Gas-electric harmonization is a suite of challenges facing the nation as we move toward a much higher natural gas fuel portfolio for electric generation. Although that move is being accelerated due to environmental regulations, the natural gas and electric industries are not compatible. Ignoring these challenges will result in serious threats to the nation’s electric grid reliability.

Gas-Electric Harmonization
An AEP Perspective
Gas-Electric Harmonization: 
An AEP Perspective

Background

Gas-electric harmonization (GEH) is a term used to describe the growing need for the gas and power industries to increase their functional and physical integration. Although several factors are at the root cause for this need, one primary driver is the U.S. Environmental Protection Agency’s implementation of new Mercury and Air Toxics Standards (MATS rules), resulting in a significant portion of the nation’s coal-fueled electric generation units being retired by mid-2015. The EPA’s recent Clean Power Plan, which calls upon states to set individual carbon constraint goals, will result in additional coal plant retirements although its impact is still undefined.

American Electric Power (AEP) is one of the largest electric utilities in the United States, delivering electricity to more than 5.3 million customers in 11 states. AEP ranks among the nation’s largest generators of electricity, owning nearly 38,000 Megawatts (MW) of generating capacity. We will have retired 6,586 MW of coal-fired generation by the EPA MATS deadline next year.

Currently, PJM Interconnection, L.L.C. – the regional transmission organization that oversees a large portion of the nation’s electric grid from the Midwest to the Atlantic coast – has announced retirement of 13,000 MW of capacity by mid-2015, including the AEP
retirements. Its current total capacity is approximately 169,000 MW. Since 2007/08, 9,800 MWs of coal-fired generation has already been retired within PJM’s footprint.  

AEP believes strongly in the merits of fuel diversity to generate electricity. In 2002, AEP’s fuel mix was 78 percent coal. Today, coal-fueled power plants account for approximately 60 percent of AEP’s generating capacity, while natural gas represents 23 percent and nuclear 5 percent. The remaining capacity (12 percent) comes from wind, hydro, pumped storage and other sources, including energy efficiency. By 2026, we project that our coal-fueled generating capacity will drop to 45 percent, while natural gas capacity will increase to 33 percent.  

The North American Electric Reliability Corp. (NERC) indicates in its 2013 Long-Term Reliability Assessment that AEP’s transition is reflective of much of the nation’s generation fleet, as coal plays a continuously diminishing role due to Federal environmental regulations. NERC forecasts indicate a total net reduction in coal-fired generation of 35.1 gigawatts (GW) by 2023. Most of those retirements are between 2014 and 2016, pending

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2. AEP 2002 SEC Form 10-K, p. 14
3. http://www.aep.com/about/MajorBusinesses/PowerGeneration/
4. Ibid.
EPA regulations. NERC’s 2013 retirement projections are substantially higher than its 2012 forecasts.

NERC-Wide Cumulative Planned Capacity Change (2014-2023)

![Graph showing cumulative planned capacity change](image)

**Legend:**
- Coal
- Petroleum
- Gas
- Nuclear
- Hydro
- Pumped Storage
- Renewables (Non-Hydro)

Source: NERC 2013 *Long-Term Reliability Assessment*

While we support the concept of fuel diversity, AEP also is concerned about preserving grid reliability. How the nation moves toward this growth in gas-fired electric generation will determine whether the reliability we have delivered for the past 108 years can continue into the future.

With less than a year until the first massive wave of coal plant retirements, we have a great deal of work ahead of us to ensure the nation’s energy infrastructure can seamlessly absorb the changes. More new gas-fired electric plant construction should already have begun. We also have many steps to take before the nation’s gas pipelines and electric grid are ready to work in harmony in the drastically increased quantities we need. Three challenges hinder our ability to make this transition smoothly: infrastructure, markets and scheduling, and cost recovery.

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Challenge One: Infrastructure

For a number of reasons, the natural gas industry and the electric industry grew up completely independent of each other. As such, very little about the way they are structured – from markets to actual facilities – is aligned. Pipelines were constructed on behalf of natural gas local distribution companies (LDCs), which typically serve a fairly predictable heating load in the winter. Those pipelines are not built to serve the vastly different load profiles with rapid and dramatic load swings that accompany electric generation. To use pipeline contractual terms, the pipelines were built to serve ratable takes, as opposed to no-notice service.

