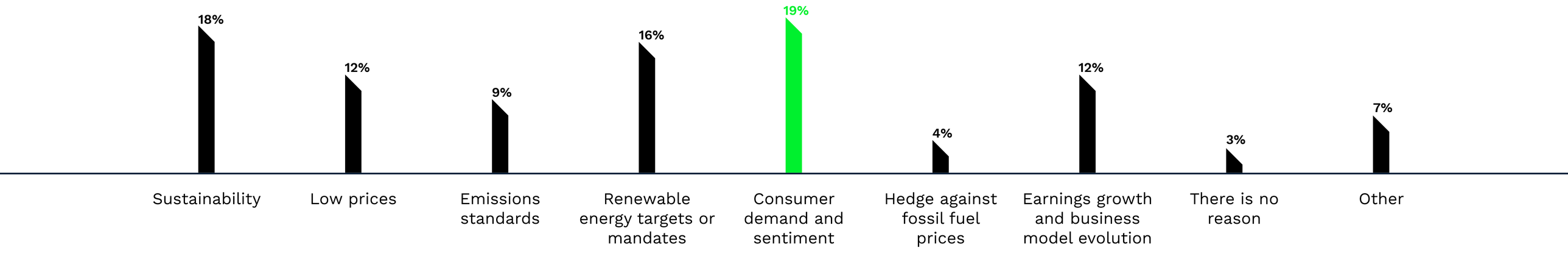
These ongoing fears relate to deeper, growing tensions over business models for regulated utilities, especially one of this year's leading regulatory challenges: justifying emerging utility investments. Since last year, that particular concern jumped sharply from 45% to 55%. (See section 6, *Regulatory Landscape*.)

35%

OF RESPONDENTS INDICATED UNCERTAINTY OVER MARKET CONDITIONS AND REGULATIONS AS THE GREATEST CHALLENGE WITH THEIR CHANGING GENERATION MIXES.

When justifying emerging investments, utilities must make that case internally and to investors or boards, as well as to state regulators. This is especially true when utilities weigh investments in clean energy technologies such as renewables and storage.

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



- **Consumer demand and sentiment** once again topped the overall North American list of compelling reasons for utilities to invest in clean energy, but not by much. Only 19% of participants named this as their top reason, with sustainability close behind at 18%.

  There were some regional variations in why utilities wish to make these investments. For instance, this year respondents from the South/Southeast region found this particular reason most compelling, at 32% — well above consensus on the West Coast (23%) and New England/Northeast (15%).

- **Sustainability** had rather lackluster support as a compelling reason for utilities to invest in clean energy. Interest was strongest in Canada (29%), the Great Plains/Rockies (27%) and the Southwest/Texas (24%), but low elsewhere in North America.

- **Renewable energy mandates** are driving interest in clean energy investments among utilities in the West Coast (27%) and in Canada (24%), but again this motivation is rare elsewhere.

- **Vanishingly few utilities** currently seem to feel compelled to invest in clean energy projects as a hedge against fossil fuels, or due to emissions standards, or for earnings growth or business model evolution. These options received marginally more support than “there is no compelling reason to invest in clean energy.” Even the rationale “low prices” received only moderate support, mostly in the Southwest/Texas (24%).

The utility sector shift toward natural gas and renewables has put financial stresses on the nation’s coal and nuclear plants, which tend to be higher priced, less flexible resources.

In response to years of coal and nuclear retirements, the Trump administration in 2017 asked the Federal Energy Regulatory Commission to approve financial support for at-risk plants in the nation’s wholesale markets. When FERC unanimously rejected that plan early the next year, the White House began discussions on an executive branch bailout for the plants, potentially using the president’s national security powers.

