Spring 2015

CLEAN POWER PLAN – OVERVIEW AND COST ALLOCATION DISCUSSION

By Amanda Alderson, Consultant and Brian Andrews, Associate Consultant

In June 2014, under direction of President Obama, the Environmental Protection Agency ("EPA") proposed the Clean Power Plan ("CPP") under the authority of the Clean Air Act, Section 111(d). The CPP will set carbon emission guidelines for existing electric utility generation plants. As proposed, the rule sets individual state CO_2 emission limits for 2030 and beyond, at levels which represent a 30% reduction from 2005 levels, and also establishes

interim goals that must be met, on average, between 2020 and 2029. The EPA has given flexibility to the states to determine the manner in which they meet their emissions targets, but utilizes a building block approach to set the goals. The EPA has also indicated that states are allowed to meet goals in either a rate-based manner (lbs/MWh) or in a mass-based manner (tons of CO_2). Additionally, this proposed rule allows for multiple states to join together to meet their goals with multi-state compliance plans.

The EPA has set an aggressive timeline for both itself and for electric utilities. The comment period for the proposed rule originally was set to end on October 1, 2014, but was extended to December 1, 2014. The EPA has received over one million comments on its proposed rule, but it is still expected to issue the final rule on June 1, 2015.

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The EPA set the interim and final goals based on a reduction of 26% for the interim and, as mentioned, 30% for the final goals of reduction from the 2005 emission levels. In order to set the emission goals, the EPA relied on a set of four building blocks of the Best System of Emission Reduction ("BSER").

The first building block is based on the assumption that all existing coal-fired facilities can achieve a 6% improvement in their heat rates. The second building block assumes that all existing natural gas combined cycle facilities can and will operate at a capacity factor of 70%. The third building block assumes that new renewable or nuclear energy can be built to meet the existing state Renewable Portfolio Standards ("RPS"). The fourth building block assumes that demand-side energy efficiency programs can reduce demand by 1.5% annually. The combined effect of these four building blocks determines the interim and final goals for each state.

This rule is widely expected to cause a significant amount of coal-fired generation facility retirements. The EPA estimates that nationwide, generation capacity will be reduced between 30 and 49 GW, or 12% to 19% of the remaining coal capacity, by 2020. Various Regional Transmission Organizations ("RTOs") are providing estimated impacts within their purviews. For example, the Midcontinent Independent System Operator, Inc. ("MISO") has estimated that up to 25% of the remaining coal capacity within its footprint would need to retire to comply. This equates to 14 GW overall, with 11 GW retiring by 2020 to meet the interim goals.

The EPA has estimated the national annual cost of complying with this rule to be between $5.4 and $7.4 billion in 2020 up to between $7.3 and $8.8 billion in 2030. MISO has estimated that the 20-year net present value of compliance for its member states will cost between $55 billion and $83 billion. The less expensive estimate would occur if all the states within MISO comply using a Multi-State Implementation Plan. PJM Interconnection ("PJM") has estimated that cost of compliance in 2020 for its member states will cost an additional $44 billion for state by state compliance and $35 billion for regional compliance.

The overall cost of the CPP will likely affect different tariff rate customer classes in different ways, based on the typical electric consumption patterns of each customer class and the various ways in which each state decides to comply with the rule. For each of the building blocks suggested by the EPA for compliance, the cost of reducing CO_2 emissions may be directly incurred by various entities, including generation companies, electric utilities, gas and electric transmission and pipeline companies, etc. These costs will then be passed on to customers in varying ways. Typically, large users of electricity are harder hit by costs incurred or allocated on an energy basis, as opposed to a demand- or customer-based allocation factor, than are customers with lower energy usage.

BSER 1, or Building Block 1, involves generation asset owners making operational adjustments or installing upgrades in order to improve the heat rate of coal-fired assets. Additional capital investments on generating units owned by traditionally regulated utilities are often allocated to end-use customer classes using a production allocator, which can be predominantly demand-based, but can also have an energy-based component to varying degrees. For independent power producers installing upgrades in order to maximize a unit's heat rate, these additional costs will be included in the total cost of power production, which is typically offered as an energy ($/MWh) price into the RTOs and Independent System Operators ("ISO") in the country. North American Electric Reliability Corporation's Initial Reliability Review of the CPP claims that additional heat rate improvements are likely not feasible for the majority of coal-fired assets remaining unretired in the country,[1] and therefore the majority of the CPP compliance cost may not ultimately come from this BSER 1.

