The Breakdown of the Merchant Generation Business Model

A clear-eyed view of risks and realities facing merchants

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1. Introduction and Overview

Over 40% of U.S. power demand is supplied by merchant generators rather than regulated utilities. During the advent of electricity restructuring in the 1990s, private generators funded by private risk capital were going to be the future of electric generation in the U.S. It has not turned out that way. To the contrary, some large merchants may be headed toward a second round of bankruptcies in less than twenty years.

Currently, merchant generators face critical challenges to recovery of invested capital, contributing to the repeated inability of such companies to meet their financial obligations.[i] Policymakers are nervous – and rightfully so – given the inherent economic challenges faced by merchant generators. Flat demand growth, increasing renewable generation with zero variable cost, and historically low gas prices create headwinds that have the merchant generation sector once again in crisis. What is more, the combination of these elements make retaining and promoting a diverse generation mix nearly impossible barring policy or regulatory intervention to prop up specific plants or specific sectors. No baseload fuel source has proven immune to the perfect storm of these three elements, as nuclear, coal and gas-fired resources are either struggling to cover costs, facing bankruptcy, or in bankruptcy.

The troubled waters for the competitive generation business model are reflected in the reported profits of some key merchant players. A recent story in the *Houston Chronicle*, for example, provided stark data points: "Calpine's 2016 profit, at $92 million, was down 60 percent from $235 million in 2015. NRG made a slight recovery from its 2015 annual loss of $6.4 billion, but still reported a loss of $891 million in 2016. Dynegy reported a $1.24 billion loss in 2016, as compared with a 2015 profit of $50 million."[ii] Moreover, on June 12, 2017 NRG unit GenOn Energy, a merchant owner of 32 gas, coal and oil generators totaling over 15 GW (61% of which is gas) across 18 states, filed for bankruptcy in Houston.[iii] NRG CEO Mauricio Gutierrez frankly observed that "the IPP model is now obsolete and unable to create value over the long term."[iv] These figures and developments illustrate the challenging market dynamics for competitive merchant generators and explain why distressed asset investors are circling around the assets of merchant generators and large merchant players are considering putting themselves up for sale.

Below we explore the challenges to the competitive generation business model, and the questions they pose for energy regulators and policy makers grappling with the challenges facing merchant generation in today's energy marketplace and seeking to ensure a reliable supply of low cost energy. Our probe of these challenges and questions leads to the conclusion that investments in new merchant generation are tolerable for only the highest-risk investment capital. As a result, markets relying on the merchant generation model for reliable and affordable power are on a path towards a future with increased costs, decreased reliability, or both, with potentially stark consequences for not only merchant generators but also the electric system, policy makers, regulators, and – most importantly – customers.

2. Challenges to Merchant Generator Business Model

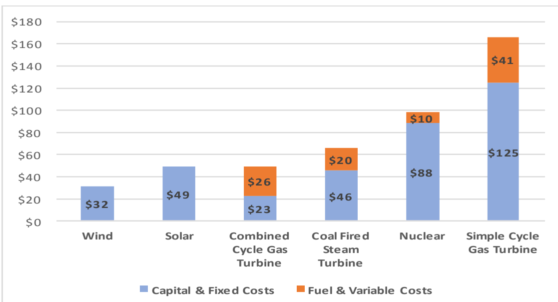
A) Marginal Pricing and Boom or Bust Pricing Inhibits Recovery of All-In Costs

The key weakness of the merchant generation business model is that generators' revenues generally do not cover the all-in cost of supply, which includes the cost of capital recovery as well as the variable cost of operation. Power generation is characterized by high capital costs for new production plant and low variable costs of production, contributing to a highly cyclical pattern of prices, profit and investment. When capacity is scarce, electricity prices (and capacity payments, when available) must rise to a level that allows recovery of the all-in cost of supply – the cost of building as well as operating a new power plant – if new power plants are to be built. As capacity is added in response to this price signal, however, the scarcity is alleviated, and competition among generators then drives the price of power down to its variable cost of production – a fraction of the all-in cost. As illustrated below, this boom/bust cycle undermines the capacity of merchant generators to recover their invested capital with an adequate return.

