THE US ELECTRICAL POWER INDUSTRY – A 2009 PERSPECTIVE

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ABSTRACT Information on the United States (US) Electrical Power Industry current major developments is provided, including:

- > Electricity use is expected to decline in 2009 and to increase moderately in the future.
- > Many of the plans for new coal unit units that were planned about 3 to 6 years ago have been set aside.
- > Most recent new generation has been natural gas combustion turbine / combined cycle plants.
- > The past two years have seen a surge in the installation of new renewable generating capacity, mostly wind turbines.
- > New nuclear units are currently in the planning phases and one is being constructed.
- > New transmission line capacity is being planned to improve the current restrictive situation.

1. INTRODUCTION

Similar perspectives were provided starting in 2001 and for each following ICOPE Conference. Major changes have occurred between each of these two year periods.

This brief overview of the current United States (US) power industry is intended to be technology neutral. There are many other topics and further details that could be included, but this brief general technical discussion should be of interest to the attendees of this conference based on the engineering that are required for these developments.

Data and charts from the following sources and reports (most are accessible on the internet) and Sargent & Lundy information were used to provide this US industry overview:

- ASME – American Society of Mechanical Engineers
- DOE – US Department of Energy has a wide range of responsibilities, including new generation R&D.
- EIA – Energy Information Administration, one of the DOE agencies providing data and forecasts, including the Annual Energy Outlook (AEO) 2009
- FERC - Federal Energy Regulatory Commission - regulates, monitors and investigates electricity, natural gas, hydropower,
- NETL - National Energy Technology Laboratory, one of the DOE research laboratories
- NERC – North American Electric Reliability Council - develops and enforces reliability standards, generation and transmission system adequacy assessments, and provides training and other services.

2. GENERATION OVERVIEW

Per the NERC 2009 Summer Reliability Assessment peak required generation has been increasing about 0.9% per year between 2000 and 2008 as shown in Figure 1 (current with the preparation of this paper). Whereas it was about 9.0%, 7.3%, 4.2%, 3.1% and 2.4% per year during the 1950s, 1960s, 1970s, 1980s and 1990s, respectively. NERC shows an unusual projection for peak 2009 US and Canada electricity demand. It declines about

1.8%, which was attributed to “decreased economic activity”. Summer reserve margins (generation availability compared to peak projected demand) in most parts of the US will be about 25% this summer, “well above the 15% NERC minimum reference “Reserve Margin” and well above the projections two years ago. However, a few local low reserve situations exist. Beyond 2009 maximum electricity demand is expected to continue to increase by about 2% per year.

Figure 1 NERC 2009 Summer Reliability Assessment

Coal, nuclear, natural gas, and conventional hydro were the respective sources for about 50%, 20%, 20% and 7% of the MW hours generated in the US during 2008, with the remaining 3% generated by renewables other than conventional hydro. Renewable generation other than conventional hydro was 53% wind, 29% biomass, 17% geothermal and 1% solar. Electricity prices over the past 20 years have been, and are projected to continue to be, generally in line with inflation.

Coal and nuclear fuel price increases are expected to be moderate. However, natural gas prices have changed dramatically as shown in Figure 2. The low current price,

about \$4/million Btu (\$3.8/kJ) is mainly because of new horizontal drilling capabilities that release natural gas from tight sand and shale deposits. EIA reports there is about a 15 year natural gas reserve which apparently supports the continued construction of new gas turbine plants. The use of imported liquid natural gas that was projected two years ago to increase significantly between 2005 and 2030, is now projected to remain at the current 2009 level, which seems to be the result of the recent decline in the natural gas price.

Figure 2: EIA Annual Energy Outlook 2009

Figure 3: EIA Annual Energy Outlook 2009

Figure 4: EIA Annual Energy Outlook 2009

Starting about 2000 and continuing to the present, a large amount of natural gas fueled combustion turbine and combined cycle new generation was installed: peaking at about 58 gigawatts in 2002. Forecasted new natural gas fueled generation based continues to be greater than other types as shown is Figure 3.