EPA's BSER 2 calls for natural gas generation to be dispatched ahead of coal- and oil-fired units where possible. Coal-fired generators usually have a lower variable operating cost than gas-fired units, which is why coal units are often dispatched before higher-cost assets. A reversal of this dispatch order for environmental reasons is likely to produce an overall higher cost of electricity. Such variable operating costs are typically allocated to customer classes — or in the case of independent power producers they are typically offered to buyers — on an energy basis, which would place a larger burden of the cost onto large users of electricity. In addition, many regions of the country will need to see a large build-out of gas transportation pipelines if gas-fired electric generation becomes a larger share of total regional generation. Gas pipeline and gas storage costs are often allocated using a combination of both demand-

[1] NERC Initial Reliability Review, November 2014, p. 8.

based and gas throughput-based (akin to energy-based) allocation factors. Pipeline build-out could be a significant component of overall CPP compliance costs in the states most lacking in sufficient pipeline capacity.

BSER 3 recommends an increase in the use of renewable energy for electricity generation, as well as saving the "at-risk" nuclear assets in the country. If states choose to accelerate their current RPS, such costs might ultimately be borne by customers in any of a demand-based, energy-based, or customer-based charge, depending on the individual design of the state RPS goals. If additional wind generation is relied upon, electric transmission lines may need to be upgraded or constructed to link high-wind areas of a region to the city centers with high energy consumption. Such costs are predominantly allocated on a demand basis. Concerning saving "at-risk" nuclear units that will perhaps shut down because of market and industry economics, where the market revenue for nuclear energy is not enough to cover production costs, any number of various schemes might be employed to assist these generators. As one example among many potential approaches, in New York, the State Public Service Commission recently ordered[2] Rochester Gas & Electric ("RG&E") to negotiate a Reliability Support Services Agreement with the R.E. Ginna Power Plant, owned by Constellation Nuclear Energy Group, whereby RG&E will be obligated to purchase the nuclear generation at a rate high enough to cover the production costs. Further legislative methods to support nuclear generation are being contemplated in other states.

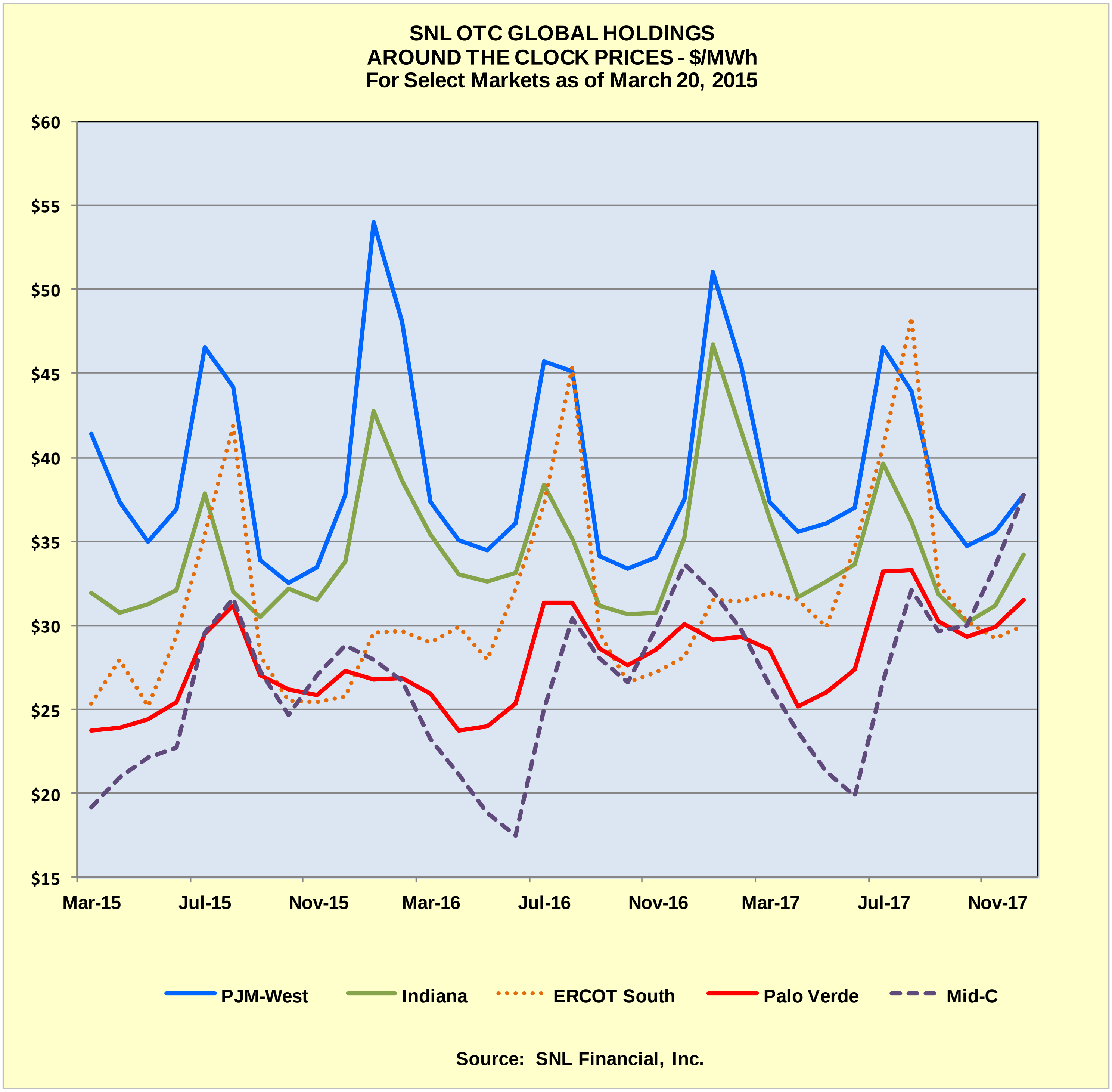
Lastly, BSER 4 calls for states to increase energy efficiency, which might come in the form of boosting payouts to end-use customers who opt to perform an energy efficiency project. These payouts are typically included in a utility-sponsored energy efficiency program, where such costs are often largely allocated on an energy-basis. For larger-scale customers who may receive an incentive for a larger energy efficiency project that does not fully cover the project cost, the remaining project cost is necessarily absorbed by the customer opting to perform the project. Overall, such efficiency project costs are likely to pale in comparison to the CPP compliance costs related to construction of new generation and transmission assets, but for an individual customer the costs may be more comparable.

