# Half of U.S. Coal Fleet on Shaky Economic Footing

### **Coal Plant Operating Margins Nationwide**

William Nelson Sophia Liu March 26, 2018

Half of U.S. coal capacity ran with net losses last year, as operating expenses exceeded revenues. In hindsight, some remaining units should have shut down long ago, but the fleet has proven stubbornly resilient. Owners have been willing to keep near-term money-losers online in hopes of grid conditions improving; and regulators have been slow to oust uneconomic units, sometimes in the name of Resource Adequacy. The possibility of widespread coal plant retirements offers upside for U.S. power (and gas) prices. With upside in mind this report sniffs out the weakest beasts in the herd.

- By our estimates, 48% of the coal fleet (135 of 280GW) posted negative margins from 2012-17. This suggests that U.S. grids may be in store for a massive, imminent upheaval as uneconomic units bow out. Indeed, many project financiers are betting that upcoming coal retirements will revitalize wholesale markets, which are currently suffocating under the weight of overcapacity. Our analysis confirms that many plants are struggling to cover fixed plus variable operating costs – and we identify which ones.
- And yet, at the conclusion of our multi-month study, we find ourselves awestruck by the resilience of U.S. coal. Plants persist even when they cost more to run than replace. As we hunt for coal closures, beware of the sometimes tenuous link between 'economics' and 'retirement decisions'. The link is especially weak in regulated regions, where high-cost coal runs regularly out of merit.
- By our analysis, Independent Power Producers (IPPs) have already shed most of their uneconomic capacity. The fleets of NRG, Vistra, FirstEnergy and Dynegy's operated above water from 2012-17. Among regulated utilities, American Electric Power Co Inc and Dominion Energy Inc have particularly healthy coal fleets. Most of Duke Energy Corp and Southern Company's coal plants, however, cost more to operate than replace.

There may be good economic arguments *not* to retire coal plants even when they start posting operating losses (notwithstanding the Department of Energy's September 2017 Notice of Proposed Rulemaking):

- The six-year period from 2012-17 featured two abnormally awful years for coal generators (2012 and 2016) and one abnormally lucrative year (2014). The period over which we define coal plant profitability is somewhat arbitrary, and operators today hope that the near future will be more lucrative than the recent past. 2018 could provide a slight boost to many plants' rolling-average operating margins on account of windfall profits earned during the extremely cold days of early January.
- The majority of 'uneconomic' units (130GW of 135GW) are regulated. They are kept online by virtue of cost-plus pacts that partially insulate owners from shifting economics. Half of these 'uneconomic' coal plants are located in vertically-integrated, regulated balancing authorities; the other half exist within liberalized markets.
- For IPPs, coal plants look like 'natural gas call options'. The possibility of future windfalls (if gas prices rise) justifies minor losses in the near term. There is also a 'game of chicken' being played by neighboring coal operators. Dark spreads and dispatch opportunities improve every time a coal plant shuts down, so the reward for 'outliving your neighbor' factors into retirement decisions.
- Plants economics are fuzzier in regulated regions. Outside of liberalized markets, the definition of 'moneyness' is loosely defined. For example, in lieu of clear price signals, regulated utilities and their regulators measure coal plants against replacement cost. Power prices at the 'interfaces' between liberalized markets and regulated balancing authorities approximate the value of energy, but no such proxy exists for the value of Resource Adequacy the ability to meet peak load. Increasingly, Resource Adequacy is what keeps flailing coal units online. Fading are the days when coal plants earned their mettle as high-output, baseload workhorses; coal is being reincarnated as backup capacity.

#### Bloomberg New Energy Finance

#### Reminder: Bloomberg does not offer investment advice.

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All operating margin calculations in this analysis are estimates. Calculations reflect the merchant value of day-ahead power production at corresponding nodes or interfaces. For a number of reasons actual plant profitability may vary from the estimates presented in this analysis.

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### Results - raw data (web - <u>click here</u>; Terminal users - run 97<GO>)

The Excel Spreadsheet accompanying this analysis includes a monthly time-series of performance, pricing and margins for every U.S. coal unit in operation since 2012.

# Introduction

### **Coal Plant Appraisals**

- The U.S. coal fleet is diverse. Unit-level nuance is necessary to untangle its economic footing. Generalizations
  oversimplify. For details on individual plants, see the Excel file accompanying this report (<u>here</u>). Our U.S.
  Power Plant Stack (web | Terminal) houses additional information relating to each unit.
- Structural changes (cheap gas, rising renewables) are pushing coal out of merit at different paces on different regional grids. For example, coal plants still run baseload in Northwest MISO; meanwhile in New England coal has devolved into backup capacity. This progression ('baseload to backup to phase-out') characterizes coal plants' lifecycles.
- Some large regulated regions (Southeast / Florida) are now clearly ill-suited for coal, on account of high burn costs and cheaper replacement options.
- What remains of the Independent Power Producer (IPP) coal fleet is, to our surprise, generally 'in the money'. IPPs have shed much of their uneconomic capacity in recent years, and even though current market conditions are lean, our analysis suggests that most of the remaining fleet yielded positive returns over the past six years – albeit aided by an extraordinarily lucrative 2014.

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### Health of U.S. Coal generators Board on August 6, 2018, RPU-203 Character Exhibit PCL-3 This graph depicts operating margins





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**Graph Interpretation:** RPU-2018-0003 This graph depicts operating margins for the U.S. coal fleet. Every little 'brick' represents an individual coal generator, in an individual month. Purple bricks post positive margins; red bricks post losses, according to our estimates. Long-Run Operating Margin (\$/MW-day)



- At 280GW<sub>nameplate</sub>, the US coal fleet is larger than the total installed capacity of every country in the world, save four (China, U.S., India, Japan).
- In 2014, when the Intergovernmental Panel on Climate Change (IPCC) released its latest (Fifth) <u>Assessment Report</u>, U.S. coal plants accounted for 4% of global emissions and almost 40% of U.S. power production.
- U.S. coal-fired generation and emissions fell 20% from 2014-16; and capacity fell 7%. Units that remain online are running less often. The average U.S. coal plant operated with a capacity factor just below 50% in 2016, after perching at 67% as recently as 2008.
- The fleet has proven vulnerable to low natural gas prices. Each plant is unique, but the past six years have frequently pushed long-run operating margins into negative territory (red) for many units. This Slide helps us visualize exactly how much of the fleet has been under water, by our estimates, on a merchant basis.
- More years like 2014 are needed to sustain U.S. coal; more years like 2016 will accelerate coal's decline.

[1] We excluded combined heat and power (CHP) plants from our operating margin analysis. This is because revenues and activities associated with CHPs' heat and steam render power-only analyses incomplete. In all, we modelled 98% of U.S. coal capacity in this report – 903 individual units on an hour-by-hour basis.