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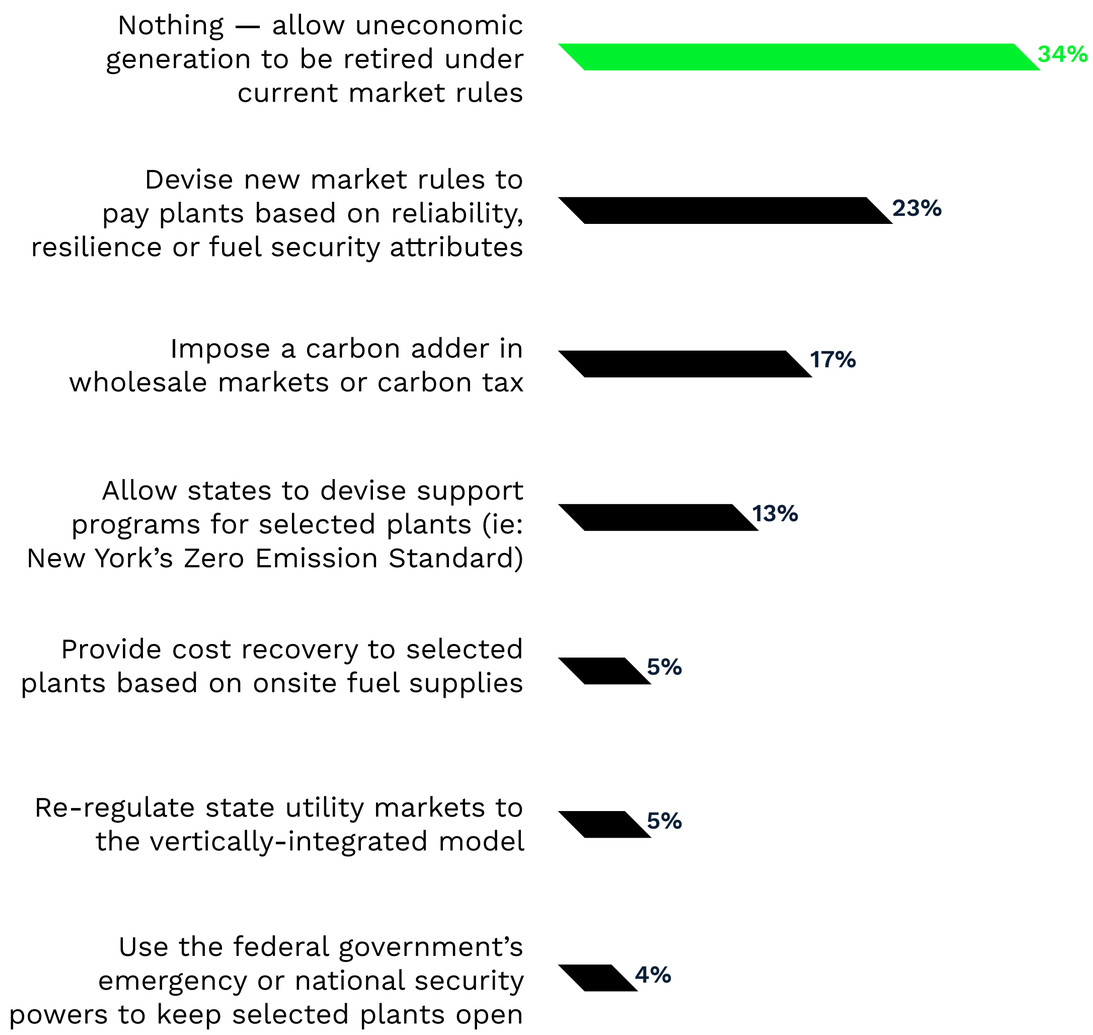
IN YOUR OPINION, HOW SHOULD POLICYMAKERS (GRID OPERATORS, REGULATORS AND LAWMAKERS) RESPOND TO THE RETIREMENT OF COAL AND NUCLEAR GENERATION?



Those discussions are reportedly on hold at the White House in early 2019 over legal concerns, and sentiment in the utility industry appears strongly against any administrative bailout attempt.

- **Let them retire.** This year, the largest portion of participants (34%) say that uneconomic generation should simply be retired under current market rules. This is a 7% increase from last year, when "nothing" fell in second place behind designing new market rules for resilience.

- **Devise new market rules** that would pay power plants based on reliability, resilience or fuel security attributes fell to second place this year, at 27%, after holding the top slot last year with 30%. The slight decrease in the level of support for this option comes after a full year of resilience debates at FERC.

- **Markedly low support** was voiced for other options. Imposing a carbon tax or carbon adder in wholesale markets was favored by just 17% of participants. Only 13% would like state supports for selected plants (like New York's Zero Emission Standard).

  All other options received 5% or less (cost recovery to selected plants based on onsite fuel supplies, reanimating the historic vertically integrated model, or using federal emergency or national security power to keep selected plants open).

The utility sector is expected to play a key role in addressing climate change by allowing other industries to cut greenhouse gas emissions through electrification.

Since the Great Recession, the U.S. utility sector had made modest reductions in carbon emissions by shifting generation from coal to natural gas and integrating more renewable energy. But in 2018, that trend reversed as utilities ramped up gas generation to meet increased power demand, boosting U.S. power sector carbon emissions for the first time in a decade.

As in past surveys, the vast majority of utility respondents continue to want the U.S. federal government to set a policy to guide decarbonization, but they remain divided on the best option.

82%

WOULD LIKE THERE TO BE SOME KIND OF FEDERAL POLICY OR ACTION TOWARD DECARBONIZING THE POWER SYSTEM.

- **Carbon tax.** The most popular option, by far, is to impose an economy-wide price on carbon and other greenhouse gases. This year, 27% of participants preferred this option, up from 23% last year (and back to the 2017 level).

- **Reinstate the Obama Clean Power Plan** and new Source Performance Standards for power plants. Each year since 2017, nearly one in five participants favored this option.

- **Doing nothing,** or not pursuing any decarbonization policy, received support from 18% of participants.

DERS, EVS, AND UTILITY BUSINESS IMPACTS

Utilities across North America are eagerly eyeing new opportunities related to distributed energy resources (DERs) and electric vehicles (EVs) — whether deployed by the utilities themselves or by third parties. As in prior years, this year's survey participants expect to see considerable growth across a wide range of these emerging technologies.

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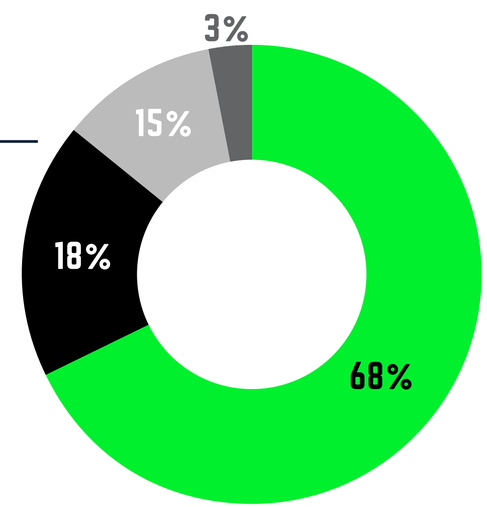
SHOULD UTILITIES BE PERMITTED TO OWN AND OPERATE DISTRIBUTED ENERGY RESOURCES?