It is simple to demonstrate how a downturn in power prices can prevent the full recovery of the cost of new generating plant. In most U.S. power markets, the marginal, price-setting generating units during the peak demand hours of the day are combined cycle gas turbines ("CCGTs"). The variable cost of operation of existing CCGTs can be estimated at ~$26/MWh.[v] (See, **Exhibit 1** below for the all-in costs of a variety of generation resources). When power prices settle at this level, not only is the fleet of CCGTs unable to recover its capital and fixed O&M costs, neither can any other resource.

The variable operating cost of CCGT generators set the price of power only when they are called upon to run; when they are not, as is frequently the case during off-peak hours, power prices will fall to reflect the even lower variable cost of operation of coal fired (~$20/MWh), nuclear ($10/MWh) or renewable power plants (zero).

Exhibit 1: Capital Recovery and Fixed Operation and Maintenance Expense Account for % of the All-In Cost of New Power Plants



	Wind & Solar	Combined Cycle Gas Turbine	Coal Fired Steam Turbine	Nuclear	Simple Cycle Gas Turbine
Capital & Fixed Costs	100%	47%	75%	90%	75%
Fuel & Variable Costs	0%	53%	32%	10%	25%

Source: Lazard's Levelized Cost of Energy Analysis – Version 10.0, Power Research Group analysis

When demand for power begins to exceed the capacity of existing generating plants, prices will rise to reflect the all-in cost of supply (*i.e.*, the cost of building as well as operating new production capacity), rather than just the variable cost of production from existing facility. But given time, prices sufficient to recover the all-in cost of new production capacity will attract new investment to the industry. These capacity additions in turn alleviate the scarcity that led to the price spike and eventually, as new entrants compete with each other for a share of the market, prices are once again driven down to the variable cost of the marginal supplier.[vi]

Wholesale power prices (including capacity market payments where available) have not reflected the all-in cost of adding new generation capacity so much as they have been capped by it. As a general matter, the price forecasts underpinning investments in competitive generation assets tend to be made during the period of scarce supply and rising prices, when investment opportunities look attractive. The prices that prevail once these investments come on line, by contrast, tend to reflect growing over-supply and the erosion of prices down to variable cost. The irony of this pattern of decision making is that investors rightly require higher expected returns, often in the mid to high teens, to compensate for the risk of investing in a highly cyclical industry. When the conditions materialize that might allow investors to achieve these returns, the flow of capital into the industry, and the oversupplied conditions that follow, render such returns permanently unattainable. This vicious cycle has undermined the financial stability of merchant generators, and eroded their capacity to attract and deploy capital over the long term.[vii]

B) The Planning of Investments in Competitive Generation Is Materially More Difficult than in Other Industries

The challenges to investors created by the pricing dynamics described above are compounded by the difficulty of planning investments in competitive generation, which in many ways is materially more difficult than in other industries. Investors in generation must anticipate the boom/bust cycle of electric power prices, the potential for the introduction of disruptive new generation technologies or significant regulatory changes, and changes in the relative costs of the fuels (the input) used to generate electricity, which can significantly alter the expected profitability of existing power plants.

In contrast to commodity industries, there is not a single production technology deployed across the electric power industry, which makes electric power distinct from commodities and their markets. Generally, a single production technology is deployed across a particular commodity industry: broadly speaking there is one way to extract copper, one way to smelt aluminum, one way to manufacture paper. Electric power, on the other hand, can be generated with radically different technologies whose input costs bear no relation to each other: photovoltaic cells energized by the sun, turbines powered by wind, hydroelectric dams, nuclear reactors, gas fired combustion turbines, gas fired combustion turbines with heat recovery steam generators, and steam turbine generators powered by boilers burning coal, fuel oil or natural gas.

