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## Challenges of Implementing a Feed-in Tariff in an RPS State

M. Ryan Hurley

**A**mong the myriad policy tools for advancing renewable energy, never has there been a more championed, more derided, and ultimately more misunderstood policy tool than the *feed-in tariff* (FIT).

Never has there been a more championed, more derided, and ultimately more misunderstood policy tool than the *feed-in tariff*.

While there are number of definitions and varieties of FITs, the most accurate definition is a policy that mandates an above-market standard offer purchase of energy (by a utility or government) in order to incent investment in and development of renewable energy resources.

Responsible for heretofore unheard-of growth in the solar industry in Germany, the FIT is often lauded as a magic renewable energy bullet by its supporters. As such, many industry leaders have made efforts to replicate German success by exporting the FIT to the United States. However, vast differences in the US energy markets and the patchwork of existing state renewable energy policies make successful FIT implementation extremely challenging and complicated. Approxi-

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mately one year ago, the Arizona Corporation Commission (ACC) considered implementing a pilot FIT program for the commission's regulated utilities.

This article will summarize those proceedings and highlight the challenges of implementing a FIT in a state with an existing Renewable Portfolio Standard (RPS).

## ARIZONA BACKGROUND

When Arizona implemented its 15 percent RPS, it was at the forefront of renewable energy policy. By all accounts, Arizona should have been one of the leaders in solar deployment. However, in 2010, although certain sectors of the industry were meeting expectations, Arizona was lagging behind in actual installations. Of particular concern was the lack of utility-scale projects moving forward. There had been several hundred megawatts contracted and not a single piece of steel in the ground. Further, for large-scale commercial rooftop solar, the cancellation rate for projects was nearly 50 percent. In short, there was a lot of talk and a lot less action.

*Arizona was lagging behind . . . There had been several hundred megawatts contracted and not a single piece of steel in the ground.*

In response to this and at the urging of several solar industry advocates, the ACC issued a notice of inquiry and held several workshops to determine the feasibility and desirability of implementing a state-level FIT. Primarily, the ACC sought to determine (1) whether and how a FIT could address any existing RPS program inadequacies, (2) could a FIT complement the existing RPS or would it conflict, and (3) did the ACC have the legal authority to implement a true FIT?

## ARIZONA'S RPS SHORTCOMINGS

As mentioned earlier, the Arizona RPS program had a number of shortcomings. For example, existing distributed generation programs were solely for "behind the meter" applications (i.e., on the customer side of the meter). Further, Arizona law limited the use of a solar sys-

tem to one customer (retail service or net metering to multiple customers would make the system owner a public utility under the Arizona Constitution).

Therefore, projects could only be built for customers who had their own available roof space and enough electricity demand to be directly offset by the entire system output. As such, the programs under the existing RPS functionally prevented a large segment of the population from participating: apartment buildings, multitenant commercial and industrial buildings, and community groups like homeowners' associations or community farms were unable to use the RPS programs to adopt retail-level renewable energy systems. By contrast, a FIT program, which purchases energy wholesale, would be available to any individual or group that had an awarded FIT contract and a desire to build. Customers would no longer be limited by the restrictions regarding retail service or the need to offset only their demand. The hope was that a FIT would, by widening the pool of potential market participants, produce better projects at lower prices.

Another shortcoming that the FIT hoped to address was the discrepancy between proposed RPS projects that were awarded and the number of projects that actually got built. As discussed earlier, the program had a very high cancellation rate and had yet to result in a single utility-scale project in several years. This slowdown was largely attributed to the issues inherent in the RFP or auction-style bid process used to award contracts. In other words, the common wisdom was that developers were bidding unrealistic project prices in hopes of winning the award and then attempting to find financing for a project after the fact.

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As a result, the vast majority of awarded projects were not moving forward because many were modeled on unrealistic pricing. During the workshops, a number of industry representatives testified that a FIT could

resolve this issue because it would offer fixed pricing and therefore it would make investor returns more certain, thus making projects more financeable and ultimately more realistic. In other words, financing would be assured upon award because the pricing would already represent the necessary return for investors and lenders.

