Implications of the Proposed Clean Power Plan for Arkansas

Review of Stakeholder Concerns and Assessment of Feasibility

A Report to
Arkansas Audubon,
the Arkansas Public Policy Panel, and
Arkansas Sierra Club

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1. Introduction

This report addresses the feasibility of meeting the state targets of the Clean Power Plan as laid out in EPA's Clean Power Plan (79 FR 34829–34958), particularly for Arkansas, and responds to concerns expressed by Arkansas utilities and regulators in preliminary discussions of options for compliance. Unless otherwise noted, the presentations cited below are from the October 2, 2014, meeting of the Arkansas Department of Environmental Quality (ADEQ), the Arkansas Public Utilities Commission (APSC) the utilities, and other stakeholders.[1]

1.1. Misconceptions Regarding the Clean Power Plan

A large amount has been written about the Clean Power Plan that reflects a widespread (real or professed) confusion about Plan's proposed rule, including conflation of EPA's modeling assumptions with the Plan's requirements.

1.1.1. The Clean Power Plan Would Not Fundamentally Change Utility Planning and Operation

A number of industry observers assert that the Plan requires specific actions by utilities, generators and states, and would result in the EPA controlling state and utility operations in an unprecedented manner. For example, Sue Kelly, President and CEO of the American Public Power Association, told a reporter

> This is not an environmental rule. This is an energy policy. It's going to dictate how much energy efficiency is achieved, what the fuel mixes are and how things are dispatched. It's being done by an agency that sets environmental rules and is not as familiar with our industry as certain other entities, for example, the Federal Energy Regulatory Commission or the Department of Energy. One of the things that really concerns me is that there seem to be certain favored renewables and certain disfavored renewables. We believe that hydro is a renewable. We have been very strong proponents of new hydro and especially new, small hydro. We just feel like this administration seems to have a little bit of tunnel vision about that. Similarly, we are very interested in doing new nuclear.… We have members that are interested in new small modular nuclear. We feel that is something that this government should be supporting.[2]

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[1]These materials are online at www.adeq.state.ar.us/air/branch_planning/carbon_pollution_materials.htm. The comments below cite these documents as "October Presentation" followed by the number on the ADEQ web page.

[2]Rosenberg, Martin. 2014. "Fed Emissions Rules Need Study: Really an Energy Policy." Oct 26, 2014, www.energybiz.com/article/14/10/fed-emissions-rules-need-study

Ms. Kelly is wrong on all these counts. Nothing in the proposed rule dictates how much energy efficiency will be achieved, what any state's fuel mix will be, or how power plants are dispatched.[3] Ms. Kelly, like many utility observers, has conflated EPA's example of how each state *could* comply with the Plan with the standard to which each state *must* comply. However, states are free to reach the goals with different mixes of resources, and even with resources that EPA did not list. New hydro and nuclear generation would be treated just like any other zero-emission resources. The proposed rule lists hydro as a renewable resource at footnote 30, and the renewable targets are based on state renewable-portfolio standards, which generally include new hydro (especially "new, small" plants). The proposed rule also discusses the potential for new nuclear generation to reduce carbon emissions.

Similarly, Nick Akins, the Chairman, CEO and President of American Electric Power, SWEPCo's parent company, told analysts in an October 23 2014 earnings call that

> the EPA's proposed Clean Power Plan['s]…cornerstone assumptions are not realistic. The timetables are much too aggressive. And it's just too complicated for the states, markets and stakeholders to comprehend without a well-thought-out plan for development and execution. The EPA's proposed rules will generally require a fundamental change in the way the electric grid, capacity and energy markets and the state review and approval processes function.[4]

As I demonstrate in the following sections, EPA's goals are modest, particularly for Arkansas. The proposed rules will not change the grid functions of the regional transmission organizations (RTOs), the capacity or energy markets, or state regulation. The RTOs (MISO and SPP) will continue to oversee the transmission system, although they may be somewhat busier reviewing the changes needed to accommodate retirements of older steam plants, additions of renewables, and increased imports. The capacity market in MISO (SPP does not have a capacity market) will not be affected, other than that the cost of new entry may vary, due to

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[3]The Arkansas Electric Coop Corporation asserts, "The proposed Rule will require RTOs to replace economic dispatch with environmental dispatch" (Clean Power Plan Comments, September 30 2014 at 10). In reality, the dispatch in MISO and SPP would be much like that in ISO-NE, NYISO and PJM, all of which add the cost of carbon allowances under the Regional Greenhouse Gas Initiative into the economic dispatch price for each fossil unit. California also dispatches on total costs, including required carbon allowances per MWh. When SO_2 and NO_X allowances are significant, regional transmission organizations and utilities include those values in the unit-specific dispatch cost.

[4]Transcript, seekingalpha.com/article/2594605-american-electric-powers-aep-ceo-nicholas-akins-on-q3-2014-results-earnings-call-transcript.

changes in market energy prices. The energy markets will operate as they do now, with lower loads (due to energy-efficiency programs), more renewable energy, less coal and more gas, and probably with the fossil plants including a regional carbon price in their energy bids, as generators in California and New England do now. Nor will state regulation change in any fundamental manner. The Arkansas PSC will still review the need and economics of new generation and transmission projects in the state, before issuing a Certificate of Public Convenience and Necessity; determine whether power-purchase contracts are beneficial before allowing them in rates; determine the ratemaking for energy-efficiency programs; and reward or penalize utilities for good or poor performance, as it does now. The Arkansas DEQ will still issue permits; it will just have one additional program under which it will issue permits and determine compliance, probably through a regional emissions-trading approach similar to that in the Regional Greenhouse Gas Initiative.

1.1.2. The Plan Does Not Have a Specific Emission Requirement for 2020

Some utility commentators treat the 2020 targets in the Plan as requirements, and suggested that utilities would not have enough time to fully comply by 2020 (e.g., Akin, op. cit.; SWEPCo slide 8; MISO slide 9; SPP slides 11, 16). In fact, the only requirements in the Plan are the 2030 annual emissions and the average emissions in 2020–2030. If Arkansas misses the target for 2020, it can make it up any time before 2030.

1.1.3. Compliance Efforts Can Start Immediately

Some commenters assume that no efforts to comply with the Plan could be initiated until the rules are finalized and the State Implementation Plans (SIPS) are developed and approved, leaving only about two years for compliance with an imaginary requirement for 2020 (e.g., October Presentation 5 at slide 9; AECC Clean Power Plan Comments, September 30 2014 at 23). Nothing could be further from the truth. There is little doubt that electric utilities, and eventually all sectors of the economy, will be called on to reduce carbon emissions dramatically over the coming decades. The utilities and other parties should be working now on implementing the following responses:

- larger energy-efficiency portfolios ;
- additional solar, wind, biogas, cogeneration and heat-recovery projects ;

- engineering analyses of heat-rate-improvement options for coal plants that may remain economic past 2030, and implementation of those options for plants that the utilities are certain will remain economic ;
- characterization of renewable potential within Arkansas ;
- identifying area of the distribution and transmission systems that can accommodate renewable generation ;
- upgrading the distribution system to permit bidirectional power flows;
- design and siting of transmission for import of renewables.

All of the above steps will be useful regardless of the details of the final rules

With other SIPs, such as for the Regional Haze Rule, utilities need to know what level of control will be required, in order to decide whether a particular control technology will be sufficient. Installing a low-cost, low-control option (perhaps achieving 40% control) would be wasteful if the eventual SIP requires 95% control and entirely different technology. The SIP for the Clean Power Plan, on the other hand, will comprise some combination of required actions, allocation of emission allowances, and a trading rule; any progress toward reducing emission made prior to the issuance of the SIP will be helpful in compliance. Hence, the relevant periods run for more than five years from today to the beginning of 2020, for more than ten years to the middle of the first compliance period, and for more than 15 years to 2030.

1.1.4. The Plan Does Not Require the Retirement of Generators

For some reason, EPA forecasts retirements of specific generation units. It is not clear how the retirement forecasts are generated, but this might be a modeling simplification to force reductions in emissions. In any case, the CPP does not require any retirements.

If a plant is required at peak, or if other plants or transmission is being maintained, the plant can remain in service, spending most of the year on standby and running when needed. Nova Scotia Power, operating under provincial emissions caps for CO_2, mercury, and other pollutants, has coal plants that shut down during the low-load summer season and run at about 10% capacity factors over the course of the year.

Over time, the utilities will want to retire the coal plants that operate at low capacity factors, but that can be delayed until they can be made redundant by efficiency, renewables, new gas plants, CCS coal, nuclear, transmission, or other solutions.

Some observers assume that the Plan would require shutdown of power plants required for reliability. In the presentation cited above, AEP CEO Akins also said:

> I instructed my team here at AEP to run system planning and performance studies, typically known as load-flow studies, that engineers use to plan and confirm the reliable operation of the grid. And I asked them to assume the EPA 2020 cornerstone assumptions and add generation that's included in the PJM queue. The results of those studies found widespread occurrences of voltage degradation, collapse, and in fact, cascading outages of the electric grid. These results are even before any contingency outages, such as loss of generation or transmission facilities. The Southwest Power Pool ran their own studies and confirmed the same results for their region of the country, which we also serve.

