POWER REFERENCE CASE
ELECTRICITY & FUEL PRICE OUTLOOK

MIDWEST REGION | FALL 2010

Ventyx Advisors

Ventyx® An ABB Company

Executive Summary

Introduction

Ventyx uses an iterative integrated process to determine the impacts that capacity additions, and retirements have on power, natural gas. This process also considers the renewable energy expansion necessary to meet state RPS targets, and the resulting renewable energy credit prices.

This Fall 2010 Reference Case assumes no federal climate legislation. Throughout 2010, the likelihood of federal GHG legislation passing continually decreased. As of November 2010, with no current active legislation, the likelihood of a climate bill passing in the next two years is low. As a result of the current political climate, the Fall 2010 North American Power Reference case does not assume the implementation of a GHG legislation during our forecast period. Similarly, Ventyx does not assume the implementation of a federal renewable energy standard as well. The Fall 2010 Reference Case meets individual state RPS through the study horizon. The Fall 2010 Federal Environmental Legislation Case assumes the implementation of a federal GHG legislation and national renewable energy standard beginning in 2015.

Power Markets

Market Overview

In 2009, the ISO "footprint" expanded in the Midwest, as the public power utilities in Nebraska (Omaha PPD, Nebraska PPD, and Lincoln Electric System) joined the Southwest Power Pool, and in Iowa, MidAmerican Energy and Muscatine Power & Light joined the Midwest ISO.

The ISO footprint in the Midwest continues to reshape with Dairyland Power Cooperative's integration into MISO in June 2010 which adds 1,300 MW of additional generation capacity to MISO footprint with 61 MW of renewable resources. This integration also eliminates about 200 tie lines and creates greater visibility of MISO system condition. Integration of Dairyland Cooperative and Big Rivers Corporation (pending) into MISO is expected to somewhat offset the impact originating from pending transfer of Duke Energy Ohio and Duke Energy Kentucky to PJM RTO effective 2012. The outcome of recent cost- benefit analysis for Entergy and Cleco Power joining SPP RTO is also likely to have impact in the region.

Midwest ISO's Ancillary Services Market (ASM), launched in 2009 to integrate operating reserves into the current day-ahead and real-time markets through a simultaneous commitment and dispatch helped consolidate twenty-four balancing authorities into one. As a result, the markets for energy and ancillary services in the Midwest ISO are now centrally administered and optimized in a manner similar to the current PJM market. Although the Southwest Power Pool currently only operates as a nodal energy imbalance market, its Future Market design effort would bring the same type of structure to that market, with a tentative launch date at the end of 2012.

Transmission Expansion and Topology

PJM's Regional Transmission Expansion Plan (RTEP) helped identify the following significant "backbone" transmission projects to relieve west-to-east congestion over the next few years:

- The Trans-Allegheny Interstate Line (TrAIL) - a new 500 kV transmission line extending from southwestern Pennsylvania to West Virginia to northern Virginia. Being built by Allegheny Energy, this project would increase the potential flows from the APS zone to PJM South, and is targeted for completion by June 2011. The construction of this project is more than 75 percent complete.
- The Susquehanna-Roseland Project - a new 500 kV line running from eastern Pennsylvania to northern New Jersey, with PPL Electric building the Pennsylvania portion and Public Service Electric & Gas building the New Jersey portion. The project would increase the flows from west to east in the PJM Mid-Atlantic region. Originally targeted for completion in June 2012, it is currently projected to be in service by 2014 because of permit issues from the National Park Service.
- The Potomac-Appalachian Transmission Highline (PATH) - a new 765 kV line running from Amos, West Virginia, to western Maryland. The project is a joint venture between American Electric Power and Allegheny Energy that would increase flows from the AEP and APS zones into PJM Mid-Atlantic. This project was withdrawn in 2009, but revived later in 2010.