Aside from the four BSERs defined by the EPA within the CPP, industry groups are citing various additional costs that will likely be incurred in order to reliably meet the CPP interim and final CO_2 reduction goals. Some regions in the country will need to replace substantial amounts of coal-fired capacity that will retire for economic reasons, in order to keep a safe level of demand capacity reserve available. Where companies build new generation units, such costs may be allocated on a combination of energy- and demand-based allocators, following whichever unique production-cost allocation approach is approved for the regulated utility. Additional ancillary services may also be needed if large amounts of coal-fired assets retire, or if coal-fired assets are dispatched less often. The cost of these services, such as voltage support, ramping capability, or operating reserves, is typically allocated on an energy basis, as the costs are of a more variable nature. Finally, RTOs and ISOs will likely push for higher operating budgets to ensure proper coordination among all operational entities, as the CPP could create a major shift in the typical operating patterns of the electrical production and transmission industry as a whole. Such administrative charges to the RTOs and ISOs might be allocated to end-use customers on an energy basis, which disadvantages high load factor customers.

In all, the EPA plan, in whatever form it is approved, is certain to add billions of dollars of cost in the U.S. electric industry. The plan grants states a high degree of flexibility in complying with the CPP, and each of the various compliance tools will yield a different allocation of ultimate compliance costs to the states' electric customers. Large electric consumers should have a voice in determining their State Implementation Plans, and should be involved directly or reach out to the specific industrial consumer group operating in their state to get involved in the process.

