The Importance of Combined Cycle Generating Plants in Integrating Large Levels of Wind Power Generation

Integration of high wind penetration levels will require fast-ramping combined cycle and steam cycles that, due to higher operating costs, will require proper pricing of ancillary services or other forms of compensation to remain viable. Several technical and policy recommendations are presented to help realign the generation mix to properly integrate the wind.

J. Nicolas Puga

J. Nicolas Puga *is a Partner with Bates White, LLC. He has more than 25 years of experience as an energy advisor to electric utilities and generation and transmission companies in U.S. and overseas markets. He provides technical and regulatory advice to renewable energy project developers and regulatory agencies in project economics, siting, permitting, and interconnection matters. The author holds an M.Sc. in Energy Engineering from the University of Arizona and a B.Sc. in Electrical Engineering from the Universidad de Guanajuato, Salamanca, Mexico. Over the course of his consulting career, Mr. Puga has advised numerous private and public sector clients in the United States, Canada, Mexico, Argentina, Chile, Venezuela, Colombia, Philippines, and Australia.*

I. Introduction

As the Southwest Power Pool (SPP) moves towards implementing its day-ahead market (''Day 2 Market'') managed under a consolidated balancing authority, it will face the challenges of integrating rapidly growing levels of wind generation into its operations. While counting on its greater load and generation diversity to facilitate the integration of large penetration of wind, SPP will have to make sure that generation sources connected to its system are flexible enough to accommodate the intermittent nature of wind generation, and that its markets for energy and ancillary services send out the proper economic signals to keep sufficient flexible generation resources in operation.

Recent wind energy integration studies in SPP reveal that even at present wind generation levels, one-third to one-half of all coal units will not be needed to supply power during minimum-load hours, and that as more wind generation is brought on line, coal plants will cycle more frequently than ever before.[1] The SPP wind integration study also showed that additional wind generation will require many coal units to cycle, particularly during low-load hours, significantly increasing the operating cost and shortening the economic life of those coal units. Furthermore, during winter peak-demand hours, combined cycle (CC) units will become the marginal generators. And, as the variability of wind generation requires more operational flexibility to compensate for wind fluctuation, this could lead to less generation by those CC units unless those plants are upgraded to operate more nimbly and flexibly. The reduction in CC generation could be so severe (over 50 percent at 20 percent wind penetration) that it is unclear whether merchant CC plants in some parts of SPP would be able to service their debt at these output levels. However, if these plants were to exit the market, it is possible that the remaining load following and regulation service would be insufficient to accommodate the high levels of wind penetration projected by SPP. Thus, it may be necessary to design new ancillary service products to provide the necessary spinning and non-spinning reserves to accommodate high wind penetration. Another, and perhaps more certain, course for the policymaker or regulator to consider would be to change the resource adequacy requirements of distribution utilities and/or to modify the procurement plans of the utilities to include more flexible generation in their resource portfolios. Policymakers might also want to consider adopting measures to encourage the development of flexible facilities or to preserve existing ones. These measures could include some form of long-term contractual commitment to cover the fixed operating costs of fast-ramping units during oversupply periods. Likely, these incentives would only be needed temporarily. As the aging coal plants are retired (likely accelerated by the adoption of carbon pricing), additional market demand would support fast-ramping plants, eliminating the need for long-term support.

The SPP wind integration study also showed that additional wind generation will require many coal units to cycle.

II. Integration of Wind Generation into a Power System

Matching the supply of electrical energy to the demand for electricity over time is a fundamental requirement for maintaining the adequate, secure, and reliable operation of the bulk power system. Wind generation introduces additional variability and uncertainty that will ultimately require changes to the current mix of generating resources and the way that they are operated.

The integration of growing levels of wind power generation mandated by state renewable portfolio standards (RPS) is starting to test the ability of some thermal generating plants to operate during the year's highest wind periods. Fuel-free wind-generated electricity not only reduces the dispatch of more expensive fossil-fuel generating plants, but in some cases increases fossil plant O&M costs by forcing more frequent cycling. Higher costs result from increased down-time, additional overhaul, and higher average heat rates. Ultimately, these higher costs will be passed to the consumer as part of the cost of meeting RPS mandates.

The balancing of supply and demand in the day-to-day operation of the power system in order to maintain reliability requires that the system's operators manage the provision of the following functions, also known as ancillary services, that

 1040-6190/$–see front matter , doi:/10.1016/j.tej.2010.07.002

are physically supplied by the generators, transmitters, and loads that are connected to the system:

1. Scheduling (unit commitment), system control, and dispatch;
2. Reactive supply and voltage control from generation;
3. Energy imbalance;
4. Regulation and frequency response;
5. Operating reserve—spinning;
6. Operating reserve—supplemental (e.g., non-spinning), and
7. Generator imbalance

These reliability-related services are the responsibility of one or more control entities – called balancing authorities – approved by the North American Electric Reliability Corporation (NERC), within a defined (metered) boundary called a balancing authority area (BAA).[2] Currently, a number of balancing authorities and transmission operators within the SPP regional transmission organization foot print are coordinated by SPP under its reliability coordinator (RC) designation by NERC. In the near future, SPP will combine the balancing authorities in its footprint into one entity that will serve as a Consolidated Balancing Authority (CBA) for its entire market footprint. As the CBA, SPP will balance supply and demand for the region, maintain frequency, and maintain electricity flows between adjacent BAs. As the CBA, SPP will also run a new day-ahead (''SPP Day 2'') market to optimize generation choices for the entire SPP footprint. This market will determine which generating units should run the next day for maximum cost-effectiveness (unit commitment) based on the marginal cost of resources available for the region. As CBA, SPP will also maintain frequency control and scheduled energy flows to other BAAs to which it is connected, by balancing power supply with power demand over two distinct time scales: for relatively slow deviations from supply–demand balance occurring between unit-commitment and real-time dispatch, and for fast random deviations in supply–demand balance taking place over a minute to a few seconds. The mechanisms that are used to balance supply and demand over these two time scales are known as load following (for slower changes) and regulation (for fast changes); Figure 1 illustrates these two time frames in SPP's Day 2 market design.

