



BAI

HELPING YOU ACHIEVE YOUR ENERGY GOALS

ENERGY Update

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BAI 2010 Annual Spring Conference, May 4-5, 2010 -- For details contact Tammy Klossner (636) 898-6725

FEATURED COMMENTARY

GREENHOUSE GAS REGULATIONS

By Brian Janous, Senior Consultant

There has been significant attention lately on the issue of climate change and the government's efforts to establish a cap-and-trade mechanism in order to reduce greenhouse gas (GHG) emissions. Much of this focus has been on the broad economic impact that would result from setting a price on the right to emit GHGs. There is certainly no consensus yet regarding how any eventual regulation will be implemented (the Senate is presently debating key issues in Committee). However, we hope to provide some insight regarding how a cap-and-trade market would work, and who would be most affected.

A review of cap-and-trade

Cap-and-trade is a market-based approach to reducing GHGs that would assign a cost to emissions in order to encourage investment in emissions reduction technologies (e.g. renewable generation, carbon capture, coal gasification, etc.) or emissions offset projects (e.g. reforestation). The government would establish a declining cap on GHG emissions. Entities would be permitted to emit GHGs to the extent that they hold allowances that match their emissions. An allowance would give the bearer the right to emit 1 metric ton of GHG. These allowances

would be initially auctioned by the government, but could later be traded among emitters in secondary markets. GHGs are a category of gases that are suspected of contributing to global warming and include carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and sulfur hexafluoride (SF₆) along with other fluorinated gases. By way of reference, a typical 500 MW coal-fired generating plant without GHG abatement emits 3.5-4 million metric tons of GHG per year.

Emitters that are subject to the regulations (i.e., those that emit greater than 25,000 metric tons of GHGs per year, which is the equivalent of using 18,000 MWh at the average U.S. emissions rate) would be required to purchase allowances equal to their annual emissions. Alternatively, an emitter could invest in emissions-abatement opportunities, either for its own process or elsewhere, if such

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alternatives would be less costly than purchasing allowances. While the current versions of legislation allow for the use of offsets to meet the compliance requirements, there are limits placed on the number of offsets that can be used in a given year.

Who would be most affected?

Only large, direct emitters of GHG would be subject to the requirement to purchase allowances. This includes electricity generators, industrial customers with significant combustion and/or process emissions, and refineries. These are considered to be direct GHG costs. The cost impact would be felt throughout the entire economy, through higher product costs and in the form of higher electricity costs. The cost associated with electricity generators' compliance would be reflected in higher electricity rates to all consumers (indirect GHG costs).

Though much of the burden associated with GHG regulation would fall on electricity generators, many generation owners in integrated utilities support a cap-and-trade regime. In regulated markets, generation owners would have the opportunity to fully recover these compliance costs in the form of higher rates. In deregulated markets, generators would recover the compliance costs through higher offer prices in spot and forward power markets. The market clearing price would likely increase to recover

The potential impact of GHG regulations should be factored in to any strategic planning regarding facility siting or expansion as the cost advantage of current low-cost regions could be significantly eroded.