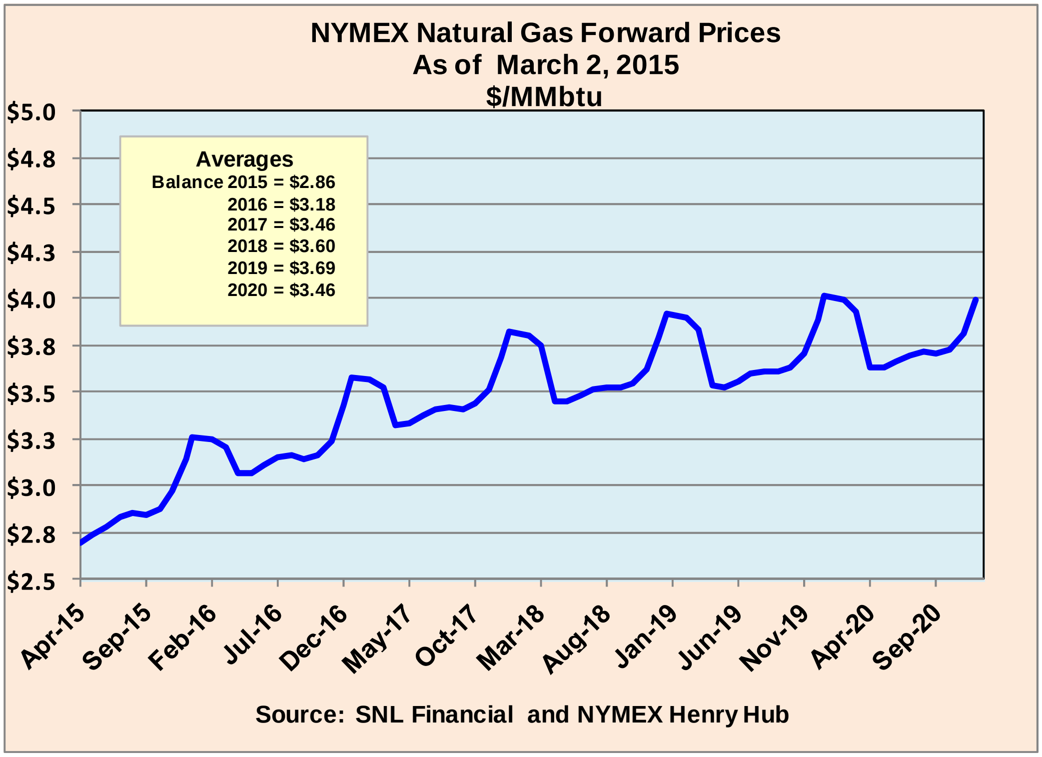
[2] See Docket 14-E-0270 before the New York State Public Service Commission.

SNL OTC GLOBAL HOLDINGS FORWARD POWER PRICES

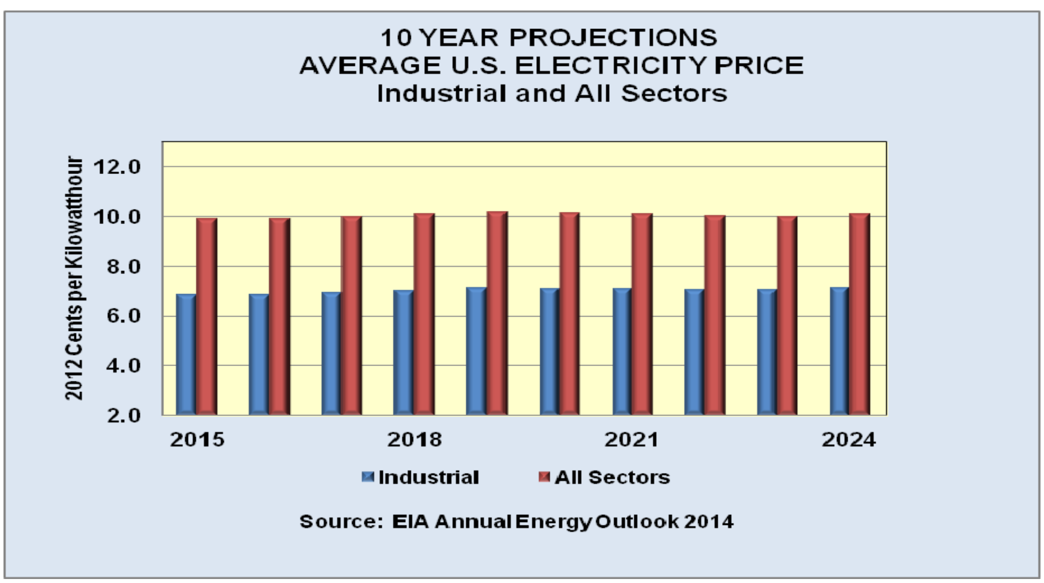


FORECASTED NATURAL GAS AND ELECTRICITY PRICES

Long-term New York Mercantile Exchange ("NYMEX") natural gas prices are forecasted to rise slowly throughout 2015 and continue a slow upward movement through year end 2020. The highest projected peak during this six-year period is expected in January 2020 at approximately $4.01/MMbtu. A low price of $2.70/MMbtu is projected for April 2015.



