

State of the Markets Report

2016

April 2017

The Office of Enforcement's Division of Energy Market Oversight is pleased to publish the 2016 State of the Markets Report. This report is staff's annual opportunity to share our assessment on natural gas, electric, and other energy markets developments during the past year to better inform the Commission's understanding of current trends.

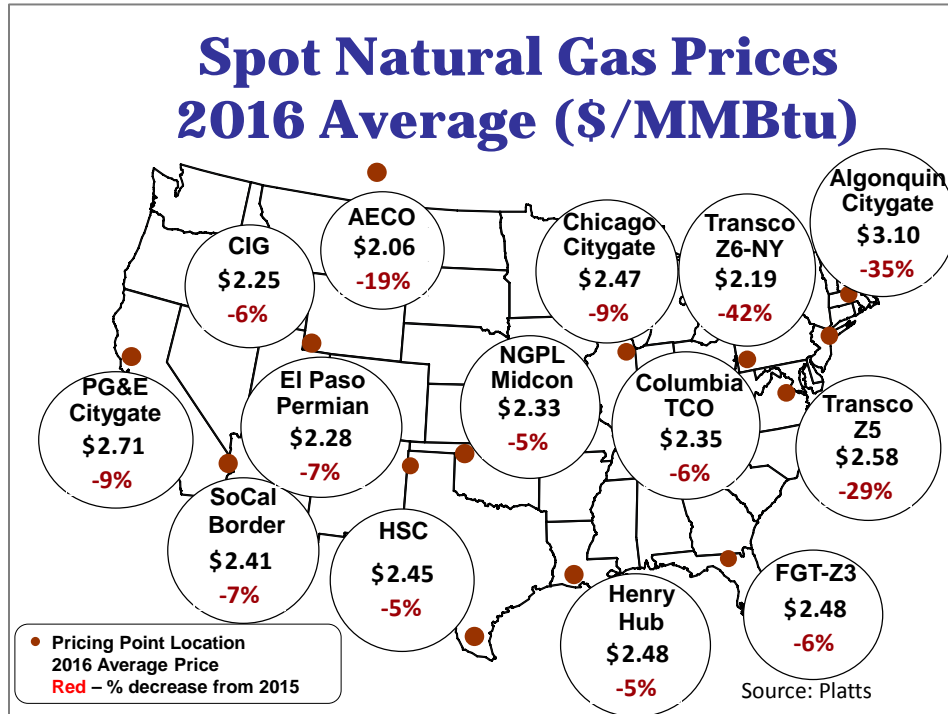
Highlights

- 2016 brought record low natural gas prices and near-record low electricity prices
- Despite a drop in natural gas production, markets remained well supplied, with only moderate growth in demand and record storage inventories
- Electricity generation from natural gas overtook coal generation for the first time on an annual basis
- Renewables continued to account for the majority of electric generation capacity additions
- Net-metering capacity continues to grow nationwide
- The Western Energy Imbalance Market (EIM) continued to expand
- California took action to ensure reliability after the loss of natural gas storage capacity at Aliso Canyon

Overall in 2016 there were record low natural gas prices and near record low electricity prices. Although natural gas production fell for the first time since 2005, flat demand due to above average winter temperatures at the start of the year and high natural gas storage inventories contributed to the low prices. The low natural gas prices further incentivized gas-fired generation in 2016, and for the first time in history, natural gas' share of total electricity generation output overtook coal's on an annual basis.

In the West, California, in coordination with the Commission, continued to work on ensuring adequate natural gas supplies were available to the region given the loss of storage capacity at Aliso Canyon. On the electricity side, the Energy Imbalance Market expanded. In the Northeast, an increase in natural gas pipeline capacity helped move low cost supplies from Appalachia to demand centers along the East Coast and into the Midwest. Adequate natural gas supplies and mild weather had a moderating impact on electricity prices in the East which fell from last year's levels. Meanwhile, the Gulf Coast and Southwest saw increases in natural gas exports via pipeline and LNG cargoes.

Natural Gas Prices Fell to Record Lows in 2016

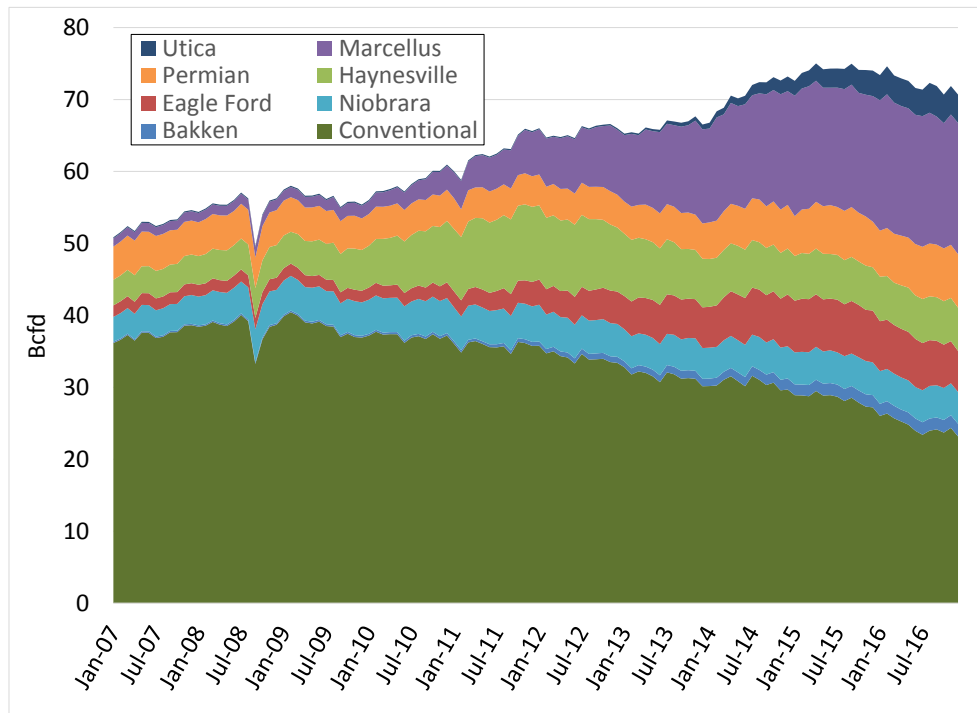


Source: Derived from Platts Daily Price Survey data
 Note: Average of Platts 2016 daily midpoint prices

Natural gas prices fell across the country, with the Henry Hub averaging \$2.48/MMBtu, the lowest level in 20 years. Above average temperatures in the 2015-2016 winter limited natural gas demand during the first three months of the year, leading to robust storage inventories at the start of the 2016 injection season in April, and reduced demand for storage injections through the summer. Prices fell to record lows in the first half of 2016, before climbing through the second half of the year driven by steady domestic demand, rising exports, and a drop in production. By December 31, the Henry Hub price had risen to \$3.68/MMBtu.