Load following by generators covers the departures of the forecast used in the real-time balancing market from the forecast used in unit commitment. At low penetration levels of wind generation, load forecast error and intra-hour variability are the main reasons for load following. At high penetration levels of wind generation, the need for load following also arises from wind forecast uncertainty and variability and, thus, becomes driven by that portion of the load not satisfied by wind generation, known as net load. Because the variability of wind generation, defined as the maximum positive or negative ramps (percentage change of power over time) can be significantly higher than that of

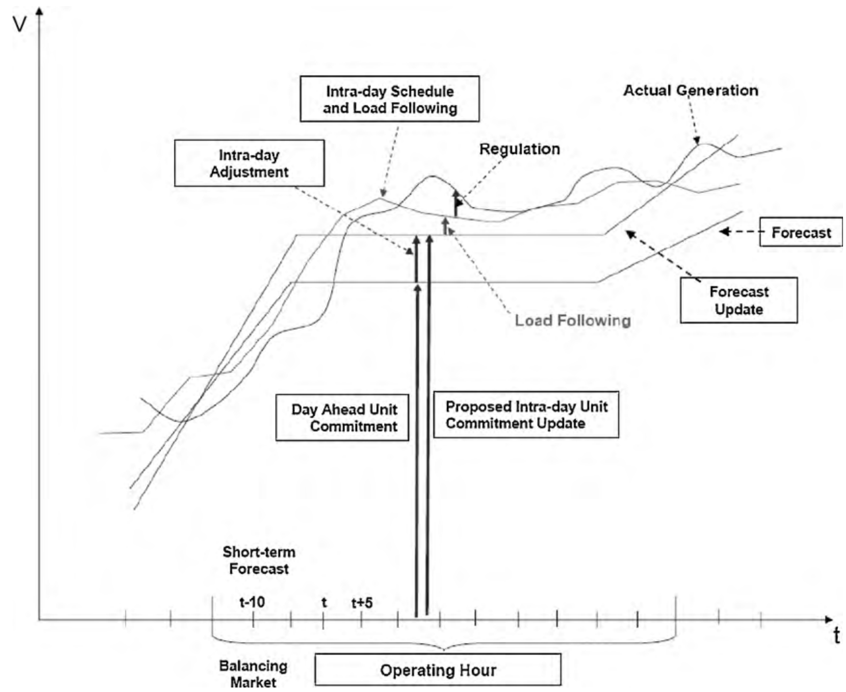

Figure 1: Timeframes for SPP Day 2 Market Design

  doi:/10.1016/j.tej.2010.07.002

load (particularly as installed wind capacity increases with respect to the load) the variability of net load becomes higher than that of load alone.

Regulation is used to balance generation to load within the dispatch time horizon (10 minutes in SPP), including intra-dispatch deviations and variations around the 10-minute-ahead forecasts used to clear the balancing markets. The need for regulation is driven by the short-term variability of load, wind generation, non-wind generation (excluding outages), and net exchanges. Historically, regulation has been provided by generators operating under automatic generation control (AGC) – an arrangement where the operation of a generation unit is under the control of the system operator, and the unit is run below its maximum capacity (to reserve room for upward movement) and above its minimum (for downward movement).[3] **Figure 2** illustrates load following and regulation.

Currently, SPP does not have any requirements for load-following reserves nor is load following currently treated as a distinct ancillary service product. However, as wind penetration levels increase, load following reserves might become necessary to accommodate net load forecast deviations and it may be advisable to create such an ancillary service product.[4,5]

While improved wind forecasting, particularly that of wind ramps, will help system operators make better unit commitment decisions, the inherently higher uncertainty of the net load forecast will compel them to maintain more flexible units, such as flexible CC plants when performing the intra-day second-stage of the commitment process (proposed as 4-hour-ahead in the SPP wind integration study). Indeed, if intra-day dispatch is not adopted by SPP, the uncertainty of the day-ahead forecast (being up to five times larger than a 4-hour-ahead forecast), would require the commitment of even more flexible units.[6]

As described above, the increased penetration of wind power resources will dramatically change the hourly load profiles of many thermal generation plants through increased load following, changes in up and down ramp rates, increased regulation duty under AGC, and ultimately through more frequent on/off line (hot, warm, and cold starts) cycling events. The ability of thermal power plants to rapidly increase or decrease their output is limited by the maximum thermal and pressure gradients that the safe and economic operation of their respective heat exchangers and turbines allow. Other factors limiting plant ramp rates include thermal inertia (mass), the ability to store and/or to dispose of heat rapidly, and the design objectives of each plant's operating controls (maximum peak efficiency or operational flexibility). Thus, depending on their operating characteristics and costs, some plant types and fuels are naturally more flexible in their operation (startup, loading, etc.) than others. In this respect, coal and natural gas fired plants are quite different from each other.

