THE SCOTTMADDEN ENERGY INDUSTRY UPDATE

TAKE IT TO THE LIMIT

Volume 20 - Issue 1

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A LETTER TO THE READER
HOW COVID-19 IS TAKING THE ENERGY INDUSTRY TO THE LIMIT

We are issuing this Energy Industry Update (EIU) at a unique time in the world, as a whole, and more specifically within the energy industry. The COVID-19 pandemic truly is changing everything, and no one is sure how the industry will look later this year, let alone in the long term. What is certain is that customers will continue to need reliable and affordable electricity and natural gas.

The way that electric and gas utility service is delivered has been heavily impacted by COVID-19. Every day we see stories about field personnel and control room operators taking extraordinary measures to keep customers and each other safe. (Please see our thoughts on the immediate effects of the pandemic.) Notwithstanding these dramatic changes to daily utility operations, it is likely that the broader trends we observed prior to this pandemic will continue to manifest in some form.

It is in that spirit that we are publishing this EIU to continue the dialogue around those industry trends that we believe will remain relevant. They include the ongoing push to 100% clean or non-greenhouse gas-emitting resources, the future of the gas utility and gas resource planning, the trends in transmission resilience and returns on equity, and lessons from Hawaii's transition to 100% renewables. The trajectory of these topics may shift due to the pandemic, but they will remain pertinent to the industry's development.

Hopefully, this EIU will provide a welcome respite from pandemic news. We welcome your thoughts on these or other topics in the industry today. Stay safe out there.

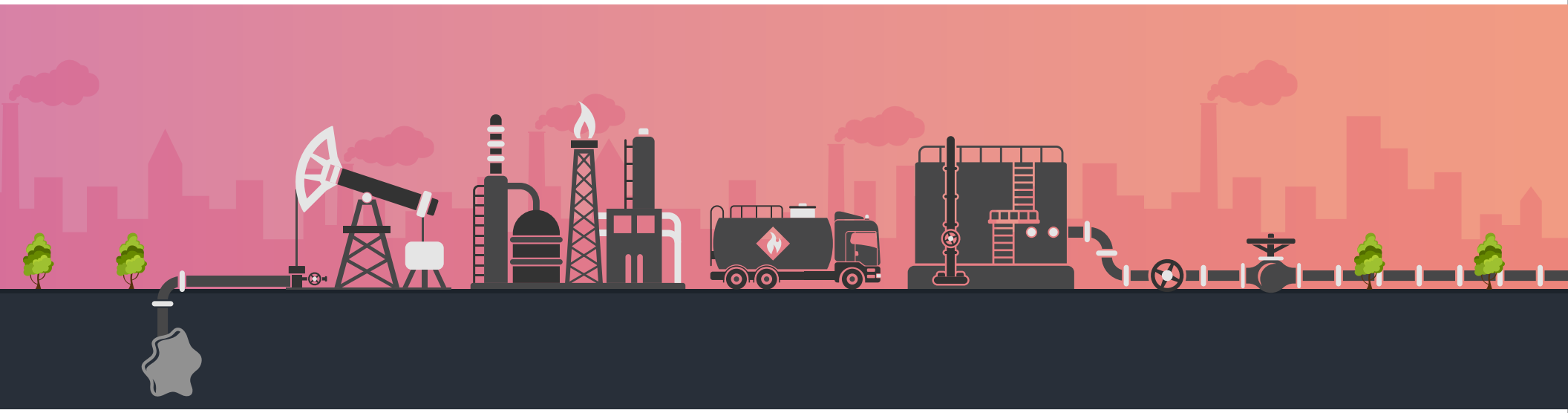
Sincerely,

Cristin Lyons
Partner and Energy Practice Leader

EXECUTIVE SUMMARY
TAKE IT TO THE LIMIT

So, how do current trends in the energy industry relate to one of the Eagles' greatest hits? This edition uncovers how factors, such as the state-by-state advances in clean energy standards, proposed moratoria and restrictions on natural gas expansion, slow progress on resilience issues, and more, may take the utility industry to its limit of financial, regulatory, and operational wherewithal. But new—and potential—technologies like hydrogen may challenge the limits of what is possible. While it is too early to tell the long-term effects of the COVID-19 pandemic, time will tell whether any related changes in customer and stakeholder priorities and behaviors will serve to accelerate or moderate these trends. All indications are that these trends—taking the industry's current approaches "to the limit"—will persist.

Some Highlights of This ScottMadden Energy Industry Update	
The Limits of Business as Usual	▪ The gas utility industry has demonstrated the value and popularity of its service. But it is facing pressure from some corners to improve its environmental profile. Utilities should review near-term and longer-term strategies to respond to stakeholders as they seek to optimize their infrastructure and reduce carbon emissions in the gas stream. ▪ Gas utilities focus on their unique situation, risks, and required flexibility in planning their resource portfolio. Some states and provinces are adopting ambitious climate goals. Gas utilities are being proactive in addressing new expectations of policymakers, regulators, and customers on these matters and thinking more expansively about their resource portfolio.
The Limits of Operations	▪ As growing numbers of states, utilities, and corporations establish clean energy goals such as 100% clean energy commitments, attention is turning to implementation. For some, technology advances are essential. Electric utilities and regulators will need to consider approaches, technologies, costs, and timing as they undertake this multi-decade journey. ▪ Electric utilities in Hawaii have become a "postcard from the future" with the rapid expansion of distributed solar energy resources and an ambitious 100% renewables by 2045 requirement. Hawaiian utilities continue to thrive and adapt to changing grid dynamics as those distributed resources and increasing amounts of utility-scale renewable generation keep the islands on the bleeding edge. ▪ In order to deploy the right grid resilience investments, utilities, regulators, governments, and other stakeholders need to agree on roles and responsibilities and the appropriate level of investment. Reliability-focused planning approaches need to be adapted to account for the unique value of resilience, and utilities and other stakeholders may need to explore cost-sharing for resilience investments needed for the common good.
The Limits of Financial Returns	▪ The Federal Energy Regulatory Commission (FERC) has been considering approaches to setting "just and reasonable" rates for power transmission, as transmission developers and owners seek returns on equity (ROE) that will attract investment in the sector. A recent FERC opinion on transmission base rate-setting has generated industry concern about adequacy of returns, but a proposed rulemaking that revisits ROE incentives may hold out some hope for transmission owners.



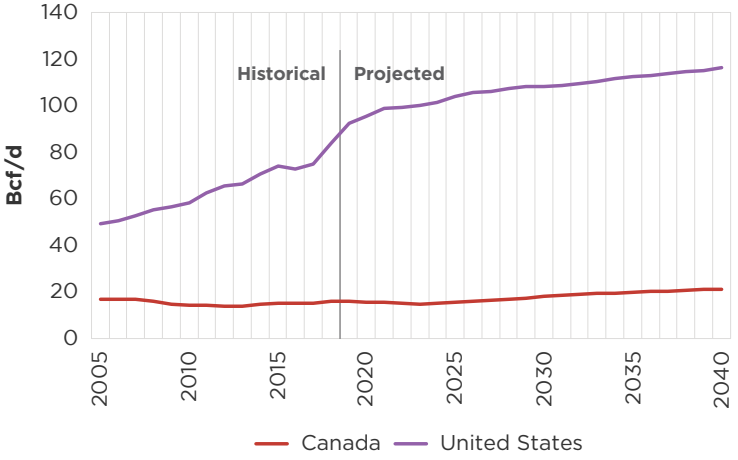
THE FUTURE OF THE GAS UTILITY
A CHANGING ENVIRONMENT FOR NATURAL GAS COMPANIES

Gas utilities face risks and opportunities with the push toward decarbonization.

Continued Natural Gas Production and Pipeline Growth

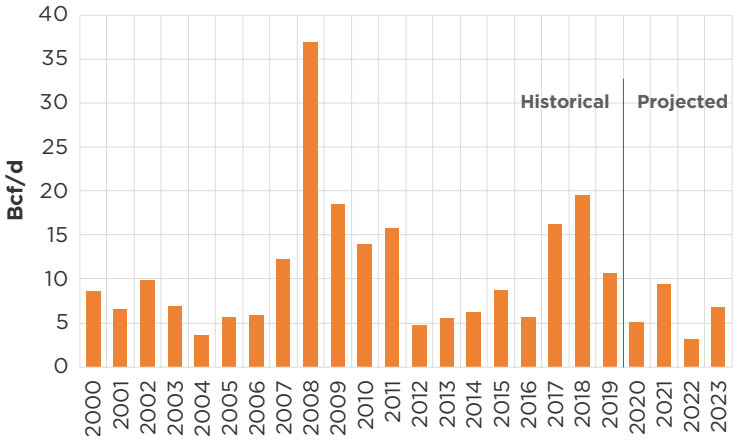
- For more than a decade, natural gas production has increased significantly and is a key part of the North American fuel mix for power generation. The U.S. Energy Information Administration continues to recognize the importance of natural gas, showing a growing role for natural gas in all but one scenario of its most recent annual energy outlook.
  - The switch from coal to natural gas-fired generation has not only provided a market opportunity for natural gas but also a concomitant reduction in CO_2 emissions (see chart on next page).
  - Notably, CO_2 emissions have fallen three-fold over the past decade as natural gas-fired power generation has increased from under 1 trillion kWhs in 2010 to nearly 1.5 trillion kWhs in 2018.
- Despite challenges, pipeline capacity additions during the 2017 to 2019 time period roughly equal the prior six years (2011 to 2016), about 46 Bcf/d.
  - FERC certificated 30.6 Bcf/d in 2017 at the peak of a Northeast build-out of pipelines, moving Appalachian gas to demand centers and expanding takeaway capacity for associated gas production from crude oil production.
  - FERC approved 18 Bcf/d of new pipeline capacity in calendar year 2019, up from 9.2 Bcf/d in full year 2018. So, while pipeline completions slowed in 2019 from prior years, approvals for new and expanded pipeline capacity continue.

U.S. and Canadian Historical and Future Dry Natural Gas Production (Bcf/d) (2005-2040)



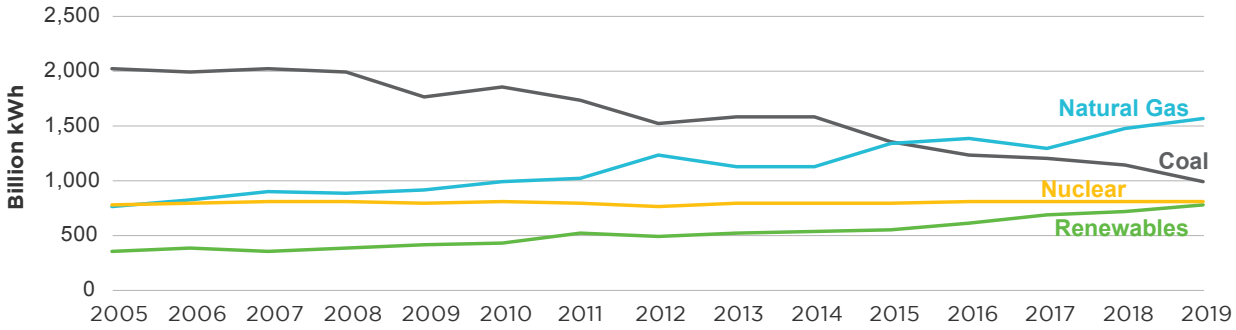
Sources: EIA; Canada Energy Regulator

Interstate Pipeline Historical and Projected Capacity Additions by In-Service Year (Bcf/d) (2000-2023)



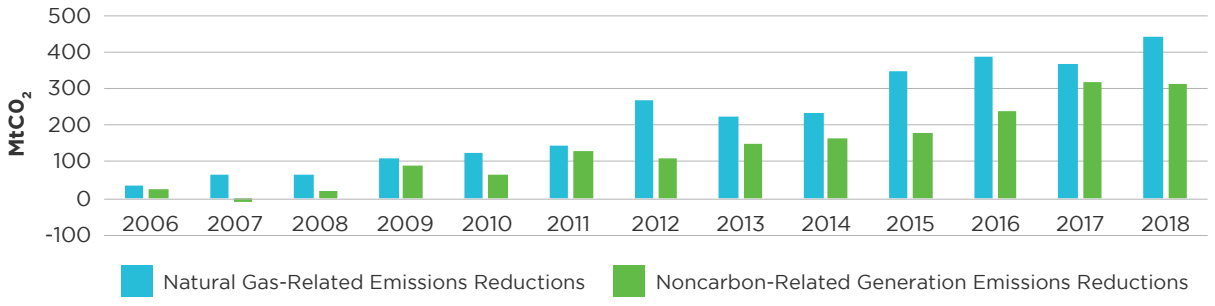
Source: EIA

U.S. Electricity Generation from Selected Fuels (in Billions of Kilowatt-hours) (2005-2019)



Sources:
EIA, Annual Energy Outlook (2020), and U.S. Energy-Related Carbon Dioxide Emissions 2018 (Nov. 2019)

Electricity Generation CO_2 Savings from Changes in Fuel Mix (Million Metric Tons of CO_2)



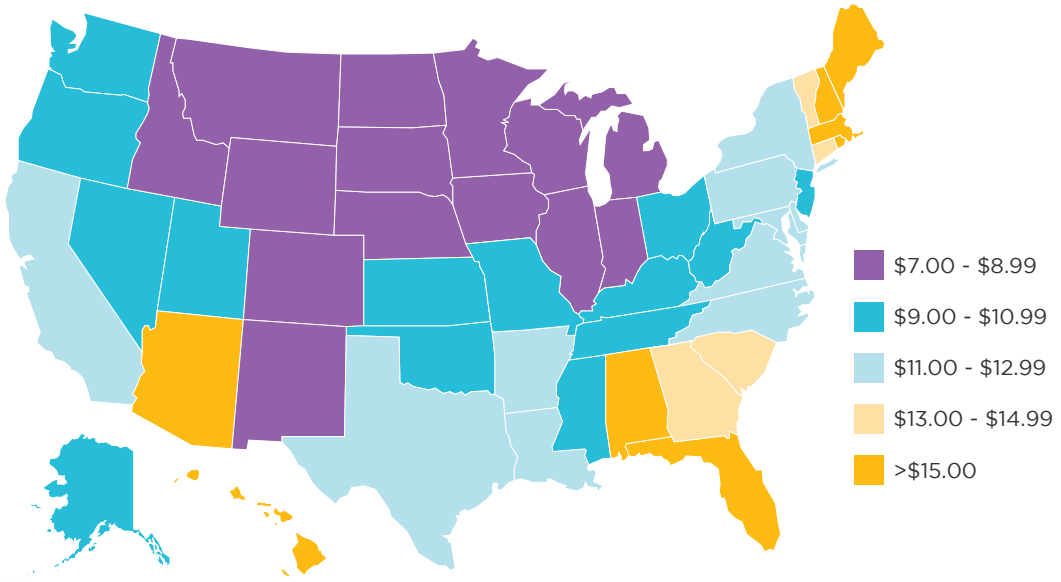
KEY TAKEAWAYS

- **Gas utilities have experienced a decade of relative price stability and customer growth.**
- **Gas-fired generation has helped drive a three-fold decrease in CO_2 emissions.**
- **Decarbonization initiatives have prompted a certain number of local agencies to institute natural gas bans, but also provide opportunities for gas utilities.**
- **Gas utilities can undertake several near-term actions and develop longer-term strategies to assist policymakers with meeting decarbonization objectives.**

Low Prices, Customer Growth

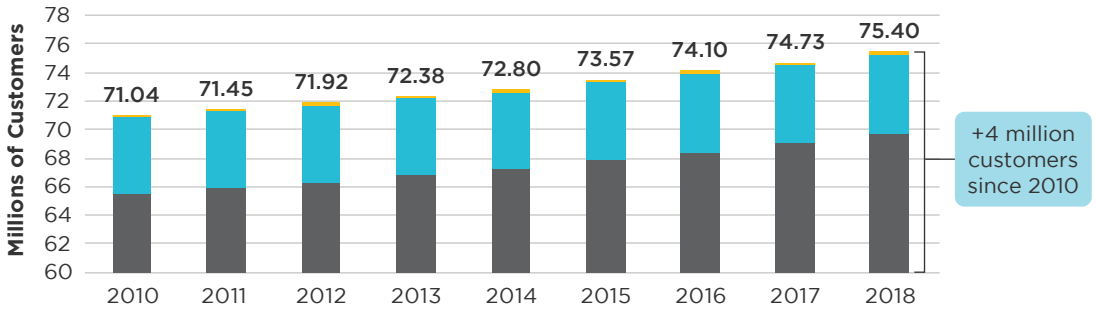
- Regional market demand and natural gas prices reflect various components, including proximity to natural gas production areas, available infrastructure, load profile, and regulatory policies.
- Low gas prices have also driven an increase in residential and commercial customers in the United States.

U.S. Average Annual Residential Natural Gas Prices by State (2018) ($/Mcf)



Source: EIA

U.S. Residential, Commercial, and Industrial Natural Gas Customers (Millions) (2010-2018)



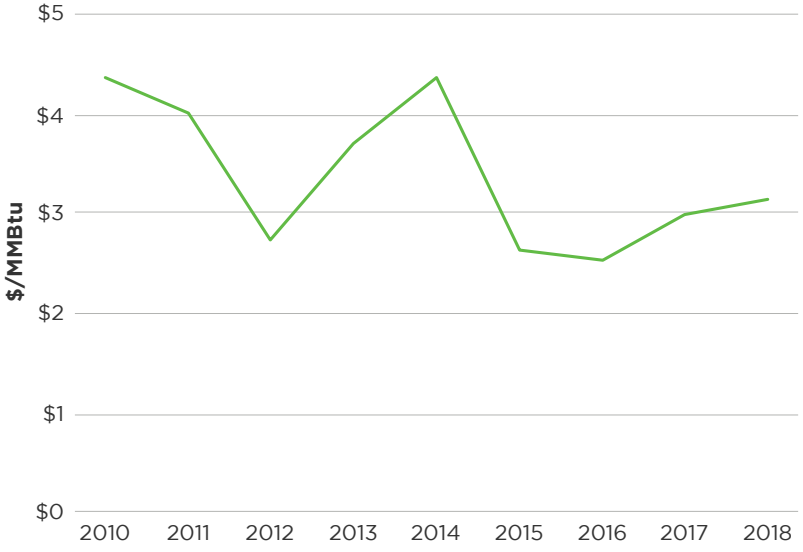
Customer CAGR (%)

Total Residential	0.77
Total Commercial	0.50
Total Industrial	-0.51
Total	0.75

Note: Portion of bar not shown (0–60) reflects residential customers.