The implication is that future power prices will reflect not only the relative scarcity or abundance of capacity, but also the prices of nuclear fuel, coal, natural gas and petroleum. It will also reflect policy shifts and technological changes that may reduce or offset the capital cost of new generation resources. Examples of technology changes are the recent precipitous decline in the cost of photovoltaic generation, while policy shifts could take the form of tax policy (e.g., the extension of the Production Tax Credit and Investment Tax Credit) or state-level policy changes such as the enactment of renewable portfolio standards, clean peak standards, or zero emission credit constructs.

Given these uncertainties, power price forecasts tend to be egregiously wrong. This inaccurate forecasting has resulted in repeated, dramatic losses for investors in competitive generation assets. For example, over the five years from 1999 through 2003, 175 GW of new gas fired capacity was added to the U.S. generating fleet, increasing its capacity by almost a quarter. The wave of investment capitalized on abundant and cheap natural gas: over the fifteen years from the deregulation of the well head price of natural gas in 1985 through 2000, the average annual price of natural gas had varied between ~$1.50 and $2.50/MMBtu. Following the huge build-out of the U.S. gas fired generating fleet, however, the average price of natural gas rose from $2.20/MMBtu in 1999 to $8.00 in 2008, almost quadrupling the operating cost of the newly built plants, curtailing their hours of operation and destroying the economic value of the prior investment. The value of coal and nuclear generation surged because on-peak prices were sustained by the high operating cost of the new CCGTs. By 2007, high gas prices, and the consequent profitability of nuclear and coal fired generation, were self-evidently the new normal, leading a KKR-led consortium (in what is now a cautionary tale) to acquire the nuclear and coal fired generator TXU for $45 billion in the largest leverage buyout (LBO) in history. Within five years, as gas prices first dropped below $4.00 in 2009 and then below $3.00 in 2012, the debt of the LBO became untenable, bankruptcy was declared in 2014, and lenders lost billions.

C) Regulatory and Legislative Intervention Suppress Wholesale Prices While Raising the Cost of Staying in Business

Persistent efforts by state and federal governments to reduce the environmental impact of power generation have suppressed wholesale power prices while simultaneously raising the cost of staying in business for many merchant generators. Increasingly stringent regulations governing air emissions and coal ash disposal and limiting the use of once-through cooling water systems add substantially to the going forward cost of steam turbine generators. Simultaneously, by supporting the construction of new renewable resources, state renewable generation mandates and federal tax credits have added zero variable cost generating assets at the bottom (lowest cost part) of the power supply curve. Once renewable capacity has been added in response to these incentives and mandates, the electric output of these facilities is available at zero variable cost (and in fact sometimes even bid into markets with negative prices)[viii] – ensuring that renewable generation will be dispatched before any conventional resource to meet prevailing demand. These new renewable resources reduce both the hours of operation as well as the prices received by the higher cost conventional generating resources on the system.[ix] The simultaneous loss of output and the erosion of prices (similar to working fewer hours at a lower hourly rate) squeezes the gross margin of exiting conventional generators[x] and potentially accelerates their second trip down a path to ruin.

3. Imminent Questions for the Merchant Generator Business Model

A) What is the Outlook for Merchant generators?

