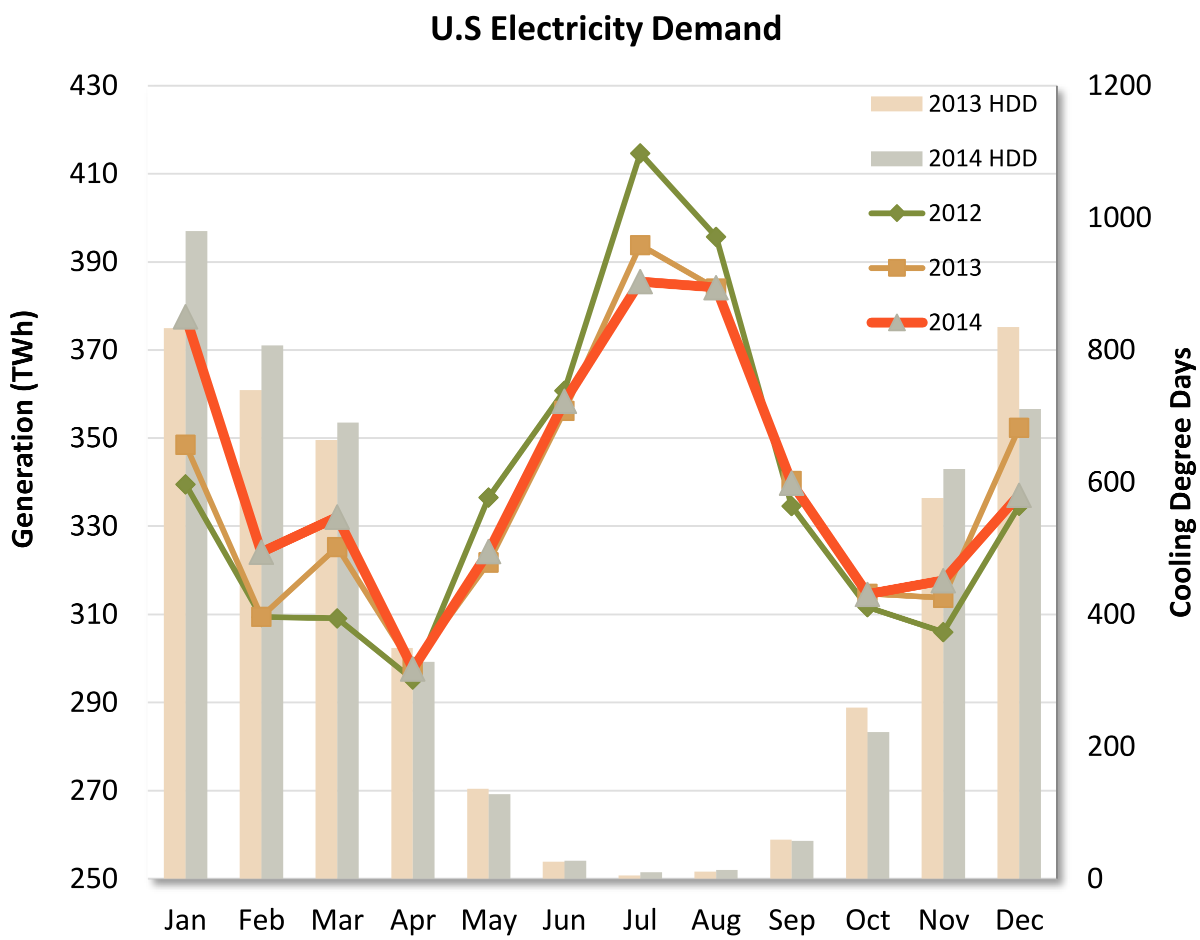
ICForecast:
Strategic Power Outlook Sample

Q2 2015

Power Markets

Q4 2014: Gain in demand growth tapers due to relatively mild winter

- Due to the "polar vortex," energy demand was 0.9% higher overall in 2014 compared to energy demand in the previous year
  - Q4 2014, however, energy demand **decreased** by 1.2% compared to Q4 2013 due to a relatively mild winter season, as depicted by low heating degree days (HDD) shown in the graph
- 2013 energy demand was 0.3% higher than 2012 due to cold weather-driven demand as well