Differing opinions are influencing the national dialogue on this issue. Does the nation have enough gas pipeline infrastructure to accommodate this dramatic growth in their load? Regional variations may yield multiple answers across the country. In many cases, scheduling changes could vastly improve our efficient use of existing pipelines without the need to build more.

A disconnect between the pipeline and power industry business models diminishes the drive to build more pipeline capacity. The electric industry prefers not to pay the premium for firm fuel supply because cost recovery of the upcharge can be difficult. The pipelines prefer not to invest in new infrastructure without that new capacity being committed to firm contracts before construction begins. The pipelines prefer firm contracts for the full capacity of any electric generation facility for every hour of every day, even though no generator operates at that level, meaning the generator is being asked to buy significantly more pipeline capacity than it could ever use.

Originally, both industries began with small local entities building their own networks, then they eventually were stitched together with their neighbors. Neither was created in a unified fashion by a single central coordinating agency.

Regional differences exist for both industries. A look at maps of the national interstate gas pipelines and the national electric transmission grid reveals a major infrastructure problem. One of two things will have to happen for GEH to occur:

- Gas-fueled generating plants will have to be built on the electric grid, with gas piped in, or
- Gas-fired plants will have to be built along the gas pipelines, with electricity transmitted by wire to the rest of the grid.
Both options are costly and complicated. In fact, it is in this regard that the two industries share a commonality. Both extra high-voltage (EHV) transmission lines and interstate pipelines cost roughly $1 million or more per mile to construct.

U.S. gas pipeline infrastructure\(^7\)  

U.S. electric transmission grid\(^8\)

Note that while a few parts of the country support both robust electric transmission networks and gas pipelines, other areas have one or the other. The disparity can be overcome. We need to consider regional infrastructure investments.

While either new pipeline or new electric transmission grid investments would serve the purpose, AEP believes expansion of the transmission grid generally is a superior solution for several reasons. First, expanding the transmission grid out to connect new gas-fired generating stations located near wellhead sites would offer the opportunity to use the new infrastructure for multiple purposes:

- It also could facilitate new renewable generation installations.
- It would expand transmission capacity to address congestion issues.
- Depending on location, it could reduce congestion charges, increasing pricing efficiency of electricity, thereby reducing costs for end-use consumers.
- Transmission expansion as opposed to pipeline expansion offers additional flexibility and safety, thereby maximizing the opportunities created by the capital investment.
- Electric transmission lines send power at the speed of light. Pipelines flow gas at roughly 20 miles an hour.

\(^7\) Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System  
\(^8\) Edison Electric Institute
EHV transmission would serve an additional purpose. EHV transmission is much more efficient than lower voltage transmission configurations. Line loss efficiencies increase exponentially with voltage. Therefore, as the nation strives to achieve the new EPA regulatory objectives, new installations of EHV transmission will help ensure that more of the electrons generated – regardless of their fuel source – actually can be used as an energy source. As new, high-efficiency EHV lines are integrated into the network, overall system losses can be reduced, offsetting the need for additional generation even as load grows.

A single 765 kV line can move 1,000 MW over 200 miles at 99 percent efficiency. During the polar vortex in January 2014, more than 8,000 MW flowed eastward across the AEP transmission system to Pennsylvania, Virginia and other areas of PJM. The bulk of that energy was carried by the 765 kV system. The efficiency of the high-voltage network helped ensure supply could be reliably delivered under these extreme conditions, irrespective of the location of available generation.

**Challenge Two: Markets and Scheduling**

Herein lies the biggest roadblock facing the coordination of the natural gas and electric industries. Two scheduling elements make the gas and power markets incompatible. The power day is real-time on a calendar day basis, from 12 a.m. to 11:59 p.m. in the time zone in which the power is dispatched. The gas day begins at 9 a.m. Central Clock Time (Central) and concludes at 8:59 a.m. Central, regardless of the time zone in which the gas is dispatched.

Today, gas generally is bought and sold in four nomination cycles (noms) per day. Two are day-ahead and two are intraday. Not all gas pipelines operate with four nom cycles: a few have one or two more. Spectra Energy Corp., parent company of Texas Eastern – one of the nation’s largest interstate pipelines – has hourly noms. But if a generator purchases a quantity of

**Market disparities: an example**

Assume an electric load unexpectedly spikes or a major coal plant has a forced outage. Suddenly, a generator needs significant additional gas for tomorrow’s early morning load.

