ELECTRICITY REGULATION

USA

LEXOLOGY
Getting The Deal Through

Consulting editor
Milbank LLP

Electricity Regulation

Consulting editors

John Dewar

Milbank LLP

Quick reference guide enabling side-by-side comparison of insights into the local legal framework; regulation of power generation, grid connection, and alternative energy sources; climate change policy; energy storage; nuclear power; transmission and distribution; sale of power, including retail and wholesale pricing and public service obligations; regulatory authorities; competition regulation including merger control; cross-border considerations including mergers and acquisitions and interconnection regulations; transactions between affiliates; and recent trends.

Generated 14 February 2023

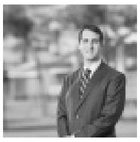
Table of contents

Contributors

USA

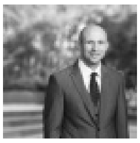
Daniel A. Hagan
dhagan@whitecase.com
White & Case

Serena Rwejuna
serena.rwejuna@whitecase.com
White & Case



John N Forbush
john.forbush@whitecase.com
White & Case

Aaron Bryant
aaron.bryant@whitecase.com
White & Case



Michael Rodgers
michael.rodgers@whitecase.com
White & Case

LEGAL FRAMEWORK

Policy and law

What is the government policy and legislative framework for the electricity sector?

No single government body sets government policy for the electricity sector. The federal government, which regulates wholesale markets, follows a generally pro-competitive policy. The competition reforms that transformed the US electricity sector represent the latest chapter in three decades of restructuring, deregulation and regulatory reforms that affected utility sectors of the economy historically subject to price regulation. Retail sales are regulated by the states. Several states have adopted choice programmes intended to introduce competition among retail suppliers of electricity. While some states have delayed or suspended retail choice plans amid concerns that deregulation may not benefit end consumers, retail choice is thriving in other states, such as New York.

US Congress

The Energy Policy Act of 2005 (EPAct 2005) represented the most significant change in US energy policy since the Federal Power Act of 1935 (FPA) and the Natural Gas Act of 1938 (NGA). EPAct 2005 granted the Federal Energy Regulatory Commission (FERC) the authority to issue rules to:

- prevent market manipulation in wholesale power and gas markets, and in electric transmission and gas transportation services;
- assess enhanced civil penalties for violations of the FPA and other energy statutes;
- oversee mandatory reliability standards governing the nation’s electricity grid; and
- approve the siting of transmission facilities, traditionally a matter of state or local jurisdiction, under certain limited circumstances.

Federal administrative agencies

Federal administrative agencies are tasked with implementing energy legislation passed by the US Congress. The mission of the US Department of Energy (DOE) is to ‘ensure America’s security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions’. FERC, an independent regulatory agency within the DOE, is the principal economic and policy regulator at the federal level for the electric power industry. FERC is charged with implementing, administering and enforcing most of the provisions of EPAct 2005, FPA, NGA and other statutes regulating the electric utility industry.

States

Beginning in the 1990s, a number of states undertook measures to require or encourage vertically integrated utilities to disaggregate into separate generation, transmission or distribution entities. Also, participation in independent system operators (ISOs) or regional transmission organisations (RTOs) was encouraged at the federal level and in some states. The American Public Power Association’s (APPA) most current data indicates that 16 states and the District of Columbia have active retail choice programmes in the electric sector.

Law stated - 27 January 2023

Organisation of the market

What is the organisational structure for the generation, transmission, distribution and sale of power? How is this reflected in the regulatory structure?

According to the APPA, the US electric industry is composed of 3,397 electricity providers, including 2,006 publicly owned utilities, 873 cooperatives, 182 investor-owned utilities, 303 power marketers and 10 federal utilities. Together, those utilities combine to serve over 152 million customers, with investor-owned utilities serving the largest share at approximately 68 per cent of the total customers, while publicly owned utilities serve approximately 14 per cent.

The private sector includes traditional utilities that are vertically integrated, generation-owning companies and power marketers, and transmission or distribution 'wires-only' companies. These companies may be privately owned or publicly traded. The public sector includes municipally owned utilities, public power districts, state agencies, irrigation districts and other government organisations, and at the federal level, the Tennessee Valley Authority and federal power marketing administrations. Rural electric cooperatives , formed by residents, operate in 47 states and comprise about 13 per cent of total US kilowatt-hour (kWh) sales and revenue.

Generation

According to the Energy Information Administration's (EIA) (part of DOE) most recent statistics , net generation of electric power increased slightly in 2022, to 4,108,303 kWh, as compared to 4,009,767 kWh in 2021.

kWhThe primary energy sources for generating electric power in the United States are fossil fuels such as natural gas and coal, with limited use of oil. Fossil fuels accounted for approximately 62.7 per cent of energy consumption in the United States in 2019. The predominant fuel source remains natural gas (supplanting coal within the past few years), accounting for 38.4 per cent of total net generation in 2019. Domestic production of crude oil and natural gas has been facilitated by ongoing improvements in extraction technologies and resultant low prices. Crude oil production has increased sharply since 2008. In 2022, the US produced 11.9 million barrels per day, an increase from 11.3 million barrels per day produced in 2021. Based on current production levels, the US is projected to average 12.4 million barrels per day in 2023, largely attributable to a rebound in capital investment in the conventional energy sector and increased emphasis on domestic drilling amid geopolitical tensions. Development of natural gas resources has also steadily grown to 35.69 thousand cubic feet in 2021, with a predicted 23.8 per cent increase in production between 2021 and 2050. Generation from renewable energy sources including hydroelectric continues to rise, accounting for over 19.8 per cent of total US net generation in 2021. In fact, both utility-scale solar and wind achieved record shares of the domestic generation pool.

EIA has predicted that total US electricity consumption will increase at an average annual rate of 0.9 per cent in the next two decades, but that energy intensity (measured as energy use per person and per dollar of GDP) will actually decline. This forecast is based on the assumption that the US population will increase by 0.9 per cent per year and the GDP will increase at an average annual rate of 2.5 per cent per year. The projected decline in energy use per capita reflects anticipated gains in energy efficiency of appliances and vehicles, an economic shift away from energy-intensive manufacturing, and the retirement of less efficient generators.

Power sales

Power marketers do not generate, transmit or distribute electricity, but are classified as public utilities under the FPA because they sell electricity at wholesale. In addition to the numerous privately owned power marketers, there are four federally owned power marketing administrations that market and sell the power produced at federal hydroelectric and nuclear plants. The APPA EIA reported in June 2018 that sales of energy to ultimate consumers by power marketers equal 21 per cent of total sales, representing a 10 per cent increase from 2005.

Transmission

The US bulk power transmission system is composed of facilities that are privately, publicly, federally or cooperatively owned that form all or parts of three electric networks (power grids): the Eastern Interconnection that stretches from central Canada to the Atlantic coast (excluding Quebec), south to Florida and west to the Rockies (excluding much of Texas); the Western Interconnection that stretches from western Canada south to Mexico and east over the Rockies to the Great Plains; and the Electric Reliability Council of Texas (ERCOT) that serves a large portion of Texas.

Historically, transmission lines owned by private-sector companies were part of a vertically integrated utility.

FERC has encouraged the development of ISOs and RTOs as independent transmission providers within a region. These entities are formed by utilities that transfer operational control – but not ownership – of their transmission assets to the ISO or RTO, which is then responsible for operating the regional transmission grid and administering wholesale markets. Today, two-thirds of electricity consumers in the US are served within markets administered by seven ISOs or RTOs: the PJM Interconnection, the Midcontinent ISO, the Southwest Power Pool, the New York ISO, ISO New England, ERCOT and the California ISO. In addition, on 1 November 2014, the California ISO and PacifiCorp launched the Energy Imbalance Market (EIM), which is a real-time energy balancing authority with the overall goal of dispatching least-cost energy on a real-time basis across the EIM market. The California ISO EIM continues to expand, as Las Vegas-based NV Energy began participating in October 2015, utilities in Washington and Arizona recently began participating in October 2016, and Idaho Power began participating in the EIM market in April 2018. Moreover, several other Western utilities have expressed interest in joining the EIM, including those located in Washington and Arizona. Further, the Los Angeles Department of Water and Power – the largest municipal utility in the United States, serving approximately four million customers – joined the EIM in April 2019.

One of the responsibilities of ISOs and RTOs, as well as other transmission providers, is to maintain the operation of the grid. Pursuant to EPAct 2005, FERC certified the North American Electric Reliability Corporation as the nation's Electric Reliability Organisation (ERO) to develop and enforce mandatory reliability requirements to address medium- and long-term reliability concerns, subject to FERC oversight and enforcement. Today, enforcement of electric reliability standards, including the protection of critical energy infrastructure, is a major focus of the ERO and of FERC, which may impose penalties of up to US$1 million a day on transmission or generation owners and operators and certain other regulated entities for a violation of mandatory reliability standards.

Law stated - 27 January 2023

REGULATION OF ELECTRICITY UTILITIES – POWER GENERATION

Authorisation to construct and operate generation facilities

What authorisations are required to construct and operate generation facilities?

The siting and construction of electric generation, transmission and distribution facilities has historically been a state and local process, although the Energy Policy Act (EPAct 2005) altered this traditional arrangement by vesting limited transmission siting authority with the Federal Energy Regulatory Commission (FERC) in certain cases. In making siting decisions, state public utility commissions (PUCs) consider environmental, public health and economic factors. The PUCs exercise their authority in conjunction with state environmental agencies or local zoning boards. A few states have a siting board or commission that provides a single forum where an electric utility or independent developer can obtain all necessary authorisations to construct electric facilities. Other states have not consolidated the siting process, and electric utilities or independent developers in those states are required to obtain the necessary permits separately from each of the relevant state and local agencies. State and local permits required for the construction of electric generation facilities include air permits and water use or discharge permits from the state environmental commission, and zoning and building permits from local commissions.

Regulated utilities are required to obtain a certificate of public convenience and necessity from the relevant PUC for the construction of generation, transmission and distribution facilities that will be subject to cost-base rate regulation. Except in limited circumstances where the relevant state commission refuses to act on an application for a year, or does not have jurisdiction to act (as in the case of certain federally designated National Transmission Corridors), no federal certificate of public convenience or necessity is available from FERC for the siting and construction of electric generation, transmission or distribution facilities under Part II of the Federal Power Act of 1935 (FPA).

A FERC licence must be obtained under Part I of the FPA for the construction of hydroelectric facilities on navigable waters. Construction affecting federal lands may also require authorisation from agencies such as the Bureau of Land Management, the US Forest Service or the National Park Service. The US Army Corps of Engineers reviews projects affecting wetlands or navigable waters. Nuclear facilities must be licensed by the US Nuclear Regulatory Commission (NRC). The Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement within the Department of the Interior are responsible for offshore oil and gas lease sales and offshore renewable energy development.

Law stated - 27 January 2023

Grid connection policies

What are the policies with respect to connection of generation to the transmission grid?

FERC-jurisdictional transmission providers are required to provide interconnection services under the terms of an open-access transmission tariff (OATT). Generators have the right to request interconnection services separately from transmission services.

In response to complaints by generators that interconnection procedures were being used by some transmission providers in a discriminatory manner, FERC implemented rules to standardise agreements and procedures for generators and required FERC-jurisdictional transmission providers to interconnect generators to the grid in a non-discriminatory manner. Under the standard interconnection procedures, generators are required to pay the full cost of any interconnection facilities up front (from the generator to the point of interconnection) and network transmission facilities (beyond the point of interconnection) necessary to connect the generator with the transmission grid. The generator is reimbursed for the cost of any network transmission facilities through credits for future transmission service on the grid. Independent system operators (ISOs) and regional transmission organisations (RTOs) have the flexibility to propose changes to the standard interconnection agreement and procedures, as well as to the procedures for recovering interconnection costs. For example, ISOs and RTOs may seek authorisation to allocate the costs of network upgrades to the generator requesting the upgrades (in exchange for granting capacity rights on the transmission system). FERC does not regulate local distribution facilities, but has authority to regulate the rates, terms and conditions of any wholesale sales transaction using such a facility.