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Installed capacity net of retirement announcements (MW)



### Historical and announced retirements (MW)



#### Information on the U.S. coal fleet (and every other generator) available in our U.S. Power Plant Stack (web | Terminal)

This slide is not a forecast. It reflects current capacity, incorporating announced retirements only. It is highly likely that coal's decline will occur faster than shown on this slide, given the near-certainty that more retirement announcements will occur between now and 2025.

### Economic footing for largest coal fleets RPU-203 control the Chernick Direct Exhibit PCL-3 RPU-203 control the Chernick Direct Exhibit PCL-3 RPU-2018-0003

### Online coal capacity - colored by long-run operating margin, 2012-17



#### **Regulated Fleets**

- The bulk of **Duke Energy's** coal capacity is based in the Carolinas. The costs of shipping coal over the Appalachian mountains renders coal more costly than local Transco Zone 5 gas – and more costly than importing replacement power from PJM or MISO. Duke's regulated plants remain online at the discretion of regulators, who may have good reason keep Duke's 'out-of-the-money' (i.e. red) coal capacity online: the Carolinas have the lowest reserve margins in the Southeast. As such, retiring Duke's coal capacity might jeopardize local grid reliability.
- The same *cannot* be said of **Southern Company's** coal fleet, which is concentrated in Georgia/Alabama, where coal costs more to burn than displace, and where in 2017 estimated reserve margins were 37%.

#### **Deregulated Fleets**

- **NRG's** coal fleet spans four ISOs (PJM, MISO, ERCOT, NYISO). Its Texas and Illinois capacity delivered healthy returns from 2012-17. But its plants in Pennsylvania are plagued by fire-sale natural gas prices emerging from the Marcellus and Utica shales. These plants and their neighbors were disappointed by the latest PJM capacity auction (EY2021), which saw 'Rest of RTO' capacity prices fall to \$76/MWh-day.<sup>[1]</sup>
- **Dynegy Inc** and **Vistra Energy Corp** have fared relatively well in recent years, against all odds. Vistra's fleet in particular is among the cheapest-running in the nation, by our estimate, and Dynegy's exposure to Northeast ISO capacity prices will grant the soon-to-be-joint<sup>[2]</sup> fleets another pathway to profitability.

#### For More

The Excel File accompanying this report has details on every plant. Click <u>here</u> or on Terminal run 97<GO>.

[1] PJM Capacity Auction Plunders Coal Country, Pays Coast (web | Terminal)
 [2] Vistra Doubles Down on Fossil Bet by Absorbing Dynegy (web | Terminal)

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## Results Database: Every Coal Plant, Every Month 103

Find data here

Revenues, Expenses and Operating Margins for select coal plants (\$m)



7 For more details: if you have questions about methodology or operation patterns of a specific, send us a message at: <u>wnelson7@bloomberb.net</u> (William Nelson) fliu161@bloomberg.net (Sophia Liu)

## Progression of Coal'S Value proposition RPU-2018 Chemick Direct Exhibit PCL-3 RPU-2018-0003

### From baseload to backup

The money-ness of coal plants in deregulated wholesale power markets is relatively straightforward; plants either turn profits or they do not. But outside of deregulated markets, 'money-ness' and 'margins' are less clearly defined. A little economic theory mixed with some lessons from markets like PJM can help shed light on the challenges and opportunities facing coal U.S.-wide.

Coal plants were originally designed to run baseload – to sell large volumes of electricity with healthy short-run operating margins (i.e. dark spreads). This was necessary to cover relatively high fixed costs. Since the shale boom, collapsing dark spreads and dwindling capacity factors have cut deeply into coal's energy revenues – so much so that plants sometimes fail to cover fixed operating costs. Ongoing operating losses can drive plants to retire.

Simply boosting output is not an option. Plants have reduced their capacity factors precisely because in many hours, fuel prices are higher than power prices. Running more would mean running at a loss.

With energy payments falling, coal plants' value propositions are changing. Plants now lean more heavily on Resource Adequacy (RA), less heavily on energy sales. Physically, this suggests i) grids have found cheaper *energy* options; and ii) some coal *capacity* is still needed for reliability purposes.

Financially, this means capacity payments (or more broadly, RA) have become critical for coal. For example, each year in PJM, coal units bid into the capacity market at prices necessary to cover net, pro-forma operating expenses (i.e. total expected expenses less expected energy revenues). Before shale, when energy revenues were high, coal plants were capacity 'price takers'; they submitted \$0/MW-day capacity bids. They accepted capacity prices wherever they cleared because they could afford to remain online without the Resource Adequacy argument altogether. Dark spreads (i.e. energy margins) were so high that supplemental RA revenues were unnecessary for their survival. Invulnerable, capacity price-taking coal plants were once common but are now rare.

More commonly, energy margins now fail to cover total expenses. Coal plants place 'break-even' capacity bids at levels needed to plug would-be losses from energy sales alone. Their bids reflect the supplementary revenues needed to remain online. Winning bids plug potential losses and keep units online; failure to clear the capacity auction can end in retirement. Failure to clear is a signal from grid operators that there are other, cheaper ways to meet peak load.

The PJM example demonstrates that what is underway on U.S. grids today (whether liberalized or regulated) is a structured, systematic removal of uneconomic coal capacity; and ii) a preservation of some coal plants with sub-zero energy margins by virtue of RA supplements. A tide has clearly turned against coal's energy dominance – gas and renewables have stolen coal's place at the front of the merit order. But the fleet cannot disintegrate all at once because of coal's role in ensuring Resource Adequacy.

The Resource Adequacy argument states that coal plants should be retired only when they cost more to keep online than replace. Markets are designed around this principle, and regulators abide by it. Coal's 'firm capacity' (i.e. peak load -serving capacity) can be replaced one-for-one only with other firm capacity – most notably, new gas plants.<sup>[1]</sup> By one line of thinking, coal will maintain a role on U.S. grids so long as upkeep costs can undercut the net costs of new entry (net CONE) for new gas plants (i.e. all-in costs net of energy revenues).

Net CONE estimates vary by project. We estimate the cost of new entry for new gas plants ranges from \$75-200/MW-day, in PJM, depending on the zone (web | Terminal). Better than our estimates though are actual capacity clearing prices in markets like PJM. For example, the \$76.53-188.12/MW-day prices fetched in the last PJM auction were influenced if not set by the 2.4GW of new gas capacity that cleared in the auction.