- Yes, in all/most circumstances **68%**
- Yes, but only through unregulated subsidiaries **18%**
- Yes, but only in specific instances where the competitive market fails to equitably deploy DERs **11%**
- No **3%**

- **EVs growing fast.** This year, 43% of participants said their utilities expect to see a significant increase in EVs in their service territory. This is down slightly from 47% in 2018, but still bullish.

  Mid-Atlantic participants voiced the strongest regional confidence for EVs, with 73% of respondents predicting moderate or significant growth. That was well ahead of the West Coast, with 59%.

  Mass adoption of EVs would represent substantial load increase, which can increase revenue but also challenge grids. For instance, even having a handful of electric vehicles in the same neighborhood might require local distribution transformers to be sized up and replaced more frequently.

- **Distributed storage.** Over one third of participants (36%) expect to see behind-the-meter storage grow signifi-

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

Electric Vehicles
46% say increase significantly

Distributed storage
54% say increase moderately

Distributed solar
55% say increase moderately

Smart inverters and other grid communication technologies
56% say increase moderately

Demand response and demand-side management
56% say increase moderately

Community shared renewables & storage
58% say increase moderately

Distributed Wind
47% say stay about the same

Combined heat & power
56% say stay about the same

cantly within their service territories — up slightly from 2018 (30%), and well above 2017 (21%).

The predictions resonates with a recent Wood Mackenzie report that predicted steep growth in behind-the-meter storage: from a modest $100 million in 2018 to about $2.5 billion by 2023, with the majority comprised by residential installations.

- **Distributed solar.** This year, utility expectations for the growth of distributed solar exactly match that of distributed storage: 36% of participants expect to see significant growth in both technologies. Last year, expectations of significant increases in distributed solar slightly outpaced those for distributed storage.

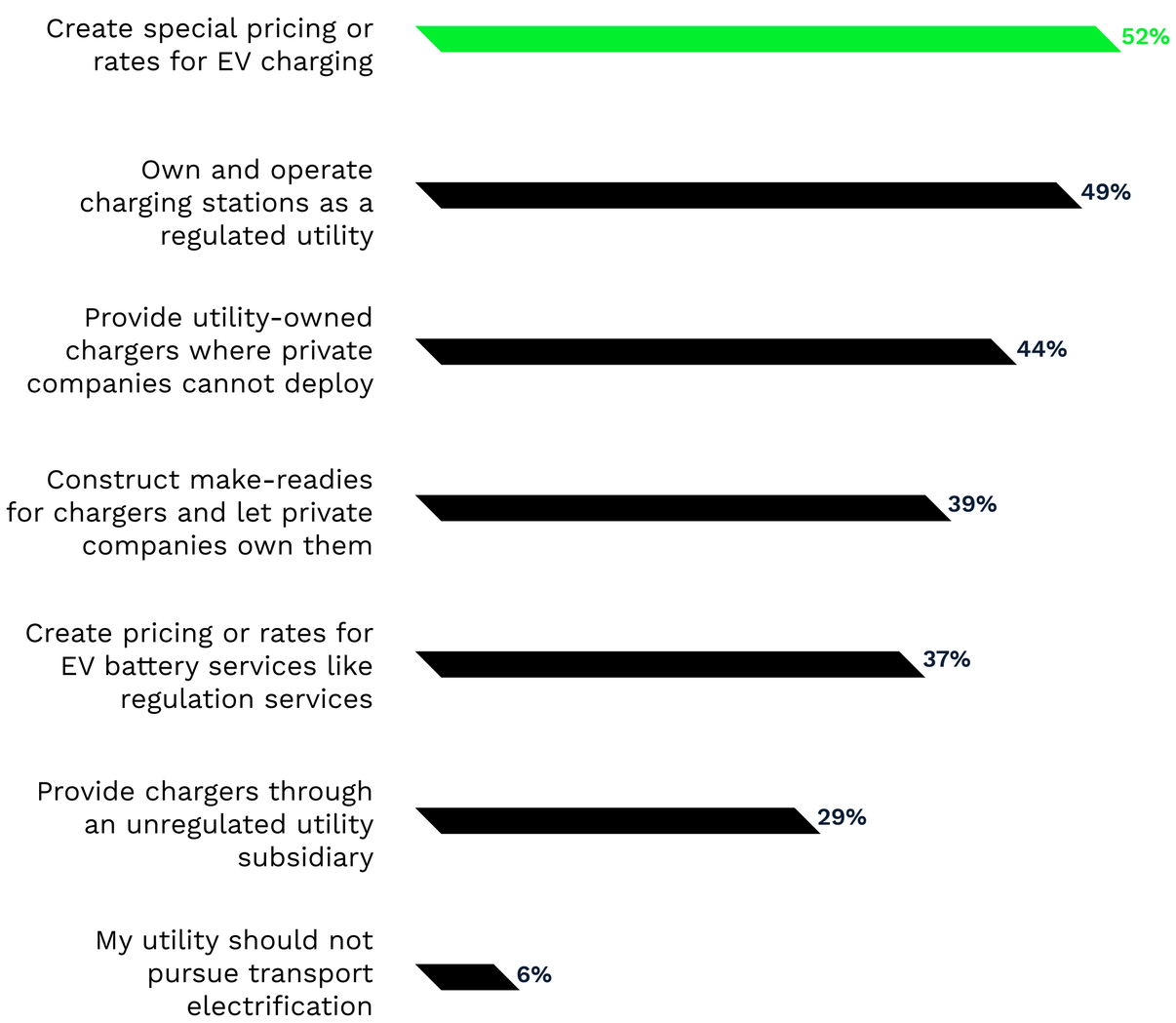
- **Smart inverters and other grid communication technologies.** Utilities still expect to see substantial growth in this area. Overall, 88% of participants said they expect to see some increase in distributed applications of these technologies, exactly the same as in 2017, although the proportion who expect this increase to be significant (rather than moderate) decreased slightly.

