TRAVERSE MERIDIAN GROUP, LLC

Precedent Gas-Fired Generation Transactions

Analysis of Key Value Drivers

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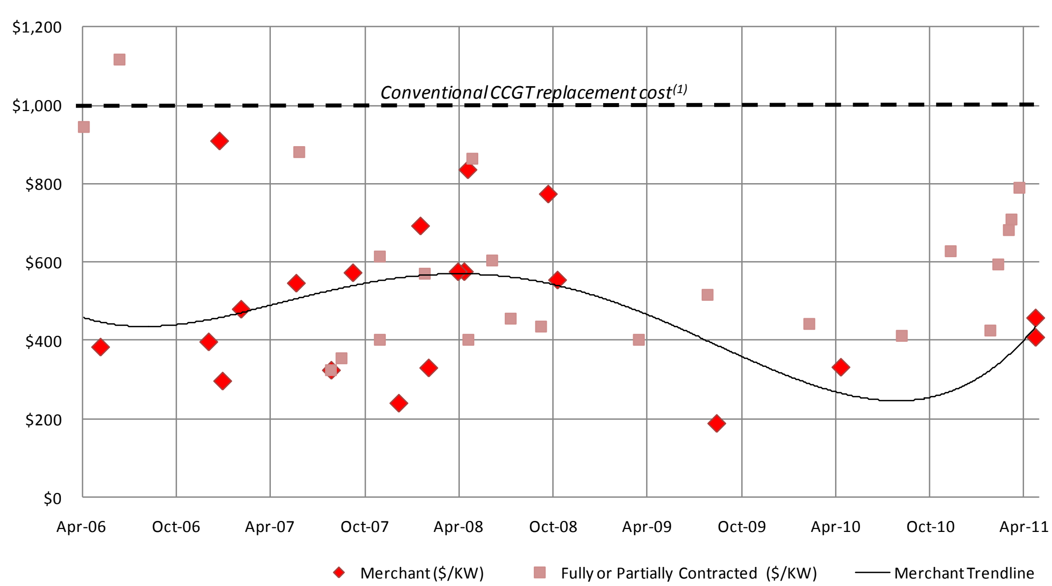
Executive Summary

As with the price of any tangible fixed asset, location matters. Pricing merchant power projects is made more difficult in that a host of other factors also come into play. Putting aside the value of any contracted generation offtake, which is often non-transparent to all but the respective contract counterparties, the value of the asset is obscured by variances in fuel input, turbine technology and configuration, as well as facility age. In the past I have been frustrated by how few practitioners in the generation asset M&A market can provide a concise and informed response to "how much should a merchant generation plant cost in the current market environment?" Obviously, there is no substitute to establishing an intrinsic point of view on valuation based on well researched commodity price forecasts and dispatch rates, but we should also be able to review relevant precedent transactions to support a preliminary value range. (Editorial note: I have assumed only a base level of familiarity with the generation market in this article, in order to appeal to a cross-section of practitioners. Additional detail on individual transactions is provided in the *Precedent Transactions Exhibit*.)

This article illuminates how natural gas-fired generation plants are priced taking into account regional and technological variations. The intentional focus here has been on gas-fired generation facilities since they account for the majority of marginal dispatch plants, i.e. the operational costs of gas plants is critical to determining the local market clearing price of power. By early May 2011, spot NYMEX natural gas prices were \$4.60/mmbtu, off of relatively recent lows but significantly below highs approaching \$14/mmbtu in June 2008**.** As such, U.S. gas-fired generation valuations remain lower than just a few years ago and are at a significant discount to replacement cost, resulting in a dynamic secondary market for these assets. Figure 1 shows asset prices relative to replacement costs. This discount to replacement cost is likely to continue for the next few years and heightens the need to understand the value of gas-fired plants independent of construction costs.

Figure 1: Precedent Gas-Fired CCGT Transaction Values (\$/KW)



Source: Company press releases, SNL Financial and U.S. EIA data, Spark Spread articles / public news, Traverse Meridian Group analysis.

(1) Reflects estimates of ~\$1,000/KW provided by U.S. EIA for conventional CCGT construction, excluding financing costs.

(2) Polynomial trend line based on merchant transactions. Consistent with peak prior to financial crisis and subsequent commodity market decline.