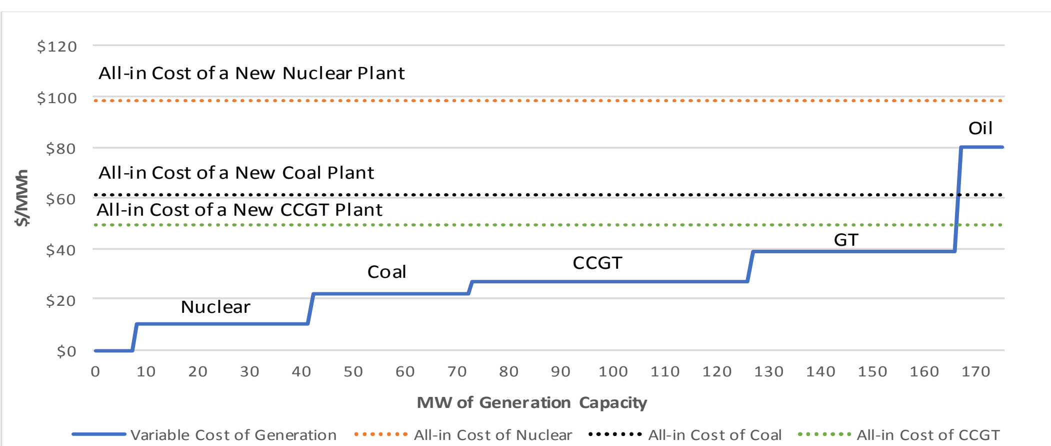
Looking forward, merchant generators will struggle with the consequence of three facts:

1. Total power output of the United States is stagnant.
2. New renewable and conventional resources are suppressing the output of existing plants.
3. The lower variable cost of new resources will erode power prices.

Over the last five years, total U.S. power output decreased by 1%, continuing a broad pattern of stagnation that has been evident since 2006. U.S. power output in 2016 was essentially unchanged from its level 10 years before, even as real GDP has increased by 14%. As the nation's power output has stagnated, the share attributable to conventional power generation resources has declined: the combined output of the hydroelectric, nuclear, coal, gas and oil fired power plants in the U.S. has fallen by 6% over the last ten years, and has decreased from 98% to 92% of total U.S. power output. The falling share of conventional generation is attributable to the rapidly rising output of new renewable power plants, particularly wind and solar: over the last ten years, non-hydro renewable generation increased by ~250 million MWh, or from 2% to 8% of total power output, while conventional generation has declined by over 230 million MWh.

This pattern is expected to continue over the next five years: net power demand (gross power demand net of self-generation) will remain flat; the ongoing growth of renewable generation will continue to erode the share of fossil fuel generation in total U.S. power output; and as result, coal and gas fired generation will decline, curtailing the capacity factors of existing fossil fuel plants. Darkening this outlook are large planned additions of CCGT capacity. These new, highly efficient CCGTs plan to capture market share based on the fact that their fuel consumption is on average 10% lower than that of the existing CCGT fleet. These units would enter the power supply curve below existing gas fired power plants, pushing these older, more expensive gas and coal units up the supply curve and reducing their hours of operation.

Exhibit 2: Marginal Cost Supply Curve versus All-in Costs



To the extent that the highest cost fossil fueled units are no longer required to meet prevailing demand, power prices fall to reflect the variable cost of supply of the lower cost units that remain.[xi] This bust in the prices further diminishes merchant generators ability to cover their costs.

Over the next three years (2017-2019), increases in low cost generation from planned additions of wind, solar and new CCGT capacity outpace the expected growth in power demand.

Over the next three years (2017-2019), increases in low cost generation from planned additions of wind, solar and new CCGT capacity outpace the expected growth in power demand. As a result, we expect the highest variable cost generators (the marginal, price-setting units) in each of the five RTOs to experience significant declines in power output and capacity factors through 2019 (see **Exhibit 3**). (In most of the RTOs, CCGTs are the marginal, price-setting units, but a mix of CCGTs and coal fired power plants are on the margin in PJM.) In CAISO and ISO New England we expect the capacity factor of the existing CCGT fleet to continue to fall through 2021, reflecting the stagnant power demand combined with continued growth in new CCGT and renewable generation capacity. In the New York ISO and PJM we expect the capacity factor of existing CCGTs to stabilize beginning in 2020, as planned retirements of nuclear and coal fired power plants materially reduce the supply of lower cost generation.