If we take these \$75-200/MW-day benchmarks for the net CONE of new gas (i.e. coal's 'firm capacity' replacement cost) we can make the following (oversimplified) claims:

- Coal plants that lose money in *deregulated* markets are vulnerable to retirement. (Margins in deregulated markets are inclusive of energy + RA payments.)
- Regulated coal plants with negative energy margins may or may not be vulnerable to retirement. Plants are *not* vulnerable if reserve margins are tight (approaching 15%) and if operating losses are less than the net CONE of new gas (~\$75-200/MW-day). Plants are vulnerable if operating losses are excessive (above the net CONE of new gas) or if reserve margins are so high (much higher than 15%) that the local grid operator can afford to cut capacity without sacrificing reliability.

When interpreting results of this analysis, take our long-run energy margins at face value for plants in ISOs. (Negative margins mean 'uneconomic' and therefore at risk.) But in vertically-integrated, regulated balancing authorities, keep in mind the Resource Adequacy replacement cost buffer. A coal plant that loses \$50/MW-day in Southern Company territory may be more 'economic' than the would-be replacement cost of building a new gas plant.

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[1]. Beware any comparison that pits the costs of one technology against another. The subsidized, levelized cost of new wind farms can now undercut the short-run marginal cost of existing coal. But coal's *value* to the grid is higher, given its firmness and dispatch-ability. Falling wind costs are hurting coal economics and displacing coal *energy*, but non-intermittent technologies are needed to fully replace coal *capacity*.

# 50,000ft Fleet Tour

# **Geographic survey of plant profitability and other indicators**

### Prerequisite Reading:

U.S. Coal Upstream to Midstream: Mines to Plants (web | Terminal)

U.S. power plants paid \$26 billion for coal deliveries in 2016, hauling 650 million tons 450 miles across the country, on average. Declining volumes and drooping hub prices have driven transaction values down 10% per year since 2011. Appalachia fell first; Illinois Basin flat-lined; and recently the Powder River Basin yielded to cheap gas, as coal generators everywhere reel. This macro-level survey tracks dollars and tons from mine to plant, unearthing insights about the longevity of U.S. coal.

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## **Coal Margins**

#### Filed with the Iowa Utilities Board on August 6, 2018, RPU-205 & Contract Exhibit PCL-3 RPU-2018-0003

Long-run operating margins for U.S. coal plants

Six-year average: 2012-17



10 Notes: pie segments denote individual generating units within each plant. Bubbles are scaled by plant size (capacity) and colored by long-run operating margin. Operating margins for regulated assets outside of competitive wholesale power markets should be interpreted in the context of retail rate-basing.

### Capacity Factors Filed with the Iowa Utilities Board on August 6, 2018, RPU-208@10003ub Chernick Direct Exhibit PCL-3 RPU-2018-0003

Long-run operating margins for U.S. coal plants

Six-year average: 2012-17



### **Fuel Costs**

All-in coal costs (delivered) for U.S. coal plants

Six-year average: 2012-17



# Short-Run Marginal Costs (SRMC)<sup>PU-20\$</sup> PU-20\$ PU-2

Six-year average: 2012-17



## Realized Power Prices Board on August 6, 2018, RPU-205 & COLD Chemick Direct Exhibit PCL-3 RPU-2018-0003

Production weighted-average power prices earned by U.S. coal plants

![](_page_14_Figure_2.jpeg)

# Margins

### Short-Run (SR) and Long-Run (LR)

#### Short-Run Operating Margins (aka Dark Spreads) = Revenues $_{SR}$ - Expenses $_{LR}$

- Revenues <sub>SR</sub> = Power Price \* Generation + Byproduct Sales
- Expenses  $_{LR}$  = (Fuel Hub + Fuel Transport) \* Fuel Burn
  - + Variable O&M \* Generation
  - + (CO2 price \* CO2 emissions) + (SO2 price \* SO2 emissions)

#### Long-Run Operating Margins

= Short-Run Operating Margins + Capacity Revenues – Fixed O&M

### Notes:

- Short-run margins govern dispatch decisions, long-run margins affect bottom line.
- All margin calculations in this report are merchant, day-ahead, pre-tax.
- We do not include hedges or power purchase agreements.
- Also missing from our analysis are ancillary service revenues and Day-Ahead/Real-Time (DART) spreads.
- We use the term 'margins' liberally in this report with regards to assets in vertically-integrated regulated balancing authorities. Positive margin calculations mean that regulated plants' costs are below replacement value; negative margins means plant costs are above replacement value.

## Operating margins for the average coal plant PU-2018 RPU-2018 Chemick Direct Exhibit PCL-3

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

16

![](_page_16_Figure_2.jpeg)

Here we are looking at the 'average' U.S. coal plant. A megawatt-weighted mash-up of all units in operation since 2012.<sup>[1]</sup> The following statements typify U.S. coal plants:

- Dark spreads have dropped so much since the shale revolution that many coal plants now fail to break even on a longrun (fixed + variable) basis in many months throughout the year.
- Power revenues cover short-run costs (fuel + variable O&M) in a diminishing number of hours. This is why capacity factors have fallen across the board (Slide 30).
- It is increasingly difficult to cover fixed O&M with energy margins alone.
   Rewards for Resource Adequacy have helped in this regard.
- Long-run operating margins have been anything but stable. In fact, one event (the Polar Vortex of 2014) is responsible for pushing the average coal plants into positive territory over the past six years.
- Note that capacity payments on the chart get diluted by the fact that many plants simply do not receive them.

## Operating margins by power region RPU-20% and Chemick Direct Exhibit PCL-3 RPU-20% and Chemick Direct Exhibit PCL-3 RPU-2018-0003

Quarterly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_17_Figure_2.jpeg)

17

[1] Necessary caveat: the coal fleet is highly eclectic. Weighted-averages like the one above conceal the nuance that arises from studying individual units. On later slides we will continually emphasize the heterogeneity of the U.S. coal fleet.

## U.S. coal fleet operating margins RPU-205 100 Club Chernick Direct Exhibit PCL-3 RPU-2018-0003

### U.S. coal fleet ranked by long-run operating margin, 2012-17

![](_page_18_Figure_2.jpeg)

- The IPP coal fleet is relatively stable. Only 7% (5GW) of the remaining IPP fleet netted negative operating margins over the past six years, thanks in large part to Mother Nature's bail-out in 2014.
- Coal economics are more vulnerable in regulated regions.
- Economics aside, regulated assets (colored in grey) tend be 'safer' than IPP-owned units (purple) simply because vertically-integrated regulated utilities are entitled to rate-base their losses, and regulators are slower to axe aging coal capacity than investors. 'Out-of-the-money', IPP-owned generators are the most vulnerable to retirement.
- Plants in ISOs/RTOs are more commonly in-the-money, according to our modelling. Here is why:
  - 1. Geography. (See Slides 10-14.)
  - Treatment of Resource Adequacy (crucial point). Long-run margins in this analysis include capacity revenues for plants in organized capacity markets – i.e. for plants in ISOs, but not for plants in regulated balancing authorities (BAs). This analysis therefore unfairly penalizes units in regulated BAs, due to a lack of a price signal.