Combined cycle plant capacity factors averaged 38% in 2008, equal to the average capacity factor for such plants

for the period 2003-2008. Combined cycle capacity factors averaged about 46% in the period 1997-2002. The approximate doubling in the price paid by utilities for natural gas largely explains the reduction in generation. The projection of about 55 gigawatts of new natural gas generation in the 2021 to 2025 time frame might be disproportionate. From 2007 to 2030, new natural-gas-fired plants account for 53% of new plant additions and coal plants account for only 18%.

New nuclear generation is currently projected after no new plants since 1996, which was the Watts Bar 1 project of which construction began in 1973.

A significant number of new coal plants were projected, but in the past few years advancement of many new coal plants was cancelled due to environmental permitting, financial, and other issues.

Generation from renewable sources (Figure 4) is projected grow by about 3.3% per year for the next 6 to 10 years.

It is important to know that the EIA AEO projections include ranges based on economic conditions and other impacts. Also, prior projections for new generation even for the first five years have been inaccurate due to economic, fuel cost, environmental permitting, tax incentives and other major changes. Additionally, these projections will probably change based on the pending legislation in the US Congress that is described in a later section of this paper.

Although the future US growth rates are low percentage values, because the US generation total is quite large these growth rates require quite a few new plants. Currently planned new electric power additions for 2008 through 2030 of 218 GW, are 55% gas-fired, 14% coal-fired, 5% nuclear, and the remaining 27% renewables. About 20% of this added capacity will be to replace capacity retired during that period, over 80% of which is gas/oil-fired steam-electric capacity or older combustion turbines and diesels, with the balance split between coal and nuclear capacity.

The following sections of this paper describe how the construction of major new plants and modifications to existing plants are driven by generation requirements, environmental regulations, fuel and capital costs, and tax credits.

3. ELECTRICITY / TRANSMISSION CAPACITY

In addition to reporting on generation capacity, NERC also reports on transmission line capabilities and has concluded that many major lines are currently carrying close to maximum capacity. This situation has been recognized for quite a few years, but construction of new lines or upgrading of existing lines has proceeded slowly because of costs, ownership issues, public resistance, and environmental concerns. However, recent regulations have been passed that might expedite installation of these new lines. NERC is reporting that about 21,000 km new transmission (230 kV and above) is proposed. Upgrading of transmission line capabilities is vital to continued wind power generation development.

4. NEW COAL POWER PLANT PROJECTS

In 2002 there were about 60 new coal plants being planned with an output of about 36,000 MW, but as of 2007 only 4500 MW (12%) have been installed. At present only about a dozen new coal-fired plants, totaling about 8 GW,

are being constructed for the 2010-2012 operation because environmental permitting, financial, and other factors have caused cancellation or deferrals that had been planned for this period. Seven new coal plants, which have total capacity of about 3500 MW are listed below. Two of those units are supercritical (Walter Scott Jr. Unit 4 by MidAmerican Energy, at 890 MW, and Weston 4, by Wisconsin Public Service, at 595 MW). The others, ranging in size from 110 to 600 MW, are subcritical cycles.

Table 1: Recent New Operating Coal Plants

Unit	MW	Year	Steam (MPa / °C / °C)
Cross 3	600	2007	Subcritical
Cross 4	600	2008	Subcritical
Hardin 1	117	2006	Subcritical
Springerville 3	450	2006	16.5 / 538 / 538
TS Power 1	242	2008	16.5 / 566 / 566
Walter Scott Jr. 4	890	2007	25.3 / 566 / 593
Weston 4	595	2008	24.8 / 582 / 582

4.1 Circulating Fluidized Bed Boilers

Nine circulating fluidized bed (CFB) boilers have entered service in the U.S. (including the territory of Puerto Rico) from year 2000 through 2009.