Exhibit 3: Forecast Capacity Factors of Existing Power Plants (2017-2022)(1)

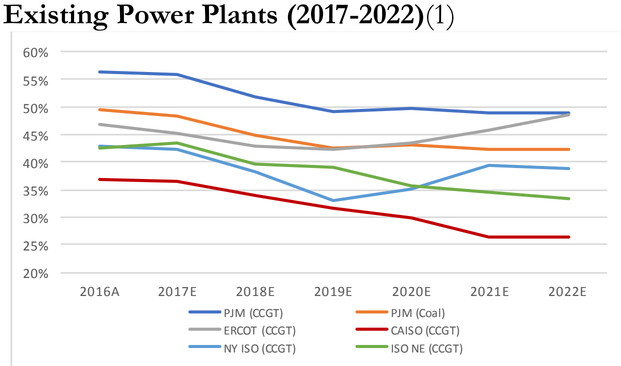
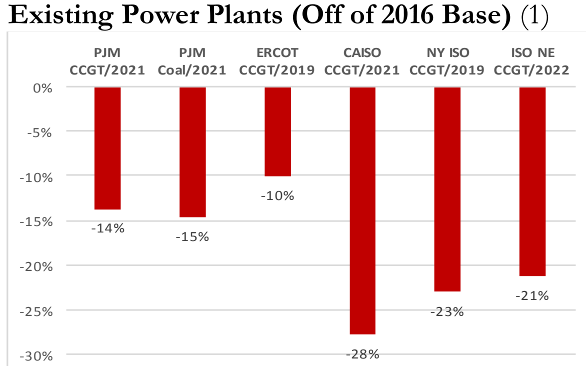


Exhibit 4: Forecast Drop in Power Output of Existing Power Plants (Off of 2016 Base) (1)



1. Estimates are for the average expected power output and capacity factors of existing CCGT plants. For PJM, we also present our estimates for the average expected power output and capacity factors of PJM's existing coal fired fleet.
Source: SNL, Power Research Group estimates and analysis

Exhibit 4: presents the forecast percentage decline in the power output of the marginal, price setting units in each of the five regions, as well as the year in which this drop in output reaches its maximum. We expect the capacity factor of the existing CCGT fleets to fall markedly, with the largest and most prolonged output declines likely to occur in CAISO, where we forecast the generation of the existing CCGT fleet will fall by 28% over 2016-2021; the New York ISO, where we expect a 23% drop in CCGT generation over 2016-2019; and ISO New England, where the generation of the existing CCGT fleet could fall by 21% over 2016-2022. We expect smaller, but still very material declines in PJM, with the output of PJM's existing CCGT fleet anticipated to fall by 14%, and that of its coal fleet to fall by 15%, by 2021. Only ERCOT may follow a different trajectory. We expect the output of ERCOT's existing CCGT fleet to fall by 10% through 2019; thereafter, power demand growth will drive output back almost to 2016 levels by 2021 and higher in 2022.

These expected declines in the power output of existing generating fleets are unlikely to be offset by increases in power prices and spark spreads, at least through 2019. The output of the existing fleet is being crowded out by zero variable cost generation from new renewable plants, and the output of low variable cost CCGTs, volumes and prices could drop simultaneously.

B) Are Merchant generators Capable of Raising the Capital Required to Build New Plants?

Finally, and critically, while there are some hopeful and planned investments, the construction of a new merchant CCGT does not pencil out to cover fixed costs of these generators. Policy makers should pause when markets count on planned merchant generation that cannot recover their fixed costs under current market conditions. The stark economics facing these plants makes it seem that either these planned additions will not be able to attract the capital to be built, or that the developers are betting on sustained and significant increases in prices to attract capital. Policy makers, regulators and customers lose under either scenario.

> ***Policy makers should pause when markets count on planned merchant generation that cannot recover their fixed costs under current market conditions.***

To estimate the cost of a CCGT generator, we have relied upon data collected by (i) the Energy Information Administration (EIA) and made available in its November 2016 publication, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, as well as by (ii) the investment bank Lazard and published in *Lazard's Levelized Cost of Energy Analysis – Version 10*.0, published in December 2016.