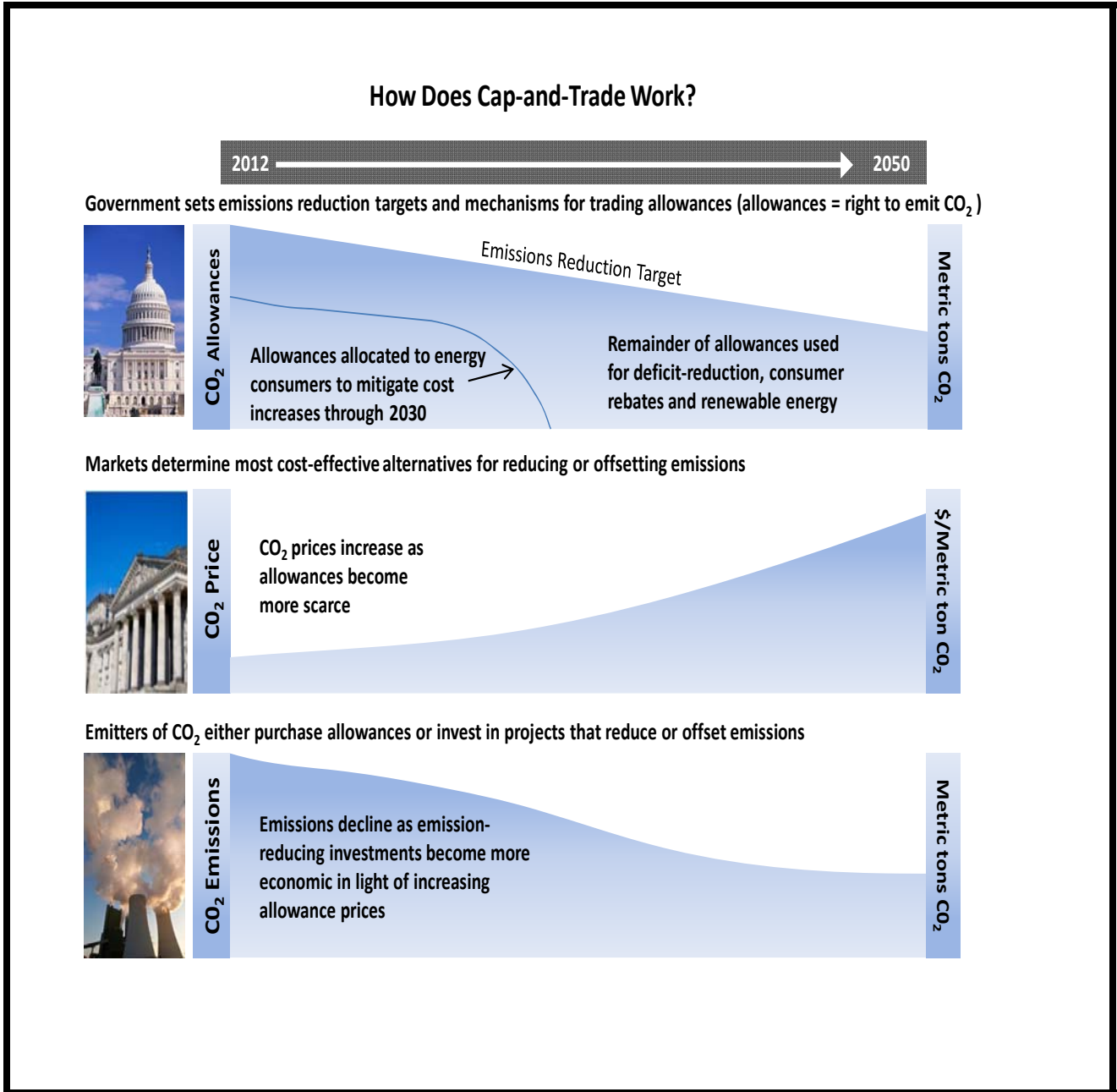
the compliance cost. As a result, low-carbon generation sources such as nuclear would benefit by higher market prices and would likely recover revenues well in excess of their cost of compliance. In either case, the cost of compliance ultimately would be borne by the consumer.

Recognizing that the cost burden will be absorbed by consumers, and particularly those consumers in regions that depend most heavily on coal-fired generation, there is a provision in both the House and Senate versions of the bill that would provide an allocation of allowances in the early years of the program that would temporarily offset the cost increases to a large degree. This allocation of allowances is one of the more contentious aspects of the legislation, as it determines how billions of dollars will be spread among consumers in every state. Regions of the country that are more dependent upon coal-fired generation could shoulder as much as five times the compliance cost as regions that have a greater supply of hydro or nuclear generation. Therefore, the potential impact of GHG regulations should be factored in to any strategic planning regarding facility siting or expansion, as the cost advantage of current low-cost regions could be significantly eroded.

Another contentious aspect of the bill is how the benefit that utilities derive from these allowances would be allocated to retail customers. The legislation proposes to allocate the benefit of these allowances on a "fixed portion" of the customer's bill. Consequently, high-load factor customers would be disadvantaged relative to lower-load factor customers because they would be allocated a greater share of the cost (which would be incurred based upon energy consumption), but a smaller portion of the allowance benefit (which may be allocated on a per-customer basis). While there is language in the legislation that attempts to correct this misallocation issue, at least for industrial customers, in our opinion the language is not sufficient to ensure that large users would receive the full benefit of these allocations.