Among other benefits, wider adoption of smart inverters behind the meter would increase opportunities for utilities to utilize customer-owned DERs in programs to help stabilize voltage and frequency across the grid — a problem that as been worsening with the growth of rooftop solar.

Utilities are largely in agreement that they want to build business models around distributed energy resources, but lack a consensus on how to do so.

For the fourth year running, many utility respondents chose more than one option when asked about DER business models, though more than two-thirds want the opportunity to rate base DER investments as a regulated utility.

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



As many utilities are still in the pilot project phase of DER deployment, the diversity of answers likely indicates that utilities are still testing different models to ascertain which works best.

- **Utilities still crave a bigger piece of the DER pie,** as part of their own business. Every year since 2017, more than two-thirds of participants have said that they think regulated utilities should be allowed to own and rate-base DER investments in all or most circumstances.

In 2019, support for that statement dropped slightly to 68%, compared to 71% in 2017 and 2018. All other options received far less support, with 18% of respondents indicating utilities should only own DERs through unregulated subsidiaries, and 11% indicating they should own them only in instances of private market failures.

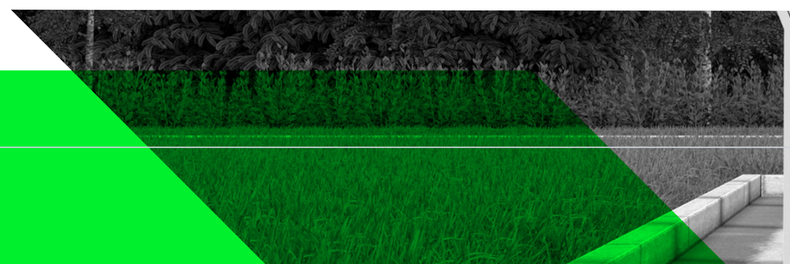
- **Transportation electrification** offers new opportunities for load growth and grid management, but utilities here also appear unsure of how to build business models.

  Like last year, the most popular option in 2019 was creating special rates or pricing for EV charging (52%), likely indicating that utilities understand the deployment and charging implications of rate design.

  Nearly half would like regulated utilities to be able own and operate charging stations, while 44% favored utilities providing chargers only where private companies would not. Slightly more than last year (39%) want utilities to construct make-readies for chargers, but then let private companies own them.

- **Utilities don't want to miss the boat again.** After missing huge opportunities during the dawn of rooftop solar, utilities don't want a repeat performance with EV infrastructure. However, when they propose EV charging projects to regulators, utilities must prove there is a public interest in charging ratepayers for their construction. That can be a difficult case to make, as indicated in utility responses about the difficulty of justifying emerging investments to regulators (See section 6, *Regulatory Landscape*).

- **Convergence of DER technologies.** Thus far, distributed solar, storage and smart inverters have often been sold and deployed separately. But in the future, these will more likely to be deployed together in integrated systems sold to residential and commercial customers. Also, since smart inverters expand customers' ability to ride through outages by using the power generated by their rooftop solar powers, they may hold more market appeal if grids become less stable. Utilities might benefit from promoting smart inverters to customers, since they could help maintain grid



stability (and thus, reliability) if they can be leveraged in programs to provide additional frequency support.

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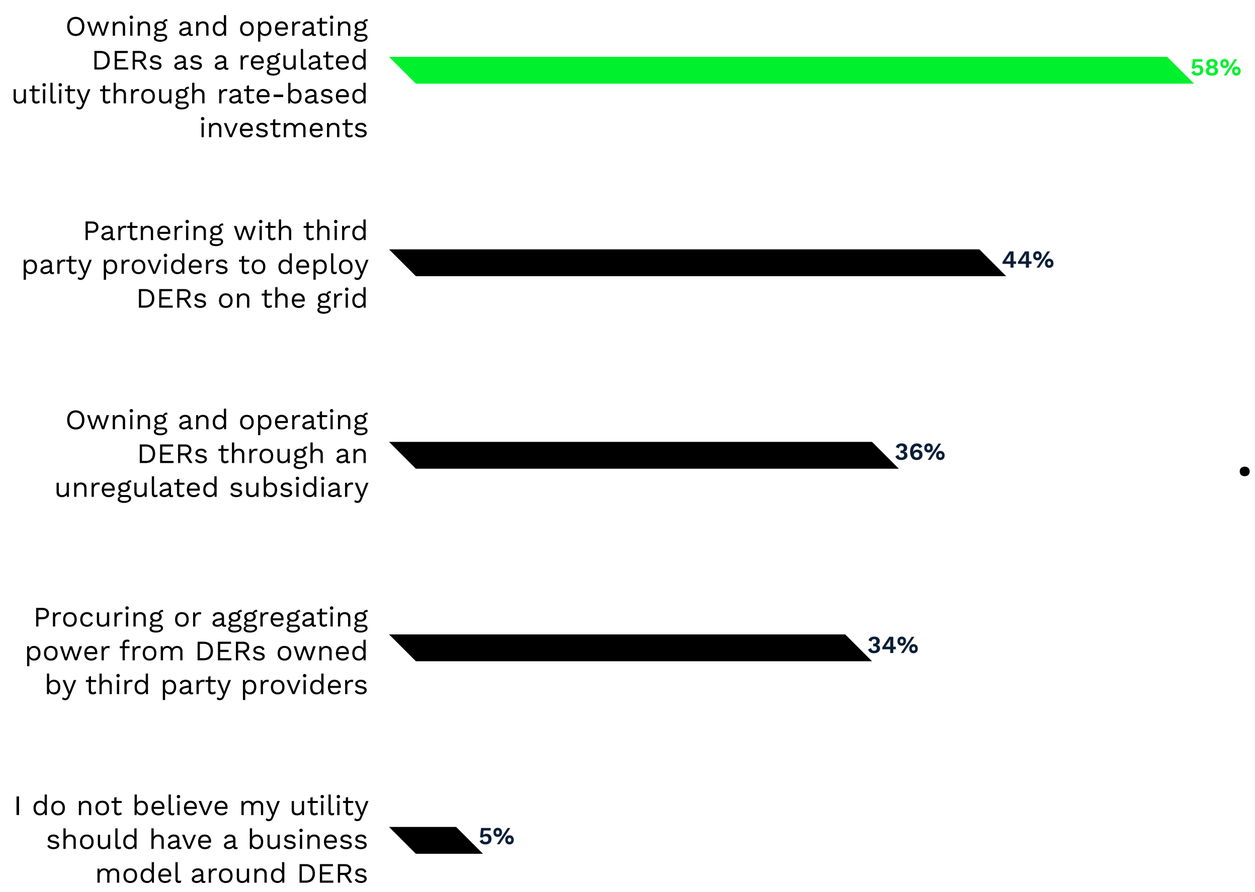
HOW DO YOU BELIEVE YOUR UTILITY SHOULD BUILD A BUSINESS MODEL AROUND DISTRIBUTED ENERGY RESOURCES? CHOOSE ALL THAT APPLY.