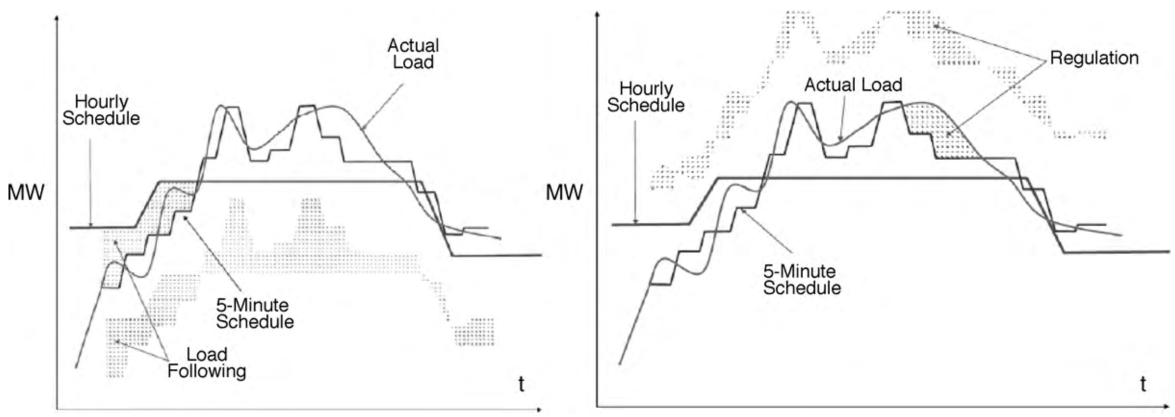

Figure 2: Load Following and Regulation

  doi:/10.1016/j.tej.2010.07.002

A. Coal plants

Coal-fired generating plants have significant thermal inertia due to the large combustor sizes required to burn coal (a fuel relatively low in net energy density). Coal plants have historically been designed to operate at relatively constant (slow-changing) load levels, with infrequent cycling, and above minimum operating levels of 45–50 percent of their design capacities. The integration of more intermittent resources will likely require existing baseload coal units to ''load follow'' more often and to drop to lower load levels than required in the past. Increased cycling of coal plants, in particular the older units, will result in significantly higher costs, including higher operating and maintenance expenses, forced outage replacement of energy and capacity, increased unit heat rate, plant startup costs, and the long-term capacity costs of a shortened unit life. It is reasonable to expect that the increased wear and tear from load following would also lead to more frequent shutdown-startup cycles. Even newer coal plants (less than 20 years old), while having better ramping capabilities and being somewhat better suited to follow load and provide regulation, still do not have the flexibility to match the real-time variability of wind, and still have to maintain minimum operating limits in the order of 35 percent of design capacity or higher.

Some generation plant owners and operators have carried out studies to quantify the increase in capital and operation and maintenance costs (including fuel) of baseload coal-fired units due to increased cyclic operation under current and future wind penetration levels brought about by state RPS mandates. The results of one such analysis, carried out by APTECH Engineering Services on behalf of Xcel Energy, are summarized in **Figure 3**.[7] The analysis was based on the actual operating statistics and costs of a 30-year-old, 500 MW, coal-fired plant over a 10-year period (1997–2008). Cycling costs were dominated by fixed and variable cost of maintaining and repairing resulting wear and tear (42 percent).

The overall per cycle cost of \$116.6k (2008\$) falls in the lower end of what APTECH characterized as the typical ''true unit cost per cycle'' for coal-fired plants – as illustrated in **Table 1**.

Table 1: Typical Generating Plant Shut-down-Start Per Cycle Cost.

Unit Type	Potential Range of Total cost
Small drum	\$3k–\$100k
Large supercritical	\$15k–\$500k
Gas turbine	\$0.3k–\$80k

The impact of cycling cost of ~\$0.21/MWh reported by Xcel is relatively low because the subject plant operated with a relatively low number of cycles and a high capacity factor during the analysis period; but both such operating conditions are unlikely to exist for many coal plants as additional wind generation comes on line.

The true cost of cycling a large coal generating plant, after long-term operational impacts and shortened plant life are considered, can be significant. Many of the most expensive, marginal baseload coal units will likely become unprofitable once forced to cycle during the spring and fall (low-load and high-wind

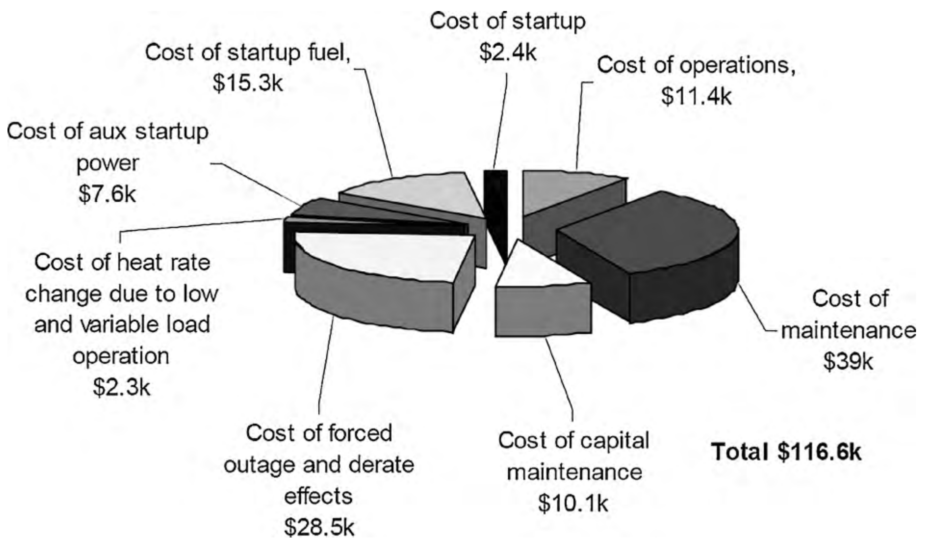

Figure 3: Illustrative Shutdown-Start Per Cycle Cost of a 30-Year-Old 500 MW Coal-Fired Steam Plant

 1040-6190/\$–see front matter , doi:/10.1016/j.tej.2010.07.002

seasons), especially when the cost of carbon is taken into account.