Source: EIA

Henry Hub Natural Gas Spot Price (Annual Average) (2010-2018)



Source: EIA

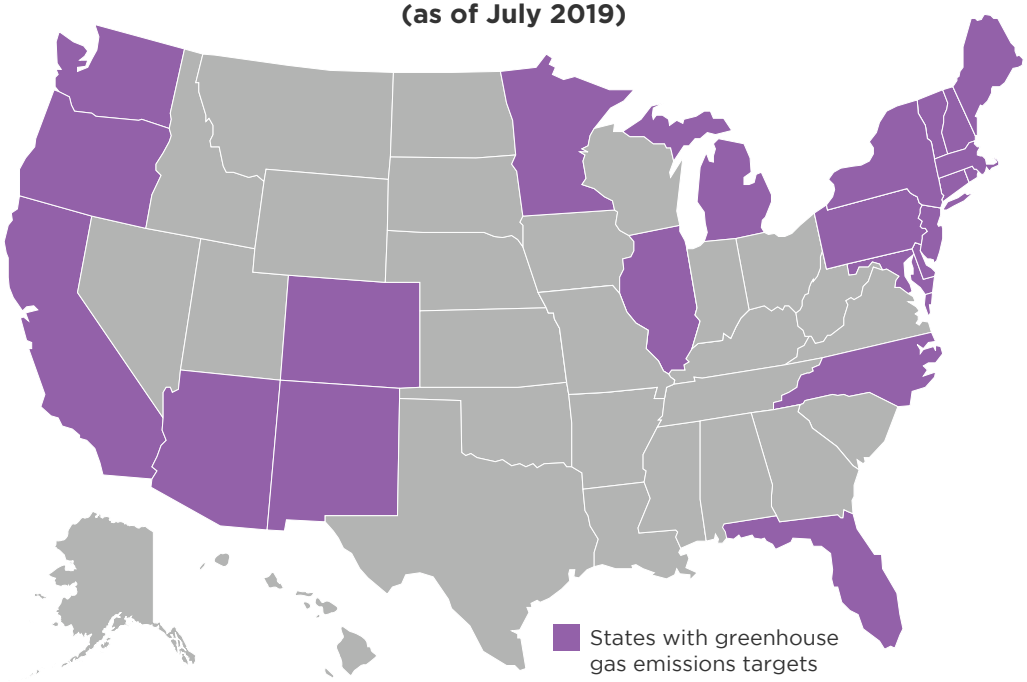
Growing Push for Decarbonization

- Many states have in place varying degrees of renewable portfolio standards with respect to volumetric targets and timing.
- More recently, certain states and municipalities have developed decarbonization initiatives—greenhouse gas emissions targets (see map at right)—some with a focus on electrification.
- Some utilities and large end users also have developed net-zero, 100% clean energy, and other similar goals (see elsewhere in this Energy Industry Update).
- Recently, some communities have gone further with local government agencies limiting end-use natural gas consumption as a way to reduce emissions.

Regulatory Headwinds Starting to Blow in Some Cities

- Some cities on the U.S. West Coast have taken aggressive action to limit development of infrastructure that would facilitate natural gas end use. This comes as the California Public Utilities Commission has initiated a rulemaking to review current reliability and safety standards and to implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet its decarbonization goals.
- Some municipalities in New York and Massachusetts have also proposed outright bans on natural gas systems either in government buildings (e.g., New York City) or as part of the municipality's permitting process or building code (e.g., Brookline, Massachusetts).
- In addition, some limits on development are coming from New York and Massachusetts gas utilities themselves, as pipeline constraints and regulatory procedures regarding new energy infrastructure affect the ability of gas utilities to add new customers.

States with Greenhouse Gas Emissions Targets (as of July 2019)

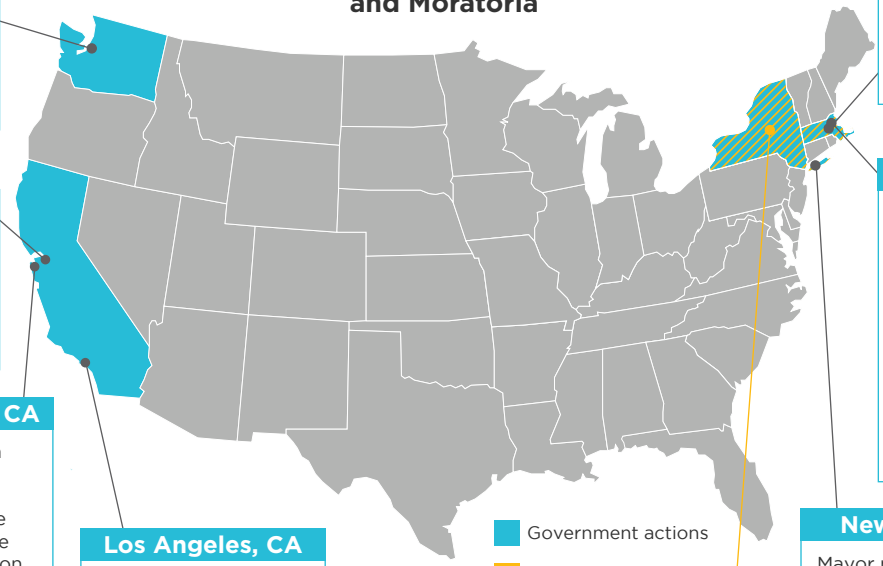


Sources: Center for Climate and Energy Solutions (c2es.org); Sierra Club; industry news; ScottMadden research

States, Cities and Towns, and Industry Groups React to Natural Gas Bans

- Some cities, towns, and customer groups have taken preemptive actions to challenge natural gas bans, including legal and legislative steps.
- In California, 114 towns, cities, and counties have adopted "energy choice" resolutions, which generally urge state officials to reject sweeping policies that would block access to gas in buildings.
- The California Restaurant Association filed suit against the city of Berkeley, alleging that the city's ban violates both state and federal laws. The suit argues that the ban will raise costs to build and operate restaurants and exacerbate the damaging impact of planned electricity blackouts meant to prevent wildfires.
- In Arizona and Tennessee, state legislators passed legislation to prohibit local governments from passing their own bans on new natural gas hookups.
- In Massachusetts, city solicitors have warned lawmakers in Cambridge and Newton that courts are likely to determine that the gas bans are preempted by state law, which broadly protects consumer access to gas and electric power, regulates state utilities, and authorizes state building codes that allow gas infrastructure inside homes and businesses.

Selected Areas with Proposed Natural Gas Bans and Moratoria



Seattle, WA

Executive order to transition municipal buildings away from using fossil fuels. Strategies for using electricity instead of fossil fuels must be submitted by June 1, 2020, for buildings to be completed or altered during the 2021 or 2022 budget year.

Berkeley, CA

Enacted legislation that prohibits natural gas pipes in low-rise (three and fewer stories) residential buildings, starting on January 1, 2020.

San Francisco, CA

Enacted a phase-in plan that requires large commercial buildings (i.e., more than 50,000 square feet) to rely solely on electricity generated from renewable sources by 2030.

Los Angeles, CA

Using rebate programs to incent customers to install electric equipment, such as heating devices, in buildings.

Brookline, MA

Issued regulation such that effective June 1, 2020, no permits shall be issued by the Town for the construction of new buildings or significant rehabilitations that include the installation of on-site fossil fuel infrastructure, except as otherwise provided.

Cambridge, MA

City Council finds that in order to reach its net-zero emissions goals in response to the climate crisis, and pursuant to its declaration of a climate emergency in 2009, fossil fuel combustion in newly constructed buildings shall be prohibited.

New York, NY

Mayor proposes to eliminate natural gas and other fossil fuels in large building systems by 2040, beginning with government buildings.

Selected Other CA Municipalities with "Reach Codes" Mandating All-Electric New Construction

Carlsbad	Santa Monica
Windsor	Menlo Park
San Luis Obispo	San Jose
San Mateo	Marin County

A few municipalities have certain exceptions for gas cooking.

Utility-Imposed Customer Growth Moratoria

New York City Area

- Consolidated Edison (Westchester County)
- National Grid (Long Island) – lifted per settlement with New York state

Massachusetts

- Berkshire Gas – Eastern Division
- Columbia Gas of Massachusetts – Northampton/Easthampton
- Holyoke Gas & Electric
- Middleborough Gas & Electric Dept.

Note: A "reach code" local building energy code that "reaches" beyond the state minimum requirements for energy use in building design and construction

Sources: Center for Climate and Energy Solutions (c2es.org); Sierra Club; industry news; ScottMadden research

A Call to Action for Natural Gas Utilities

- The pressure to decarbonize is unlikely to abate, and policymakers will continue to review and assess the role of natural gas in meeting environmental objectives.
- With competing tailwinds of significant natural gas production, price stability, and customer additions and the headwinds of initiatives to ban natural gas in end use applications, natural gas utilities will continue to adapt near-term tactics and develop long-term strategies to reshape service offerings that meet an evolving energy market.
- These tactics and strategies will be along two fronts: (i) continuing and enhancing existing programs, processes, and initiatives and (ii) developing new services and business practices that help achieve decarbonization goals. Some examples of these efforts are shown on the figure at right.

	Customers	Gas Supply	Emissions Baseline
Continue and Extend Existing Programs, Processes, and Initiatives	▪ Leverage available data (which is increasing) ▪ Respond to a growing need to focus on subregions or more localized issues, which may require customized solutions ▪ Review energy efficiency programs with a focus on expanding funding (i.e., increase scale and scope of programs)	▪ Continue to develop and enhance planning processes (e.g., demand forecasting scenarios and regional gas supply issues and opportunities) ▪ Continue development of a gas supply portfolio that balances reliability and security, diversity, flexibility, resilience, risk mitigation, and cost effectiveness ▪ Expand process used to identify viable upstream/ downstream gas supply and load management options ▪ Expand use of quantitative and qualitative metrics to assess resources	▪ Continue (and potentially accelerate) replacement of leak-prone pipeline and upgrading of infrastructure ▪ Prepare detailed lost and unaccounted for gas (LAUF) analysis for methane emissions, including a root cause analysis ▪ Conduct benchmarking analyses over time and with peer groups to identify changes or innovations
Engage in Activities to Decarbonize the Gas Stream	▪ Review and modify rate design to address changing circumstances ▪ Develop renewable natural gas (RNG) supplier interconnection tariff to address gas quality standards and specifications ▪ Develop “green” opt-in tariff for customers to support RNG projects ▪ Increase information availability to allow for price-responsive services that provide customer input over usage	▪ Stress test the gas supply portfolio ▪ Assess renewable natural gas projects that support decarbonization (upstream contracts or assets) and also address load pockets and increase local deliverability (e.g., downstream projects) ▪ Support trade groups focused on methane emissions reductions (e.g., ONE Future) ▪ Support initiatives that rate companies on various metrics associated with natural gas production (e.g., TrustWell™)	▪ Develop program and targets that considers unique circumstances of the utility and region ▪ Develop cost recovery mechanisms for decarbonization and methane reduction investments that comply with pre-approved strategies (e.g., develop RNG procurement program with targets and budgets) ▪ Review operations to identify sources of carbon emissions ▪ Implement initiatives to measure, manage, and mitigate carbon emissions ▪ Evaluate and test the viability of blending hydrogen into the natural gas stream – Support industry studies – Develop pilot programs as test cases – Evaluate activities in other states and countries

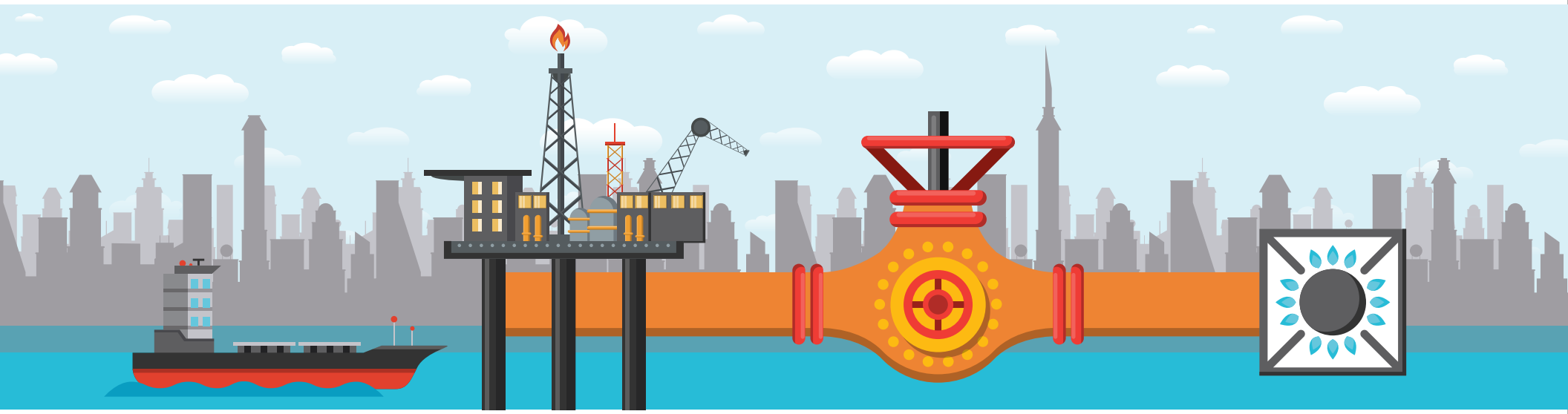
Certification of Environmentally Responsible Natural Gas Production: One tool for gas utilities to consider in their decarbonization efforts is supply certification. TrustWell™, for example, evaluates facilities and operations through transparent, verifiable technical evaluations. Certifying entities will look at techniques such as risk management, wellbore integrity, subsurface integrity monitoring, environmental programs, spill prevention, and operator procedures.

IMPLICATIONS

Gas utilities (LDCs) are at the forefront of managing and responding to the tailwinds of high production, stable prices, and customer demand with the headwinds of evolving expectations regarding decarbonization policy objectives. To address these expectations, LDCs will not only continue and expand existing strategies of accelerating replacement of infrastructure and investing in energy efficiency programs, but they will also initiate decarbonization activities and new service and resource initiatives, including new behind-the-meter programs and local supply resources. Near-term initiatives include expanding customer programs and acquiring new supply resources, such as RNG, while long-term initiatives require an expanded planning process to redefine how resource portfolio and gas infrastructure alternatives are evaluated, optimized, and implemented.

Sources:

U.S. Energy Information Administration (EIA) (natural gas data); EIA pipeline data, at www.eia.gov/naturalgas/data.cfm#pipelines (as of Jan. 22, 2020); EIA, Annual Energy Outlook 2020 (gas production forecast); EIA, National Gas Annual (Oct. 2019); Canada Energy Regulator, Canada's Energy Future 2019 (gas production data); S&P Global Market Intelligence (spot natural gas price indexes); FERC Office of Energy Projects, Energy Infrastructure Update for December 2019 (Mar. 2020) (for pipeline certification data); Center for Climate and Energy Solutions; Sierra Club, "Forward-Looking Cities Lead the Way to a Gas-Free Future" (Feb. 18, 2020); California Public Utilities Commission, *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning*, Agenda ID #18075 (Jan. 16, 2020); Testimony of Eversource Energy with Massachusetts Dept. of Public Utilities, D.P.U. 19-120, *Petition of NSTAR Gas Company doing business as Eversource Energy for Approval of General Increases in Base Distribution Rates for Gas Service* (re: environmentally responsible natural gas); Independent Energy Standards Program TrustWell™ Responsible Gas Program; ONE Future Coalition; National Grid, Natural Gas Long-Term Capacity Report for Brooklyn, Queens, Staten Island and Long Island, filed with New York Public Service Commission, Case 19-G-0678 (Feb. 24, 2020); industry news; ScottMadden analysis



GAS RESOURCE PLANNING
PLANNING IN A CHANGING ENVIRONMENT

A gas utility's integrated resource planning process incorporates a unique mix of factors that continue to evolve.

Adapting the Planning Process to New Requirements and Opportunities

- Integrated resource planning (IRP) has been a process used by local gas distribution companies (LDC) to guide and inform natural gas supply planning and procurement activities. Although each LDC IRP is unique to that gas utility's circumstances, there are certain topics that are typically included:
  - Evaluation of the impact of regional energy market conditions and potential changes, including higher utilization of existing pipeline capacity (e.g., increased demand from power generation segment)
  - Incorporation of changes in weather patterns and trends that drive demand, including assessment of exposure to low probability but high-risk weather events, such as extreme cold conditions, which may have volume and price risks to mitigate
  - Evaluation of the impact of regional economic conditions on demand
  - Assessment of historical consumption and demand data. The increasing availability of data supports more detailed analysis and use of optimization software and Monte Carlo simulation
  - Description of gas supply planning and procurement objectives
  - Outline of the resource portfolio challenges and opportunities, including identification, evaluation, and development or contracting for new resources
  - Compliance with regulatory requirements, including identification and discussion of longer-term objectives, such as decarbonization

KEY TAKEAWAYS

- **IRP is a process used by LDCs to guide and inform natural gas supply planning and procurement activities.**
- **Each LDC IRP addresses its unique circumstances, which include changes to local economic conditions and demand, opportunities for new supply resources, and regulatory requirements.**
- **Recent New York initiatives to change the planning process include more detailed and subregional demand and supply analysis, a focus on demand-reducing and on-system resources, and consistent and tariffed approaches for implementing moratoria.**
- **LDCs are reviewing the scope of their current planning efforts and considering new factors and analysis that will guide future plans and procurement decisions.**

- The planning process needs to be flexible to incorporate changes in demand resources (e.g., energy efficiency), changes in supply resources (e.g., renewable natural gas, compressed natural gas, or liquefied natural gas) and changes in regulatory requirements (e.g., non-pipe alternatives, decarbonization initiatives).