The U.S. Energy Administration Annual Energy Outlook 2014 National Energy Modeling System has projected the average U.S.'s ("EIA") electricity price for industrial users to remain within the 6.0¢ to 7.0¢/kWh range through 2024. The all sector group is expected to average around 10.0¢/kWh over the same period.



ELECTRIC RATE CASES
AUTHORIZED INCREASES in 2014 and 2015 TO DATE

Utility	Order Date	Company Requested ($ millions)	Commission Authorized ($ millions)
ARIZONA			
Arizona Public Service Co.	12/18/14	65.4	57.1
CALIFORNIA			
Pacific Gas and Electric Co.	08/14/14	713.0	196.0
COLORADO			
Black Hills Colorado Electric	12/18/14	13.2	9.2
Public Service Company of Colorado*	02/24/15	28.5	-39.4
CONNECTICUT			
Connecticut Light & Power Co.	12/17/14	221.1	134.1
DELAWARE			
Delaware Power & Light Co.*	04/02/14	39.0	15.1
DISTRICT OF COLUMBIA			
Potomac Electric Power Co.	11/12/14	4.7	4.7
Potomac Electric Power Co.*	03/26/14	44.8	23.4
FLORIDA			
Florida Public Utilities Co.	09/15/14	5.9	3.8
GEORGIA			
Georgia Power Co.	12/18/14	26.6	26.6
IDAHO			
Avista Corp.	09/18/14	NA	0.0
ILLINOIS			
Ameren Illinois *	12/10/14	201.3	200.6
Commonwealth Edison Co.*	12/10/14	270.0	232.8
MidAmerican Energy Co.*	11/06/14	20.9	16.4
IOWA			
MidAmerican Energy Co.*	02/28/14	266.2	263.6
KANSAS			
Kansas City Power & Light	07/17/14	11.5	11.5
LOUISIANA			
Entergy Louisiana LLC*	07/10/14	11.4	9.3
MAINE			
Central Maine Power Co.	07/29/14	41.4	24.3
Emera Maine	06/30/14	8.1	5.3
MARYLAND			
Baltimore Gas and Electric Co.	12/12/14	98.7	22.0
Potomac Electric Power Co.	07/02/14	37.4	8.8
MASSACHUSETTS			
Fitchburg Gas & Electric Light	05/30/14	6.9	5.6
MISSISSIPPI			
Entergy Mississippi Inc.	12/11/14	204.5	177.7
MONTANA			
Northwestern Corp.	09/25/14	121.0	116.9
NEVADA			
Nevada Power Co.*	10/09/14	37.8	0.0
NEW HAMPSHIRE			
Liberty Utilities Granite State	03/17/14	13.0	9.8
NEW JERSEY			
Atlantic City Electric Co.	08/20/14	61.7	19.0
Rockland Electric Co.	07/23/14	23.3	13.0
NEW MEXICO			
Southwestern Public Service Co.*	03/26/14	21.0	12.7
NEW YORK			
Consolidated Edison Co. of NY*	02/20/14	425.0	-76.2
NORTH DAKOTA			
Northern States Power Co.	02/26/14	14.9	9.0
OREGON			
Portland General Electric Co*.	12/04/14	110.6	44.3

Utility	Order Date	Company Requested ($ millions)	Commission Authorized ($ millions)
PENNSYLVANIA			
Duquesne Light Co.	04/23/14	76.3	48.0
SOUTH CAROLINA			
South Carolina Electric & Gas	09/24/14	70.0	66.2
TEXAS			
Entergy Texas Inc.*	05/16/14	38.6	18.5
Southwestern Public Service Co.*	12/18/14	76.9	37.0
UTAH			
PacifiCorp*	08/29/14	76.3	54.2
VERMONT			
Green Mountain Power Corp.	08/25/14	-0.2	-8.8
VIRGINIA			
Appalachian Power Co.	11/26/14	0.0	0.0
Virginia Electric & Power Co. (Rider BW)	07/08/14	57.2	41.1
Virginia Electric & Power Co. (Rider S)	03/14/14	39.2	-9.0
Virginia Electric & Power Co. (Rider B)	03/14/14	10.1	3.3
Virginia Electric & Power Co. (Rider W)	02/28/14	39.6	14.8
WASHINGTON			
Avista Corp.*	11/25/14	18.2	7.0
WEST VIRGINIA			
Monongahela Power Co.	02/04/15	212.6	124.3
WISCONSIN			
Madison Gas and Electric Co.	11/26/14	11.5	15.4
Northern States Power Co.	12/12/14	20.6	14.2
Wisconsin Electric Power Co.*	11/14/14	78.5	15.4
Wisconsin Power and Light Co.	06/06/14	0.0	0.0
Wisconsin Public Service Corp.*	11/06/14	76.8	24.6
WYOMING			
Cheyenne Light Fuel Power Co.*	07/31/14	12.8	8.4
PacifiCorp*	01/23/15	32.6	20.2

*** BAI involvement**

Includes 2015 electric cases authorized through March 2, 2015

Sources: SNL Financial, Regulatory Research Associates and state regulatory commissions.