Although prices in Boston were the highest in the country in 2016, they were 33 percent below 2015 levels. New York City prices experienced the largest year-on-year decrease, falling 42 percent, and in the fall prices fell to record lows, with Transco Zone 6-NY averaging 32 cents per MMBtu on September 30, as new pipeline infrastructure transporting lower-priced Marcellus Shale gas into New England, New York, and the Mid-Atlantic states became operational. Despite the logistical challenges posed by the loss of storage capacity in California's Aliso Canyon, natural gas prices at the SoCal Border averaged \$2.41/MMBtu throughout the year.

Natural Gas Production Declines in 2016 but Could Rebound in 2017



Source: Derived from Energy Information Administration data

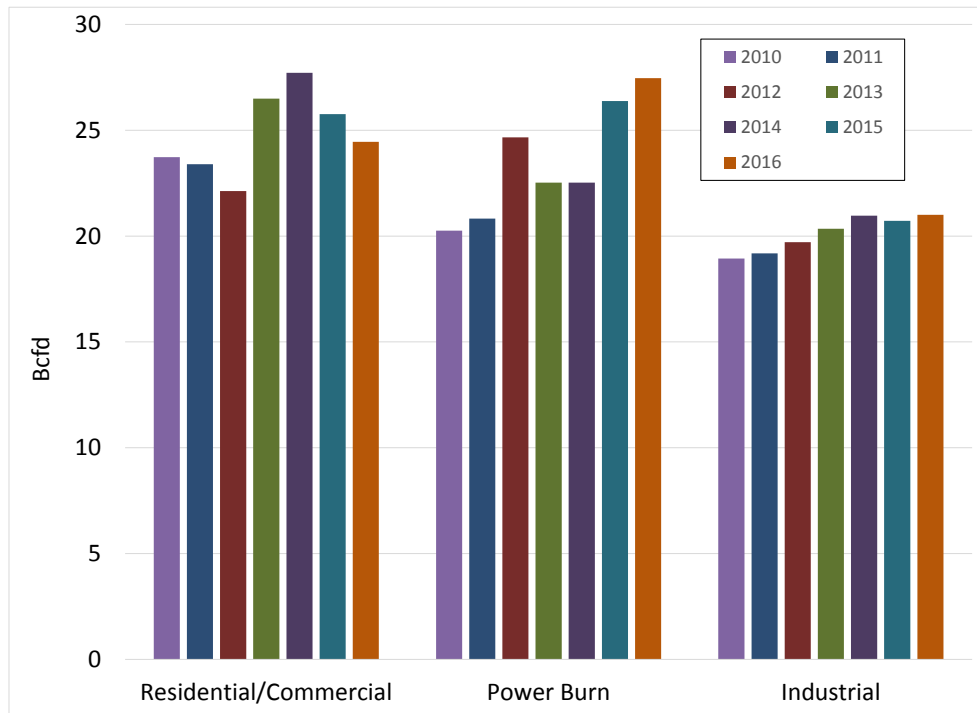
During 2016, U.S. natural gas production fell 2.5 percent, averaging 72.3 Bcfd, the first year-over-year drop since large scale shale production began in 2005. However, as oil prices recovered beginning in the first quarter of 2016, natural gas production rose 11 percent in the oil and natural gas liquids rich Bakken Shale in North Dakota, Marcellus and Utica shales in Pennsylvania, West Virginia, and Ohio, and Permian Basin in Texas and New Mexico. These gains were offset by an estimated 14 percent drop in conventional production, and by production declines in the Eagle Ford Shale in Texas, the Haynesville Shale in Texas and Louisiana and the Niobrara Shale in Colorado and Wyoming.

Natural gas production from the Marcellus and Utica shales accounted for 30 percent of the U.S. total in 2016, due to the prolific nature of these formations, relatively low production costs, and proximity to the large Northeast markets. In addition, new pipeline infrastructure reduced bottlenecks allowing additional gas to reach the demand centers. Total U.S. production is poised to rebound slightly in 2017, driven by a projected 26 percent increase in oil and gas exploration and production investment in North America from 2016 levels.

Helping support the increased production are drilled but uncompleted wells (DUC). EIA estimates that as of December 2016, there were 803 DUC wells in Marcellus and Utica, which accounts for 13 percent of the total U.S. backlog. Other areas with large numbers of DUC wells are the Eagle Ford with nearly 1,300 and the Permian Basin with over 1,700. The number of these wells is significant as they can allow production to recover quickly if prices rise. Additional pipeline infrastructure, including gathering lines and other midstream facilities, may be needed before natural gas from DUC wells can be accessed by demand centers.

Increased production and high levels of demand for natural gas transportation has led to one of the largest increases in natural gas pipeline capacity in U.S. history. In 2016, 7.1 Bcf of FERC jurisdictional pipeline capacity went into service, with 43 percent designed to move natural gas from Appalachia to markets in the Northeast and Midwest. Staff expects the new natural gas pipeline capacity to continue contributing towards shrinking price differentials between regions throughout the U.S., and help keep natural gas prices relatively low.

Powerburn and Industrial Customers Drive Domestic Demand Growth

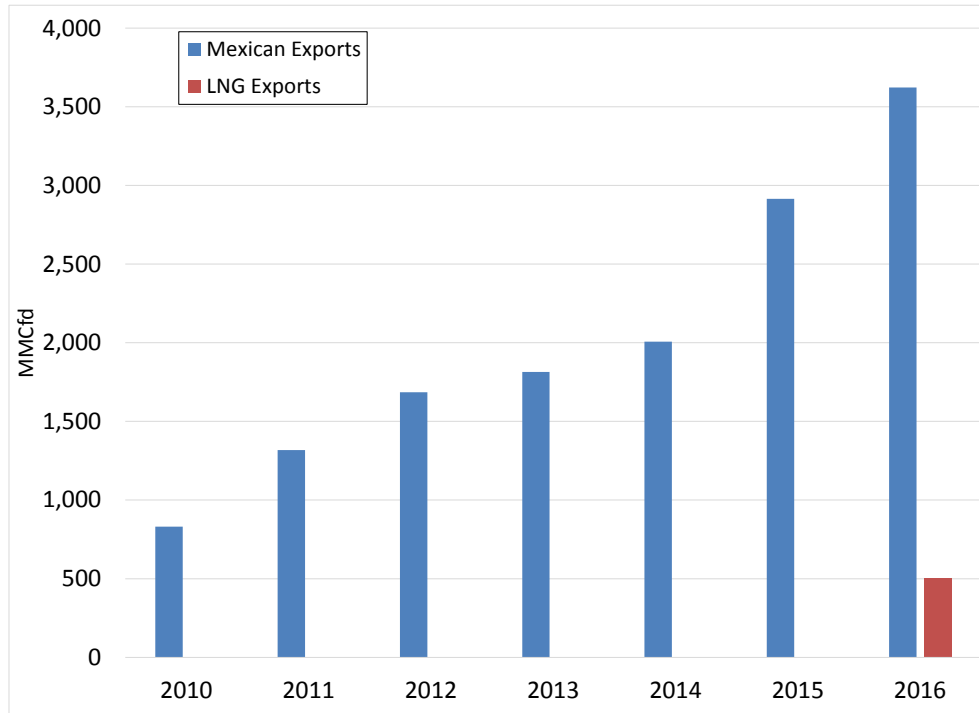


Source: Derived from Bentek Energy data

Following a 17 percent increase in 2015, natural gas demand from power generators rose 4 percent in 2016, averaging 27.5 Bcfd. According to EIA data, for the first time ever natural gas was the primary source of electric generation output on a national level, outpacing coal generation almost every month of the year. States in the Midcontinent, Southeast, and Mid-Atlantic experienced the highest increases in natural gas power burn in 2016. In the Southeast, natural gas demand for power generation rose two percent in 2016, after experiencing a 21 percent increase between 2014 and 2015. Powerburn averaged a combined 7.9 Bcfd in the SERC Reliability Corporation and the Florida Reliability Coordinating Council regions.