Source: EIA Electric Power Monthly, August 2014 and NOAA

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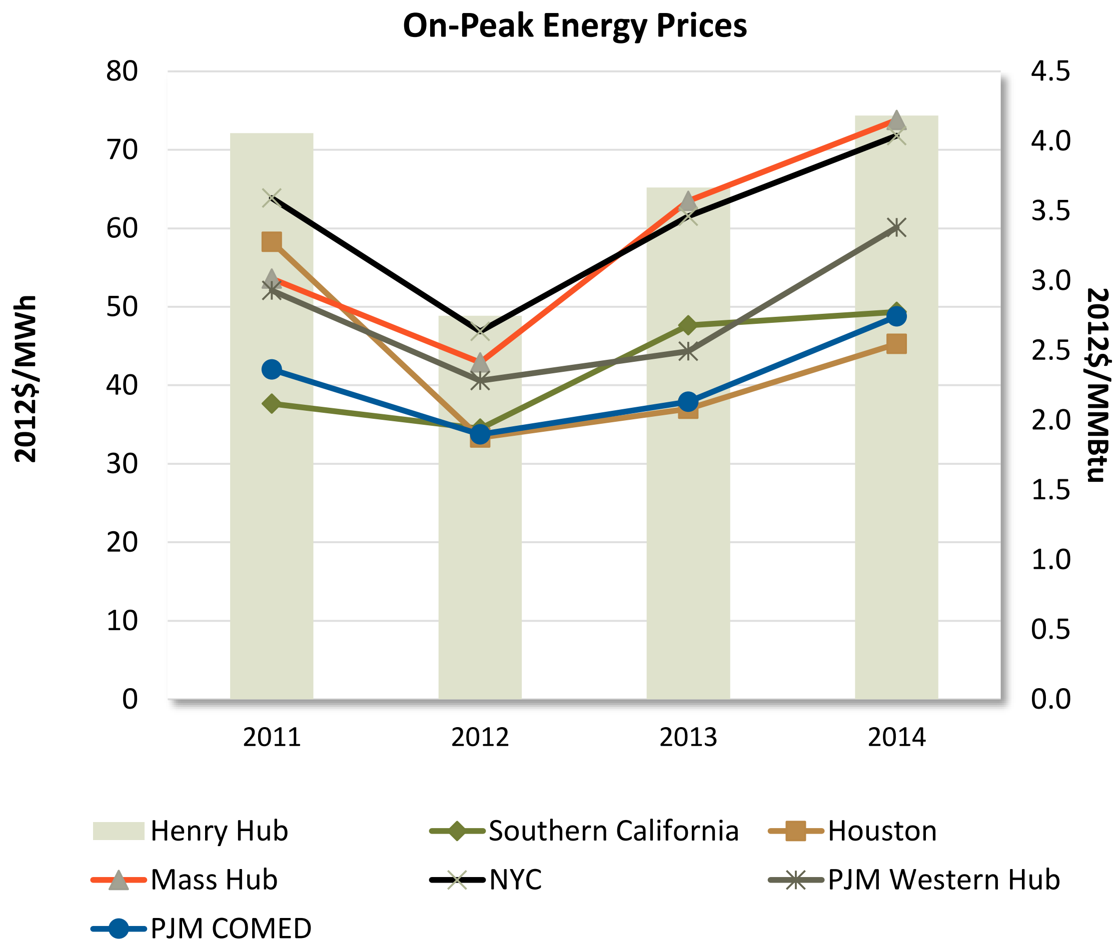
On-Peak prices spike due to volatile weather and higher gas prices

- Higher energy demand and gas prices due to extreme cold weather in Q1 2014 resulted in higher year-over-year average on-peak prices in 2014
- In 2013, on-peak energy prices recovered from the previous year based on higher gas prices rather than strong demand growth
- Energy prices are still far below highs seen in 2008, due in part to much lower natural gas prices and a gradual recovery from the recession

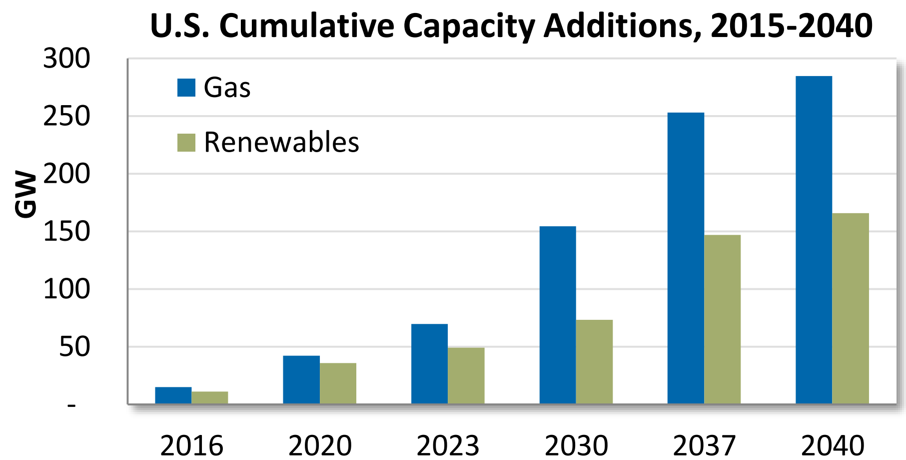


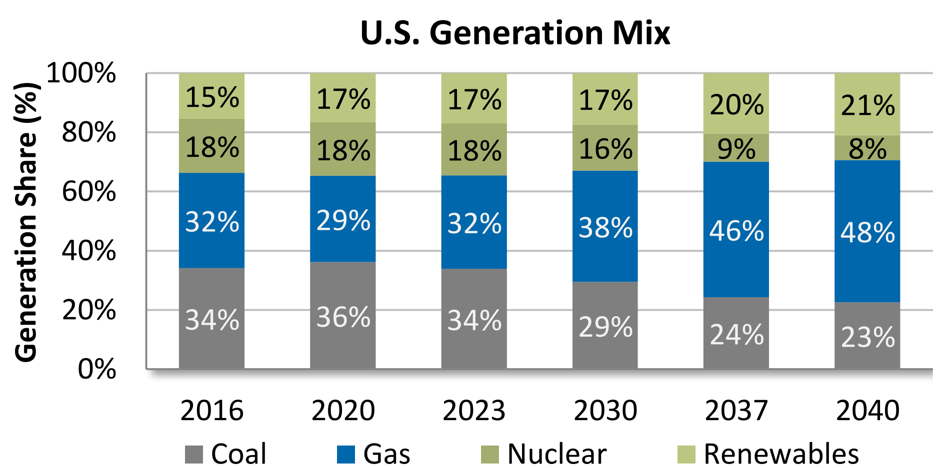
Source: ISO data (historical):2011, 2012, 2013, 2014

Market Projections

Opportunity for gas, wind and solar developers

- U.S. power market will add approximately 230 GW of new capacity by 2030, beyond what is already under construction, to meet demand and state renewable portfolio standards
  - Recent CO_2 proposals for new and existing power plants, if implemented, will further strengthen current market trends favoring natural gas and renewable technologies
- Wind and solar technologies will continue to dominate the renewable build mix, but low capacity factors keep their share of total generation nearly constant through 2030, growing slightly in share to 20% by 2040
- In absolute terms, coal generation remains almost flat through 2020
  - More efficient, newer coal units increase dispatch to replace generation lost from retirements
  - By 2030, the CO_2 price will be high enough to force more coal out of the dispatch stack, and gas starts to dominate the generation mix
  - By 2040, retirement of nuclear units provides further momentum to gas-based generation