To encourage development of new generation, FERC issued Order No. 807, easing the requirement for certain generator owners and operators to have an OATT on file with FERC for public utilities that are subject to those regulations solely because they own or operate Interconnection Customer Interconnection Facilities (ICIF), namely, those that own generator tie lines. Previously, an ICIF owner must have either had on file an OATT or received a case-by-case waiver of the OATT requirement, and also was obliged to provide interconnection service to other generators that sought to interconnect to the grid using its ICIF. To ease the regulatory burden on new generation developers, the new rule grants a blanket waiver of all OATT and other open access requirements to any public utility that is subject to those requirements solely because it owns, controls, or operates an ICIF, including entities that do not sell electricity. In addition, the rule provides a 'safe harbour' period for five years in which there would be a rebuttable presumption that the ICIF owner has definitive plans to use its capacity and therefore are not required to provide interconnection service to other generators seeking to interconnect generation in the same location during the safe harbour period.

Law stated - 27 January 2023

Alternative energy sources

Does government policy or legislation encourage power generation based on alternative energy sources such as renewable energies or combined heat and power?

Yes. There are significant tax benefits provided to renewable energy projects, mainly in the form of income tax credits that were modified or introduced in the Inflation Reduction Act (IRA), which was signed into law in August 2022. The IRA extends and expands key energy tax credits that provide incentives for investment in renewable and other innovative energy technologies that reduce greenhouse gases. In addition to tax credits, certain other incentives relating to renewable energy projects and technologies, such as accelerated depreciation methods (allowing in certain cases for 100 per cent of the cost of certain property to be immediately deducted and offset against taxable income) also remain in place after the IRA.

Extension for PTCs and ITCs

A significant tax benefit for renewable energy projects are the Production Tax Credits under section 45 of the Internal Revenue Code of 1986 (PTC and Code) and the Investment Tax Credit under section 48 of the Code (ITC). The PTC, which the IRA extended for three years for facilities beginning construction before 2025, provides taxpayers a tax credit of 0.3 cents/kWh (adjusted annually for inflation), which can be increased to 1.5 cents/kWh for facilities that meet certain 'prevailing wage' and 'apprenticeship' requirements (discussed below). While the PTC is traditionally associated with wind energy projects, after the IRA, solar projects may now also take the PTC in lieu of the ITC. The PTC is also extended for biomass, geothermal, solar, landfill gas, trash, qualified hydropower, and marine and hydrokinetic resources. The IRA also provided a one-year extension for the ITC, in the case of projects for which construction begins before 2025. The ITC offers a base rate of 6 per cent (as a percentage of the tax basis of eligible energy property) with an increased rate of 30 per cent if prevailing wage and apprenticeship requirements are met.

As mentioned above, the IRA proposes a set 'base' rate for certain renewable energy tax credits. This base rate can be increased by a factor of five if the project meets prevailing wage and apprenticeship requirements, as determined by Department of Labor Standards.

To meet prevailing wage requirements, the project owner must ensure laborers employed by the contractors and subcontractors are paid prevailing wages both during construction and for any repairs and alterations needed during the applicable tax credit period. Prevailing wages are defined as wages at rates for similar work in the location of the project site as determined by the Secretary of Labor. To obtain the relevant information, taxpayers may refer to the Department of Labor website to view publications of official wage determinations for different types of applicable job titles.

To meet apprenticeship requirements, a certain percentage of the project's labor hours, defined as the minimum amount of hours of the construction, alteration or repair work with respect to a facility, must be performed by qualified apprentices from an apprenticeship programme registered with the Department of Labor. The required percentage of labour hours varies depending on the year in which construction of the applicable project began.

Project construction	% of Required apprentice labour hours

Construction begins before 2023	10%
Constructions begins in 2023	12.5%
Construction begins in or after 2024	15%

The IRS determines the beginning of construction using one of two methods – the Physical Work Test or the 5 per cent Safe Harbor. The Physical Work Test is met once physical work of a significant nature has begun on the project. The 5 per cent Safe Harbor is met once 5 per cent or more of the total cost of the project is paid or incurred. Both the Physical Work Test and 5 per cent Safe Harbor require that continuous efforts to advance towards completion of the project facility must also be made (the Continuity Requirement). The IRS provides a 'continuity safe harbor' to help taxpayers meet this requirement, whereby the Continuity Requirement is automatically deemed satisfied if the project is placed in service within the four-year period starting at the end of the year construction began. In certain cases, the four-year safe harbour period has been officially extended (eg, in the case of projects affected by the covid pandemic or in the case of qualified offshore wind projects).

Further, the IRA creates an additional 'bonus' tax credit if domestic content requirements are met (generally up to a value of 10 per cent of the credit amount or an additional 10 percentage points in the case of the ITC) or if the project is located in certain energy communities or low-income communities (generally up to an additional 20 per cent of the credit amount or an additional 20 percentage points in the case of the ITC). For purposes of the energy community bonus credit, an energy community is defined as being a brownfield site; an area that has or had certain amounts of direct employment or local tax revenue related to oil, gas, or coal activities and has an unemployment rate at or above the national average; or a census tract or any adjoining tract in which a coal mine closed after 31 December 1999, or in which a coal-fired electric power plant was retired after 31 December 2009. For purposes of the low-income community bonus credit, projects that are part of a low-income residential building project or qualified low-income economic benefit project may be considered eligible. The domestic content bonus credit requires a project to certify that certain steel, iron and manufactured products used in the facility were produced in the United States.

Extension of existing tax credits

In addition to the modifications to the PTCs and ITCs used mainly by wind and solar energy projects, the IRA also extends and modifies other tax credits focusing on different renewable energy sources.

The IRA extends and modifies the section 45Q carbon oxide sequestration tax credit (45Q Credit) by seven years, for projects beginning construction before 2033. The credit amount is increased if prevailing wage and apprenticeship requirements are met. Further, the IRA significantly lowers the amount of qualified carbon oxide that projects must capture to qualify for section 45Q credits. The charts below address the amount of tax credits available to facilities and the new minimum carbon capture thresholds.

End use	Pre-IRA amount	IRA Amount without wage & apprenticeship requirements	IRA Amount with wage and apprenticeship requirements
Traditional carbon capture: carbon oxide used or utilised	$35	$12	$60
Traditional carbon capture: carbon oxide sequestrated	$50	$17	$85

Direct air capture: carbon oxide used or utilised	$35	$26	$130
Direct air capture: carbon oxide sequestrated	$50	$36	$180

Facility	Minimum capture threshold under the IRA
Direct air capture facility	1,000 metric tons (previously 100,000 metric tons)
Electricity generating facility	18,750 metric tons + the facility must have a capture design capacity of at least 75% of the baseline carbon oxide production of such unit
Any other facility	12,500 metric tons

The IRA also extends and modifies the advanced energy manufacturing tax credit, which is a 30 per cent tax credit for investments in projects that reequip, expand, or establish certain energy manufacturing facilities, subject to a total funding cap. Along with an expanded definition of projects that would be considered a 'qualifying advanced energy project' eligible for the credit, an additional $10 billion in funding for the credit is provided with at least $4 billion to be allocated to energy communities. The base rate for the tax credit is 6 per cent and can be increased to 30 per cent if wage and apprenticeship requirements are satisfied.

The IRA also extends, but does not modify, existing tax credits for alternative fuels, biodiesel and renewable diesel, as well as second-generation biofuel incentives, through the end of 2024.

Newly created tax credits

The IRA also creates brand new tax credits, incentivising different types of renewable and net zero energy projects and technologies. One such credit is the nuclear power PTC. This credit applies to projects using nuclear power to generate electricity. Notably, this credit is available only to projects placed in service before the date of enactment of the IRA. The nuclear power PTC rate is 0.3 cents/kWh of electricity produced by the taxpayer at a qualified nuclear power facility, with a 1.5 cents/kWh rate available to facilities that meet prevailing wage requirements. This PTC terminates at the end of 2032. Notably, the amount of this tax credit is subject to reduction by an amount equal to 16 per cent of excess of the gross receipts from a facility over the product of 2.5 cents and the number of kilowatt hours of electricity produced and sold by the facility.

Another tax credit created in the IRA is the clean hydrogen PTC. This credit is available for qualified clean hydrogen produced at a qualifying facility during the facility's first 10 years of operation. The credit rate is based on $0.60/kg of clean hydrogen multiplied by a percentage based on the level of greenhouse gas that remains after the hydrogen production process, and this rate is multiplied by five if prevailing wage and apprenticeship requirements are met. An ITC is also available for clean hydrogen facilities. The ITC rate is equal to a percentage of the cost of facility, and the ITC rates vary depending on the level of greenhouse gas that is removed.

CO2/kg of H2 remaining	PTC credit %	ITC value
Between 2.5kg and 4kg	20%	1.2%
Between 1.5kg and 2.5kg	25%	1.5%

Between .45kg and 1.5kg	33.4%	2%
Less than .45kg	100%	6%

Under the IRA, there is also a newly-created advanced manufacturing PTC that incentivises the domestic (United States) production and sale of qualifying components of renewable energy projects and certain qualified 'critical minerals'. Qualified components for these purposes includes solar components such as photovoltaic wafers, wind components such as blades, nacelles and towers, and qualified critical minerals include aluminium, graphite, vanadium and many others. The credit rate for the advanced manufacturing PTC depends on the component being produced, and the credit is also phased down over time. The credit will begin to phase out at a rate of 25 per cent/year for components sold after 2029 and no tax credit will be available for components sold after 2032.

The IRA also introduces a new clean electricity PTC and ITC. These 'technology neutral' credits are available to projects that generate electricity and yield zero greenhouse gas emissions, irrespective of what technology is utilized in order to generate the electricity (eg, wind, solar, hydrogen, etc). The clean electricity PTC and ITC apply to facilities placed in service after 2024 and phase out in 2032 or the year certain emissions thresholds are achieved, whichever is later. These credits mirror other PTCs and ITCs in both value and calculation methodology. The clean electricity PTC is worth 0.3 cents/kWh, and can be increased to 1.5 cents/kWh if the wage and apprenticeship requirements are met, with this rate being adjusted for inflation annually. The clean electricity ITC has a base rate of 6 per cent (as a percentage of the tax basis of eligible energy property), and can be increased to 30 per cent by meeting wage and apprenticeship requirements.

The DoE Office of Energy Efficiency and Renewable Energy (EERE) is the focal point for several alternative energy programmes, including the biomass programme, the geothermal technologies programme, the solar energies technologies programme, the hydrogen, fuel cells and infrastructure technologies programme, and the wind and hydropower technologies programme. The EERE provides a variety of forms of financial assistance for the research and development of renewable energy, including grants, laboratory subcontracts, and cooperative research and development agreements. Moreover, as of August 2020, 30 states plus the District of Columbia and two US Territories have adopted renewable portfolio standards that require electricity providers to obtain a minimum percentage of their power from renewable energy resources by a certain date, and eight others (and one US territory) have set voluntary goals for adopting renewable energy resources. As of March 2015, 20 of these states include combined heat and power and/or waste heat recovery as an eligible resource.

Cogeneration and small power production purchase and sale requirements

EPAct 2005 amended the mandatory purchase and sale requirements of the Public Utility Regulatory Policies Act (PURPA). Historically, electric utilities were obligated to purchase or sell electric energy from or to a facility that is an existing qualifying cogeneration or small power production facility (QF). However, if the QF is selling in a market that meets certain criteria established by FERC, that purchase obligation may be terminated. In 2006 FERC issued Order No. 688, which permits the termination of the requirement that an electric utility enter into new contracts to sell energy to or purchase energy from a QF after the electric utility files for such relief from FERC, and FERC makes appropriate findings. Several utilities have successfully pursued relief under Order No. 688. These changes do not affect pre-existing contracts or obligations. In July 2020, FERC issued Order No. 872, implementing many significant revisions to PURPA, notably aimed to increase state-level flexibility relating to variable rates for purchases of energy from renewable generation (qualifying facilities, or QFs). In addition, Order No. 872 lowers the threshold of QFs from 20MW to 5MW, enabling electric utilities to more easily terminate legally enforceable contractual obligations to purchase energy from those small power production facilities.