It’s 6:30 p.m., and gas nominations are already scheduled for tomorrow. The last day-ahead nom time was at 5 p.m. Even if capacity exists, there is no means by which to contract for it.

The capacity goes unused because the generator is shut out. Electric customers could face brownouts or blackouts, even though adequate gas transportation capacity was available.

Additionally, the generator could face NERC reliability compliance violations, depending on the nature of its contractual obligations to serve.
gas that must be transported through two or more pipeline systems, the generator is limited to the lowest common denominator in terms of nom frequency.

Meanwhile, electric generators must bid their generation into power markets according to the protocols of the Regional Transmission Organization (RTO) or Independent System Operator (ISO) to which they belong. This generally means they commit to generation on an hourly, real-time basis. Some RTOs have 15 minute bidding cycles.

Gas pipeline day-ahead noms are the most reliable, but they occur before the electricity dispatch markets have cleared and generators must schedule their fuel before they can even be sure they will be dispatched. Furthermore, most gas pipelines require customers to take gas on a steady hourly rate, known as a ratable take, but electric demand is neither static nor pro-ratable. To the extent that ratable takes remain the norm in the gas industry going forward, storage infrastructure will also be needed to accommodate the fluctuating electric load.

Additionally, gas purchased through these cycles is “bumpable” from the pipeline. If a pipeline customer who purchases firm transport wants to use the pipeline and a non-firm customer has purchased capacity through these nom cycles, the firm capacity customer can bump the non-firm customer from using the pipeline, except during the last nom cycle of the day. Firm capacity is significantly more expensive than non-firm, and under certain conditions, firm transport customers can also be bumped.

In its Notice of Proposed Rulemaking (NOPR) RM14-2-000, The Federal Energy Regulatory Commission has proposed two scheduling alterations to resolve issues facing the gas and electric industries. FERC suggests moving the start of the gas day from 9 a.m. Central to 4 a.m. Central. The Commission also suggests adding two additional intraday nom cycles. Moving the gas day to 4 a.m. could allow the necessary fuel purchases to occur prior to the beginning of the electric industry’s morning peak time – when businesses are opening and consumers are getting ready for their workdays. However, it also creates complications for some generators that would then be required to schedule ratable flows of gas as much as 24 hours in advance, depending on their pipeline access and the capacity situations on those pipelines.

FERC adopted a unique approach for the NOPR, having provided a starting point for new procedures and providing both industries a 6-month period in which to either rally behind the proposals or offer a different alternative. That alternative, according to FERC’s direction, would be achieved through consensus built between both industries, using the standards drafting procedures of the North American Energy Standards Board (NAESB). If NAESB could reach consensus and offer alternatives, stakeholders would have two more
months in which to comment before FERC sets protocols in place. If consensus was not reached, FERC’s proposals would be adopted.

After an exhaustive attempt to reach that consensus, NAESB informed FERC on June 18, 2014, that it failed. With several hundred industry representatives participating in a series of two-day meetings, all contentious issues were carefully debated from all angles. And in the end, those industry representatives casting binding votes on the various considerations almost all voted exactly as they had in straw votes taken early in the process. However, the biggest point of contention was the start of the gas day, with a vast majority of the gas industry preferring to keep the start time at 9 a.m. Central, and a vast majority of the electric industry preferring to move it to 4 a.m. Central.

On June 4, 2014, the NAESB Board of Directors passed a motion recognizing that there appeared to be broad support from interested parties in both the gas and electric industries for changes in the intraday nomination cycles and the day-ahead nomination cycles. Therefore, the Board directed the Wholesale Gas Quadrant (WGQ) to develop new standards and modify existing standards to support the scheduling timelines developed by the GEH Forum for the timely, evening, intraday (ID)1, ID2, and ID3 nomination cycles. NAESB later filed a report with FERC outlining all standards changes that would be required to facilitate changes proposed in the NOPR.