An additional impact of wind on the operation of coal plants will be the increased emissions of criteria pollutants caused by departure from optimal operating conditions during cycling. A recent study, carried out on behalf of the Independent Petroleum Association of Mountain States,[9] looked at NO_x, SO_x, and CO_2 emissions of coal plants during wind-driven, coal plant cycling events in Colorado and ERCOT, and found significant increases in these pollutants as a result of cycling. For example, the cycling of one plant in Colorado to accommodate wind generation caused 8 percent more SO_2 and 10 percent more NO_x than it would have produced on flat-level operation.[10] Moreover, temporary and long-term heat rate degradation in coal generation facilities can negate most or all the CO_2 reduction benefit of wind generation.

B. Natural gas plants

Unlike coal-fired facilities, which are better suited to relatively steady baseload operation, recent vintage natural-gas-fired combined-cycle gas turbine plants (CCGT) can be ramped up or down more rapidly and cycled more frequently with less impact on the long-term economic viability of the plant. Older CCGT plants, built during the 1990s and earlier, were designed to operate at maximum efficiency in baseload operation and are thus characterized by slow sequential startup times. Nevertheless, these plants can be retrofitted to operate at higher cycling duty and faster up and down-ramping, while reducing the impact of cycling on O&M costs and plant operating life. Some of these re-engineered facilities have achieved remarkable startup time reductions of more than 50 percent following an overnight shutdown.

The key factors limiting a CCGT plant's ability to rapidly vary its output are the allowed pressure and temperature transients of the steam turbine, the waiting times of the heat recovery steam generator (HRSG) to reach proper steam chemistry conditions, and the warmup times for the main piping system and other plant. These limitations of the steam side of the plant in turn limit the fast startup and rampup capabilities of the gas turbine.

CCGT plant vendors have addressed each of these factors in their new plant designs, and offer upgrades for existing CCGT plants that enable plant operators to start their plants faster and operate them with increased flexibility; these are both essential capabilities as wind generation pushes CCGTs up the dispatch stack. An additional benefit of these upgrades is the reduction in NO_x and CO emissions under unfavorable loading conditions. An example of the upgrade packages offered by plant vendors is Siemens' ''hot-start on the fly'' concept, illustrated in Figure 4. The concept includes new control concepts like a modified high pressure/hot reheat steam temperature control, a new high-pressure and hot-reheat bypass control philosophy, modifications to the steam turbine controller, and new balance of plant system signals. An improved gas turbine control enables the plant operator to use the maximum load ramps over a wide operating range.[11]

While CCGT plants already provide a significant share of the

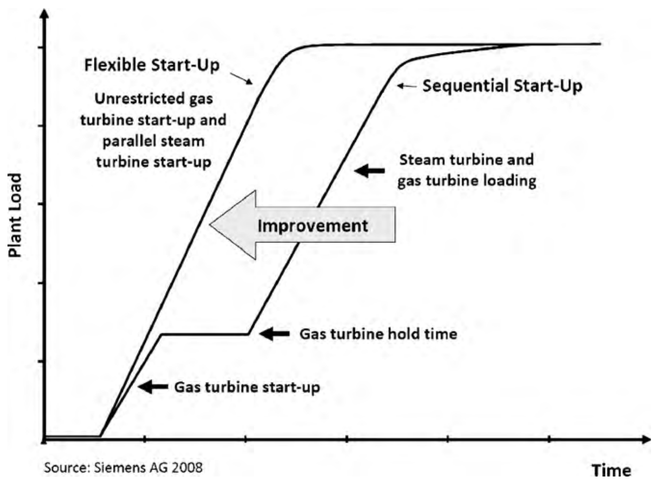

Figure 4: More Flexible CCGT Plant Startup Concept

 1040-6190/$–see front matter , doi:/10.1016/j.tej.2010.07.002

load following service across all U.S. electricity markets, CCGT plants retrofitted for additional flexibility could satisfy the need for additional load following and regulation capability created by the integration of large amounts of wind powered generation.

III. Experience with the Effect of Wind Integration in Other Regions

In markets like ERCOT, where wind represents a growing, yet still relatively small share of electricity generation, wind has already caused substantial displacement of fossil-fired generation during times of lower demand and high winds.