These sources point to an overnight cost for the engineering, procurement and construction of an H-Class CCGT generator of $1104/kW installed.[xii] The sum of the plant's capital cost recovery charge and its fixed O&M expense determines the annual generation gross margin required by the plant to recover its invested capital and fixed costs and earn a competitive return (which is required to attract capital). The equivalent gross margin per MWh is calculated by dividing the annual generation gross margin requirement of the plant by its expected power output. **Exhibit 5** provides an estimate of the spark spread, or differential between average revenue per MWh and cost of fuel to generate that MWh, required for full recovery of a new plant's capital cost and fixed and variable O&M expense. The exhibit also explains the assumptions that gave rise to the numbers.

Exhibit 5: Estimated Cost of a New CCGT by Region, Corresponding Annual Fixed Cost Recovery Charge and Generation Gross Margin per MWh Required for Full Cost Recovery (1)

Regions	Overnight Cost of CCGT Plant	Cost of Funds Used During Construction	Total Capital Cost	Capital Cost Recovery Charge	Fixed O&M Expense	Total Annual Fixed Charges	Capacity Factor	Required Gross Margin per MWh
	$ per kW of Installed Capacity						%	$/MWh
CAISO	1,380	168	1,548	195	10	205	0.45	54
ERCOT	1,016	118	1,133	136	10	146	0.48	37
ISO-NE	1,270	155	1,424	179	10	189	0.73	32
NYISO - Zone G	1,281	156	1,437	181	10	191	0.58	39
PJM-East	1,336	163	1,499	189	10	199	0.61	39
PJM-West	1,104	135	1,239	156	10	166	0.61	33
AEP-Dayton	1,104	135	1,239	156	10	166	0.61	33
NIHub	1,148	140	1,288	162	10	172	0.61	34

1. To estimate the regional overnight cost of a new H-Class CCGT generator, we have relied upon the Energy Information Administration's *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, published November 2016.

Capital cost recovery charges and cost of funds used during construction were calculated using a pre-tax weighted average cost of capital (WACC) of 12.2%, assuming a 60/40 debt/equity capital structure, a 7% cost of debt and a 12% after-tax target ROE. We have used an effective tax rate for 40% for federal and state taxes combined. In Texas, which has no income tax, the effective tax rate falls to 35% and the pre-tax WACC to 11.6%. We have assumed a 30 year useful life for the new CCGTs. Capacity factors reflect the average capacity factors achieved by CCGTs that have entered operation in these regions over the last three years. Required gross margin includes $2/MWh for the recovery of variable non-fuel operation and maintenance expense.
Source: Bloomberg, SNL, Energy Information Administration, Lazard's *Levelized Cost of Energy Analysis – Version 10.0*, Power Research Group analysis

Exhibit 6 provides the expected average gross margin of a new CCGT in various competitive power markets around the country, including both its expected spark spread and capacity revenues, and compares the expected gross margin to the gross margin required by the plant to recover its capital costs, with a competitive return, plus its fixed and variable non-fuel O&M expense (as derived in **Exhibit 4**).

As **Exhibit 6** illustrates, the expected gross margins of new CCGTs fall well short of required gross margins in each of the markets analyzed. The shortfalls range from 13% of the required gross margin in the New York ISO's Zone G to 59% in ERCOT, which has no capacity market. While the cost of individual projects can vary from the EIA's estimates, our analysis suggests that (i) given the EIA's estimated construction and operating costs for a new CCGT, (ii) given currently prevailing forward prices for electricity and natural gas and known forward prices for capacity, and (iii) applying our estimate of the pre-tax WACC of a competitive generator, the competitive generation industry is not currently in a position to recover the capital required for the construction of new CCGT capacity.

