Trends in US power, gas, and renewable economics

- Factors pushing and pulling on wholesale power prices
  - Fuel prices
  - Renewable merit order effect
  - Slowing load growth
  - Energy smart technologies (demand shifting)

- Key trends in US power and gas markets
  - Overcapacity and lingering coal plants - waiting for martyrs?
  - US gas: low-cost production and increasing exports
  - Operational trends for combined-cycle gas turbines
  - Renewables pipeline, system costs, realized prices and associated merit order effect
Factors that have contributed (and will continue to contribute) to wholesale power price suppression

Supply curve (merit order)

Demand curve (load)

Wholesale price

Price - $/MWh

Source: Bloomberg New Energy Finance
COAL AND GAS GENERATION ECONOMICS
Henry Hub natural gas price, 2007-17

Source: Bloomberg
Short-run marginal cost of generation of coal and gas versus ERCOT North Hub on-off peak spreads ($/MWh real 2016 USD)

- Gas marginal costs have undercut coal and the forward curves show fierce competition.
- Transport (railcar) costs make up approximately 65% of delivered fuel costs and 50% of a TX coal plant’s SRMC, assuming 2014 average rail costs of $22/ton from WY.
- Texas is the greatest consumer of PRB coal, leaving the Wyoming producers’ very dependent on ERCOT coal demand.

Source: Bloomberg New Energy Finance Note: Assumes heat rate 7MMBtu/MWh for CCGT and 10MMBtu/MWh assuming constant $22/st transport for PRB8800 coal. Excludes variable O&M which is typically higher for coal than for gas.
Short-run marginal cost of generation of coal and gas versus PJM West Hub on-off peak spreads
($/MWh real 2016 USD)

Source: Bloomberg New Energy Finance
Note: Assumes heat rate 7MMBtu/MWh for CCGT and 10MMBtu/MWh assuming constant $10/st transport for App coal. Excludes variable O&M which is typically higher for coal than for gas.

Additional 2017/18 build of 8Bcfd pipeline capacity out of the App basin region will lift the extremely low fuel costs for PJM gas plants
Daily power mix, 2012 - yesterday

US generation by fuel type (TWh/day)

Source: Bloomberg New Energy Finance
GEFME OTHR Index (Genscape US Power Generation E) US power mix Daily 01JAN2012
EIA reports about 8GW of US coal planned to retire in the next few years. Even more could be driven by:

- Overcapacity: the low cost of gas and the policy-driven addition of renewables (discussed later) are pushing coal out
- Load growth is sub-1% in almost all markets
- Will Munis and Co-ops respond differently? The value of local jobs?

Source: Bloomberg New Energy Finance
Energy production anticipated from CCGTs across the US
Based on Bloomberg Fair Value futures curves and historical hourly profiles;
Realized prices account for ‘cherry-picking’ of positive spark spread hours,
based on operating patterns of a typical CCGT with a heat rate of 7.0MMBtu/MWh

Capacity factor expectations for CCGTs operating at benchmark US hubs –
levelized averages, 2019-54
(output as a % of nameplate)

<table>
<thead>
<tr>
<th>US benchmarks</th>
<th>CAISO SP15 / SoCal CityGate</th>
<th>ERCOT North Hub / Waha Hub</th>
<th>ISONE Mass Hub / Algonquin CityGate</th>
<th>NYISO Zone J - NYC / Transco Z6</th>
<th>MISO Illinois / Chicago CityGate</th>
</tr>
</thead>
<tbody>
<tr>
<td>West</td>
<td>Northern IL / Chicago CityGate</td>
<td>COMED / Chicago CityGate</td>
<td>AEP (Dayton) / Columbia TCO Pool</td>
<td>AE / Transco Z6 Non-NY</td>
<td>APS / Columbia TCO Pool</td>
</tr>
<tr>
<td>Central (Pennsylvania)</td>
<td>Duquesne / Columbia TCO Pool</td>
<td>Duquesne / Dominion South Pt</td>
<td>West Hub / Tetco M3</td>
<td>West Hub / Leidy</td>
<td>PPL / Tetco M3</td>
</tr>
<tr>
<td>East</td>
<td>METED / Tetco M3</td>
<td>BGE / Tetco M3</td>
<td>PEPCO / Tetco M3</td>
<td>DPL / Transco Z6 Non-NY</td>
<td>PSEG / Transco Z6 Non-NY</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>JCPL / Transco Z6 Non-NY</td>
<td></td>
</tr>
</tbody>
</table>

- The low-gas price story actually varies regionally and so does CCGT operation
- Using history as a guide, we use regression analysis to determine the statistical relationship between monthly-average spark spreads and monthly-aggregate capacity factors. This lets us tie the knot, allowing us to infer from Fair Value curves how often a CCGT will run, at each hub.