Law stated - 27 January 2023

Climate change

What impact will government policy on climate change have on the types of resources that are used to meet electricity demand and on the cost and amount of power that is consumed?

Federal and state climate change policies promoting carbon-free energy sources are more likely to have an impact on the types of resource used to meet US electricity demand in the medium- or long-term time frame than in the short term. The US electric industry’s reliance on fossil fuels (particularly coal) to meet rising energy demands is driven primarily by cost considerations: coal, for many years, has been a cheap and plentiful domestic fuel source. That dynamic is shifting, however, as the influx of low variable-cost renewable projects and the continued development of shale gas resources (and the resultant low natural gas prices) has narrowed the energy cost advantages of coal generation, particularly for older, less efficient coal units. Although recent federal and state legislative initiatives have provided down payments toward the creation of cost-competitive renewable energy technologies, the large-scale deployment of these technologies is still hampered by variability of resources such as wind, the need for additional backbone transmission capacity between regions and the lack of storage capacity.

Other proposed state and federal legislation (for example, cap-and-trade schemes) and foreign policy initiatives could impose additional costs on electricity generators using carbon-rich fossil fuels. In general, legislative proposals and environmental regulations are likely to impose greater costs on the energy that is consumed. State or federal governments could subsidise renewable energy and carbon mitigation initiatives by surcharges on electricity generation or consumption. Compliance costs incurred by utilities arising from state or international cap-and-trade legislation, federal regulations or state regulation of vehicular carbon emissions would be passed on through every transaction involving electricity.

The Environmental Protection Agency (EPA) is the chief US agency tasked with issuing regulations under the Clean Air Act (CAA) regarding pollutants and carbon dioxide emissions from power generation sources. For instance, new and existing coal-fired plants may be incentivised or required to have carbon capture and sequestration (CCS) capabilities. In 2011, the EPA issued the Cross-State Air Pollution Rule under the Clean Air Act that requires coal companies in 28 states to reduce emissions of sulphur dioxide and nitrogen dioxide by 73 per cent and 54 per cent, respectively, from 2005 levels by 2014. The rule was controversial, with many in the coal industry claiming that it will be cost-prohibitive to obtain and instal the CCS technology necessary to meet the standard. As a result, the coal industry warns that coal generating facilities will be forced to prematurely shut down. In April 2014, the US Supreme Court upheld the EPA rule, affirming EPA’s authority to regulate existing power plants for greenhouse gases so long as they are being regulated for other pollutants as well.

The issue of how to properly account for compliance costs of pollution reduction was at the heart of a 2015 US Supreme Court case. There, the US Supreme Court remanded an EPA rule setting limits on mercury and other toxic pollutants from power plants, ruling that the EPA violated the CAA by failing to consider costs when deciding whether to set those emissions limits in the first place, although the EPA did eventually undertake a cost-benefit analysis when subsequently deciding how to regulate. As the EPA continues to issue regulations related to pollution and climate change, whether and how to account for compliance costs will remain a key issue.

Perhaps the largest and most impactful regulatory initiative pertaining to climate change concerns the regulation of carbon dioxide emission limits from existing power plants. In June 2013, the US president ordered the EPA to create the first ever carbon emissions limit for existing power plants , stating that the US should lead the world in a ‘coordinated assault’ on climate change. In August 2015, pursuant to the president's directive, the EPA promulgated its final regulations under part 111(d) of the CAA, which is known as the Clean Power Plan (CPP). In general, the CPP would have established broad carbon-dioxide emission targets for coal- and natural-gas fired power plants intended to cut CO_2 emissions by 32 per cent by 2030, leaving the states (excluding Vermont, Hawaii, Alaska and the District of Columbia) to choose from a variety of methods – such as renewable energies, efficiency improvements, or participating in an emission credit trading programme – to develop a plan to meet individual targets. However, in February 2016, the US Supreme Court stayed implementation of the CPP while court challenges to the plan were pending before the US Court of Appeals for the DC Circuit. Then, in March 2017, the presidential administration issued an Executive Order ordering the EPA to review the CPP to consider whether to 'suspend, revise, or rescind' the CPP. Regardless, the EPA has not proposed revoking its 2009 'endangerment finding' – a determination that greenhouse gases, including carbon dioxide, are a threat to human health – and as such, the EPA therefore is required to regulate greenhouse gasses under the statutory directive of the CAA.

Irrespective of the enabling regulatory environment, utilities will continue to need to devote additional investment capital toward developing new generating capacity to replace the loss from the retirement of coal-fired plants. However, there may be some offset by a decreased demand in electricity as consumption becomes more efficient through technological advancements.

Nonetheless, the development of renewable resources is expected to continue. This is due in large part to state initiatives aimed at incentivising development of renewable resources and technological developments making the use of renewable resources more and more economical. However, it should be noted that the increased integration of renewable resources into the electric grid raises issues around grid reliability. In general, FERC and North American Electric Reliability Corporation (NERC) are tasked with maintaining reliability for the Bulk Electric System. As generating capacity from coal-fired and other traditional baseload resources decreases, it will be important to develop suitable replacement generation and transmission resources that are sufficient to maintain capacity to meet electricity demand, particularly during times of peak usage in order to avoid reliability problems. Moreover, as most renewable generation resources, such as wind and solar sources, are in remote locations, additional transmission infrastructure must be constructed. Energy storage resources may also be needed to ensure reliability, such that sufficient energy can be saved and then deployed during times of peak usage given that generation from variable resources inherently fluctuate. In addition, a number of utilities have closed or announced plans to shut down certain, mostly older, less efficient, coal power plants.

Law stated - 27 January 2023

Storage

Does the regulatory framework support electricity storage including research and development of storage solutions?

Most direct support for development of commercial energy storage resources has occurred at the state level. For instance, California adopted in 2014 a mandate to require utilities to create 1.3 gigawatts of energy storage capacity by 2022. As of June 2022, California surpassed this goal substantially following a period of exponential growth, with over 3.1 gigawatts in storage connected to its grid. Federal legislation has primarily been focused on research and development of innovative storage technologies that are not yet ready for private investment. For instance, in 2007, Congress passed the America COMPETES Act which established the Advanced Research Projects Agency within the DOE (ARPA-E) to fund research and development of new innovative technologies including storage.

From a regulatory perspective, FERC, in recent years, has issued several rules that, while not specifically aimed at energy storage resources, accommodate and encourage participation of non-traditional resources, including energy storage resources, in the wholesale energy markets. For instance, in 2011, FERC issued Order No. 755, requiring RTOs and ISOs to implement a 'pay for performance' compensation structure for frequency regulation service. Though not specifically aimed at energy storage resources, the intention of Order No. 755 was to ensure that flexible resources were receiving adequate compensation in the wholesale electric markets. In 2013, FERC issued Order No. 784, requiring all public utility transmission providers to have in their OATT a statement that it will take into account the speed and accuracy of regulation resources, as well as amended its accounting regulations to improve the accounting for and reporting of transactions associated with energy storage resources. Other FERC orders since, such as those concerning small generator interconnection policies and frequency response, also are intended to ensure RTO and ISO rules do not discriminate against newer technologies. In April 2016, FERC commenced an informational proceeding to examine 'whether barriers exist to the participation of electric storage resources in the capacity, energy, and ancillary service markets potentially leading to unjust and unreasonable wholesale rates'. In some RTO/ISO markets, steps have been taken to revise market rules to improve the ability of storage resources to participate; for example, recently FERC approved changes to the California Independent System Operator Inc tariff allow market participants to submit state of charge as a bidding parameter, allowing storage providers flexibility in their offers. However, in an order issued in February 2017, FERC affirmed that market rules in MISO do not accommodate the unique physical and operational characteristics of energy storage resources. Other RTO/ISO markets, namely PJM and ISO New England, have identified disparities in the barriers to entry for storage resources (eg, penalties that are disproportionate to traditional resources due to technological characteristics).

Regulators at both the state and federal level have undertaken efforts to reduce regulatory barriers in order to facilitate the integration of energy storage into the grid. Most notably, in February 2018, FERC issued Order No. 841, a landmark order that will pave the way for integrating energy storage systems in US wholesale energy markets. Previously, existing market rules did not align well with the operational aspects of energy storage systems, as the rules were created with traditional baseload resources in mind. Order No. 841 sought to remedy this and directed each of the RTOs and ISOs under FERC's jurisdiction to revise their tariffs to establish a participation model for energy storage resources that properly recognise their physical and operational characteristics.

Each regional grid operator has since submitted a compliance filing, at a minimum, outlining its proposed participation model and intended effective date. While the overarching goal is the same, each approach varies due to the unique market of each RTO and ISO as well as their current degree of electric storage integration. In May 2019, FERC affirmed its guidance on electric storage by issuing Order No. 841-A. This clarifying order preserved the core tenets of Order No. 841 and refused to include a provision proposed by intervenors that would have allowed states to opt out of the participation model requirement.

Industry groups and the National Association of Regulatory Utility Commissioners (NARUC) opposed the mandate furnished in Order Nos. 841 and 841-A, and in May 2020, argued before the United States Court of Appeals for the District of Columbia Circuit (DC Circuit) to invalidate FERC compelling states to incorporate electric storage. NARUC and the industry groups claimed that FERC contravened the FPA by infringing on the jurisdiction granted to states over local electricity distribution systems. The principal argument centered on the physical nature of those local systems – typically under state purview – and the logical extension that utilising those systems to integrate storage on wholesale markets would unlawfully intrude into federal jurisdiction. Additionally, the industry groups and NARUC argued that providing an 'opt-out' mechanism in Order No. 841 would be an appropriate legal remedy.

On 10 July 2020, the DC Circuit denied the petition. In the decision, the court contemplated the line between federal and state jurisdiction in this matter, siding with FERC in its application of the FPA.

The DC Circuit ultimately determined that a state cannot mandate opting out of policies that integrate storage because the states do not have the authority to block sales of any resource in wholesale power markets. Under the FPA, states are precluded from delegating which resources are able to participate in wholesale markets – such an action would clearly invade federal authority vested in the FPA where FERC holds jurisdiction over wholesale (ie, federal) facilities and markets. Conversely, if FERC had attempted to enact an order pertaining to retail (ie, state) markets, the line would be drawn in favor of states' jurisdictions and FERC would have been rebuffed.

At the state level, regulators have issued regulations and craft policies focused on accommodating battery storage as well. For instance, in California, grid operators created a product that is intended to value the capabilities of storage that is paired with solar or wind generation. And in Maryland, the state government created a tax incentive programme aimed at residential and commercial customers who instal qualified energy storage systems, the first of its kind in the United States. These efforts are expected to continue, with several discussing or implementing legislation that would create similar tax incentive programmes, including Oregon, Nevada, Arizona, New York, New Jersey, Massachusetts and Virginia. As is common with transmission projects and rate proposals, most utility-scale electric storage installations are subject to approval by a state public utility commission (or other agency with a similar remit). Public utility commissions are conducting assessments and soliciting stakeholder feedback regarding potential multi-use applications of electric storage. These agencies are contemplating how to modify existing tariffs or market rules in order to incorporate storage without contravening contractual arrangements or provisions. As it stands, state utility regulators in California, Hawaii, Massachusetts, Minnesota, New York and Texas are undertaking such efforts relating to multi-use applications.