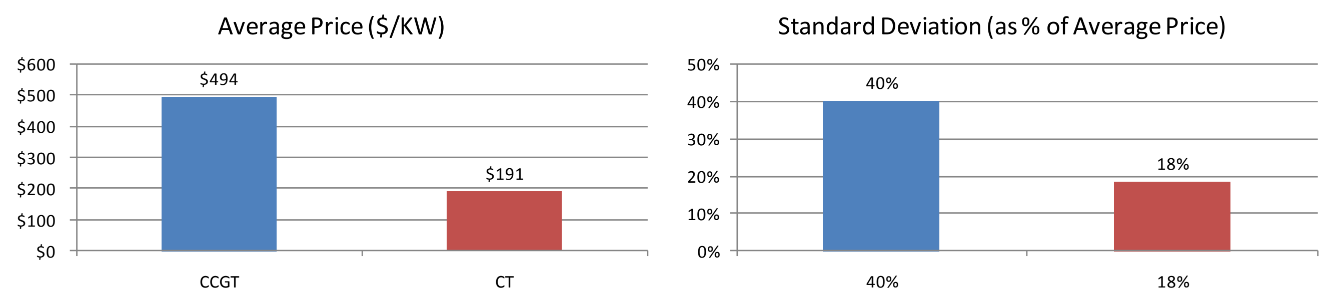
The scope of this article does not address merchant prices for power plants that are not dependent on natural gas. Both coal and nuclear traditionally operate as baseload plants resulting in smaller regional variances in facility prices. Hydroelectricity accounts for a relatively small share of overall generation capacity outside of the Northeast and Pacific Northwest. Other renewable energy sources such as wind, solar, and geothermal are primarily operated on a contracted basis in the United States or are highly dependent on renewable energy credits to be economical. Natural gas, by contrast, will continue to remain integral to our energy future regardless of which side of the environmental debate you stand. It provides both a dispatchable solution to intermittent renewable generation and a low-carbon alternative to other fossil fuel sources.

Technological Considerations

As a first step, it is important to understand fundamental technological differences in gas-fired plants and their potential impact on power prices. Simple cycle combustion turbines (CT) are up to 50% less efficient than combined cycle generation (CCGT) facilities. The resulting value difference, shown in Figure 2, highlights CT values at less than half the value of equivalent CCGT plants. In both cases, turbines are powered by natural gas to create electricity. In a CCGT configuration, the efficiency is further boosted by using the heat of the gas turbine's exhaust to generate steam and passing that steam through a heat recovery steam generator. This steam drives a steam turbine and is used to produce incremental electricity. In some cases, with additional duct-firing of the exhaust, the steam turbine will also provide incremental condensate and heat. The separate steam output could be sold to generate an additional revenue stream for the generation facility.

Given the lower efficiency of CT plants, they function primarily as peaking units, are rarely dispatched, and are much less dependent on regional around-the-clock (ATC) power price differences. The best measure for plant efficiency is its heat rate, which represents the amount of electricity produced per unit of energy content in the fuel. The lower the heat rate the more efficient the plant. CT plant heat rates are typically 9,500 – 11,000 btu/KWh, compared to 6,250 – 7,750 btu/KWh for CCGT plants. The absence of economical dispatch opportunity for CT units, regardless of location, supports more consistent pricing that is relatively agnostic to regional differences. Conversely, the significant variation in prices for CCGT merchant assets underscores the need to understand subtle regional differences and historical trends. Figure 2 highlights CCGT vs. CT pricing as well as calculated standard deviations for both kinds of plants.

Figure 2: Comparison of CCGT and CT Merchant Prices – Trailing 5-Year Average / Standard Deviation