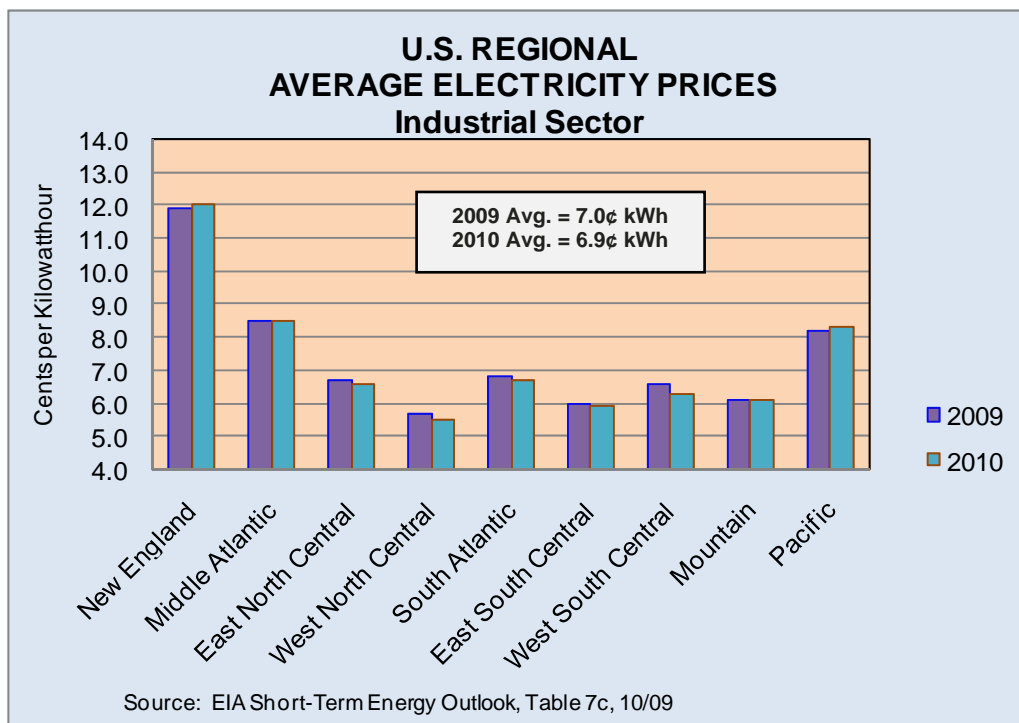
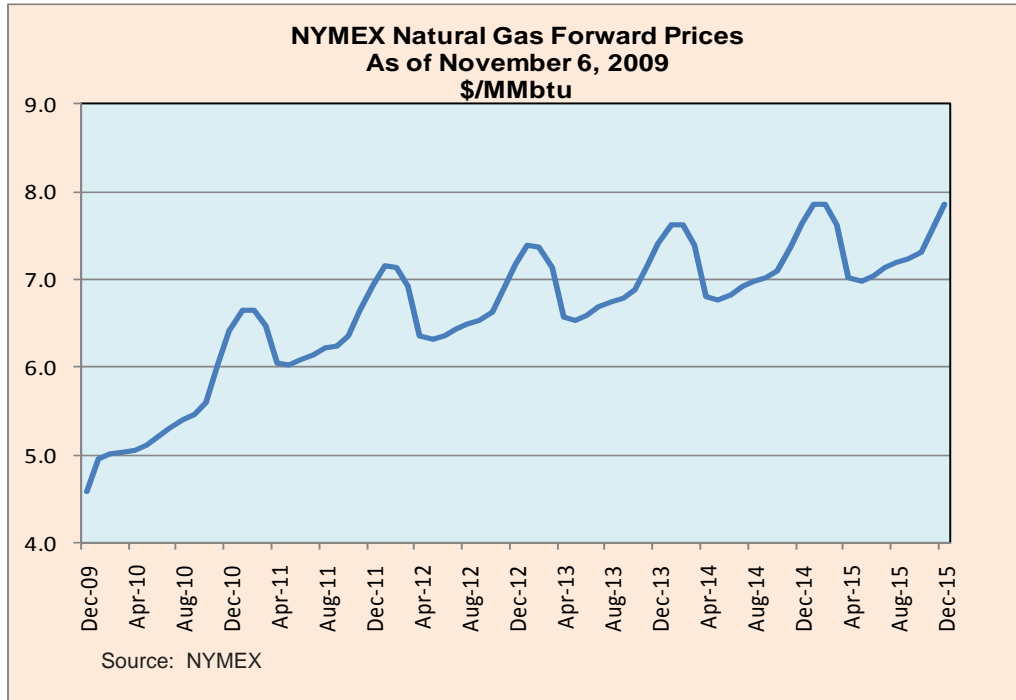
The intent of this legislation is to increase the cost of GHG emitting processes in order to encourage reductions in GHGs over time. The current versions of this bill would result in a cost impact that is greater for certain regions of the country with high GHG emissions, such as the Midwest. Given the makeup of representation in the Senate, without some consideration given to coal-based states, there likely will not be sufficient votes to pass comprehensive climate legislation. We will see over the coming months whether legislation can be crafted that will appeal to the environmental lobby as well as to the manufacturing and energy interests, while garnering votes that will be needed to pass the Senate.

If your company is concerned about the potential impact of this legislation, please contact us to discuss how BAI can assist with carbon footprint assessment, GHG cost impact analyses and the development of mitigation strategies.