Exhibit 6: Expected Generation Gross Margin of a New CCGT by Region Compared to the Generation Gross Margin Required for Full Cost Recovery (1)

Regions	10 Year Average of Forward Spark Spreads	Average of Forward Capacity Prices	Expected Gross Margin	Required Gross Margin	*Shortfall*	
	$/MWh	$/kW-Month	$/MWh	$/MWh	$	%
CAISO	15.77	3.00	24.91	54.10	***29.19***	***54%***
ERCOT	15.10	0.00	15.10	36.59	***21.49***	***59%***
ISO-NE	9.18	6.99	22.28	31.62	***9.34***	***30%***
NYISO - Zone G	24.21	5.85	34.10	39.39	***5.29***	***13%***
PJM-East	15.88	5.76	28.72	38.92	***10.20***	***26%***
PJM-West	13.70	3.38	21.24	32.84	***11.60***	***35%***
AEP-Dayton	15.77	3.38	23.31	32.84	***9.53***	***29%***
NIHub	11.15	5.39	23.15	34.00	***10.85***	***32%***

1. For purposes of our analysis, we have averaged the next ten years' forward spark spreads, or gross margin per MWh, and the next three years' capacity prices. Forward spark spreads reflect currently prevailing forward price curves for electricity and the estimated cost of the natural gas required to generate it at a CCGT with an assumed heat rate of 6.5 MMBtu/MWh. In markets with established capacity markets, we assumed that the new CCGT would earn annual capacity revenue over its useful life at the average of currently available forward capacity prices.
Source: Bloomberg, SNL, Energy Information Administration, Lazard's *Levelized Cost of Energy Analysis – Version 10.0*, Power Research Group analysis

4. Conclusion

Policy makers and regulators looking to merchant generators to provide reliable low cost power to consumers must have a clear-eyed understanding of the challenging economics facing merchant generators without avenues to recover their fixed costs. These fundamental economic realities erode the viability of current merchant plants (absent an ‘around market’ subsidy) and render investments in new merchant generation tolerable for only the highest-risk investment capital. While electricity markets may seem flush with capacity and low prices at the moment, similar to the housing boom in the early 2000s, policy makers and regulators ignore fundamental economics at their own peril. Grids dependent on the merchant generation model are on a course for a future with increased costs, decreased reliability, or both. The losers in this scenario are not just the merchant plants with suffering bottom lines. Customers lose in the form of higher and more volatile prices, decreased reliability, or both, and policy makers and regulators lose because they are left with the mess and no clear remedy.

While electricity markets may seem flush with capacity and low prices at the moment, similar to the housing boom in the early 2000s, policy makers and regulators ignore fundamental economics at their own peril.

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[i] Notable bankruptcies of merchant generators include Calpine, Dynegy, Mirant, NRG Energy and Texas Energy Future Holdings, as well as the competitive generation subsidiaries of AES (AES Eastern Energy), Edison International (Midwest Generation) and PG&E Corp. (National Energy Group).

[ii] Ryan Maye Handy, *Changing markets challenging Houston power companies*, Houston Chronicle (June 10, 2017), http://www.houstonchronicle.com/business/article/Changing-markets-challenging-Houston-power-11210955.php.

[iii] Robert Walton, *NRG unit GenOn files for Chapter 11 bankruptcy protection*, UtilityDive (June 14, 2017).

[iv] Robert Walton, NRG CEO: Independent power producer model 'obsolete', UtilityDive (March 1, 2017).

[v] This number is derived in the following way: the average heat rate of the U.S. CCGT fleet is ~7.4 MMBtu/MWh, and assuming the price of natural gas is $3.00/MMBtu, the fuel cost of these marginal generating units can be estimated at ~$22.00/MWh; adding variable operation and maintenance expense of ~$4/MWh.