In fact, many FIT supporters believed that by removing this uncertainty and increasing the percentage of projects that come to fruition, FITs actually result in a lower cost per installed watt than an auction award process. Ultimately, however, this counterintuitive assertion was vehemently challenged by the incumbent utilities and even by some that called themselves FIT advocates.

### **A FIT BY ANY OTHER NAME**

At this point in the Arizona workshop, it became apparent that one of the biggest challenges in implementing a FIT in the United States was making sure that everybody was using the same definition. While standard-offer, fixed pricing is a central feature of a true German-style FIT, this feature tends to get eliminated when FITs are proposed in RPS jurisdictions. Presumably this is done in an attempt to address some of the legal challenges to fixed-price FITs (discussed later) and more importantly to assuage the public perception issues surrounding government-mandated, above-market pricing.

*A number of FIT advocates in the United States are advocating state-level programs that have some of the features of a FIT (i.e., standard contracts) but instead substitute auction-based pricing.*

Consequently, a number of FIT advocates in the United States are advocating state-level programs that have some of the features of a FIT (i.e., standard contracts) but instead substitute auction-based pricing. Ultimately, supporters of this structure say, auction-based pricing will result in a lower market-based price and eliminates the difficulties of having the regulator set a price. This argument resonates well with regulators who are loath to set a FIT price too high (overheating the program and ostensibly overspend-

ing rate-payer dollars) or too low (discouraging participation and making the policy a failure).

Furthermore, auction-based pricing is an easy solution for another challenge posed by implementing a FIT in an RPS program—the issue of program-size caps. For example, in an RPS state with a particular megawatt or megawatt-hour target, regulators want to incent the proper amount of incremental new development to reach their target. Moreover, they are often prohibited or at least politically restrained from spending more rate-payer dollars than necessary to reach that goal.

In contrast, the German FIT program was meant to incent as much development as the market would bear at a certain price. Thus, for a German project developer, the only limitation to receiving a FIT contract at a certain price was completing the project before the end of the year. But US developers are limited by the size of their state's RPS program.

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In the context of a FIT program that means that a limited amount of contracts would be available for a large number of proposed projects. Thus, a FIT program designer must fashion some way to deal with this scarcity. An easy and popular way to do this was a reverse auction mechanism (i.e., the lowest bid gets the award).

### **FERC OR FICTION?**

The reverse auction mechanism also proved to be a temptingly easy way for regulators to deal with the jurisdiction issues of the Federal Energy Regulatory Commission (FERC). Unlike in Germany, US energy markets are subject to both state and federal jurisdictions. Without a national renewable energy policy, states have been left to determine their own policies, largely resulting in a patchwork of RPS programs.

These programs generally pose no problems of FERC jurisdiction, as they simply provide

renewable energy targets for intrastate activities. However, one area that FERC has exclusive jurisdiction over is that of wholesale electricity rates. In other words, the purchase price between a utility and an independent generator is governed solely by federal law and must be approved by FERC under the Federal Power Act (FPA). Thus, theoretically, any above-market purchase price mandated by a state FIT program is preempted by the FPA and therefore illegal and invalid.

Accordingly, the only valid price that a state could legally mandate was the purchase of energy from qualified facilities at the utility's avoided cost under the Public Utility Regulatory Policies Act (PURPA). The avoided cost is generally the levelized long-term cost for base-load electricity generated by a new natural gas combined-cycle plant. This is often described as the Market Price Referent (MPR). As such, the avoided cost under PURPA is well below the price necessary to incent the development of renewable energy. Although it is possible for a state to redefine and increase the MPR to include external costs such as environmental impacts, this proves to be a politically undesirable way forward.

One way around this limitation is by using the market-based rates exemption under the FPA. In other words, if an energy seller has no undue influence over the market, then the seller can enter into a purchase contract that is the result of an arm's-length, market-based transaction. A FIT program with a reverse auction award mechanism meets these criteria and thus avoids FERC scrutiny.

For this reason, many state regulators are keen to adopt auction-style FITs to avoid creating any questions of jurisdiction or federal preemption. This was ultimately the case in Arizona where the FIT proceedings occurred against the backdrop of FERC hearings on the matter. The prospects of legal challenges and the difficulties of setting a proper price and program participation guidelines resulted in an auction-style pricing mechanism.<sup>1</sup>

## RECS AND EFFECTS

Unfortunately, many a FIT proceeding in many a state has succumbed to the challenges posed by program participation caps and

FERC jurisdiction. Ultimately the result of these challenges is the state's adopting so-called FIT programs that really resemble nothing of a true FIT. Essentially, these programs end up being mere extensions of modifications of their current RPS programs.