The economics of DER integration, aggregation and growth remain challenging for utilities.

- **Utilities want to rate-base DERs.** Rate-basing remains the most popular option for how utilities could build a business model around DERs. Since 2017, nearly 60% of participants have preferred this approach. Additionally, 44% would like to leverage third-party partnerships to deploy DERs to the grid — but that's down from 52% last year. Some of that support has apparently shifted toward the idea of running DERs via unregulated subsidiaries (up slightly this year, to 36%)

- **Third parties will be the main DER aggregators.** A key challenge with integrating DERs onto the grid is assembling disparate DERs as dispatchable resources. Utilities are keen to take advantage of these resources, but most don't believe they will be the ones to aggregate them. All told, 31% of participants believe that in five years, regulated distribution utilities will be doing most

of this aggregation, while 37% think that third parties will be the main DER aggregators.

The lack of consensus in DER aggregation reflects trends present in surveys over the past two years and illustrates continued uncertainty over the future of DER aggregation. In 2019, 19% of participants were unsure who will be aggregating DERs — up 6% from last year. It's unclear how aggregation will play out in energy markets.

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.

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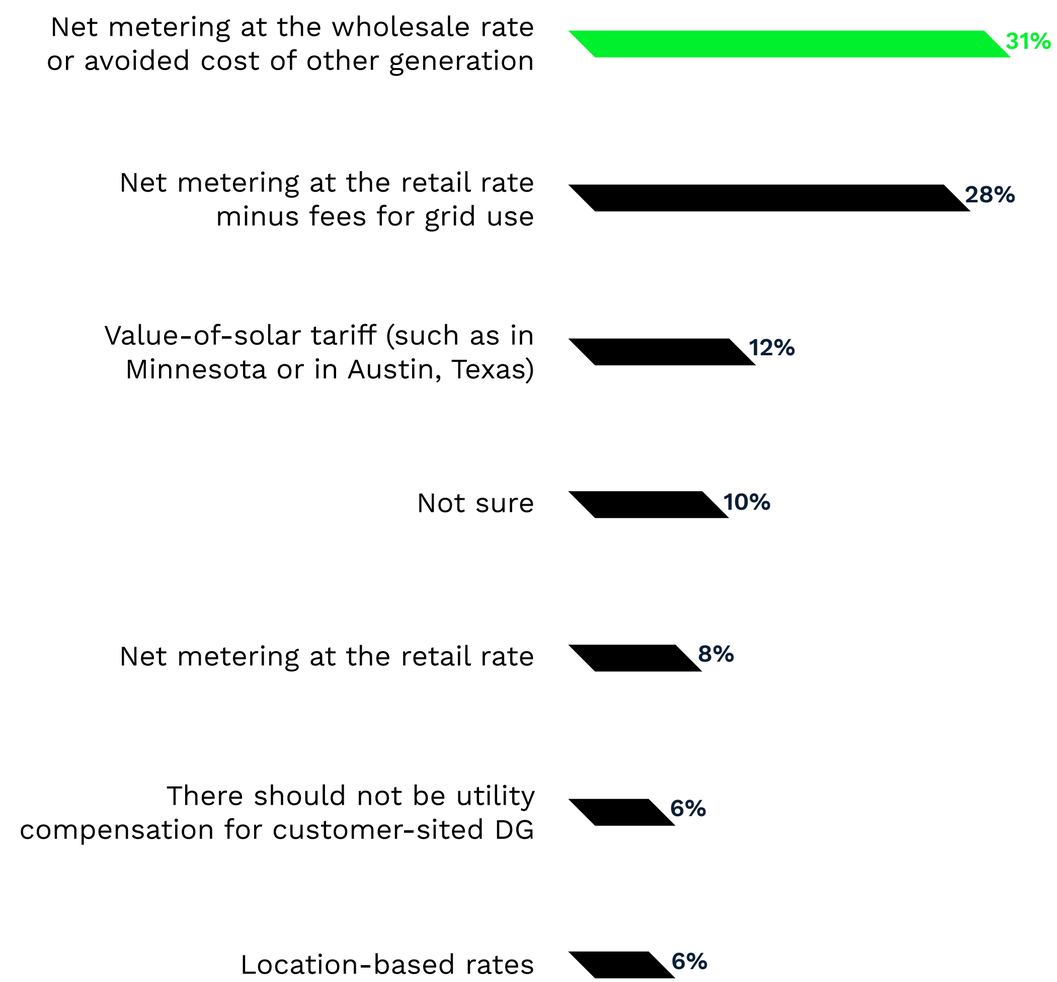
IN YOUR SERVICE TERRITORY, WHAT IS THE MOST APPROPRIATE COMPENSATION MECHANISM FOR DISTRIBUTED GENERATION, PARTICULARLY ROOFTOP SOLAR?