The Gas Integrated Resource Planning Process

Understand Market and Policy Dynamics

- Summarize natural gas trends and drivers
- Characterize weather and seasonal patterns reflecting gas usage
- *Review energy and environmental policy objectives and/or legislative mandates potentially affecting demand and supply options (e.g., decarbonization)*

Establishes macro parameters and constraints for planning

Describe the Utility Situation

- Review distribution system and links to upstream pipelines and on-system assets
- Summarize system demand drivers—customer segments, volumes, growth, trends
- *Inventory gas supply portfolio—assets, decision points, load management*
- Assess performance of past forecasts (including energy efficiency) and incorporate lessons learned

Feeds experience and developments into new plan

Forecast Demand

- Define planning objectives
- Develop planning standards (probability of occurrence or actual experience—normal/design year, design day)
- Forecast demand over IRP period, considering:
  - Interdependence with distribution system design
  - Demand offsets (efficiency, price response)

Quantifies potential risks and range of possible outcomes

Evaluate the Potential Resource Portfolio

- Evaluate performance of supply portfolio over planning scenarios
- Identify and quantify deficit and gaps
- *Identify available and viable resources to meet potential shortfalls*
- Analyze resource alternatives (quantitative and qualitative metrics)
- Outline resource decisions and risk mitigation strategies
- Identify resource portfolio that is diverse, flexible, and better positioned to manage uncertainty

Develops a gas supply portfolio that balances customer needs, costs, benefits, and policy requirements

Italics indicate some points of increasing IRP complexity.

New York Regulators Seek to Modernize the Planning Process

- The New York Public Service Commission (NYPSC) has recently initiated a regulatory proceeding (Case 20-G-131) to modernize the IRP planning process and to address gas supply resources and announced moratoria. Specifically, the NYPSC order identified the objective as "establish planning and operational practices that best support customer needs and emissions objectives while minimizing infrastructure investments and ensuring the continuation of reliable, safe, and adequate service to existing customers."
- As part of this proceeding, LDCs are required to submit various compliance information, including:
  - Supply/demand information, particularly areas vulnerable to supply constraints
  - Proposals for peaking services and moratoria management
  - Potential proposals regarding the extent to which the utility currently uses or anticipates using demand-reducing measures, including energy efficiency, demand response, non-pipe alternatives, and other measures to address identified areas of supply/demand imbalance or to aid in the management of moratoria, including targeting of existing and new energy efficiency and electrification programs
- NYPSC staff are directed to file a proposal to modernize the gas system planning process in August. The order and timelines are summarized in the figure below.

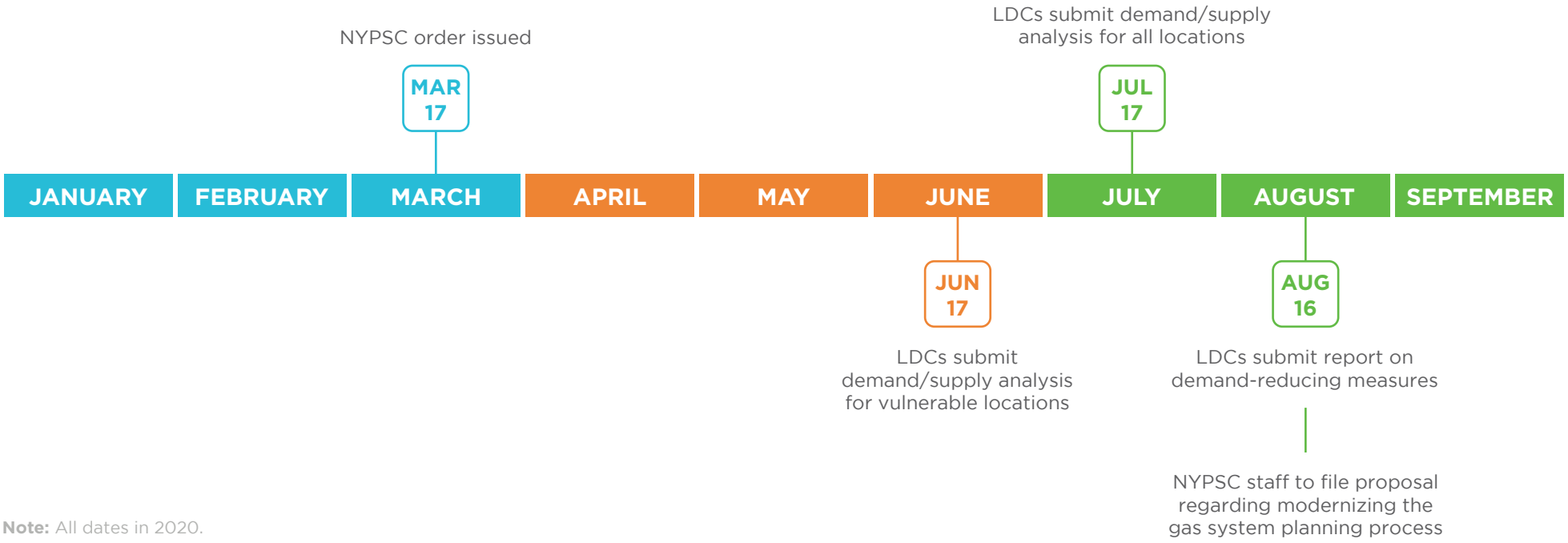
Overview of Key Provisions of NYPSC Gas Planning Proceeding (Case 20-G-131)

		NYPSC-Identified Considerations	Updating the Planning Process – Actions Required
Locational constraint analysis		▪ Constraints due to pipelines, distribution infrastructure, or both	▪ For each municipality or borough in the LDC service area, develop analysis of demand and supply balance, current and projected ▪ Prioritize analysis of vulnerable locations
Transparent, comprehensive planning information	**Transparent planning**	▪ Value of forward planning with comprehensive consideration of supply alternatives and demand-side options ▪ Avoiding supply constraint surprises and ensuring forward planning considers best possible alternatives, managing reliability	▪ Balance LDC confidentiality concerns with providing relevant information to customers and stakeholders
	Policy-aligned planning	▪ Challenges to conventional planning approaches due to recent supply/demand imbalances; emergence of viable, less-traditional solutions; controversy over major gas infrastructure decisions; and state climate policy ▪ Investment in gas infrastructure with significant long-term financial implication for customers	▪ Address certain policy issues, including consideration of supply and demand alternatives, timeframe for analysis and decision, and risk and costs to customers ▪ Examine affiliate relationships for incentives not aligned with state policies ▪ Issue (through NYPSC staff) a proposal to modernize gas planning process

Overview of Key Provisions of NYPSC Gas Planning Proceeding (Case 20-G-131) (Cont'd)

		NYPSC-Identified Considerations	Updating the Planning Process – Actions Required
Non-pipe solutions		▪ Temporary supply, energy efficiency, electrification, and clean demand response typically considered on an as-needed basis	▪ Build into the planning process an assessment of non-pipe alternatives using as criteria: reliability, practicality, environmental impact, avoided infrastructure, and local community impacts
Criteria for reliance on peaking services		▪ More reliance on peaking services (e.g., CNG) and potentially higher cost delivered services (short-term pipeline service) possibly not available for renewal ▪ Moratoria decisions based, in part, on avoiding over-reliance on delivered services	▪ Establish clear and common standards for acceptable levels of reliance
Standards governing moratoria	**Declarations**	▪ Differing utility tariffs governing gas utility moratoria declarations on new customer additions	▪ Explore best practices and opportunities for enhancements to these moratoria processes
	Treatment of applicants and customers	▪ Impact of moratoria on customers with projects that may have relied upon the ability to receive firm gas service	▪ Establish standards and practices for treatment of applicants and customers
	Communications	▪ Address entities that might be planning to apply for gas service	▪ Establish standards and practices for communications with applicants for service, current customers, and the public
	Prioritization	▪ All-or-nothing approach to gas moratoria ▪ Need depends on severity of forecast imbalance and availability of alternatives	▪ Consider partial moratoria, prioritizing new or expanded service applications, including clear and equitable standards
	Lifting of moratoria	▪ Timing of relief of supply constraints	▪ Establish timing and approach to clarifying whether and when moratoria can be lifted
Demand response and rate design		▪ Interruptible rates for customers as primary tool for peak demand reduction, but customers switch to alternative, less clean fuels (especially oil)	▪ Develop demand response methods, peak reduction, and price signals
Criteria pollutant reduction		▪ Alternative to firm gas may mean oil and propane combustion at peak period, causing local pollution impacts	▪ Consider conditions to interruptible rate tariffs, incentive programs, or other methods

An Ambitious Timeline for Gas Utility Analysis and Changes to the Planning Process



Note: All dates in 2020.

IMPLICATIONS

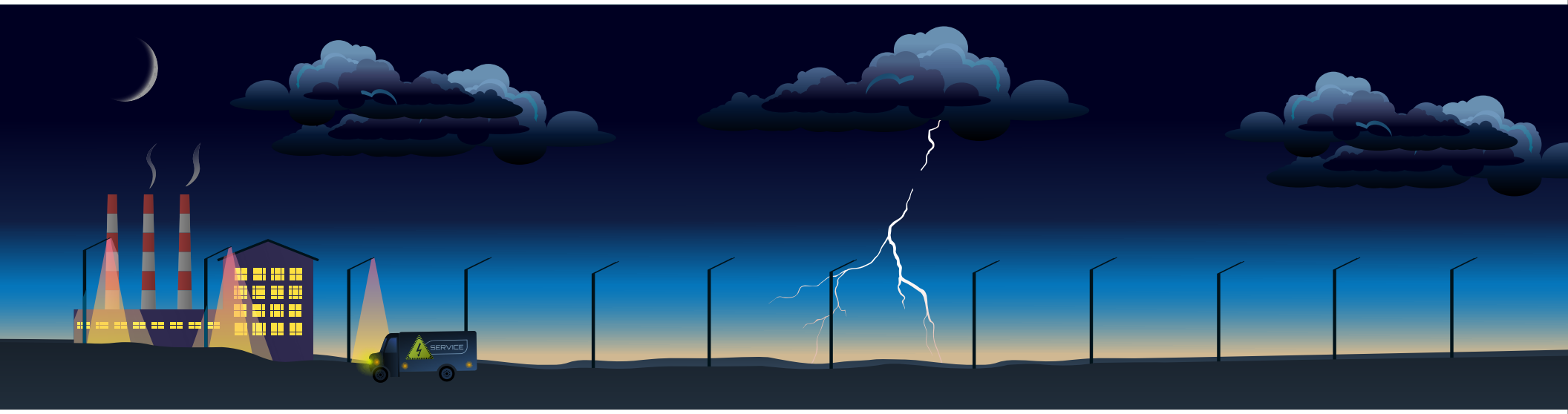
LDCs use the IRP process as a framework to systematically assess demand scenarios (based on various economic, demographic, or weather assumptions) against existing resources thus identifying required changes or adjustments to the gas supply portfolio. This planning framework allows LDCs to evaluate changing policy objectives (e.g., greenhouse gas emissions) in a rigorous and consistent basis within the overarching objectives of providing reliable and cost-effective service.

Note:

For additional discussion of gas utility developments, see "The Future of the Gas Utility" section of this Energy Industry Update.

Sources:

New York Public Service Commission, *Order Instituting Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Case 20-G-0131 (Mar. 19, 2020); ScottMadden analysis



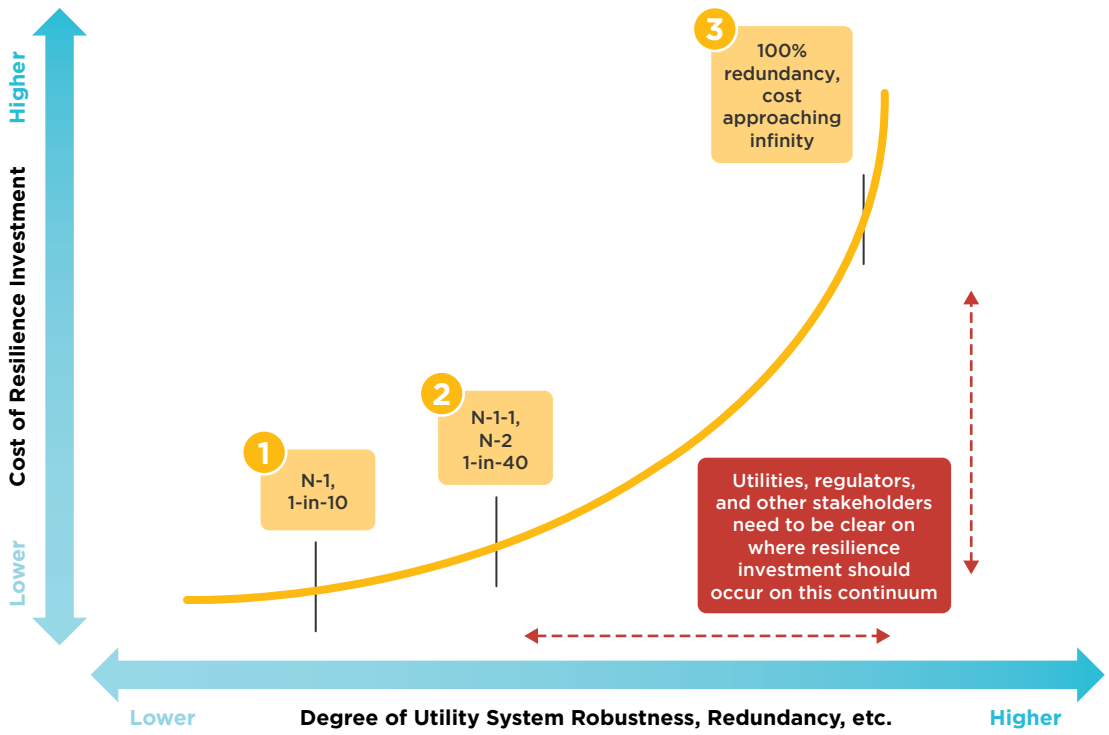
GRID RESILIENCE
ENABLING NEEDED INVESTMENT

As resilience needs grow, planning challenges persist.

Roles and Responsibilities in the Resilience Discussion

- Who owns it? Federal and state governments, utilities, and grid operators have sought to find the right balance of authority and jurisdiction. But lines of demarcation and roles and responsibilities—particularly the scope of responsibilities, extent of preventative and remedial actions, and who ultimately pays—have not yet been clearly established. In the meantime, resilience is owned by everyone and no one at once.
- Why does it matter? While reliability has always been a focus of FERC and NERC, resilience—particularly involving significant and catastrophic events—has implications affecting first responders, governmental agencies, and others, in addition to utilities. Risk tolerance, investment priorities, and policy objectives may not naturally align among the long list of stakeholders.
- In resilience planning, the balance between utility and other government or non-utility entities needs to be assessed and consideration given to “where the line should be” between those investments and where opportunities may exist to co-invest. The preparation activities may be different too. While reliability is addressed by event and outage planning within the utility, resilience planning may involve preparing broader responses among the utility and other government agencies.

Continuum of Theoretical Resilience Investment



Source: ScottMadden analysis

What Is Resilience?

The NERC framework: NERC and other government agencies have been studying resilience needs for the U.S. electric system. NERC, tasked with overseeing bulk power system reliability, has also developed a resilience framework. These resilience activities are especially focused on significant and catastrophic events that can impact other critical infrastructure as well as first response and social services. NERC's framework envisions four elements, reflecting different parts of an event:

- **Robustness –** the ability to absorb shocks and continue operating
- **Resourcefulness –** the ability to detect and manage a crisis as it unfolds
- **Rapid Recovery –** the ability to get services back as quickly as possible in a coordinated and controlled manner, taking into consideration the extent of the damage
- **Adaptability –** the ability to incorporate lessons learned from past events to improve resilience

KEY TAKEAWAYS

- **Resilience continues to be a focus for utilities, and there is some evidence of planning procedures being updated and adapted to address resilience needs. More adaptations may be needed if significantly greater investment is required.**
- **The balance between utility versus other infrastructure must be assessed and consideration given to "where the line should be" between those resilience investments.**
- **Adapting planning models that were designed for reliability may be tricky. Some creative approaches will be needed in considering multiple values associated with resilience investments, sharing costs, and adapting planning procedures to resilience objectives.**

The Planning Gap: Traditional Approaches Ill-Suited for Resilience

- Transmission planners, operators, and owners continue to focus on reliability, including weather and fuel dependency, as those are most clearly actionable and drive infrastructure investment. But as major weather disturbances, cyber events, and other low-frequency, high-impact events threaten the electric grid, existing planning approaches reveal gaps.
- NERC has noted for less probable, severe events, "bulk electric system owners and operators may not be able to apply economically justifiable or practical measures to prevent or mitigate an adverse reliability impact on the bulk electric system even if these events can result in cascading, uncontrolled separation, or voltage collapse."
- Resilience also has broader societal implications involving more stakeholders, with government as a key facilitator. And its costs may more properly be, at least in part, a societal decision.