Demand from the U.S. industrial sector continued a steady increase as new plants built to consume natural gas entered service. Demand from this sector rose 1.3 percent from 2015, to 21 Bcfd, 17 percent higher than in 2005, before the growth in shale gas production. U.S. residential and commercial demand fell 5.1 percent in 2016, to 24.5 Bcfd, as above average temperatures in January and February contributed to lower space heating needs. Overall domestic demand rose almost 1 percent, to 75.6 Bcfd.

Natural Gas Exports Continue to Grow

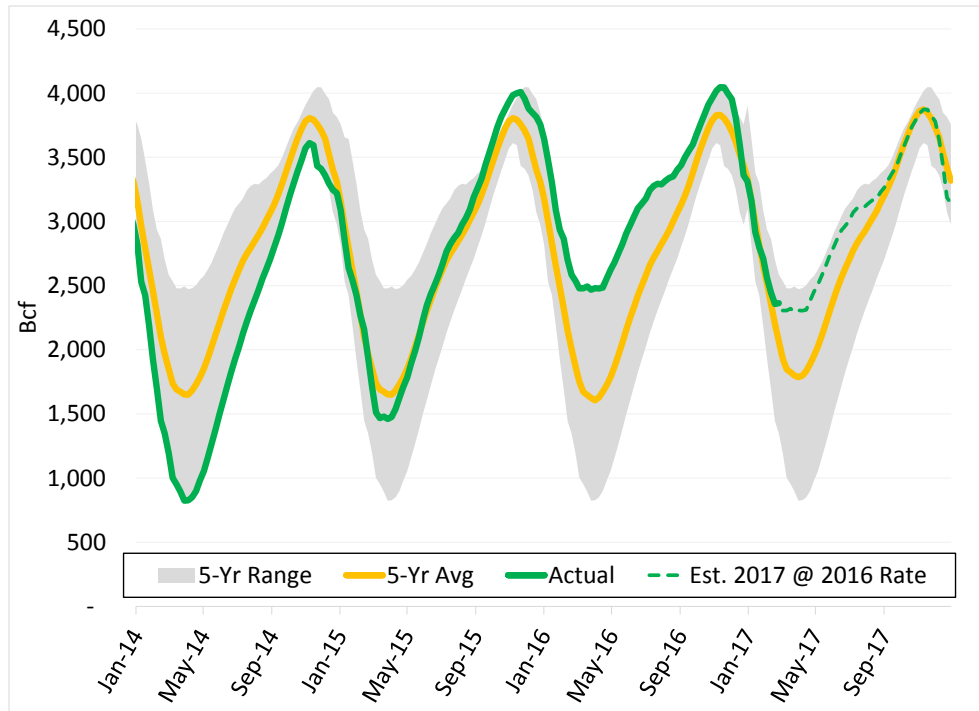


Source: Derived from Bentek Energy and DOE LNG exports data

Pipeline exports to Mexico continued to grow in 2016, averaging 3.6 Bcfd, up 0.7 Bcfd from 2015. This is the sixth year in a row exports to Mexico have increased. Growing demand from power generators and industrial customers in Northern Mexico along with increased pipeline transportation capacity on both sides of the border, are driving the growth in exports. Pipeline capacity into Mexico on the U.S. side totaled 7.3 Bcfd by the end of 2016 and will increase by 3.5 Bcfd in 2017, as three new pipelines are scheduled to go into service.

LNG exports became a source of demand growth in 2016, after the first liquefaction train at Cheniere's Sabine Pass in Louisiana entered service in February, and a second train entered service in the fall. U.S. LNG exports jumped from virtually zero in 2015 to an average of 635 MMcf/d in 2016. At this time, construction is underway at five U.S. LNG export terminals, with expected in service dates ranging from August 2017 to 2021. When completed, these facilities will have a combined liquefaction capacity of over eight Bcfd.

Second Consecutive Record Year for Natural Gas Storage



Source: Derived from EIA data

The 2015-2016 winter was the warmest on record (since 1880), reducing natural gas demand. As a result, storage withdrawals during that season totaled 1.8 trillion cubic feet (TCF), the lowest in four years. By April, storage inventories stood at 2.5 TCF, the highest level at the start of the traditional injection season. Operators injected gas at a moderate rate throughout the summer and fall, and by November 11, 2016, storage reached a record of 4.047 Tcf, edging the previous record of 4.009 Tcf set in 2015.

December 2016 recorded 38 percent more heating degree days (HDD) than December 2015, resulting in a 12 percent increase in demand from commercial and residential customers. Operators withdrew 684 Bcf of natural gas from storage, more than triple the 200 Bcf withdrawn in December 2015, leaving inventories below both the 2015 and the 5-year average. While inventories ended 2016 nine percent below the inventory levels in 2015, January and February 2017 experienced 18 percent fewer HDD than the same period in 2016. In addition, the week ending February 24 of this year recorded the first ever February injection.