Figures 5 and 6 show the daily variations in generation by fuel type over the course of a typical

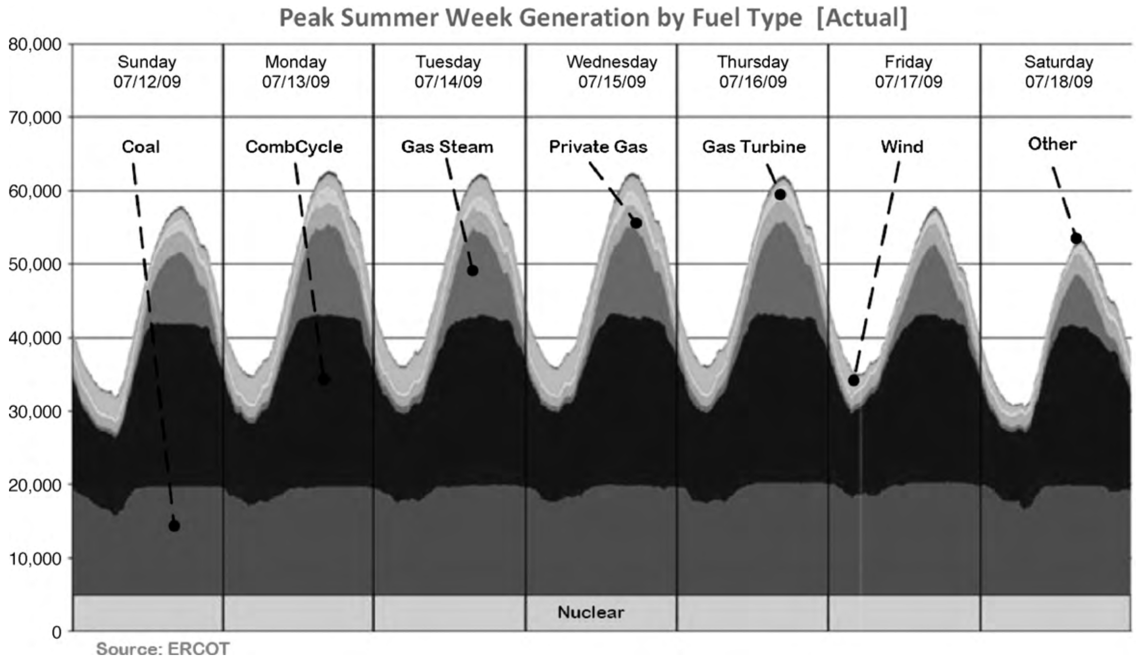

Figure 5: ERCOT Summer Generation by Fuel Type

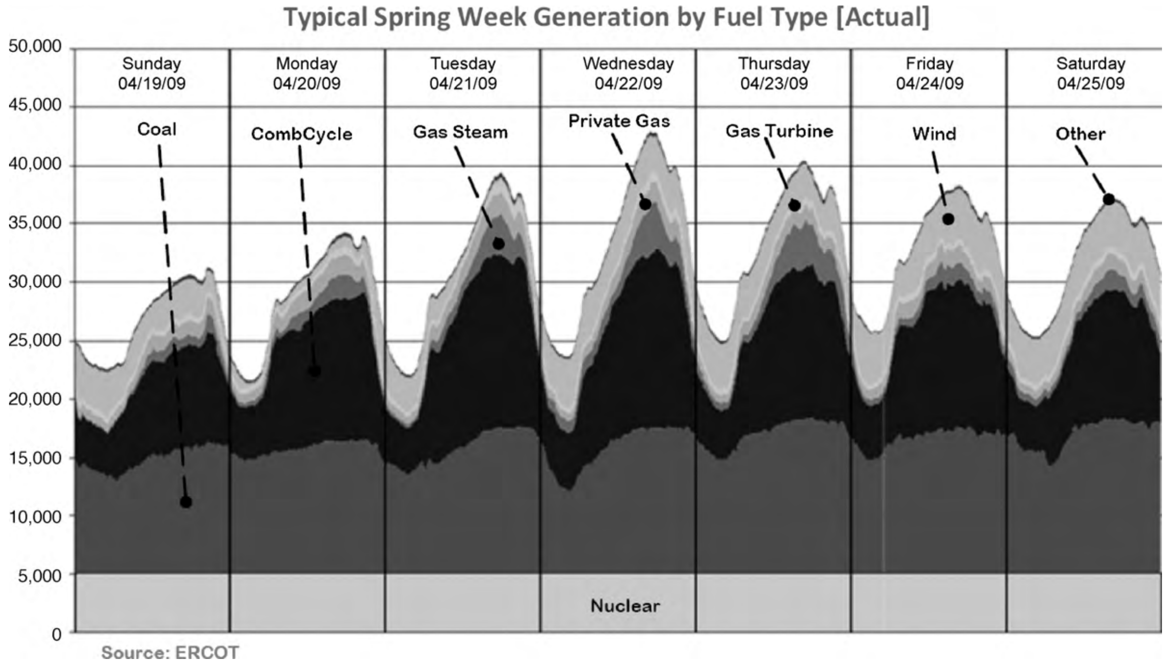

Figure 6: ERCOT Spring Generation by Fuel Type

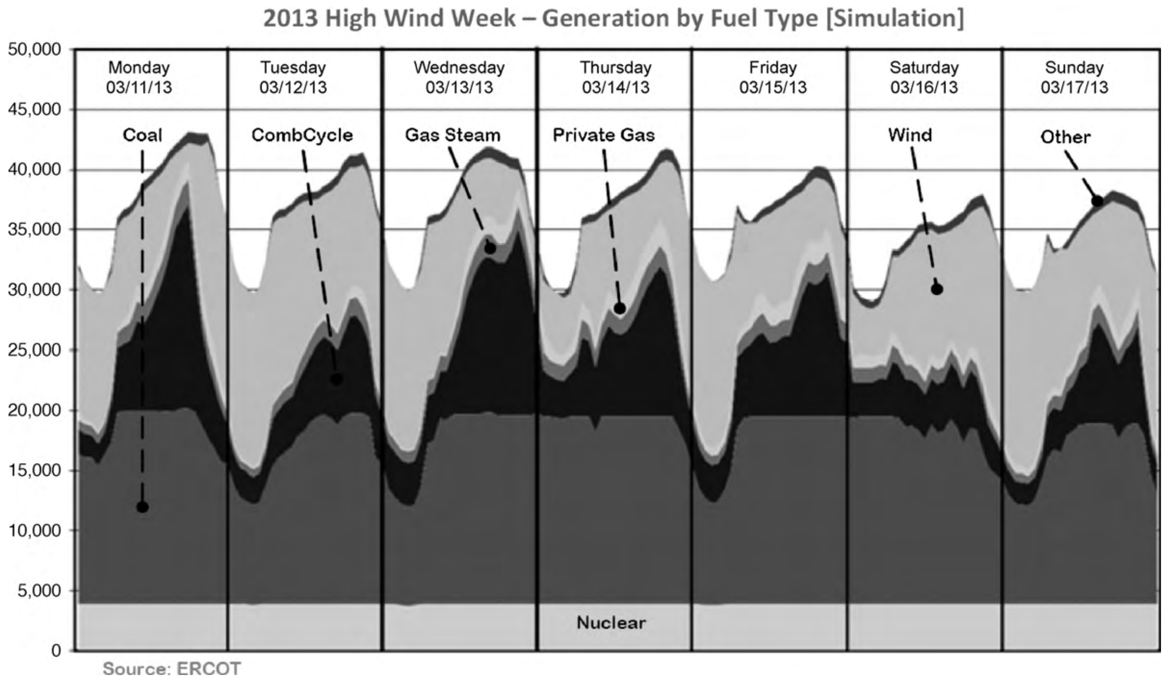

Figure 7: ERCOT Projected 2013 Spring High-Wind Week

week in the summer and spring, respectively. A comparison between Figures 5 and 6 indicates that wind, with a very small variable cost, easily displaces the dispatch of more expensive natural-gas-fired and coal-fired electricity.[12] Projected increases in wind power capacity across ERCOT will have a significantly larger impact on natural gas and coal-fired generation, as can be appreciated in **Figure 7**. Moreover, the impact of wind generation can further be amplified by transmission constraints surrounding wind-rich areas with poorly diversified fossil generation. An early example of this can be found in West Texas, where coal-fired plants are experiencing lower capacity factors and more frequent shutdowns whenever the net-of-wind load falls below that needed to sustain a plant's minimum operating load.