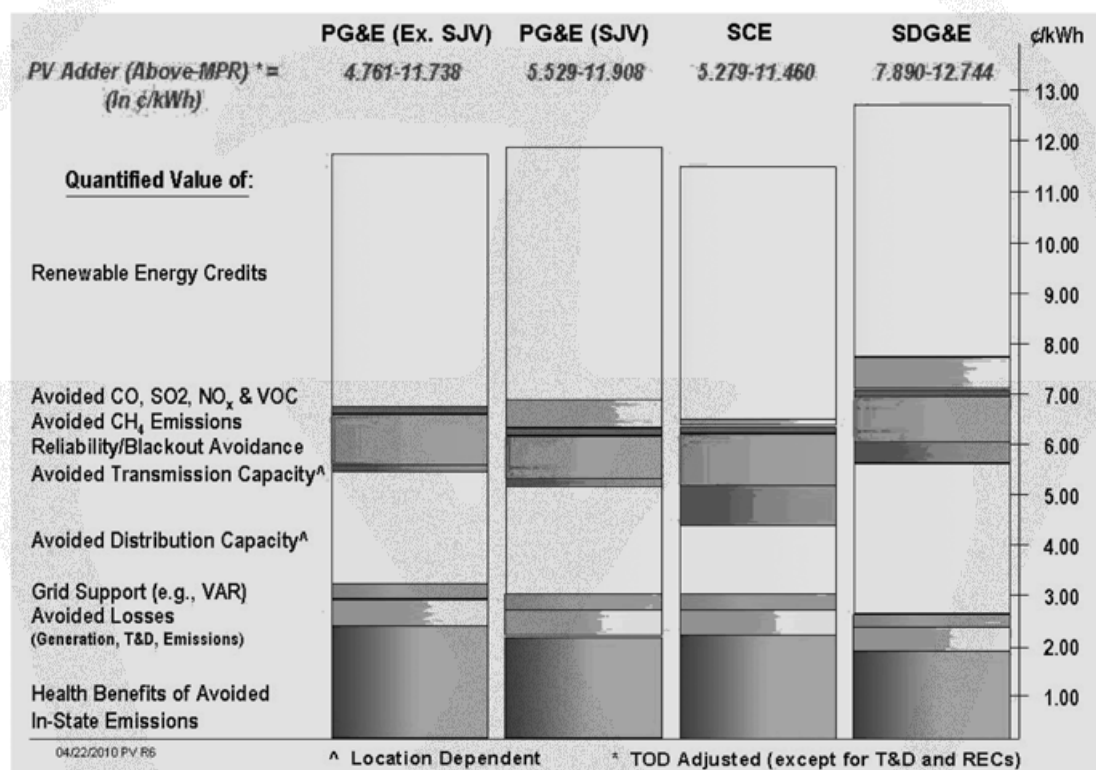
For example, the resulting pilot program in Arizona created a standard offer reverse auction for projects up to 20 megawatts. However, in reality, this program was no different than recurring requests for proposal that the utilities issued under the existing RPS programs. Thus, these types of FITs are unlikely to address shortcomings of existing programs and unlikely to result in more effective deployment of renewable energy resources. The central aspect of a true FIT requires a fixed price. Without this feature, states would be better served by refining their existing processes and programs instead of adopting another version of their existing policies just with a different name.

Thus, if states with existing RPS programs truly want to do something innovative and adopt a fixed-price true FIT, they must find a way to design the program to address the concern discussed earlier. Fortunately, the concept of renewable energy credits (RECs), which generally already exist in RPS states, provides an avenue to adopt a true FIT that avoids legal pitfalls and addresses practical participation issues.

Essentially a REC represents the "green" or "renewable" attributes of a megawatt-hour of energy. Thus, for every megawatt-hour of energy generated by a solar system, two commodities are created, the underlying energy and the green attributes that are embodied in the REC. In other words, a generator can sell a utility not only the energy from the system, but also the REC associated with that energy.