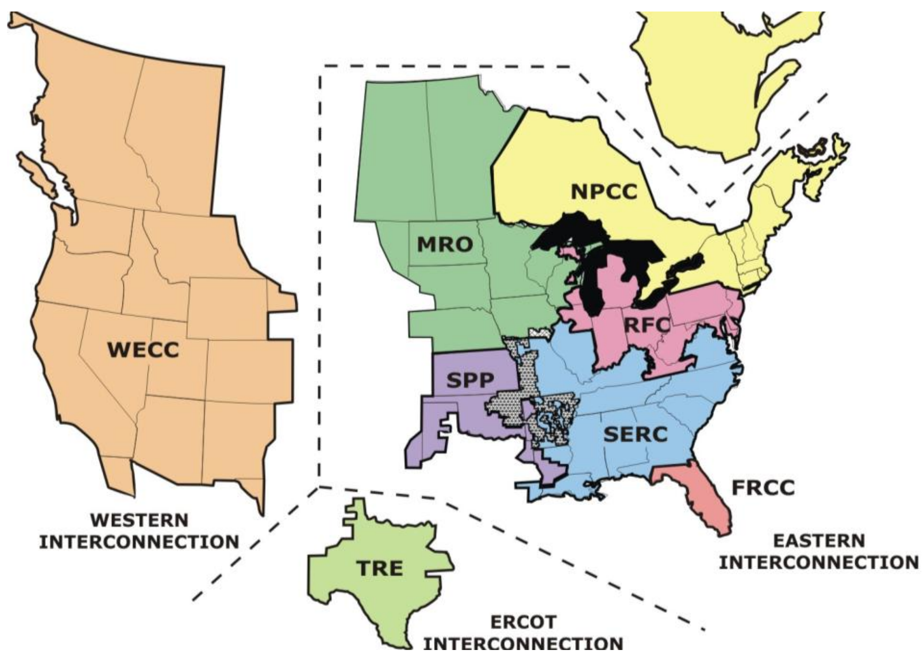
Source: Company press releases, Spark Spread articles / public news, Traverse Meridian Group analysis.

Differences in turbine technology and manufacturer also impact heat rate (efficiency) and operating costs. For example, the heavy duty construction of the GE 7FA renders it more suitable for utility-scale generation projects. In addition, GE's large installed base existing 7FA turbines establishes the proven nature of the technology and ensures that spare parts are readily accessible, while the company's own creditworthiness ensures reliable long-term maintenance. However, differences in turbine manufacturing technology have a smaller impact on value than differences in turbine configuration (e.g., CCGT vs. CT).

Regional Determinants

In global terms, North American markets have been relatively effective over the past decade in ensuring adequacy and security of bulk electric power. The North American Reliability Corporation (NERC), an independent not-for-profit organization, sets and monitors reliability standards as mandated by the U.S. Federal Energy Regulatory Commission (FERC), and through reciprocal agreements in Canada and with utilities operating in Baja California Norte, Mexico. NERC is organized into eight regional entities and has a broad membership that comprises the full spectrum of electricity producers, distributers, consumers and regulators. Figure 3 illustrates the different NERC regions in North America and major regional interconnections.

Figure 3: NERC Regions and Transmission Interconnections



Source: NERC.

Reserve Margins. Asset pricing differences are partially explained through structural differences in each of the eight NERC regions. A good measure of the difference between electricity demand and supply is the reserve margin. Specifically, reserve margins measure the capacity of a producer to generate more energy than the system normally requires. NERC maintains target reserve margins in the 15% range across its sub-regions, which provides a supply cushion to enhance overall grid reliability. However, in the majority of the U.S., peak season reserve margins are well in excess of target levels as a result of significant generation capacity additions in the early part of the prior decade and slow demand growth in the current recessionary environment. Absent other factors, regions with relatively low excess capacity should ordinarily feature higher asset prices as a result of greater periods of shortage pricing.

As cautionary note, the regional reserve margin does not fully reflect plant-specific demand as it does not account for isolated demand pockets, particularly around high-density metropolitan areas. However, in the absence of any localized constraints, reserve margins in the sub-region provide a good overall sense of supply / demand imbalances.

Supply Mix. Regardless of reserve margins, merchant gas-fired generation assets may also experience high valuations if limited baseload generation forces gas-fired assets to run more frequently. Given its low marginal costs, baseload generation (such as coal, hydro, and nuclear) have dispatch priority over intermediate (CCGT) assets which in turn have dispatch priority over peakers (CT) assets. As reserve margins approach target levels, intermediate dispatch facilities will run closer to baseload capacity factors. According to SNL Financial, when a region is operating at target reserve margins, approximately 65-70% of the region's capacity is running as baseload. This baseload component may include some CCGT facilities in regions where traditional sources of baseload generation are limited, especially in a low gas price environment where CCGT plants may displace some existing coal-fired facilities.