Indeed, SPP's presentation in Arkansas (October Presentation 4) claims as follows:

> If CPP compliance begins before generation and transmission infrastructure is added [the region will experience] extreme reactive deficiencies of approximately 5,200 MVAR across SPP system, [which] will result in significant loss of load and violations of NERC reliability standards. During CPP compliance without additional transmission infrastructure, loading on 38 facilities in SPP [would] exceed equipment ratings, some overloads would be so severe that cascading outages would occur, [resulting] in violations of NERC reliability standards. (Slide 11)
>
> By 2020, SPP's anticipated reserve margin would be 4.7%, representing a capacity margin deficiency of approximately 4,600 MW. By 2024, SPP's anticipated reserve margin would be -4.0%, representing a capacity margin deficiency of approximately 10,100 MW. (Slide 14)

The errors in these analyses are straightforward. When Akins referred to EPA's "2020 cornerstone assumptions," he apparently meant EPA's projected retirements, which are not required or fundamental to compliance.[5] He mentions only the capacity currently in the PJM queue, and not the additional central and distributed renewables that can be built within five years.[6] He does not mention the currently planned energy-efficiency programs (which PJM does not net from its load forecast) or expanded programs. But most importantly, he assumes that generators and utilities would retire plants required for reliability, which PJM has mechanisms to avoid.

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[5]He also appears to be referring to the EPA's 2020 file that erroneously showed the retirement of Plum Point, and may have incorporated other errors.

[6]PJM has found that combined-cycle plants can be built in a little over three years.

Similarly, SPP started with the EPA's projected retirements by 2020 with the Plan (at slides 8 and 9), including the erroneous listing of Plum Point, and assumes that no new generation could be added in five years. Since many of the generators that EPA assumed would be retired by 2020 are already planned for retirement (e.g., one Northeastern and the equivalent of a Muskogee unit in Oklahoma, a Welsh unit in Texas) by 2020, plans for replacing much of that capacity are underway.[7]

In addition, SPP says it "used current load forecasts supplied by SPP members, currently planned generator retirements, currently planned new generator capacity with GIAs [generation-interconnection agencies], and EPA's assumed retirements" (at slide 14). So SPP appears to have made the following errors:

- ignoring future energy-efficiency programs;
- ignoring any new generation that does not yet have a Generation Interconnection Agreement (including renewables earlier in the interconnection process) or does not require one (distributed generation);
- counting both the planned SPP retirements and the EPA's retirements, which may double-count some retirements. For example, the EPA analysis assumes that Muskogee will retire, but not Mustang, while OG&E has decided to retire Mustang and convert Muskogee, to operate more like Mustang has. It appears that SPP has counted both the Muskogee and Mustang retirements.

Again, it is important to recall that the Plan does not require retirement of any capacity, and utilities will keep units available if they are required for reliability. While a few coal units in a few places may need to operate at low capacity factors for a few years while transmission and renewables (and perhaps CCS and new nuclear) are completed. Many oil- and gas-fired steam plants operate as peakers, and their owners find ways to minimize further reduce costs, stretching out maintenance schedules, using the plant staff to perform maintenance on other units in the off-periods, and so on. Costs will be modest on a statewide basis.

The EPA's modeling of CPP compliance assumed retirement of a number of generating units, as shown in Table 1.

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[7]Oklahoma G&E plans to convert two 500-MW Muskogee units to gas, while retiring 450 MW of Mustang steam-gas units and replacing them with combustion-turbine peakers.

Table 1: EPA June 2014 Assumed Retirements by 2025

				Compliance Case	
	Unit	**Capacity**	**Base Case**	State	Regional
Harvey Couch	2	123	Retire	Retire	Retire
Lake Catherine	3	96	Retire	Retire	Retire
Lake Catherine	4	524	Retire	Retire	Run
White Bluff	1	806.9	Run	Retire	Retire
White Bluff	2	835.7	Run	Retire	Retire
Independence	1	827.7	Run	Retire	Retire
Independence	2	833.6	Run	Retire	Retire
Plum Point	1	670	Run	Run	Retire

The gas-steam retirements in EPA's base case are quite sensible. Harvey Couch did not generate any electricity in 2013, and Lake Catherine 3 operated in only two months (and not much even then). Entergy's 2012 Deactivation Study recommended retirement of both these units by 2016, regardless of carbon limits, and the units are listed as retired in the Entergy Statistical Report and Investor Guide 2013. Lake Catherine 4 was apparently out of service for the first half of 2013, ran at about a 10% capacity factor when it was available, and is listed as a peaking plant in the 2013 Statistical Report. In any case, whether these units are retired or continue to remain in standby and low-output operation makes little or no difference in Arkansas's compliance with the Plan.

In the regional compliance case, EPA's modeling switches the fates of Lake Catherine 4 and the brand-new Plum Point plant. This outcome is unlikely. In contrast, White Bluff is likely to retire by 2020 or so, with or without the Plan. In 2009, my analyses (unpublished) indicated that retrofitting White Bluff with all the control equipment necessary to comply with the Regional Haze Rule, maximum-achievable-control-technology rules, and other pending requirements was probably uneconomic, compared to purchasing and running underutilized gas plants, converting White Bluff to burn gas, or even building new gas combined-cycle capacity. I reached those conclusions with a forecast of gas prices reaching \$10/MMBtu in 2020; gas price futures for 2020 are now about \$4.50/MMBtu. The Independence units are very similar to White Bluff in age, efficiency, operating costs, design and existing controls. Consequently their future is similarly doubtful. One or both Independence units may stay in operation, depending on local reliability requirements and carbon allowance prices, but they will probably be economic only during summer peak periods and (depending on gas prices) perhaps the winter.

The Virginia SCC Staff comments to EPA similarly assert (at 14) "that the Proposed Regulation will cause 2,851 MW of generation retirements in the

Dominion transmission zone before 2020." The VSCC Staff relied on a draft analysis of state-based compliance from April 2014, rather than the final analysis from June 2014. The EPA's April 2014 estimate of 2020 retirements in the Dominion zone in the Base Case without the CPP was 1,923 MW, so EPA was estimating only 928 MW of additional retirements due to the Plan.

1.2. Arkansas's Situation

1.2.1. Arkansas's Role as Exporter of Coal Power

Arkansas is an exporter of coal-fired energy, and hence has more coal capacity covered by the CPP than other states with the same consumption of coal-fired energy. In 2012, Arkansas energy generation was 26% more than the sum of Arkansas retail sales and 10% retail losses.[8] In 2013, Arkansas generated at least 18% more energy than it used. These large exports are partially due to the fact that 30% of Arkansas coal capacity is owned by or sold under long-term contracts to out-of-state utilities. These non-Arkansas entitlements comprise the following:

- Independence 1 is 25% owned by Entergy Mississippi. According to its 2012 IRP, Entergy Arkansas sells another 4% of Independence 1 in long-term wholesale sales, most out of the state.
- Independence 2 is owned 25% by Entergy Mississippi, 7.1% by East Texas Coop, and 14.4% by Entergy Power for sales into the wholesale market.
- According to its 2012 IRP, Entergy Arkansas sells about 8% of each White Bluff unit in long-term wholesale sales, most out of the state.
- Plum Point is 36% owned by out-of-state utilities; 57% is owned by LS Power, which sells another 38% to out-of-state utilities and 11% into the wholesale market. The remaining 15% or so (about 100 MW) is owned by or sold to Empire District Electric, which has a peak load of about 1,150 MW and about 3.3% of its sales (or a peak of about 40 MW) in Arkansas. So even this capacity is mostly serving out-of-state load.
- Turk is owned 8% by Oklahoma Municipal Power Authority and 7% by East Texas Electric Coop, Inc.

[8]The 10% loss assumption is at the high end of the plausible range. Lower retail losses would imply greater

- Meanwhile, SWEPCo has two coal units (Turk and Flint Creek) in Arkansas, for about a third of its coal capacity, even though Arkansas represents only about a fifth of SWEPCo's sales.

See Table 2.

Table 2: Summary of Exports from Arkansas Coal Plants

	Capacity (MW)	% Owned or Sold Out of State	% Sold into Interstate Market	Capacity Sold out of State	Capacity Sold to Market
Independence 1	900	25%		225	0
Independence 2	900	32%	14%	289	126
White Bluff 1	900	8%		72	0
White Bluff 2	900	8%		72	0
Plum Point	720	83%[a]	11%	598	79
Turk	609				0
SWEPCo	445	40%		178	0
Other Owners	164	30%		91	0
Flint Creek	558				0
SWEPCo	279	40%		112	0
Other Owners	279				0
Total	5,487	30%		2,017	205

[a]Includes Empire District excess Arkansas coal.

The costs of reducing emissions from Arkansas's coal fleet will, and should, fall heavily on the out-of-state utilities with entitlements in Arkansas coal plants. If the Arkansas DEQ allocates those plants' CO_2 allowances equal to their share of total Arkansas coal-plant emissions, the out-of-state owners will need to pay other generation owners for emission credits or accept lower production levels. If the Arkansas DEQ allows unused allowances from other states to count towards Arkansas compliance, the owners may reduce output at out-of-state plants, or retire them entirely, to free up allowances to meet their Arkansas obligations.