PENDING
RETAIL ELECTRIC RATE CASES

Utility	Filing Date	Company Requested Rate Increase ($ millions)
CALIFORNIA		
Southern California Edison Co.	11/12/13	34.4
HAWAII		
Hawaiian Electric Co.	06/27/14	0.0
Maui Electric Co. Ltd.	12/30/14	0.0
INDIANA		
Indianapolis Power & Light Co.*	12/29/14	67.8
KANSAS		
Kansas City Power & Light Co.*	01/02/15	56.3
KENTUCKY		
Kentucky Power Co.	12/23/14	-4.7
Kentucky Utilities Co.	11/26/14	153.4
Louisville Gas & Electric Co.	11/26/14	30.3
MICHIGAN		
Consumers Energy Co.*	12/05/14	162.7
DTE Electric Co.*	12/19/14	370.4
Wisconsin Public Service Corp.	10/17/14	5.7
MINNESOTA		
Northern States Power Co. – MN	11/04/13	248.1
MISSISSIPPI		
Entergy Mississippi Inc.	See Notes	NA
Mississippi Power Co.	See Notes	NA
MISSOURI		
Empire District Electric Co.*	08/29/14	24.3
Kansas City Power & Light *	10/30/14	120.9
Union Electric Co.*	07/03/14	264.1
NEW JERSEY		
Jersey Central Power & Light Co.	11/30/12	11.0
NEW MEXICO		
Public Service Co. of New Mexico*	12/11/14	107.4

Utility	Filing Date	Company Requested Rate Increase ($ millions)
NEW YORK		
Central Hudson Gas & Electric	07/25/14	40.1
Consolidated Edison Co. of NY*	01/30/15	368.1
Orange & Rockland Utilities Inc.	11/14/14	33.4
OKLAHOMA		
Public Service Co. of Oklahoma	01/17/14	37.7
OREGON		
Portland General Electric Co.*	02/12/15	122.3
PENNSYLVANIA		
Metropolitan Edison Co.	08/04/14	151.9
Pennsylvania Electric Co.	08/04/14	119.8
Pennsylvania Power Co.	08/04/14	28.5
West Penn Power Co.	08/04/14	115.5
SOUTH DAKOTA		
Black Hills Power Inc.	03/31/14	14.6
Northern States Power Co.	06/23/14	24.6
NorthWestern Corp.	12/19/14	26.5
TEXAS		
Southwestern Public Service Co.*	12/08/14	64.7
VIRGINIA		
Virginia Electric & Power Co. (Rider B)	06/16/14	-2.2
Virginia Electric & Power Co. (Rider R)	06/16/14	13.5
Virginia Electric & Power Co. (Rider S)	06/16/14	5.8
WASHINGTON		
Avista Corp.*	02/09/15	33.2
PacifiCorp*	05/01/14	27.2
WEST VIRGINIA		
Appalachian Power Co.	06/30/14	226.1

BAI involvement
Includes 2015 electric pending cases as of March 2, 2015.

Notes: Entergy Mississippi (Docket 2012-AD-302) and Mississippi Power (Docket 2012-AD-303) involve the investigation and review of current methods used to calculate return on equity in formula rate plans.

Sources: SNL Financial, Regulatory Research Associates and various state regulatory commissions.

ELECTRIC RETAIL INDUSTRIAL CUSTOMER SHOPPING

The tables below summarize the percent of industrial users who receive their electric supply competitively. Figures for Texas industrials are not publicly available, however published reports show Texas as the retail customer choice leader. Industrials in states such as Illinois, New York, New Jersey and Pennsylvania continue to report high competitive choice switching.