A recent analysis of 15-minute-interval generation data by fuel type for ERCOT for the years 2007, 2008, and 2009, produced by Bentek Energy, LLC, established the increase of coal plant cycling attributable to wind generation. This analysis identified the number of instances where coal-fired power plants cycled down by 300–500 MW, 500–1,000 MW, and more than 1,000 MW during the same time periods that wind generation increased by at least a like amount. **Figure 8** shows the results of the analysis.

In many regions of the U.S., relatively low wind penetration levels and the historical

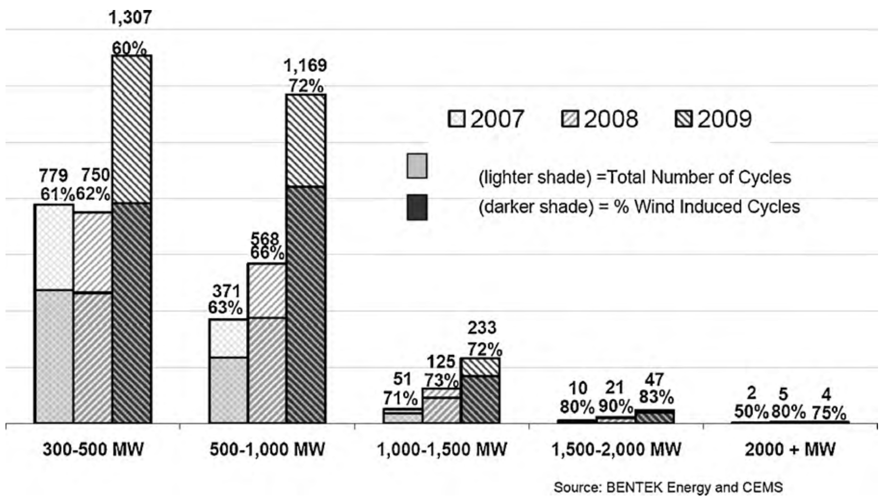

Figure 8: Distribution of ERCOT Coal Cycling Instances – Hour-Over-Hour Change

 1040-6190/$–see front matter , doi:/10.1016/j.tej.2010.07.002

relationship between coal and natural gas prices (lower coal cost per Btu) have so far preserved the place of coal as a base resource in the economic dispatch of generation. However, increasing wind development and growing natural gas availability at relatively low prices – such as those experienced over much of the past year (~$4/MMBtu) – could ultimately reverse this historical dispatch order and subject coal plants to the rigors of load-following duty and more frequent (and costly) cycling. An article in the April 2010 issue of *Public Utilities Fortnightly*[13] compared the production costs of natural-gas- and coal-fired marginal generation fleets,[14] finding these costs at close to break even at natural gas prices slightly above $4/MMBtu – not far from prices observed in the recent past.