The nomination deadlines for the timely and evening cycles are the same as those proposed in the NOPR—1:00 pm Central and 6:00 pm Central, respectively. The timelines for ID1, ID2 and ID3 vary from those proposed in the NOPR and the nomination deadlines would be at 10:00 am, 2:30 pm, and 7:00 pm, all Central time. The NAESB standards do not include an ID4 cycle as proposed in the NOPR. The standards are neutral on the gas day start times and essentially are “fill in the blank” standards pending a Final Order by the Commission in the RM14-2 docket. NAESB filed consensus-based standards on the scheduling timeline, without a gas day start time, with the Commission on Sept. 29 as directed in the NOPR.

The other two open dockets are narrower in focus. The first, RP14-442-000, a show-cause docket, requests that the gas pipelines explain why a secondary market for unused pipeline capacity cannot be created allowing bilateral transactions between those entities with firm capacity they do not need and those entities in need of non-firm capacity. Currently, if such transactions occur they must use the pipeline company as a broker.

The second actually is a suite of dockets — EL14-22-000 through EL14-27-000 are individual but identical dockets for each RTO, investigating their unique scheduling practices to determine the physical reasons behind each.
Challenge Three: Cost Recovery

Because of the high cost of constructing pipelines, gas transporters desire firm contracts to cost-justify construction of new lines. A firm contract commits the purchaser to pay for 100 percent of full capacity of the generating station all day every day for the course of a year, over the term of the contract.

Electric plants don’t run that steadily. A peaker plant – reserved specifically for those times when inadequate capacity is threatening to disrupt reliability – may run at close to 100 percent capacity only a few days a year, and possibly only a few hours during those days. While a base load electric plant runs much more consistently, it rarely operates at 100 percent capacity.

Firm contracts generally guarantee capacity access to the generator for whenever gas is needed. But that guarantee comes at a price. Firm contracts typically are costlier than non-firm capacity, because firm capacity is paid for even if it is not used. The math becomes cost-prohibitive for the electric generator when the excess cost for unneeded capacity far outweighs the cost for needed capacity.

Whether regulated or competitive, the electric generator meets a roadblock when encountering the excess cost of firm pipeline capacity. Competitive bidding into the RTO dispatch queue drives electricity down to marginal costs, making fixed transportation costs unrecoverable. Least-cost dispatching means more expensive plants don’t get scheduled. Regulated utilities sometimes have difficulty defending firm transportation commitments for more than their annualized capacity factor. State utility regulators who approve regulated utility cost recovery are not amenable to the excess cost that accompanies firm transportation, especially when – under certain circumstances – even firm contracts do not prevent them from being bumped.

If AEP were to secure 100 percent firm transmission for its gas generating fleet today, the cost to ratepayers would be hundreds of millions of dollars a year for reservation fees alone.

Such costs would be on top of all the other increased costs the nation’s utility consumers are facing. MATS and other new environmental regulations will drive up costs by requiring new generation. FERC and the North American Electric Reliability Corp. (NERC) are closely examining the physical and cyber security of our nation’s energy infrastructure, with new
requirements to address those issues. Those costs will combine to dramatically increase the electric bills of American consumers.

The National Dialogue

Issues relating to gas-electric harmonization have been discussed for decades. The EPA MATS regulations have elevated their prominence in the national energy dialogue. Recent events have illustrated all too clearly that we no longer have the luxury of time to continue discussion.

The polar vortex of January 2014 was an opportunity: it was a chance for this nation to gain a better understanding of the threats to reliability we are facing. Lack of gas-electric coordination was part of that threat. In early January, much of the Midwest and East Coast faced record cold temperatures. In New England, infrastructure issues made the choice very real between supplying electric generators or local gas distribution utilities that power home furnaces. When the storm had passed, the nation’s grid had held – but barely.


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The fact that the grid held when severely stressed under such extreme conditions is a good sign. However, had the polar vortex occurred after June 2015, things might have been different. Although gas is expected to be the fuel of choice for new base load generation, those plants should already be under construction if they are to go online in a year. While some plants are under construction, they are not enough (see chart below). An even bigger question is whether, when they do come online, they will be able to get the gas they need delivered to them during periods similar to the polar vortex.