Table 2: Recent CFB Units

Unit	Boilers	Total MW	Year	Steam (MPa / °C / °C)
Warrior Run 1	1	205	2000	12.4 / 538 / 538
Red Hills 1	2	500	2001	16.5 / 566 / 538
Puerto Rico 1 & 2	2	255	2002	17.4 / 541 / 541
Northside 1 & 2	2	300	2002	17.3 / 541 / 541
Seward 6	2	521	2004	17.4 / 541 / 541
Spurlock 3 & 4	2	290	2005	16.5 / 538 / 538

Important features of some of these units are summarized in Table 2. All are subcritical cycles. Two of the nine burn coke, with the remainder burning coal. According to public information provided by some of the Owners, CFB technology was selected mainly based on the type of fuel to be fired, allowable emissions and the costs for the size of these units compared to similar size pulverized coal boilers.

4.2 Supercritical Boilers

Although only two new US supercritical units have been placed into operation in the past 17 years there are 151 supercritical units operating in the US, and 12 of these units have unit capacities ranging between 1100 and slightly over 1400 MW, the largest units in the world. Twenty-six of these units have double reheat.

Previously, selection of subcritical instead of supercritical units was mainly based on lower capital costs, shorter startup times, easier operation, and higher reliability. However, currently US subcritical and supercritical units have similar reliability, resulting from improved operating procedures, improved metallurgy and welding procedures, improved startup system designs and improvements in valves, combustion, water treatment systems, and other components and systems.

Current justification for supercritical cycles in the US

is mainly because of reduced emissions (on a per MWh basis due to higher cycle efficiency) that is aggressively pursued during the environmental permitting activities, and which is supported by the current proven highly reliable pressure boiler designs. The ASME Position Statement, The Need for Additional US Coal-Fired Plants that is posted on the ASME website provides additional relevant information.

Data (approximate values) for some of the current supercritical units that are in the construction phase are listed below:

Table 3: Public Information - Advanced US Supercritical Pulverized Coal Units Data

Units	MW	Year	Steam (MPa / °C / °C)
Comanche 3	816	2009	27.1 / 568 / 596
Elm Road 1 & 2	2 x 625	2009-2010	26.2 / 566 / 566
Iatan 2	914	2010	24.6 / 582 / 582
Longview Power 1	769	2011	26.5 / 569 / 556
Oak Grove 1 & 2	2 x 855	2009-2010	24.5 / 538 / 538
Turk 1	1 x	2011	24.5 / 600 / 605
Cliffside 6	878	2012	25.5 / 566 / 566

All of these units are equipped with Hg, NO_x, SO₂, and high efficiency particulate removal equipment resulting in flue gas emissions similar to shown in Table 4. Following are salient features of two of these plants:

- The Longview boiler will be the first installation of the new Siemens furnace vertical wall low mass flux design.
- Turk plant is considered an ultra supercritical unit based on steam temperatures above 593 °C.

The Weston plant rated at 595 MW, 27.1 MPa / 582 °C / 582 °C was placed into operation last year.

A significant aspect of the US power generation industry is the operation of the existing pulverized coal plants. Although coal units 100 MW and larger have an average age of these plants of 39 years, the average capacity factors of coal units are high. At stations installed since 1960 the average capacity factor has increased from 62% in 1994 to 72% 15 years later, in 2008.

One possibility that seems to be overlooked for CO₂ reductions is to convert existing coal plants with subcritical cycles to supercritical cycles. Sargent & Lundy has prepared studies for this option. For a 500 MW unit the efficiency increased approximately 8 % and fuel consumption was reduced by the same amount. This efficiency increase and based on a 90% capacity factor resulted in CO₂ emission reduction of about 9% or 400,000 tonnes per year. The new cycle was a conventional supercritical cycle, so with an ultra-supercritical cycle CO₂ reductions would be greater. Additionally, there would be reductions in other emissions. Alternatively, additional power could also be generated with the same fuel consumption. The cost was about \$1700 per MW for the new boiler, high pressure turbine sections, feedwater heaters, boiler feed pumps and high pressure piping. A major consideration in the cost of these projects is the need to replace other major plant components; e.g., generator, main transformer, condenser. However, the modified /

refurbished unit operating life would probably be more than 25 years.