It is important to view the anticipated supply mix together with existing reserve margins in order to create a more complete picture of relative value. Regional reserve margins provide an indicator of near-term value, but an examination of the generation mix provides a view on relative value by asset class as reserve margins approach equilibrium targets. Figure 4 highlights NPCC as a sub-region of constrained supply and both SPP and TRE sub-regions with significant surplus supply. It is important to note, however, the potentially adverse pricing impact on TRE is partially mitigated by the region's lower mix of baseload generation. Consequently, a number of existing CCGT facilities are dispatched more frequently resulting in higher asset prices. SPP, on the other hand, is further hobbled by high baseload generation and low peaking capacity, forcing many CCGT plants to operate on a peaking basis.

Figure 4: Reserve Margins, Capacity Mix and Five-Year Average Price

	Reserve Margin Metrics			Capacity Mix Estimates [2]			Average
NERC Region	Peak Reserve Estimates [1]	NERC Target Margin	Implied Surplus	Baseload / Renewables	Intermediate Gas	Peaking	Price ($/KW)[3]
Florida Reliability Coordinating Council (FRCC)	29%	15%	14%	29%	33%	38%	N/A
Midwest Reliability Organization (MRO)	29%	15%	14%	74%	15%	11%	488
Northeast Power Coordinating Council (NPCC)	23%	15%	8%	62%	14%	24%	704
ReliabilityFirst Corporation (RFC)	34%	15%	19%	64%	20%	16%	552
SERC Reliability Corporation (SERC)	31%	15%	16%	55%	22%	23%	390
Southwest Power Pool, RE (SPP)	35%	14%	21%	48%	43%	9%	471
Texas Reliability Entity (TRE)	35%	13%	22%	29%	52%	19%	542
Western Electricity Coordinating Council (WECC)	29%	15%	15%	55%	37%	8%	634
U.S. Average	**31%**	**15%**	**16%**	**57%**	**28%**	**15%**	**541**

Source: NERC data, news articles, Traverse Meridian Group analysis.

(1) Based on 2010 adjusted potential reserve margins provided by NERC. Adjusted to reflect confidence-weighted anticipated additions net of deratings.

(2) Baseload / Renewables include lower marginal cost plants, primarily reflecting coal, nuclear, hydro and wind. Peaking consists of oil / dual use plants.

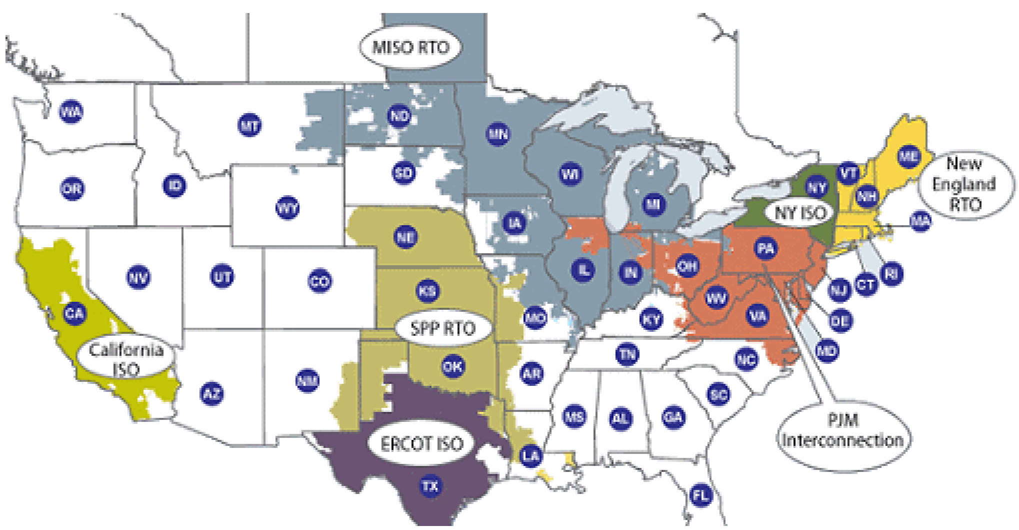
(3) Average price based on both merchant and contracted facilities. Limited public price disclosure for precedent transactions in the FRCC sub-region.