Partly as a result of coal generation for exports, a much greater percentage of Arkansas energy production is from coal than the national average. In 2013, 53% of Arkansas electric energy production came from coal, more than a third greater than the 39% of national energy generation from coal (EIA Form 923, 2013).

Retirement of the exporting coal plants would reduce Arkansas's generation requirements. Retiring the four Independence and White Bluff units would require replacing only about three of them with renewables, energy efficiency, and increased operation of gas combined-cycle units. Under a mass-based approach, as advocated by SWEPCo and the Bipartisan Policy Center presentations (October

Presentations 1 and 2), these reduced exports would move Arkansas toward compliance with the Plan.

1.2.2. Failure to Accommodate National Trends Away from Coal

While other states were announcing the retirement of coal capacity, generation companies were building coal plants in Arkansas. The 665 MW Plum Point was completed in 2010, and SWEPCo completed the 600-MW Turk plant in 2012. Since 2008, 96% of Arkansas capacity additions have been coal, compared to 15% in the rest of the U.S. The two plants added in Arkansas, a plant with only about 1.5% of U.S energy output, amounted to over 8% of national coal-plant additions.

While SWEPCo was adding Turk to Arkansas's compliance burden, SWEPCo announced the retirement of its Welch 2 unit in Texas, and its affiliate Public Service of Oklahoma has announced retirement of both of its Northeastern coal units, which will make compliance in Texas and Oklahoma easier. No coal capacity has been retired in Arkansas, and no retirements have been announced. Nationally, about 230 coal-fired units totaling 22,000 MW were retired in 2005–2013, or about 7% of total coal capacity. Another 35,000 MW, roughly 11% of the fleet, are scheduled for retirement in 2014–2026, even before any effect of the Plan.[9]

1.2.3. Other Poor Decisions by the Arkansas Utilities

The Arkansas utilities have come late to energy-efficiency. Until the Arkansas PSC ordered the investor-owned utilities to ramp up their efforts, starting in 2009 (Order, APSC Docket Nos. 06-004-R, 08-144-U), none of the Arkansas utilities had made any significant effort to improve customer efficiency.

The Arkansas utilities have also been passive with respect to renewable resources, neither acquiring significant amounts of utility-scale renewables nor encouraging customers to add roof-top solar and other behind-the-meter renewables.

The decisions of the utilities led to their current situation, and some additional effort may be required to catch up to the Northeast on energy-efficiency, neighboring states on renewables, or most states in replacing their coal fleets with cleaner generation. As I discuss below, Arkansas has some offsetting advantages, including the ramp-up of energy-efficiency programs much earlier and faster than

[9]For 2012–2021: Brattle Group "Coal Plant Retirements and Market Impacts" presentation by Martin Celebi at the Wartsila Flexible Power Symposium, February 5, 2014, at 12 www.brattle.com/system/publications/pdfs/000/004/982/original/Coal_Plant_Retirements_and_Market_Impacts.pdf?1391611874. For 2005–2011 and 2022–2026: www.sourcewatch.org/index.php?title=Coal_plant_retirements.

the EPA anticipated, the development of large amounts of wind capacity (and transmission to bring it to market) in adjacent states, a large amount of underutilized natural-gas combined-cycle (NGCC) capacity, and falling costs for solar and wind resources.

The following sections lay out the issues with respect to the EPA's Building Blocks 2 (redispatch), 3 (renewables and clean energy), and 4 (energy efficiency).[10] It is important to recognize that the EPA's proposed rule does not mandate any particular mix of these building blocks. While the state goals are derived from EPA's very conservative estimate of achievable reductions from each block, Arkansas should be able to exceed any of the three targets and meet its goals with multiple combinations of dispatch, renewables and efficiency. While SWEPCo was correct in observing that "EPA's building blocks are based on flawed assumptions," those flaws mostly understate the magnitude of resources for compliance.

2. Building Block 2: Redispatch Opportunities

2.1. Resources in Arkansas

2.1.1. Underutilized Capacity

Arkansas has seven NGCC plants, totaling about 4,800 MW of summer capacity, 98.5% of which was built since 2001. Table 3 summarizes the capacity and capacity factors of these plants.

[10]The potential in Block 1 (heat-rate improvement) is very plant-specific, accounts for only about 3% of the EPA's proposed emissions reduction by 2030, and is beyond the scope of this report.

Table 3: Arkansas Natural-Case Combined-Cycle Capacity (MW) and Capacity Factors

	Summer Capacity	2009	2010	2011	2012	2013
Thomas Fitzhugh	165.0	4.28%	5.71%	6.46%	7.90%	0.33%
Pine Bluff Energy Center	192.0	79.90%	71.72%	85.22%	88.29%	88.70%
Harry L. Oswald	548.0	3.34%	9.54%	16.51%	7.40%	6.62%
Dell Power Station	464.0[a]	8.31%	16.59%	10.82%	16.88%	4.73%
Union Power Partners	2020.0	23.82%	36.04%	40.63%	55.86%	35.42%
Hot Spring Power Project	630.0	30.92%	14.75%	20.49%	9.28%	31.22%
Magnet Cove	641.5.0	49.44%	32.50%	10.82%	45.76%	19.54%
Weighted Average	4,660.5	25.97%	28.02%	28.63%	38.23%	27.18%

[a]The 464-MW summer capacity reported by EIA for Dell in 2012 appears to be an error. The plant actually generated more than 550 MW in some hours in 2013 and is listed at 580 MW by its owner, the Associated Electric Cooperatives. Using a more-realistic capacity, Dell operated at even lower capacity factors than shown in this table.

The coal plants that are most likely to be retired prior to 2030, White Bluff and Independence, with or without the CPP, produced about 20,950 GWh of energy in 2013. (See page 7 for a discussion of the reasons for these plants to be shut.) Bringing the NGCC plants with the capacity factors of less than 70% in 2013 up to 70% would produce about 17,800 GWh of additional energy. Raising the NGCC capacity factors to about 78% would replace all the energy from Independence and White Bluff, without any renewables or load reductions.

The EPA uses nameplate capacity for the NGCCs in computing the feasible capacity factors. A unit's nameplate capacity is often greater than its summer or winter rated output, so a 70% capacity factor on nameplate capacity will require more than 70% capacity factor for the other ratings. Based on the summer ratings above (and a corrected 580 MW rating for Dell), the capacity factors equivalent to 70% of nameplate would be 77% to 84% and 82% overall for the various non-cogenerating units. These are readily achievable capacity factors for most NGCCs. While the AECC asserts that "the actual tested ratings of NGCCs, and not the nameplate ratings, should be used to determine a state's NGCC capacity under the proposed Rule" (Clean Power Plan Comments, September 30, 2014, at 4), the requirements for Arkansas would be the same at an 82% capacity factor based on summer rating.

2.1.2. Availability of Natural Gas

While some observers have expressed concerns about the availability of natural gas supply and storage in Arkansas (ADEQ October Presentation 5, Analysis of Clean Power Plan Buildings Blocks 2 & 3 at slides 11 and 12), the state is unusually well-supplied with gas. Arkansas produces an average of 3,132,000 MMBtu/day, or 131,000 MMBtu/hour, enough to power about 18,000 MW of NGCC at 100% capacity factor or 26,000 MW at 70%. Arkansas also lies on a massive pipeline corridor from the gas fields of Oklahoma, Texas, and Louisiana to the Midwest, carrying 7.8 million MMBtu/day of gas, of 325,000 MMBtu/hour, enough to power over 43,000 MW of NGCC with a heat rate of 7.2 MMBtu/MWh at 100% capacity factor or 62,000 MW at 70%. Obviously, not all of that gas will be used in Arkansas, since Arkansas has only a total of about 5,100 MW of coal plants subject to reduced usage or retirement, and had only about 700 MW of underutilized NGCC capacity in the average hour of 2012.[11] As long as gas is available in North America, which seems very likely for at least the next few decades, adequate supply should be available for Arkansas generation.

The EPA's Air Permits Program Database shows each of Arkansas NGCC operating at or above its rated capacity in some hours of each year, so they clearly have adequate connections to the gas pipeline system.

The Arkansas DEQ (October Presentation 5, Analysis of Clean Power Plan Buildings Blocks 2 & 3 at slide 11) also expressed concern that "only four years are available to complete necessary…pipeline infrastructure projects needed to ramp up NGCC utilization rate to 70%." The existing NGCCs in Arkansas have sufficient gas supply to run at 100% capacity now under most conditions.[12] Considering the enormous supplies available from the Arkansas wellheads and pipelines, no additional infrastructure is likely to be necessary for Arkansas NGCCs to operate at 70% capacity factors.

2.1.3. Existing Natural-Gas Combined-Cycle Capacity Can Increase Output

The Arkansas NGCCs are all connected to the transmission system, have sufficient gas supply (as demonstrated in the previous section), and most have permits that

[11]The existing gas-steam units will also be subject to reduced usage or retirement, but every MWh not generated at one of those units free up enough gas to produce at least 1.5 MWh and probably much more.