Key Issues to Address to Close the Planning Gap	
Design Criteria	What are key design criteria and what level of resilience is needed? According to the National Infrastructure Advisory Council, without design basis guidance, "it is difficult for owners and operators to justify investments, receive regulatory approval, or even know what standards are realistic and sensible to build to."
Cost Effectiveness	Designing a system against any threat will be cost-prohibitive and unlikely to be supported by regulators and customers. How to balance cost against potential impacts and possible benefits remains a challenge. Indeed, planning and designing for graceful degradation and rapid recovery may be appropriate instead of hardening against all risk.
Cost Allocation	Resilience can be considered a "social good" given the reliance of key sectors on the power system for ongoing operations. Those include governmental agencies, critical infrastructure (communications, water, wastewater and sewage, natural gas, fuel processing and distribution), and financial institutions. All of these provide essential services necessary to sustain communities during a long-lived outage. How best to allocate a resilience "insurance premium" is crucial to ensuring an investment is made.
Incentives	How to provide incentives, or to de-risk resilience investments, is another important consideration for utilities. Some have argued that FERC should establish an incentive for FERC-approved, company-specific resilience and action plans, suggesting this would encourage proactive grid resilience efforts that go beyond minimum reliability standards. Given the challenges of grid development under normal planning assumptions, adding resilience may benefit from some support.
Bottom Line	In resilience planning, the balance between utility versus other entities—government or non-utility—needs to be assessed and consideration given to "where the line should be" between those investments. If utilities, regulators, or governments wish to improve the resilience of the electric system, all parties should agree upon the plan. Because resilience preparation considers unspecified or incipient events (not unlike the unfolding COVID-19 pandemic) with implications and interdependencies across multiple sectors and services, broad planning efforts are needed to ensure an agile response to any scenario.

Reliability vs. Resilience: Different Stakeholders, Cost Bearers, Responsibilities, and Levels of Planning Maturity

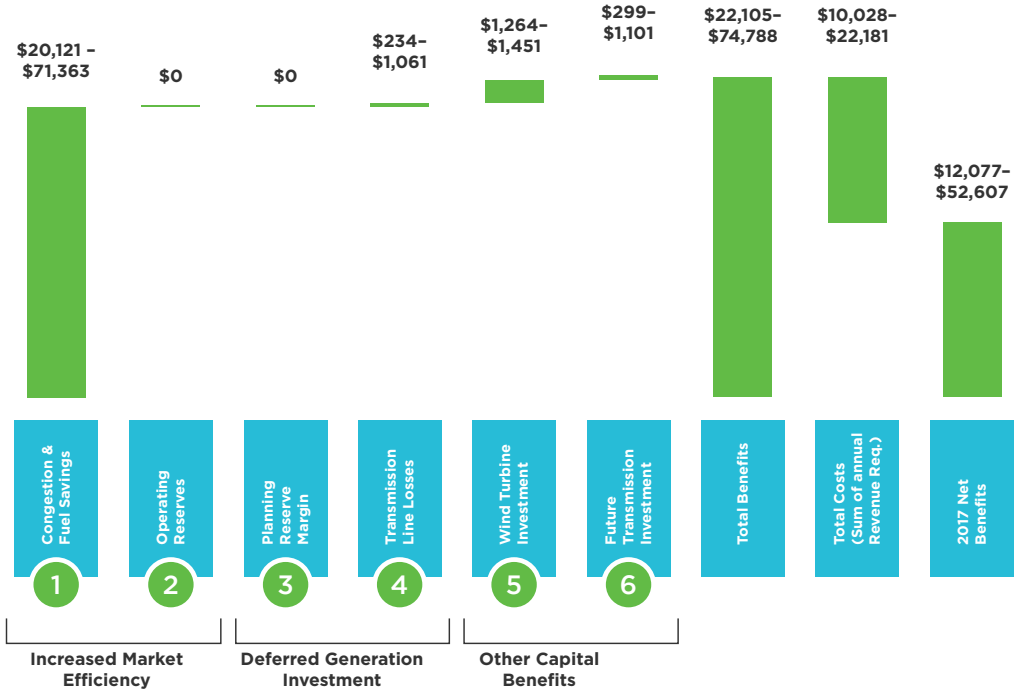
	RELIABILITY	RESILIENCE
Planning criteria	Well-established N-2 planning	Unspecified or incipient "black swan" planning
Scenarios considered	Stated contingencies	Unlikely/unknown contingencies beyond reliability planning
Primary focus	Prevention, protection, and risk mitigation	Critical infrastructure recovery; social stability
Potential value of event "insurance"	Estimable through system modeling	Difficult to ascertain; policy driven
Costs borne by	Ratepayers	Taxpayers
Funded by	Utility capital expenditures	▪ Federal emergency funds ▪ State infrastructure ▪ Municipal, county government
First response responsibility	Utility	Government, community response
Stakeholder coordination	Utility, independent system operator led	Government led

Source: ScottMadden analysis

Recognizing Multiple Values: Lesson from the Not-So-Distant Past

- One potential approach to incorporating resilience in transmission planning is to include the values of resilience as a part of an evaluation of transmission projects with multiple benefits. Resilience touches upon each of the reliability, economic, and public policy objectives of multiple benefit projects, and resilience values could be quantified, expanding the range of potential outcomes to incorporate more extreme scenarios.
- While it did not specifically incorporate resilience at the time, this model was successfully demonstrated in Midcontinent ISO (MISO) almost 10 years ago. By coordinating across state borders within the MISO region, several transmission owners were able to develop a portfolio of projects that could achieve multiple values (deemed Multi-Value Projects or MVPs). It worked because there was a common understanding of, and agreement on, the investment objectives and needs of the transmission system, and states were able to identify common policy objectives. The 17 projects selected for the portfolio in 2011 represented a total budget of more than $5.5 billion at the time, and as of the latest status report in January, all but one portion of a project were complete and in service.
- As for the benefits achieved, MISO's latest Triennial MVP Project Review in 2017 estimated that the MVP portfolio does the following:
  - Provides benefits in excess of its costs, with its benefit-to-cost ratio ranging from 2.2 to 3.4; an increase from the 1.8 to 3.0 range calculated in MTEP11
  - Creates $12.1 billion to $52.6 billion in net benefits over the next 20 to 40 years
  - Enables 52.8 million MWh of wind energy to meet renewable energy mandates and goals through year 2031

MVP Portfolio Economic Benefits from MTEP17 MVP Triennial Review



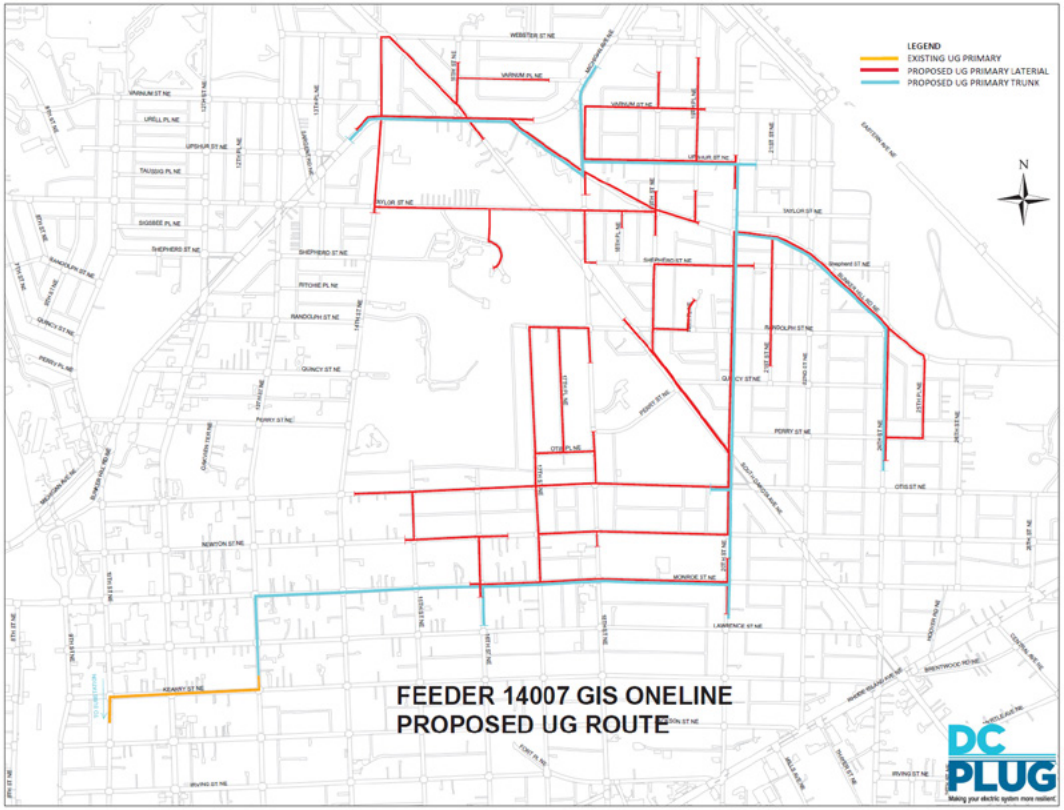
Source: Midcontinent ISO

Note: MTEP is the MISO Transmission Expansion Plan. Numbers following the "MTEP" indicate the year the plan was formulated.

Co-Investing in Resilience: Creative Approaches to Sharing Costs

- A pair of winter storms in 2010, followed by a derecho (a line of intense and fast-moving windstorms) in June 2012, resulted in power outages lasting as long as a week. In response, the District of Columbia launched a blue ribbon panel, chaired by a leader from the local utility, Pepco Holdings, Inc. (Pepco), and the city administrator for the District of Columbia, with the objective of reducing the frequency and duration of outages resulting from storms.
- After incorporating input from various stakeholders through the process, the D.C. Public Service Commission (DCPSC) and the utility agreed to a plan to deploy $500 million to deliver high-impact projects to improve the grid's ability to withstand and more quickly recover from the impacts of severe storms, with half of the costs borne by ratepayers and half of the cost recovered from the municipality (i.e., taxpayers) through a public-private partnership.
- The initiative is referred to as the D.C. Powerline Undergrounding Initiative, or D.C. PLUG, and it involves ranking overhead feeders for undergrounding based on a number of criteria, including the number and duration of outages and customer minutes of interruption for the years 2010–2019.
- The first portfolio of six projects was approved in 2017, and the DCPSC approved a second portfolio of 10 additional projects in January, together representing approximately $400 million. A third and final solicitation is expected to identify projects representing the balance of the approved budget in 2022.
- The projects address overlapping elements of reliability and resilience, again demonstrating the challenges associated with making the distinction between the two. But the proceeding also features novel performance metrics intended to measure benefits to the electric system that go beyond traditional measures of reliability (e.g., Customers Experiencing Long Interruption Duration or CELID).

Illustrative Map of Feeder Undergrounding Proposal



Source: D.C. PLUG

Planning for Resilience: PJM Transmission Owners Seek to Plan Critical Facilities Differently

- **Novel planning proposal:** In January 2020, PJM Transmission Owners (TOs) filed a request with FERC to approve a novel planning procedure to address a limited subset of projects designated to mitigate the risk associated with critical transmission substations identified pursuant to NERC reliability standard CIP-014-2 for physical security and to improve grid resilience. If approved, the new procedures would only apply to the discrete set of NERC CIP-14 mitigation projects (CMPs), and the procedures would only be applicable for a limited time.
- **Sensitivity vs. transparency:** In the filing with FERC, the TOs argue that, because the planning procedure for other Supplemental Projects* requires an open and transparent review with outside stakeholders, the existing procedure cannot be used for critical facilities for which the identification and location must be kept confidential and protected from public disclosure. Divulging such information may provide would-be attackers with the location of those substations, as well as the consequences of rendering them inoperable.
- **Resilience impact:** The TOs state that the proposed planning procedure is intended to allow for the reduction of the consequences of the loss of critical facilities, beyond the physical security measures already undertaken to ensure compliance with CIP-014-2, by implementing projects which allow for those facilities to be removed from the list of critical facilities by adding redundancies. The TOs also argue that removing a facility from the list may increase resilience and reduce the security threat to the transmission system by eliminating a single point of vulnerability. The TOs argue that these projects will protect against widespread instability, uncontrolled separation, and the successive loss of system elements—each of which would result in significant service interruption.
- **Making the case to stakeholders:** The TOs have explained the public imperative of mitigating the criticality of these facilities through a time-limited alternative tariff mechanism, and they have conducted meetings since 2018 with stakeholders, including states, NERC, and ReliabilityFirst, in anticipation of their filing with FERC. In order to ensure that proceeding with proposed CMPs is just and reasonable, the proposed process also outlines a method of developing plans in consultation with PJM and affected states, while protecting sensitive information about critical facilities.
- **Alternative funding and public notice:** As part of the proposed process, the TOs would also commit to make reasonable efforts to seek alternative funding for CMPs, including from the U.S. Department of Energy, through grants for advancing national security, critical infrastructure, or resilience. PJM TOs also emphasized that after the construction of CMP is complete, public notice of its existence will be provided as a precondition to any project being eligible for recovery of costs.
- **Intervenor comments:** Since filing the proposed tariff amendment with FERC in January, many parties have intervened to express a range of concerns, arguing that:
  - PJM already has procedures in place to protect sensitive information, allowing for third-party review under non-disclosure agreements.
  - System reliability projects should be routed through the RTEP**, not processed as Supplemental Projects.
    - PJM TOs have complied with CIP-014-2, at great expense, and additional expense should not be incurred.
    - Additional transparency could be incorporated in the proposed process, without compromising sensitive confidential information.

Some Observations:

- Striking a balance between sensitivity and transparency is challenging for certain grid resilience investments.
- Investments made beyond the threshold of "compliance," as PJM TOs have achieved related to CIP-014-2, in order to improve grid resilience, require a framework under which they can be justified.
- The introduction of competition with FERC Order 1000 has also created an expectation of transparency in the planning process that may make some resilience investments more difficult to deploy.

IMPLICATIONS

In order to prudently deploy the right resilience investments, utilities, regulators, governments, and other stakeholders need to agree on roles and responsibilities related to grid resilience and the appropriate level of investment for the resilience appropriate for the need. Planning approaches may need to be further adapted to account for the unique values of resilience. And utilities and other stakeholders may need to explore sharing costs for investments needed for the common good to improve resilience.

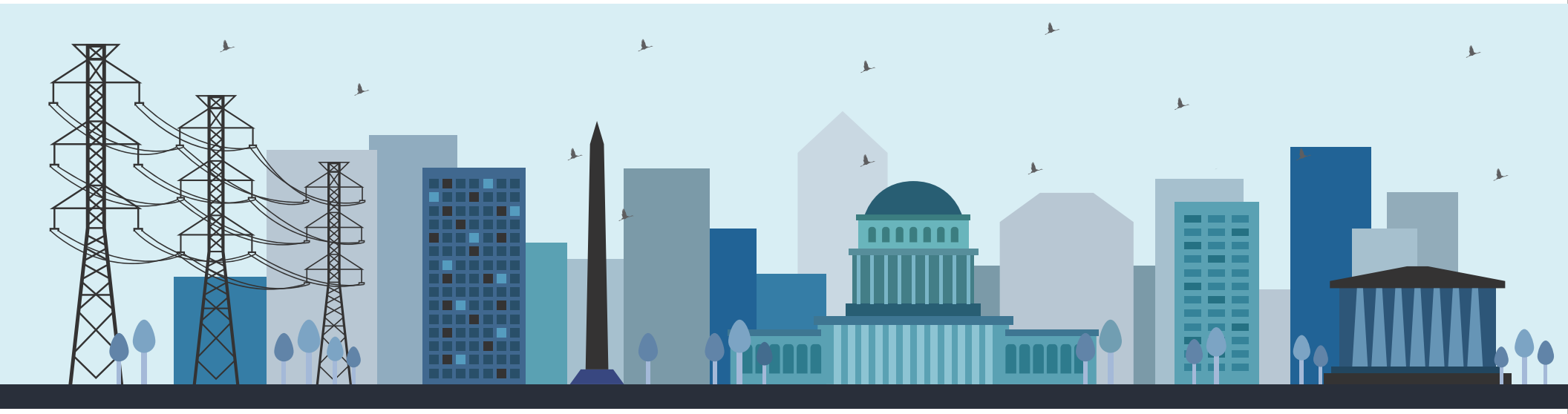
Notes:

*A Supplemental Project is "a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii)." Operating Agreement, Schedule 6, Section 1.42A.

**RTEP is PJM's Regional Transmission Expansion Plan, published annually, created through a process that identifies transmission system additions and improvements that allow the transmission system to deliver power reliably and economically over the long term.

Sources:

National Infrastructure Advisory Council, Surviving a Catastrophic Power Outage: How to Strengthen the Capabilities of the Nation (Dec. 2018); Midcontinent ISO, 2017 MVP Triennial Review Report; Amendments to the Electric Company Infrastructure Improvement Financing Act of 2014 passed in 2017; Government of the District of Columbia, Executive Office of the Mayor, Mayor's Power Line Undergrounding Task Force; District of Columbia Power Line Undergrounding Initiative Community Hearing, Pepco, DDOT (July 24, 2017); PJM Transmission Owners Submission of Proposed Tariff Revisions for a Limited Subset of Supplemental Projects that Require Special Planning Procedures, FERC Docket ER-20-841 (Jan. 17, 2020); WIRES & ScottMadden, Informing the Transmission Discussion (Jan. 2020); WIRES Comments on Grid Resilience in Regional Transmission Organizations and Independent System Operators FERC Docket No. AD18-7-000 (May 9, 2018); ScottMadden analysis



RETURNS ON EQUITY FOR TRANSMISSION INVESTMENT
FERC AND UTILITIES TRY TO "GET THE PRICE RIGHT"

Transmission developers seek stable and improved returns to incentivize growth in investment for the energy transition.