Source: Bloomberg New Energy Finance
Daily spark spread and capacity factor profiles
For a typical CCGT selling day-ahead power into CAISO’s SP15 Hub; buying SoCal CityGate gas and California carbon allowances; operating at a heat rate of 7.0MMBtu/MWh.

Spark spreads ($/MWh)

Gross margins ($/MW)

Two weeks in March 2016

Mar 2016

Mar 2016

Capacity factor (%)

CCGT output (capacity factor)

Spark spreads

Gains from producing during positive spark-hours

Startup and shutdown costs

Losses associated with out-of-the-money energy output
U.S. NATURAL GAS
Production in the Utica and Marcellus shale plays has been growing rapidly in recent years, increasing nearly 70% since 2014.

Ohio, Pennsylvania and West Virginia fill the 22.5Bcf/d of pipeline capacity that moves gas out of the region. Growth in production therefore depends on growth in pipeline infrastructure.

Takeaway pipeline capacity, or what we call “first mile” pipelines, are the bottleneck in Appalachian production. Therefore, it is no surprise that many projects are underway to increase this takeaway capacity.

Some projects plan to expand capacity on existing pipelines in the region or reverse the direction of pipes that were originally designed to move gas into the North-Atlantic.
The build-out of pipelines in the Northeast will lead the growth in the U.S. over the next three years. Other plays that will drive growth will be South Central associated gas plays, particularly the Permian and Oklahoma (SCOOP/STACK) oily plays. In these areas, the rising volumes of associated gas will help counteract the natural declines from existing conventional and unconventional wells.

BNEF expects production to grow to over 81 Bcf/d by the end of 2019 with a small number of basins driving the majority of the growth.
LNG exports

- Over the last decade, the U.S. went from an importer to an exporter of LNG.
- 95 tankers with 298Bcf have left for 18 countries (in South America, the Middle East, Europe, and Asia)
- Sabine Trains 1, 2, and 3 have commenced operations, while Sabine Train 4 and Cove Point are expected to come on in H2 2017. Cheniere’s commercial structure has a stated cost structure of 115% Henry Hub with a $2.25/MMBtu fixed fee. (We view this fixed fee as a sunk cost)
- US LNG appears cost-competitive, offering positive netbacks throughout the year based on NBP, SLInG and Brent futures prices.

Source: Bloomberg
Upcoming LNG terminals

- Alaska LNG (on hold)
- Pacific Northwest (likely)
- LNG Canada (on hold)
- Triton FLNG (cancelled)
- Douglas Channel (cancelled)
- Woodfibre (FID)
- Oregon LNG (cancelled)
- Jordan Cove (FERC denied)
- Cove Point (under construction)
- Elba Island (FID)
- Magnolia (likely)
- Sabine Pass (in operation)
- Corpus Christi (under construction)
- Freeport (under construction)
- Cameron (under construction)

Capacity by region

- Canada 2.1MMtpa (0.28Bcfd)
- US East 7.75MMtpa (1.0Bcfd)
- US Gulf 61.8MMtpa (8.1Bcfd)
  - South Texas 24.3MMtpa (3.2Bcfd)
  - Henry Hub 37.5MMtpa (4.9Bcfd)

Source: BNEF/Bloomberg
Gas exports to Mexico

Source: Bloomberg
Over 3Bcf/d of new capacity was added from West Texas through 1Q 2017, supplying Mexico with additional gas to power generation units amidst local production tapering off.