RECs are a creation of state law and are primarily used as a measure of compliance with a state RPS program (i.e., the utility may purchase and retire RECs to demonstrate compliance with renewable energy mandates). Thus, the value of a REC can be thought of in one way as the utility's cost of compliance with the RPS. All of this is a roundabout way of saying that the price of a REC is separate from the price of energy and is therefore a matter of state law and not FERC jurisdiction.<sup>2</sup> Thus, states that wish to adopt a

**Exhibit 1. Small-Scale Solar PV in California: PV Adder (=Above-MPR Value)**



fixed-price FIT may do so using a combination of the avoided cost for energy and the necessary above-market cost for RECs. See **Exhibit 1** that depicts the components of such a proposal in California for a fixed-price solar PV FIT.

Furthermore, the price of RECs can be set and differentiated to address the problem of program participation as well. It is simply not political reality yet in the United States to advocate for an unlimited FIT program as in Germany. Thus, any FIT proposal with fixed pricing must provide a way to deal with a capped program. First come, first served is generally not desirable, as this leads to overnight lines and programs that stop and start abruptly. Rather, a more useful way to determine program participation is to give an advantage to more desirable projects. This can be done by offering different prices for RECs. For example, if a state is examining a FIT because community solar projects are not being built, it could offer a higher REC price to those

types of projects. Another example would be to incent projects that fit well with existing transmission and load constraints.

## CONCLUSION

In conclusion, a true fixed-price FIT can be adopted within the confines of a state RPS program. However, the program design must be well-planned in advance and defensible to regulators who are prone to capitulate to the status quo under the specter of FERC and a voting public. Nonetheless, without this a FIT truly is not a FIT, and efforts to adopt one would be much better spent revising existing RPS programs. ☐

## NOTES

1. Ultimately, the Arizona FIT pilot program was repealed within months of passage upon the election of a more conservative Commission.
2. See American Ref-Fuel Co., 105 FERC ¶ 61,004, at P 23 (2003).

# Year of Big Decisions About Retiring or Retrofitting Coal-Fired Units

*Block Andrews*

**F**or the electric utility sector, the Environmental Protection Agency (EPA) regulatory compliance timelines have started the clock ticking about big decisions that will have to be made about whether to retrofit or to retire existing coal-fired boilers. If the utility's decision is to retrofit their boilers with new air quality control equipment, then what air quality controls are likely to meet existing and potentially future regulations? What impact does the air quality control equipment have on other operations? What significant maintenance costs are likely required to keep the boilers operating for another two decades? What are expected delivered coal prices? Is a carbon tax in the foreseeable future?

If the electric utility decides to retire units, new generation is no easy decision either. Will national, regional, or state requirements for renewable generation be ratcheted up? If natural gas is the new generation source, will gas prices stay low for the foreseeable future? What chance do you have to build new coal units? Can nuclear be built in a timely and cost-effective manner without breaking the bank?

Other factors are also considered when making retirement decisions such as prudence concerns with public service commissions, jobs lost from unit retirements, philosophical considerations about whether the utility is comfortable relying on the market for some or most of the utility's power needs, fuel diversity considerations, transmission costs and constraints, and many others.

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## THE DECISION DRIVER—THE ENVIRONMENTAL TRAIN WRECK

To answer the questions posed above, many electric utility executives have to make billion-dollar-or-greater, long-term financial decisions without having definitive data points. Utilities have always had uncertainty in their planning process. Some of the uncertainties around load growth could be managed by purchasing power, building generation, peak shaving, or other tools. Fuel volatility could be reduced by contractual arrangements or fuel mix strategies.

Generally, the load growth and fuel issues do not drive utilities to a choice of retiring a facility or spending an undetermined amount of capital and operating costs. However, environmental regulations have led to an all-or-nothing paradigm (i.e., retrofit or retire one or several units without knowing the environmental "all-in" costs). Utilities have actively been evaluating multiple scenarios but typically are not committing significant capital until most environmental constraints are known. Unfortunately, with the multiple regulatory compliance dates, once the first regulation is finalized, decisions will have to be made. The nature of the regulation, whether it is unit-specific, and whether there is cap-and-trade regulation can give more or less flexibility in the decision.