California Works to Ensure Reliability after the Aliso Canyon Incident



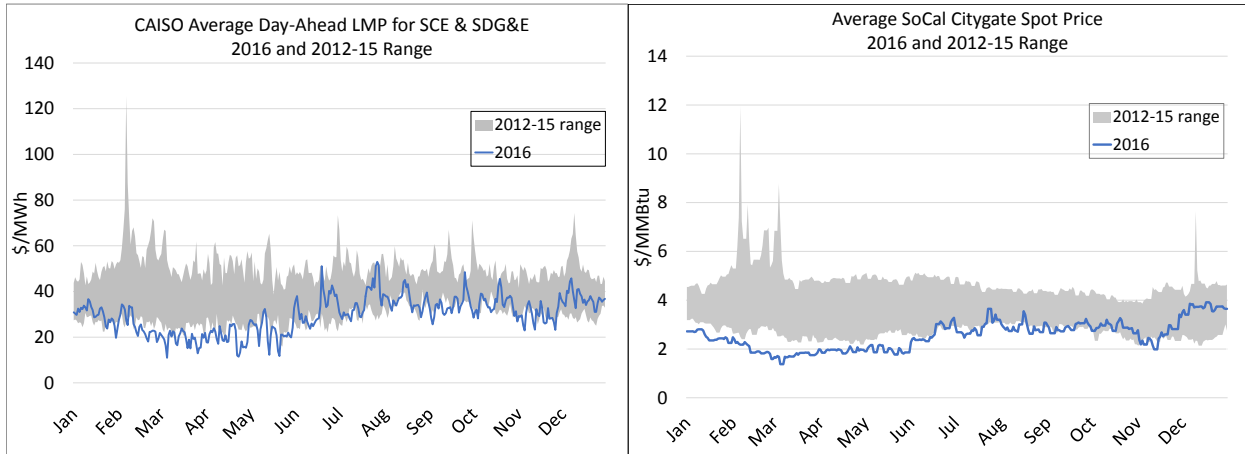
California continues to address the natural gas leak at the 86 Bcf Aliso Canyon natural gas storage facility detected on October 23, 2015, causing SoCalGas, the facility's operator, to withdraw all but 15 Bcf of working gas and to discontinue injections. California put in place several measures to mitigate the impact of the loss of Aliso Canyon on natural gas and electric operations. These included a new Operational Flow Order authority granted by the California Public Utilities Commission (CPUC), which SoCalGas used to help ensure adequate pressure and supply flows into its system. CAISO, with approval from FERC, implemented a natural gas constraint to factor the loss of storage capacity in its market clearing processes and to help manage dispatch of affected natural gas generators and their associated natural gas use. The constraint was used during two cold weather events this past winter. These and other initiatives helped CAISO maintain reliability throughout several periods of high demand for electricity and natural gas during extreme weather, both in summer and winter, with no major impact to the system or to natural gas and electricity prices. Further, the CPUC approved protocols for the withdrawal of natural gas from Aliso Canyon, and natural gas was withdrawn to help meet demand during a cold weather event in late January of this year. The various stakeholders continue to prepare for challenges that may arise this coming summer.

At this time it is unclear whether or at what level Aliso Canyon may resume natural gas injections, decisions that involve the CPUC and California's Division of Oil, Gas and Geothermal Resources (DOGGR). On January 17, 2017 DOGGR completed its safety review, and will make a decision about whether injections at Aliso Canyon can resume once they review public comments. The CPUC, at its public Voting Meeting on February 9, 2017, initiated a proceeding to determine the feasibility of reducing or eliminating the use of Aliso Canyon while maintaining electric and natural gas reliability in the region. If the CPUC's analysis determines

that it is feasible to eliminate or reduce the usage of Aliso Canyon, a following study will determine the conditions and time-frame for implementing this action.

The Commission considered and approved on an expedited basis CAISO's request for market rules that would allow it to address limitations that could adversely impact the reliability of CAISO's electric grid and market operations resulting from Aliso Canyon outage in the natural gas delivery system in southern California. Staff conducted outreach with industry and State agencies, participated in State workshops, and hosted Commission technical conferences discussing the effect of the outage on 2016 summer market operations in California. Staff also participated on the White House-established interagency taskforce on Natural Gas Storage Safety established after the leak at Aliso Canyon.

Southern California Natural Gas and Power Prices in 2016 Generally Remained Low Relative to the Past Five Years



Sources: Derived from ICE and ABB data.

Note: Lower figure reflects simple average of day-ahead hourly LMPs at load zones for Southern California Edison and San Diego Gas & Electric.

As shown in these graphs, 2016 natural gas and power prices in Southern California generally fell within or at the low end of the 2012-16 five-year range of prices. SoCalGas' use of its operational flow order authority helped ensure natural gas was available in Southern California, which helped maintain power plant availability. Other factors, such as greater hydro generation in the spring and increased levels of renewable generation reduced the need for natural gas use by generators, helping to ease natural gas and power prices. When CAISO triggered the natural gas constraint or manually dispatched generation during summer heat or winter cold events, prices still generally remained below those of recent peak day events. Persistently low wholesale electricity prices can place downward pressure on energy costs; however, such prices may also create challenging market conditions for certain market participants, such as merchant generators.

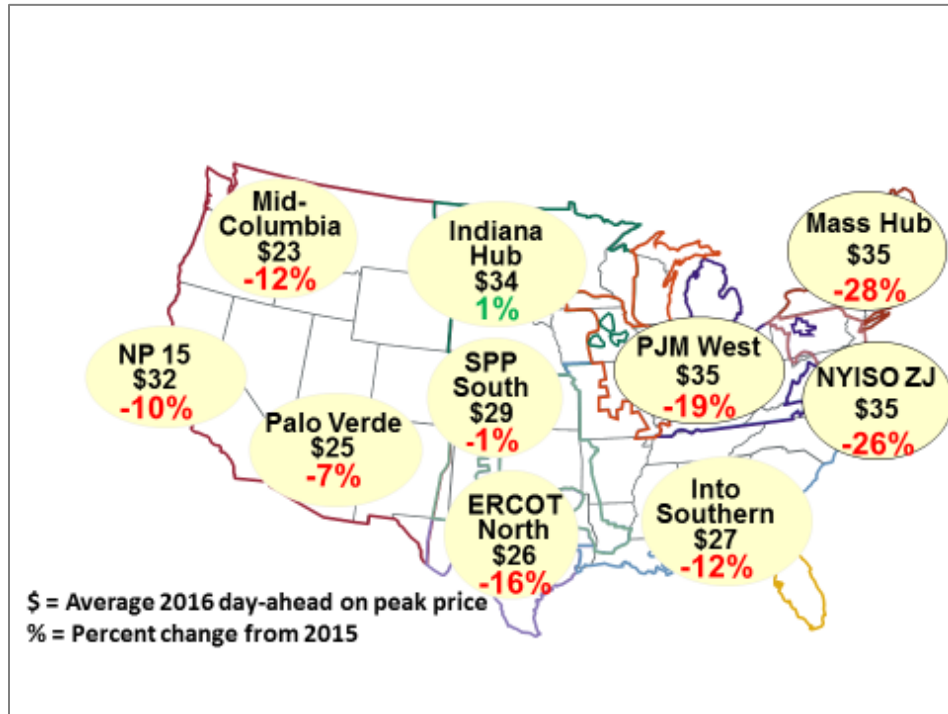
Other Notable Regional Natural Gas Developments



Source: Spectra Energy

In the Northeast, approximately 1.0 Bcfd of new FERC jurisdictional pipeline infrastructure capacity went into service in 2016, allowing more low-cost natural gas from the Appalachian region to move to markets in New England and the Mid-Atlantic. For example, Spectra's Algonquin Incremental Market Project (AIM) began operation in the fall of 2016 and became fully operational in January 2017. AIM increases the capacity on the Algonquin pipeline by 342 MMcfd. Other notable pipeline projects in the region include the 192 MMcfd Transco Rock Springs Expansion Project and 152 MMcfd First ECA Midstream Existing Pipeline Project, both of which transport Marcellus Shale gas to electric generators and other customers.

Day-Ahead On-Peak Electric Prices Reach Near-Record Lows in 2016



Source: Derived from SNL data

Note: Prices are a simple average of Day-Ahead On-Peak physical prices

Wholesale electricity physical prices were down at most major trading hubs across the nation in 2016 compared to 2015, driven primarily by low prices for natural gas.

Monthly average wholesale electricity prices were highest in the Northeast, PJM, and MISO, while SPP and the West had slightly lower prices. In 2016, PJM prices were near the lowest they have been since the RTO was formed in 1999.