[12]The operator of Oswald indicates that its supplier, Natural Gas Pipeline of America, had limited gas availability due to system conditions for 66 days in the extraordinarily cold winter of 2013/14, about 18% of the year. Oswald could reach 70% annual capacity factor by operating at 85% capacity factor in the remainder of the year, if necessary. More likely, economic dispatch with carbon caps or allowance pricing would result in other NGCC plants running more than 70% and the less-efficient Oswald and Fitzhugh running less.

cover their entire potential to emit. For example, the ADEQ permit for the NGCCs contain the following features:

- Union Power Station:

> The CTs are permitted for continuous operation (i.e. 8760 hr/yr) while duct burners may be fired up to 4,000 hours per year each (285 MMBtu/hr HHV). (Permit No. 1861-AOP-R2 at 5)

- Pine Bluff Energy Center: The permit provides “The hourly emission rates...based on a worst-case scenario” of 12 lb/hr of particulates for the first combined-cycle set running on gas and 14.8 lb/hr for the second set, and sets the annual emission level at 56.1 T/year (9,350 hours of operation on gas) and 66.6 T/year (9,000 hours), respectively (Permit No.1822-AOP-R1 at. 26 and 27). The corresponding limits for NO_X are equivalent to 9,000 and 15,500 full-load gas-fired hours. The higher annual emissions limits allow for full-load operation even with substantial use of fuel oil, which is unlikely to be economic in Arkansas.

- Magnet Cove:

> The units are expected to operate continuously (8,760 hours per year), except for maintenance and repair activities or during periods of low electrical demand. The duct burners are fired to meet peak electrical demands at a maximum of 2,500 hours per year.

  The annual NO_X emission limit is more than 13,000 times the hourly limit (Permit No. 1987-AOP-R1 at 10 and 15)

- Dell: Annual emission limits are 8,760 times the hourly limits. (Permit No. 1903-AOP-R8 at 17)

- Hot Spring Power: The annual NO_X emission limit is about 8,000 times the hourly limit) and about 14,000 times the average hourly emissions at high load.[13]

- The Arkansas DEQ also expresses concern (at 12) that “Increased generation from NGCC may trigger…PSD review due to increased emissions of other pollutants.”[14] The ADEQ air permits generally allow most of the NGCCs to

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[13]Hourly Limits Permit No. 1936-AOP-R6 at 7; Emissions data from EPA Air Pollution Monitoring Database

[14]The only criteria pollutant that NGCCs emit in any significant quantity is NO_X.

> operate at full capacity all year long.[15] Increased use of a facility, within existing permit levels, would only trigger PSD review if the increase was caused by a major modification or reconstruction.[16] Increased operation of an NGCC due to increased economic dispatch would not constitute a major modification. The EPA Regulatory Impact Analysis notes (at 9-14),
>
> > In the period of analysis (through 2025) the EPA anticipates few sources will trigger either the modification or the reconstruction provisions…. the EPA believes it unlikely that [power plants] will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations.

In any case, PSD review would only trigger a BACT review, and all modern NGCCs would meet BACT.

Nor are NGCCs technically limited in their capacity factors. In July 2012, with favorable market conditions, Pine Bluff and Magnet Cove ran at well over 90% capacity factor and Union Power at about 70%. Carbon emission limits will create even more favorable conditions for NGCC dispatch after 2020, until renewable energy starts to crowd out gas.

In 2013, about 67 NGCCs nationwide ran at capacity factors ranging from 70% to 94%. A capacity factor of 70% or even 85% is not ambitious for an NGCC's whose output is needed.

2.2. NGCC Efficiency and Emissions

The EPA's analyses assume that the average emission rates for the existing NGCCs will remain constant as the output of the units increase. This is a conservative assumption.

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[15]Fitzhugh and Oswald are limited to about 60% capacity factor by their air permits, but they are unlikely to be dispatched even that much, given their lower efficiency than the other NGCCs.

[16]From EPA Regulatory Impact Analysis at 9-2–9-3:

> Reconstructed sources are defined, in general, as existing sources that replace components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, and for which compliance with standards of performance for newly constructed sources is technologically and economically feasible….A modification is any physical or operational change to a source that increases the source's maximum achievable hourly rate of emissions (i.e., lbs/hour). The EPA, through regulations, has determined that certain types of changes (such as pollution control projects) are exempt from consideration as a modification.

The 2012 heat rates and emission rates for the NGCCs (other than the Pine Bluffs cogenerator) reflect relatively low levels of operation. In the periods in which the units operate near full power, the four plants comprising 2×1 combined-cycle blocks driven by frame turbines (GE F7A turbines at Hot Spring, Union and Dell, Siemens 501G at Magnet Cove) typically have CO_2 emission rates around 820 lb/MWh (compared to emission rates of 840 to 920 lb/MWh in 2012). The Oswald and Fitzhugh typically have high-load emission rates of around 930 lb/MWh (compared to average emission rates of 1,010 to 1,130 lb/MWh in 2012).

The improvement of each plant's emission rates as output increases may be offset by the fact that the plants with the greatest opportunity for increasing output have the highest heat rates and emission rates.

3. Building Block 3: Renewables Contribution

3.1. Renewables Target

Some parties have complained that the EPA based its renewable target for Arkansas on the Kansas renewable portfolio standard, on the grounds that Kansas has a larger potential for wind energy than does Arkansas (e.g., AECC September 2014 Comments at 20). In fact, the Kansas RPS is 20% in 2020, while the EPA target for Arkansas is only 2.6% in 2020 and 7.2% in 2030. The Plan's state goals are modest compared to the renewables targets that have been shown to be feasible by many other states that are no better positioned than Arkansas for renewables development. Table 4 compares the EPA renewable targets for Arkansas with the renewable portfolio standards in other states without particularly large potential for low-cost wind (such as Kansas, Nebraska, Oklahoma, and Texas) or solar (such as Nevada, Arizona, and Colorado).

Table 4: Renewable Targets as Percent of State Retail Sales

	EPA Target	State Renewable Portfolio Standards										
	AR	CT	DE	DC	MD	MA	MO	NJ	NC	OH	PA	RI
2012	2.6%	10%	7%	8%	9%	11%	2%	9%	6%	2%	10%	7%
2013		12%	9%	9%	11%	12%	2%	10%	6%	2%	10%	8%
2014		14%	10%	11%	13%	13%	5%	13%	6%	3%	11%	9%
2015		15%	12%	12%	13%	14%	5%	14%	12%	4%	11%	10%
2016		16%	13%	14%	15%	15%	5%	15%	12%	5%	14%	12%
2017	2.8%	17%	15%	15%	16%	16%	5%	16%	12%	6%	14%	13%
2018	3.0%	18%	16%	17%	18%	17%	10%	18%	20%	7%	15%	15%
2019	3.2%	20%	18%	18%	17%	18%	10%	20%	20%	8%	15%	16%
2020	3.5%	21%	19%	20%	18%	19%	10%	22%	20%	9%	16%	
2021	3.8%		20%	20%	19%	20%	15%	24%	23%	10%	18%	
2022	4.1%		21%	20%	20%	21%				11%		
2023	4.5%		22%	20%		22%				12%		
2024	4.9%		23%			23%				13%		
2025	5.3%		24%			24%						
2026	5.7%		25%			21%						
2027	6.2%		25%			22%						
2028	6.7%					23%						
2029	7.2%					24%						
2030						25%						

Notes:
Arkansas EPA target from the Technical Support Document.
RPS values from DSIRE RPS Data Spreadsheet (http://www.dsireusa.org/rpsdata/).
The RPS values for Massachusetts exclude the municipal-waste standard.

It is important to recall that replacing coal and other fossil fuels is an environmental program, and like other pollution controls required by EPA and ADEQ, that program may cost money.[17]

The EPA does not require any particular mix of resources to achieve compliance. SWEPCo expresses its concern that "Without codification of the renewable and EE targets EPA might disapprove of mass goal. [EPA] Likely would require state EE and RE legislation" (October Presentation 1 at slide 15), but so long as each generator's emissions are limited to a level that collectively meets the state (or

[17]The ADEQ October Presentation 5 (Blocks 2 and 3 at slide 14) could be read to suggest that renewables be required only to their "Economic Potential," and SWEPCo suggests limiting renewables to "State assumed levels of renewables and EE" (October Presentation 1 at slide 15). Either of these approaches would be a significant error. The EPA has never limited compliance requirements to measures that pay for themselves or to those a State has already adopted.

regional) requirement, the EPA's goal will be met. Nothing in the Plan regulates how the reduction in operation of the covered units is achieved, whether through legislative mandates, Arkansas PSC regulations, or economic decisions made by the plant owners to stay within the carbon-emission allowances they are given in the State Implementation Plan.

3.2. Arkansas Can Import Renewable Energy

Wind resources are better in the SPP Plains states, including Arkansas's neighbors Oklahoma and Texas, and along the Gulf coast, than in Arkansas. A significant portion of Arkansas's renewable requirement will probably be met with imports of wind from the west and south. Those imports can be concentrated in off-peak hours and seasons, as needed to accommodate transmission constraints, with local Arkansas fossil generation carrying more of the load on peak.