Today, we know the Cross State Air Pollution Rule (CSAPR) is final with a compliance date beginning in 2012. The first decision is upon utilities: rely on the market for allowances and/or patch together quickly installed, low-capital-cost but high-operational-cost air pollution controls. The latter approach concerning air pollution control installation is becoming less feasible as time goes by due to permitting time frames for the new equipment, ancillary impacts to other operations such as ash handling, the limited number of sup-

pliers, and the large amount of utilities needing the pollution controls.

It is possible that some utilities will spend the money on air pollution controls to comply with CSAPR and then find that the next rule that comes along such as the Utility Maximum Achievable Control Technology (MACT) rule requires significant capital costs for compliance. If those costs are too expensive to maintain the facility's economic viability, the utility may choose to retire the unit and absorb the stranded air pollution control costs rather than spend additional capital to comply with the next regulation. Of course, the other compliance choice for CSAPR would be to not control your own path and rely on an allowance market that may or may not have adequate allowance liquidity.

There is a long list of regulations/requirements that have been proposed or finalized that could require additional environmental controls (see **Exhibit 1**). As shown in Exhibit 1, the compliance time frame for some rules is in the very near future and what controls may be required for long-

term compliance are vague. Without relief from the EPA, courts, Congress, or the president, utilities have to go forward hoping that their decisions are cost-effective and will not degrade reliability. Some would argue that environmental regulatory uncertainty has always existed in the electric utility sector. This is true, but the economic magnitude and regulatory compliance time frames from the environmental regulations are unprecedented.

Concerning the economic magnitude, the amounts are enormous. The EPA's own estimates have predicted up to 32 gigawatts of flue gas desulfurization (FGD) units, 59 gigawatts of selective catalytic reduction (SCR), 59 gigawatts of dry sorbent injection, 93 gigawatts of activated carbon injection, 10 gigawatts of low nitrogen oxide (NO<sub>x</sub>) burners, and 166 gigawatts of baghouses from CSAPR and utility MACT alone. The overall cost could be well over \$100 billion. This does not include several other air regulations that can/will drive many gigawatts of additional controls.

The second part of the equation is the compliance time frame. Some people say that elec-

**Exhibit 1. Environmental Train Wreck**

Regulation	Compliance Date	Unit-Specific or Systemwide Regulation	Potential Compliance Control(s)
Cross State Air Pollution Rule	SO <sub>2</sub> —2012 and 2014 NO <sub>x</sub> —2012 and 2014 NO <sub>x</sub> ozone—2012 and 2014	Cap-and-trade regulation	SO <sub>2</sub> —DSI, FGD, low-sulfur fuels NO <sub>x</sub> —combustion improvements, SNCR, SCR
Utility MACT	Nov. 2014 to Nov. 2015*	All coal units	Hg—ACI, oxidation agents Acid gases—DSI, FGD PM—ESP, baghouse
Regional Haze	5 years after SIP/FIP approval (2016*)	Unit-specific	SO <sub>2</sub> —DSI, FGD NO <sub>x</sub> —combustion improvements, SNCR, SCR PM—ESP, baghouse
Revision of NAAQS	Ozone—2013–2030 SO <sub>2</sub> —2017 NO <sub>x</sub> —2021 PM <sub>2.5</sub> —2010–2015	All units	SO <sub>2</sub> —DSI, FGD NO <sub>x</sub> —combustion improvements, SNCR, SCR PM—ESP, baghouse
New Source Review	3 to 5 years after settlement	Unit-specific	SO <sub>2</sub> —DSI, FGD NO <sub>x</sub> —combustion improvements, SNCR, SCR PM—ESP, baghouse
Clean Water Act Section 316	2016*	All coal units	Intake screen/structure modifications, cooling towers
NPDES Water Discharge	2017*	All coal units	Water treatment, deep well injection, zero liquid discharge
Coal Combustion Residual	2019*	All coal units	Dry materials handling, dry ash conversion, new landfill

\*Estimated compliance date (rule not final).

tric utilities knew what new air quality requirements were coming and that units should have started pollution controls early. Let us look at how early a unit had to start planning in order to install major pollution controls to meet the 2012 CSAPR compliance date. There are several steps that need to be completed for a successful project: the planning process to review technologies and regulatory requirements; decisions concerning control technology; permitting new controls; detailed engineering; construction; start-up shakedown; and, finally, commercial operation. In some states, investor-owned utilities may also require predetermination with the public service commission. A reasonable schedule for these activities is shown in **Exhibit 2**, assuming that the air pollution control market is not flooded with other utility projects.