4.3 Integrated Gasification Combined Cycle (IGCC)

Currently there are two IGCCs operating in the US (both were DOE/industry projects) and six in the world. However, based on a NETL list there are 20 US operating gasifiers. The NETL 2007 list showed about 30 future IGCC units (~14,000 MW) in various initial planning stages. The Edwardsport Plant (a 2x2x1 configuration, nominal 600 MWnet) is currently being constructed in Indiana. Generating costs for IGCC units are higher than for pulverized coal units except when there is governmental cost sharing or tax credits are provided. The expected reliability of IGCC units is lower than for conventional coal units. However, the advanced IGCC designs may require lower costs for carbon capture and sequestration.

5. DOE PROGRAMS

The US Department of Energy continues to advance power industry technology through funding of research and development projects. Future-Gen is a current major DOE power industry project, combining in a single project the demonstration of coal gasification, advanced emissions controls, hydrogen production, electricity generation, and carbon dioxide capture and storage (CCS) technologies. This project was cancelled about a year ago because of high cost, but has been reactivated with modified goals; including only designing for one type of coal (bituminous) and capturing and sequestering about 60% instead of 100% of the flue gas CO₂. By capturing 60% of the CO₂, the CO₂ emissions from this coal plant will be similar to emissions from a natural gas fueled plant. Sequestration will be about 3000 meters deep in a saline geologic rock formation. The current estimated cost (including escalation) is about \$2.0 billion US. DOE is planning to provide about \$1 B US and the 20 member participating companies would provide the remaining funding.

6. COAL PLANT FLUE GAS EMISSIONS

Permitting is mainly done in the US Environmental Protection Agency framework called Best Achievable Control Technology (BACT), which has resulted in ongoing emission reductions for successive new units. Current environmental permit flue gas emission rates for pulverized coal units, which are generally in the range shown in the table below, are very challenging. Increased air pollutant concentrations in cities and visibility reductions in national and state parks are also major considerations. Plant permitting requires extensive computer modeling to determine that the air quality and other requirements are not exceeded. Locating plant sites that meet fuel transportation, transmission, water, air quality and other requirements is difficult. Margins need to be included for operational issues.

Table 4: Sargent & Lundy - Typical (not specific)

Example: New Pulverized Coal Plant - Upper limits

Emission	kg/MWhr - LHV (net generation)	kg/GJ (fuel fired)
SO ₂	0.427	0.048
NO _x	0.300	0.034
Particulate	0.065	0.007

Mercury capture (typically with activated carbon) is usually required at rates that are determined on a project specific basis, but usually greater than 50%.

These emission rates are based on the equipment operating at the highest levels that can be expected.

The permitting process involves detailed reviews by local, state and other federal government agencies. Almost all permits for new coal units are challenged via public hearings and through the courts. Many projects have been cancelled because of failure to get the needed permits or the expense and financial risk of attaining the permits.

Figure 5: NETL. Coal Plant Data

This figure shows the very large emissions reductions that have been achieved and coal consumption history.

7. RENEWABLES – CO₂ REDUCTIONS

The following figure shows energy consumption for recently installed and current future planned renewable power generation. The significant and rapid increase in wind energy can be mainly attributed to the very substantial tax subsidies provided at the federal level and to “renewable portfolio standards” requirements in varying forms by 28 US states. Renewable portfolio standards are requirements that power companies provide some minimum percentage of total energy source (usually between 15% and 30% of total generation) from wind, biomass and other defined renewable forms of generation. Normally there is a phase-in to meet the requirements, such that it must be achieved by 2015, or 2020, or other specific time.

Most publicity has been focused on the U.S. Congress energy/environment legislation that will require CO₂ emission reduction and energy efficiency requirements, which is described later. However, through these regulations and federal tax credits, there currently are significant US power industry CO₂ reduction activities that have not received much recognition. The objective of these credits is to reduce reliance on fossil-fired generation thus reducing CO₂ emissions. The tax credit escalates with inflation and is currently about two cents per kWh for wind, geothermal, and hydroelectric generation and one cent per kWh for biomass and landfill gas fueled generation. Solar generation also benefits from an investment tax credit. Some states also provide incentives for renewables.