FERC opened a rulemaking docket in 2013, RM13-17-000, regarding communication of non-public information between the gas and electric industries. It resulted in FERC Order 787, which both PJM and ISO New England implemented early during the polar vortex. Order 787 allows pipelines to discuss non-public information related to gas capacity directly with the RTOs, bypassing electric generators. In the case of the polar vortex, both RTOs said Order 787 was helpful. However, AEP still has concerns about our own

\[\text{10 Power Market Transition, Andrew Ott, PJM Executive Vice President – Markets, PJM General Session, February 2, 2014}\]
proprietary information being shared between outside entities in situations where we are not present.

Although NERC is not responsible for reliability in the gas industry, the organization has begun tracking coordination efforts because they have such significant implications for electric reliability. In May 2013 – two years before MATS rules go into effect – NERC issued a special reliability analysis related to gas-electric harmonization. The 117-page report provides its highest-level recommendations in the Executive Summary: “NERC assesses reliability concerns based on fundamental principles: BPS (Bulk Power System) reliability must be maintained, regardless of the generation mix and all generation must contribute to system reliability within its physical capabilities. Therefore, solution sets that are implemented in the future should consider the reliability concepts presented in this report. Additionally, a constant theme throughout this report is the need for inter-industry coordination to be focused at the regional level, because of both significant differences in operational characteristics as well as regulatory rules and market environments.”

These issues should not be considered new information. The 2013 special report was NERC’s second on the topic, the first one being published in 2011. That report highlighted all of the topics we are discussing today, calling for increased integration in the planning processes of the two industries, with emphasis on mitigation factors. These would include such considerations as fuel storage, scheduling coordination, etc.

As previously mentioned, FERC has taken a unique approach to addressing these issues in its most recent round of dockets related specifically to scheduling misalignments between the industries. It has outlined in RM14-02-000 revised scheduling practices that the FERC believes would make the industries more compatible. FERC provided a six-month window during which it charged NAESB with reaching industry consensus in both the gas and electric industries on an alternative proposal the industries might prefer to the one suggested by FERC. Following the Sept. 29 filing deadline for any consensus points reached, a two-month public comment period is underway before FERC issues a Final Order.

Both industries have engaged in independent solution proposals. The Natural Gas Council (NGC) is an umbrella organization that collectively represents nearly all companies that produce, transport and distribute natural gas consumed in the United States. It includes members of the American Gas Association, America’s Natural Gas Alliance, the Independent Petroleum Association of America, the Interstate Natural Gas Association of America and the Natural Gas Supply Association. The NGC touted its proposal as a “consensus

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strawman,” and while it may have been a consensus from gas industry representatives, it included no input from the electric industry.

The NGC proposal called for:
- Extending the timely nomination deadline to 1 p.m. CT (from 11:30 a.m.)
- Two bumpable intraday cycles during the business day
- A third intraday cycle in the evening for early morning gas flow

Although additional cycles of any kind are helpful, the proposal did little to address the actual issues confronting electric generators. The start of the gas day (which the NGC proposal did not address) combined with timing of the gas nomination cycles, makes it difficult for many electric generators to obtain the fuel they need. As people begin to wake up and start their days, and as factories and businesses begin to ramp up their daily activities, electric load grows very quickly beginning at 5-6 a.m. Gas-fired electric generators struggle to meet this quick ramp-up due to current scheduling misalignments.

<table>
<thead>
<tr>
<th>Current and Some Proposed Gas Day Alternatives12</th>
<th>Current (CCT)</th>
<th>NOPR (CCT)</th>
<th>NGC (CCT)</th>
</tr>
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<tbody>
<tr>
<td><strong>Timely</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nomination Deadline</td>
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<td>1:00 PM</td>
<td>1:00 PM</td>
</tr>
<tr>
<td>Schedule Issued</td>
<td>4:30 PM</td>
<td>4:30 PM</td>
<td>5:00 PM</td>
</tr>
<tr>
<td>Start of Gas Flow</td>
<td>9:00 AM Next Day</td>
<td>4:00 AM Next Day</td>
<td>9:00 AM Next Day</td>
</tr>
<tr>
<td>Bump IT</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td><strong>Evening</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Nomination Deadline</td>
<td>6:00 PM</td>
<td>6:00 PM</td>
<td>6:30 PM</td>
</tr>
<tr>
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<td>10:00 PM</td>
<td>10:00 PM</td>
<td>9:30 PM</td>
</tr>
<tr>
<td>Start of Gas Flow</td>
<td>9:00 AM Next Day</td>
<td>4:00 AM Next Day</td>
<td>9:00 AM Next Day</td>
</tr>
<tr>
<td>Bump IT</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td><strong>Intra-Day 1</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nomination Deadline</td>
<td>10:00 AM</td>
<td>8:00 AM</td>
<td>9:00 AM</td>
</tr>
<tr>
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<td>2:00 PM</td>
<td></td>
<td>12:00 PM</td>
</tr>
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<td>12:00 PM Current Day</td>
<td>3:00 PM Current Day</td>
</tr>
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<td>Yes</td>
<td>Yes</td>
</tr>
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<td></td>
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<tr>
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</tr>
<tr>
<td>Schedule Issued</td>
<td>NA</td>
<td></td>
<td>11:30 PM</td>
</tr>
</tbody>
</table>