STATES WITH FULL CUSTOMER CHOICE

STATE	PERCENT	STATE	PERCENT	STATE	PERCENT
CONNECTICUT		**MASSACHUSETTS**		**OHIO**	
Connecticut Light & Power	N/A	National Grid	76.8%	AEP-Ohio	50.9%
United Illuminating	N/A	NStar	70.2%	Cleveland Electric	77.3%
DELAWARE		Northeast Utilities	84.5%	Dayton Power & Light	73.7%
Delmarva Power & Light	31.7%	UNITIL	80.8%	Duke Energy	68.8%
DISTRICT OF COLUMBIA		**NEW HAMPSHIRE**	N/A	Ohio Edison	76.6%
Potomac Electric Power Co.	33.5%	**NEW JERSEY** (>1,000 kW)		Toledo Edison	85.7%
ILLINOIS		Atlantic City Electric	88.3%	**PENNSYLVANIA**	
Ameren IL (1MW or Greater)		Jersey Central Power & Light	80.9%	Duquesne Light	64.4%
Rate Zone I	85.9%	Public Service Electric & Gas	85.9%	MetEd	86.0%
Rate Zone II	91.7%	Rockland Electric	100.0%	PECO Energy	90.2%
Rate Zone III	88.9%	**NEW YORK** (NonRes LG-TOU)		Penelec	83.2%
ComEd 400 kW & Above	90.1%	Central Hudson	62.7%	Penn Power	96.2%
MAINE (Statewide)	86.4%	Con Edison	90.1%	PPL	89.3%
MARYLAND (Large C&I)		New York State Electric & Gas	70.6%	UGI	37.3%
Baltimore Gas & Electric	93.3%	Niagara Mohawk	78.8%	West Penn Power	88.1%
Delmarva Power & Light	92.3%	Orange & Rockland	27.4%		
Potomac Edison	87.3%	Rochester Gas & Electric	93.3%	**RHODE ISLAND**	
Potomac Electric Power Co.	88.3%			National Grid	N/A
				TEXAS	N/A

STATES WITH LIMITED CHOICE

STATE	PERCENT
CALIFORNIA	22.5%
(All IOU Industrials >500 kW)	
MICHIGAN	
Consumers Energy	10% CAP
Detroit Edison	10% CAP
MONTANA	N/A
NEVADA	N/A
OREGON	
Pacific Power & Light	1.4%
Portland General	14.4%
VIRGINIA	N/A
WASHINGTON	N/A

Notes:
Above figures are based on data provided by various state regulatory commission websites.
Data not available for Connecticut, Montana, New Hampshire, Nevada, Rhode Island, Texas, Virginia and Washington

BAI DOES THAT*?*

By Bob Stephens, Principal

If you've worked with BAI in the past, you may know us for our participation in standard utility rate cases or assistance in energy procurement for clients. This is certainly true. In rate cases, we often testify on the utilities' need for additional revenue, class cost of service and customer rate design. In energy procurement, we assist clients in determining their expected needs and risk tolerance going forward solicit and evaluate energy supply offers and assist with contract negotiation and execution. For some, we monitor their costs and exposures on an ongoing basis and recommend strategic purchases, as appropriate. But you may not know that we actually are involved in a much wider variety of projects for our clients. We outline a few of these below:

Other Regulatory Cases

In addition to standard rate cases, BAI participates in a number of other cases before state commissions and the Federal Energy Regulatory Commission ("FERC").

Securitization

An example of an outside-the-normal regulatory issue is securitization cases. Securitization is a financing mechanism that allows a utility to retire certain of its outstanding indebtedness in conjunction with a regulatory or legislative assurance of payment. This allows for an attractive interest rate. For example, the Michigan Public Service Commission on December 6, 2013 issued an order authorizing Consumers Energy the recovery of the remaining book value of several generating units through securitization. Consumers Energy will issue the securitization bond(s) to recover the remaining book value of $361 million. The use of a securitization bond can reduce costs to customers, because the average interest rate will be below 3%, as compared to something over 9% that the utility would have sought for using utility investor capital. However, complicating issues that must be worked out include changes to amortization periods and deferred tax balance treatment.

Electric Transmission Lines

Another area in which BAI is involved is in transmission line certification and routing cases. Utilities generally must seek commission approval before investing in major new transmission lines, especially if they intend to be able to exercise eminent domain, if necessary, in order to acquire the necessary right-of-way easements from landowners. These cases can be highly contentious, as affected landowners may object to the proposed routing, and/or the utility's consideration of alternative options. In addition, on occasion the proposed line may not be necessary in that it is not the lowest reasonable cost alternative to the issue that needs to be addressed. BAI has assisted clients in these cases in determining whether the new line is needed, if the proposed line is the best solution to address the issue that is being proposed to be addressed by the proposed line and whether the proposed route for the line has the least aggregate adverse impact to landowners and the public of the alternative routes that are available for the line. We utilize state of the art transmission planning and Geographic Information System (GIS) software programs to analyze these issues and we sponsor testimony with respect to these issues.