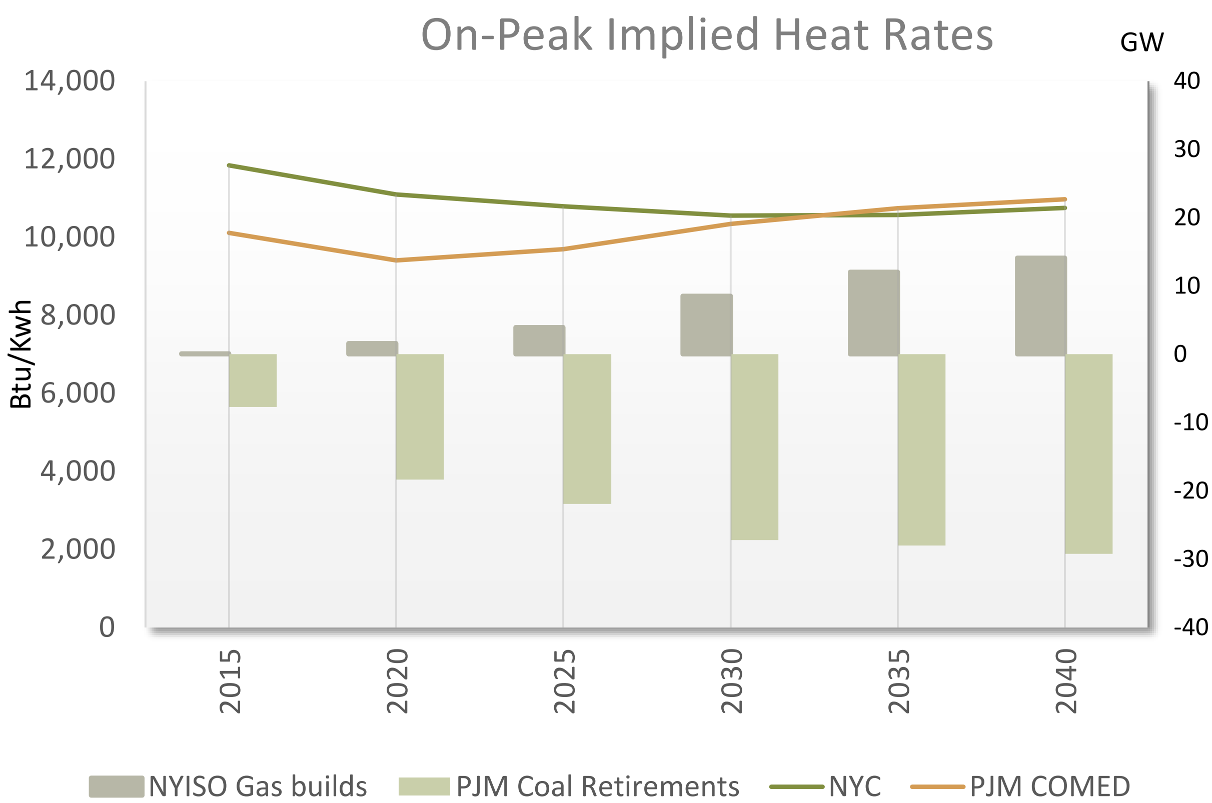




Note: Reported capacity is cumulative with 2015 as base year.

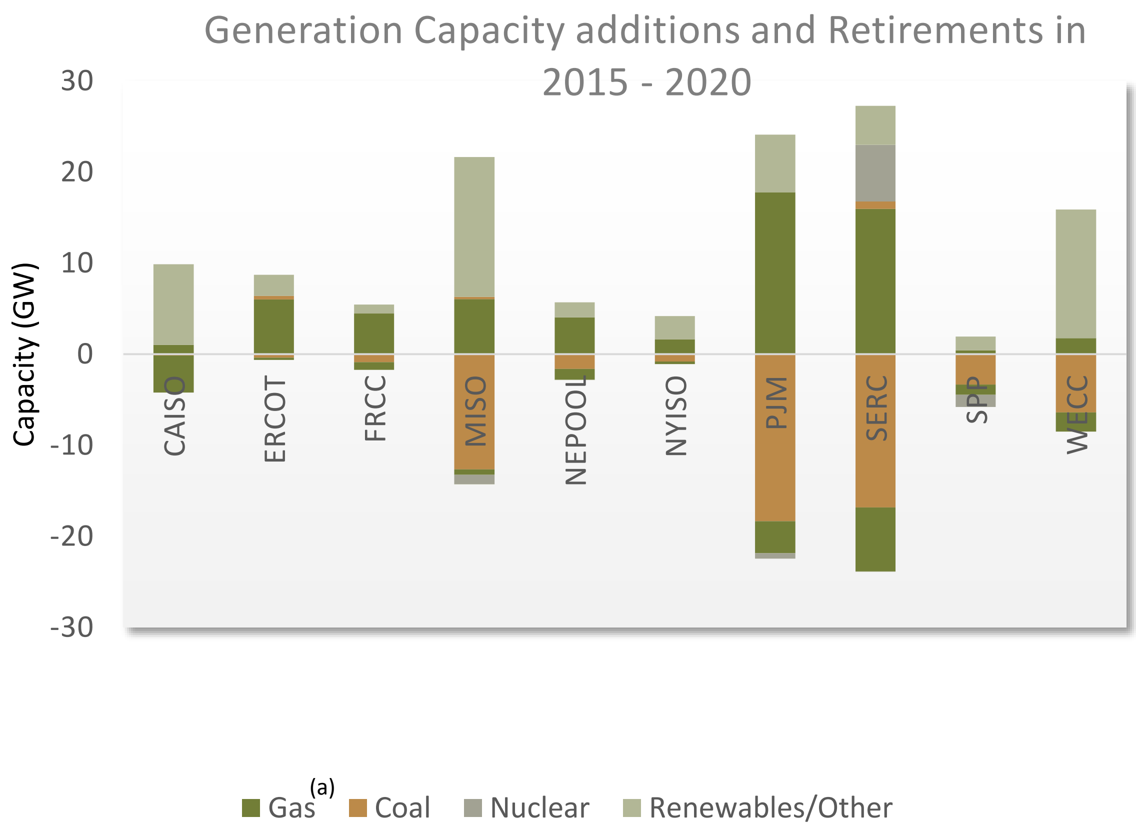
Growth in implied heat rates higher in regions with more coal retirements