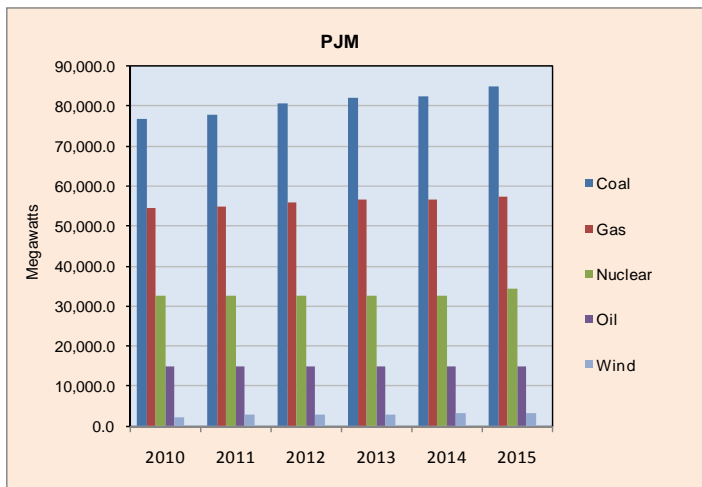
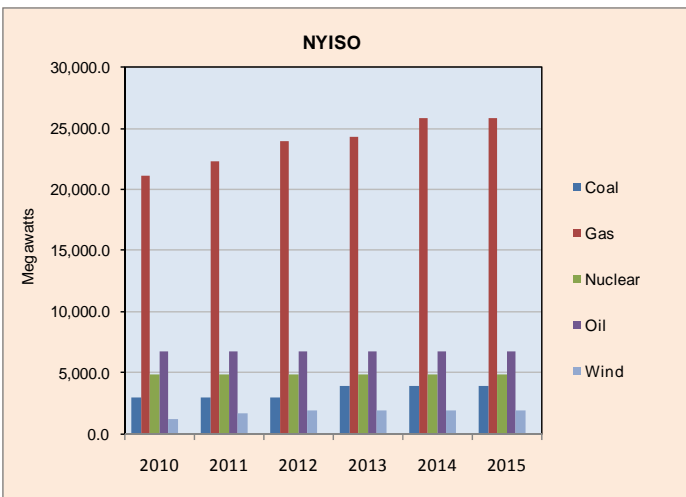
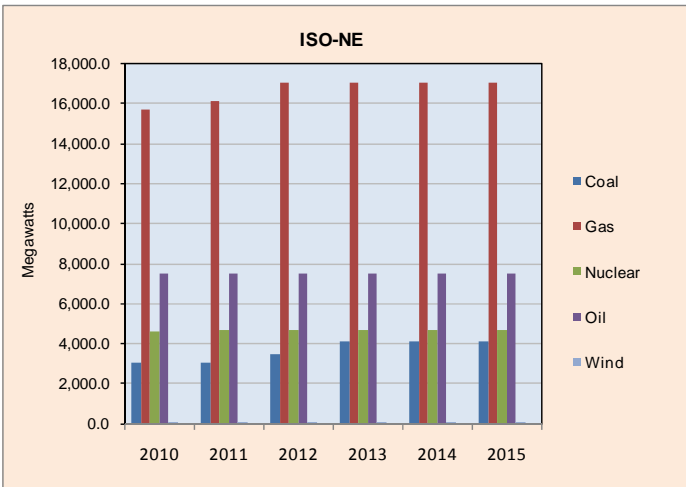
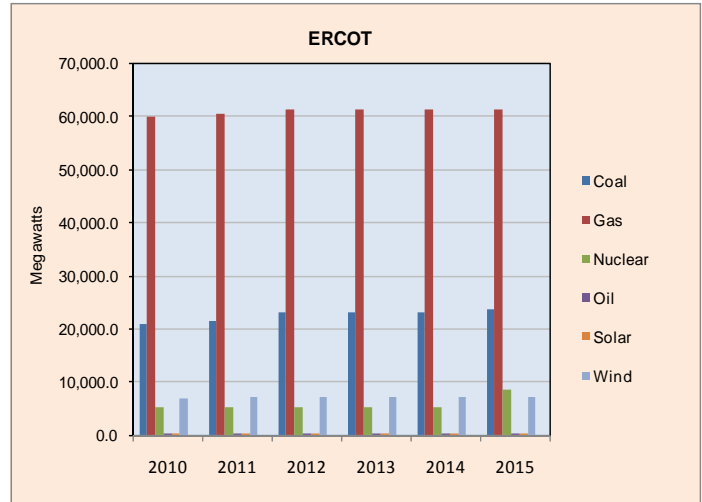
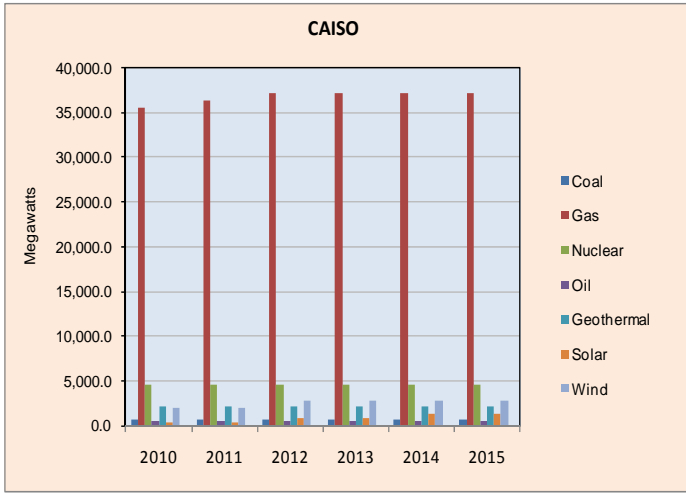
FORECASTED NATURAL GAS AND ELECTRICITY PRICES