To correct for this information asymmetry, we must keep in mind how Public Utility Commissions treat Resource Adequacy.

- 3. Fleet turnover. Uneconomic coal plants in IPPs tend to retire. (Retired units do not appear on this slide.) Regulated assets are stubborn; they are shielded by cost-of-service returns, and tend to linger longer after their economics sour.
- 4. Coal contracts. The IPP fleet enjoys lower fuel prices – geographic advantage notwithstanding. This is the case because regulated assets tend to lock into longer-term fuel + transport contracts. Coal prices have fallen in recent years, leaving many legacy, regulated fuel contracts out-of-the-money relative to recent spot prices.

### U.S. coal fleet operating margins RPU-205 Could Chemick Direct Exhibit PCL-3 RPU-2018-0003

![](_page_19_Figure_1.jpeg)

![](_page_19_Figure_2.jpeg)

#### **Regional Characterizations:**

- NYISO/ISO-NE: very expensive coal, cost of RGGI carbon allowances, very low capacity factors make the Northeast a unique case. Plants are kept generally healthy by virtue of winter-time power spikes and very high capacity prices.
- ERCOT: A slew of early 2018 retirements have drastically improved conditions for the surviving fleet. Even without capacity payments, the EROCT coal fleet is poised to capitalize on cold Northeast winters and hot Texas summers. Without nature's blessing, ERCOT coal can eek out a living in spite of meagre power prices by relying on its young, efficient fleet, burning cheap Powder River Basin (PRB) subbituminous coal and cheaper local lignite.
- WECC: An eclectic mix of generally very large power plants that burn cheaply. Many are located close to Wyoming's Powder River Basin, as the crow flies -- but shipping over the Rockies is cost-prohibitive, encouraging some large WECC plants to burn more expensive Uinta Basin coal instead. Some legacy Power Purchase Agreements with California utilities force some of these plants to pay for expensive carbon allowances.
- SPP: The last coal plant in the country might be located in SPP. Perfectly located next to the PRB, feedstock is cheap. Wind is severely undermining power prices, however.
- PJM: A wave of retirements in 2015 ousted the weakest plants in this fleet. Proximity to Appalachian coal is a blessing; proximity to Appalachian shale gas is a curse. Capacity payments here are crucial, and the latest auction did not help.
- MISO: hard to generalize what is (geographically) the largest power pool in the country. It also contains a mix of IPPs and regulated assets in what amounts to a semi-competitive power market. Most of MISO burns relatively cheap (and somewhat close-by) PRB coal, but the region suffers from some of the lowest power and capacity prices nationwide. Coal burn in MISO is likely to retreat West as the App and Illinois Basins falter.
- **Southeast / Florida**: simply too far away from any major coal basin to compete with gas. The regulated fleets here could linger or we could see Public Utility Commissions (PUCs) turning against coal en masse.

# U.S. coal fleet operating margins – by year RPU-203 Brow OBub Chernick Direct Exhibit PCL-3 RPU-2018-0003

![](_page_20_Figure_1.jpeg)

### U.S. coal fleet ranked by long-run operating margin, 2012-17 (\$/MW-day)

#### **Yearly Characterizations**

- 2014: The Polar Vortex of 2014 delivered windfall profits for most of the U.S. coal fleet. If every winter were as cold as 2013/14, no coal plant in the country would be on shaky economic footing today. (Plants with negative 2014 margins on this Slide are located in regulated balancing authorities, where they would likely be kept online for Resource Adequacy.)
- 2012: At the other extreme, 2012 was the first abnormally mild winter during the shale era. It was a frightening time for the coal fleet, which had not anticipated sub-\$3/MMBtu gas at Henry Hub. Margins were crushed across the board.
- 2016: The coal fleet was hit again with a second shaleera 'year of no winter' in 2016. Gas prices dipped even lower in 2016 than in 2012, and yet, the coal fleet performed better. This is because i) coal prices (hub and transport) dropped in the interim, partially in response to falling demand; and ii) many of the least economic units retired between 2012 and 2016, leaving behind a healthier core fleet.
- Odd years (2013, 2015, 2017): These are the 'new normal' years for the U.S. coal fleet. The important point to recognize from this chart is that the outlier years (incidentally, 'even years') have an outsized influence on margins.
- **2018:** Early 2018 brought the blistering cold on which coal thrives. There were thoughts in January that 2018 could be another 2014, but the weather grew mild and gas prices subsided. We are likely locked in to another year of uninspiring returns for U.S. coal.

# **Appendix:**

# **Appendix:**

### **Methodology and Data**

# Data and Methodology Eiled with the lowa Utilities Board on August 6, 2018, RPU-205 & 100 CBub Chernick Direct Exhibit PCL-3 RPU-2018-0003

This publication is the first in a series of upcoming BNEF research that features a new tool for appraising power assets. The tool calls Bloomberg Terminal API (inside a Python script) to assemble pricing and performance data for U.S. power plants. The strength of the tool is its ability to integrate very large datasets.

#### Methodology – Revenues

The bulk of the revenues in this analysis are *derived* rather than reported. Our appraisals reflect our best estimates of the merchant value of power production, assuming plants sell into the Day-Ahead market. What we have *not* captured is any power hedges. Actual plant proceeds may differ from our estimates.

#### • Power Revenues = Electricity Generation \* Power Price

We solved the above equation by pairing *hourly* strings of Day-Ahead power prices with *hourly* generation data. We used nodal power prices where available, and supplemented these with hub-level (and Interface-level) prices where necessary.

#### • Capacity Revenues = Firm Capacity \* Capacity Price

Straightforward exercise of applying zonal capacity prices to each plants' summer capacity rating. We assume that all plants clear capacity auctions (nearly all of them do). We *did not* assume a value of Resource Adequacy outside of regions with organized capacity markets.

#### • Byproduct Revenues = Reported to EIA

Power plants report revenues associated with the sale of environmental byproducts like coal ash. This revenue stream is negligible for most plants. It *is* included in this analysis.

#### Methodology – Costs

All-in coal costs (delivered) are reported to the EIA but redacted for plants owned by IPPs. We fill those IPP gaps by regressing delivery costs on hub-to-plant transport distances from each major basin, for a each transport type (rail, river, etc). We have incorporated the variable costs associated with running environmental controls using plant-specific data reported to the EIA. Other fixed and variable operating and maintenance (O&M) costs represent BNEF estimates, taking into account location, boiler age, generator size, etc.