- High delivered gas prices and transmission congestion lead to NYC having the highest projected IHRs throughout the forecast
  - However, in the long-term, regions such as NYC show a declining IHR trend as more efficient gas capacity comes on-line, making the market as a whole more efficient
- In contrast, coal dominant regions, for example PJM-COMED, show a generally increasing IHR trend. PJM COMED pricing is currently set mainly by baseload coal and nuclear units.
  - Over time, energy prices increase sharply, particularly when compared to other forecast regions
  - This is due to low variable cost coal generation retiring or becoming more expensive due to the need to meet ever more stringent environmental regulations



Wind capacity growth in MISO, natural gas in PJM and SERC over the next five years

- Out of 125 GW of capacity expected to come online through 2020, natural gas, wind and solar account for 89%
  - Natural gas additions of 59 GW are spread throughout the US, of which PJM and SERC will account for 17.8 GW and 16 GW added in respectively through 2020
  - Wind capacity is primarily added in MISO, with nearly 15 GW, or 52% of total wind additions
  - Approximately 6 GW of nuclear will be added in SERC in the next five years. After a lag of 20 years, a new nuclear facility, Watts Bar 2 of Tennessee Valley Authority will be coming online in the US in December 2015
- Nearly 85 GW of generating capacity is expected to retire in 2015-2020, 72% of which (61 GW) is coal-fired generation, retiring primarily in MISO, PJM and SERC regions.

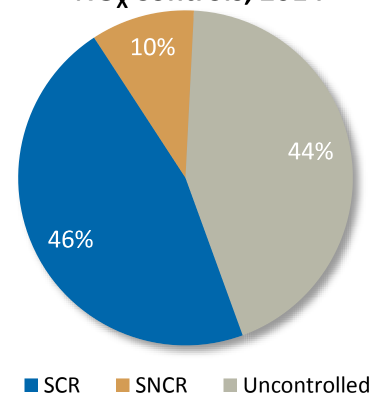


(a) Includes CC, CT, Cogen, Jet Engine and Oil/Gas

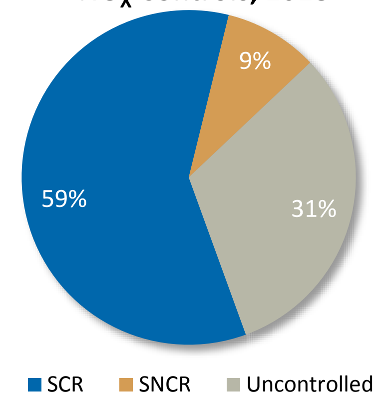
Return of CSAPR to Drive incremental NO_x Installations

- As previously finalized by EPA, CSAPR was reinstated January 2015.
  - By 2018, approximately 70% of the remaining post-MATS coal capacity will have some kind of post-combustion NO_X control
  - Units may also consider low cost compliance options, such as Low NO_X burners, Overfire Air etc.
- As a result of the MATS acid gas requirement, further PM regulation may have less impact on incremental SO_2 control decisions. There will be unit-specific needs in some states.
  - By 2018, over 85% of remaining coal capacity will have some kind of SO_2 /HCl control
  - The remaining 15% of uncontrolled units will burn MATS-compliant subbituminous coals or install DSI to guarantee control across coal shipments with uncertain chlorine levels, but those controls may not operate over all hours