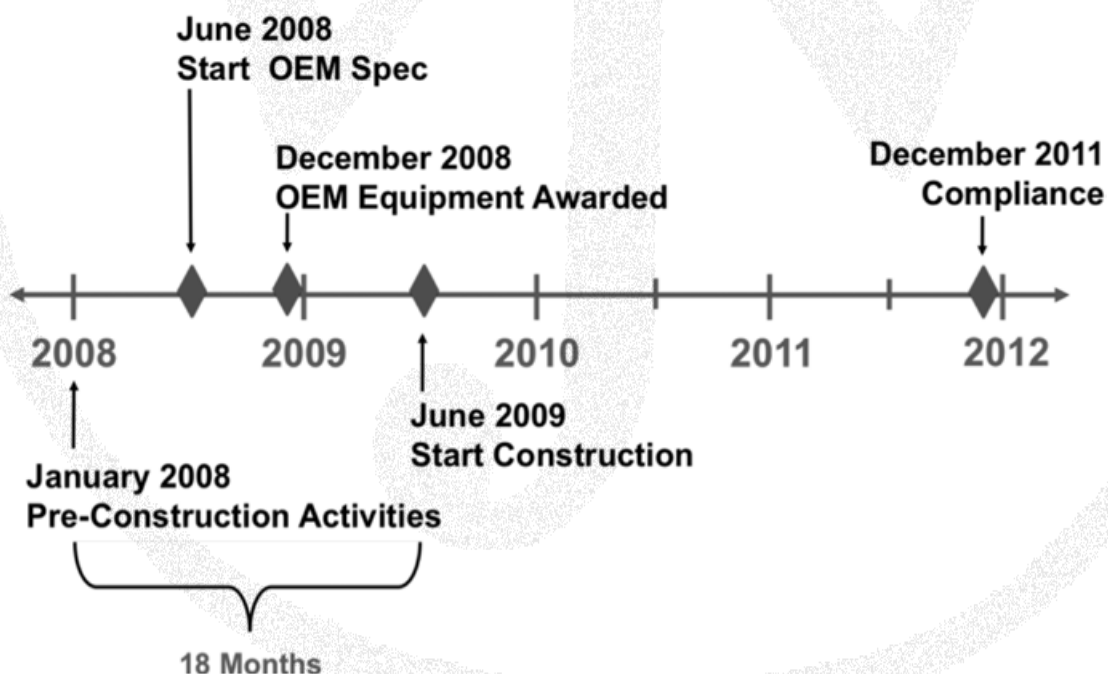
For installation of major air pollution controls meeting a January 1, 2012, CSAPR compliance date, the utility would have started the planning process in early 2008. Looking back in time to January 2008, there was no CSAPR, no Utility MACT, no revised sulfur dioxide (SO<sub>2</sub>) and NO<sub>x</sub> National Ambient Air Quality Standards, and no

decision concerning Best Available Retrofit Technology (BART) controls. Therefore, for CSAPR compliance, the utility would have had to go to their customers and convince them that it was appropriate to install expensive environmental controls on their coal units with no regulatory driver or retire the units and either build new generation or rely on market-purchased power. (I would not have wanted to be the person explaining that case to my customers.)

The utility would have had to go to their customers and convince them that it was appropriate to install expensive environmental controls on their coal units with no regulatory driver or retire the units.

If we fast forward to today, we have a final CSAPR and several proposed regulations. A better case can be made to the public concerning installing pollution controls on coal-fired plants. However, now there are hundreds of units that are somewhere in the process of spending major dollars on installing controls. It is possible that the time frame described in Exhibit 2 will be extended because

**Exhibit 2.** Schedule Needed to Support CSAPR Compliance for Major Air Quality Control Systems (AQCS)



of labor or supply constraints. In fact, if historical air pollution control projects are overlaid with the EPA's expected controls for utility MACT and CSAPR, then the future build-out is significantly greater than has been done before (see **Exhibit 3**).