NYMEX natural gas forward prices are predicted to increase throughout 2010 then decrease slightly in the first quarter of 2011. Prices are anticipated to remain in the \$6 to \$7 range through 2015. EIA projects industrial electricity prices to average 6.9¢ per kWh during 2010 with expected growth in electricity industrial sales to be approximately 1.1%.



FUTURE RTO CAPACITY

A review of forecasted installed capacity, over the next six years, reveals coal will continue to be the leading fuel in the MISO and PJM regions. Gas will continue to be the dominant fuel for the CAISO, ERCOT, ISO-NE and NYISO regions.



Source: SNL Financial, Inc.

BEWARE OF SMART GRID COST RECOVERY PROPOSALS

By Bob Stephens, Principal

Utilities in many states are pursuing technologies that fall within the umbrella term "Smart Grid." Utilities are lumping largely unrelated technologies, both existing and emerging, into the category of Smart Grid. One Electric Power Research Institute (EPRI) commenter distills Smart Grid technologies into the following four categories: the transmission grid, advanced metering infrastructure, distributed generation and customer engagement. The US DOE recently awarded over \$3 billion in stimulus funds to utilities and other entities to invest in Smart Grid technologies. With or without stimulus funding, utilities in many states are beginning to implement Smart Grid measures, either through regulatory mandate or on their own initiative.

If the Smart Grid technologies and applications currently contemplated are fully realized, it will increase utility plant investment by many billions of dollars. Proponents claim that these investments will lead to better utilization of the generation and delivery systems, enhanced grid security and reliability, facilitation of renewable energy and distributed generation resources, and other benefits. Skeptics question whether the projected benefits are realistic and whether the beneficial impact is likely to outweigh the costs to customers and society. Indeed, some question whether the contemplated enhancements in services and reliability exceed the standard definitions of basic electric service and whether the new technologies are necessary for regulated electric utility service.

These types of questions inevitably lead to discussion and dispute as to the cost recovery mechanisms for utilities' investments in Smart Grid technologies. BAI has been involved on behalf of large customers in numerous proceedings where utility cost recovery mechanisms are being proposed and analyzed. The common goal in these cases is to seek cost recovery from the customer classes for which the investments are being made and who receive benefits from the service enhancements. In some cases, utilities are seeking recovery mechanisms that would recover a disproportionate share of the costs from large, energy intensive industries, particularly those who take service at transmission voltage.

Most of the Smart Grid technologies discussed to date are either geared toward customer groups other than industrials, lower voltage parts of the delivery system, or are already being recovered through other means. For example, advanced metering infrastructure, once deployed, would allow interested customers to monitor their energy usage on a near real-time basis and receive information about the market price of power on a comparable basis. In theory, this will allow residential and small commercial customers to take measures to use energy more efficiently and reduce their energy bills.

Industrial customers, of course, have engaged in this type of activity for years, using equipment and technology they paid for themselves. Consequently, the incremental benefit of wide scale deployment of advanced metering infrastructure is likely very small, or non-existent, for industrial customers.

Similarly, technologies that enhance the deployment of distributed generation benefit most directly those customers who wish to install distributed generation resources and have been unable to do so. Large industries who have already installed distributed generation or cogeneration facilities, based on their own merits, have already overcome such barriers to their deployment and have already been providing much of the types of benefits contemplated under a Smart Grid regime. Finally, many of the technologies that will enhance the reliability of the distribution system are deployed on lower voltage parts of the distribution system, e.g., 12 kV and below. Customers who take service at voltages above these levels receive little, if any, direct benefit from such technologies.

Consequently, it is important for industrial customers to be engaged in utility regulatory filings related to the implementation and cost recovery of Smart Grid projects, in order to help shape the regulatory policies, including cost recovery. Recently, BAI testified on behalf of industrial customers in a case where the utility proposed to recover its Smart Grid costs (which consisted primarily of the cost of "smart meters") through an equal per kWh usage charge, applicable to all customer classes. This recovery approach does not follow cost causation and would have unjustly imposed millions of dollars of cost burden on the large energy users. The industrial group was successful in explaining the inequity of that approach, which resulted in the utility modifying its proposal, to seek cost recovery on an equal percentage of revenues basis. However, even this improved approach would still recover a disproportionately large part of the cost from customers who receive very little, if any, benefit from the meters, and cause little of the costs to be incurred. In its decision, the commission adopted the position of the industrial customers, to recover the program costs on the basis of an allocated meter charge. This is more in line with traditional cost recovery principles and greatly reduced the proposed cost burden on the industrial customers in that state.