In addition to the impact of growing wind generation, if cap-and-trade legislation becomes law, carbon trading prices could force many coal-fired plants to be dispatched as intermediate resources subject to increased cycling duty. This has already occurred in Europe, where carbon has been traded since 2005. An analysis of European and American generation plant statistics carried out by Solomon Associates shows that after carbon trading began in the European Union (EU), the utilization of CCGT plants rose, while coal plants, originally designed for baseload duty, were forced into cycling operation. Upon the initiation of EU carbon trading in 2005, the utilization of CCGT units increased dramatically and, the utilization of EU coal units, meanwhile, declined significantly during the same period. In 2008, utilization of CCGT units exceeded that of coal units for the first time. According to Solomon, today, coal plants in the EU now experience about six times more

starts each year than comparable plants in North America. The increased cycling of EU coal plants has resulted in reduced availability, a rise in O&M costs due to more frequent outages, and increased repair time and costs.[15] The same role reversal between CCGT plants and coal plants is likely to take place in the U.S. electricity markets once U.S. carbon trading begins. At current gas and coal prices (April 2010), and even if natural gas returned to the $5–$7/MMBtu prices implied by recent NYMEX futures, CCGT and coal-fired steam electricity prices are close enough that a carbon price of less than $30/ton would shift economic dispatch in favor of gas-fired CCGT away from the marginal coal plant fleet.[16]

IV. The Need to Insure that Flexible Generation Will Be Available in SPP

As SPP moves toward a Day 2 Market under a Consolidated BA with improved unit commitment and dispatch processes, SPP will be in a better position to leverage greater load and generation diversity to integrate higher levels of wind penetration. Nevertheless, the recently released SPP WITF Wind Integration Study, prepared by CRA International, reveals some worrisome potential impacts of SPP's change to single BA operation on its fossil fuel plants. Even at SPP's current wind penetration levels, one-third to one-half of all coal units will not be needed to supply power during minimum-load hours.[17] Further, as is already happening in other regions, the introduction of additional wind will require many coal units to cycle, especially during low-load hours. During the winter-peak hours, combined-cycle units will become the marginal generators. Because the variability of wind generation requires more operational flexibility (typically provided by peaking units), this will lead to less generation by those CCGT units showing the least flexibility. The impact of reduced output by coal and CCGT units due to additional wind is worrisome, as these units are the main providers of ancillary services, such as spinning reserves and regulation in SPP. This change points to an urgent need to establish either a market for more flexible CCGT units that can provide these needed ancillary services or some form of long-term contractual commitment to cover the fixed operating costs of such fast-ramping units during oversupply periods.[18]

The wind integration study carried out in SPP shows significant impacts on many intermediate generation units (CCGT and STgo).[19] On an aggregate annual basis, at 10 percent wind penetration, CCGTs and STgos in SPP would respectively generate 36 percent and 40.3 percent less than at today's wind penetration. At 20 percent wind penetration, all non-wind plants would generate less and cycle more: CCGT and ST_{go} generation would be reduced by 57 percent and 38.6 percent, respectively, and coal-fired steam plants would cycle 44 percent more.[20] However, the study also suggests that the impact at the individual balancing area (and unit) level would vary significantly across SPP depending on the makeup of the generation mix within each BA, and its location with respect to transmission constraints. It is possible that the most heavily impacted merchant CCGT and STgo plants in some parts of SPP would not be able to service debt at the resulting generation levels. Unfortunately, if these plants were to exit the market, it is possible that load following and regulation service availability would be insufficient to accommodate the high wind penetration levels modeled in the study.[21]

V. Policy Recommendations

If the ambitious levels of renewable generation (mainly

wind) established by RPS mandates are to be successfully integrated into electricity markets, policymakers and regulators will have to make sure that sufficient fast up- and down-ramping generation resources are available as operating reserves to the grid operator. Availability of these resources will be essential to maintaining reliability during periods of low load with high wind generation, when normally baseload-duty coal plants are already close to their minimum generating levels and rampdown capability is greatly diminished. During these periods of low load and high wind generation, it may be economic to replace the marginal (most expensive) coal generation with more flexible new and re-engineered CCGT plants.

Alternatively, wind generation could simply be curtailed during periods of very high generation. However, this would tend to increase energy costs and would ultimately lead to a less balanced and flexible generation portfolio.[22]

While a well functioning, real-time market should secure sufficient balancing energy from flexible facilities, assuming they are not put out of business by wind-generated energy first, it may also be necessary to design new ancillary service products to provide the necessary spinning and non-spinning reserves to accommodate high wind penetration. Another, and perhaps more certain, course for the policymaker or regulator would be to change the resource adequacy requirements of distribution utilities and/or to modify the procurement plans of the utilities to include more fast-ramping resources. Policymakers might also want to consider adopting measures to encourage the development of flexible facilities or to preserve existing ones. Recent proposals for energy and operating reserve markets in SPP's Future Markets Design, when adopted, incorporate week-ahead and day-ahead reliability unit commitment of must-run units. In the meantime, in order to keep needed flexible generating units viable until more wind comes on line, a potential solution may be long-term contracts to cover the fixed operating costs of fast-ramping units.[23] The good news is that, as aging coal plants are retired (likely accelerated by the adoption of carbon pricing), additional market demand will support fast-ramping plants, eliminating the need for long-term support.

As this process may take time and require the passage of climate legislation, in the short-term regulators could require that electric utilities developing integrated resource plans (IRPs) that focus on acquiring fossil-fired resources with sufficient flexibility to functionally accommodate RPS-mandated wind and solar resource levels in their generation portfolios. This would lead utilities to consider the partial or full retirement of their most uneconomical and polluting coal generation facilities while accomplishing the reliable integration of these clean and abundant renewable energy resources.[24]■

Endnotes:

1. The effects of high levels of wind generation penetration on the utilization rates of fossil generation have also been experienced in other U.S. regions with high wind generation penetration.