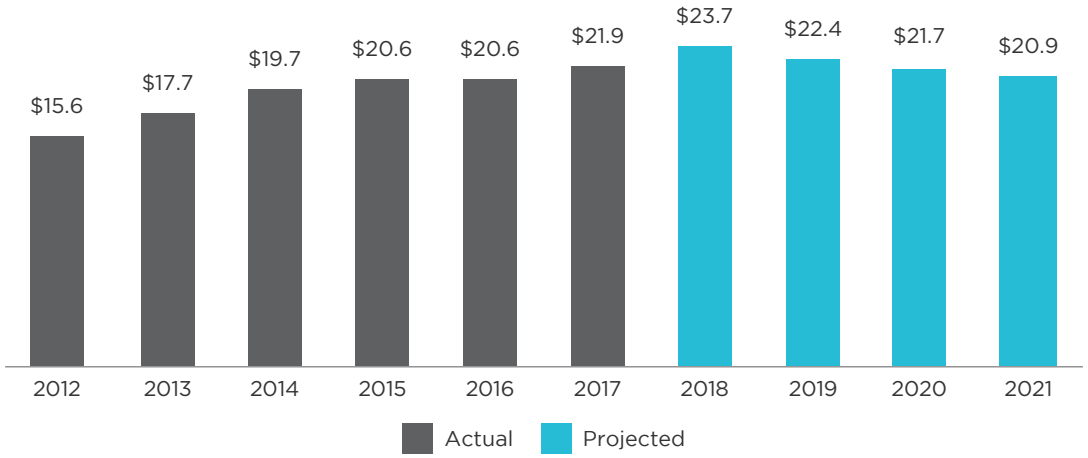
Trends in Returns and Investment in Transmission

- Beginning with the Energy Policy Act of 2005 and the resulting FERC Order 679, FERC established a series of incentives to encourage investment in the aging U.S. electric transmission system—and those incentives achieved many of their desired effects. Investments in power transmission increased markedly in the mid-2000s, and that trend continued into the middle of the last decade.
- More recently, however, due to a combination of headwinds to investment in large transmission projects, including increasing pushback on the cost of transmission from some customer advocates and declining returns to transmission owners, investments in transmission have lagged their prior pace.
- Though the number of projects and the dollars allocated to transmission projects have continued to increase, the total miles of transmission peaked in 2013, and projected transmission expenditures are projected to fall in each of the next five years.
- In this context, FERC's recently issued Opinion 569 modifying the methodology for setting base allowed ROEs for transmission comes at an important time.

KEY TAKEAWAYS

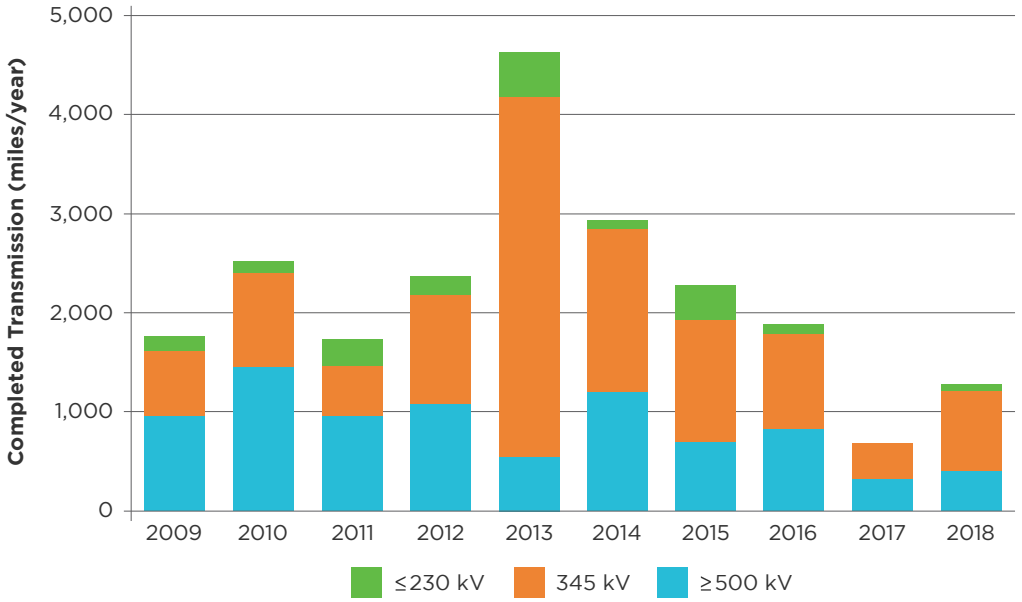
- **The net result of Opinion 569 points to significantly lower ROEs on FERC jurisdictional transmission assets, and the ROE methodology adjustments may have precedential impacts for proceedings in other regions.**
- **The relationship between FERC's base ROE for transmission and the ROE established by state public utility commissions for other utility investments will be critical in determining the level of transmission development.**
- **The picture may not be complete until FERC's proposed rule on transmission incentives is resolved.**

Actual and Planned Transmission Investment* ($ Billions Nominal) (as of Oct. 2018)



Note: *By investor-owned utilities and standalone transmission companies
Source: EEI

Completed Miles of U.S. Power Transmission Projects by Year and Voltage



Sources: DOE; FERC

What's in a Number? Much Ado about Transmission ROEs

- FERC's Opinion 569, issued in November 2019, would establish a new methodology for determining ROEs for electric utility transmission under the Federal Power Act Section 206, which mandates that transmission rates be "just and reasonable." Opinion 569 was issued in the context of a challenge to MISO transmission owners' base rates of return. The net result of the case and related opinion reduced the ROE for MISO transmission owners from 12.38% to 9.88%.
- Opinion 569 is a response to *Emera Maine v. FERC*, in which the U.S. Court of Appeals for the D.C. Circuit vacated and remanded FERC's Opinion 531, and in so doing, rejected FERC's prior ROE methodology. The D.C. Circuit found that FERC did not show that setting the base ROE for Emera Maine's transmission investment at the upper midpoint of a "zone of reasonableness" (using two-step discounted cash flow analysis) rather than the midpoint was just and reasonable.
- This represents the latest attempt by the Commission to resolve a series of transmission ROE cases that have been considered over the past decade and more recently considered with initiation of a March 2019 FERC inquiry.
- In Opinion 569, FERC reversed previous policy which recommended the use of four different methodologies in determining a "zone of reasonableness" for base ROE for transmission: the Two-Step Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), Bond Yield Plus Risk Premium model (Risk Premium), and the Expected Earnings approach. Those methodologies are summarized in the figure below.
- Opinion 569 establishes a composite "zone of reasonableness" for base ROE using equal weighting of the DCF and CAPM analyses, but it excludes Expected Earnings and Risk Premium methods, which FERC had initially proposed to include in the ROE evaluation. It also presumes an existing ROE is "just and reasonable" if it falls within the range of ROEs for the quartile corresponding to the utility's (or group of utilities') risk profile.
- In addition to potentially reducing base ROEs for transmission investment, the order's effect is to reduce the amount of valuable, opportunity-cost and investment-focused analysis that could help fully inform ROE decisions.
- Opinion 554-A, issued in January 2020, established a paper hearing to review the four methods.

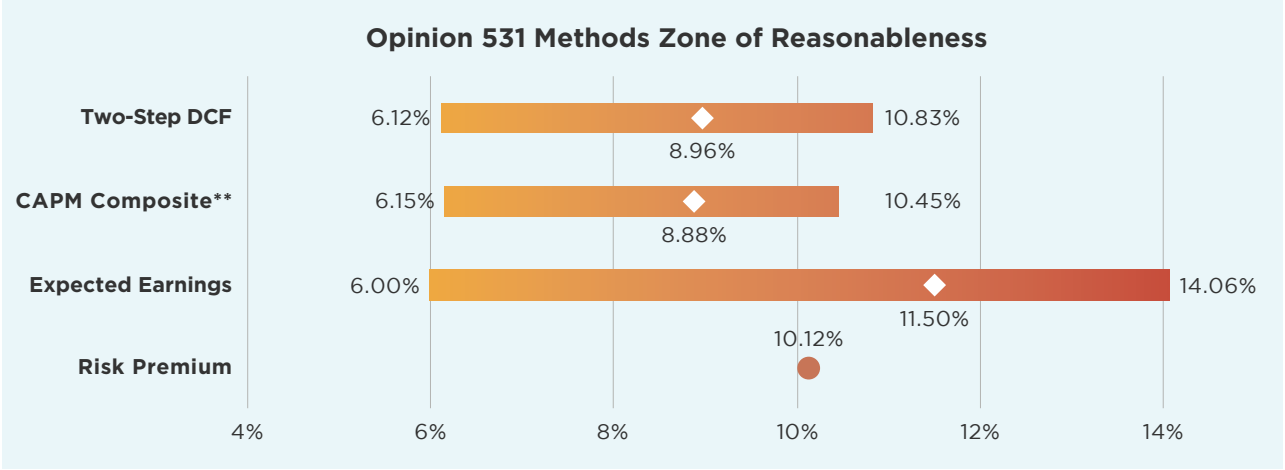
Comparing and Contrasting Valuation Methodologies

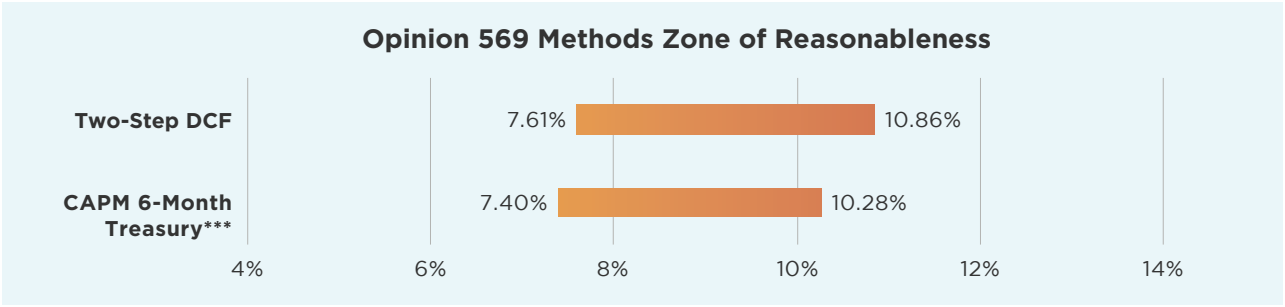
Method	Inputs	Perspective Provided	Comments
Two-Step DCF	Observed stock prices, observed dividends, consensus analyst growth rates, estimate of long-term GDP growth	Investors' expectations of future growth in perpetuity	Assumes variables such as growth rates, payout ratios, P/E ratios remain constant in perpetuity
CAPM	Risk-free rate, beta, and market risk premium	Provides a direct measure of undiversifiable risk	A risk-positioning model reflecting expected utility risks relative to overall market risks and expected returns
Expected Earnings	Investment analyst expectations of return on book value for a proxy group of companies	Simple to apply; not as affected by unstable markets as other methods; based on data that is important to investors	Provides an alternative to market-based methods; consistent with the rate-setting process; considered by many state regulatory commissions
Risk Premium	Estimates the cost of equity as the sum of (1) the equity risk premium and (2) the yield on a particular class of bonds	Reflects the inverse relationship between interest rates and the equity risk premium	Accounts for the premium equity investors require over the return they would earn as a bondholder

Word on the Street: Reaction from Industry and Investment Analysts

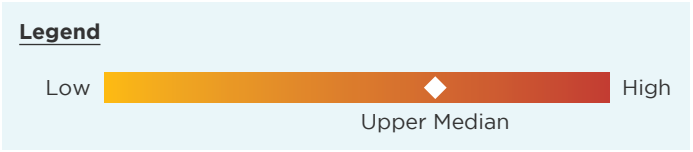
- Analysts have expressed concern about the implications for future transmission investment, and some have suggested that utilities may shift investment away from transmission if the decision holds.
- Some analysts have concluded that the ruling produces unreasonably low results in the near term for utilities with MISO transmission assets and may have impacts across other regions with a downward bias toward potential returns.
- While certainty is appreciated after an extremely protracted process, some view the outcome as a negative for investor-owned utilities using RTO base ROEs.
- In addition to base ROEs breaking below the 10% threshold, some see the shift to a two-prong (DCF and CAPM) approach from the previously outlined four-method (DCF, CAPM, Risk Premium, and Expected Earnings) approach may lead to more volatile ROEs.
- Some observers have noted the importance of maintaining the analytical flexibility provided by four methods as FERC endeavors to set just and reasonable ROEs.
- Some also note the potential to see further complaints on transmission ROEs in other regions, and FERC's opinion will likely be subject to litigation. Many observers also suggest that this may not be the final word from FERC on the matter.

Opinion 531 vs. Opinion 569 Illustrative Return on Equity Ranges*





Notes: *For above-average risk utility.
**Composite based on six-month average and near-term 30-year U.S. Treasury.
***Using six-month average 30-year U.S. Treasury Rate.



Source: Testimony of LS Power Grid New York Power Corporation I, Appendix H, filing with FERC, Docket No. ER20-716-000 (Dec. 31, 2019)

A Possible Remedy for Transmission: FERC Takes Action on Incentives

- After focusing on base ROE policies through a notice of inquiry in March 2019 and Opinion 569 issued in November (discussed earlier), FERC initiated a notice of proposed rulemaking (Incentives NOPR) addressing transmission ROE incentives.
- The Incentives NOPR, issued on March 20, 2020, proposes a number of changes to the Commission's transmission incentive framework, originally promulgated under Order 679, issued in July 2006 and refreshed by way of a 2012 policy statement. FERC pointed to a number of factors affecting transmission development since Order 679 that warranted a re-examination of incentives:
  - An evolving resource mix, with more natural gas and renewables vs. coal as well as different types of resources, such as distributed energy resources and storage
  - Increase in new resources seeking transmission service
  - Shifts in load patterns, with low load growth but potential for electrification and increasing peak demand
  - Increased sophistication in transmission planning and experience in regional planning since the issuance of Order 1000
- Most significantly, the proposed rule would eliminate Order 679's "nexus test", which requires applicants to show a connection between the requested incentives and the risks and challenges associated with the project, and instead provide several incentives based on economic and reliability benefits, effectively rewarding efficiency and impactful solutions. A description of key aspects of the proposed rule are summarized on the next page.
- FERC has solicited comments on the proposed rule, with those comments due in June.

Some Questions Regarding the Incentives NOPR:

- Does the NOPR suggest that FERC is now open to a broader application of ROE incentives to promote the expansion of the electric transmission grid?
- How will FERC implement the more discretionary elements of the proposal (e.g., evaluating potential reliability benefits offered by projects)?
- Given the relatively low chance that FERC will issue a final rule prior to the 2020 election, could the proposal face headwinds if a change in administration occurs?
- Will incentives be used by FERC as a tool to offset some of the impact of lower base ROEs?

Overview of FERC's March 2020 Notice of Proposed Rulemaking on Electric Transmission Incentive Policy

Area	Proposed Rule	What It Means
ROE Incentives for Economic Benefits	Provides ROE incentives up to 100 bps to economic transmission projects based on two economic benefit-to-cost tests: ▪ Ex-ante: a 50-bp incentive for transmission projects that meet an ex-ante benefit-to-cost (BTC) threshold (75th percentile net benefit ratio) ▪ Ex-post: an additional 50-bp incentive for projects that demonstrate on an ex-post basis that they satisfy a higher BTC threshold (90th percentile) when constructed	▪ Limits measurement of economic benefits to adjusted production costs or similar measures of congestion reduction or certain other "quantifiable benefits that are verifiable and not duplicative" ▪ Permits regional or local transmission projects to be eligible for this incentive ▪ Establishes $25 million as cost difference between small and large projects and sets different national BTC thresholds based upon a study group of projects: – 75th percentile: 3.98 (large) vs. 33.91 (small) – 90th percentile: 5.17 (large) vs. 77.04 (small)
ROE Incentive for Reliability Enhancement	Establishes ROE incentive of up to 50 bps for projects that provide "significant and demonstrable reliability benefits"	▪ Gives examples of reliability benefits, such as increased import/export capability between balancing areas ▪ Requires quantification where possible, such as reduced loss of load probability, reduced unserved energy, etc.
Non-ROE Incentives	Retains incentives for: ▪ 100% cost recovery of abandoned plant (prudently incurred) ▪ Inclusion of 100% of construction work in progress in rate base ▪ Hypothetical capital structures ▪ Accelerated depreciation for rate recovery ▪ Recovery of prudently incurred pre-commercial operations costs as an expense or through a regulatory asset	▪ Effectively de-risks some investment despite pivot to benefits-based ROE incentives
Transcos	Eliminates ROE incentive and alternative ratemaking treatment for stand-alone transmission companies (transcos)	▪ Asserts transco business model has not enhanced the deployment of transmission infrastructure sufficiently to justify unique incentives based on this business model
RTO/ISO Membership	Establishes a 100-bp incentive to transmitting utilities that turn over their transmission facilities to an RTO or ISO, whether or not participation is voluntary	▪ Recognizes the benefits, risks, and associated obligations of RTO membership ▪ Makes RTO/ISO incentive available both prospectively and to current RTO/ISO participants
Transmission Technologies	Establishes 100-bp ROE transmission technology incentive on the cost of the advanced transmission technology project and a two-year regulatory asset treatment for costs related to deploying and operating that technology (deployment incentive), including pilot programs	▪ Encourages technologies that enhance reliability, efficiency, capacity, and improve the operation of new or existing transmission facilities ▪ Pegs rate base for ROE incentive to ratio of weighted cost of the new technology to entire project cost
Cap on Incentives	Sets a 250-bp cap on total ROE incentives	▪ Replaces current policy of limiting ROE incentives to the utility's "zone of reasonableness"

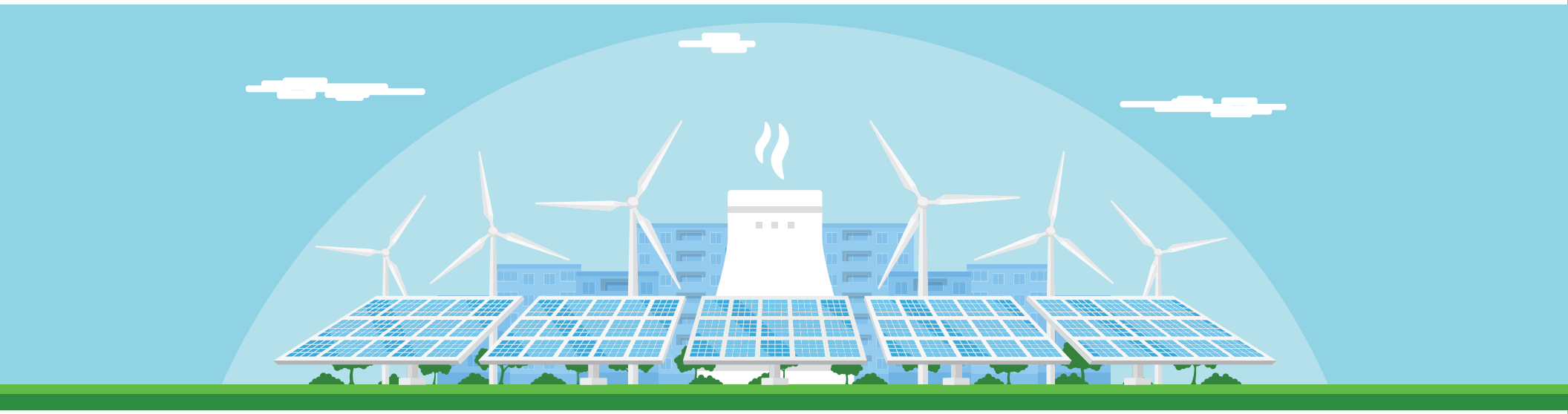
Sources: FERC Transmission Incentives NOPR, Docket No. RM20-10-000; ScottMadden analysis

IMPLICATIONS

Regardless of the specific methodology used by FERC to establish just and reasonable returns for transmission, how FERC establishes the zone of reasonableness, or the generosity of incentives layered on top, capital attraction and allocation decisions will be driven by the overall ROEs for transmission. Where those ROEs land, and how they compare to other returns available to utilities for investments in areas other than transmission, will be pivotal for future transmission development.