Increased wind and solar requires changes in planning and operations of other plants to account for the fact that the availability of wind energy and solar energy varies significantly; e.g., spinning reserve availability.

Other challenges for wind and solar include finding locations with an adequate renewable energy source (e.g., wind, insolation), suitable topography, and adequate transmission.

The renewable output variations shown in the Figures 7 and 8 show that coal and natural gas plants. New types of plants (e.g., compressed air storage, flywheels, H₂ generation) need to be respond to the variations of these wind and solar sources for stable voltage, frequency and power supply.

Biomass is another renewable resource being encouraged in the US. Firing biomass in new or existing boilers presents challenges in achieving proper combustion and low emissions, and avoiding slagging, fouling, corrosion, and other effects due to the wide range of constituents in wood, bark, straw, agricultural, and other biomass materials. The very large volumes of biomass materials needed for appreciable electricity generation is a major transportation cost and logistics issue and tends to limit large-scale biomass use to certain areas where such fuels are readily available. For example, a 100 MW plant fueled by bark with 50% moisture requires approximately 3550 tonnes of fuel per day. This size unit would require about 160 trucks per day. The fuel storage, handling and preparation equipment are quite expensive.

Currently there are quite a few plants planning to co-fire biomass and several plants (e.g., First Energy, Burger Units 3 & 4 totally 310 MW) are converting to 100% biomass firing.

Figure 6: EIA 2008 Energy Outlook

8. COMBINED CYCLES

As described above a substantial amount of new combustion turbine generating capacity has been added in recent years and appreciable new future additional generation will be installed. However, based on past data and future projections shown in Table 5, the yearly operating time (capacity factor) will probably be fairly low for these units. High fuel cost is the main reason for this situation. Also, it appears that improvements in combustion turbine efficiencies have stabilized.

Figure 7: NERC Report, Accommodating High Levels of Generation, April 2009

Figure 8: NERC Report, Accommodating High Levels of Generation, April 2009

Table 5: EIA Data (Natural Gas = Combustion Turbines)

Fleet Generation Capacity Factors			
	1994	2005	2007
Nuclear	74%	89%	98%
Coal	62%	74%	74%
Natural Gas	N/A	33%	37%

9. NUCLEAR

The US existing nuclear units achieved an outstanding combined capacity factor of approximately 98% in 2007 and 2008 that results in continued low electricity prices from these units.

Recently, new nuclear unit construction has been receiving more favorable opinions in newspapers, and other public communications that could be mainly attributed to the highly successful operations of existing units and the fact that nuclear units have no appreciable CO₂ emissions.

There is one nuclear unit currently being constructed. It is the Watts Bar Unit 2 nuclear unit that was originally permitted in 1972, TVA suspended construction of Watts Bar Unit 2 in 1985. TVA informed NRC of its plan to resume construction of Watts Bar Unit 2 August 3, 2007. The current expected completion date is 2012.

According to the information posted in July 2009 on the US Nuclear Regulatory Commission web site,

combined construction and operating licenses applications have been submitted for 25 new nuclear units at 17 sites. These units will provide the additional nuclear power generation additions shown in Figure 2.

The development of Nevada Yucca Mountain nuclear waste disposal facility, which was to receive US nuclear plant wastes, has been halted. Obviously, at some point in the future it will be necessary to resolve that issue.

10. CONSTRUCTION COSTS

There has been a very large increase in costs for constructing new or modifying existing plants: e.g., the EIA 2009 AEO states that since 2000 plant costs have almost doubled. The increases are generally for all the major plant components and equipment; including cement, steel. Boiler and turbine suppliers have had quite a major increase in business compared to before year 2000. Coal and nuclear plant economics are greatly impacted by these increased costs.