Arkansas has major transmission interconnections with the Gulf coast, through Entergy's transmission system, and with the wind-rich SPP. Indeed, about 30% of Arkansas load (SWEPCo, OG&E, Empire District, and the Carroll, Ozarks, Arkansas Valley, and Southwest Arkansas coops) is in SPP, and should have little difficulty sourcing Plains wind energy. The Arkansas utilities have significant amounts of out-of-state wind capacity in service or under contract, including about 200 MW for the Arkansas electric coops, 500 MW for SWEPCo (of which about 100 MW would be attributed to Arkansas), and 800 MW for OG&E (of which about 80 MW would be attributed to Arkansas).

The Plains and Eastern Clean Line would deliver 3,500 MW of power to converter stations in central Arkansas and the Memphis area over a high-voltage DC line from the wind-rich Oklahoma Panhandle and surrounding areas of the Texas Panhandle and Kansas. Completion of the project is expected in 2018, well before the compliance period under the Plan. The central-Arkansas converter station would deliver 500 MW. In addition, Arkansas can access some of the 3,000 MW to be delivered in the Memphis area over a number of transmission ties, including the following:

- a 500-kV line through the Oswald plant and on to Little Rock;
- a 500-kV line north to Dell and the Independence plant, and southwest to the Little Rock area;
- a 230-kV line through Mississippi to the Ritchie plant and on to Pine Bluff;
- three 161-kV lines running north and west to Jonesboro and the Moses, Bailey and Independence plants.

The reduced utilization or retirement of the various fossil plants would free up capacity on the lines to bring capacity and energy from Memphis to Arkansas's load centers.

The 500-MW converter station, delivering wind energy at a 40% capacity factor, would meet EPA's renewable target through 2025, even without any in-state wind, solar, or hydro, or imports over the existing alternating-current transmission system or from the Memphis-area converter.

Wind imports appear to be a low-cost resource, as the following examples suggest:

- Austin purchased 300 MW of wind in February 2014 at about 2.6–3.6¢/kWh.
- SWEPCo purchased 359 MW in January 2012 that were "expected to slightly lower SWEPCo's projected overall cost to customers."[18]
- Public Service of Oklahoma contracted for 600 MW of wind in October 2013 and said, "Estimates show the agreements will reduce customer costs by $53 million in the first year, with annual savings growing over the 20-year length of the contracts."[19]
- In September 2012, Alabama Power purchased 400 MW from wind farms in Oklahoma and Kansas under a "20-year contract for wind [that] locks in a price for power that's lower than it could cost the company to generate it."[20]
- The Annual Economic Impacts of Kansas Wind Energy 2014 Report reported that power from the 2012 wind farms at Ironwood and Post Rock cost $3.5¢/kWh.[21]
- The DOE's 2013 Wind Technologies Market Report (August 2014, Figure 46) reports wind contract prices for the Interior region (including Oklahoma,

[18]"AEP SWEPCO Signs Wind Power Purchase Agreements for 359 Megawatts," SWEPCo news release 1/25/12, www.swepco.com/info/news/ViewRelease.aspx?releaseID=1183

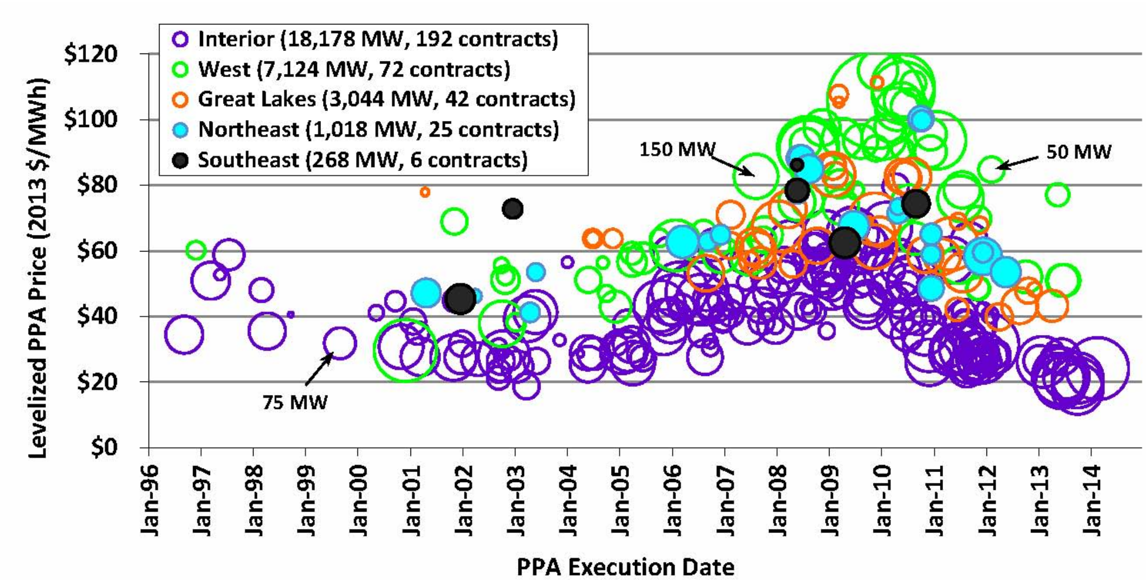
[19]PSO Wind Contracts Win Approval PSC news release 2/4/14 www.psoklahoma.com/info/news/viewRelease.aspx?releaseID=1518

[20]Spencer, Thomas, "Alabama Power Purchases Electricity Generated by Wind in Oklahoma, Kansas" Birmingham News 9/29/2012 rev. 9/30/2012 blog.al.com/spotnews/2012/09/alabama_power_purchases_electr.html

[21]Anderson, Alan, Britton Gibson, Scott White, and Luke Hagedorn. 2014. Kansas City, Kans.: Polsinelli, at 4.

Kansas, and the Texas Panhandle) falling from about 3.5¢/kWh for 2011 contracts to about 3¢/kWh in 2012 and 2¢/kWh in 2013. That figure is reproduced below as Figure 1.[22]

Figure 1: Levelized Wind PPA Prices by PPA Execution Date and Region



Note: Size of "bubble" is proportional to project nameplate capacity
Source: Berkeley Lab

Ironically, SWEPCo (October Presentation 1 at slide 15) suggests that having goals "based on in-state renewable projections" would be helpful since such goals "would help ensure state remains energy self-sufficient," even though its generation resources serve SWEPCo and PSO customers in four states. Arkansas is part of a vigorous multistate power market, as demonstrated by the overlap of service territories with state lines, by the out-of-state ownership of many Arkansas power plants (see Table 2, above), and by the participation of the Arkansas utilities in the SPP and MISO energy markets. Especially under the mass-based compliance approach, renewables procured anywhere in the interconnected regions will contribute to Arkansas's compliance, so long as they reduce the operation of the fossil-fired power plants.

Some commenters vastly overstate the costs of renewable energy in Arkansas. MISO shows the renewables costing $237/ton of carbon reduction,[23] implying a

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[22]Wiser, Ryan, and Mark Bollinger. 2014. "2013 Wind Technologies Market Report." Washington, D.C.: U.S. DOE.

[23]"GHG Regulation Impact Analysis–Initial Study Results." MISO presentation to Planning Advisory Committee, September 1 2014, at slide 7.

renewable cost of $250/MWh at EPA's estimate of the Arkansas coal emission rate after the Block 1 heat-rate improvement, or about $100/MWh if the wind is backing down NGCCs. Since utilities have been purchasing wind energy at $50/MWh or less, and since wind energy saves on fuel, variable O&M, and capacity costs, MISO's claimed costs of renewables are vastly overstated.[24]

3.3. Local renewables should also be included in the plan

3.3.1. Solar Photovoltaic

Photovoltaics are an important resource category in jurisdictions with much less sunshine than Arkansas, including Ontario, Massachusetts, Vermont, Germany and more recently Minnesota and Wisconsin. The following are some examples of the falling costs of utility-scale solar:

- Georgia Power recently contracted for 515 megawatts of PV capacity, planned for build-out in 2015 and 2016, at an average price of 6.5¢. Georgia Power received bids for 5,100 MW.
- In Texas, Austin Energy recently signed a PPA for 150 megawatts of solar for less than 5 cents per kilowatt-hour.
- In Colorado, Xcel Energy agreed to purchase 170 megawatts of solar power, after finding that they were less expensive than natural gas plants.
- Xcel Energy Minnesota contracted for 187 MW of PV capacity for an expected levelized price of 7.3¢/kWh over 25 years.
- In Utah, Rocky Mountain Power has contracted for 400 MW of solar at prices below its estimates of avoided cost.

Solar is especially valuable in areas with existing or future T&D constraints, to avoid need for additional facility investments. Some smaller utility-scale PV facilities can provide these benefits, as can most customer-sited solar installations.

[24]The reported high cost for renewables may be explained by the cryptic note "Present value calculation for costs is the driver for the higher cost" ("GHG Regulation Impact Analysis–Initial Study Results." MISO presentation to Planning Advisory Committee, September 1 2014 at 7). Perhaps MISO assigned the present-value of all the renewables costs to a fraction of their operating lives.