Generation Certificate Cases

Compliance with environmental regulations and the aging of current generating resources will cause utilities to invest billions of dollars in new generation, with significant impacts on customers' utility costs. Utilities must seek Commission approval prior to investing in the construction or purchase of such generation assets. In order for a Commission to grant approval, a utility must demonstrate that the proposed generation asset(s) are the lowest cost reasonable resource that will meet the reliability standards and provide safe and adequate electric service to its customers. Typical generation assets have operating lives between 30-60 years and their costs will affect rates for many years. BAI has assisted clients in several recent cases in determining whether the proposed generation asset(s) are needed, and if the generation asset(s) are the best solution to the utility's identified need at the lowest cost impact to its customers, considering the full range of potential future scenarios. We have used a variety of proprietary capacity expansion, production cost and power flow software models, as well as internally developed economic models to analyze and support testimony addressing these issues. Our participation in these cases has resulted in large savings and desired results for our clients.

Integrated Resource Planning

BAI consultants often participate in cases where utilities present their evaluations of projected load growth, demand-side management cost and performance, economics and suitability of multiple generation resource choices and reserve requirements.

Legislative Analysis and Advocacy

Increasingly, utilities are going to their state legislatures to propose changes in laws that would give them the right to charge customers for increased costs outside of rate cases. BAI provides support to utilities' customers by preparing impact analyses of proposed legislation, briefing papers, and customized issue analysis. We also appear before legislative committees and present testimony that explains why the proposed legislation is not needed, should be modified, or eliminated.

Other Client Consultation

A considerable portion of our work is with individual clients, advising them on energy matters that help manage their bottom line energy costs.

Natural Gas Bypass

An issue that we have recently worked on for several clients is natural gas bypass. As aging pipelines of natural gas local distribution companies ("LDC") are replaced over the next several years, these replacements could significantly impact LDC rates. The cost of LDCs' main replacement programs, coupled with Commissions' approval of main cost allocators that have a large volumetric component could contribute to large increases in industrial customer transportation rates. As a result of these increases, LDC delivery rates, large customers should be aware of how the cost of bypassing the LDC system altogether compares with their incumbent utility's tariff transportation rates. Bypass could be a viable option to utility tariff service, offering cost savings and potentially more delivery flexibility of customer-owned gas as compared to utility delivery service. Customers with special contracts expiring in the near term also may want to consider bypass studies of their LDC systems. If bypass is a viable alternative, customers could use this as leverage in negotiations for renewed transportation contracts with their LDCs.

Energy Price Forecasts

Another way that BAI helps clients is with energy price forecasts. These forecasts are done in both regulated and non-regulated markets. Depending on the market structure, the supply portfolio involved and commodity in question, BAI can develop multi-contingency stochastic forecast and scenario analyses, using industry information and modeling tools that we have either developed or licensed. Shorter term forecasts tend to rely more on existing utility portfolios and near-term projected fuel costs, while longer term forecasting can also involve projecting the need for utility expansion and estimating the timing, cost, and future operational capabilities of the generating units.

Renewable Energy

In the renewable energy and environmental field, BAI has assisted customers in determining their carbon footprints, both for corporate environmental policy reasons and for risk assessment under potential environmental legislation. We have also worked with alternative energy providers to help them understand the utility markets in which they seek to operate and the costs of power against which they would need to compete.

Cogeneration

BAI works with clients to evaluate the potential economics of cogeneration facilities, as compared to alternatives. This often involves the analysis of standby rates and the selection of the proper amounts of standby power and supplemental power. Also, the facility may generate more electricity in some hours than is needed by the facility. In such cases, we help the customer determine the best contracting and negotiation strategy to accommodate that surplus.

Moreover, we have assisted clients with application, study and the negotiation process associated with establishing parallel operation and transmission interconnection agreements for new and existing cogeneration facilities.

Conclusion

These are a few examples of the kinds of analyses that BAI conducts for our clients that are beyond the traditional rate case or electricity procurement matters for which you have known us. If you have projects that require expertise in the energy field, there is a good chance we may have done similar work before, and we would welcome the opportunity to discuss our capabilities and how we might assist you.

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