The US-to-Mexico border pipes are connecting to an expanding internal pipeline system that is allowing gas to transfer from region to region.
2010 natural gas markets

<table>
<thead>
<tr>
<th>Category</th>
<th>2010</th>
<th>vs. 2007</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>58.4</td>
<td>5.6</td>
</tr>
<tr>
<td>Canadian Imports</td>
<td>7.0</td>
<td>-2.1</td>
</tr>
<tr>
<td>LNG Imports</td>
<td>1.2</td>
<td>-0.9</td>
</tr>
<tr>
<td>Power</td>
<td>20.2</td>
<td>1.5</td>
</tr>
<tr>
<td>RC</td>
<td>21.7</td>
<td>0.4</td>
</tr>
<tr>
<td>Ind</td>
<td>18.7</td>
<td>0.5</td>
</tr>
<tr>
<td>Other</td>
<td>6.3</td>
<td>0.6</td>
</tr>
<tr>
<td>Total Consumption</td>
<td>66.9</td>
<td>2.9</td>
</tr>
<tr>
<td>Mex Exports</td>
<td>0.8</td>
<td>0.2</td>
</tr>
<tr>
<td>LNG Imports</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Source: Bloomberg
2019 natural gas markets

Source: Bloomberg

<table>
<thead>
<tr>
<th>Category</th>
<th>2019 (Bcfd)</th>
<th>vs. 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
<td>81.0</td>
<td>8.7</td>
</tr>
<tr>
<td>Canadian Imports</td>
<td>6.5</td>
<td>0.7</td>
</tr>
<tr>
<td>LNG Imports</td>
<td>0.1</td>
<td>-0.1</td>
</tr>
<tr>
<td>Power</td>
<td>28.3</td>
<td>1.0</td>
</tr>
<tr>
<td>RC</td>
<td>20.1</td>
<td>-0.5</td>
</tr>
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<tr>
<td>Other</td>
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<tr>
<td>Total Consumption</td>
<td>78.1</td>
<td>2.6</td>
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<tr>
<td>Mex Exports</td>
<td>6.0</td>
<td>2.3</td>
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<tr>
<td>LNG Imports</td>
<td>5.5</td>
<td>5.0</td>
</tr>
</tbody>
</table>
US natural gas balance
The drivers of transformation in US gas

- Low-cost production and new transport options
  - Well-head breakeven costs dropping with technological break-throughs
  - Associate gas with modest oil price recovery
  - Greenfield and brownfield pipeline projects

- LNG exports
  - Gulf Coast LNG economics work
  - Build out of new projects along the Gulf cost

- Mexican exports
  - Steady decline in Mexican oil and gas production from offshore fields
  - Mexico’s thirst for natural gas grows with incremental demand from power and industrial customers
  - Major pipeline projects in the U.S. and Canada are filling the domestic production gap

- Canadian imports
  - Midwest, Northeast, and Eastern Canadian markets switching to cheap Marcellus and Utica gas
  - New and modified pipelines making this feasible

must follow gas economics to follow power economics
US wind and solar build is still largely driven by states’ RPS and federal tax credits.

Note: New England has a 17.2% target by 2030, and PJM has a 12% target by 2030. *MI target is to be achieved by 2025.

For dataset, see U.S. renewable portfolio standard (RPS) demand database (web | terminal).

Source: Bloomberg New Energy Finance.
Wind and solar realized power price estimates versus Day-Ahead Around-the-Clock, On-Peak, and Off-Peak prices ($/MWh – real 2015USD)

There is more variation in wind realized power prices than in those of solar. Because of that variation, there is no rule of thumb for US wind realized power prices.

Solar catches a premium realized price in all regions nationwide, except in California.

Solar benefits disproportionately from its daytime premium in markets like ERCOT where average prices are very low but daytime prices spike during the summer. ERCOT has the lowest average prices in the US, but solar prevails, realizing a $32/MWh average power price that is comparable with other regions.

Source: Bloomberg Fair Value Curves, ISO wind production data, NREL PVWatts. Notes: Wind capacity factors employed at the ISO level. Solar capacity factors are hub-specific estimates (see Appendix A). Assumes a project online date of 2017, based on 20 year lifetime.
Texas (ERCOT) wind realized price versus Day-Ahead ERCOT West Hub Around-the-Clock power prices, 2011-2020 ($/MWh – real 2015USD)

- ERCOT power prices have fallen partially because of wind output itself

Source: BNEF, ERCOT, Bloomberg Fair Value Curves
Notes: Historic values are derived from hourly capacity factors aggregated at ISO level, averaged over 5 years. Future years maintain the historic monthly relationship between monthly realized price and ATC prices.
West Texas “fixed-tilt” solar estimated realized price versus Day-Ahead ERCOT West Hub Around-the-Clock power prices, 2011-2020 ($/MWh – real 2015USD)

- ERCOT’s top-heavy price profile gives solar an on-peak realized price premium, rewarding summer daytime generation.