Solar-plus-storage projects are emerging as more viable in certain markets, in large part due to evolving consumer preferences, net metering programmes and revisions to utility rate tariffs that carve out provisions for storage. With the exception of early adopters, the capital intensive nature of this burgeoning sector has mostly limited solar-storage pairings to markets with clear enabling policy environments such as California (Self-Generation Incentive Program) and Hawaii (Customer Self-Supply Program). The state of Hawaii has led the charge in arranging solar-plus-storage power purchase agreements. This may be somewhat attributable to high electricity costs (the highest in the US, due to the proportion of imported conventional fossil fuel resources) but has been buttressed by a commitment to deploy electric storage installations alongside solar generation at both the utility and residential levels. Hawaii's goal of achieving 100 per cent renewable resources by 2045 also spurs the solar-plus-storage boom.

Finally, many recent offshore wind solicitations in the US have specifically included a requirement for electric storage (via batteries) and transmission. For instance, all three proposals selected in the Massachusetts offshore wind round in 2020 included either battery or hydroelectric storage as part of the project. With more states carving out specific goals for storage, their respective RFPs for large solar and/ or wind projects are likely to include similar requirements.

Law stated - 27 January 2023

Government policy

Does government policy encourage or discourage development of new nuclear power plants? How?

Historically, government policy has encouraged the development of new nuclear power plants. In 2010, the DoE launched a nuclear power programme in an attempt to jump-start the proposed construction of new nuclear plants by co-funding with the nuclear industry efforts to evaluate and bring new technologies to market. This included utilising an NRC licensing process intended to streamline NRC approval of such projects. The DoE also put in place a Generation IV Nuclear Energy Systems initiative , which aims to develop new plant designs that minimise waste and are safer and more proliferation-resistant than today’s nuclear plant designs. EPAct 2005 also encouraged the construction of new nuclear plants by establishing a production tax credit. Under that plan, operators of the first 6,000MW of capacity from nuclear power plants that are placed in service before 2021 received a production tax credit of 1.8 cents per kWh during the first eight years of the plant’s operation.

The US DoE Loan Guarantee Program was designed to promote development of the nuclear power industry through loan guarantees for the construction of new nuclear power plants in the US. These loan guarantees help developers of new nuclear plants in the US to obtain favourable financing terms, which is of critical importance when constructing plants with a projected price tag in the range of US$7 to US$10 billion per unit. Indeed, many companies that are considering building new plants have publicly stated that, absent a federal loan guarantee, they will not be able to finance and build their proposed projects. Seventeen companies building 21 nuclear units have applied for the guarantees. To date, a conditional loan guarantee of US$8.33 billion has been granted to the developers of two nuclear units in Georgia. The DoE's Loan Guarantee Program also has earmarked an additional US$4 billion for the construction of new uranium enrichment facilities in the United States. Access to additional supplies of enriched uranium fuel will be critical to support the development of new nuclear plants in the United States. In May 2010, the DoE announced that it would grant a conditional loan guarantee of US$2 billion for the construction of a uranium enrichment plant in Idaho. In December 2014, the DoE Loan Guarantee Program issued a solicitation for an additional US$12.5 billion in available loan guarantees to support the construction of new large or small nuclear reactors, or provide upgrades to existing facilities, including US$2 billion set aside for uranium conversion or enrichment projects.

Since the Fukushima nuclear reactor crisis in March 2011, however, development of nuclear power plants in the US has slowed, particularly with respect to licensing of new power plants or the relicensing of existing plants. Following an August 2012 decision by the US Court of Appeals for the DC Circuit ruling that the NRC did not sufficiently examine proper storage of nuclear waste in its regulations, the NRC suspended new licensing and licensing renewal for nuclear plants until a full reassessment of nuclear waste storage was completed. In September 2014, the NRC issued its rule and resumed licensing decisions. The NRC's rule was upheld in a June 2016 decision by the US Court of Appeals for the DC Circuit. Additionally, in August 2013, the US Court of Appeals for the DC Circuit ordered the NRC to make a key decision regarding a proposed nuclear waste disposal site in Yucca Valley, NV, stating that the NRC did not have the legal authority to continue to delay making a decision regarding the licensing of the project. That process remains ongoing, with DOE and NRC working to develop an Environmental Impact Statement. In August 2017, the NRC voted 2-1 to proceed with the 'information-gathering stage' of Yucca Mountain, enabling DOE to move forward on the licensing process. Whether and when this site becomes operational impacts the licensing and relicensing of nuclear power plants, as those decisions may require a permanent storage and disposal site for nuclear waste.

A persistent hurdle facing nuclear power is the relatively low price of other energy resources, such as natural gas and subsidisation of renewable resources, which combine to reduce the economic viability of nuclear generation. In May 2014, for example, several nuclear power facilities failed to be selected to sell energy into a capacity market run by PJM Interconnection, Inc (PJM) because the price offered in the capacity market was insufficient to cover the costs of the nuclear facilities. As a result, the nuclear facilities must either cease production or find private purchasers and some utilities have announced that they will close certain nuclear plants. For instance, Exelon Corporation, operator of the largest nuclear fleet in the US, announced it was permanently closing two facilities in Illinois, citing the fact that the facilities had lost $800 million over the last seven years. It remains to be seen, however, whether changes to capacity auctions that seek to reward high-performing generating units, such as those planned for the PJM and ISO New England markets, will benefit nuclear power generators.

In July 2016, New York adopted a proposal that would allow nuclear facilities in the state to earn 'Zero Emission Credits', or ZECs, as part of New York's renewable energy standard. The ZECs would be calculated using a formula that uses the expected power costs in the region and the federal government's calculation of the social price on carbon used by federal agencies use in rulemaking. Utilities in the state would then be required to purchase a pro rata share of ZECs, thus providing a value for the emissions-free energy produced by nuclear facilities. The result of this proposal was immediate – a New York nuclear facility that had been slated to close was purchased by a buyer that agreed to keep the facility open. Illinois passed legislation providing for similar credits in 2016. To date, legal challenges to the credits have failed and several additional states, including Ohio, Pennsylvania, New Jersey and Connecticut, are considering similar initiatives.

Law stated - 27 January 2023

REGULATION OF ELECTRICITY UTILITIES – TRANSMISSION

Authorisations to construct and operate transmission networks

What authorisations are required to construct and operate transmission networks?

Construction of transmission facilities is primarily a state-regulated function, but federal authorities have jurisdiction over siting on federal lands, and multi-state projects may require the authorisation of several states. Historically, this fragmented system for siting new power lines, in addition to other factors such as regulatory uncertainty on the state and federal levels associated with transmission cost recovery, has been a significant barrier to the development of new transmission in the United States. The Energy Policy Act (EPAct 2005) provides tools to facilitate new construction and improvements to the existing transmission infrastructure.

EPAct 2005 directed the Department of Energy (DOE) to conduct a nationwide study of electric transmission congestion and identify areas in which transmission capacity constraints or congestion adversely affects consumers and designate such areas as national interest electric transmission corridors (NIETCs). The most recent draft nationwide electric transmission congestion study was published in August 2014, but it did not propose nor designate any new NIETCs. EPAct 2005 gave the Federal Energy Regulatory Commission (FERC) supplemental permitting authority to ensure the timely construction of transmission facilities to remedy transmission congestion in those corridors. The DOE initially designated two such corridors in 2007, but the US Court of Appeals for the Ninth Circuit vacated and remanded the designations to the DOE for further proceedings in February 2011. The DOE announced that it will collaborate with FERC to prepare drafts of transmission congestion studies and environmental analyses for proposed NIETCs in the future. In addition, the US Court of Appeals for the Fourth Circuit limited FERC's supplemental backstop siting authority, ruling that it applied only in situations where a state refuses to act on a permit application or imposes uneconomic conditions, but determined FERC lacked the authority to overrule a state denial of a permit application. Thus, a state may be able to circumvent FERC backstop siting authority by properly denying an application .

EPAct 2005 also provided a mechanism for the private use of the eminent domain power of the US government, where necessary, to obtain property for transmission infrastructure projects. In addition, EPAct 2005 required that the federal government identify rights of way across federal lands that can be made available for siting electric transmission.

On 21 July 2011, FERC issued Order No. 1000 , a final rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities. The goal of Order No. 1000 is to ensure more reliable transmission service at just and reasonable rates. Order No. 1000 lays out certain requirements for coordinating transmission planning and allocating transmission costs so that transmission planners seek the most efficient and cost-effective way to meet needs in their respective regions and between regions. The implementation of Order No. 1000 is left largely to public utility transmission planners, which were directed to submit compliance filings in October 2012. The process of review, clarification and refiling is largely still underway for most transmission planners and as a result, the impact of the order is still evolving. In 2016, FERC convened a technical conference to assess the progress of implementing Order No. 1000.

Operation

FERC issued a series of orders, beginning with Order No. 890, which were intended to eliminate the broad discretion that transmission providers had in calculating available transfer capacity (ATC), increasing non-discriminatory access to the grid and ensuring that customers are treated fairly in seeking alternative power supplies. Since Order No. 890-A, transmission providers have implemented new service options for long-term firm point-to-point customers and adopted modifications to other services. Instead of denying a long-term request for point-to-point service because as little as one hour of service is unavailable in the course of a year, transmission providers are now required to consider their ability to offer a modified form of planning redispatch or a new conditional firm option to accommodate the request. This increases opportunities to utilise transmission efficiently by eliminating artificial barriers to the use of the grid. This standardisation reduces the potential for undue discrimination, increases transparency and reduces confusion in the industry that resulted from the prior lack of consistency.

Also, FERC regulations require the posting of ATC values associated with a particular path, not available flowgate capacity values associated with a flowgate. With respect to energy and generation imbalance charges, a transmission provider must post the availability of generator imbalance service and seek imbalance service from other sources in a manner that is reasonable in light of the transmission provider's operations and the needs of its imbalance customers. FERC also limited rollover rights to contracts with a minimum term of five years. In Order No. 890-B, FERC reiterated that a power purchase agreement must meet all of the requirements for designation as a network resource in order to be designated by the network customer or transmission provider's merchant functions.

Law stated - 27 January 2023

Eligibility to obtain transmission services

Who is eligible to obtain transmission services and what requirements must be met to obtain access?

In 1996, FERC issued Order No. 888, requiring each public utility subject to FERC's jurisdiction to:

- file an open-access transmission tariff (OATT) declaring the terms and conditions for using its transmission system; and
- functionally unbundle its services.

Accordingly, public utilities operating under a FERC-approved OATT must provide non-discriminatory access to interstate transmission service. In 1999, FERC issued Order No. 2000, establishing regional transmission organisations (RTOs) and independent system operators (ISOs) and delegating to those entities the purview of managing and operating the bulk electric grid. Any public utility participating in an RTO or ISO passes control of its transmission facilities to the grid operator in the interest of centralising the system and achieving efficiencies at scale that benefit ratepayers and utilities alike. For systems operating beyond the bounds of an RTO or ISO, utilities provide unbundled transmission service under a different FERC-approved tariff.

FERC established standard interconnection agreements and procedures for interconnecting large and small generators. Each transmission utility must adhere to the terms and provisions furnished in those agreements and cannot impose additional burdens or obligations without FERC approval.

Law stated - 27 January 2023

Government transmission policy

Are there any government measures to encourage or otherwise require the expansion of the transmission grid?

Pursuant to EPAct 2005, FERC has established incentive-based rate treatments to encourage investment in and expansion of the US's aging transmission infrastructure. FERC Order No. 679, issued in 2006, includes a number of key provisions to promote transmission investment, including:

- incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies);
- a higher rate of return on equity for utilities that join or continue to be members of transmission organisations

(eg, RTOs and ISOs); and

- various advantageous accounting methods, including:
  - full recovery of prudently incurred construction work in progress, pre-operation costs and costs of abandoned facilities;
  - use of hypothetical capital structures for rate-making purposes;
  - accumulated deferred income taxes for stand-alone transmission companies;
  - adjustments to book value for stand-alone transmission company sales or purchases;
  - accelerated depreciation; and
  - deferred cost recovery for utilities with retail rate freezes.

In Order No. 679 and Order No. 679-A, FERC extended incentive rate treatments to all utilities joining ISOs or RTOs, irrespective of the date they join. However, this incentive does not apply to the transmission rate base that has already been built, as the incentive's purpose is to attract new investment in transmission.