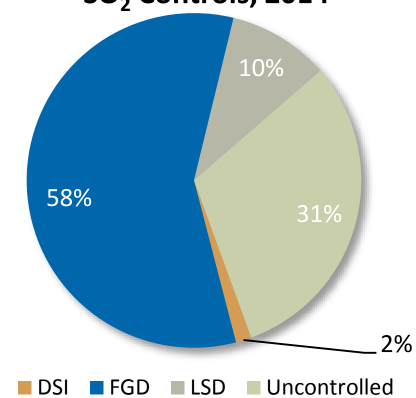
NO_X Controls, 2014



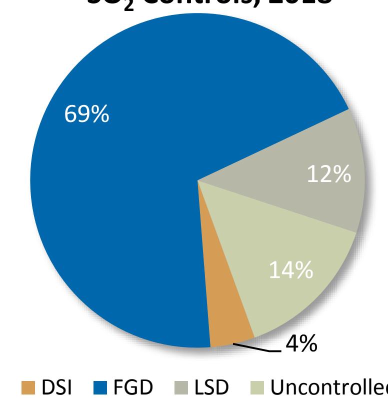
NO_X Controls, 2018



SO_2 Controls, 2014



SO_2 Controls, 2018



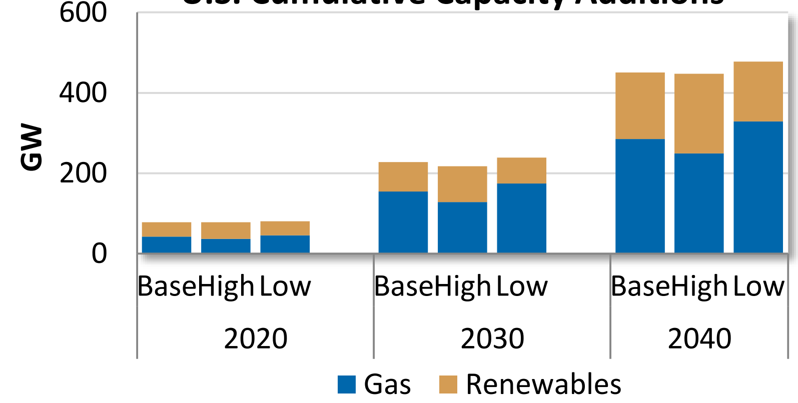
Note: Charts represent control status based on the existing and projected emission controls. For NO_X, if a unit has both SCR and SNCR, its share is counted under SCR.

*see appendix for details on CSAPR assumptions.

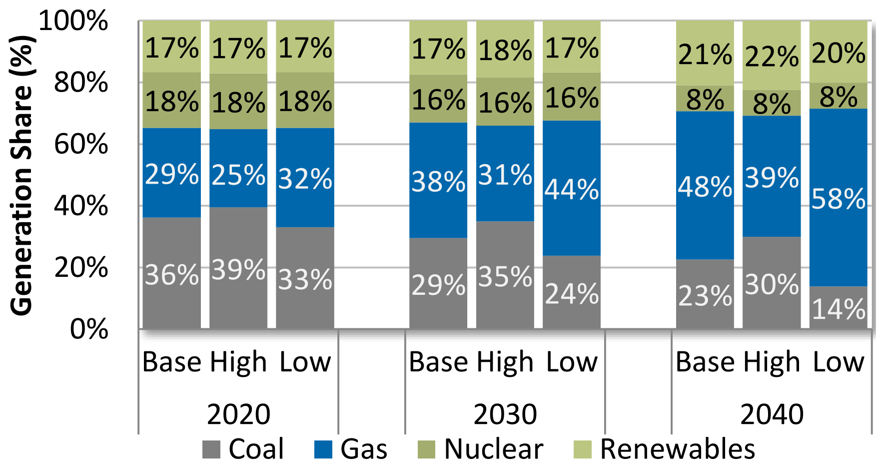
High/Low Cases: Higher gas prices provide coal one third of dispatch share in long-term

- The ICForecast includes high and low gas price sensitivity cases
- Gas price differences translate directly into movements in retirement and build projections
- Higher gas prices translate into more coal capacity remaining online post-2016 and also contribute to the economics of new wind capacity relative to new gas-fired builds
- Higher gas prices decrease coal retirements by nearly 35% and keep coal's generation share at approximately 35% by 2030
- Lower gas prices increase coal retirements by nearly 26% and drive coal's generation share to just over 20% by 2030

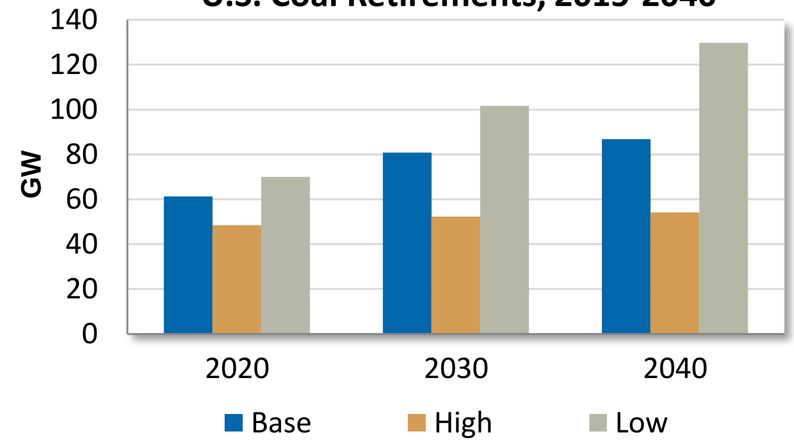
U.S. Cumulative Capacity Additions



U.S. Generation Mix



U.S. Coal Retirements, 2015-2040



Note: Reported capacity is cumulative with 2015 as base year.