The workforce to build the air pollution controls would include not only equipment suppliers and their supply chain but also experienced power plant construction workers and design engineers. This entire workforce needs to have the proper experience and staffing to successfully complete a project. An added timeline and risk complexity can be the up-front permitting and approvals, as there is certain to be groups that obstruct and/or sue utilities and state air agencies over issuing air pollution control or other environmental construction permits to coal-fired plants.

### NEW GENERATION

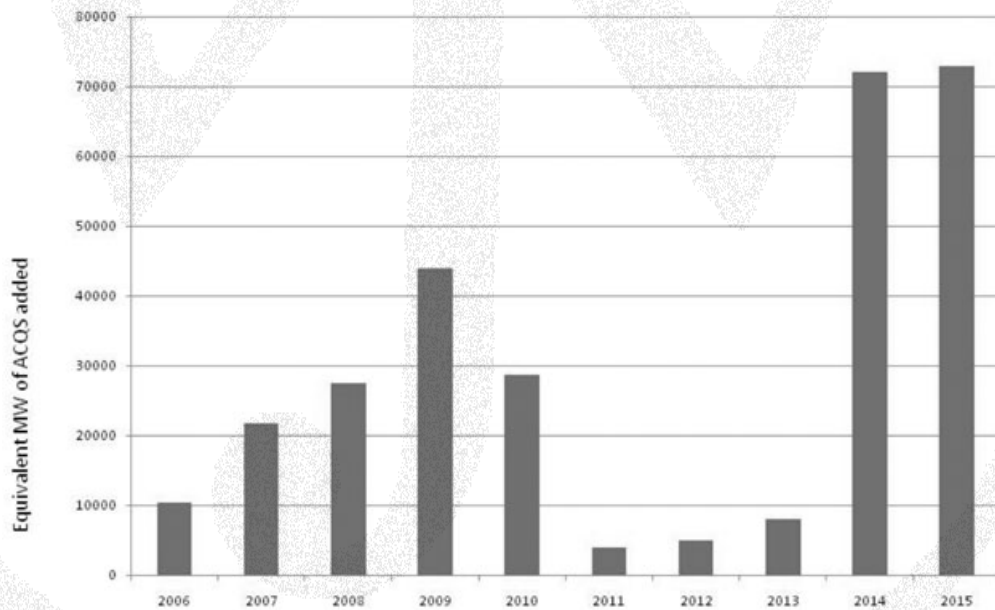
Several electric utilities have begun the process of retiring units and building new generation. The generation mix has primarily been natural gas-based or based on renewable sources needed to meet state-mandated renewable energy standards.

Many, but not all, of the coal unit retirements have been influenced by the additional costs from multiple environmental regulations. Some of the existing units already have low capacity factors and are generally uneconomical today even without the new environmental regulations. Regardless of the retirement justification, some of the capacity and energy needs to be replaced. A general timeline for a brownfield combined-cycle unit is shown in **Exhibit 4**. This schedule assumes the labor and materials market is not constrained.

Knowing what we do today, we have seen announcements of unit retirements because of CSAPR beginning in 2012. If a utility is just beginning the process today to construct a new unit, then it is clear that the retirement unit's capacity and energy will need to be replaced for three years or longer. Because the new generation labor and material supply pool is generally similar to the retrofit resource pool, timeline constraints for new generation could also be extended.