Wholesale electricity prices also remained low with the mild winter weather in 2016, which both reduced electricity consumption for heating and simultaneously reduced demand for natural gas. This effect was especially prominent in New England, where prices in the first quarter of 2016 were significantly lower relative to the first quarter of 2015.

Capacity Price Trends Vary Across Regions

ISO/RTO	Capacity Auction Price	Zone or Region	Period of Comparison	Percent Change
ISO-NE	Forward Capacity Auction Clearing Price	System-wide	2019-20 vs. 2018-19	-26
PJM	Base Residual Auction Clearing Price for <i>Base Capacity</i>	rest-of-RTO	2019-20 vs. 2018-19	-47
	Base Residual Auction Clearing Price for <i>Capacity Performance</i>	rest-of-RTO	2019-20 vs 2018-19	-39
MISO	Planning Resource Auction Clearing Price	Zone 4	2016-17 vs 2015-16	-52
	Planning Resource Auction Clearing Price	Zones 2, 3, 5, 6, and 7	2016-17 vs 2015-16	+1,969
NYISO	Average ICAP Spot Market Auction Price	Zone J, NYC	2016 vs 2015	-17

Source: Derived from PJM, ISO New England, MISO, and NYISO data via SNL

Note: Comparisons shown for selected zones/regions to illustrate variation.

In 2016, capacity auction prices declined in many parts of the country, with some notable exceptions.

ISO-NE and PJM

In ISO-NE, the Forward Capacity Auction Price fell by 26 percent compared to the prior year. In PJM, the Base Residual Auction Clearing Price for Capacity Performance fell by 39 percent between 2015 and 2016.

While drivers of lower capacity clearing prices in the latest auctions include lower system-wide target requirements, increased supply, and fewer major retirements, staff notes that comparisons must be made with a degree of caution due to changing market rules. In particular, both PJM and ISO-NE have in recent years instituted various changes to their capacity markets.

MISO

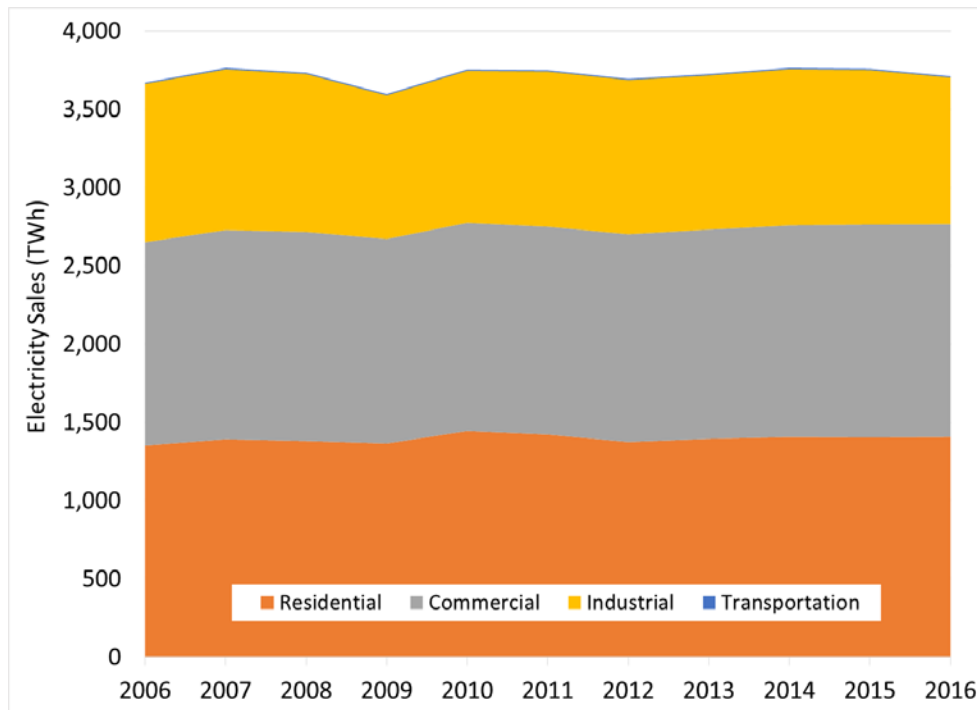
In MISO, the capacity auction clearing prices saw sharp changes compared to the previous year. Zone 4, which saw a large increase in price during the 2015-16 Planning Resource Auction, fell by 52 percent for the 2016-17 auction (from \$150.00/MW-day to \$72.00/MW-day). Meanwhile, prices in Zones 2-7 with the exception of Zone 4 increased sharply, from \$3.48/MW-day to \$72.00/MW-day. Rule changes resulted in more sharing of capacity between zones in 2016-17, causing prices not to separate as they had in the prior auction. In addition, the market tightened causing Zones 2-7 to move on to a steeper portion of the supply curve and clear at a higher price.

Elsewhere in MISO, capacity auction clearing prices in Zone 1 increased from \$3.42/MW-day to \$19.72/MW-day, a , while capacity auction clearing prices in Zones 8 and Zone 9 decreased by 9 percent.

NYISO

New York also had mixed capacity results but less volatility than other markets. Average monthly prices for NYISO's Zone J, representing New York City, fell by 18 percent in 2016 compared to 2015. The prices for the NYCA region, representing upstate New York, rose moderately by 6 percent during the same time period.