12 Chart created by Edison Electric Institute
Other proposals included a 2 a.m. start to the gas day, favored in New England; a bifurcated start to the gas day – one applying to the (electric) Eastern Interconnection and one applying to the west; and a variety of alternatives in between.

Many other organizations, including AEP, have proposed their own solutions that largely are variations of the themes outlined in the matrix above. Throughout the NAESB negotiations, it was apparent that while variations existed between individual proposals, all proposals fell into two categories – those presented by the gas industry and those presented by the electric industry – with a vast chasm between them.

**AEP Positions**

AEP supports:
- Hourly nomination cycles
- Gas and power day alignment
- One no-bump cycle daily
- Organized markets that include cost of firm transport
- Secondary market for unused pipeline capacity
- Comparative economic analysis of alternatives.

**Hourly nomination cycles.** Ours is a 24/7 world, and we need energy sources to match that. Currently, Texas Eastern pipeline – the largest in the nation – offers hourly nom cycles, so it is physically possible. Texas Gas Transmission, LLC, offers 12 nom cycles daily.

We face reliability issues in those instances where a coal-fired base load unit is suddenly and unexpectedly offline and we cannot bring peaker plants online immediately because fuel cannot be nominated, even when pipeline capacity is available and gas could be delivered. Such reliability issues will increase as natural gas’ percentage of the nation’s electric fuel portfolio continues to grow.
**Gas and power day alignment.** We need both internal and external coordination between these industries. Regional differences need to be respected, but we also need regional consistency in both the gas and power industries. The gas day starts at 9 a.m. Central time across the country. The electric day starts at midnight in the time zone in which the electricity is generated. That's as far as consistency goes in either industry. Electric scheduling and planning protocols vary from one RTO to the next. As the electric industry enters an era in which it becomes much more dependent on the gas industry, consistency will play an ever more important role.

FERC’s desire in Dockets EL14-22-000 through EL14-27-000 is laudable. AEP believes the RTO protocols not only need to be consistent, but the initial decision by the RTO or ISO to schedule the generator needs to be concluded prior to the purchase of gas and the timely nomination deadline.

Gas-electric harmonization issues are conflicts between the two industries, and cannot be resolved if the only solutions considered are contained within only one of the two. Both industries need to come forward in a spirit of compromise and collaboration. That said, timelines and alignment of the gas and power days become less critical if we implement hourly nomination cycles.

**Bumping rules.** Currently, the gas industry has a standard four nomination cycles (individual pipelines may vary), with firm transport customers able to bump non-firm customers in the last cycle of the day and in Intra-Day 1, which has a 10 a.m. nomination deadline. RM14-02-000 proposes the addition of two more intra-day cycles, with bumping allowed in five of the six cycles. Bumping procedures create a roadblock for non-firm customers, primarily merchant generators. At least one no-bump cycle must be retained in whatever scenario becomes the reality of the future.

**Hourly gas price updates.** The Southwest Power Pool currently allows generators to update the cost of generation for which they have already contracted when the price of natural gas goes up. RTOs and ISOs must ensure there is a mechanism to allow a generator to update their fuel costs.

**Comparative economic analysis.** A great many alternatives to the current gas day have been proposed, and an equal number of revisions to the operations of electric generators. But gas-electric harmonization is just one of a litany of reliability issues being simultaneously addressed. While expediency is critical, we also need to take a moment to weigh both the real costs and the opportunity costs of each alternative. A poorly planned “solution” to gas-electric harmonization could ultimately become more costly and more counterproductive than the status quo.