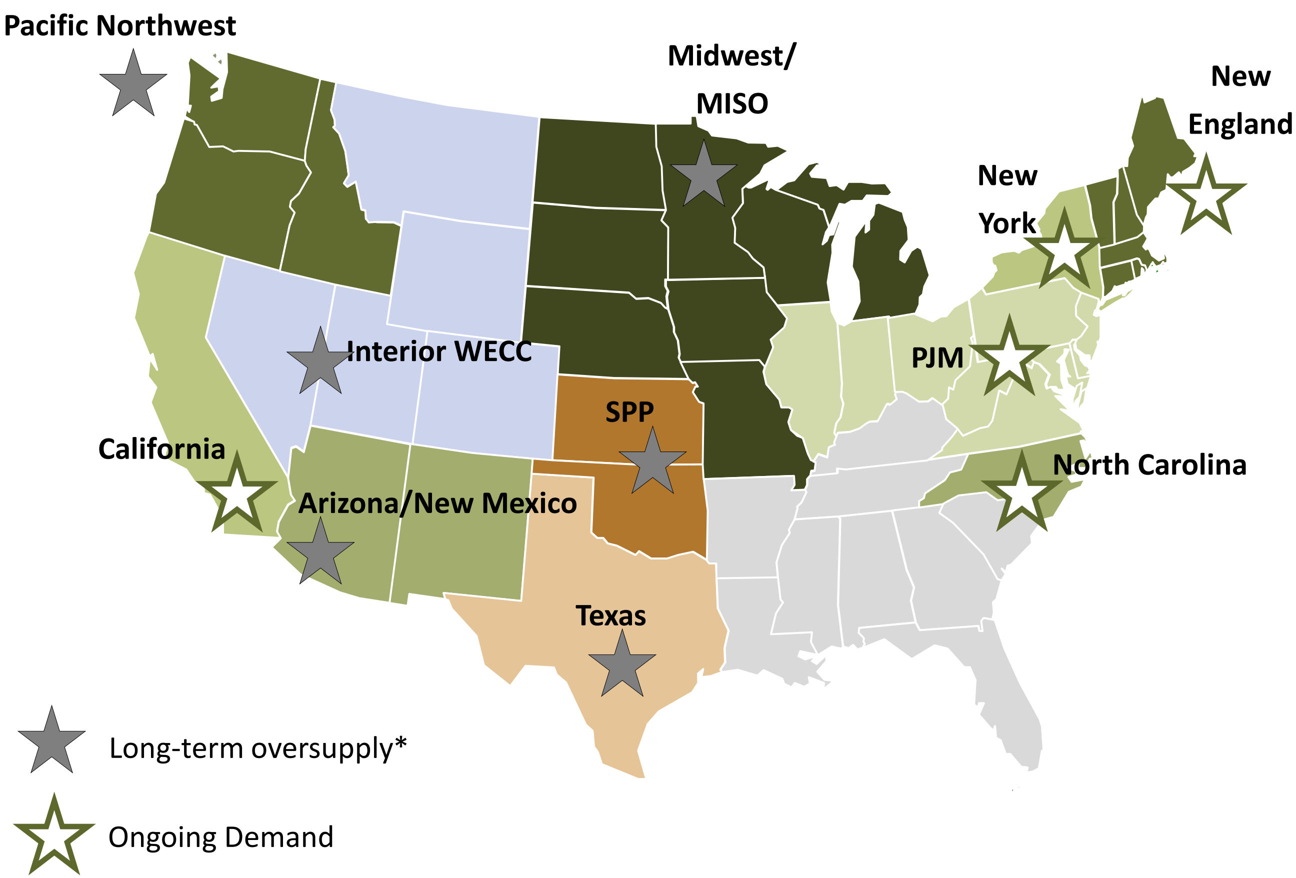
Renewable Energy Markets

In Focus: Utility's strategic responses to growth of distributed solar PV

- With the continued growth of distributed solar PV installations apparent, utilities are responding in a number of ways that allow them to adapt to this new reality, ensure that they can cover their costs, and diversify their revenue options

Strategy	Reason	Companies and Actions
Purchase solar development and installation firms	Acquire revenue from distributed solar installations	**NRG**: Purchased Pure Energies (Solar Acquisition Platform) and Roof Diagnostics (Solar Installer), creating a vertically-integrated distributed solar PV operation
		Duke Energy: Recently acquired a majority stake in REC Solar, a California-based developer with 140 MW of installations
		NextEra: Acquired Smart Energy Capital in 2013. At the time, the company had developed 75 MW of commercial PV across several states
Install Solar PV on customer's homes	Own the distributed solar PV systems, instead of a third-party developer	**NRG**: Install 2,500 MW of residential solar PV in the next seven years through subsidiary NRG Home
		Tucson Electric Power: Install 500 residential systems in 2015 through new Residential Solar Program
		Arizona Public Service: Proposed installing 20 MW of residential solar PV on 3,000 homes in their service territory
Alter customer incentives for those installing distributed solar PV	Increase costs of owning a distributed solar PV system to cover system (transmission and distribution) costs	**Hawaiian Electric Company**: Proposed repealing net metering in Hawaii and replacing it with a tariff system that incentivizes grid supporting technologies including smart inverters and energy storage
		Arizona Public Service: $5/kW/month fee for new solar PV customers approved by Arizona Corporation Commission in November, 2013
		Salt River Project: SRP officials voted to approve a $50/kW/month fee for new solar PV customers. Not yet approved by Arizona Corporation Commission
Change rate structure for all utility customers	Increase fixed customer costs to cover the utility's costs associated with grid connectivity	**NV Energy**: Submitted a new fixed charge of $15.25/month for residential customers to the state PUC, an increase of 50%
		Wisconsin Energies (WE Energies): In November, the state Public Utilities Commission approved a $7 increase in the fixed charge for residential customers (from $9 to $16). In addition, the utility will pay less for customer generated solar energy.
		Rocky Mountain Power: Utah PUC recently rejected requests from RMP that included an increase in fixed charges for all customers and an additional net metering fee for customers with solar PV