We have not included capital expenditures in our analysis, nor does our analysis consider debt servicing or decommissioning costs.

### Data & Methodology:

### Results - raw data (web - click here; Terminal users - run 97<GO>)

The Excel Spreadsheet accompanying this analysis includes a monthly time-series of performance, pricing and margins for every U.S. coal unit in operation since 2012.

#### Inputs

This analysis features heavy use of hourly power pricing and fundamentals data available on the Bloomberg Terminal.

#### Asset list

 Bloomberg's U.S. Power Plant Stack (web | Terminal). This dataset contains details on all U.S. generator, including the entire coal fleet. It also like plant ids to other datasets listed below (CEMS, Nodes, Hubs, Owners).

#### Plant Performance

• EPA CEMS (Environmental Protection Agency's Continuous Emissions Monitoring System). This dataset provides hourly generation, fuel burn and emissions at the generator level. To access on the Bloomberg Terminal, find your unit's CEMS Ticker in the Plant Stack. Here's an example: type {CE5MH3 24AV Index GP <GO>} to see 24-hour average production from TX's Big Brown coal plant.

#### Pricing

- Nodal power prices: Bloomberg Terminal Ticker Finder (web | Terminal)
- Hub-level power and fuel prices: U.S. Power and Fuel Prices (web | Terminal)
- Capacity prices: U.S. Capacity Prices: All in One Place (web | Terminal)
- Transport: U.S. Coal's Financial Collapse Outpaces Physical Decay (web | Terminal)

#### Contact

#### wnelson7@bloomberg.net

Please get in touch with us if you would like to discuss results and/or methodology. And please send us your feedback.

## Coal-to-gas fuel with the low a Utilities Board on August 6, 2018, RPU-205 @ 000000 Chernick Direct Exhibit PCL-3 RPU-2018-0003

![](_page_24_Figure_1.jpeg)

![](_page_24_Figure_2.jpeg)

days in April 2012. Rising shale gas production and an exceptionally mild winter pushed Henry Hub prices below \$2/MMBtu, prompting the fuel switch. After April 2012 another three years went by before gas again out-produced coal.

Pay attention to the gas-to-coal fuel switch that occurred in early 2018. For all the hype surrounding cold-weather days in January, in historical terms, the boost to coal-fired production was relatively meagre and shortlived.

![](_page_24_Picture_6.jpeg)

## Coal versus gas prices board on August 6, 2018, RPU-203 and OBub Chernick Direct Exhibit PCL-3 RPU-2018-0003

![](_page_25_Figure_1.jpeg)

• U.S. coal prices are typically quoted in 'dollars per short ton'. Coal quality (heat content, sulfur content, ash content, moisture content) varies considerably from basin to basin, and this makes hub comparisons a challenge. On this chart we have converted historical prices to \$/MMBtu.

Notice how coal prices dipped in 2015-16. This is directly related to falling natural gas prices. Producers were forced to lower prices in attempt to manufacture demand, in the face of cheap gas. As gas prices rose in 2017 coal prices followed.

![](_page_25_Picture_4.jpeg)

## Coal versus gas on the One Onio River Source Revealed to August 2018, RPU-205 100 Club Chernick Direct Exhibit PCL-3 RPU-2018-0003

Example of pricing and production data on the Bloomberg Terminal

### Hanging Rock gas

John E Amos coal

![](_page_26_Figure_4.jpeg)

### Live Charts – click on the charts to open and update them in the Bloomberg Terminal

**Costs:** Short-run marginal costs (SRMC) at the Marcellus-fuelled Hanging Rock CCGT plunged well below \$15/MWh in 2015-16, and normalized around \$20/MWh in 2017. Comparatively, John E Amos struggles to get dispatched while burning coal for over \$25/MWh.

**Generation:** What was once a 'baseload' plant, since 2015 John E Amos is lately forced to take part in considerable amounts of ramping. The Hanging Rock CCGT's have assumed a 'baseload' paradigm with a 2017 capacity factor of 73% (compared with Amos' 60%), according to CEMS and GENSCAPE generation data on the Bloomberg Terminal.

Margins: Coal in the region is often out of the money except in high demand winter and summer months. Alternatively, the CCGTs at Hanging Rock are so cheap to run that they are nearly always in the money.

# Revenues

### Power Price \* Production + Capacity Price \* Firm Capacity + Byproducts

#### High-Level Methodology for Capturing Coal Plant Revenues:

The bulk of revenues still come from energy sales, everywhere outside New York and New England. Locational marginal power prices in deregulated wholesale markets vary point-to-point, hour-by-hour. This pairs hourly, nodal price strings with hourly, generator-by-generator production data. These calculations reflect the merchant, realized value of each units' energy output.

A similar principal applies for coal plants in regulated regions, except, instead of nodal power prices we assign to each coal plant energy values associated with nearby 'interface prices' – i.e. the prices at which verticallyintegrated regulated utilities sell their power to neighboring balancing authorities. (For example, plants in Southern Company's balancing authority are appraised against 'MISO-SOCO Interface' power prices. These are the prices at which Southern Company trades power with MISO. Interfaces are imperfect, if useful proxies for the locational marginal value of plants in regulated regions.

Our calculations assume plants sell merchant (no forward hedges considered in this analysis); and our calculations assume plants sell Day-Ahead. No Real-Time or Ancillary Service revenues considered in this analysis.

Capacity payments in this analysis reflect zonal prices from organized markets.

Byproduct revenues are negligible, as reported to EIA Form 923.

		RPU-2018-0003	
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## Total (long-run) revenues versus total costs RPU-203 is no Otub Chemick Direct Exhibit PCL-3 RPU-2018 total costs RPU-2018-0003

![](_page_28_Figure_1.jpeg)

Our analysis compares revenues to costs on a hour-by-hour basis. Power sales still make up the majority of plant revenues, but in Northeast ISOs supplemental capacity payments are crucial for keeping coal online. Capacity revenues are relatively passive (i.e. 'costless') compared to power sales, which carry with them fuel and variable O&M expenses.

• We modelled capacity prices only where there are organized capacity markets. This represents a shortcoming of our analysis, because in reality, plants in regulated balancing authorities do derive value from the Resource Adequacy benefits they provide.

## Variable (short-run) revenues versus variable (short-run) revenues versus variable

![](_page_29_Figure_1.jpeg)

The previous slide showed power (and capacity) revenues in \$/MW-day terms. This slide puts power revenues in more familiar \$/MWh terms – i.e. it shows 'realized' power prices, which represent production-weighted average prices, taking into account hourly fluctuations in price and production. In this analysis power revenues are calculated with nodal, generator-level specificity, assuming that 100% of each plants' output is sold Day-Ahead (rather than Real-Time or hedged).