Law stated - 27 January 2023

Rates and terms for transmission services

Who determines the rates and terms for the provision of transmission services and what legal standard does that entity apply?

FERC has jurisdiction over unbundled transmission services (including transmission services provided over low-voltage facilities) provided by public utilities to wholesale customers or to retail customers with direct access. The states have jurisdiction over bundled retail service (namely, a combined generation and delivery product sold to retail customers) where direct access is not available. Court decisions and the interconnectivity of the transmission grid in the continental United States have led to an expansive view of what constitutes transmission service in interstate commerce in all areas of the United States except Alaska, Hawaii and the Electric Reliability Council of Texas. The Federal Power Act of 1935 (FPA), however, reserves to the states jurisdiction over the local distribution of electricity.

FERC-jurisdictional utilities offering transmission services must do so under FERC-approved tariffs. Order No. 888 required jurisdictional electric utilities to submit pro forma open-access transmission tariffs (OATTs) that functionally unbundled transmission operations and services, and set forth rates for transmission and ancillary services. In 2007, FERC issued Order No. 890, which modified the pro forma OATT to better remedy undue discrimination by, among other things, providing greater transparency and consistency in the calculation of available transmission capacity, and requiring coordinated open transmission planning between regions.

Transmission providers are also required to maintain an open-access, same-time information system to publish information with respect to their transmission systems, including services, rates, and available transmission capacity as well as business rules, practices, and standards that relate to transmission services provided under the pro forma OATT.

Finally, the FPA empowers FERC to review rates and terms of transmission services to ensure that they are just and reasonable and not unduly discriminatory or preferential. Generally, tariffs and contracts for transmission services must be filed with FERC before service commences to allow an opportunity for Commission review, as well as public notice and comment. Because transmission services are a natural monopoly, Order No. 888 envisions that FERC will determine whether a particular tariff is just and reasonable via a traditional cost-of-service rate making inquiry that balances ratepayers and the utilities' financial interests to realise a rate within the zone of reasonableness. Tariffs can be challenged for being unjust, unreasonable, unlawful or discriminatory.

EPAct 2005 authorises FERC to require transmission providers not subject to its jurisdiction to provide open access to their transmission system at terms and conditions comparable to those the unregulated entity provides to itself. An unregulated entity may be exempt from this requirement if it sells less than 4 million megawatt hours of electricity annually or if it does not own or operate the transmission facilities needed to operate an interconnected system. However, many of these regulated entities already provide open access based on reciprocity agreements with transmission providers.

Law stated - 27 January 2023

Entities responsible for grid reliability

Which entities are responsible for the reliability of the transmission grid and what are their powers and responsibilities?

Since 1968, the North American Electric Reliability Corporation (NERC) has operated as the primary entity responsible for assuring the reliability of the grid. NERC was founded by the electric utility industry to develop and promote rules and protocols to enhance the reliability of the bulk power electric system in North America through a voluntary, self-regulatory process. EPAct 2005 added section 215 to the FPA, which provides for the creation of an Electric Reliability Organisation (ERO) to be the organisation responsible for establishing and enforcing reliability standards for the bulk power system in North America. In 2006, FERC certified NERC as the ERO. The ERO oversees an enforcement programme that includes compliance audit monitoring and reliability readiness review.

In 2007, FERC strengthened the reliability regime by approving mandatory reliability standards for the bulk electric system proposed by the ERO, approving delegation agreements between the ERO and eight regional entities and creating a ninternal Office of Electric Reliability. The mandatory reliability standards apply to entities designated by NERC as users, owners and operators of the bulk electric system. Both monetary and non-monetary penalties may be imposed for violations of these standards. In July 2014, a revised definition of the bulk electric system went into effect. The definition expanded the scope of facilities that form part of the bulk electric system to facilities operated at or above 100 kV, thereby covering entities that own or control these facilities with certain limited exceptions. However, NERC developed a risk-based assessment and registration initiative intended to reduce regulatory burden and align compliance obligations with issues that pose a greater potential impact to reliability. Additional NERC reliability initiatives include standards to minimise potential disruption from geomagnetic disturbance events as well as to create cyber security standards to protect operational infrastructure.

In addition, the replacement of coal-fired, nuclear or other conventional generation resources with natural gas-fired or variable energy resources has affected grid reliability. As such, grid operators, such as RTO and ISOs, are developing approaches to effectively manage capacity during hours of peak demand, as well as manage overgeneration during off-peak hours.

For instance, PJM, the RTO tasked with administering the transmission grid and energy and capacity markets for the Mid-Atlantic region, implemented a revised auction model for capacity called the ‘Capacity Performance Resource’ model intended to improve overall reliability. The model was created after the ‘Polar Vortex’ in the winter of 2014 in which natural gas shortages resulted in the failure of multiple generating units. The Capacity Performance Resources structure contains bonus and penalty payments that are structured to provide greater assurance that energy and reserves will be available during instances of peak demand created as a result of emergency operating conditions and to incentivise participating generators to receive higher capacity payments. Additionally, the PJM structure implicitly requires that these generators utilise the additional capacity revenue stream to, in turn, invest in equipment modernisation and adaptations to a diversified supply mix. Ultimately, according to a NERC report following Winter Storm Uri in Texas during February of 2021 , ‘natural gas-electric infrastructure interdependencies remain unsolved … despite the actions taken before and after [a prior weather event impacting Texas in 2011]’. The NERC assessment also found that generators can be penalised during a Performance Assessment Interval if PJM determines that the generator did not meet demand in accordance with the higher capacity payments.

Technological developments, such as improvements to grid forecasting and the development of smart grid technology, will likely assist grid operators in providing the flexibility needed to address the challenges presented by variable resources and decreased generation capacity from more traditional resources.

Law stated - 27 January 2023

REGULATION OF ELECTRICITY UTILITIES – DISTRIBUTION

Authorisation to construct and operate distribution networks

What authorisations are required to construct and operate distribution networks?

Similar to generation siting, distribution is regulated primarily at the state level.

Law stated - 27 January 2023

Access to the distribution grid

Who is eligible to obtain access to the distribution network and what requirements must be met to obtain access?

Specific procedures for connection to the distribution grid vary from state to state. However, state laws generally provide that distributors cannot deny service that is in the public interest.

Law stated - 27 January 2023

Government distribution network policy

Are there any governmental measures to encourage or otherwise require the expansion of the distribution network?

Specific government measures to encourage or require the expansion of the distribution network vary by state.

Law stated - 27 January 2023

Rates and terms for distribution services

Who determines the rates or terms for the provision of distribution services and what legal standard does that entity apply?

The Federal Energy Regulatory Commission (FERC) has jurisdiction over transmission of electric energy in interstate commerce by public utilities, regardless of the voltage level of the delivery facilities. Section 201 of the Federal Power Act (FPA) reserves regulatory authority over all facilities used in the local distribution of electricity to the state utility commissions. FERC, in Order No. 888, promulgated a seven-factor functional test for the case-by-case determination of the jurisdictional separation between FERC-jurisdictional interstate transmission service (including service over low-voltage distribution lines) and state-jurisdictional local distribution service, and FERC generally defers to the states' application of this test. The functional test looks at:

- the proximity of the facilities to retail customers;
- whether the facilities are radial in character;

- whether power flows into or out of the facilities;
- whether power entering the facilities is transported to another market;
- whether power is consumed in a defined area;
- whether the facilities include meters to measure power flow into the facilities; and
- the voltage of the power flowing through the facilities.

FERC determines the rates, terms, and conditions of transmission service in interstate commerce (including service over low-voltage facilities) under the FPA's just and reasonable standard based on cost-of-service principles. Where retail customers buy electricity from a wholesale provider, and the electricity is then delivered over distribution facilities by the load-serving entity, the state determines the rates, terms, and conditions of such distribution service. Because distribution services are considered to be a natural monopoly, state public utility commissions generally review tariffs for distribution services proposed by the utilities via a traditional cost-of-service rate making inquiry. State utility commissions generally approve the tariffs submitted by utilities if they are just and reasonable. The tariffs offered by various utilities will typically vary, even within a state.

Law stated - 27 January 2023

REGULATION OF ELECTRICITY UTILITIES – SALES OF POWER

Approval to sell power

What authorisations are required for the sale of power to customers and which authorities grant such approvals?

The Federal Energy Regulatory Commission (FERC) has jurisdiction over sales of power at wholesale in interstate commerce other than sales by federal or state governmental bodies and rural cooperatives that are indebted to the Rural Utilities Service (RUS) or cooperatives that sell less than 4 million megawatt hours of electricity per year. Retail sales of electricity are regulated at the state level, with variation from state to state.

Law stated - 27 January 2023

Power sales tariffs

Is there any tariff or other regulation regarding power sales?

Tariffs and contracts pursuant to which public utilities sell power generally must be filed with FERC (wholesale sales) or the applicable state public utility commission (retail sales) before service commences to allow the applicable regulatory entity an opportunity for review, as well as for public notice and comment. Under the Federal Power Act of 1935 (FPA), FERC has jurisdiction over wholesale rate making and is charged with assuring the rates, terms, and conditions pursuant to which public utilities offer wholesale power sales are 'just and reasonable'.

FERC permits wholesale sales of power at market-based rates if the seller demonstrates a lack of market power by passing a series of horizontal and vertical market screens. FERC has commenced investigations to determine whether utilities should retain their authority to sell power at market-based rates after finding that certain utilities did not pass at least one of the screening tests. In response, several utilities voluntarily agreed to implement cost-based rate caps in the areas where FERC found a presumption of market power and revoked the market-based rate authority of a utility.

Sellers of wholesale power that have applied for and received FERC approval to sell power pursuant to a market-based rate tariff can thereafter enter into new power sales contracts and transactions without filing the contracts before commencing service. Instead, such sellers file quarterly reports of their power sales contracts and transactions under their market-based rate tariff. In the absence of a showing of a lack of market power, FERC regulates the rates for wholesale sales under cost-of-service rate-making principles, and each new contract must be filed with FERC before the commencement of service.

Unlike the situation with respect to transmission tariffs, FERC does not generally dictate specific non-price terms and conditions in wholesale power sales contracts but does dictate specific non-price terms and conditions in the market-based rate tariff. The regulatory structure allows complaints to be filed challenging contracts or reported power sales transactions as being unjust, unreasonable, unlawful or discriminatory.

Retail sales are regulated at state level, with significant variation from state to state. In the absence of a competitive retail market, retail rates are typically established based on cost of service.

Law stated - 27 January 2023

Rates for wholesale of power

Who determines the rates for sales of wholesale power and what standard does that entity apply?

Section 201 of the FPA grants FERC exclusive regulatory authority over the wholesale sale of electricity in interstate commerce by jurisdictional entities. The state utility commissions retain regulatory authority over wholesale sales of electricity by purely intrastate wholesale sales (in practice, this class is limited to wholesale sales in Alaska, Hawaii and the Electric Reliability Council of Texas), as well as wholesale sales by non-jurisdictional entities such as rural electric cooperatives, municipal utilities, and state- or federally created utilities.

FERC's exclusive regulatory authority was reaffirmed in a recent decision by the US Supreme Court that invalidated a state incentive programme that provided a guaranteed income to new natural gas-fired generating facilities to ensure the facility would clear the wholesale capacity auction operated by the regional transmission organisation. A unanimous US Supreme Court struck down the programme, finding that subsidy artificially suppressed wholesale power prices, and therefore infringed on FERC's exclusive authority to regulate wholesale sales of electricity in interstate commerce.

The FPA grants FERC authority over all jurisdictional wholesale sales of electricity to ensure that wholesale rates are just, reasonable and not unduly discriminatory or preferential. Although traditionally FERC had employed a cost-of-service rate making inquiry when reviewing wholesale rates to realise this statutory mandate, FERC has also allowed the market to determine wholesale power rates where it has found that the seller and its affiliates lack or have mitigated vertical or horizontal market power, and have adequately restricted affiliate transactions with captive customers. Once FERC approves a jurisdictional entity's generic market tariff, the jurisdictional entity is free to negotiate with other parties in the marketplace over the specific rate charged for the wholesale sale without having to seek FERC approval of the agreement before commencing service.