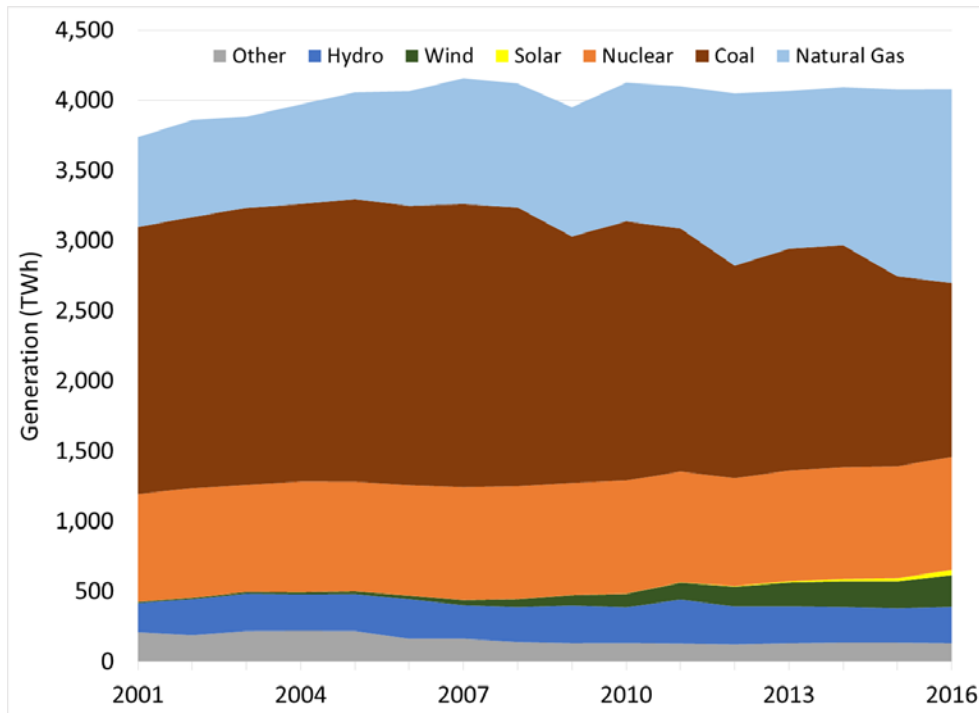
Electricity Demand Growth Remains Low



Source: Derived from EIA data

Nationwide electricity demand as measured by sales fell by 13 percent from 2015 to 2016. This continues a trend of relatively flat demand growth dating back more than a decade. As the U.S. Energy Information Administration has reported, long-term trends indicate that U.S. electricity demand growth is slower than the overall economic growth. The flat growth in electricity demand can be explained by a number of factors, including greater utilization of energy efficient technologies, and reduced demand for heating and cooling from the residential and commercial sectors because of mild weather in 2016. Also, the increase of behind-the-meter generation contributes to lower growth in wholesale electricity sales, as it reduces the need for energy from utility-scale plants.

Share of Natural Gas-fired Generation Continues to Increase

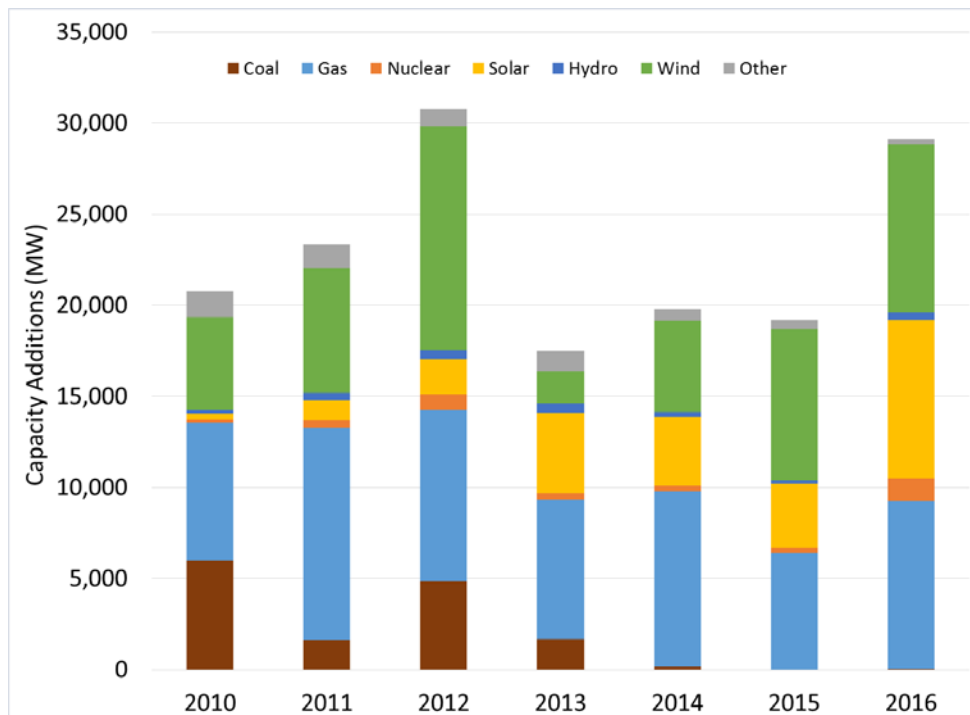


Source: Derived from EIA data

Note: Totals reflect net generation from utility-scale plants.

The annual share of electricity produced from natural gas exceeded coal fired generation for the first time in 2016, with natural gas-fired plants producing 34 percent of total generation compared to 30 percent for coal. This milestone was the product of many years of relative gains by natural gas plants relative to coal plants. Economic conditions have proved favorable to natural gas-fired generation while the viability of coal plants has declined in most markets. Renewables also continued to grow in share of total generation capacity.

Renewables Account for the Majority of Capacity Additions in 2016



Source: Derived from Velocity Suite ABB Enterprise Software (ABB) data

Note: Capacity additions include new capacity, uprates, repowering, and return to service of plants out for more than five years.

In 2016, the markets saw continued growth in utility-scale renewable generation capacity, and renewables represented the majority of generating capacity additions. Renewable capacity was buoyed by the extension of both the production tax credit (PTC) for wind resources and the solar investment tax credit (ITC) for photovoltaic resources in December 2015. Both tax credit systems are slated to decline, with the PTC expiring completely in 2020 and the ITC reducing to 10 percent for commercial projects and expiring for residential projects.

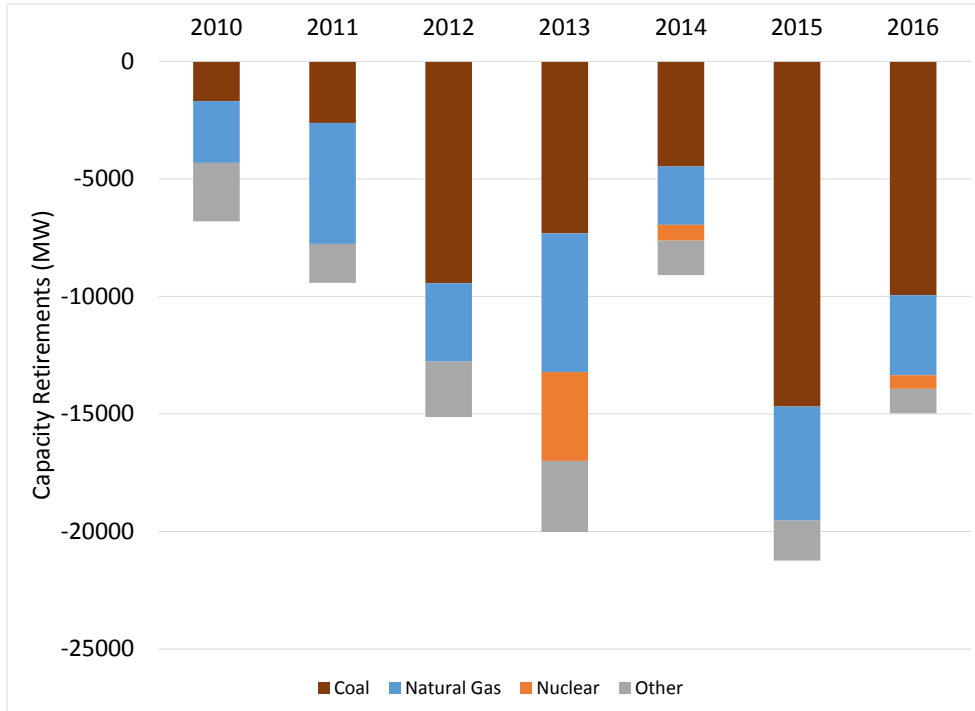
At the same time, state-level policies such as Renewable Portfolio Standards (RPS) drive renewable capacity additions and affect markets. The specifics of State RPS rules vary substantially state to state but encourage the procurement of either energy or capacity from renewable sources. Currently 29 states and the District of Columbia have some form of RPS. Some states, including Massachusetts, New Jersey, and others have instituted RPS solar carve-outs to encourage the use of distributed solar. In 2016, several RPS goals expanded. New York adopted a new clean energy standard requiring utilities to purchase 50 percent of electricity from eligible clean sources by 2040. Oregon increased its requirement to 50 percent by 2040 for large investor-owned utilities, and the District of Columbia increased its requirement to 50 percent by 2032.