PJM recently announced the intention of proceeding with the regulatory filings for
The Mid-Atlantic Power Pathway (MAPP) project, a new 500 kV line connecting the Possum Point plant in northern Virginia to the Calvert Cliffs nuclear plant in southern Maryland, and a 640-kV DC line that will run under Chesapeake Bay and extend to the Indian River plant in Delaware.

The Midwest ISO Transmission Expansion Plan (MTEP) has 274 new approved projects with a cost estimate of $903 million. These projects extend out to the year 2019 with the last major project's expected in-service date of 2016.

FERC has recently approved SPP's new integrated transmission planning (ITP) process. That will determine the most effective transmission (priority) projects to satisfy the system reliability and provide optimum short- and long-term economic benefits to the region. The ITP addresses both regulatory and economic perspectives. The ITP is a three-year iterative planning process that includes.

- 20-year assessment - addresses long-term planning issues due to load growth and potential developments in the transmission voltage range of 345kV or above. The 20 year assessment will begin in year one with completion in year two.
- 10-year assessment - evaluates lower-voltage (100-365 kV) solutions for meeting needs over the next decade, and analyzes whether projects identified in the 20-year assessment need to be initiated earlier in the transmission voltage range of 100kV or above. The 10 year assessment goes from year two to year three.
- Near term assessment - addresses reliability issues in the transmission voltage range of 69kV or above. The near term assessments are performed annually.

Nuclear Expansion

The Nuclear Regulatory Commission (NRC) currently has active applications for combined construction and operating licenses (COL) covering 22 new reactors, all of which are in ERCOT, the Midwest, and the Southeast. The construction cost estimates for these new reactors continues to be a

major obstacle for successful completion of these projects, with costs ranging from $4,500/kW to $7,000/kW.

The Energy Policy Act of 2005 authorized the Department of Energy (DOE) to institute a loan guarantee program that would facilitate early commercial use of new or improved technologies in energy-related projects. On June 30, 2008, the DOE announced that $18.5 billion would be available under a Nuclear Power Facilities solicitation, and, on October 2, announced that applications had been received for 21 new reactors at 14 different power plant sites. In 2009, four applicants were informed of their selection to receive federal loan guarantees for these projects, with estimated size and completion dates shown:

- PJM Mid-Atlantic: Calvert Cliffs 3, 1,600 MW, 2015;
- Southern: Vogtle 3 & 4, 2,234 MW, 2016 and 2017;
- Carolinas: VC Summer 2 & 3, 2,234 MW, 2016 and 2019; and
- ERCOT: South Texas 3 & 4, 2,716 MW, 2016 and 2017.

Of the four projects, only Vogtle units 3 & 4 received $8.3 billion federal loan guarantee. Southern Company and its co-owners for this project will use the NRC-certified Westinghouse AP1000 reactor which will cost an estimated $14 billion.
In October 2010, Constellation decided to pull out of the Calvert Cliff unit 3 project due to the reasons that the federal government's proposed terms and conditions for the guarantee are "unworkable". The company also stated that the proposed cost is unreasonably burdensome and would create unacceptable risks and costs for the company.

Coal Development

Ventyx forecast includes close to 5 GW of coal fired generation under construction in the Midwest footprint between 2011 and 2012. There are no new coal fired units in the model beyond 2012 given high cost of construction and uncertainty in the federal climate legislation.

Given the fact that federal climate change legislation has been put on hold , there seems to be uncertainties in federal cap and trade initiatives. Taking these factors in to account, Ventyx Fall 2010 forecast uses no federal climate change in the input assumptions. Hence no carbon capture, sequestration, and retrofits are considered in the base case for the entire forecast range.

Overall Capacity Mix

Natural gas-fired generation dominates the market over the forecast range. Although no new coal capacity is projected in this forecast, this forecast indicates higher coal capacity as compared to the Spring 2010 forecast because of no federal climate legislation assumption in Fall 2010 model.