Between central and customer-sited solar installations, North Carolina added about 430 MW of solar in 2011–2013, and another 70 MW in the first half of 2014.[25] The solar resource is very similar in North Carolina and Arkansas, so Arkansas should be able to install at least as much solar in the next five and a half years as North Carolina has in the last three and a half years.

3.3.2. Arkansas Wind

A study by NREL estimated that Arkansas had potential of 9,200 MW and about 26,900 GWh of wind resources, using just 1.34% of the state's land, and with the following limits: [26]

- assuming only 80 m hub height, even though new turbines are increasingly being built with hubs at 100 m or above.
- including only sites with capacity factors over 30%.
- excluding 60% of the high-wind land area, to reflect "protected lands (national parks, wilderness, etc.), incompatible land use (urban, airports, wetland, and water features), and other considerations."

The EPA goals assume that Arkansas would add only about 630 GWh of renewables by 2020 and 4,700 GWh by 2029, so Arkansas could meet the entire renewable target with 17.5% of the in-state high-wind potential.

3.3.3. Hydro Development at Non-Powered Dams

While EPA does not count existing hydro generation in its renewable category, and does not assume any new hydro generation in goal-setting, any new renewable energy would count towards the goals.[27] Some observers, such as Ms. Kelly of the APA (op. cit.), believe that hydro would not count towards the goals; this assumption is patently untrue.

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[25]U.S. Solar Market Trends 2013, July 2014, at Table 4; U.S. Solar Market Trends 2010, June 2011, at Table 2; Solar Market Insight Report 2014 Q1 at Figure 2.2; U.S. Solar Market Insight Report 2014 Q2.

[26]Excel file wind_potential_80m_30percent.xls, available for download online at apps2.eere. energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=ar.

[27]There would be little effect on the stringency of compliance, whether the existing hydro is counted in both the baseline and the rate-based compliance formula, or is counted in neither the baseline nor the formula. The decision by EPA to omit existing hydro generation is reasonable.

A 2014 study by DOE found that Arkansas has 1,108 MW and 5,964 GWh of additional potential capacity along stream reaches that do not currently have dams or other infrastructure.[28] A 2012 study by NREL found adding generation to currently non-powered dams could produce 1,136 MW in Arkansas; assuming capacity factors similar to those in the DOE, these plants would produce about 6,000 GWh.[29] The capacity at the existing dams could be developed more quickly and would have less environmental effect than the capacity that would require impoundments.

The renewable-energy targets used in EPA's determination of Arkansas's goals could be met with about 6% of the potential at existing dams in 2020 and 80% in 2029.

3.4. Summary of Renewable Energy Potential for Arkansas

Table 5 summarizes the data on renewable potential for Arkansas, based on the capacity data presented above, with the addition of specific estimates for capacity and capacity factor, as necessary.

Table 5: Arkansas Renewable-Energy Potential

	2012	2020	2029
Arkansas Renewable Energy (GWh)			
Actual	1,660		
Targets		2,288	4,709
Increment		628	3,048
	Potential GWh	**Potential as % of Incremental Target**	
		2020	2029
Imports (wind at 40% capacity factor)			
500 MW at AR DC converter	1,752	279%	57%
500 MW from Memphis converter	1,752	279%	57%
500 MW over AC lines	1,752	279%	57%
Domestic Wind			
9,200 MW (NREL)	26,900	4284%	882%
Solar at 23% capacity factor			
500 MW	1,007	160%	33%
Hydro at Existing Dams			
1,136 MW	6,000	956%	197%

[28]"New Stream-Reach Hydropower Development" DOE/EE 1077. April 2014. Washington, D.C.: U.S. DOE at 2nd unnumbered page.

[29]Hadjerioua, Boualem, Yaxing Wei and Shih-Chieh Kao. 2102. "An Assessment of Energy Potential at Non-Powered Dams in the United States." Washington: D.C.: U.S. DOE. at 25, Table 4.

The potential adds up to nearly thirteen times the EPA's renewable-energy target for 2030. While not all of this potential will be developed, Arkansas certainly can exceed the EPA targets with imports, indigenous renewables, or a combination of the two.

3.5. Recommended Rule Clarifications for Building Block 3

The EPA should clarify that, where renewable energy is generated in one state and delivered to a utility or other entity serving load in another state, through ownership or firm purchase, the receiving entity may assign that energy to any state in which it has load responsibility. Such energy would not be included in the rate-based compliance formula for the generating state, but would be included in the formula for the designated purchasing state.[30]

Renewable energy sources—especially hydroelectric generation, and to a lesser extent wind and solar—are subject to significant annual variation due to the vagaries of the weather. Lower renewable output will typically require additional fossil generation, increasing carbon emissions above the average expected levels given installed resources and demand levels. This should not be a problem for most states in the transition period, since the only requirement is that the average emissions over the decade be less than the state's allocation, and high-rainfall years will tend to offset low-rainfall years. The EPA should allow SIP provisions that would permit the states to compensate for weather-related compliance shortfalls in a particular year with excess compliance in earlier and later years. The three-year averaging allowed by the rule (preamble at section VIII.B.2.c.) would address this concern to some extent, but may be inadequate under drought conditions.

4. Building Block 4: Energy Efficiency

The EPA's assumptions regarding Arkansas energy-efficiency potential are quite modest, compared to Arkansas's current portfolios and the experience of other states. In part, this is due to apparent under-reporting of energy-efficiency achievements in Entergy's report to EIA. Table 6 compares the energy-efficiency report for 2012 by the IOUs to EIA and the APSC.

[30]If the State Implementation Plan relies on mass-based compliance, no such accounting rule is required, since compliance will be demonstrated by reduction in the carbon emissions from covered generators in the state.

Table 6: Incremental IOU 2012 Energy-Efficiency Savings Reported to EIA and APSC, MWh

	EIA Report	APSC Report, Evaluated
Entergy Arkansas Inc.	26,300	107,627
Empire District Electric	158	158
Oklahoma Gas & Electric	8,139	7,596
Southwestern Electric Power	17,680	17,767
Total	52,277	133,148

The data from the APSC report indicates that the IOU energy-efficiency programs saved about 0.47% of IOU sales and about 0.28% of total Arkansas sales in 2012.[31] In 2013, the IOUs reported evaluated savings of about 0.82% of IOU sales, or about 0.5% of total Arkansas sales.

The Arkansas PSC does not currently mandate or review energy-efficiency programs by the coops. While the Arkansas Electric Cooperative Corporation (AECC) asserts that "AECC and its member-owners have a rich history of demand-side management and energy efficiency educational programs and services" (AECC Clean Power Plan Comments, September 30, 2014 at 22), AECC's list of its efforts is limited to distributing information and some audit programs (none of which are listed on its web site), which produce little or no savings without incentive, direct installation, and facilitation of retrofits. Only one coop reports energy-efficiency savings to the EIA. The coops can and should adopt the modern programs that the investor-owned utilities have been ramping up over the last few years.

The AECC also claims that "it is unlikely that the State of Arkansas will get credit for AECC's past actions because it is not an improvement to existing load" (ibid.). That is correct: the coops have not demonstrably reduced load, so Arkansas will get little credit for the coops' inaction.

The AECC also fails to understand that energy-efficiency savings increase the denominator in the rate-based compliance formula (ibid. at 23) and incorrectly asserts that "EE benefits prior to 2020 will not count toward meeting the Clean Power Plan goals" (ibid., Appendix B at slide 21). In any case, the EPA did not intend that its energy-efficiency scenario be interpreted as a maximum potential for energy-efficiency savings. For example, the EPA assumes no new energy-efficiency savings between 2012 and 2017. As the EPA itself says,

[31]This error is not systematic in the reporting. Entergy's 2011 reports to EIA and the PSC match to the MWh.

> The scenario…does not represent an EPA forecast of business-as-usual impacts of state energy efficiency policies or an EPA estimate of the full potential of end-use energy efficiency available to the power system, but rather is intended to represent a feasible policy scenario showing the reductions of CO2 emissions from fossil fuel-fired EGUs resulting from accelerated use of energy efficiency policies in all states, generally consistent with ongoing industry trends. 79 FR 34872

In the case of Arkansas, the IOUs' energy-efficiency efficiency efforts have already produced larger savings than the EPA expects the state to achieve through 2019. The EPA's assumed annual savings cap of 1.5% of retail sales has already been exceeded by several states (Arizona, California, Hawaii, Massachusetts, Michigan, Rhode Island and Vermont). The Northwest Power Planning Council is expecting to surpass that level for its four-state region by 2016.

Table 7 shows the annual and cumulative savings for the EPA assumptions, the current Arkansas targets with slow expansion to 1.5% annually, and the current Arkansas targets with more aggressive portfolio expansion to 2.15% annually. In modeling the cumulative savings, I adopted EPA's assumption that savings from each year's installations decay linearly over 20 years.[32]

[32]This assumption is embedded in the EPA's data file for Greenhouse Gas Abatement Scenario 1, http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-ghg-abatement-measures-scenario1.xlsx (Excel spreadsheet).