Notes: Basis point (or bp) is 1/100th of a percent. 100 bps, for example, is equal to 1%.

Sources: Emera Maine v. FERC, 854 F.3d 9 (D.C. Cir. 2017); "FERC Adopts New Base ROE Methodology, Addresses Complaints Against MISO," FERC News Release (Nov. 21, 2019); Wright & Talisman, "FERC's Opinion No. 569 Again Modifies Methodology for Setting Transmission Owners' Base Rate of Return on Equity" (Nov. 25, 2019); Jones Day, "FERC Opens a New Phase in Fights Over Utility Returns on Equity" (Dec. 2019); Troutman Sanders, "FERC Revises ROE Methodology, Applies New Approach in Complaints Against MISO TOs" *Washington Energy Report* (Nov. 26, 2019); FERC Notice of Inquiry Regarding the Commission's Policy for Determining Return on Equity, Docket No. PL19-4-000 (Mar. 21, 2019); FERC Notice of Proposed Rulemaking, Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, Docket No. RM20-10-000 (Mar. 20, 2020); "FERC Proposes Reforms to Electric Transmission Incentives Policy," FERC News Release (Mar. 19, 2020); Troutman Sanders, "Executive Summary of FERC's Notice of Proposed Rulemaking Regarding its Electric Transmission Incentive Policy Under Federal Power Act Section 219," *Washington Energy Report* (Mar. 23, 2020); RBC Capital Markets; Wolfe Research; ScottMadden analysis



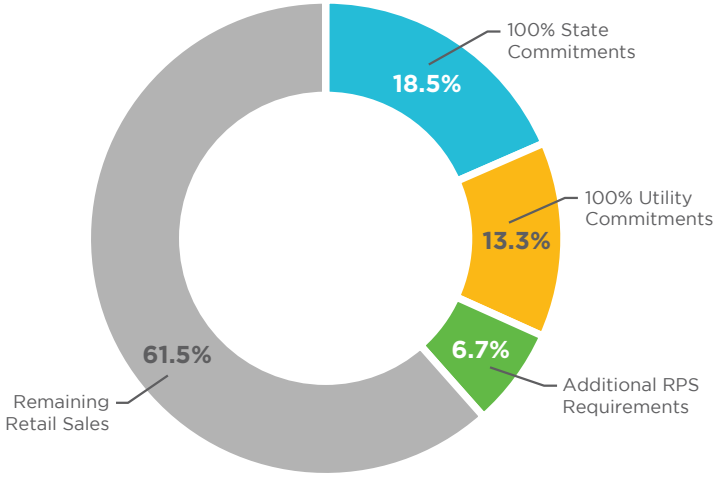
100% CLEAN ENERGY COMMITMENTS
THE ULTIMATE LONG-TERM GOAL

Stakeholders look beyond renewable portfolio standards.

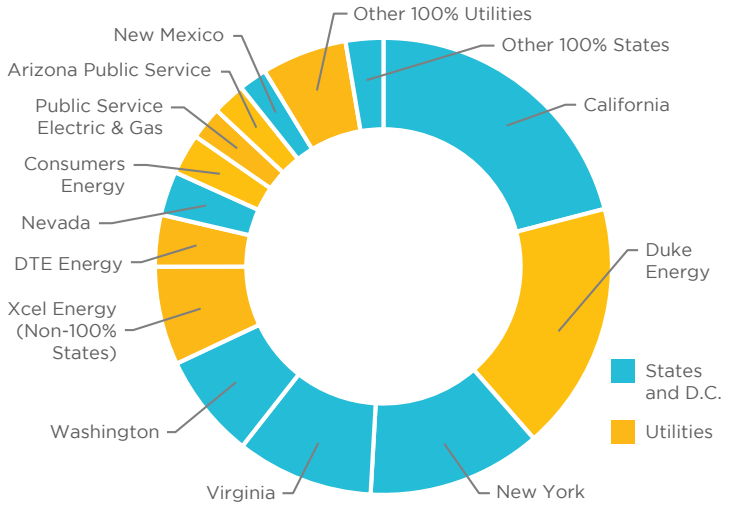
100% Clean Energy Commitments Become More Common

- Hawaii made waves in 2015 with the first 100% renewable energy portfolio goal. In the last year, a growing of number of states, utilities, and end users have staked a claim on a new and aggressive long-term target: 100% clean energy commitment. These clean energy commitments come from a wide variety of stakeholders:
  - Eight states (CA, HI, NV, NY, NM, ME, WA, and VA), the District of Columbia, and Puerto Rico have passed legislation enacting 100% clean energy commitments.
  - More than a dozen electric utilities have made 100% clean energy commitments, including large utilities such as Xcel Energy, Duke Energy, Arizona Public Service, DTE Energy, PSEG, Consumers Energy, and Dominion Energy.
  - An estimated 230 companies around the globe have committed to go "100% renewable" through the RE100 leadership initiative.
  - According to the Sierra Club, more than 175 cities and counties have enacted 100% clean energy commitments.
- Even more importantly, the commitments are starting to represent a significant portion of electric usage. The 100% clean commitments from states and electric utilities alone account for more than 30% of U.S. electricity sales (see charts on next page).
- Further, a review of where these commitments are occurring finds that they are not isolated to coastal geographies alone (see map on next page).

100% Clean Energy Commitments and RPS Requirements (as Percentage of 2018 Retail Electricity Sales)

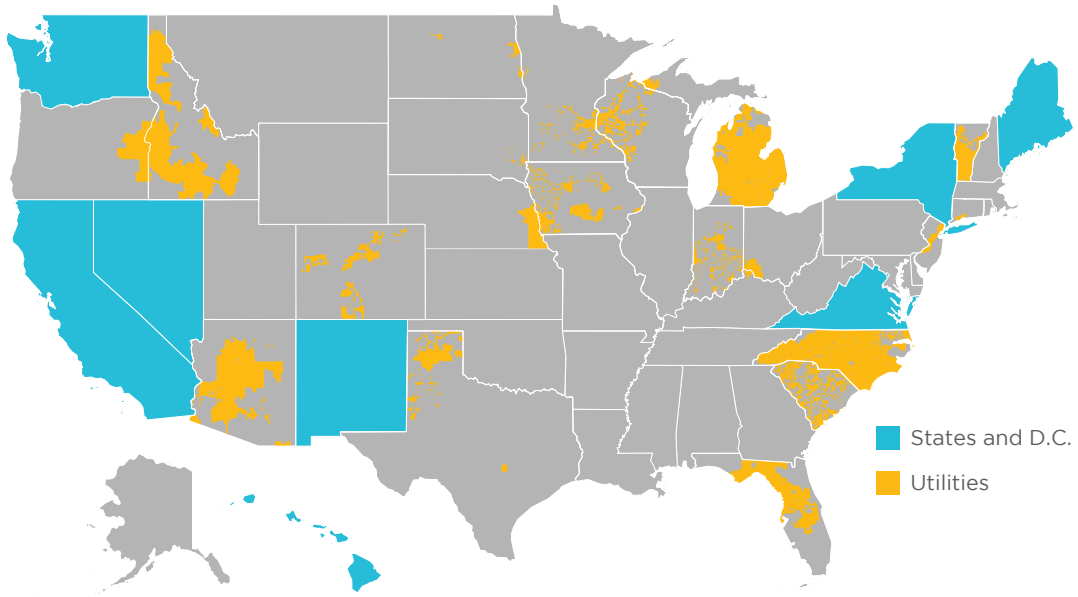


Comparison of 100% Clean Energy Commitments by State and Utility (Based on 2018 Retail Electricity Sales)



Sources: EIA; SEPA; Center for American Progress; Sierra Club; ScottMadden analysis

States and Electric Utility Service Territories with 100% Clean Energy Commitments



Sources: EIA; SEPA; Center for American Progress; Sierra Club; ScottMadden analysis; S&P Global

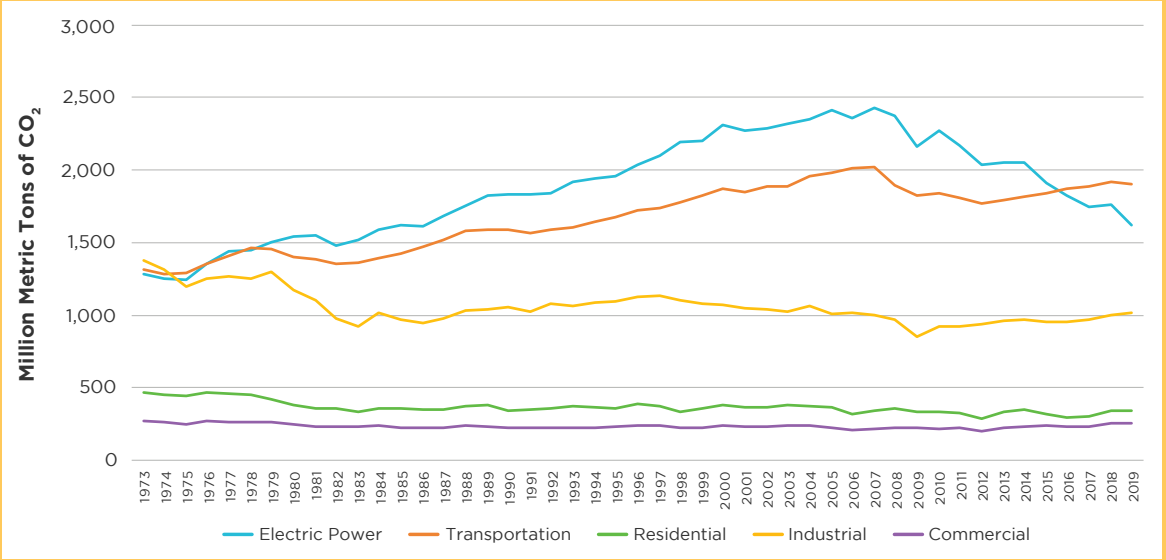
KEY TAKEAWAYS

- **Renewable generation is being pushed forward by 100% clean energy commitments from a variety of stakeholders.**
- **Current 100% clean energy commitments from state legislation and electric utility commitments represent more than 30% of U.S. retail electricity sales.**
- **Overcoming hidden barriers (e.g., system upgrade costs) and aligning utility interests could accelerate renewable deployment.**
- **Challenges will remain as the transition will require a balancing act between costs, technology selection, and compliance accounting.**

Electric Sector Drives Carbon Dioxide (CO_2) Emissions Decline in the United States

- CO_2 emissions from the electric power sector have been on a steady decline with the transition from coal to natural gas in power generation and emergence of renewable energy.
  - Since peaking in 2007, CO_2 emissions have declined 33%.
  - The 1,620 million metric tons of CO_2 released in 2019 are on par with emissions last seen in 1985.
- The decline in electric power sector emissions leaves the transportation sector as the largest source of CO_2 emissions in the United States.

Carbon Dioxide Emissions by Sector (1973–2019)



Source: EIA

A Common Objective, but a Variety of Approaches

- 100% clean energy commitments all share a common objective—remove CO_2 emissions from operations.
- However, the details and the nomenclature become important as stakeholders may rely on one of several approaches.

Approach	Common Resources	Observations
100% Renewable Energy	▪ Renewable resources	▪ The most challenging clean energy commitment to achieve due to the limited number of generation resources. ▪ This approach is adopted by a number of less populous states (Hawaii and Maine), the District of Columbia, and a territory (Puerto Rico).
100% Carbon-Free	▪ Renewable resources and nuclear energy	▪ Significantly reduces the need for renewables in states or utilities with existing nuclear generation (i.e., nuclear accounted for 30% of net generation in Virginia in 2019). ▪ These commitments provide strong rationale for renewing the licenses of existing nuclear facilities.
100% Net-Carbon Neutral	▪ Renewable resources, nuclear energy, carbon capture, and/or carbon offsets	▪ The most flexible approach due to the addition to carbon capture and offsets. ▪ A common approach for electric utilities that also note the importance of sustained investment in emerging technologies.

Addressing Hidden Barriers and Aligning Utility Interests Could Accelerate Renewable Energy Deployment

- Interconnections on the distribution system could quickly stall with expensive network upgrades required to mitigate grid impacts.
  - While FERC rules allow reduced cost burden on developers for system upgrade costs, interconnections on the distribution system most commonly rely on a "cost-causer pays" principle.
  - This principle assigns full cost responsibility to the first project or a group of projects that trigger the need for system upgrades.
  - This approach will hinder long-term growth of renewables, as projects may not be able to economically absorb large system upgrade costs.
  - New models for cost allocation may need to be developed, such as the post-upgrade reimbursement or pre-emptive utility upgrades.
- New approaches to renewable power purchase agreements (PPAs) could make scaling up renewable resources more attractive to electric utilities.
  - Most renewable energy is procured by electric utilities through a PPA.
  - Contract costs are recovered from customers but are not part of the rate base that forms the foundation of utility earnings.
  - In June 2019, Michigan Public Service Commission approved a financial compensation mechanism for PPAs signed by Consumers Energy, thereby removing any disincentive to arrange supplies from third parties.
- The U.S. Internal Revenue Service recently issued a private letter ruling that mitigates the adverse impact of tax normalization rules on tax equity structures involving regulated utilities.
  - A historical challenge to utility development of renewable resources was the application of tax normalization rules that would not allow a regulated utility to take full advantage of accelerated depreciation and tax credits.
  - A recent private letter ruling from the IRS may make ownership by a regulated utility more economically attractive for electric customers.
  - The letter from November 2019 will allow a tax equity investor and regulated utility to participate in a tax equity financing arrangement for a wind project without being subject to tax normalization rules.

Achieving Balance along the 100% Path Will Require Difficult Decisions

- Designing a 100% clean energy portfolio will require careful planning and assumptions on the cost and availability of new and emerging technologies. Unless mandated by state law, the costs for new or emerging technologies, especially in later years, are likely to receive close regulatory scrutiny.
- The need to scale rapidly—and concerns about cost—may push electric utilities to aggressively pursue utility-scale resources rather than distributed renewables.
- The use of renewable energy certificates (RECs) or carbon offsets will mean load is not being matched to clean energy generation in real time. It is unclear whether and how RECs and offsets factor into the compliance toolkit, depending upon the finer points of the targets being set by states and companies.
- The impact of these standards on system operations complexity over the long term has yet to be determined, particularly for 100% renewables approaches, as intermittent resources gain higher penetration.
- Finally, the COVID-19 pandemic will adversely impact state and local budgets and may result in short-term headwinds as public policy priorities focus on public health and economic recovery.

IMPLICATIONS

The renewable energy industry must scale rapidly to meet the growing list of 100% clean energy commitments. Implementation and generation portfolio vary, depending on the type of commitment (i.e., 100% renewable vs. 100% net-carbon neutral). Regulatory reforms related to system upgrade costs, recovery on third-party PPAs, and tax normalization rules could facilitate renewable energy development. However, electric utilities and regulators will need to carefully consider generation technologies, balance costs, and consider timing as they undertake this multidecade journey.

Sources:

EIA; Smart Electric Power Alliance; Center for American Progress; Sierra Club; McDermott, Will, & Emery; Internal Revenue Service Letter Ruling 201946007; company websites; PUC websites; ScottMadden analysis

ALOHA FROM HAWAII
UPDATING POSTCARDS FROM THE FUTURE

Fact-finding mission reveals importance of planning, stakeholder engagement, and a willingness to learn.