In recent years, a number of states have sought to reshape net metering policies into successor tariffs that reward customers for exported power while also taking into account the locational and temporal values of their resources.

Utilities, however, appear to desire simpler compensation mechanisms for DERs in the 2019 survey.

- **A desire for simplicity.** Over 30% of participants prefer net metering at the wholesale or avoided cost rate for utility central station generation. Nearly as many (28%) prefer net metering at the retail rate, but with the addition of fees to ensure customers pay their share for grid upkeep.

Depending on the scale of the fees, both of those models could make distributed resources uneconomic in many utility service areas, which may hold some of their appeal for respondents from incumbent utilities.

Respondents may also desire the relative simplicity of these tariffs over more complicated net metering successors. Value-of-solar tariffs, for instance, are slightly more popular than last year, but still not widely desired (12%). Uncertainty around DER compensation also rose slightly this year, by 4%.

THE WAY FORWARD: NAVIGATING UNCERTAINTY AND CHANGE

For the most part, utilities have begun to adapt to a “new normal” of heightened uncertainty, and they appear motivated to stretch themselves -- especially to embrace new technologies, and to think creatively about the types of services they can offer to maintain or increase their competitiveness.

25

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

21%

#1
Cost of transition to ratepayers (stranded assets, grid modernization, etc.)

18%

#2
Reliable integration of new generation and grid technologies

18%

#3
Internal resistance to change at utility

It's notable that, in recent years, utilities began to feel better aligned with regulators. Back in 2016, 37% of participants considered "state regulator or regulatory model resistance" to be a significant obstacle to transforming their business model. By 2017, only half as many felt that way, and it's been dropping ever since, currently at 13%. It seems that utilities now feel that regulators better understand their motives and challenges. That can make it less daunting to takes some risks when proposing new utility investments.

Still, regulatory approval of new kinds of investments is not easy. Regulators still have a mandate to keep utility prices low, and reliability and service high, which sustains pressure on utility revenues. Since it's still fairly difficult for utilities to justify the cost of new kinds of investments, this year's top obstacle to utility business model evolution is not too surprising: more than 20% of participants are most concerned about the cost of transition that ratepayers might be asked to shoulder, in the form of stranded assets and grid modernization expenses.

This tension is evident in recent tug-of-wars at public utility commissions in several states. In December 2018, the North Carolina Clean Energy Technology Center report, 50 States of Grid Modernization, detailed how regulators in Kentucky and New Mexico denied some utility AMI proposals due to inadequate justification of costs. Similarly the ScottMadden consultancy advised utilities to clarify their objectives, validate new technologies, prioritize investments and show a cost-benefit analysis that bolsters proposed grid modernization expenditures.

> **WE DO 'NO REGRETS' PLANNING: DEPLOYING ASSETS IN A FASHION THAT, EVEN IF A NEW TECHNOLOGY OR INITIATIVE DOESN'T PROVE OUT, WE STILL GAIN SOME VALUE.**
>
> *Northeast Co-op*

After that, there's a tie for the second-place business transformation obstacle, at 18% each:

- **Reliable integration of new generation and grid technologies**
- **Internal resistance to change at the utility**

In coming years, utilities might take some lessons from Amazon and Netflix about how to set rates in an increasingly competitive environment. Time- and location-based price signals to customers are already becoming a more popular tool to guide usage. But regulators could support more ambitious plans to reward utilities for best performance while meeting customer demand. This year's survey saw a clear desire across the utility for more performance-based regulation.

Wildly different business model transformation strategies also are possible. Navigant recently suggested that, similar to the communications and entertainment industries, utilities might offer subscriptions for electricity services. Customers could choose between fixed monthly price points to receive varying levels of utility-provided products and services. While controversial, this idea gets to the heart of a shift utilities are trying to make: selling electricity as a service, rather than as a commodity.

Another innovative approach could be rates based on DER time and location attributes. Currently, only a handful of utilities are experimenting with locational values. California has been developing a locational net benefit analysis tool, but it's not yet ready for use.

Currently, more utilities are deploying time of use (TOU) rates to more customer classes — usually on a voluntary basis. On average, a mere 3% of customers opt-in. But 51% of Arizona Public Service (APS) customers chose the TOU option. Currently Xcel Energy is conducting a pilot opt-out TOU rate. And other dynamic rate schemes are in the works.

If utilities get the performance-base regulation that they desire, expect innovation to heat up in an industry once define by its resistance to change.

INDEX

1

WHICH TYPE OF UTILITY COMPANY EMPLOYS YOU?

Investor-owned utility	**57%**
Electric cooperative	**15%**
Municipal utility or public power utility	**28%**

2

HOW MANY CUSTOMERS DOES YOUR ELECTRIC UTILITY SERVE?

Fewer than 100,000	**18%**
100,000-500,000	**18%**
500,000-1 million	**14%**
1-4 million	**28%**
More than 4 million	**21%**

3

IN WHICH REGIONS DOES YOUR REGULATED UTILITY HAVE SERVICE AREAS?