Table 7: EPA Assumptions and Arkansas Targets for Energy Efficiency, as % Retail Sales

	EPA Target		IOU Actual	Arkansas Targets							
				Modest				*Aggressive*			
	Annual	Cum		IOU	Coop	Total	Post-2012 Cum	IOU	Coop	Total	Post-2012 Cum
	a	b	c	d	e	f	g	h	i	j	k
2011			0.22%	0.25%		0.15%		0.25%		0.15%	
2012			0.47%	0.50%		0.30%		0.50%		0.30%	
2013			0.82%	0.75%		0.45%	0.45%	0.75%		0.45%	0.45%
2014				0.75%		0.45%	0.86%	0.75%		0.45%	0.86%
2015				0.90%	0.25%	0.61%	1.41%	0.90%	0.25%	0.61%	1.41%
2016				1.05%	0.50%	0.77%	2.06%	1.15%	0.50%	0.83%	2.12%
2017	0.11%			1.20%	0.75%	0.92%	2.83%	1.40%	0.75%	1.04%	3.00%
2018	0.31%			1.35%	0.75%	1.01%	3.62%	1.65%	0.75%	1.19%	3.95%
2019	0.51%			1.50%	0.90%	1.14%	4.47%	1.90%	0.90%	1.38%	5.00%
2020	0.71%	1.52%		1.50%	1.05%	1.18%	5.29%	2.15%	1.15%	1.60%	6.17%
2021	0.91%	2.31%		1.50%	1.20%	1.22%	6.07%	2.15%	1.40%	1.67%	7.30%
2022	1.11%	3.24%		1.50%	1.35%	1.26%	6.81%	2.15%	1.65%	1.74%	8.38%
2023	1.31%	4.28%		1.50%	1.50%	1.31%	7.52%	2.15%	1.90%	1.80%	9.42%
2024	1.50%	5.42%		1.50%	1.50%	1.31%	8.16%	2.15%	2.15%	1.87%	10.41%
2025	1.50%	6.46%		1.50%	1.50%	1.31%	8.72%	2.15%	2.15%	1.87%	11.29%
2026	1.50%	7.41%		1.50%	1.50%	1.31%	9.22%	2.15%	2.15%	1.87%	12.07%
2027	1.50%	8.26%		1.50%	1.50%	1.31%	9.64%	2.15%	2.15%	1.87%	12.74%
2028	1.50%	9.03%		1.50%	1.50%	1.31%	10.01%	2.15%	2.15%	1.87%	13.32%
2029	1.50%	9.71%		1.50%	1.50%	1.31%	10.31%	2.15%	2.15%	1.87%	13.81%
2030	1.50%	9.71%		1.50%	1.50%	1.31%	10.55%	2.15%	2.15%	1.87%	14.21%

Column Notes:
a. From GHG Abatement Measures Appendix 5-4.
b. From State Goal Data Computation workbook.
c. From utility annual reports to APSC.
d. Arkansas IOU goals to 2015, 0.15% annual increase per EPA to 1.5% cap, per EPA.
e. [d] lagged by four years, starting in 2015.
f. [d] × 60% + [e] × 27%, reflecting fraction of Arkansas retail sales by IOUs and coops.
g. Computed from EPA Scenario 1 workbook, with [f] as first-year savings.
h. Arkansas IOU goals to 2015, 0.25% annual increase (as in 2011–2013) to 2.15% cap.
i. [h] lagged by four years, starting in 2015.
j. [h] × 60% + [i] × 27%
k. Computed from EPA Scenario 1 workbook, with [j] as first-year savings.

Even excluding (1) any energy-efficiency efforts by municipal utilities and (2) all coop savings through 2014, these cases result in cumulative savings about four times EPA's assumptions by 2020. In 2020, the increased efficiency above EPA's assumptions would be equivalent to about 40–50 lb/MWh, or about 7% of EPA's target for Arkansas's reduction in emission from 2012 to 2020.

The analysis from assumed that energy-efficiency programs would cost about $70/ton or roughly 7¢/kWh, and appears to have neglected to include the energy, capacity, and transmission-and-distribution costs associated with energy efficiency.[33] Energy efficiency generally has costs on the order of 5¢/kWh and negative net costs, after accounting for the avoided costs.[34]

5. Summary

In this section, I combine reasonable levels of redispatch, energy-efficiency savings and renewable development to demonstrate the achievability of the EPA's emissions-reduction target for Arkansas. I assume the energy-efficiency savings of the modest case from Table 7. The generation requirement equals the state sales forecast used by the EPA (20140602tsd-ghg-abatement-measures-scenario1.xlsx), plus 10% losses and net exports, which are set at the out-of-state ownership shares of the coal plants (and which therefore decline as coal-plant output declines). See Table 8.

I assume that in 2020, White Bluff retires, Turk capacity factor falls to 68%, and the capacity factors of the other three coal plants fall to the 30–35% range. After 2020, I ramp down the capacity factors for the remaining coal plants, with Flint Creek retiring in 2027, Turk reaching 60% capacity factor in 2030, and the other plants reaching capacity factors near 20%. For the NGCC plants in 2012, I assume that Oswald and Fitzhugh operate as they did in 2012 (at 7% capacity factor and high emission rates), Pine Bluff operates as it did in 2012, and that the other four

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[33]"GHG Regulation Impact Analysis–Initial Study Results." MISO presentation to Planning Advisory Committee, September 1 2014, at slide 7. That error appears to have contributed to MISO's conclusion (October Presentation 3 at slides 7, 8) that compliance will cost MISO $20B–$80B.

[34]The Virginia SCC Staff similarly claims,

> The Proposed Regulation's claim that overall customer bills will go down…could only be accurate if the costs of reducing CO_2 emissions through energy efficiency programs are less than the variable operating costs (primarily dispatch costs) that would be avoided by the compliance action since compliance requires the displacement of existing generation." (Comments at 26–27)

The Staff even denies that variable costs are variable, asserting that if

> variable operating costs do exceed energy efficiency costs, there are two possible outcomes: 1) aggregate bills are lower and the resource provider receives reduced compensation, or 2) rates are adjusted and aggregate bills are increased." (Comments at 28)

Energy-efficiency programs will also avoid the fixed operating costs and capital additions of retired plants, as well as transmission and distribution capacity additions. The VSCC Staff complains that energy-efficiency programs will "reduce revenues that are necessary to support existing…transmission and distribution investments" (Comments at 27), but ignores the fact that they will also avoid the need to expand T&D capacity.

plants operate at an average capacity factor around 55%, based on nameplate rating.[35] Thereafter, I ramp down the combined-cycle generation to keep total generation near the output requirement. I also ramp down the oil and gas steam generation, to reflect pending retirements and the effects of higher renewable generation. For the "other generation" category (mostly combustion turbines), I keep generation fixed at the average of 2012 and 2013 levels.

Table 8: Redispatch in the Example Compliance Plan

						Generation GWh					
	AR BAU Sales	Exports	Modest EE	Sales w EE	Output Req	Coal	NGCC	OG Steam	Other Covered	Non-covered	Total
2012	46,912	13,417		46,912	65,020	28,379	15,651	860	1,311	18,819	65,020
2013	47,317	9,369	0.45%	47,106	61,186	31,889	11,094	1,019	153	16,339	60,494
2014	47,725	9,538	0.86%	47,314	61,583	31,755	11,094	940	732	16,339	60,860
2015	48,137	9,538	1.41%	47,460	61,745	31,755	11,094	940	732	16,339	60,860
2016	48,553	9,538	2.06%	47,550	61,844	31,755	11,094	700	732	17,973	62,254
2017	48,972	9,538	2.83%	47,587	61,884	31,755	11,094	700	732	18,389	62,670
2018	49,395	9,538	3.62%	47,608	61,907	31,755	11,094	700	732	18,878	63,159
2019	49,821	9,538	4.47%	47,595	61,893	31,755	11,094	700	732	19,476	63,757
2020	50,251	5,060	5.29%	47,595	57,415	12,505	23,159	600	732	20,565	57,562
2021	50,685	4,969	6.07%	47,609	57,339	12,190	23,013	600	732	21,216	57,750
2022	51,122	4,829	6.81%	47,639	57,231	11,630	22,601	600	732	21,919	57,483
2023	51,563	4,688	7.52%	47,684	57,141	11,070	22,350	600	732	22,623	57,375
2024	52,008	4,478	8.16%	47,765	57,019	10,350	22,115	500	732	23,326	57,024
2025	52,457	4,337	8.72%	47,882	57,007	9,791	22,110	500	732	24,030	57,163
2026	52,910	4,197	9.22%	48,033	57,034	9,231	21,954	500	732	24,733	57,151
2027	53,367	3,769	9.64%	48,220	56,811	8,404	21,837	400	732	25,437	56,810
2028	53,827	3,671	10.01%	48,441	56,956	8,184	21,838	400	732	26,140	57,293
2029	54,292	3,573	10.31%	48,696	57,139	7,963	21,500	400	732	26,843	57,439
2030	54,761	3,475	10.55%	48,986	57,359	7,742	21,200	400	732	27,547	57,621

The "Non-covered Generation" category in Table 8 includes the new renewables listed in Table 9. The 2020 renewable capacity in each category is a small fraction of the potential estimated in Table 5; other than wind imports, the same is true for the 2030 capacity. The timing of the renewables reflects the lead times, which are minimal for wind imports from the Plains and for solar, with in-state wind and addition of capacity at existing dams taking longer for licensing, design, and construction. Each of these categories of renewables can be developed faster to back down the NGCCs and/or support further reductions in coal use.