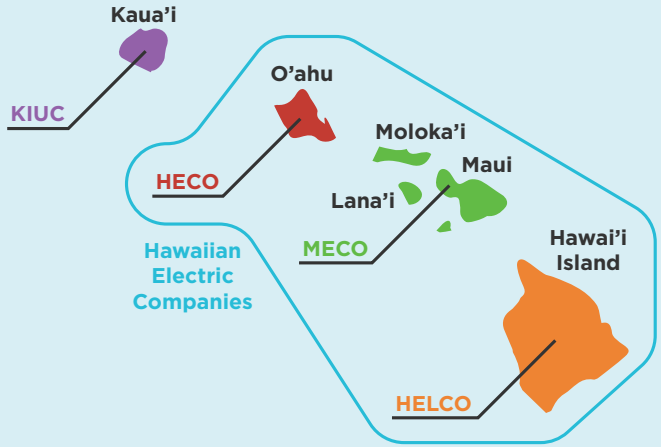
SEPA and ScottMadden Comb the Beach for Lessons Learned

- With the rapid expansion of distributed solar, Hawaii became known as the "postcard from the future" for other utilities seeing a similar trend and for states pursuing clean energy goals.
- Hawaii's position as a renewable energy leader expanded when it was the first U.S. state to enact a 100% renewable energy portfolio standard (RPS) in 2015.
- In November 2019, utility executives from the continental United States traveled to Hawaii to gain a first-hand understanding of how the state remains on the forefront of an industry preparing to transition to higher renewable penetrations.
- The Smart Electric Power Alliance (SEPA) and ScottMadden confirmed that bold visions require new paradigms.
- In addition, the group identified three key learnings, described on the following pages, that are applicable to electric utilities operating on the mainland.

The First Postcard from the Future

- SEPA and ScottMadden first visited Hawaii with utility executives in September 2015.
- With the rapid growth of distributed solar, Hawaii's electric system was being stretched beyond what engineering experts initially thought possible.
- In response, Hawaii was beginning to analyze "hosting capacity" of individual circuits and the use of smart inverters, load management, and storage.
- One key finding of this initial fact-finding mission was that when a utility emphasizes limited system capabilities, it risks losing credibility with customers and regulators when high renewable penetration becomes a reality and those initial issues are quite easily overcome.
- Instead, utilities are better served by delivering a "yes, with…" approach, which allows them to clarify customer and regulatory goals and better explain what would be needed to achieve these goals.
- Throughout the most recent trip, it was clear that utilities in Hawaii have embraced and are now expanding on this early set of lessons learned.

Hawaii's Islands and Electric Utilities



The primary electric utilities servicing the state's power needs are Hawaiian Electric Industries Inc. (HEI) and Kauai Island Utility Cooperative (KIUC). HEI operates three electric utilities, collectively called Hawaiian Electric Companies:

- Hawaiian Electric Company, Inc. (HECO)
- Maui Electric Company, Limited (MECO)
- Hawaii Electric Light Company, Inc. (HELCO)

KEY TAKEAWAYS

- **Hawaii is a postcard from the future because of its high penetration of distributed PV and 100% RPS by 2045.**
- **Electric utilities in Hawaii are focused on the journey by laying a strong foundation for the future with thoughtful planning and technology adoption.**
- **Using stakeholder connections to solve tangible community problems will be critical as utilities work to meet aggressive renewable goals.**
- **The transition to high-renewable penetrations will require relearning how to best operate both the electric grid and renewable energy resources.**

Key Lesson #1: Understand the Path, Not Just the Goal

- Hawaii grabbed headlines as the first state to set a 100% RPS by 2045. The fact-finding mission found electric utilities in Hawaii laying a strong foundation for the future with specific, intentional planning and technology adoption.
- The Hawaiian Electric Companies are building a path by aligning long-term planning and near-term actions.
  - The most recent power supply improvement plan assumes all single-family residential homes and 20% to 25% of commercial customers will offset their energy consumption with distributed solar by 2045.
  - However, even with this deployment of distributed generation, the island of Oahu, which includes Honolulu, does not have enough rooftop and other land-based renewable resources to meet its 100% RPS targets.
  - Consequently, long-term RPS compliance on Oahu will require offshore renewable resources or underwater transmission to connect to a neighboring island.
  - In the near-term, distributed generation policies have focused on transitioning from traditional net metering to programs that allow midday curtailment or pay a premium for delivery of excess energy during peak hours.
  - These efforts meet the needs of current customers and the electric grid, but they also serve as the cornerstones to future actions.
- Kauai Island Utility Cooperative (KIUC) developed first-hand storage experience with incremental additions of battery energy storage technologies.
  - The company's first foray into battery storage involved a lead acid battery system that quickly degraded due to cycling demands.
  - More recent solar plus storage systems relying on lithium ion technologies are performing better, offering reliable capacity during evening peak hours.

Aerial view of Oceanfront homes on the north shore of Oahu, Hawaii

> **"Understanding the journey is just as important as hitting the goal."**
>
> - Hawaii utility representative

Key Lesson #2: Drive Stakeholder Connections

- The fact-finding mission discovered stakeholder connections being used to solve tangible community problems. These connections will be vital to building and refining the path toward meeting the 100% RPS requirement.
- In one innovative approach, Hawaiian Electric Companies hosted potlucks to discuss resilience expectations and enhancement opportunities.
  - A hurricane could challenge reliability in the eastern portion of Oahu since the region lacks firm generation and is served by a single transmission substation.
  - Despite that reliability risk, the local community strongly opposes the addition of new generation.
  - The utility has hosted a series of potlucks to discuss reliability expectations and alternative approaches.
  - The process has resulted in high levels of engagement-producing mutual respect and enhanced trust.
  - The events also produced new ideas to enhance reliability, including critical service hubs or buildings designed to operate independently from the grid using mobile emergency generators.
- For KIUC, open and transparent communications were critical during a recent island-wide outage.
  - In July 2019, KIUC implemented rolling blackouts following an island-wide outage.
  - The situation was caused by a sustained fault at the largest generator on the island, but it was exacerbated by other fossil generators being offline for maintenance and cloudy weather limiting solar production.
  - During the rolling blackouts, KIUC maintained transparency with customers by using Facebook and radio announcements to provide updates and encourage energy conservation.
  - Customer complaints during the incident were minimal despite the inconvenience.

Trend to Watch: KIUC Pushes the Envelope with 100% Renewable Energy

- KIUC achieved an impressive 56% renewable energy production for 2019. KIUC's power generation mix for 2019 included 35% solar, 11% hydro, and 10% biomass. Rooftop solar from residential and commercial members accounted for more than one-third of the solar generation.
- The achievement exceeds state RPS requirements to achieve 30% renewable by 2020 and 40% renewable by 2030; it also exceeds KIUC's own strategic goal to reach 50% by 2023.
- Even more impressive, KIUC has started operating for extended periods of time at 100% renewable energy. Since 2017, KIUC has routinely achieved 90% or more renewable generation during midday on sunny days. Beginning in November 2019, the utility started operating at 100% renewable energy for extended periods of several hours.
- The jump to 100% renewable energy was made possible with two utility-scale solar facilities that can simultaneously feed power to the grid and to on-site batteries for storage and use after sunset, as well as a gas turbine retrofitted to run in synchronous condenser mode in order to provide inertia, fault current, voltage support, and frequency stabilization to the grid without burning fuel.
- KIUC's generation portfolio also includes one biomass plant and a number of small hydro generation facilities.
- The prevalence of 100% renewable energy continues into 2020. In late April, KIUC reported it is routinely running the grid on 100% renewable energy during daytime hours. This included 441 hours at 100% renewable energy, averaging five hours per day for about 90 days since January 1, 2020.

Key Lesson #3: Prepare to Relearn How to Operate the Grid

- The electric utilities in Hawaii consistently find themselves on the bleeding edge. This has not only required a "yes, with…" mindset, but also a total rethinking of how best to operate both the electric grid and renewable energy resources.
- The Hawaiian Electric Companies have deployed a new and innovative power purchase agreement (PPA) to dispatch renewable energy.
  - In February 2018, the Hawaiian Electric Companies launched a request for proposals using a renewable dispatchable generation (RDG) PPA.
  - The RDG PPA was new and innovative because it allowed bidders to receive two potential payments:
    - *Price for Purchase of Electric Energy ($/MWh)* was designed to cover variable operations and maintenance costs.
    - *Lump Sum Payment ($/month)* was designed to cover the fixed costs of the project.
  - The RDG PPA also allows the utility to dispatch the renewable system's energy production—even if the dispatch order falls below potential output available.
  - In March 2019, six solar-plus-storage PPAs approved by the Hawaii PUC relied solely on lump sum payments and did not include any purchases of electric energy payments.
  - Contract terms allow lump sum payments to be reduced if renewable energy systems do not meet minimum performance and availability metrics.
- KIUC uses high-speed data recorders to gain deep insights after island-wide outages.
  - KIUC has deployed high-speed data recorders on its electric system in order to capture detailed system data.
  - The recorders have allowed the utility to better manage frequency and voltage fluctuations by updating renewable energy and battery storage invertor settings, thereby resulting in reduced reliance on load-shedding.

Bold Visions Require New Paradigms

- Since 2015, Hawaii's goal of 100% RPS has spurred new planning and operating paradigms.
- Even though Hawaii remains early in the transition process, it is clearly laying the groundwork for a long-term transition to a renewable energy future.
- By offering new and innovative technologies and services, the electric utilities are transforming their role from a commodity supplier to a community-engaged service provider.
- The growing number of 100% clean energy commitments on the mainland will require utilities to enhance long-term planning, customer engagement, and grid operations.
- Even in regions without these ambitious targets, growing penetrations of renewable energy will require new approaches.
- Throughout the transition, Hawaii will remain a postcard from the future and of interest to those seeking inspiration and innovation.

IMPLICATIONS

The electric utilities in Hawaii became the postcard from the future with the rapid expansion of distributed PV. Today, Hawaiian Electric Companies and KIUC continue to thrive and adapt as distributed and utility-scale renewable generation keep the islands on the bleeding edge. The state will remain a rich source of innovation and inspiration for mainland utilities undertaking similar journeys.

Sources: S. Allan & J. Pang, "Lessons Learned from Hawaii: Bold Visions Require New Paradigms," in *Public Utilities Fortnightly* (Apr. 2020)

For more detail on the broad steps being taken in Hawaii, see "Hawaii Testbed: Bold Visions Requires New Paradigms" in the Fall 2019 ScottMadden Energy Industry Update, themed "Everything Counts…in Large Amounts." (available at www.scottmadden.com/insight/the-energy-industry-update-volume-19-issue-2/)

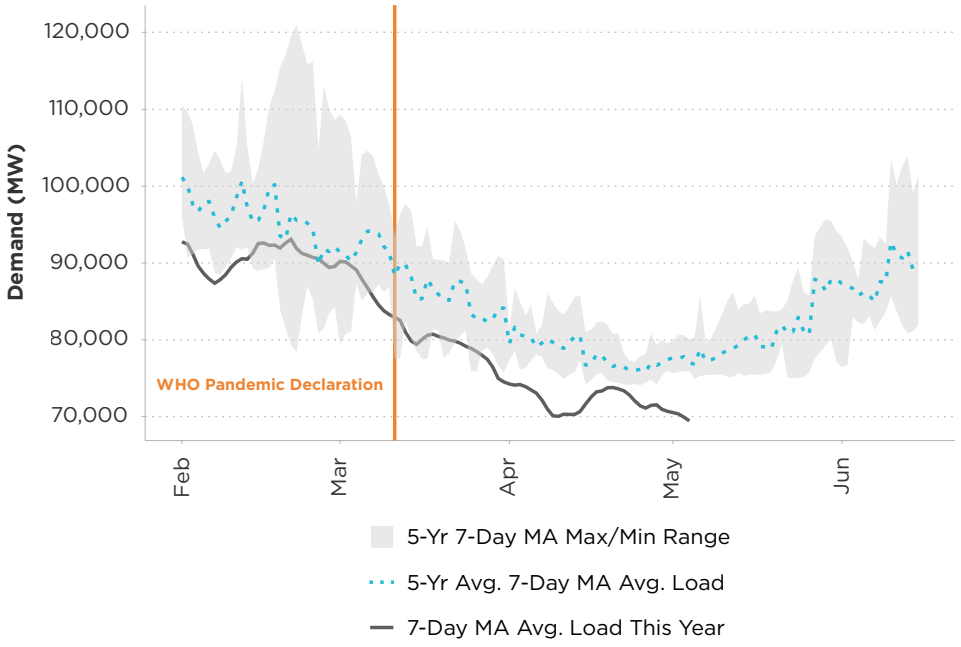
THE ENERGY INDUSTRY IN CHARTS

COVID-19 and Electricity Supply and Demand

- Shelter-in-place orders across the United States have had distinct impacts on energy demand in many regions, even after normalizing for weather.
- New York's ISO, for example, estimated weekly weather adjusted energy use for the state to be approximately 8% lower than expected.
- Generation to meet that reduced load has also experienced some adjustments, as lower demand has been served by an increasing proportion of renewables, and thermal (gas, oil, and coal) generation sources have been swing resources.
- We examined a few power markets to gather some insight into the supply and demand dynamics of this unusual phenomenon.

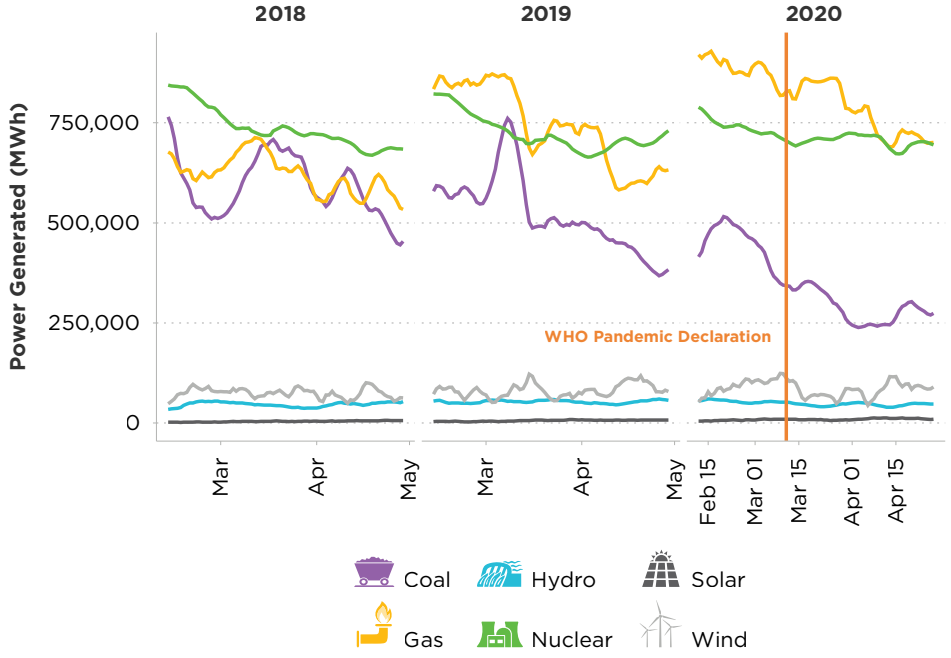
Comparison of Electricity Demand and Supply for Selected Regions (February to Early May)

PJM 7-Day Moving Average of Average Daily Load vs. Past 5-Year Average, Minimum, and Maximum (Feb. 1 to May 4)



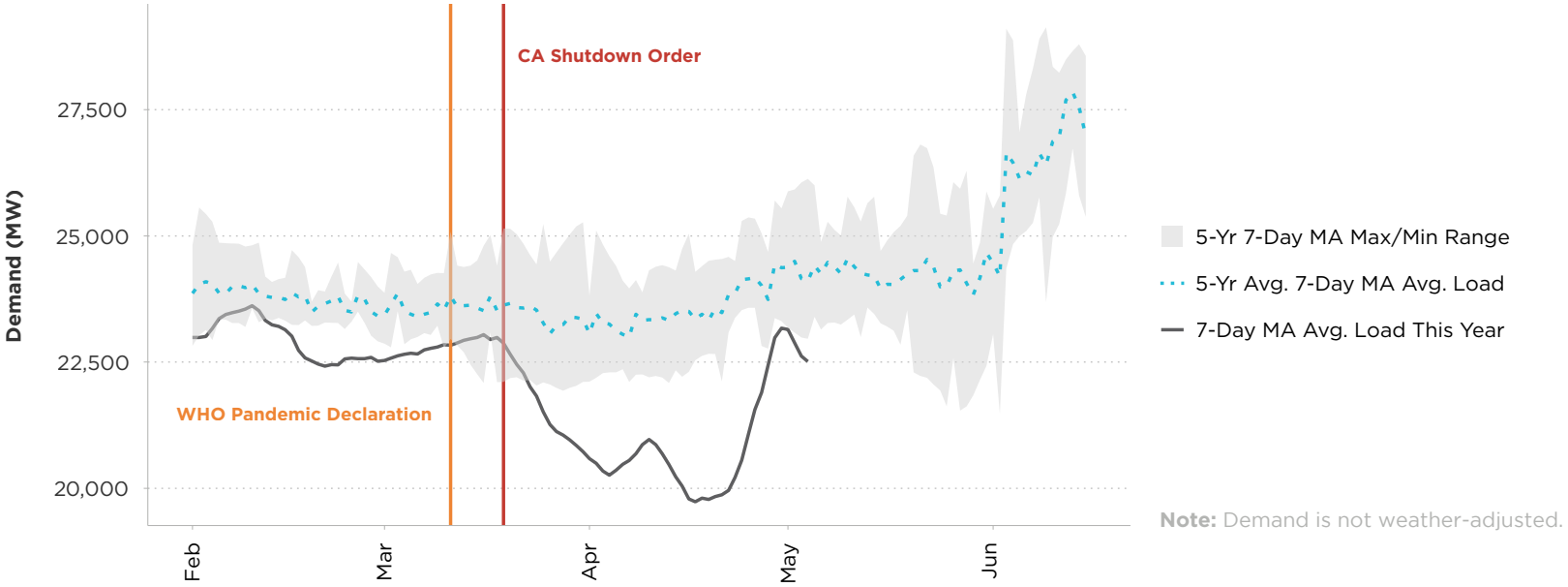
Note: Demand is not weather-adjusted.