Wholesale Energy Markets. Established markets in which power can be actively bought and sold provide some pricing support. This does not mean that power plants in regions where there are active power markets would be priced at a premium to equivalent power plants in regions where there is no active power market. Rather, active power markets merely ensure that generation output would increase market efficiency and price transparency, and would consequently support overall average prices that are higher than what they would have been had the same market been illiquid. As an example, within ERCOT, an active trading market spanning NERC's TRE sub-region, power plants trade at a discount to a few other areas where power is not actively traded given significant excess supply in ERCOT. However, ERCOT does still benefit from pricing transparency in its markets relatively to where trading levels would otherwise have been. Improving liquidity also reduces price volatility and supports the overall business planning needs for electricity customers in the region.

Active wholesale markets, such as ERCOT, are managed by independent system operators (ISOs) or regional transmission organizations (RTOs) that enable the free trading of power between power producers and wholesale consumers. (ISOs coordinate and control the operation of the electrical power system, typically within a single U.S. State, while RTOs perform the same functions over a larger geographic area across multiple states and are governed by FERC.) ISOs and RTOs also create a liquid market for ancillary services provided by individual dispatch units which support the overall reliability of the grid. Such services balance any shortfalls experienced by load-serving entities by compensating plants for quick start capacity (e.g. spinning and non-spinning reserve service) and automatic adjustments to operating plant output (e.g. regulation reserve service).

Apart from ERCOT, other U.S. ISOs include CAISO (California) and NY-ISO (New York). In addition, there are currently four RTOs in the U.S.: ISO-NE (New England), MISO (Midwest), SPP (Southwest) and PJM (Pennsylvania/New Jersey/Mid-Atlantic). Figure 5 illustrates the coverage territories of each RTO and ISO operating in the United States.

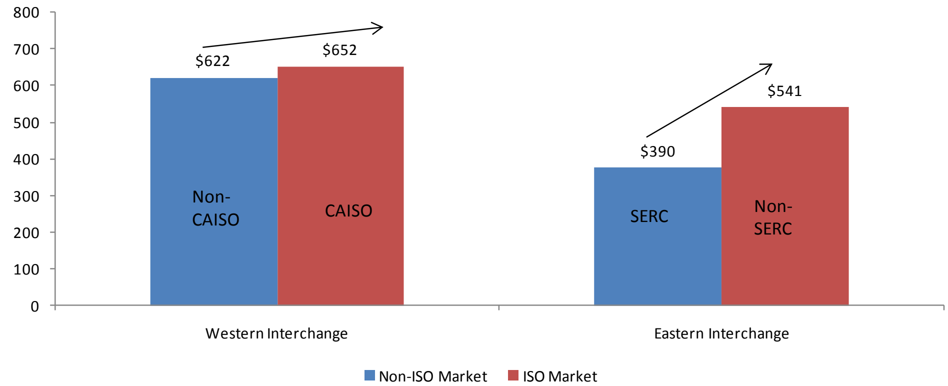
Figure 5: Independent System Operators and Regional Transmission Organizations



Source: FERC, Energy Velocity

Figure 6 further illustrates how ISO assets within the Eastern Interchange are at a significant premium to non-ISO/RTO assets within the same region. Within the Western Interchange, ISO assets also reflect a premium, albeit a modest one given other factors such as supply mix differences and localized transmission constraints across the regions. The Texas Interchange is entirely represented by single ERCOT ISO with an average precedent transaction value of $542/KW over the past five years.

Figure 6: Five-Year Average Transaction Value by Regional ISO Category ($/KW)

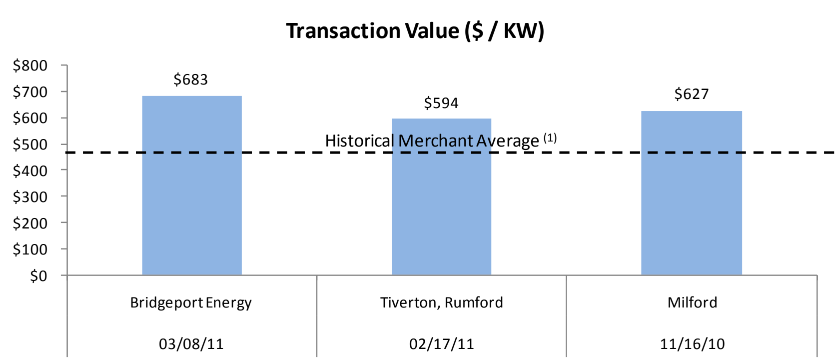


Source: Public news articles, Traverse Meridian Group analysis.