12. GENERATING COSTS

Environmental permitting, fuel and capital costs, and financial risk are usually the main issues when comparing natural gas combined cycle and pulverized coal plant generating costs. Generally, environmental permitting for a new plant is a significant activity because of time and cost on most projects. Most coal projects are faced with significantly more permitting challenges than the natural gas fueled combustion turbine plants.

Table 6 Generation Costs - Sargent Lundy LLC

Year 2010 Base Load	Low US \$/MWh	High US \$/MWh
<u>Combined Cycle</u>		
Capital	9.50	14.20
Fixed	1.60	1.80
Variable	2.90	3.20
Fuel	31.80	64.90
Total	45.80	84.10
<u>Pulverized Coal</u>		
Capital	32.00	47.50
Fixed	3.50	3.90
Variable	3.80	4.20
Fuel	17.10	23.00
Total	56.40	78.60

A comparison of the range of estimated combined cycle and pulverized coal supercritical cycle base load 500 MW plant generating costs based on Sargent & Lundy experience is provided in Table 6, expressed in levelized 2010 constant US dollars. Both the combined cycle and pulverized coal plant costs include the equipment required for current US environmental permits. Often these costs are presented in technical papers as single values; however, Sargent & Lundy's experience has shown that costs vary considerably. This table is levelized cost (\$/MWh), using assumed ranges of fuel, capital costs, financing, and other costs for 500 MW plants that are typically applicable to new plant construction and operation. The same capacity factor for both types of units (85% which might be high for the combined cycle unit based on typical natural gas costs)

has been used. The ranges occur from differences in plant location, fuel source and other site-related requirements. Based on this experience the lowest generating cost plant might be natural gas or coal. One major cause of the difference between the low and high columns is the interest rate for capital. Investor-owned developers (either traditional utilities or independent power producers) typically have the highest costs of capital, and government entities and cooperatives have the lowest costs of capital. Another impact is the very large increase in construction costs described previously. Fuel costs are another major difference; e.g., natural gas or coal costs vary significantly based on location. The low costs for each of the categories are typically not achievable; i.e., the plant generating costs are higher than what is shown in the Low column. IGCC plant costs are projected to be about 15% higher than the PC costs, assuming no carbon capture requirement or CO₂ allowance costs.

In addition to costs, many other matters must be considered in deciding on generating technology; e.g., potential permitting difficulties, long term fuel availability and cost, type of new generation required (peaking, cycling or base load), cost and available project financing, adding an additional unit to an existing site or at a new site, coal transportation costs. Generating costs for IGCC, nuclear, and wind might be mitigated by tax credits.

13. LEGISLATION and REGULATIONS

At the time this report was written, the U.S. Congress was actively debating several proposed energy, environmental, and greenhouse gas (GHG) bills, including the American Clean Energy and Security Act of 2009 (the "ACES Act"). The U.S. House of Representatives passed the ACES Act on June 26, 2009, and the act is currently being debated in the Senate. It is not known whether the Senate will pass a similar, or significantly altered, energy/environmental act. Although it is beyond the scope of this paper to review potential affects that the ACES Act (or similar legislation) could have on the electric generating industry in the U.S., it is important to note that the act based by the House of Representatives included, among other things: (1) energy efficiency and renewable standards for electricity generating units; (2) CO₂ cap-and-trade program; (3) provisions concerning the development of a smart grid; (4) provisions to provide for the development of electric vehicle infrastructure; and (5) a strategy to address barriers to the commercial-scale deployment of carbon capture and sequestration. It appears likely that some form of CO₂ legislation will be passed into law this year or next year. Depending on the final CO₂ and efficiency standards, this legislation could have a very significant impact on the U.S. electricity generating industry over the next decade.

About 20 years ago many of the US states were changing regulations and laws to deregulate electrical power generation. Figure 9 shows there is a reversal of deregulation in some states and continued regulation in other states. A main reason for this difference is that some States appear to have reached the conclusion that deregulation would result in higher rather than lower electricity costs contrary to the expectation that competition would drive costs down. The general opinion of the States avoiding deregulation seems to be that generation costs are lower through diligent regulation and a more stable power