BAI believes that these types of issues will be prevalent over the next several years, as states and utilities wrestle with questions about how, and to what degree, Smart Grid investments should be pursued. Industrial customers need to be diligent to ensure that they are only required to pay for their fair share of the associated costs, and not overpay for systems and technologies which they have already procured for their own use, or which provide little direct benefit to them.

2009 RETAIL ELECTRIC RATE CASE OVERVIEW

AS OF NOVEMBER 1, 2009

DECISIONS

| Utility | Order Date | Authorized Amount (\$ millions) | Allowed ROE % |
|--|------------|---------------------------------|---------------|
| ARKANSAS | | | |
| Oklahoma Gas & Electric | 05/20/09 | \$13.3 | 10.25% |
| CALIFORNIA | | | |
| Southern California Edison | 03/17/09 | \$308.1 | 11.50% |
| COLORADO | | | |
| Public Service Co. of Colorado | 06/09/09 | \$112.2 | 10.5% |
| CONNECTICUT | | | |
| United Illuminating ¹ | 02/04/09 | \$6.1 | 8.75% |
| FLORIDA | | | |
| Tampa Electric | 04/30/09 | \$147.7 | 11.25% |
| IDAHO | | | |
| Avista Corp. | 07/17/09 | \$12.5 | 10.50% |
| Idaho Power Co. | 05/29/09 | \$10.5 | 10.50% |
| Idaho Power Co. | 01/30/09 | \$27.0 | 10.50% |
| PacifiCorp | 4/16/2009 | \$4.4 | NA |
| INDIANA | | | |
| Indiana Michigan Power | 03/04/09 | \$19.1 | 10.50% |
| KANSAS | | | |
| Kansas City Power & Light Co. | 06/24/09 | \$59.0 | NA |
| Westar Energy and Kansas Gas & Electric ² | 01/21/09 | \$130.0 | 10.40% |
| KENTUCKY | | | |
| Kentucky Utilities | 02/05/09 | (\$8.9) | NA |
| Louisville Gas & Electric | 02/05/09 | (\$13.2) | NA |
| LOUISIANA | | | |
| Entergy New Orleans | 04/02/09 | (\$24.7) | 11.10% |
| MINNESOTA | | | |
| Minnesota Power | 04/03/09 | \$21.1 | 10.74% |
| Northern States Power Co. | 09/29/09 | \$91.4 | 10.88% |
| MISSOURI | | | |
| AmerenUE | 02/10/09 | \$161.7 | 10.76% |
| Kansas City Power & Light - MPS | 06/10/09 | \$48.0 | NA |
| Kansas City Power & Light - L&P | 06/10/09 | \$15.0 | NA |
| Kansas City Power & Light | 06/10/09 | \$95.0 | NA |
| NEVADA | | | |
| Nevada Power | 06/24/09 | \$222.7 | 10.80% |
| NEW MEXICO | | | |
| Public Service Co. of New Mexico | 05/28/09 | \$77.1 | 10.50% |
| Southwestern Public Service Co. | 07/14/09 | \$14.2 | NA |
| NEW YORK | | | |
| Central Hudson Gas & Electric | 06/18/09 | \$39.6 | 10.00% |
| Consolidated Edison Co. of NY | 04/21/09 | \$523.4 | 10.00% |
| OHIO | | | |
| Cleveland Electric Illuminating | 01/21/09 | \$29.2 | 10.50% |
| Duke Energy Ohio Inc. | 07/08/09 | \$55.3 | 10.63% |
| Ohio Edison | 01/21/09 | \$68.8 | 10.50% |
| Toledo Edison | 01/21/09 | \$38.5 | 10.50% |
| OKLAHOMA | | | |
| Oklahoma Gas & Electric | 07/24/09 | \$48.3 | NA |
| Public Service Oklahoma | 01/14/09 | \$59.3 | 10.50% |
| TEXAS | | | |
| Entergy Texas | 03/11/09 | \$30.5 | NA |
| Oncor Electric Delivery Co. | 08/13/09 | \$115.1 | 10.25% |
| Southwestern Public Service Co. | 05/22/09 | \$57.4 | NA |
| Texas-New Mexico Power Co. | 08/13/09 | \$12.7 | NA |
| UTAH | | | |
| PacifiCorp | 04/21/09 | \$45.0 | 10.61% |
| WYOMING | | | |
| PacifiCorp | 05/20/09 | \$18.0 | 10.25% |
| | | ROE Average | 10.51% |

¹Represents a distribution increase.

²Both utilities were allowed \$65M.

Note: The above cases represent various electric rate cases filed before state regulatory agencies throughout the U.S.