[vi] ERCOT comes closest to this market design, with a very high market cap of $9,000/MWh and no capacity market other than an Operating Reserve Demand Curve (“ORDC”) designed to provide a price signal in the energy markets as the market approaches shortages of capacity, but before true shortages exist. If it works as planned, this market design will result in price spikes for consumers before new generation is built to relieve the scarcity, while bringing prices back down thereafter. This should average out to lower costs for consumers, as brief periods of high prices are followed by extended periods of low prices. The disadvantage of this market design is increased volatility in electricity prices and periodic declines in reserve margins during the periods of scarcity. These costs could rise over time, as the inability of generators to recover their investments during the period of lower prices could result in generators waiting for even higher prices before committing capital, implying longer scarcity periods with even tighter reserve margins. Over the long-term, this could increase the average cost for consumers and increase the risk of a true shortage of capacity developing. Capacity markets are another “solution” and are intended to provide the “missing money” to cover fixed cash costs. But even capacity markets – particularly in light of their relatively short duration – provide no assurance to new market entrants that they will recover their capital investments. New generation is being built in regions with capacity markets, but that is based on hedging enough cash flow to secure financing and then believing that prices will eventually go higher, which would provide a return for the equity investors. Once the equity investors secure financing, the plant is essentially an option on the power markets. Recently, the only time these options have worked is when the plant is bought at a depressed price following an earlier default.

[vii] The electric sector is not unique in suffering from these vicious cycles of investment, margin erosion and failure. The original impetus to regulate railroads in the 19th Century stemmed from just this investment boom, competition down to marginal cost and waves of failure. *See* Thomas McCraw, *Prophets of Regulation* (Harvard University Press, 2009-) Ch. 1. On Charles Francis Adams. A similar boom bust cycle engulfed telecommunications immediately after deregulation. Though a more complex story involving regulator-mandated malpricing in wholesale markets, the boom-bust cycle for

nationwide fiber networks evokes the same phenomenon. *See*, Nuechterlein, Jonathan and Philip Weiser, *Digital Crossroads: American Telecommunications Policy in the Internet Age*. MIT Press, 2005.

[viii] *See, e.g.* California ISO Q4 Market Report on Market Issues and Performance, *available at* http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf.

[ix] Currently, 29 states and the District of Columbia – jurisdictions that together account for 65% of U.S. retail electricity sales – have adopted renewable generation mandates, imposing an obligation on electric utilities to supply a stipulated fraction of their retail electricity sales from renewable resources. Another eight states, accounting for 10% of retail electricity sales, have adopted renewable energy goals, which set target levels of renewable generation but impose no mandatory requirement on utilities. These measures effectively mandate the build-out of renewable generation by requiring regulated utilities to procure renewable generation in stipulated amounts, and permitting these utilities to recover the cost of these purchases in their regulated rates.

[x] Moreover, while the increased portfolio of renewable resources have been eroding the revenues and gross margins of merchant generators, federal environmental regulations have been imposing unrecoverable capital cost on merchant generators. Merchant generators can expect no compensation for their unrecovered investment in these retired units; nor are merchant generators likely to recover the incremental investments they must make to upgrade existing power plants to comply with the new rules. Once made, these investments represent a sunk cost. To maximize their output and revenues, merchant generators will continue to offer the output of their plants at their variable cost of generation. In most cases, variable operating costs are unlikely to change markedly and, among the gas fired generators that are frequently the marginal, price-setting units, are unlikely to change at all. As a result, we expect little upward pressure on power prices and consequently limited incremental revenue to offset the capital cost of required upgrades.

[xi] By way of example, new CCGTs have heat rates of ~6.5 MMBtu/MWh, some 12% below the average heat rate of ~7.4 MMBtu/MWh of the existing CCGT fleet. Thus, for each hour that a new CCGT supplants an existing one as the marginal, price-setting unit on the system, the marginal cost of supply and thus the price of power will be 12% lower than would otherwise be the case.

[xii] The EIA publishes regional cost adjustment factors for different regions of the country which we have adopted as well. To capture the cost of capital used during construction, we have assumed that construction disbursements are spread evenly over a two year construction period, and have calculated the required return on this capital by applying our estimate of the pre-tax, weighted average cost of capital of a competitive generator.