Fuel Markets

Natural Gas Markets

Since mid-2009 the NYMEX forward strip has routinely traded at a significant premium to cash prices. The value of the forward strip has experienced sustained periods of a $2 premium over the moving average cash price. Because most producers hedge a significant portion of their production on the futures market they are less responsive to cash price levels and have been able to continue to

produce through some of the most depressed spot prices for natural gas in recent history. The futures premium over cash markets fell over the last several months and the 12 month forward strip was trading at the same level as the 12 month moving average cash price as of October 2010.

It would appear that the "Shale Gas Revolution" has fully arrived. However, Ventyx believes it is important to remember that there were two primary factors that led to this revolution. One was the technological advances made by producers pioneering new techniques that utilized horizontal drilling in conjunction with hydraulic fracturing to unlock previously unrecoverable reserves of natural gas. The other was relatively high price levels for natural gas that provided drillers the profit margins necessary to develop these new techniques. While the technology to access shale gas resources continues to improve, increasing initial production and potentially the ultimate gas recovery from shale wells and lowering the "break even" cost of production, the market price levels that supported a massive shift of investment in North American shale plays have collapsed.

The Ventyx Fall 2010 Reference Case forecasts the power generation sector to be the primary driver for natural gas demand. Gas demand for power generation increases by 100% over current levels during the 25-year forecast period at a compound annual growth rate of 2.9%. Growth in gas consumption by the power sector is most accelerated in the post 2028 period when gas is expected to be increasingly used to meet incremental base load power demand. Gas demand for the residential, commercial and industrial sectors is expected to be essentially flat over the forecast period. This is largely due to efficiency gains in gas use in these sectors offsetting moderate increases in demand.

Ventyx forecasts that the U.S. will rely on continued growth from unconventional gas production, particularly shale and tight gas, to meet the demand growth. Shale gas production is estimated to grow from current levels of about 15% of domestic supply to about 26% of domestic supply when shale gas production peaks around the 2018 to 2020 time frame. This represents an increase of 5.9 Bcfd over current levels of shale gas production. Total import levels are expected to gain little market share over the forecast period as increases in LNG imports are offset by declines in net pipeline imports from Canada. Net Canadian Imports are expected to decline due to decreasing domestic production levels in western Canada and increasing domestic consumption levels. While increases in LNG imports are expected to be somewhat masked by declines in net pipeline imports from Canada it is important to note that the timing on which LNG imports arrive to the U.S. market will be much more variable than pipeline imports. Future LNG import patterns into the U.S. market are expected to be higher during periods of low international demand when LNG producers utilize the storage capacity of the U.S. Gulf Coast market as a destination for excess cargoes.

In the Fall 2010 forecast, natural gas prices are expected to increase over time with real price escalation driven in the near term by the need for domestic producers to achieve higher realized prices in order to profitably fund drilling levels and in the long term by the increasing demand for natural gas from the power generation sector. The marginal supply of gas during the forecast period continues to be provided by relatively high cost conventional resources, which have resource cost (or "break even" cost) in the $8-$10/MMBtu range over the forecast period.

Coal Markets

Ventyx believes that overall coal commodity price growth will be slow over the next three to five years as power generators respond to a tightening emissions regulatory environment, low natural gas

prices, and a slow economic recovery. However, power generators' actions to reduce exposure to potentially volatile Central Appalachian coal supply will support prices for PRB, Illinois Basin and Northern Appalachian coal. Volatility in eastern U.S. coal markets is possible in the event of rapidly increasing demand, either domestically or from abroad, due to the tightening supply-demand balance as producers have continued to exhibit discipline and utilities have significantly reduced stockpiles, eliminating much of the 2009 supply overhang.