Note: CAISO category includes both CAISO assets and AZNMSNV assets directly linked into CAISO via Palo Verde interconnect. ISO markets within the Eastern Interchange include MRO (MISO), NPCC (NYISO / ISO-NE), RFC (PJM / MISO) and SPP. Data for trailing five years ended April 2011.

Capacity Markets. Current ISOs with active capacity auction markets include ISO-NE, NY-ISO and PJM. In regions with active capacity auction markets, power plants receive monetary compensation from the ISO / RTO to make idle capacity available. This is an important consideration for intermittent generation, like gas-fired plants, where plants may be sitting idle for the majority of available hours. For the 2014/2015 forward planning year, capacity auction prices range from $126/MW-day in western PJM to $137/MW-day in PJM-EMAAC (which is the transmission constrained area in eastern PJM). In NYISO, capacity market price for the same planning year is $355/MW-day in New York City and $62/MW-day for the rest of the state, reflecting the significantly higher load concentration in the city. Estimated ISO-NE capacity price for the 2014/2015 planning year is $105/MW-day. Figure 7 shows publicly disclosed precedent merchant CCGT transaction values in ISO-NE and highlight the positive value impact of a capacity markets.

Figure 7: Precedent Transactions in Capacity Markets



Source: Public information, Traverse Meridian Group analysis.

Note: Transactions examples reflect relevant recent ISO capacity market transactions with publicly disclosed valuation as of April 2011.

(1) Historical average of $494/KW based on merchant prices in non-capacity market regions for the trailing five years.

Other Regional Market Factors. Valuation is impacted by several demand factors, including retail markets and local load. Retail competition increases power market liquidity in much the same way as deregulated wholesale markets do, but account for a lower share of the overall load. Retail competition is also limited to select U.S. states, primarily in the Northeast and Texas. Separately, as previously mentioned, it is important to note whether the power plant being sold is located close to any regional load pockets. Major urban areas such as those located in Southern California or downstate New York result in power plants being sold at a premium.

On the supply side, any anticipated regional regulatory differences may impact the dispatch mix and consequently impact value. For example, aggressive renewable portfolio standards, particularly in California, have increased demand for renewable dispatch. In such regions, demand for gas-fired plants may also increase in order to balance the intermittent nature of renewable dispatch. Any potential differences in carbon pricing or taxation could introduce further regional differences in asset pricing. Separately, projected periods of low gas prices should ensure more favorable dispatch relative to coal-fired units, and could partially influence the CCGT investment decision in regions that have traditionally been more coal reliant.

Of lesser note, there are also regional cost differences that may impact plant profitability. Both labor costs and property taxes, which could differ by location, are important components of non-fuel operating and maintenance expenses.

Acquisition Environment

Finally, as with any other sale process, pricing is often impacted to the extent that there is a large inventory of other power projects for sale. Just as this inventory was built up during the financial downturn and subsequent period of low natural gas prices, inventory is expected to shrink significantly with the increasing pace of generation asset M&A. This pace and the relative attractiveness of gas-fired plants would increase further during with long-term anticipated natural gas price recovery. Other considerations, including the availability of lower cost financing for financial buyers and the stronger financial condition of certain strategic buyers, have increased overall M&A market demand. The *Precedent Transactions Exhibit* included with this article highlights this upward trajectory in value.

Conclusions

Gas-fired generation asset valuation is impacted by a number of project-level (e.g., technical configuration, turbine technology, age, environmental overhauls), region-specific (e.g., reserve margins, energy markets, capacity markets, transmission/supply constraints, regulatory and supply mix outlook, retail choice) and acquisition market considerations (e.g. competing processes, buyer profile, financing availability). By careful analysis of precedents, general valuation themes can be explained in terms of key technological considerations impacting the project, as well as regional considerations impacting each market. Overall asset values will be further supported by to the extent the M&A market environment continues on a path to recovery.

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