In 2016, there were some notable developments related to offshore wind capacity. The 30 MW Block Island facility in Rhode Island, which began production in December of 2016, became the

first operational offshore wind farm in the United States. Also, a Massachusetts law signed in August 2016 requires utilities in that state to procure up to 1,600 MW of offshore wind by 2027.

After renewable resources, the next-largest share of new capacity in 2016 came from natural gas-fired resources, with about 9 GW added, according to ABB. In addition, 2016 saw its first new U.S. nuclear unit in 20 years, as the Tennessee Valley Authority's Watts Bar Unit 2 commenced commercial operation in October.

Baseload Retirements Continue in 2016



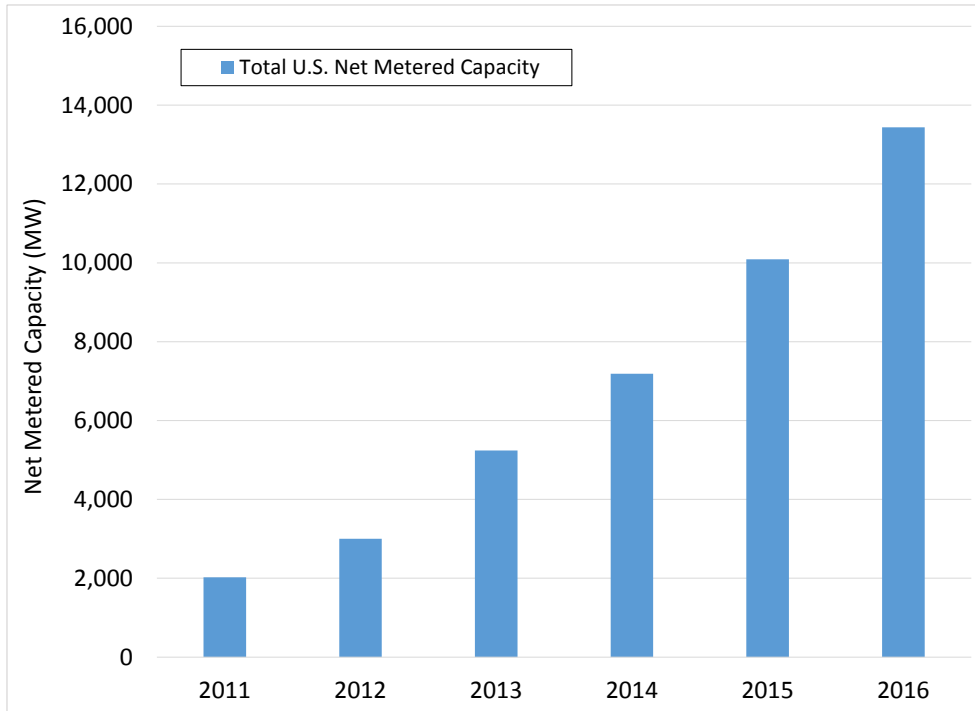
Source: Derived from ABB data

The continued low cost of natural gas, among other factors, contributed to the reduced competitiveness of coal-fired power plants. Approximately 10 GW of coal-fired capacity retired in 2016.

Low wholesale electricity prices have also contributed to nuclear plant retirements in recent years. In October of 2016, the 478 MW Fort Calhoun plant in Eastern Nebraska shut down. Despite this retirement, the completion of the Watts Bar Unit 2, mentioned previously, resulted in a net gain in nuclear generating capacity in 2016. Since 2013, however, nuclear generating capacity has declined with retirements of 5GW of nuclear capacity in total. Similarly, a number of retirements have also been announced for future years.

These trends have led some states to pursue policy support for certain baseload resources. In August of 2016 for example, New York state initiatives led to the creation of Zero Emissions Credits (ZECs) which provide selected nuclear plants with payments of up to \$17.5394/MWh for the first year, and similar payments for the next 10 years. Similarly, the Illinois state legislature approved a plan which would provide up to \$16.50/MWh in the first year to support the continued operation of nuclear plants at risk of retirement for the next 10 years. Both of these plans are currently being challenged in the courts and at FERC.

Net Metering Capacity Continues to Grow Nationwide



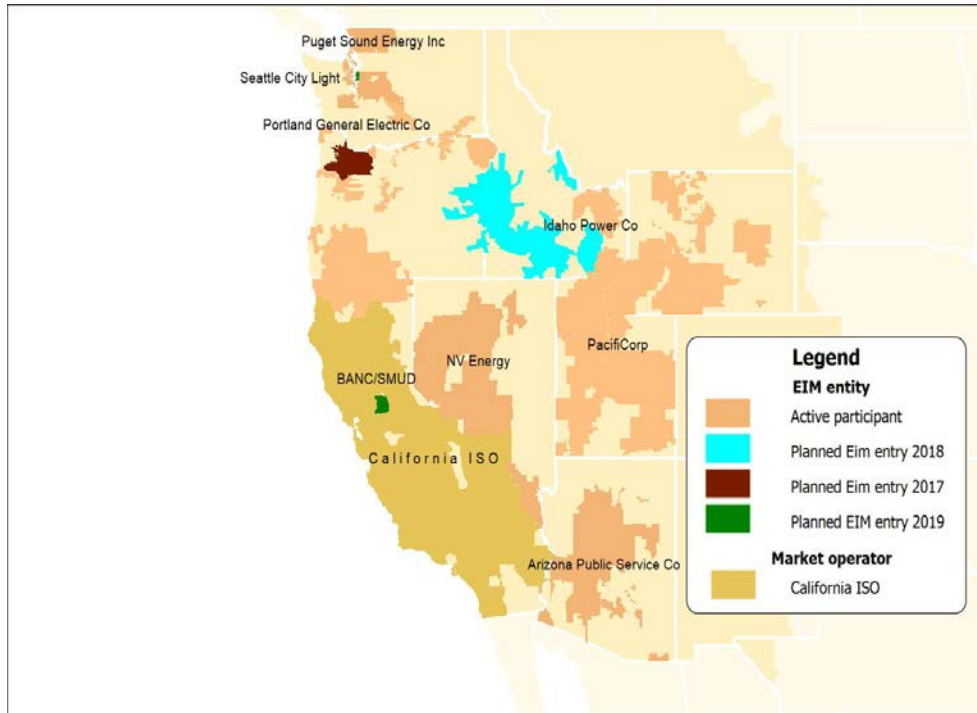
Source: Derived from EIA Form 826

Net metering capacity has seen high growth in recent years, driven in part by wide scale adoption of small-scale photovoltaic generators. In recent years, cost reductions in solar photovoltaic systems drove substantial installation of both utility scale and distributed solar energy projects across the country. Solar currently accounts for 99 percent of net-metered capacity.