West Coast	**19%**
Midwest	**18%**
South & Southeast	**12%**
Southwest & Texas	**11%**
New England & Northeast	**10%**
Other countries	**8%**
Great Plains & Rocky Mountains	**8%**
Canada	**5%**
Mid-Atlantic	**4%**
Non-contiguous states & territories	**3%**
Multiple US	**1%**
Mexico	**0%**

4

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

Distribution	**84%**
Transmission	**74%**
Generation	**71%**
Retail	**51%**

5

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)CHOOSE ALL THAT APPLY.

	5	4	3	2	1
Physical and/or cyber grid security	48%	35%	11%	2%	3%
Bulk power system reliability	43%	27%	19%	7%	4%
Aging grid infrastructure	32%	34%	23%	7%	4%
Rate design reform	26%	30%	28%	11%	6%
Compliance with state renewable and clean energy mandates	25%	23%	25%	16%	11%
State regulatory model reform	23%	24%	29%	15%	9%
Generation retirements and/or stranded assets	20%	29%	24%	16%	10%
Compliance with federal clean air standards	19%	23%	27%	17%	13%
Stagnant/negative load growth	18%	35%	24%	15%	7%
Wholesale market reform	11%	26%	34%	21%	8%

6

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

	YES	NO	I DON'T KNOW
Implemented the NIST Cybersecurity Framework	40%	10%	51%
Contract outside firm to assess risk profile	44%	15%	41%
Implemented a breach response mitigation plan	64%	7%	28%
Implement NERC CIP cyber protections	63%	9%	28%
Appointed a chief information security officer or chief security officer	67%	17%	16%
Modernized IT and grid control systems	81%	7%	12%
Developed a companywide cybersecurity strategy	89%	3%	8%
Educated employees on how to avoid cyber threats	95%	2%	3%

7

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

	DECLINING LOAD	STAGNANT LOAD	INCREASING LOAD
Industrial	17%	48%	35%
Commercial	10%	45%	45%
Residential	16%	38%	46%
Overall	16%	46%	44%

8

REGIONAL LOAD TRENDS ACROSS ALL CUSTOMER CLASSES

	DECLINING LOAD	STAGNANT LOAD	INCREASING LOAD
New England & Northeast	13%	75%	13%
Mid-Atlantic	20%	60%	20%
South & Southeast	7%	41%	52%
Midwest	10%	59%	31%
Great Plains & Rocky Mountains	9%	32%	59%
Southwest & Texas	3%	21%	76%
West Coast	18%	33%	49%
Non-contiguous states & territories	13%	50%	38%
Mexico	0%	0%	0%
Canada	0%	43%	57%

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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.

Move consumers to time-of-use rates	50%
Increase fixed charges/fees	47%
Move net metered customers or those with DG to a separate rate class	29%
Impose demand charges on all customers	25%
Impose demand charges on all customers with DG	24%
Institute decoupling	20%
Impose a minimum bill for low-use customers	17%
Not sure	12%
Offer block rates	10%
Other (please specify)	4%
My utility should not change its rate design	3%

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WHICH OF THE FOLLOWING BEST DESCRIBES YOUR CURRENT REGULATORY ENVIRONMENT?

Oversight by an elected board or government	**35%**
Traditional cost-of-service regulation	**34%**
Cost-of-service regulation with a mix of performance-based regulation	**22%**
Not sure	**5%**
Predominantly performance-based regulation	**4%**

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

Yes, we currently have or have completed a proceeding	**30%**
No, but we anticipate a proceeding soon	**24%**
No, but we would like to see regulators open a docket	**20%**
No, we don't have one and do not want one	**26%**

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

Cost-of-service regulation with a mix of performance-based regulation	**35%**
Oversight by an elected board or government	**29%**
Predominantly performance-based regulation	**14%**
Not sure	**13%**
Traditional cost-of-service regulation	**9%**

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

Cost-of-service regulation with a mix of performance-based regulation	**37%**
Predominantly performance-based regulation	**31%**
Not sure	**14%**
Oversight by an elected board or government	**12%**
Traditional cost-of-service regulation	**5%**

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REGULATORY COMPARISON

	TODAY	EXPECTED IN 10 YEARS	WHAT THEY WANT
Hybrid: Cost-of-service regulation with a mix of performance-based regulation	22%	35%	37%
Predominantly performance-based regulation	4%	14%	31%
Not sure	5%	13%	14%
Oversight by an elected board or government	35%	29%	12%
Traditional cost-of-service regulation	34%	9%	5%

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IDENTIFY THE TOP THREE DIFFICULTIES ASSOCIATED WITH YOUR STATE REGULATORY MODEL

Justifying emerging utility investments (ie: energy storage, EV chargers, microgrids)	55%
Recovering fixed costs through rate design	43%
Managing distributed resource growth and net metering/value of solar debates	41%
Recovering revenue lost to efficiency and negative load growth	34%
Meeting renewable and other clean energy mandates	24%
Recovering costs from stranded utility assets	22%
Justifying traditional utility investments (wires, poles etc.) to regulators	19%
Meeting performance mandates for efficiency, customer engagement etc.	11%
Meeting pollution mandates and/or climate standards	11%
Other (please specify)	10%
Obtaining adequate generation capacity	7%
Resolving waste issues related to nuclear decommissioning, coal ash etc.	5%
None of the above	0%