RPS supply/demand balance – many markets oversupplied



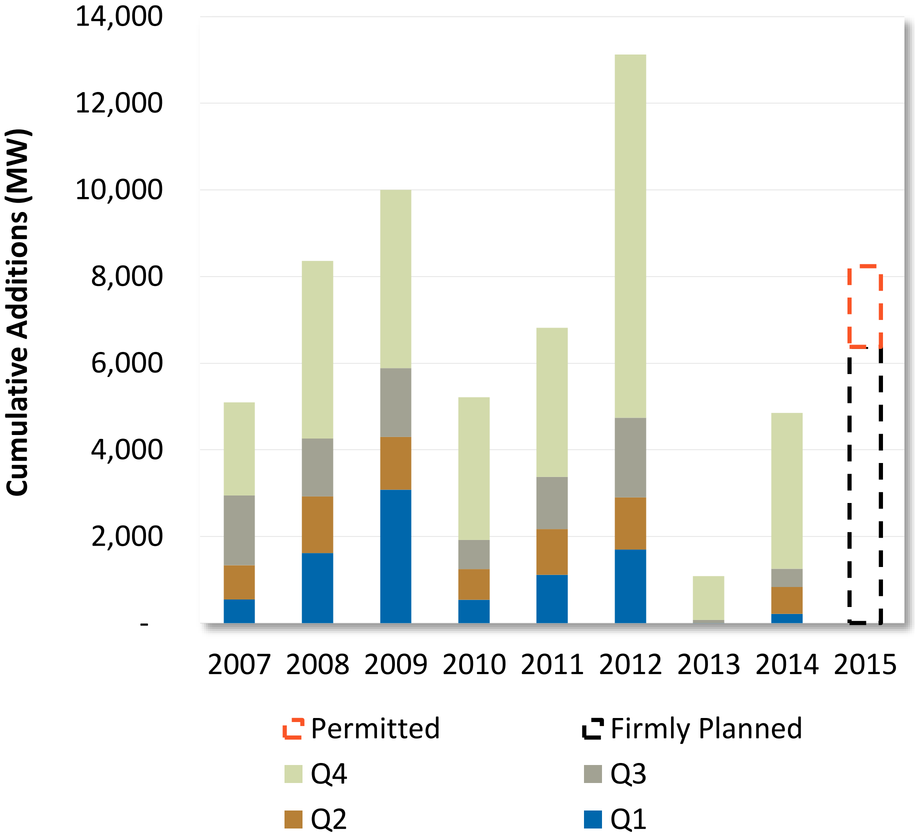
- Many RPS regions are oversupplied, while others still offer development opportunities
- Supply/demand position is determined based on RPS policy requirements and generation from renewable projects eligible to meet these requirements
- This map shows the regional configuration used to capture the impact of REC trading for this analysis
  - Many state markets coalesce into broader regional markets due to overlapping geographic sourcing policies

* In some cases, states in oversupplied regions may see limited incremental development for RPS compliance purposes.

Wind builds expected to stage comeback in 2015

- The extension of the PTC in late 2014 effectively provided no time for developers to act on that extension. Therefore, no incremental capacity was developed as a result of that extension.
- Q4 2014 wind capacity additions were 3,600 MW
  - Installations in 2014 were nearly five times greater than in 2013
  - Up to 8.2 GW of PTC-eligible capacity may come online through 2015, and over 6 GW of capacity additions are firmly planned for this year
- According to the Solar Energy Industries Association, nearly 2.3 GW of distributed solar was installed in 2014
  - Over half of 2014 installations were in California, where 93% of installations in Q4 2014 occurred without state incentives
  - The majority of 2014 installations in the mature state markets (California, Arizona, Massachusetts, Colorado, etc.) were third-party owned

Incremental On-shore Wind Installations: 2007-2014

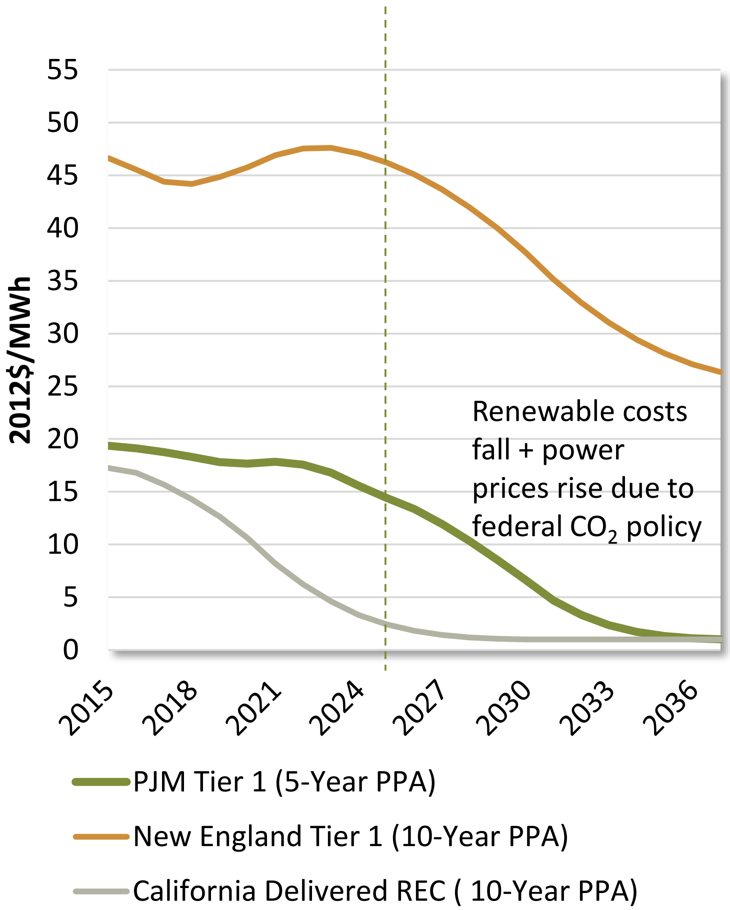


Source: AWEA, SNL

New England prices near ACP; rising demand is maintaining upward pressure in PJM

- In **New England**, prices remain close to Alternative Compliance Payment (ACP) levels
  - With RPS requirements increasing in the coming years, REC prices will be affected by how many firmly planned projects come online. Currently, even fully permitted and/or financed projects have been experiencing significant project delays in the region.
  - The recently announced cancellation of PPAs for Cape Wind has yet again cast uncertainty on the project's potential start date. Given the project's size, it would alleviate some pressure on REC prices. Our analysis assumes that the 468 MW project will become operational in 2018.
- In **California**, the three large Investor Owned Utilities (IOUs) have announced that they have procured enough contracts to fulfill their renewable requirements
  - REC premiums will fall over time unless the state changes their long-term RPS requirements
- REC prices in **PJM** have been robust thus far in 2015
  - Prices have stabilized since the change in Ohio's renewable policy (freeze of AEPS standards through 2016).