[35] At the lower summer ratings, this is equivalent to a 65% capacity factor.

Table 9: Assumed Renewable Additions in the Example Compliance Plan

	Additions (Megawatts)				
	Wind				**Total**
	Imports	Arkansas	Solar	Hydro	**GWh**
Capacity Factors	40%	33%	25%	60%	
2016	100		20		394
2017	200		50		810
2018	300	10	100		1,299
2019	400	20	200		1,897
2020	500	30	500	10	2,986
2021	600	40	600	20	3,637
2022	700	50	700	40	4,341
2023	800	60	800	60	5,044
2024	900	70	900	80	5,747
2025	1,000	80	1,000	100	6,451
2026	1,100	90	1,100	120	7,154
2027	1,200	100	1,200	140	7,858
2028	1,300	110	1,300	160	8,561
2029	1,400	120	1,400	180	9,265
2030	1,500	130	1,500	200	9,968

Applying emission rates by generation category yields an estimate of total emissions in the example compliance plan; see Table 10. On a mass basis, this plan would reduce emissions 41% by 2020, an average of 47% over 2020–2029 (compared to a target of 41%), and 54% in 2030 (compared to a target of 44%). The average emission rate under the EPA formula would be about 878 lb/MWh for 2020–29 (compared to the target of 968 lb/MWh) and 734 lb/MWh for 2030 (compared to a target of 910 lb/MWh).

This compliance trajectory should be readily achievable. The Arkansas DEQ can establish a SIP that exceeds the EPA goals, adopt a mass-based target, assign emission allowances to each covered unit, and accept allowances from other states. Inclusion of allowance prices in planning and dispatch would result in reduced usage and/or retirement of coal capacity, while meeting local reliability constraints. If any one component of the compliance trajectory (four types of renewables, energy-efficiency programs, and increased output at four NGCC plants) were to be problematic, the generation owners would purchase more allowances, dispatch would shift more towards low- and no-CO_2 resources, utilities can accelerate their energy-efficiency programs, and addition of renewables will be more attractive to utilities and more profitable for developers.

Table 10: Emissions from the Example Compliance Plan

	Emission Rates lb/MWh				Emissions (MT)					Change from 2012
	Coal	NGCC	OG Steam	Other Covered	Coal	NGCC	OG Steam	Other Covered	Total	
2012	2,276	827	1,446	602	32.3	6.5	0.6	0.4	39.8	
2013	2,279	827	1,446	602	36.2	4.6	0.7	0.0	41.6	5%
2014	2,275	827	1,446	602	36.1	4.6	0.7	0.2	41.6	5%
2015	2,275	827	1,446	602	36.1	4.6	0.7	0.2	41.6	5%
2016	2,275	827	1,446	602	36.1	4.6	0.5	0.2	41.4	4%
2017	2,275	827	1,446	602	36.1	4.6	0.5	0.2	41.4	4%
2018	2,275	827	1,446	602	36.1	4.6	0.5	0.2	41.4	4%
2019	2,275	827	1,446	602	36.1	4.6	0.5	0.2	41.4	4%
2020	2,232	781	1,446	602	14	9.0	0.4	0.2	23.7	−41%
2021	2,231	781	1,446	602	13.6	9.0	0.4	0.2	23.3	−41%
2022	2,231	781	1,446	602	13	9.0	0.4	0.2	22.7	−43%
2023	2,231	781	1,446	602	12.4	9.0	0.4	0.2	22.1	−45%
2024	2,232	781	1,446	602	11.6	9.0	0.4	0.2	21.2	−47%
2025	2,232	781	1,446	602	10.9	9.0	0.4	0.2	20.6	−48%
2026	2,232	781	1,446	602	10.3	9.0	0.4	0.2	19.9	−50%
2027	2,234	781	1,446	602	9.39	9.0	0.3	0.2	18.9	−52%
2028	2,233	781	1,446	602	9.14	9.0	0.3	0.2	18.7	−53%
2029	2,232	781	1,446	602	8.89	9.0	0.3	0.2	18.4	−54%
2030	2,231	781	1,446	602	8.64	9.0	0.3	0.2	18.2	−54%

The EPA's targets for Arkansas are feasible. The more-modest reductions required of most other states should be equally achievable.

5.1. Other Issues in the Regulations

5.1.1. Mass-Based Compliance Is Preferable to the Rate-Based Approach

The proposed regulations give each state the choice of a rate-based or mass-based compliance targets. Given the practical and administrative advantages of the mass-based approach, the EPA should encourage all states to adopt it. To that end, EPA should make the computation of the mass-based targets as simple as possible to reduce uncertainty for states taking the preferred compliance path. For example, as an alternative to the multiple scenarios suggested in the proposed rule, the EPA might allow states to adopt a mass emissions reduction at the percentage reduction required under the rate-based formula, so that Arkansas could opt to reduce average emissions in 2020–2029 by 41% from 2012, and reduce emissions by 44% for 2030 and beyond.

5.1.2. Multi-State Compliance

Every analysis of the costs of compliance indicates that regional compliance would be less expensive than state-specific compliance, due to the increased flexibility in achieving emissions reductions. For example, the EPA found that regional compliance would save $1.5 billion to $2 billion over state-specific compliance (Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, Table ES-4). Similarly, MISO found that "Regional compliance options save approximately $3B annually compared to sub-regional compliance."[36] A group of energy economists concluded, "At a minimum, states within the same electricity interconnection should coordinate to implement the plan in a way that harmonizes emissions reduction incentives across states."[37]

The EPA should thus endeavor to make interstate coordination, formal or informal, as easy and straightforward as possible. The requirements for multi-state plans should be no more burdensome than those for single-state implementation plans. In addition, the EPA should permit states to allow regulated sources to use tradable mass-based emissions credits purchased from sources in other states, without any formal multistate plan, so long as any ton of emissions allowance can only be used in one state. For states that use the rate-based emissions approach, EPA should clarify that renewable energy generated in one state can be included in another state's compliance formula, at the discretion of the owner of the energy, as discussed at page 23, above.

5.1.3. Goal-Setting Refinements

The goals set for Arkansas in the proposed rules are reasonable and achievable. The EPA could set stricter CO_2 emissions limits, by recognizing that energy-efficiency savings and renewables can be ramped up much faster than assumed in the proposed rule. Every state should be able to reach at least 20% renewables by 2030.

One area in which EPA may want to revise its goal computations is the treatment of NGCC emission rates and potential output. The proposed rules treat all NGCCs in a state as being essentially the same, and assume that all NGCCs can be

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[36] "GHG Regulation Impact Analysis–Initial Study Results." MISO presentation to Planning Advisory Committee, September 1 2014, at Slide 7. The MISO compliance cost estimates are greatly exaggerated. Note that some of the sub-regions cover more than one state, so even the sub-regional compliance would include some multi-state compliance.

[37] Fowlie, Merideth, et. al. "An economic perspective on the EPA's Clean Power Plan" Science (11/14/14) 346(6211):815–816.

operated at 70% capacity factor with the average 2012 emission rate of the state's combined-cycle fleet. This assumption is problematic, because NGCCs come in at least three varieties:

- Cogenerating units with significant steam load, which have very low net heat rates and emission rates, and whose output may be limited by the energy requirements of the steam host. Assuming that these units can increase output from 2012 levels may not be realistic, and their net emission rates are not representative of the potential performance on non-cogenerating units.
- Modern NGCCs using frame-type turbines, which can operate at heat rates under 7,500 Btu/kWh and emission rates well under 850 lb/MWh, at high load. These units can generally operate at capacity factors over 85%, but many operated at much lower capacity factors in 2012. At low load levels, or with many starts and stops, the units had much higher 2012 heat rates and emission rates (over 900 lb/MWh in some cases). Rather than assuming that these units will operate at 2012 emission rates at 70% capacity factor, EPA should assume that they will have a heat rate typical of high-load operation.
- Older NGCCs, from the 1970s and 1980s, and those that use less efficient combustion turbines (such as the aero-derivative turbines optimized for fast starts and rapid ramps). In 2012, many of these units operated at very low capacity factors, often under 10%, resulting in very high heat rates and emission rates. For example, the Arkansas Oswald and Fitzhugh plants operated at 7% capacity factors and (respectively) 8,500 and 9,400 Btu/kWh in 2012, while a handful of other plants (Stony Brook and Cleary in Massachusetts, Coolwater in California, Brunot Island in Pennsylvania, Sterlington in Louisiana, Beaver in Oregon) ran at capacity factors as low as 1% and heat rates as high as 15,000. While these units will never operate at the efficiency and CO_2 emission rates of the high-efficiency plants, their performance would improve remarkably were they operated at higher capacity factors.

The EPA should examine the feasibility of differentiating the NGCCs into these three categories, and using generic (rather than 2012 state-specific) values for the emission rates of groups 2 and 3 at 70% capacity factor.