 It is rare for generators to sell below short-run marginal cost. In theory, coal plants should shut down (temporarily) when darks spreads are negative. This is complicated by the take-or-pay nature of long-term coal contracts, and it clearly breaks down in regulated service territories, where the incentives to obey economic dispatch are less pronounced.

# Plant performance Filed with the Iowa Utilities Board on August 6, 2018, RPU-205 & 100 OBub Chernick Direct Exhibit PCL-3 RPU-2018-0003

### Quarterly capacity factors versus heat rates

![](_page_30_Figure_2.jpeg)

- Coal capacity factors have fallen across the board as the shale boom has set in. 2016 was a low point for U.S. coal-fired generation. A slight uptick in 2017 gas prices is responsible for the recent uptick seen in many regions. What stands out on this chart is the fact that in NYIOS/ISO-NE coal plants are peakers; while in WECC many plants still run baseload.
- Heat rates for the U.S. coal fleet operate in a narrow range, from 9.0-11.0MMBtu/MWh. Plants with lower heat rates run more often, and plants that run more often (and ramp less) operate with lower heat rates. Older units typically have higher heat rates.<sup>[1]</sup> Coal quality also plays a role: coal with high heat contents (MMBtu/st) can be burned more efficiently.<sup>[2]</sup>

[1] Bloomberg's U.S. Plant Stack (<u>web</u> | <u>Terminal</u>) demonstrates how heat rates vary unit-to-unit.
 [2] Appalachia, Illinois and Uinta have relatively high heat contents; PRB and lignite have low heat contents. More details can be found here (<u>web</u> | <u>Terminal</u>), on Slide 18.

# Costs

### Fuel Costs + Emissions Costs + Fixed and Variable O&M

High-Level Methodology for Capturing Coal Plant Costs:

Coal costs are more eclectic than revenues.

Further Reading – market mechanisms linking weather to coal plant profits

How Seasonal Storage Commands U.S. Power, Gas and LNG (web | Terminal)

This is a story every gas trader knows. It begins at 10:30am ET every Thursday and ends with the whole LNG world watching. Ongoing coordination between gas and coal markets manipulates U.S. power grids, every day, with a specific objective: to enter November with gas storage reservoirs full. This banal obsession governs power plant economics, fuel burn, carbon emissions and LNG supply. It wields influence over hundreds of billions of dollars annually. It's a story everyone in energy should know.

## Short-run costs of coal-fired generation RPU-205 crooctub Chemick Direct Exhibit PCL-3 RPU-2018-0003 RPU-2018-0003

### **U.S. coal fleet ranked by short-run marginal cost, 2012 – Q3 2017** (Online units only – does not include generators that have retired since 2012)

![](_page_32_Figure_2.jpeg)

- Generation costs vary across the coal fleet. The cheapest-burning plants break even on a short-run basis around \$15/MWh; the middle quartiles produce in the \$20-35/MWh range; high-cost outliers produce above \$40/MWh.
- Fuel costs (hub purchases + transport costs) make up the bulk of most plants' operating expenses. Transport costs vary dramatically.
   For example, Powder River Basin coal is sold cheaply at the hub (short black columns) but its distance from most buyers boosts transport costs considerably (tall grey columns).
   Appalachian coal is better located (lower transport costs for the bulk of the fleet) but costs much more at the mine.
- Throughout this report we characterize fuel costs as 'variable' (ie. relevant for short-run cost calculations). In reality, plant operators sometimes treat fuel as 'sunk', in recognition of the fixed, take-or-pay nature of their long-term delivery contracts. The distinction encourages some plants to sell power at loss-inducing levels, lower than indicated on this graph.
- Variable O&M costs associated with running environmental control equipment has risen on account of tightening emissions regulations.
- A handful of plants are subject to carbon allowance burdens – those tied to California; and those located in Regional Greenhouse Gas Initiative (RGGI) states.

### Coal costs versus SRVC and on August 6, 2018, RPU-205 & 00 Club Chernick Direct Exhibit PCL-3 RPU-2018-0003

### Cost costs (\$/MMBtu)

### Short-run marginal cost of generation (\$/MWh)

![](_page_33_Figure_3.jpeg)

- A handful of U.S. coal hubs serve the entire U.S. fleet. Geography determines where plants source their coal. Transport costs can be substantial. By rule of thumb plants pay around \$0.02/ton-mile to move fuel by rail around the country. We know this because plants report their all-in fuel costs to the Department of Energy. We back out the 'transport' component by subtracting the prevailing price of coal at the hub.
- Illinois and Appalachian coal is considerably more expensive (at the hub) than coal from the Powder River Basin. A straight 'hub versus hub' comparison is misleading however, because transport costs from Appalachia are considerably lower for the average buyer.

![](_page_33_Picture_6.jpeg)

## Coal costs versus SRIVIC source on August 6, 2018, RPU-205 & Course Chemick Direct Exhibit PCL-3 RPU-2018-0003

### Cost costs (\$/MMBtu)

Short-run marginal cost of generation (\$/MWh)

![](_page_34_Figure_3.jpeg)

 ERCOT burns the cheapest coal in the nation, on average, according to our estimates. This is somewhat surprising given the +1,000-mile distance separating Houston from the Powder River Basin, where much of ERCOT's coal originates. Cheap local lignite, a young, efficient fleet keep variable costs low. ERCOT's unregulated coal fleet has also managed to avoid the long-term out-of-the-money fuel contracts that are so common in regulated regions.

![](_page_34_Picture_5.jpeg)

34

## U.S. coal shipments – 2016 RPU-203 Brow Obub Chernick Direct Exhibit PCL-3 RPU-2018-0003

Sited by destination (power plants); sized by shipment quantity (Btus); colored by origin (mine basin)

The U.S. coal transport apparatus is truly remarkable. Freight rates, coal quality and hub prices govern coal procurement choices. Low oil prices have mitigated (somewhat) the transport costs for far-travelling PRB coal.

![](_page_35_Figure_3.jpeg)

### U.S. coal transport costs – PRB rail example RPU-2018, RPU-2018, RPU-2018, RPU-2018, Direct Exhibit PCL-3 RPU-2018-0003

Some plants (most regulated plants) report their all-in fuel costs (hub + transport) to the EIA. Lets call them 'reporting plants'. We need a way to infer costs for 'non-reporting plants'. This section describes how we infer fuel costs for 'non-reporters', using information from 'reporters'.

Since hub-level coal prices are well-known, the hard part is inferring transport costs for 'non-reporters'. To do this, we first calculate the 'implied transport premium' associated for the 'reporters'.