Law stated - 27 January 2023

Public service obligations

To what extent are electricity utilities that sell power subject to public service obligations?

At the retail level, electric utilities have traditionally operated under an obligation to serve. In exchange for what is generally an exclusive service territory and an opportunity to recover prudently incurred expenses through cost-based rates, utilities are obliged to provide service to all customers in that service territory, as well as to plan adequately for the future needs of customers. In states that adopt retail competition, certain electric utilities may still retain an obligation to provide service to customers who do not select a competitive supplier.

FERC has recognised that wholesale electricity sales are generally governed by private contract, rather than by regulatory order or an express obligation to serve.

Law stated - 27 January 2023

REGULATORY AUTHORITIES

Policy setting

Which authorities determine regulatory policy with respect to the electricity sector?

A number of government agencies are involved in different aspects of the regulatory policies governing electricity. At the federal level, Congress ultimately determines the direction of national energy policy through legislation, but it delegates broad authority to implement legislative mandates to the Federal Energy Regulatory Commission (FERC), the Department of Energy and other administrative agencies. At the state level, electric utilities are regulated by public utility commissions (PUCs).

Law stated - 27 January 2023

Scope of authority

What is the scope of each regulator's authority?

FERC has authority to regulate sales of wholesale power and transmission in interstate commerce and to grant and administer licences for hydroelectric plants on navigable waters. Under the Public Utility Holding Company Act of 2005 (PUHCA 2005), FERC also has authority to grant exempt wholesale generator (EWG) status and foreign utility company (FUCO) status. FERC exercises authority under the Public Utility Regulatory Policies Act with respect to qualifying small power production facilities and cogeneration facilities (QFs).

FERC has jurisdiction over the disposition of assets subject to its jurisdiction, including through mergers, asset divestitures, corporate reorganisations and other transactions in which there is a change in the control of jurisdictional assets. FERC also has oversight authority with respect to the issuance of securities (except if regulated by a state) and interlocks among the officers and directors of public utilities and financial institutions, or the utility's suppliers of electrical equipment. Public utilities under FERC's jurisdiction are subject to various requirements with respect to accounting and record retention and are required to satisfy various reporting requirements.

Under PUHCA 2005, FERC has increased oversight over, and access to, the books and records of public utility holding companies and their subsidiaries and affiliates to the extent that such books and records pertain to FERC-jurisdictional rates or charges. Any service company in a holding company system providing non-power goods and services to an affiliated FERC-jurisdictional public utility or natural gas company must file annual reports disclosing detailed information about their businesses. Public utility holding companies may seek exemptions and waivers from these regulatory requirements. However, an automatic exemption from all of the requirements is available to companies that are holding companies solely with respect to ownership of EWGs, QFs or FUCOs. In addition, single-state holding companies are entitled to a waiver from some, but not all, of the requirements but must seek the waiver from FERC.

The NRC licenses the construction and operation of nuclear power plants and other nuclear facilities to ensure the protection of public health and safety. The Atomic Energy Act governs the use of nuclear materials by both military and civilian entities, requires that all nuclear facilities be licensed, and establishes compensation for, and limits damages arising from, nuclear accidents. The NRC has developed detailed regulations and guidelines concerning all aspects of the operations of a nuclear power plant.

State PUCs regulate terms and rates for retail sales and delivery of electricity. PUCs are charged with ensuring that the public has access to safe, reliable utility service at reasonable rates and, thus, also have authority over at least some aspects of the organisation and finances of public utilities. Many PUCs also have authority to make siting decisions for transmission lines and generation facilities. However, in other states, siting decisions are delegated to other agencies.

Many local governments operate municipal utilities to provide electric service to their local communities. While the majority of municipal utilities serve smaller communities, several large cities, such as Los Angeles, San Antonio, Seattle and Orlando, operate publicly owned electric utilities. City councils and boards of elected or appointed officials generally govern municipal utilities.

The Rural Utilities Service (RUS) promotes electrification of rural America by providing financing to local cooperatives. Electric cooperatives are governed by their member customers through an elected board of directors. Cooperative boards set rates as well as determine the types of services available and other policies. PUCs regulate some aspects of cooperatives' activities in approximately 20 of the states in which cooperatives operate (The Regulatory Assistance Project, Electricity Regulation in the US: A Guide, page 24 (March 2011)). Rural cooperatives with loans outstanding from the RUS are also obliged to comply with various loan covenants and regulations that affect their operations. The Tennessee Valley Authority (TVA), formed in 1933 as a wholly owned corporation of the US government, generates and transmits power in seven south-eastern states. Under the Consolidated Appropriations Act of 2005, the TVA is governed by a nine-member, part-time board, appointed by the president and confirmed by the Senate to serve staggered five-year terms .

The four federal power marketing administrations (PMAs) (the Bonneville, Southeastern, Southwestern and Western Area Power Administrations – the Alaska Power Administration was privatised in 1998) operate as agencies of the Department of Energy. The PMAs do not own or operate generating facilities but market the power produced by federally owned hydro-facilities. Administrators of the PMAs have authority to set rates and must certify that rates are 'consistent with applicable law' and 'the lowest possible rate to customers consistent with sound business principles'.

Law stated - 27 January 2023

Establishment of regulators

How is each regulator established and to what extent is it considered to be independent of the regulated business and of governmental officials?

FERC and NRC are each authorised to have five commissioners. The president nominates and Congress confirms commissioners for FERC and the NRC for staggered five-year terms. The president also appoints one commissioner to serve as chair of each commission. No more than three commissioners may belong to a single political party. Furthermore, FERC and NRC decisions are not subject to review by the president, Congress, the DoE or other agencies.

State PUCs vary in size, but generally have between three and seven commissioners. It is common to limit the number of commissioners who may be from a single political party. In most states, the governor appoints commissioners, with approval by the upper house of the state legislature, for staggered five- or six-year terms. In some states, commissioners are elected. The governor typically designates one commissioner to serve as chair of the commission, although in some states the commissioners select the chair. State commissioners are generally subject to restrictions similar to those of their federal counterparts with respect to employment, investments and ex parte communications.

Law stated - 27 January 2023

Challenge and appeal of decisions

To what extent can decisions of the regulator be challenged or appealed, and to whom? What are the grounds and procedures for appeal?

Decisions by FERC can be challenged on both substantive and procedural grounds. Within 30 days of a final decision or order by FERC, a party to the proceeding (either the applicant or an intervenor) may file a request for rehearing with FERC. Within 60 days of issuance of the decision on rehearing, an aggrieved party may request a review of FERC decisions by a US Court of Appeals. In general, the Court of Appeals will not consider any objections not raised in the request for rehearing to FERC. US Supreme Court review is possible upon a showing of compelling cause (eg, a conflict between decisions of two or more circuits of the US Court of Appeals or often where a major rule issued by a federal agency is invalidated by a Court of Appeals). PUC decisions can also be challenged through judicial appeals in state courts, or if the decision violates federal law, a cause of action could be brought in federal court (subject to various limitations).

Law stated - 27 January 2023

ACQUISITION AND MERGER CONTROL – COMPETITION

Responsible bodies

Which bodies have the authority to approve or block mergers or other changes in control over businesses in the sector or acquisition of utility assets?

Federal Energy Regulatory Commission (FERC) approval is required before the disposition of any facilities subject to its jurisdiction under the Federal Power Act (FPA) of a value in excess of US$10 million, as well as direct or indirect mergers or consolidations of public utility facilities with those of any other person regardless of the value of the facilities. Facilities under FERC’s jurisdiction under section 203 of the FPA include facilities used for transmission or sale of electric power in interstate commerce (including ‘paper facilities’ such as contracts for wholesale power sales) as well as generation assets used for wholesale sales. FERC review is required if there is a change in ‘control’ of jurisdictional facilities. In general, FERC will presume that a transfer of less than 10 per cent of a public utility’s holdings is not a transfer of control.

Any holding company that owns an entity selling power at wholesale or transmitting electric energy must obtain FERC authorisation to acquire securities valued in excess of US$10 million in any entity that sells at wholesale or transmits electric energy or to otherwise merge with any such entity with a value in excess of US$10 million. In addition, the transfer of specific assets or licences may necessitate additional reviews. For example, the transfer of a nuclear generating facility requires NRC approval.

FERC has established blanket authorisations for a variety of transactions. For example, transactions in which a holding company that includes a transmitting utility or an electric utility seeks to acquire or take any security of a transmitting utility or company that owns, operates or controls only facilities used solely for transmission in intrastate commerce or sales of electric energy in intrastate commerce, or facilities used solely for local distribution or sales of electricity at retail, are automatically authorised. Transactions involving internal corporate reorganisations that do not present cross-subsidisation issues or involve a traditional public utility with captive customers or that owns transmission assets are also automatically authorised. Acquisitions by holding companies of non-voting securities do not require prior FERC authorisation. Acquisitions by holding companies of voting securities do not require prior FERC authorisation if, after the acquisition, the acquiring holding company will directly or indirectly own less than 10 per cent of the outstanding voting securities. Moreover, acquisitions by holding companies of foreign utility companies do not require FERC authorisation except where the holding company or its affiliates have captive customers in the United States, in which case the holding company must make certain representations that the transaction will not adversely affect such captive customers.

The Federal Trade Commission (FTC) and the Antitrust Division of the Department of Justice (DOJ) (collectively, the antitrust agencies) are the primary agencies with authority to enforce US antitrust and fair trade practice laws. The antitrust agencies can review the antitrust implications of proposed mergers and certain acquisitions of assets or securities in the electricity sector under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the HSR Act). Their authority is not specific to any one industry, but they, in addition to FERC and the states, may challenge in court anticompetitive practices in the electricity sector. The antitrust agencies' authority comes from laws including the HSR Act, the Federal Trade Commission Act (FTCA), the Clayton Act and the Sherman Act.

Finally, individual state regulatory bodies often must approve an acquisition or divestiture of utility companies or assets in that state, pursuant to state law. The procedures and standards for that review vary from one state to another.

Law stated - 27 January 2023

Review of transfers of control

What criteria and procedures apply with respect to the review of mergers, acquisitions and other transfers of control? How long does it typically take to obtain a decision approving or blocking the transaction?

In considering an application to merge, acquire or transfer control of assets under section 203 of the FPA, FERC must determine whether the proposed transaction is in the public interest. As provided in FERC's merger policy statement in Order No. 592, such determination requires an evaluation of the proposal's effect on competition, rates and regulation. FERC must also consider whether proposed acquisitions will result in cross-subsidisation of any non-utility company in the same holding company system or in any pledge of utility assets for the benefit of any company in the same holding company system. FERC may approve an acquisition resulting in such cross-subsidisation or pledge of utility assets only if FERC determines that such cross-subsidisation or pledge will be consistent with the public interest.

With respect to assessing a proposed transaction's impact on competition under section 203 of the FPA, FERC's merger policy statement generally requires that applicants provide it with a competitive screen analysis (horizontal or vertical, as appropriate) showing the effect of the proposed disposition on relevant products in relevant geographical markets. The competitive screen analysis must:

- identify the relevant products (such as economic capacity and available economic capacity) and the geographical markets in which the competitive effects of the acquisition can be analysed;
- determine the market shares of all participating firms and the degree of concentration in the market, both before and after the proposed acquisition; and
- identify the market characteristics that will influence the ability of the combining entities to adversely affect competition, such as barriers to entry into the relevant market by other firms.

Market power is measured in part using the Herfindahl-Hirschman Index (HHI) measure of market concentration. The current DOJ and FTC guidelines have higher HHI thresholds than FERC for determining market concentration, making it less likely for a particular market to be deemed 'moderately concentrated' or 'highly concentrated' based on HHI alone. However, FERC's appendix A horizontal electric utility merger analysis does not follow the DOJ and FTC guidelines, but instead uses a more stringent standard to measure market concentration.