Sources: SNL Financial, EEI and various State Public Service Commissions

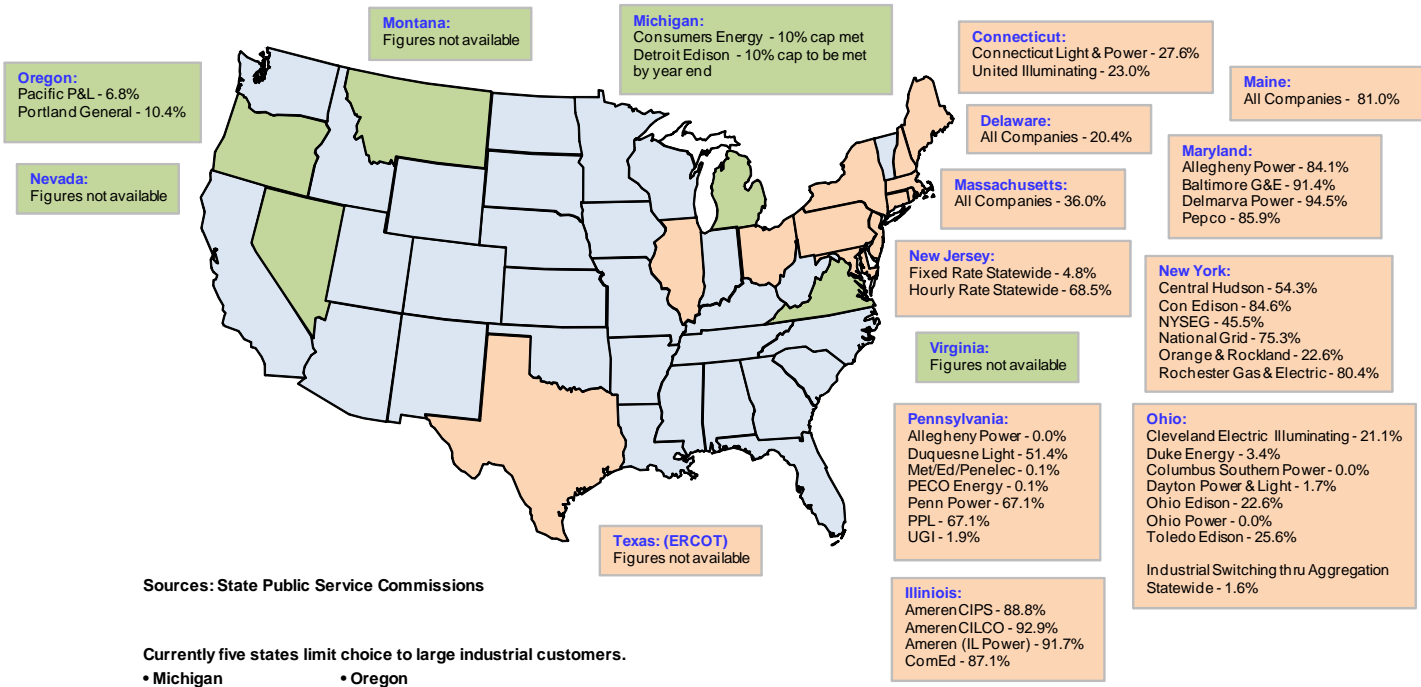
PENDING CASES

| Utility | Company | Filing Date | Requested Rate Increase (\$ millions) |
|-----------------------------|-------------------------------------|-------------|---------------------------------------|
| ARKANSAS | | | |
| | Entergy Arkansas Inc. | 9/4/2009 | \$223.2 |
| | Southwestern Electric Power Co. | 2/19/2009 | \$25.3 |
| ARIZONA | Arizona Public Service Co. | 3/24/2008 | \$448.2 |
| CALIFORNIA | Pacific Gas and Electric Co. | NA | \$844.0 |
| COLORADO | Public Service Co. of Colorado | 5/1/2009 | \$288.3 |
| DISTRICT OF COLUMBIA | Potomac Electric Power Co. | 5/22/2009 | \$51.7 |
| DELAWARE | Delmarva Power & Light Co. | 9/18/2009 | \$27.6 |
| FLORIDA | | | |
| | Florida Power & Light Co. | 3/18/2009 | \$1,044.0 |
| | Florida Power Corp. | 3/20/2009 | \$500.0 |
| HAWAII | | | |
| | Hawaiian Electric Co. | 7/3/2008 | \$89.8 |
| | Maui Electric Company Ltd. | 9/30/2009 | \$28.2 |
| IOWA | Interstate Power & Light Co. | 3/17/2009 | \$146.7 |
| ILLINOIS | | | |
| | Central Illinois Light Co. | 6/5/2009 | \$27.8 |
| | Central Illinois Public Service Co. | 6/5/2009 | \$50.6 |
| | Illinois Power Co. | 6/5/2009 | \$102.3 |
| INDIANA | Northern Indiana Public Service Co. | 8/29/2008 | \$85.7 |
| KANSAS | | | |
| | Kansas Gas and Electric Co. | 6/2/2009 | \$10.0 |
| | Westar Energy Inc. | 6/2/2009 | \$9.7 |
| MASSACHUSETTS | Massachusetts Electric Co. | 5/15/2009 | \$111.3 |
| MARYLAND | Delmarva Power & Light Co. | 5/6/2009 | \$14.1 |
| MICHIGAN | | | |
| | Detroit Edison Co. | 1/26/2009 | \$377.7 |
| | Upper Peninsula Power Co. | 6/26/2009 | \$12.2 |
| | Wisconsin Electric Power Co. | 7/2/2009 | \$42.1 |
| MINNESOTA | Northern States Power Co. | 11/3/2008 | \$135.8 |
| MISSOURI | | | |
| | AmerenUE | 7/24/2009 | \$401.5 |
| | Empire District Electric Co. | 10/29/2009 | \$68.2 |
| MONTANA | NorthWestern Energy Division | 10/16/2009 | \$15.5 |
| NORTH CAROLINA | Duke Energy Carolinas LLC | 6/2/2009 | \$481.7 |
| NORTH DAKOTA | Otter Tail Corp. | 11/3/2008 | \$6.1 |
| NEW HAMPSHIRE | Public Service Co. of New Hampshire | 6/30/2009 | \$68.2 |
| NEW JERSEY | | | |
| | Atlantic City Electric Co. | 8/14/2009 | \$55.2 |
| | Public Service Electric and Gas Co. | 5/29/2009 | \$133.7 |