For generators that report all-in fuel costs: Implied transport premium = all-in cost (reported to EIA 923) – hub price (quality-adjusted)<sup>[1]</sup>

#### One example:

- In September 2011 Ameren's Rush Island Coal Plant (EIA ID = 6155) in Missouri received subbituminous spot shipments from Buckskin mine (MSHA ID = 4801200) in the Powder River Basin, Wyoming. Distance traveled = 1138 miles.
- Ameren paid a \$20/ton *premium* over and above the prevailing PRB 8400 spot price, after adjusting for coal quality.<sup>[1]</sup>
- From this shipment we imply a transport cost of ~\$0.01/ton-mile, after adjusting for loading fees, etc. (Full calculation on Slide 38). A \$0.01/ton-mile transport fee is typical in the wide-open Midwest, where the rail networks face limited congestion.
   Freight rates rise further east (around the Illinois and Appalachian coal basins; serving PJM, Southeast, New York and New England).
- Limitation: note our loose definition of 'transport costs'. Throughout this report we ascribe the full hub-to-plant premium (\$/20/ton, in this case) to the cost of 'transport'. In reality, other factors contribute to the delta between coal hub prices and all-in delivery costs.
  - In particular, hedging costs (or savings) can influence all-in delivery premiums (or discounts). In our Rush Island example, coal was bought 'spot' (purchased within 12 months of delivery). PRB 8400 hub prices did not move much in the interim, so the forward nature of the purchase likely had little impact. But many coal shipments and/or rail reservations are purchased years in advance; these distort our 'transport cost' estimates.

### Transport premiums versus freight distances for spot coal sales delivered by rail from PRB, 2008 – March 2017

![](_page_36_Figure_11.jpeg)

36

[1] A note on quality-adjusted coal prices: the heat content of the coal delivered to Rush Island was 8,341Btu/lb, slightly below the benchmark 8,400Btu/ton contract specifications. In recognition of the coal's sub-standard quality, the buyer was entitled to a (slight) per-ton discount. Standard operating procedures apply apply similar discounts whenever sulphur, ash or moisture contents exceed contract specifications.

### U.S. coal transport costs – PRB rail example RPU-2018-Chub Chernick Direct Exhibit PCL-3 RPU-2018-0003

- For this report we compiled over a 100,000 mine-to-plant deliveries, each with the following characteristics:
  - Inferred transport cost (all-in cost minus quality-adjusted hub price)
  - Miles traveled (distance from mine to plant)
  - Contract type (spot versus long-term contract)
  - Delivery method (rail, barge, truck, etc)
- The graph on this slide demonstrates how we can deduce certain aspects of coal's value chain. Here we look at transport premiums for spot coal sales delivered from the Powder River Basin by rail.
- The upward-sloping regression coefficient can be interpreted as the average per-ton-mile freight rate charged by railroads (\$0.0137/ton-mile).
- In addition to a per-mile fee, the average PRB coal delivery incurred a \$7.42/ton loading fee, which is given by the regression line's y-intercept.

#### How we use this information:

- Ultimately, the purpose of this exercise is to determine all-in fuel costs for the entire U.S. coal fleet. Hub prices alone are insufficient, given the substantial costs of coal transport for some plants.
- We use our transport premium regression results (lines on this chart) only for plants that *do not* report all-in fuel costs. (Most independent power producers *do not* report fuel costs to the EIA; most regulated generators *do*.)

### Transport premiums versus freight distances for spot coal sales delivered by rail from PRB, 2008 – March 2017

![](_page_37_Figure_13.jpeg)

### Coal Combustion Wath RPU-2018-0003

![](_page_38_Figure_1.jpeg)

38 This slide simplifies some components of coal's value chain, but covers all the first-order factors influencing coal costs.

### Coal plant O&Mied with the Iowa Utilities Board on August 6, 2018, RPU-2058 0000 CBub Chernick Direct Exhibit PCL-3 RPU-2018-0003

### Fixed and variable O&M – regional weighted averages

![](_page_39_Figure_2.jpeg)

#### Fixed O&M

- Fixed O&M (FO&M) costs in this analysis are estimates, not empirical measurements. We estimate that the average plant incurs fixed O&M costs around \$40/kW-year, which equates to \$110/MW-day.
- Larger, newer generators tend to have lower FO&M. Generators are also aided by 'sister units' (in multi-generator plants) with which they can split some aspects of fixed O&M.
- Finally, it is cheaper to operate plants in sparse, mild-weather locations like ERCOT, SPP and WECC than in the populous, severeweather Northeast (NYISO, ISO-NE, PJM).

#### Variable O&M

- Variable O&M (VO&M) costs in this analysis consist of two components:
  - Costs of operating environmental controls. This data is reported to the EIA and reflected in our analysis.
  - Other VO&M associated with ramping, start-up/shut-down and 'normal' wear and tear. These costs are estimated.

The split between 'enviro' and 'other' VO&M is roughly 50-50 for the average plant. Outliers are typically plagued by exorbitant enviro VO&M.

### Coal plant O&M with the Iowa Utilities Board on August 6, 2018, RPU-205 & 100 CBub Chernick Direct Exhibit PCL-3 RPU-2018-0003

### Fixed and variable O&M – for individual generating units

![](_page_40_Figure_2.jpeg)

#### Unit-by-unit granularity

- Like so many aspects of the U.S. coal fleet, O&M costs carry wide variance, unit-to-unit. (Not shown on this graph – but captured in the analysis – is how these metrics evolve in time.)
- For some units, variable O&M costs can approach (and exceed) \$10/MWh. Such high variable O&M costs can crush dark spreads.
- These high-VO&M outliers are saddled with expensive environmental compliance costs.
  - Lets look at FirstEnergy's Bruce Mansfield plant, as an example. For every dollar earned in the power market, by our estimates, from 2012-16, it spent 14 cents collecting and disposing emissions using its flue gas desulphurization (FGD) unit. After accounting for fuel costs, additional environmental control costs (ash and water clean-up) and 'other VO&M', it's easy to see why healthy margins elude many coal plants. Incidentally, Bruce Mansfield has been slightly 'in the black', according to our estimates, in spite of its high VO&M.
  - San Miguel is the least economic unit in ERCOT. See Slides 44-46 for details.

# **Hourly Accounting**

### **Price and Performance**

#### **Hourly Granularity**

Results of this analysis are presented as monthly aggregates, but the back-end methodology appraised the fleet on an hourly basis. This level of detail was made possible by the Tickerized time-series data available of the Bloomberg Terminal.

This section dives briefly into coal-plants' intra-daily operations.