FERC evaluates both the magnitude of increases in market power and overall post-transaction concentrations of market power to identify those transactions that are likely to have an adverse impact on competition. Applicants, however, are allowed to identify in their analysis other factors that may help to negate the presumption, such as benefits that the proposed acquisition will bring.

FERC will provide expedited consideration of completed applications for approval of transactions that are not contested, do not involve mergers and are consistent with FERC precedent, as well as uncontested transactions involving a disposition of only transmission facilities under the functional control of a FERC-approved regional transmission organisation (RTO) or independent system operator (ISO); transactions that do not require a competitive screen analysis; and internal corporate reorganisations that do not present cross-subsidisation issues. For transactions that do not qualify for such expedited action, FERC is required to act within 180 days after the filing of an application, unless FERC determines there is good cause for requiring additional time, in which case the time for action may be extended up to 180 days. For example, FERC might extend the time frame for action if it finds that an evidentiary hearing is needed to determine whether the transaction is in the public interest.

The antitrust agencies may review the antitrust implications of mergers and certain acquisitions of assets or securities before those transactions are consummated under the HSR Act. The FTC promulgated a set of detailed rules that govern the pre-merger notification that must be filed in connection with such a transaction. A transaction subject to the HSR Act may not close before the expiry of the applicable waiting period, which is initially 30 days. If the antitrust agency decides to open a second-phase investigation, the waiting period will be extended until the 30th day following substantial compliance with a second request. If the reviewing antitrust agency determines that the transaction may harm competition in a relevant market, it may seek a preliminary injunction in a federal court, which would bar the consummation of the merger until the court (in a DOJ action) or the FTC (in an FTC action) has an opportunity to decide whether to seek a permanent injunction following a full trial. Such a preliminary injunction does not issue automatically; in deciding whether to preliminarily enjoin a merger, the courts give heavy consideration to whether the antitrust agency will eventually be able to prove its case at trial.

If the reviewing antitrust agency determines that the transaction may harm competition in a relevant market, such issues must be resolved before the transaction can proceed. In the electric sector, FERC (not the antitrust agencies) generally takes the lead in addressing any anticompetitive issues presented by a proposed transaction. Under the HSR Act, however, merging entities in such a situation often enter into a consent order with an antitrust agency under which the acquiring company agrees to divest a portion of its existing assets or of the assets it will be acquiring.

Finally, individual state regulatory bodies often must approve an acquisition or divestiture of utility companies or assets in that state, pursuant to state law. The procedures and standards for that review vary from one state to another.

Law stated - 27 January 2023

Prevention and prosecution of anticompetitive practices

Which authorities have the power to prevent or prosecute anticompetitive or manipulative practices in the electricity sector?

The federal agencies that are primarily concerned with anticompetitive practices in the wholesale electricity sector are FTC, DOJ, FERC and the Commodity Futures Trading Commission (CFTC). State utility commissions and attorneys general ordinarily, but not exclusively, focus on such practices in the retail electric sector.

Law stated - 27 January 2023

Determination of anticompetitive conduct

What substantive standards are applied to determine whether conduct is anticompetitive or manipulative?

FERC enforces compliance with tariffs or contracts in an effort to assure service is 'non-discriminatory' and charges are 'just and reasonable'. The Energy Policy Act (EPAct 2005) amended the FPA to prohibit buyers or sellers of interstate wholesale electric energy or transmission services from knowingly providing a federal agency with false information or from using any manipulative or deceptive device or contrivance in violation of FERC regulations. Further, a seller of electric products and services applying for market-based rate authority must show it does not possess unmitigated market power in the affected markets.

The CFTC has authority to ensure futures and options markets operate fairly and orderly under the Commodity Exchange Act. This authority overlaps FERC's authority to the extent conduct involves trading and hedging activities of electricity and similar commodities. In 2010, the Dodd–Frank Wall Street Reform and Consumer Protection Act went into effect, which overhauled much of the US financial regulatory system and conferred additional authority to the CFTC. The CFTC issued two final orders – the first in 2013 and the second in 2016 – exempting all RTO and ISO system operators from CFTC regulation. The exemption covers certain financial transmission rights, energy transactions, and forward capacity transactions sold pursuant to an RTO or ISO governing tariff if the transaction is related to the allocation of physical electric energy and carried out by an 'appropriate person' (ie, those individuals or entities meeting certain sophistication or financial thresholds). However, the exemption does not apply to the CFTC's anti-fraud or anti-manipulation regulation.

The FTC has concurrent authority, pursuant to the FTCA, to enjoin 'unfair methods of competition'. The FTC's authority extends to acquisitions that tend to substantially lessen competition, as well as to price discrimination and other anticompetitive actions. The FTC also has authority to directly protect consumers from any 'unfair or deceptive' practice, defined as an act 'that causes or is likely to cause substantial injury to consumers that is not reasonably avoidable by consumers themselves and not outweighed by countervailing benefits to consumers and to competition'.

The FTC and the DOJ have concurrent power to prosecute violations of the other federal antitrust statutes. States and private parties may also bring actions under federal and state antitrust laws. This was recently reaffirmed by the US Supreme Court, which ruled that the federal Natural Gas Act of 1938 does not pre-empt state antitrust laws, meaning a private party may bring state antitrust claims for alleged pipeline price manipulation.

Section 1 of the Sherman Act prohibits 'agreements, conspiracies or trusts in restraint of trade'. Under the Sherman Act, some agreements (such as agreements of horizontal price fixing or territorial division) are determined to be per se illegal because the conduct of the agreement is overwhelmingly considered to be harmful. Other agreements that might be, but not necessarily, harmful are analysed under the rule of reason, requiring the plaintiff to prove that the agreement caused economic harm. Section 2 of the Sherman Act prohibits monopolies, specifically targeting anticompetitive conduct that creates or maintains market domination. The Clayton Act bars certain types of price discrimination and tying arrangements when they lessen competition.

Law stated - 27 January 2023

Preclusion and remedy of anticompetitive practices

What authority does the regulator (or regulators) have to preclude or remedy anticompetitive or manipulative practices?

If a proposed tariff or contract is found by FERC to be unjust and unreasonable, FERC will order mitigating revisions. FERC may require the sellers to refund the difference between the rates collected and the rates FERC determines are just and reasonable, beginning with the date the investigation was initiated. In order for a seller to be eligible to sell wholesale energy at market-based rates (instead of at cost-based rates), it must demonstrate to FERC that it and its affiliates lack (or have mitigated) market power. FERC can refuse to grant market-based rate (MBR) authority to an applicant that fails to show it does not possess market power. At any point, FERC has the authority to revoke market-based rate authority upon a determination that the seller possesses market power. In addition, FERC maintains the ability to revoke prior grants of MBR authority if the company's behaviour involves fraud, deception or misrepresentation.

Once initially granted MBR authority, sellers are required to take additional measures in order to maintain the market-based rate authority. For example, sellers who control more than 500 megawatts of generation in any region of the country must file updates every three years to demonstrate their continued lack of market power. Also, such an electrical provider must notify FERC within 30 days of any significant change that might affect its qualification for market-based rates. Further, FERC has enacted market behaviour rules to govern sellers' conduct in the wholesale market. These rules address unit operations, communications, price reporting and record retention.

On an ongoing basis, FERC has authority under section 206 of the FPA to regulate markets and protect them against anticompetitive activity. Section 206 grants FERC authority to initiate an investigation, upon its own motion or third-party complaint, regarding whether any rate charged by a utility for any transmission or sale is 'unjust, unreasonable, unduly discriminatory or preferential'.

EPAct 2005 amended the FPA to allow for increases in the maximum penalty amounts for violations of the FPA. FERC is now able to assess civil penalties and fines of approximately US$1 million or imprisonment for not more than five years, or both, for wilful and knowing violations, through acts or omissions, of any section of the FPA. Also, EPAct 2005 provides for civil penalties of approximately US$1 million per violation per day to be assessed for violations of regulations located in section II of the FPA after notice and the opportunity for a public hearing. While FERC has used its penalty authority sparingly in the past, FERC has been acting more forcefully on enforcement matters pursuant to its expanded authority. In fiscal year 2022, FERC's enforcement division obtained settlements to assess civil penalties in the amount of approximately US$23.59 million for violations of the FPA and ordered disgorgement of unjust profits in the amount of approximately US$33.92 million. Since 2007, FERC has assessed almost US$813.5 million in civil penalties and over US$553.9 million in disgorgement (not including several significant pending matters).

The FTCA authorises the FTC to issue 'cease and desist' orders requiring electric utilities to refrain from prohibited unfair trade practices and may assess civil penalties for violations, up to US$11,000 per violation per day. Violations of sections 1 and 2 of the Sherman Act may result in fines up to US$100 million for corporations, or by imprisonment of up to 10 years, or both. In addition, under the antitrust acts, private parties are able to bring enforcement actions to address unfair trade practices in the electric sector, including tying arrangements, price squeezes and denial of access to essential facilities.

Law stated - 27 January 2023

INTERNATIONAL

Acquisitions by foreign companies

Are there any special requirements or limitations on acquisitions of interests in the electricity sector by foreign companies?

Several current or former US utilities are or have been owned by foreign parties. Investors should be mindful of current US regulatory and political attitudes toward foreign investment in the energy sector.

The Committee on Foreign Investment in the United States (CFIUS) is an inter-agency committee chaired by the Secretary of the Treasury and includes as members the heads of the Departments of Justice, Homeland Security, Commerce, Defense, State, and Energy, as well as of the Office of the US Trade Representative and Office of Science and Technology Policy. CFIUS has long been responsible for reviewing certain foreign investment transactions for national security concerns and had jurisdiction to review any transaction that could result in control of a US business by a foreign person.

In August 2018, the United States enacted the Foreign Investment Risk Review Modernization Act (FIRRMA), which reformed and modernised the CFIUS review process and represents the first update to the CFIUS statute in more than a decade. Generally, FIRRMA broadened the scope of 'covered transactions' subject to CFIUS's jurisdiction to capture new categories of transactions not previously covered. Under FIRRMA and its implementing regulations, CFIUS now also has jurisdiction to review (1) certain non-controlling, non-passive foreign investments in certain types of US businesses, including those involved in specified ways with ‘covered investment critical infrastructure or critical technologies and (2) certain real estate transactions. Covered investment critical infrastructure are systems and assets, whether physical or virtual, specifically enumerated in Appendix A to the CFIUS regulations (31 CFR Part 800). While historically the definition of critical infrastructure has been applied to ports and oil companies, it is now clear that electricity generating and transmission or distribution facilities would also be captured under the definition of covered investment critical infrastructure. As a result, FIRRMA confirms the broad range of energy and infrastructure transactions that may be covered by CFIUS’s jurisdiction, and intensifies the screening for certain transactions.

In addition to broadening CFIUS’s jurisdiction, FIRRMA also affected other CFIUS requirements and processes. While CFIUS remains largely a voluntary process (which it was entirely pre-FIRRMA), post-FIRRMA, a CFIUS filing is mandatory under certain circumstances. One of the two mandatory filing requirements is that acquisitions of (1) 25 per cent or more of the voting shares of (2) a US business operating covered investment critical infrastructure (or other specified types of businesses, including those involved with critical technologies as defined in the CFIUS regulations) by (3) an acquirer that is at least 49 per cent-owned by a non-US government will, with few exceptions, result in a mandatory notification obligation to CFIUS. The other mandatory filing requirement concerns acquisitions of or investments in US businesses that deal in critical technologies, irrespective of the percentage interest thresholds. If mandatory, the filing must be made no fewer than 30 days before the transaction’s completion date. Failure to notify CFIUS of a transaction subject to a mandatory filing requirement could result in penalties up to the value of the transaction. Notification to CFIUS, whether voluntary or mandatory, can be made through two types of CFIUS filings under FIRRMA: a short-form ‘declaration’ (introduced under FIRRMA) or a full ‘notice’ (the traditional method). The declaration includes a 30-calendar-day assessment period and overall requires less information from the parties than a full notice. The statutory review period for a notice starts at 45 calendar days, which can be extended into a second 45-calendar-day investigation period for certain transactions. The form itself requires more detail about the parties and the transaction than the declaration.