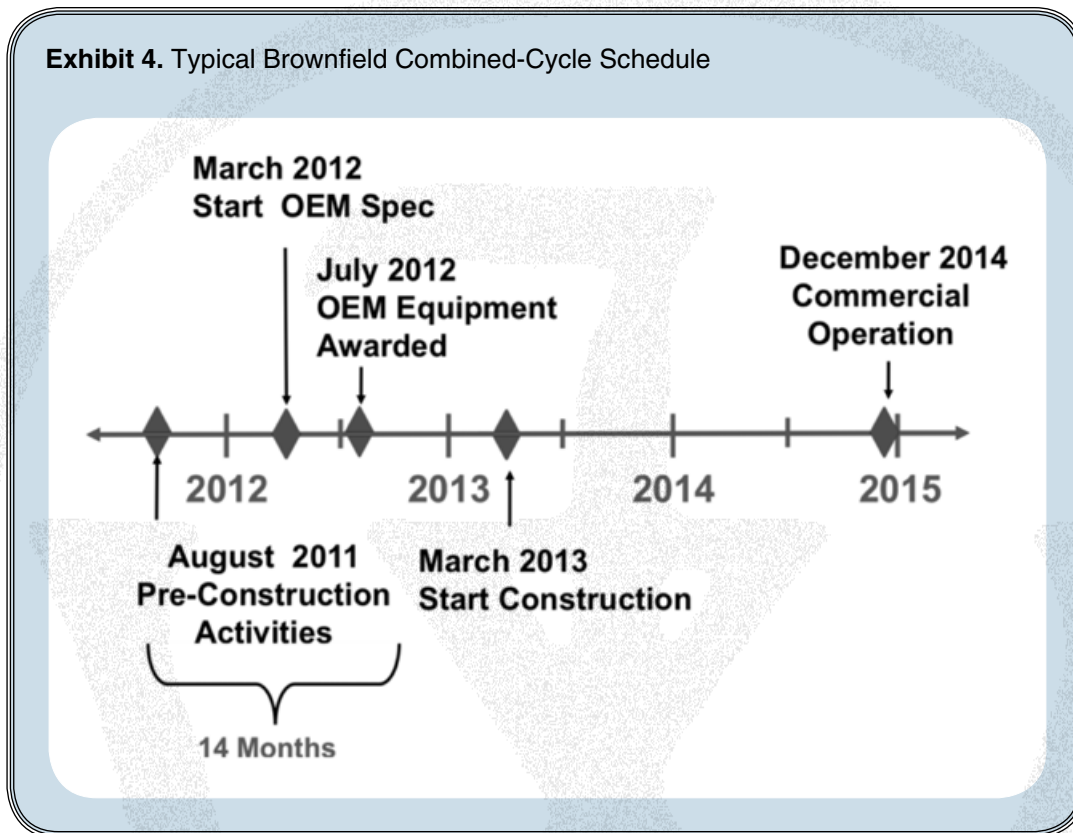
No matter whether the electric utility decides to retire coal-fired units or build new generation, a reasonable time frame is needed to com-

**Exhibit 3. Equivalent Historical AQCS MW Versus Projected AQCS**



1 MW FGD = 1 equivalent MW  
 1 MW SCR = 0.5 equivalent MW  
 1 MW FF (baghouses) = 0.25 equivalent MW

**Exhibit 4. Typical Brownfield Combined-Cycle Schedule**



plete the project. ERCOT, Southwest Power Pool, and PJM regional transmission organizations (RTOs) have all expressed reliability concerns with the EPA's expedited compliance time frames. Given the RTOs' expertise, their warnings should be taken seriously, and regulatory compliance time frames need to be extended.

A reasonable time frame is needed to complete the project.

### CONCLUSION

Environmental laws and regulations have served to improve the health and welfare for all Americans. However, some situations have arisen that were not likely contemplated by Congress when it enacted the Clean Air Act. One such case is the series of electric utility environmental regulations with problematic timelines.

The EPA and the courts have been forced to interpret and enforce time frames established under congressional laws. However, the president has an option to extend compliance dates under certain sections of the law. For example, concerning Utility MACT, Section 112(i)(4) of the Clean Air Act states:

**PRESIDENTIAL EXEMPTION.**—The President may exempt any stationary source from compliance with any standard or limitation under this section for a period of not more than 2 years if the President determines that the technology to implement such standard is not available and that it is in the national security interests of the United States to do so. An exemption under this paragraph may be extended for 1 or more additional periods, each period not to exceed 2 years. The President shall report to Congress with respect to each exemption (or extension thereof) made under this paragraph.

I believe that a reasonable argument can be made that the market may not be able to install all the necessary controls in a timely manner and that having reliable electricity is a national security issue. Congress could certainly act to modify portions of the environmental laws as well. For the electric utility sector, the president and/or Congress should extend compliance dates. If we cannot figure out how to get out of this box we are in, we are playing Russian roulette with our electric power system. I, for one, like low-cost, reliable electricity. ☺