Although net metered projects largely participate in retail markets, their aggregate impact has begun to affect wholesale markets with large penetration of distributed solar projects. These impacts can largely be seen as a functional reduction on demand from the RTO/ISO perspective, with subsequent shifting of system load curves.

Some states and regions are seeking to integrate distributed energy resources into the market through alternative mechanisms. CAISO has introduced market rules to allow for aggregating distributed resources into a “virtual power plant” which would sell into the wholesale markets. In November, the Commission issued a Notice of Proposed Rulemaking (NOPR) which would require each RTO/ISO to create rules to accommodate the participation of electric storage and distributed energy resource aggregators in the organized wholesale markets.

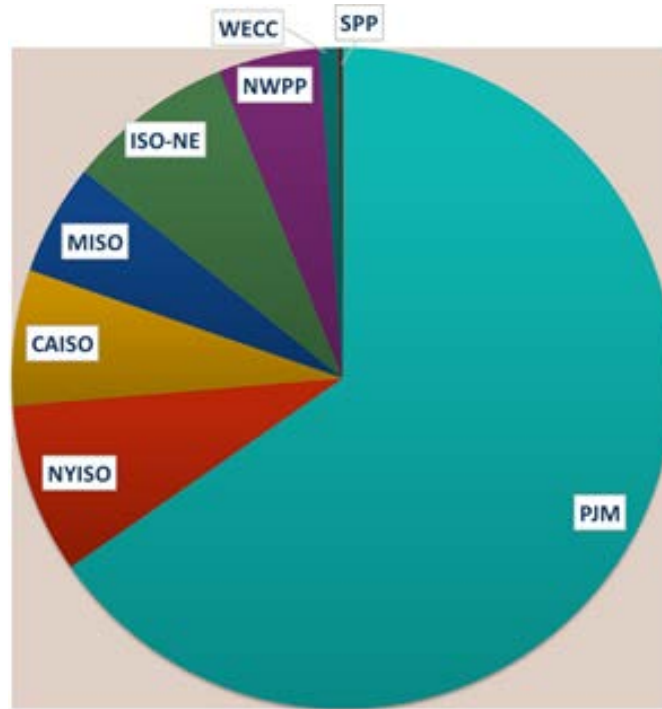
EIM Expansion Continues



Source: Commission staff based on CAISO and ABB

Since its launch in 2014, the EIM has steadily expanded its geographic footprint in the west. In October of 2016, Puget Sound Energy and Arizona Public Service expanded the EIM to portions of eight western states. Three entities also announced their intention to join the EIM; Idaho Power in 2018, and both Seattle City Light and the Balancing Authority of Northern California (BANC) in 2019. The Los Angeles Department of Water and Power (LADWP), the Mexican operator El Centro Nacional de Control de Energía Baja, CA (CENACE), the Salt River Project, and Northwestern Energy are exploring membership in the EIM.

PJM Continued to Lead Financial Trading of Electric Products in 2016

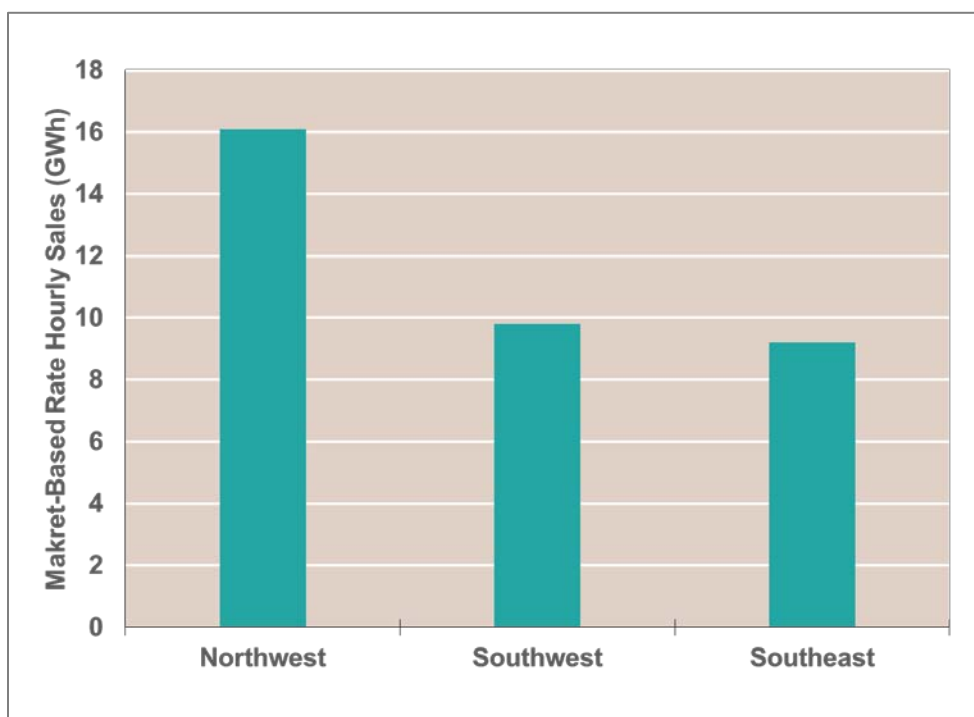


Source: Derived from Intercontinental Exchange Data (ICE)

This chart shows all cleared futures traded on the InterContinental Exchange (ICE) for electric products outside ERCOT in 2016. PJM's financial products continue to be the most traded on ICE, with 65 percent of the total volume of financial trades involving a PJM product, up from 64 percent in 2015.

Last year, 94 percent of the financial trading of U.S. electricity products outside ERCOT took place at an RTO hub, same as in 2015. All regions of the country outside of ERCOT experienced an increase in financial trading volumes compared to 2015 with the highest proportional increase happening in SPP.

Northwest Region Had Largest Share of Hourly Market-Based Rate Sales Outside of RTOs/ISOs in the First Three Quarters of 2016



Source: Derived from Electric Quarterly Reports (EQR)

The Electric Quarterly Reports (EQR) summarize data on electric power contracts and wholesale power sales by utilities with rates on file, as required by section 205(c) of the Federal Power Act. The EQR provides data to the public and market participants, which increases transparency in wholesale energy markets.

As shown in the figure above, the Northwest region reported the largest volume of hourly sales of energy and booked out power at market-based rates in the first three quarters of 2016 among bilateral (non-RTO/ISO) markets. The large volume of hourly market-based rate sales in the Northwest continues a trend seen in past years and reflects the structure of the bilateral markets in that region. The Northwest has a robust trade in short-term products, which is reflected in the larger number of sellers reporting trades in the region.

The volume-weighted price for hourly market-based rate sales reported to the EQR for the first three quarters of 2016 closely tracked the annual reported price at nearby trading hubs. Among the regions shown in the figure above, the volume-weighted price for hourly market-based rate sales was highest in the Southwest (approximately \$26/MWh), followed by the Southeast (approximately \$23/MWh) and the Northwest (approximately \$20/MWh).