As the picture for 2010 has developed, we see that coal-fired power generation has picked up significantly, increasing fuel demand by 6.5 percent through July according to the EIA. A hot summer has increased power demand and in some regions, RFC and NPCC in particular, increased coal consumption significantly. A strong drawdown of utility coal stockpiles has resulted. The EIA's August estimate was 157 million tons of coal stockpiles in the Electric power sector, down from 192 million tons in August of 2009, a decline of 18 percent. Preliminary analysis of transaction data suggest that June 2010 year-to-date deliveries are slightly *below* 2009 deliveries for the same period and down significantly in Central Appalachia. This suggests that power producers do not anticipate a large increase in coal demand over the next one to two years. Coal producers have responded with continued production cuts.

Our forecast for coal-fired power shows 2.4 percent demand growth for coal to fuel power generation in 2011 (in Btu terms) compared to 2010, as utilization returns to existing capacity. However, annual demand growth is forecast to average 1.0 percent in 2012-2013 and fall to flat from 2013 through the end of the decade as lower overall power load growth and higher projected coal-fired retirements largely balance the amount of capacity that is currently under construction. In addition, continued competition from natural gas, combined with the state policies encouraging renewables is expected to continue to displace coal in some regions.

While coal production costs are expected to continue to increase as input prices increase modestly, the major driving force for increased costs are the declining economic quality of coal reserves. Muted demand growth in the near term combined with adequate production capacity are expected to keep prices from increasing dramatically in the near term and likely to moderate price growth in the long-term. For the period 2010 to 2015, we forecast average mine prices climbing 1.0 percent per year in real terms with increasing demand for Powder River Basin, Illinois Basin, and Northern Appalachian coal pushing prices in those areas up faster than average. Delivered prices are forecast to increase 0.5 percent per year through 2015.

Environmental Markets

Renewable Energy

The PJM market region covers portions of 10 states. Six of the states within the PJM region along with the District of Columbia have established renewable energy portfolio standards (Delaware, Illinois, Maryland, New Jersey, Ohio, and Pennsylvania). Of these, all but Illinois have solar generation targets as well. Additionally, all but Illinois and Ohio have targets by class of renewable. Primarily, the Tier I categories are the traditional renewable resources, while Tier II categories will include hydro facilities, energy efficiency, and other non-traditional renewable definitions. For the District of Columbia and Maryland, Tier I resources can be used to satisfy Tier II requirements. Under the proposed federal legislation, primarily the eligibility looks more like the Tier I .

West Virginia passed an Alternative and Renewable Energy Portfolio Standard, which calls for 25 percent of electricity sales to come from alternative or renewable energy sources. Alternative energy sources include clean coal technology, energy efficiency measures and demand response.

The SPP and MISO market regions cover portions of an additional 10 states. Six of the states within the SPP and MISO regions have established renewable energy portfolio standards, while two have adopted voluntary requirements. By 2020, Michigan and Wisconsin utilities must rely on 10 percent of their generation from renewable resources, Missouri 15 percent, and Kansas 20 percent. In Minnesota, all electricity providers must achieve 25 percent renewable generation by 2025, while Xcel Energy has a 30 percent target. Iowa was the first state to implement an RPS with a 105 MW statewide renewable capacity requirement. This target has been met and the state does have additional voluntary goals, which are also close to being met. In general, the SPP and MISO markets will be exporters of renewable energy credits as they have abundant renewable potential and less demand.

Between 2000 through October 2010, biomass and landfill gas capacity has increased slightly from 2.8 GW to 3.8 GW. Wind capacity saw moderate growth through 2007, growing from 1 GW to 5 GW. In 2008 and 2009, 9 GW of wind was brought online, but only 1 GW has been added through October 2010.

Ventyx forecasts a steady increase in renewable generation in the region through 2020 to meet increasing state requirements and then levels off to maintain the renewable energy requirement required under state legislation. The overall capacity factor for renewable generation in the region is about 42 percent. Approximately one-half of the capacity and energy in the region is built and generated in the SPP, MISO, and MRO regions and the other half in PJM. However, of the 170 TWh requirement in 2035 for the region, 110 TWh is required by the PJM states, versus 60 in the non-PJM states. PJM will continue to be a significant importer of renewable generation to meet their needs. Overall, the region reaches 11 percent of generation from renewable as compared to retail sales.