PJM 7-Day Moving Average of Total Generation by Fuel Type (Feb. 12 to Apr. 27)



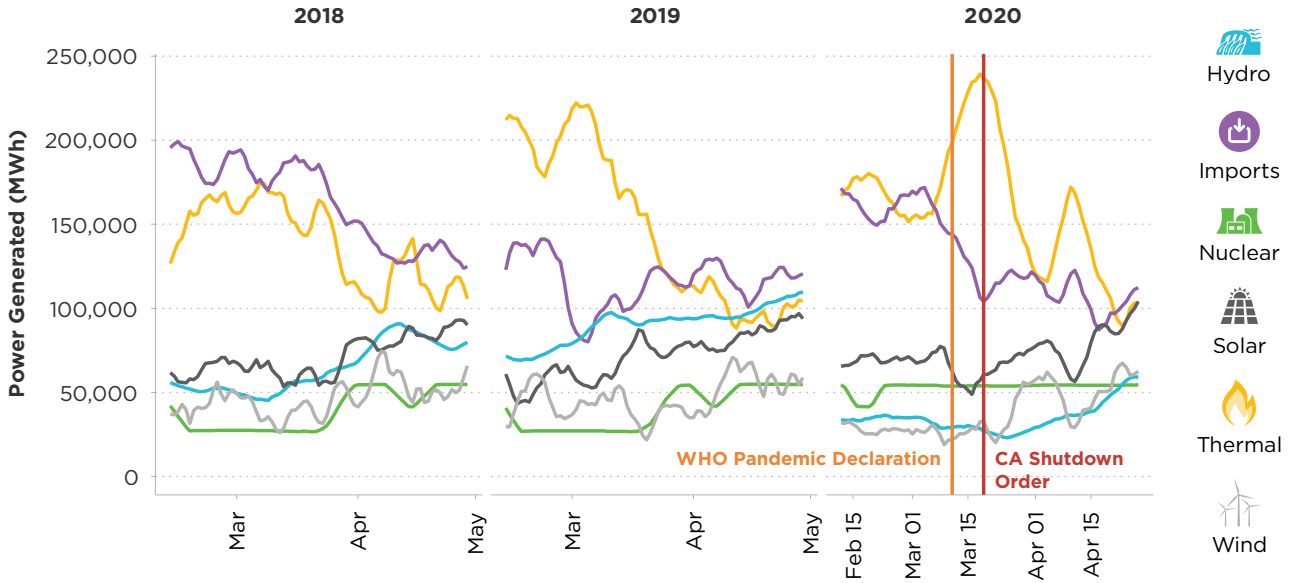
Comparison of Electricity Demand and Supply for Selected Regions (Cont'd)

California ISO 7-Day Moving Average of Average Daily Load vs. Past 5-Year Average, Minimum, and Maximum (Feb. 1 to May 4)



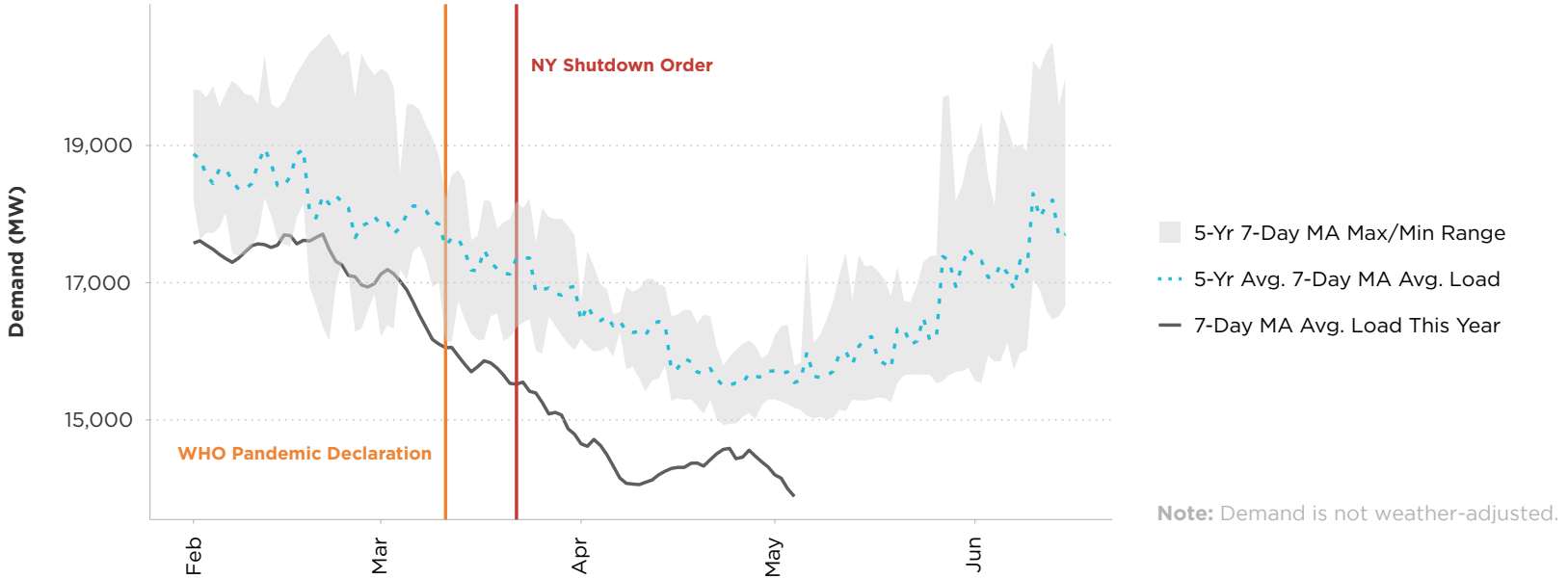
Note: Demand is not weather-adjusted.

California ISO 7-Day Moving Average of Total Generation by Fuel Type (Feb. 12 to Apr. 27)



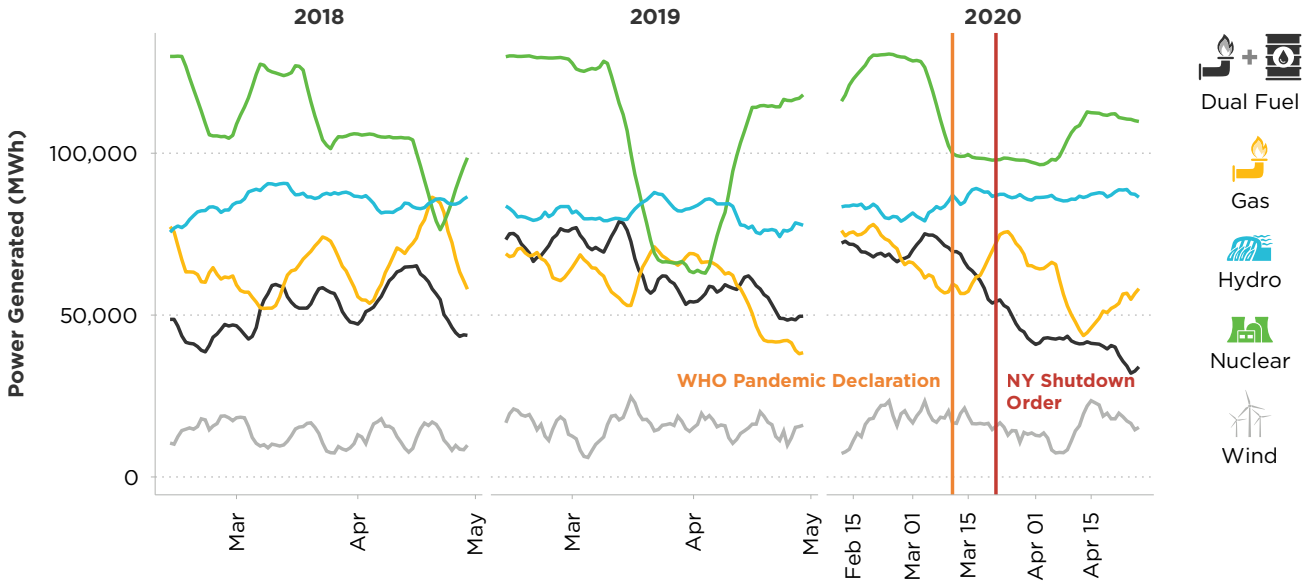
Comparison of Electricity Demand and Supply for Selected Regions (Cont'd)

New York ISO 7-Day Moving Average of Average Load vs. Past 5-Year Average, Minimum, and Maximum (Feb. 1 to May 4)



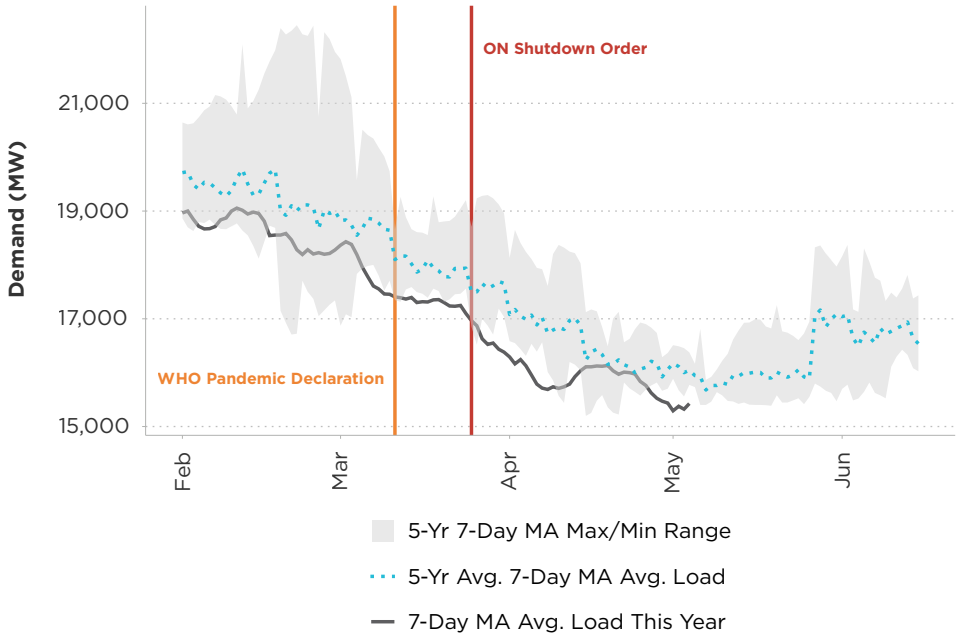
Note: Demand is not weather-adjusted.

New York ISO 7-Day Moving Average of Total Generation by Fuel Type (Feb. 12 to Apr. 27)



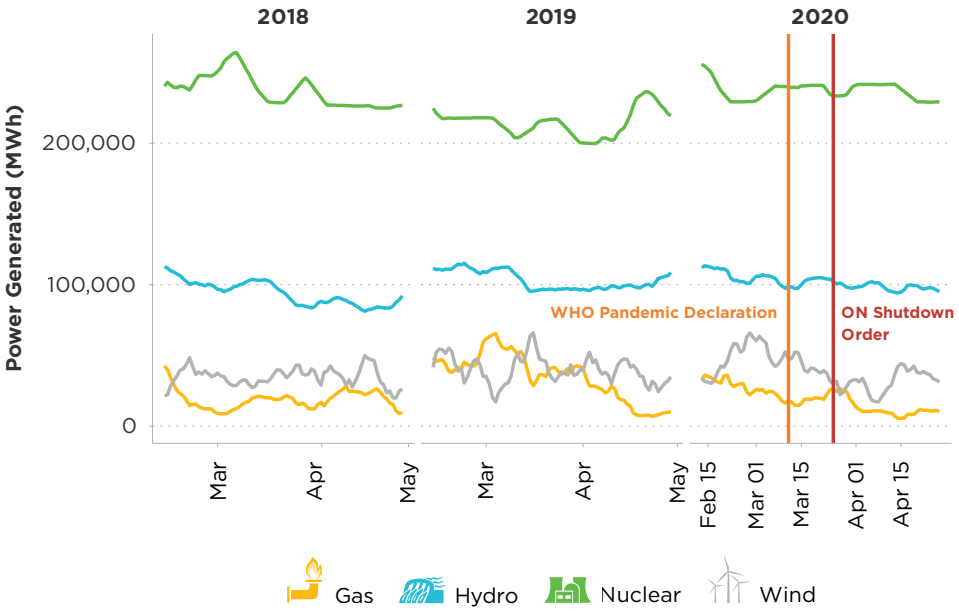
Comparison of Electricity Demand and Supply for Selected Regions (Cont'd)

IESO* 7-Day Moving Average of Average Load vs. Past 5-Year Average, Min, and Max (Feb. 1 to May 4)



Note: Demand is not weather-adjusted.

IESO* 7-Day Moving Average of Total Generation by Fuel Type (Feb. 12 to Apr. 27)



The Global View

"Lockdown measures have significantly reduced electricity demand, affecting in turn the power mix. Increases in residential demand were far outweighed by reductions in commercial and industrial operations.

Daily data collected for more than 30 countries, representing over one-third of global electricity demand, show that the extent of demand declines depends on the duration and stringency of lockdowns.

We find that every month of full lockdown reduced demand by 20% on average, or over 1.5% on an annual basis."

—International Energy Agency (Apr. 30, 2020)

Notes: *IESO means the Independent Electricity System Operator of Ontario.

MA means moving average. Demand figures are not weather-adjusted. Generation analysis omits sources that contribute less than 5% to total generation. Thermal can include gas, oil, coal, or other thermal combustion technology. Dual fuel is typically gas with oil backup. Periodic updates on evolving demand patterns are available at www.scottmadden.com/insight/coronavirus-outbreak-impact-on-electricity-demand/.

Sources: ISO data; International Energy Agency, Global Energy Review 2020 (Apr. 30, 2020); New York ISO Demand Forecasting & Analysis Team, Estimated Impacts of COVID-19 on NYISO Demand: Analysis Through 4/25/2020 (Apr. 28, 2020); ScottMadden analysis

GLOSSARY

Bcf
billion cubic feet

Bcf/d
billion cubic feet per day

bp
basis point

CNG
compressed natural gas

CO_2
carbon dioxide

DOE
U.S. Department of Energy

EIA
U.S. Energy Information Administration

FERC
Federal Energy Regulatory Commission

IRP
integrated resource plan

ISO
independent system operator

kWh
kilowatt-hour

MA
moving average

Mcf
thousand cubic feet

MISO
Midcontinent ISO

MMBtu
million British thermal units

$MtCO_2$
million metric tons CO_2

MW
megawatt

MWh
megawatt-hour

N-2
the simultaneous loss of two elements of the bulk power system, analyzed as contingencies in determining system reliability

NERC
North American Electric Reliability Corporation, a not-for-profit corporation that is the Electric Reliability Organization for North America

NOPR
notice of proposed rulemaking

PJM
PJM Interconnection, LLC, an RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia

PPA
power purchase agreement

PSC
public service commission

PUC
public utilities commission

PV
photovoltaic

RNG
renewable natural gas

ROE
return on equity

RPS
renewable portfolio standard

RTO
regional transmission organization

transco
a stand-alone transmission company that has been approved by FERC and that sells transmission service at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility

RECENT INSIGHTS
AVAILABLE AT SCOTTMADDEN.COM

ScottMadden posts energy and utility industry-relevant content and publications on a regular basis. The list below is a sample of recent insights prepared by our consultants.

Energy Markets	▪ FERC Announced Notice of Proposed Rulemaking
Generation	▪ Coronavirus Outbreak: Impact on Electricity Demand ▪ COVID-19: What Could it Mean for Renewable and Grid Edge Technologies? ▪ Lessons Learned from Hawaii: Bold Visions Require New Paradigms
Grid Edge	▪ Energy Efficiency and COVID-19: Implications and Considerations ▪ The Electricity Business of the Future
Rates & Regulation	▪ COVID-19 Response – What You Should be Thinking About: Regulatory Strategy and Cost Recovery ▪ Decoupling Impact and Public Utility Conservation Investment
Strategy & Services	▪ Utilities and COVID-19: Some Early Lessons
Transmission & Distribution	▪ Informing the Transmission Discussion

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ENERGY PRACTICE
SCOTTMADDEN KNOWS ENERGY

About ScottMadden

We know energy from the ground up. Since 1983, we have served as energy consultants for hundreds of utilities, large and small, including all of the top 20. We focus on Transmission & Distribution, the Grid Edge, Generation, Energy Markets, Rates & Regulation, Enterprise Sustainability, and Corporate Services. Our broad, deep utility expertise is not theoretical—it is experience based. We have helped our clients develop and implement strategies, improve critical operations, reorganize departments and entire companies, and implement myriad initiatives.

Stay Connected

ScottMadden will host a free webcast based on this report on **Thursday, June 18 from 1-2PM EST** to further explore issues affecting the future of the gas utility, 100% clean energy goals and how they may be impacted by COVID-19, and regulatory strategy during a pandemic. We look forward to sharing our views and fielding questions related to these issues. If you are unable to attend the live event or would like to replay the session at a later date, the on-demand recording can also be accessed.

Contact Us

Brad Kitchens
President and CEO
sbkitchens@scottmadden.com
919-781-4191

Cristin Lyons
Partner
Energy Practice Leader
cmlyons@scottmadden.com
919-781-4191

Bob Hevert
Partner
Rates, Regulation, & Planning Practice Leader
bhevert@scottmadden.com
508-202-7918

Greg Litra
Partner
Director of Research
glitra@scottmadden.com
919-781-4191