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MARKET TYPE COMPARISON

	TODAY	EXPECTED IN 10 YEARS	WHAT THEY WANT
Restructured wholesale and retail markets	18%	28%	28%
Not sure	14%	25%	27%
Restructured wholesale market with some vertically-integrated utilities	18%	20%	20%
Vertically-integrated utilities with sub-ISO energy trading (i.e. Western EIM)	24%	18%	14%
Vertically-integrated utilities — no wholesale or retail markets	21%	6%	5%
Restructured wholesale market, no vertically-integrated utilities, no retail choice	4%	3%	6%

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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
Solar (utility-scale)	0%	0%	6%	42%	51%
Distributed generation & storage	0%	1%	7%	52%	40%
Grid-scale energy storage	0%	0%	12%	52%	35%
Wind	0%	1%	21%	52%	26%
Natural gas	7%	14%	28%	41%	10%
Hydro	1%	4%	79%	14%	3%
Oil	43%	18%	37%	1%	1%
Nuclear	17%	21%	55%	6%	1%
Coal	67%	19%	15%	0%	0%

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

Sustainability	18%
Low prices	12%
Emissions standards	9%
Renewable energy targets or mandates	16%
Consumer demand and sentiment	19%
Hedge against fossil fuel prices	4%
Earnings growth and business model evolution	12%
There is no compelling reason to invest in clean energy	3%
Other (please specify)	7%

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IN YOUR OPINION, HOW SHOULD POLICYMAKERS (GRID OPERATORS, REGULATORS AND LAWMAKERS) RESPOND TO THE RETIREMENT OF COAL AND NUCLEAR GENERATION?

Nothing — allow uneconomic generation to be retired under current market rules	34%
Devise new market rules to pay plants based on reliability, resilience or fuel security attributes	23%
Impose a carbon adder in wholesale markets or carbon tax	17%
Allow states to devise support programs for selected plants (ie: New York's Zero Emission Standard)	13%
Provide cost recovery to selected plants based on onsite fuel supplies	5%
Re-regulate state utility markets to the vertically-integrated model	5%
Use the federal government's emergency or national security powers to keep selected plants open	4%

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

Yes, regulated utilities should be able to own and rate-base DER investments in all/most circumstances	68%
Yes, but only through unregulated subsidiaries	18%
Yes, but only in specific instances where the competitive market fails to equitably deploy DERs	11%
No	3%

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

	INCREASE SIGNIFICANTLY	INCREASE MODERATELY	STAY ABOUT THE SAME
Electric vehicles	46%	50%	3%
Distributed storage	36%	54%	8%
Distributed solar	36%	55%	7%
Smart inverters and other grid communication technologies	32%	56%	11%
Demand response and demand-side management	21%	56%	21%
Community shared renewables & storage	15%	58%	25%
Distributed wind	8%	39%	47%
Combined heat & power	4%	34%	56%

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

Create special pricing or rates for EV charging	68%
Own and operate charging stations as a regulated utility	18%
Provide utility-owned chargers where private companies cannot or will not deploy	11%
Construct make-readies for chargers and let private companies own them	3%

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

Create special pricing or rates for EV charging	**52%**
Own and operate charging stations as a regulated utility	**49%**
Provide utility-owned chargers where private companies cannot or will not deploy	**44%**
Construct make-readies for chargers and let private companies own them	**39%**
Create pricing or rates for EV battery services like regulation services	**37%**
Provide chargers through an unregulated utility subsidiary	**29%**
My utility should not pursue transport electrification	**6%**

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

Owning and operating DERs as a regulated utility through rate-based investments	**58%**
Partnering with third party providers to deploy DERs on the grid	**44%**
Owning and operating DERs through an unregulated subsidiary	**36%**
Procuring or aggregating power from DERs owned by third party providers	**34%**
I do not believe my utility should have a business model around DERs	**5%**

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

Net metering at the wholesale rate or avoided cost of other generation	31%
Net metering at the retail rate minus fees for grid use	28%
Value-of-solar tariff (such as in Minnesota or in Austin, Texas)	12%
Not sure	10%
Net metering at the retail rate	8%
There should not be utility compensation for customer-sited DG	6%
Location-based rates	6%

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

Cost of transition to ratepayers (stranded assets, grid modernization, etc.)	21%
Reliable integration of new generation and grid technologies	18%
Internal resistance to change at utility	18%
State regulator or regulatory model resistance	12%
Political pressure (from legislature, governor, or others)	7%
Nothing. My utility is not transitioning, or does not need to transition. from our current model	6%
Outside stakeholder resistance (e.g. consumer advocates, business interests)	5%
Nothing. There is general consensus in my jurisdiction over the path and process of utility evolution	5%
Wholesale market constructs and regulation	4%
Federal emissions and environmental regulations	1%
Other	1%
Resistance from financial markets, creditors	0%

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

Impose an economy-wide price on carbon and other greenhouse gases	**27%**
Reinstate the Obama administration's Clean Power Plan and New Source Performance standards for power plants	**19%**
The U.S. government should not pursue a policy of decarbonization	**18%**
Scale back the Clean Power Plan to cover only emissions "inside the fenceline" of existing power plants, as in EPA's proposed Affordable Clean Energy rule.	**15%**
Impose an economy-wide cap-and-trade system for greenhouse gases	**13%**
Devise a carbon regulatory package more ambitious than the Clean Power Plan	**8%**

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

Uncertainty over market conditions & regulations for future generation	**35%**
Reliably integrating new resources	**24%**
Financial impact of stranded assets	**13%**
Customer costs of new generation	**11%**
Building new transmission to serve new resources	**7%**
Building/contracting sufficient resources to meet demand	**4%**
Other (please specify)	**4%**
Cost overruns/delays with generation construction	**2%**

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