Nationally, renewable power energy sources have grown significantly since the beginning of this decade. In addition, the Energy Policy Act mandated increased federal government purchases of renewable energy from 3 percent in 2007 to 7.5 percent in 2013, extended the renewable PTC, and created a new PTC for hydroelectric facilities. The American Clean Energy and Security Act of 2009 (ACES) called for a combined efficiency and renewable electricity standard (RES) of 20 percent by 2020. Up to 25 percent of the RES can be met through energy efficiency, with the remainder to come from renewable resources. The main bill in the Senate, introduced by Senator Bingaman in July 2009, would require electric utilities to meet 15 percent of their electricity sales through renewable energy or energy efficiency by 2021. At this time, forward progress on either of these bills in 2010 appears unlikely.

In Fall 2010 REC forecast, The REC prices for 2010-2012 are based on REC prices seen in the markets today. There is an increase in prices through 2020 as state RPS begin to ramp up and more capacity is needed to meet energy needs. As we get past the bulk of the new renewable additions and higher gas prices result in greater market revenues, RECs begin to decline and continue to do so through the end of our study horizon.

Greenhouse Gas Limits

Climate change is still a hot political topic. Until the very end of 2009, national greenhouse gas (GHG) regulation seemed inevitable. However, progress was delayed by other pressing issues; primarily health care. While GHG legislation is still likely to be passed, there is no leading proposal at this time and a 2012 start is unlikely. Unlike other emission regulation, to date most of the leading proposals in Congress do not single out the power industry. Instead they seek to cover GHG emissions from all sectors. As such, most legislative proposals cover all six GHGs: carbon dioxide (CO_2), methane (CH4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). While political debate continues at the national level, many corporations, municipalities, and states are moving forward with their own plans to reduce GHGs.

In Spring 2010, Kerry and Lieberman introduced the American Power Act (APA). The APA was similar to the Waxman-Markey bill. It established a cap on CO_2 covering all sectors and it allowed for offsets to meet the cap. The main difference was a CO_2 price floor and ceiling at $15/ton and $30/ton. The bill was never formally introduced in the Senate and future action is unlikely.

As this Congress appears likely to fail to successfully pass GHG legislation, the focus has shifted to the EPA and the regulations that they have been implementing.

In late 2007, nine states of the Midwestern Governors Association along with Manitoba signed the Midwestern Greenhouse Gas Accord (MGGA). Similar to RGGI and WCI in scope and direction, the Accord seeks to establish GHG reduction targets, reduction strategies such as energy efficiency and renewable energy programs, and a cap-and-trade program.

If there is not a federal GHG plan by 2012, it is likely that both MGGA and WCI will have a GHG cap-and-trade in effect. Further, it is possible that these regional markets would converge with RGGI into a single cap-and-trade market as the respective market participants have already discussed the possibility.

Clean Air Interstate Rule (CAIR) and Clean Air Transport Rule

CAIR was promulgated by EPA on March 10, 2005 to reduce sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) emissions in 28 eastern states. The intent of CAIR was to reduce pollution in non-attainment areas that are impacted by emissions from stationary sources. The implementing vehicle was a cap-and-trade program under which individual generators could exceed their emissions allocations, but the system as a whole was required to remain below the cap.

On July 11, 2008, the DC Circuit Court vacated CAIR in its entirety and remanded the rule to EPA. The Court stated that the rule was fundamentally flawed primarily because the program does not connect states' emission reductions to any measure of their own contribution to downwind pollution. On July 6, 2010, EPA proposed the Clean Air Transport Rule in response to the court decisions. Currently, CAIR remains in effect while the EPA proceeds with the rulemaking process for the Transport Rule. The proposed Transport Rule would apply to the District of Columbia and 31 eastern states.