2. As a result of the Energy Policy Act of 2005, reliability standards are now mandatory in the U.S., and NERC is the federally mandated Electric Reliability Organization (ERO).

3. In some markets, interruptible load controlled by under-frequency relays can also be used to provide regulation.

4. SPP WITF Wind Integration Study, Final Report, Jan. 4, 2010, at 6–12.

5. *Id.*, at 6–11.

6. *Id.*, at 5.29.

7. Xcel Energy, in the course of acquiring wind resources identified in its 2007 IRP, proposed to add coal plant cycling costs attributable to the integration of wind resources to all wind energy bids. Xcel ultimately abandoned its proposal due to strong opposition to its proposal by wind developers and renewable energy advocates in the state. Public Utilities Commission of the State of Colorado – Docket 07A-447E.

8. Steven Lefton, *et al.*, *The Cost of Cycling Coal Fired Power Plants*, Coal Power Magazine, Winter 2006.

9. How Less became More; Wind, Power and Unintended Consequences in the Colorado Energy Market, Bentek, Energy, LLC, April 16, 2010.

10. *Id.*, at 66.

11. Norbert Henkel, *et al.*, Operational Flexibility Enhancements of Combined Cycle Power Plants, Siemens AG, Presented at Power-Gen Asia 2008, Kuala Lumpur, Malaysia, Oct. 21–23, 2008.

12. The generating sources in Figures 1 and 2 are stacked in order of increasing generation cost with the exception of wind, which is stacked near the top to facilitate the viewing of its impact on coal and gas.

13. Sean Casten, *Fuel Swap: Natural Gas as a Near Term CO_2 Mitigation Strategy*, Pub. Util. Fortnightly, April 2010, at 41–44.

14. The analysis assumed marginal fleet heat rates of 7,100 Btu/kWh for gas-fired combined cycle plants and 11,500 Btu/kWh for coal-fired steam plants. ''Marginal fleet'' refers to the plants with the highest production costs of their class – i.e., the last of their kind to be dispatched.

15. *The Impact of Carbon Trading on Performance: What Europe's Experience Can Teach North American Generators*, W. Edward Platt and Richard B. Jones, Power, Jan. 2010.

16. Casten, *supra* note 11, at 42.

17. SPP WITF Wind Integration Study, Final Report, Jan. 4, 2010, at 6-2.

18. *Id.*, at 6-2, 6-3.

19. Simple cycle gas/oil-fired steam turbine plants.

20. SPP WITF Wind Integration Study, Appendices B.14–B.21, at B83–114, Jan. 4, 2010.

21. The models used in the SPP WITF Wind Integration Study assumed that SPP will be dispatched as a single balancing authority with a co-optimized energy and ancillary services market, and that SPP's transmission system will be incrementally expanded to accommodate the growing levels of wind penetration. The study also assumed no wind curtailment regardless of cost.

22. In some of the U.S. transmission regions most impacted by growing wind generation, there have been calls for curtailment of wind resources under oversupply conditions. For example, as more wind comes on line, the Bonneville Power Administration (BPA) has increasingly been forced to curtail wind generators during high-wind light-load periods. BPA already carries close to 2,000 MW of balancing capacity to manage the variability and uncertainty on its system, mainly as a result of the up and down ramps of the 2,800 MW of wind generation operating within its 10,500 MW balancing authority. As BPA's hydro electric dispatch flexibility is limited by fish preservation and other water management considerations, it will increasingly have to rely on additional flexible gas-fired generation and mandatory intra-hour interchanges with neighboring balancing areas, if further uneconomic wind curtailment is to be avoided. See *Post-Workshop Reply Comments of the Bonneville Power Administration*, Public Utilities Commission of the State of California, Docket R. 06-02-012 and R. 08-08-009, May 12, 2010.

23. When called to operate, these generators would be paid their marginal operating costs, not the market clearing price. The payments would be intended to cover the fixed operating costs of the units, including property tax payments, wages and salaries and debt service, but would not include any return to equity or the owners.

24. Voluntary economic retirements are already taking place in various markets. AEP recently announced the partial retirement of 10 old coal units, which will now be run part-time and only if load and market prices warrant it. See *AEP to Run 10 Old Coal Units Part-Time Due [to] Economy*, Reuters, May 27, 2010.

❖ *Meetings of Interest* ❖

Conference	*Date*	*Place*	*Sponsor*	*Contact*
FRI Annual Public Utility Symposium	Sept. 29	Columbia, MO	Univ. of Missouri's Financial Research Institute	www.FRI.Missouri.edu
Advanced Energy Storage 2010	Oct. 12–14	San Diego	Fullpower Inc.	http://www.fullpowerinc.com/AES2010/AESHome.html
EP China 2010 / Electrical China 2010	Oct. 19–21	Beijing	Chinese Electrical Council	http://www.epchinashow.com/JasperWeb/Shows/sid-263/lang-eng/details.aspx
Power Plants 2010	Oct. 23–26	Serbia	Society of Thermal Engineers of Serbia	http://e2010.drustvo-termicara.com/
1st IEEE Energy Conference & Exhibition	Dec. 18–20, 2010	Manama, Bahrain	IEEE Region-8	http://www.conferencealerts.com/seeconf.mv?q=ca16xsis
14th Annual Energy & Environment Conference	Jan. 31–Feb. 2, 2011	Phoenix	Bloomberg	http://www.euec.com/content/index.aspx
Energy and Sustainability 2011	April 11–13	Alicante, Spain	University of Alicante	http://www.wessex.ac.uk/11-conferences/energy-2011.html

  doi:/10.1016/j.tej.2010.07.002