| | Rockland Electric Co. | 8/14/2009 | \$9.8 |
| NEW MEXICO | El Paso Electric Co. | 5/29/2009 | \$12.7 |
| NEW YORK | | | |
| | Central Hudson G&E Co. | 7/31/2009 | \$15.2 |
| | Consolidated Edison Co. of NY | 5/8/2009 | \$853.0 |
| | NY State Electric & Gas Corp. | 9/17/2009 | \$169.7 |
| | Rochester Gas & Electric Corp. | 9/17/2009 | \$87.4 |
| OREGON | | | |
| | Idaho Power Co. | 7/31/2009 | \$7.3 |
| | PacifiCorp | 4/3/2009 | \$92.1 |
| RHODE ISLAND | Narragansett Electric Co. | 6/1/2009 | \$75.3 |
| SOUTH CAROLINA | Duke Energy Carolinas LLC | 7/27/2009 | \$132.9 |
| SOUTH DAKOTA | | | |
| | Black Hills Power Inc. | 9/29/2009 | \$32.0 |
| | Northern States Power Co. | 6/30/2009 | \$18.6 |
| TEXAS | Southwestern Electric Power Co. | 8/28/2009 | \$81.9 |
| UTAH | PacifiCorp | 6/23/2009 | \$66.9 |
| VIRGINIA | | | |
| | Appalachian Power Co. | 7/15/2009 | \$154.0 |
| | Kentucky Utilities Co. | 6/3/2009 | \$12.2 |
| | Virginia Electric & Power Co. | 3/31/2009 | \$250.2 |
| WASHINGTON | | | |
| | Avista Corp. | 1/23/2009 | \$69.8 |
| | PacifiCorp | 2/9/2009 | \$38.5 |
| | Puget Sound Energy Inc. | 5/8/2009 | \$148.1 |
| WISCONSIN | | | |
| | Madison Gas and Electric Co. | 4/29/2009 | \$16.0 |
| | Northern States Power Co. | 6/1/2009 | \$30.4 |
| | Wisconsin Electric Power Co. | 3/13/2009 | \$126.6 |
| | Wisconsin Power and Light Co. | 5/8/2009 | \$85.5 |
| WEST VIRGINIA | Monongahela Power Co. | 8/13/2009 | \$122.1 |
| WYOMING | | | |
| | MDU Resources Group Inc. | 8/14/2009 | \$6.2 |
| | PacifiCorp | 10/2/2009 | \$62.0 |

Sources: SNL Financial, EEI and various State Public Service Commissions

INDUSTRIAL POWER SHOPPING

Large industrial customers in deregulated states continue to select competitive supply. The current switching percentages for these industrials, as reported by State Commissions, are listed below.



Sources: State Public Service Commissions

Currently five states limit choice to large industrial customers.

- Michigan
- Montana
- Nevada
- Oregon
- Virginia

“BAI Energy Update” is a publication of Brubaker & Associates, Inc. (BAI). Please contact Bob Stephens (bstephens@consultbai.com) or Mary Zielinski (mzielinski@consultbai.com) with questions regarding this publication. BAI’s office phone number is (636) 898-6725.

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