Source: BNEF, NREL PVWatts, Bloomberg Fair Value Curves
Notes: Historic values are derived from hourly capacity factors for the city of Lubbock, TX. Future years maintain the historic monthly relationship between monthly realized price and ATC prices.
Hourly average ERCOT West Hub power prices and ERCOT wind capacity factors (average price over 2011-16)

Five-year average daily profile

- Over 75% of Texas wind capacity is located in the West, where production is heavily skewed to nighttime (off-peak) hours.

Source: BNEF, ERCOT, Bloomberg Fair Value Curves CFVL<GO>

Notes: Capacity factors are at aggregated ISO level, averaged over 2 years. Actual output of a single project is likely more volatile.
Five-year average daily profile

$/MWh – real 2015USD

- ERCOT West Hub Day-Ahead ATC power prices
- ATC capacity factor

Five-year average daily profile by month

$/MWh – real 2015USD

- ERCOT daily prices are bi-modal in winter and evening-spiking in summer. Solar will partially capture the summer price spikes but few of the winter morning price spikes.

Source: BNEF, NREL PVWatts, Bloomberg Fair Value Curves CFVL<GO>

Note: The representative solar capacity factors shown correspond to a “fixed-tilt” project located in Lubbock, TX.

Compared with other TX hubs (next slides), West Texas solar power captures more of the sharp evening price spike in ERCOT.
US capacity additions and retirements (GW)

Source: Bloomberg New Energy Finance 2016 New Energy Outlook
The system costs of adding variable renewable energy

1. **Reduced utilization rate of existing asset base**
2. Backup costs (capacity payments and resource adequacy)
3. Ramping costs (losses in efficiency of operation of existing assets)
4. Network costs
5. Curtailment
6. Ancillary services

Many factors are very system-dependent and terribly difficult to quantify.
Back-of-the-envelope power price projections – according to ‘implied heat rate on net load’ regressions, assuming BNEF solar build forecast (real 2015USD)

**Power, gas and carbon prices**
- **Power – SP15 ($/MWh)**
- **California carbon prices ($/tCO2e)**
- **Gas prices – SoCal CityGate ($/MMBtu)**

**Implied heat rates and marginal emissions factors**
- **Implied heat rates (MMBtu/MWh)**
- **Marginal emissions factor (t/MWh)**

The marginal solar megawatt-hour displaces less and less gas, and mitigates less and less CO2.

The average solar megawatt-hour displaces more gas and carbon than the marginal solar megawatt-hour.

Source: Bloomberg New Energy Finance
Hourly solar production profile versus net load profile and implied heat rate profiles in California

Average hourly utility-scale solar output on CAISO’s grid, by year (GW)

Average hourly net load on CAISO’s grid, by year (GW)

Average hourly real-time implied heat rates at SP15 hub (MMBtu/MWh)

Hourly solar production, net load and implied heat rates, H1 2016

Source: Bloomberg New Energy Finance, Bloomberg Terminal functions ISO<GO>, SPRK<GO>, CAISO daily renewable watch

Notes: in Figures 26-28, the thinnest line represents 2012, with the thickest lines representing H1 2016 data; net load is defined as total load minus solar, wind, hydro and nuclear; implied heat rates are measured by dividing real-time SP15 power prices by SoCal CityGate gas (and adjusting for the price of California carbon allowances).

Source: Bloomberg New Energy Finance
Merit order effect: predicted reductions in West Hub on-peak power prices associated with BNEF’s solar build forecast, 2016-20

- **Utility-scale solar is making its debut in ERCOT.**
- **ERCOT CDR is planning for 2GW by decade end**

**BNEF forecasts 4GW of utility scale solar by end of decade**

- **Merit order effect will continue, threatening ERCOT’s historically peaky day-time pricing**

**Source:** Bloomberg New Energy Finance
Trends in US power and gas

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