# Hourly Accounting

### Daily power price and production profiles for the ERCOT coal fleet, 2014-17

![](_page_42_Figure_2.jpeg)

- Coal plants' 'ramp-ability' (i.e. ability vary output hour-to-hour) is often under-appreciated. In their 'baseload' heyday, coal plants ran with flat intra-daily profiles, and this gave coal plants a lethargic, slow-moving reputation. But flat operating patterns were as much a function of economics as engineering. Today, coal plants ramp more often, now that renewables and (sometimes) gas occupy the front of the merit order.
- In ERCOT, there is an important distinction between coal plants that buy fuel from the Powder River Basin (subbituminous) and those that burn local lignite. Lignite bids lower into the power market because of cheaper (or sunk) fuel costs. We see these economics manifest in production profiles of the two groups of plants: subbituminous units ramps more, unable to stomach power prices as low as their lignite counterparts.

# Hourly Accounting

### Daily performance patterns for the U.S. coal fleet, 2014-17

![](_page_43_Figure_3.jpeg)

- Ramping helps coal plants capture high power prices and avoid low power prices. But it comes at a cost. Plants often ramp down to their minimum stable capacities on nights and weekends, in response to low power prices. They do this in lieu of shutting off entirely - an action that imposes high O&M costs. The downside is plants run less efficiently at minimum stable capacity than they do running while running full speed.
- The inverse relationship between capacity factor and heat rate is a function of the inefficiencies of ramping and running at minimum capacity. This phenomena is so strong that it overshadows another, countervailing factor at play: at night, only the most efficient units remain in operation. Based on that fact alone we might expect weighted-average nighttime heat rates to be *lower* at night. They are not, because of the inefficiency of running at minimum stable capacity.

### Hourly Scatter Demonstrates Operating Constraints

![](_page_44_Figure_1.jpeg)

![](_page_44_Figure_2.jpeg)

- The chart demonstrates how effectively coal plant operators maximize operating margins. On average, capacity factors rise when dark spreads are highest; coal plants seek to maximize their production when energy production is most profitable
- Ramping, runtime, start-up and shut-down constraints prevent units from realizing dark spreads equal to the theoretical maximum. This is evident from the money coal plants leave on the table by running at less than 100% when dark spreads are positive; and it is evident by the losses absorbed in hours with negative dark spreads and non-zero capacity factors.
- Likely what is happening in these sub-optimal dispatch hours is units are positioning themselves to maximize profits over the course of a day. For example, Texas coal plants are willing to remain online at night, at a loss, at their minimum stable factors (commonly around 40%), in order to avoid full shutdown costs and to maintain a readiness to ramp back up to full output during the day when dark spreads rise.

#### **One Texas Coal Plant Missing: San Miguel**

We omitted data from one outlier Texas coal plant (San Miguel) because it detracts from the main message of this slide. San Miguel does not reduce its output during negative dark spread hours (as we define them). See details on next Slide.

### San Miguel Debunks Dark Spread Calculation 52018 Procession Club Chemick Direct Exhibit PCL-3 Part 1

Hourly dark spread and production profiles for San Miguel Coal Plant – 2016

![](_page_45_Figure_2.jpeg)

- We are highlighting the 410MW San Miguel Coal Plant here because it represents an exception to the rule of economic dispatch. It shows how coal plant economics can be insulated from power market signals. We hope this case study helps put the rest of our analysis in context.
- Our analysis pegs San Miguel as the least economic coal plant in ERCOT, and yet, it may survive due to external factors.
- Most power plants in ERCOT are owned by IPPs. But San Miguel is regulated – it is owned and operated by the San Miguel Electric Cooperative. All of its output is sold to two neighboring electric cooperatives via a unique/arcane power purchase agreement that "cannot be terminated before 2037" and renders the off-takers "responsible for San Miguel's total cost of owning and operating the plant".<sup>[1]</sup> This is an example of a stubborn contract and regulatory structure that insulates San Miguel, allowing the plant to run at a loss during most hours of the year. (San Miguel's power market losses are recouped via the PPA.)
- Inflated fuel costs are what plague San Miguel economics, alongside exorbitant environmental control (VO&M) expenses.
  - For example, San Miguel reported paying \$2.50/MMBtu for fuel (delivered), on average, in 2017. This is over \$1.00/MMBtu more than estimated ERCOT averages. San Miguel is a mine-mouth lignite burner. The same company owns both the mine and the plant, selling power to third-party off-takers at above-market prices.
  - San Miguel spent nearly \$10/MWh in 2016 to run its environmental controls. Most of these costs are associated with ash collection, on which San Miguel spent \$21m in 2016. This is an outlier unit, to be sure.

### San Miguel Debunks Dark Spread Calculation Score Processing Control Direct Exhibit PCL-3 Part 2

Hourly dark spread and production profiles for San Miguel Coal Plant

![](_page_46_Figure_2.jpeg)

- Our analysis treats fuel as a short-run (i.e. variable) expense. This means fuel costs impact dark spreads. Under this assumption, fuel costs would impact dispatch decisions, since plants would only fire up if the value of power was high enough to compensate fuel expenses. Most coal plants operate under this premise, which is why in Slide 44 capacity factors respond to dark spreads.
- San Miguel pays little attention to our dark spread calculations. It generates when spreads are negative because it treats fuel costs as 'sunk'. The terms of San Miguel's PPA effectively forces its off-takers to buy fuel, regardless of whether it is used.
- The take-or-pay (i.e. 'sunk') nature of San Miguel's power and fuel contract alters the retirement decision-making process. Were offtakers to break their commitment to the unit they would swallow a lump sum loss that might exceed the losses associated with honoring the outdated and overpriced PPA.
- This is one example of how an uneconomic unit can avoid retirement. Throughout the U.S., regulated plants are much more likely than IPPs to enjoy this kind of protection against power market signals. Reminder: our analysis appraises power plants against wholesale market signals; our analysis is less relevant for a plant like San Miguel, which operates outside of 'normal/ market rules.

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46 [1] More details can be found at San Miguel's website.

# **Regional Margins**

### **Just Pictures**

### PJM

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_48_Figure_3.jpeg)

### ERCOT

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_49_Figure_3.jpeg)

### MISO

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_50_Figure_3.jpeg)

New Energy Finance

### **New York**

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_51_Figure_3.jpeg)

## **New England**

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_52_Figure_3.jpeg)

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_53_Figure_3.jpeg)

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### Southwest

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_54_Figure_3.jpeg)

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### Northwest

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_55_Figure_3.jpeg)

### Southeast

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_56_Figure_3.jpeg)

### Florida

### Monthly revenues, costs and long-run operating margins (\$/MW-day)

![](_page_57_Figure_3.jpeg)

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