Tier 1 REC Prices



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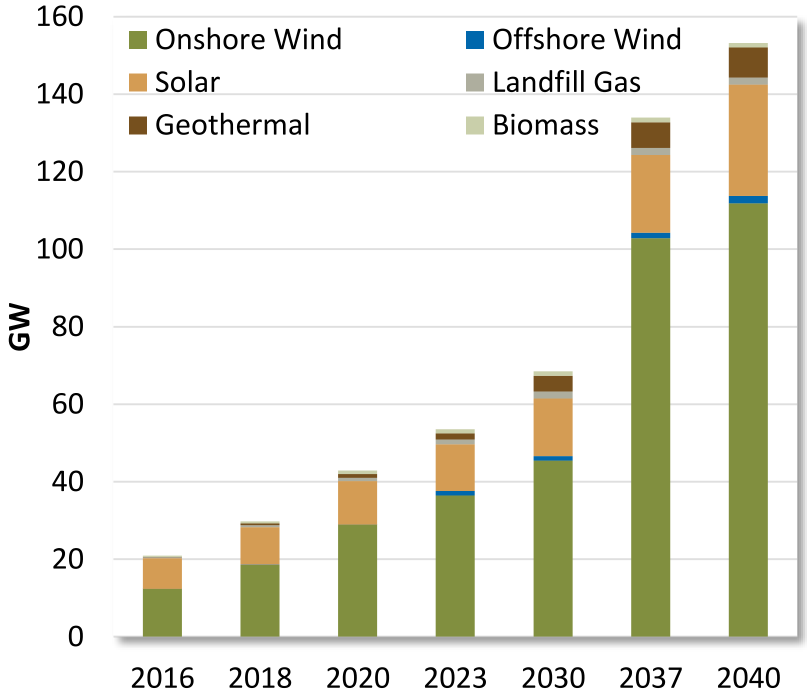
Majority of central-station renewable additions are wind

- ICF projects that firm and non-firm wind capacity additions from 2015 to 2016 will amount to 12 GW and will represent nearly 60% of total central-station renewable capacity additions
  - These projections do not assume any further PTC extension
- Long-term wind capacity deployment (2023 and beyond) will drive future renewable energy development independent of the PTC or RPS mandates, as falling technology costs and rising power prices drive development
- Central station solar additions consist primarily of firmly planned large-scale solar PV.
- Through 2016, ICF projects over 5.3 GW of projected central-station solar additions. While the majority will be PV projects, nearly 1 GW will use solar thermal technology

Cumulative New Renewable Capacity Additions by 2040



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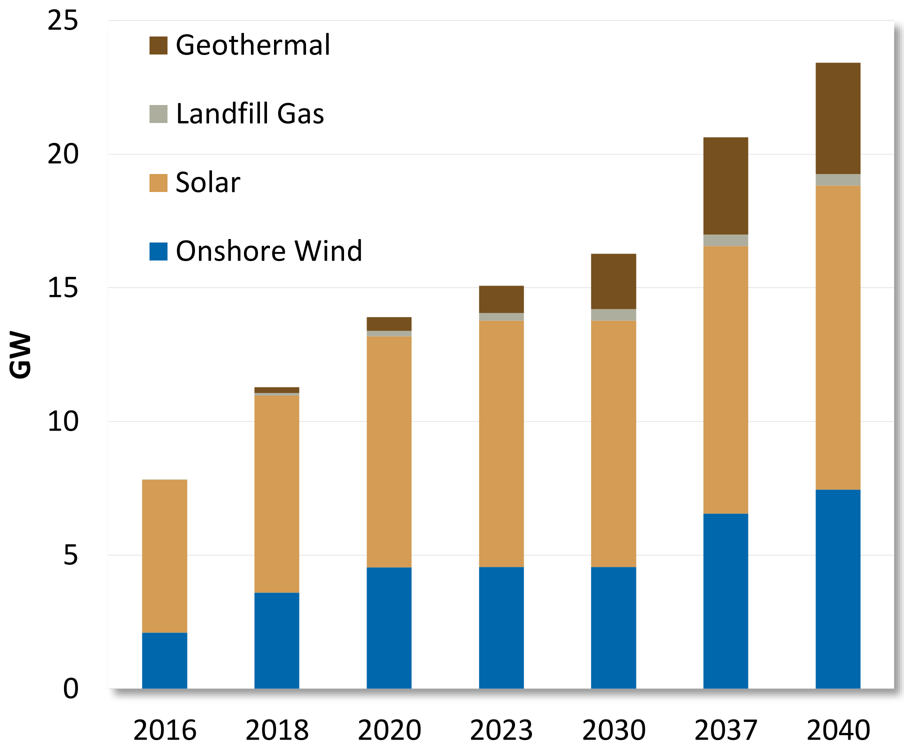
Utility-scale solar plants continue to meet RPS goals in California

- California's largest load serving entities (IOUs) remain well-positioned to meet their RPS compliance obligations through 2020.
- Planned large utility-scale solar PV projects will play a significant role in helping utilities meet their RPS obligations—approximately 29% of California's 2020 Tier 1 generation mix will be sourced from utility-scale solar projects
- The magnitude of new development opportunities will depend on the success rates of contracted projects currently under early stages of development. ICF assumes a failure rate of approximately 38%.
- Even though California utilities have contracted with many utility-scale solar additions through 2016, many of these projects will need to overcome permitting challenges.
- While this analysis does not include an extension of California's RPS after 2020, renewable installations will certainly be affected by further changes to the state's RPS.

Cumulative Tier 1 Deliverable Renewable Capacity Additions Through 2040



Note: Reported capacity is cumulative with 2015 as base year.

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Schedule a 20 minute demonstration
with one of our representatives to
learn more about the
ICForecast Strategic Power Outlook.

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