For nuclear-generating facilities, the Atomic Energy Act generally bars the issuance of a reactor licence to a non-US person. For example, the NRC Atomic Safety and Licensing Board denied a licence for a proposed nuclear project in Maryland because it is 100 per cent owned by a foreign entity. Situations where a foreign company would be able to hold a licence include when it owns up to 50 per cent of an entity whose officers and employees responsible for special nuclear materials are US citizens, or when it owns a US subsidiary that will hold the licence, the foreign company’s stock is ‘largely’ owned by US citizens, and the subsidiary’s officers and employees responsible for special nuclear materials are US citizens. In May 2016, the NRC issued a draft regulatory guide describing the acceptable methods for determining when a nuclear facility is owned, controlled or dominated by an alien, a foreign corporation or a foreign government.

Law stated - 27 January 2023

Authorisation to construct and operate interconnectors

What authorisations are required to construct and operate interconnectors?

No electric transmission lines crossing the US international border may be constructed or operated without a presidential permit. The secretary of energy (through the Department of Energy’s (DOE) Office of Electricity Delivery and Energy Reliability) will issue a permit upon determining that the project is in the public interest. The two primary criteria used to determine if a proposed project is consistent with the public interest are the impact the proposed project would have on the operating reliability of the US electric power supply and the environmental consequences of proposed projects. The DOE must also obtain concurrence from the secretary of state and the secretary of defence before issuing a permit.

The Federal Power Act (FPA) allows exports of electric energy unless the proposed export would impair the sufficiency of electric power supply within the United States or would impede or tend to impede the coordinated use of the US power supply network. Based on these guidelines from the FPA, DOE (again through the Office of Electricity Delivery and Energy Reliability) grants authorisation to export electric energy if it determines that sufficient generating resources exist such that the exporter could sustain the export while still maintaining adequate generating resources to meet all firm supply obligations and the export would not cause operating parameters on regional transmission systems to fall outside of established industry criteria. The DOE must also comply with the National Environmental Policy Act before granting authorisation to export electric energy. No federal permit is required to import electricity into the United States, and no federal permit is required to sell imported electricity, if the sale at issue takes place outside of interstate commerce.

Law stated - 27 January 2023

Interconnector access and cross-border electricity supply

What rules apply to access to interconnectors and to cross-border electricity supply, especially interconnection issues?

Federal regulation of a sale for resale in interstate commerce of imported or domestic electricity will apply if title to the electricity changes hands at a point within the United States. In this case, the seller must apply to Federal Energy Regulatory Commission (FERC) for approval of the rates, terms and conditions of the sale. There are two exceptions. First, in the event the sale for resale in interstate commerce of imported or domestic electricity is conducted by a US government-owned, US state-owned or US municipally owned utility, or is conducted by a US Department of Agriculture Rural Utilities Service-financed rural electric cooperative, there will be no FERC regulation of the sale. Second, there will be no FERC regulation of retail sales of imported or domestic electricity. The state public utility commission may regulate the retail sales of electricity within its border.

Law stated - 27 January 2023

TRANSACTIONS BETWEEN AFFILIATES

Restrictions

What restrictions exist on transactions between electricity utilities and their affiliates?

In October 2008, the Federal Energy Regulatory Commission (FERC) issued Order No. 717, which adopted significant changes to its standards of conduct governing relations between transmission providers for both electricity and natural gas and their affiliates. The rule concentrates on three principles as the way to prevent affiliate abuse. The main elements of this are the independent functioning rule, the no-conduit rule, and the transparency rule.

Independent functioning rule

FERC eliminated completely the concept of energy affiliates as well as the corporate separation approach to separating grid operators from marketing affiliates, two aspects of the old Order No. 2004 rules that had proved difficult to understand and enforce. Instead, the new rules are based on the employee functional approach that was first utilised in industry restructuring orders from the 1980s and 1990s. This approach focuses on an employee's actual function on the job rather than the employee's position in the organisation chart. Thus, whereas under the former rules any employee of a marketing or energy affiliate was prohibited from interacting with transmission function employees, Order No. 717 limits the category of employees who must function independently from transmission operators to those who are actively and personally engaged on a day-to-day basis in marketing functions. By narrowing the focus in this manner, the rule provided needed clarity to supervisors, managers and executives and allowed the free flow of the type of information needed for long-term planning.

No-conduit rule

The no-conduit rule prohibits a transmission provider from using anyone as a conduit for the disclosure of non-public transmission function information to its marketing function employees. This rule covers both information and employees not falling within the scope of the independent functioning rule. For example, although there is no general requirement that lawyers employed by transmission providers need to function independently of the company's marketing function employees, lawyers must, nevertheless, avoid serving as a conduit for passing non-public transmission information to marketing function employees.

Transparency rule

Order No. 717 is also designed to promote transparency through the collection, reporting, and public posting requirements of information that may alert interested persons and FERC to potential acts of undue preference.

Reliability exception

Reflecting the importance of reliability, the order makes an exception to the independent functioning rule and the no-conduit rule for the exchange of information 'pertaining to compliance with reliability standards approved by the Commission' and information 'necessary to maintain or restore operation of the transmission system or generating units, or that may affect the dispatch of generating units'.

Law stated - 27 January 2023

Enforcement and sanctions

Who enforces the restrictions on utilities dealing with affiliates and what are the sanctions for non-compliance?

FERC has authority to impose penalties in the amount of US$1 million per day per violation under sections 316 and 316A of the Federal Power Act of 1935 or to use its rate authority to remedy affiliate abuse. Mechanisms for enforcement and remedies for violations of states' affiliate rules vary.

Law stated - 27 January 2023

UPDATE AND TRENDS

Key developments of the past year

Are there any emerging trends or hot topics in electricity regulation in your jurisdiction?

Reliability concerns amid frequent extreme weather events

In 2021 and 2022, respectively, major winter storms disrupted power grid reliability in the United States. The first, Winter Storm Uri, mainly impacted the state of Texas in February of 2021 . During the period of 15 through 17 February, the weather conditions – persistent frigid temperatures, snow and freezing rain – overwhelmed the isolated Texas power grid. Demand for electricity and residential heating soared as many residents hunkered down, but thermal generating sources (such as natural gas, coal, and nuclear) encountered issues in producing power and transmitting it to end customers. As a result, widespread rolling blackouts were scheduled throughout the Electric Reliability Council of Texas, Inc (ERCOT) region. The ERCOT footprint comprises 90 per cent of Texas ratepayers, more than 25 million customers in all.

Total thermal generation capacity plunged from 70 gigawatts (GW) to 45GW in just a few hours. The extreme supply disruption was largely attributable to weather-induced equipment failures. ERCOT was forced to engage in extreme load-shedding to preserve minimum grid functionality and prevent a complete blackout of the entire ERCOT grid. In advance of the storm, ERCOT forecasted a peak load of 82GW through its scenario analysis. Based on winter supplies, a lion's share of that estimate – 50GW – would be served by natural gas. However, the same factors that caused the increase in forecasted load hindered the production and distribution of gas. In some cases, natural gas power plants could not operate due to frozen instrumentation and pipelines.

Complicating matters, ERCOT was unable to draw on neighbouring grid operators for resources, as it does not fall under Federal Energy Regulatory Commission (FERC) jurisdiction and is not interconnected with the two major interconnections in the US. Following the winter storm, FERC and the North American Electric Reliability Corporation (NERC) conducted joint inquiries in order to assess what faltered and how to bolster the grid going forward in anticipation of future adverse weather events. Namely, the regulatory agencies found that winterisation and weatherproofing practices should be applied to natural gas infrastructure in the state, as well as a broader emphasis on diversifying the portfolio of resources in the state to reduce the reliance on natural gas.

In December 2022, Winter Storm Elliott also brought frigid weather for a period of three days in the PJM Interconnection, LLC (PJM) region. Despite the grid operator sufficiently forecasting the incoming storm and advising for cold weather, electricity use in its footprint was approximately 10 per cent higher than anticipated and some power plants failed to operate as needed, leading to another prolonged period of generation outages in the US during winter. Similar to Winter Storm Uri, FERC and NERC announced that both agencies will conduct a joint inquiry as to the operations of the bulk power system during extreme weather conditions and determine root causes as well as propose solutions for the future.

Generator interconnection queue reforms

Due to a significant – and growing – backlog of new generation projects languishing in interconnection queues, FERC and the regional grid operators initiated rulemaking to streamline and expedite the study process for (largely) renewable resources into the power system. The corresponding queue has reached nearly 1,900 projects awaiting interconnection studies necessary for review pursuant to Tariff-mandated deadlines. In a generator interconnection queue, each proposed project undergoes a system impact study, which models and assesses how the new project would affect the balance and operation of existing grid infrastructure.

As of 2021, renewable projects (including electric storage, both as standalone batteries and as hybrid facilities attached to solar or wind generation) comprised approximately 1357 gigawatts (GW) of the estimated total 1,444GW in interconnection queues. Over 600GW in interconnection requests were added in 2021 alone, indicating a substantial uptick in market activity particularly given the high proportion of renewable projects in the queues. For projects that ultimately achieve operation, the time to conduct a full interconnection study has increased significantly from 2.1 years in 2010 to 3.7 years in 2021. Approximately 73 per cent of projects currently in the queue requested to come online before 2025, which presents a clear mismatch between finishing the interconnection study process and adhering to such commercial deadlines. Among those projects, 13 per cent have executed an interconnection agreement.

Pursuant to its authority vested under section 206 of the Federal Power Act, FERC is currently evaluating how to improve the interconnection queues, namely by: Implementing a 'first-ready, first-served' cluster study process; instituting rigorous site control and commercial readiness requirements; increasing the speed of interconnection queue processing; and incorporating technological advancements into the interconnection process.

PJM pursued its own suite of reforms to the generator interconnection queue process within its footprint. In November 2022, FERC approved those revisions, which will immediately apply to 450 ‘fast-lane,’ high-priority projects and enhance other components of the queue process going forward. The reforms will also add requirements such as commercial readiness deposits and improving site control procedures.

Incumbent utility right of first refusal in play at courts

In December 2022, the attorney general’s office of Texas filed a petition for writ of certiorari at the US Supreme Court to review a ruling issued by the Fifth Circuit court, which found that the existing Texas law granting incumbent transmission companies the first chance to build new power lines is unconstitutional. In the petition, Texas argued that the Fifth Circuit decision could subvert the regulation and oversight of electric utilities by the state. In Texas, electric transmission is not a competitive market and is fully regulated by the state.

Specifically, the ruling follows the enactment of Texas Senate Bill 1938, which aimed to ensure that intrastate transmission lines would be constructed and operated in accordance with evolving demand factors and in optimal locations to serve load. The Fifth Circuit asserted that S.B. 1938 contravened the dormant commerce clause and effectively discriminated against out-of-state transmission developers, since the state law, in practice, precludes any company that does not already operate in the state from building new projects.

Given the increasingly prevalent role of transmission development to support renewable generation, a potential outcome stemming from the Supreme Court petition could furnish increased regulatory certainty in states such as Texas or blunt progress toward building new infrastructure.

Law stated - 27 January 2023

Jurisdictions

Australia	King & Wood Mallesons
Belgium	Linklaters LLP
Bulgaria	Kinkin & Partners
Chile	Pruzzo Ruscica Brotfeld
Ghana	Kimathi & Partners Corporate Attorneys
India	Trilegal
Japan	Nishimura & Asahi
Panama	Anzola Robles & Asociados
Turkey	Boden Law
United Kingdom	Milbank LLP
USA	White & Case