Appendix H
Energy Supply Sector
Policy Recommendations

Summary List of Policy Recommendations

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value (Million $)	Cost-Effectiveness ($/t$CO_2$e)	Level of Support
		2015	2025	Total 2009–2025			
ES-1*	Green Power Purchases and Marketing	*Transferred to RCI TWG*					Unanimous
ES-2*	Technology Research & Development	*Not Quantified*					Unanimous
ES-3†	3a: Renewable Portfolio Standard (RPS)	0.3	3.6	21.9	$548	$25.0	Majority (10 objections)
	3b: Renewable Energy Feed-In Tariff (REFIT)	0.2	2.0	12.3	$399	$32.5	Super Majority (4 objections)
ES-4†	Grid-Based Renewable Energy Incentives and/or Barrier Removal	*Not Quantified*					Unanimous
ES-5†	Approaches Benefiting From Regional Application	*Not Quantified*					Unanimous
ES-6*	Combined Heat and Power	0.6	2.9	20.0	$886	$44.3	Unanimous
ES-7†	Geological Underground Sequestration for New Plants	2.9	5.6	56.5	$1,801	$31.9	Majority (10 objections)
ES-8†	Transmission System Upgrades	*Not Quantified*					Unanimous
ES-9*	Nuclear Power	0.0	9.8	58.9	$1,574	$26.7	Unanimous
ES-10†	Carbon Tax	*Not Quantified*					Super Majority (4 objections)
ES-11*	Efficiency Improvements and Repowering of Existing Plants	2.3	2.3	31.8	$1,568	$49.3	Unanimous
	Sector Total After Adjusting for Overlaps‡	**6.0**	**22.6**	**179.4**	**$6,228**	**$34.7**	
	Reductions From Recent Actions	**0**	**0**	**0**	**$0**	**$0.0**	
	Sector Total Plus Recent Actions‡	**6.0**	**22.6**	**179.4**	**$6,228**	**$34.7**	

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/t$CO_2$e = dollars per metric ton of carbon dioxide equivalent; RCI = Residential, Commercial, and Industrial; TWG = Technical Work Group.

Negative values in the Net Present Value and the Cost-Effectiveness columns represent net cost savings.

The numbering used to denote the above policy recommendations is for reference purposes only; it does not reflect prioritization among these important policy recommendations.

* The GCGW approved this option at Meeting #9 (September 9, 2008); 18 members present and voting (one by phone).

† The GCGW approved this option at Meeting #10 (September 25, 2008); 21 members present and voting (none by phone).

‡ The cumulative results are based on the sum of the following:

- ES-3b (Renewable Energy Feed-In Tariff [REFIT]);
- ES-6 (Combined Heat and Power);
- ES-7 (Geological Underground Sequestration for New Plants);
- ES-9 (Nuclear Power); and
- ES-11 (Efficiency Improvements and Repowering of Existing Plants).

ES-3b and ES-6 overlap with AFW-4 (Expanded Use of Agriculture and Forestry Biomass Feedstocks for Electricity, Heat, or Steam Production: Energy From Biomass and Capture of Waste Heat). These overlaps were addressed by excluding the emission reductions and costs/savings associated with the biomass and waste heat components for AFW-4 from the cumulative totals for all AFW policy recommendations combined.

ES-1. Green Power Purchases and Marketing

[The Energy Supply (ES) Technical Work Group (TWG) recommended and the Arkansas Governor's Commission on Global Warming (GCGW) approved that this recommendation be moved and combined with Residential, Commercial, and Industrial recommendation RCI-7, where it is more appropriately located and quantified.]

ES-2. Technology Research & Development

Policy Description

Research and development (R&D) funding can be targeted toward a particular technology or group of technologies as part of a state initiative to build an industry around that technology in the state, and/or to set the stage for adoption of the technology for use in the state. For example, an agency can be established with a mission to help develop and deploy energy storage technologies. R&D funding can also be made available to any renewable or other advanced technology through an open bidding procedure (i.e., driven by bids received rather than by a focused strategy to develop a particular technology). Funding can also be given for demonstration projects to help commercialize technologies that have already been developed, but are not yet in widespread use. Finally, funding can be targeted to increase collaboration among existing institutions in Arkansas for R&D.

States can undertake initiatives focused on developing, promoting, and/or implementing one or more specific fossil fuel or nuclear technologies that show promise for reducing GHG emissions. Technologies could include, among others, carbon capture and storage (to sequester carbon dioxide [CO_2] emissions from power plants, oil and gas operations, and/or refineries); biomass blending in coal power plants; and implementation of equipment in oil and gas operations that increases efficiency and reduces losses (e.g., remote sensors of leaks).

Policies to encourage CO_2 capture and storage or reuse (CCSR) could include a state agency or department within an existing agency tasked with promoting CCSR, evaluation studies to identify geologically sound reservoirs, R&D funding to improve CCSR technologies, and/or financial incentives or mandates to capture and store carbon or to capture and reuse it.

Policy Design

Goals:

- Identify the likely funding mechanisms and policy tools that would provide further stimulus for the development of new, reasonable-cost, low- and zero-GHG-emitting electricity generation in Arkansas.
- Complete a detailed and comprehensive evaluation study for renewable energy potential in Arkansas.
- Complete a least one high-visibility R&D demonstration to showcase alternative energies.

Timing: Establish funding in the 2009 legislative session. Finish study within two years. Issue first request for proposals as soon a possible after obtaining legislative approval.

Parties Involved: State government, voluntary private and public partners.

Implementation Mechanisms

Use of existing regulatory authority to address relevant issues—pricing, etc.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Reductions in all GHG emissions from the market penetration of innovative GHG-reducing technology and practices.

Estimated GHG Reductions and Costs or Cost Savings

The GCGW considers this policy recommendation as not quantifiable.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Not applicable.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-3a. Renewable Portfolio Standard (RPS)

Policy Description

A renewable portfolio standard (RPS) requires utilities to supply a certain, generally fixed percentage of electricity from an eligible renewable energy source(s). An environmental portfolio standard expands that notion to include energy efficiency or other GHG emission-reducing technologies as an eligible resource. About 20 states currently have an RPS in place. In some cases, utilities can also meet their portfolio requirements by purchasing Renewable Energy Certificates from eligible renewable energy projects.

The application of an RPS in Arkansas is provisional. That is, ES-3b (Renewable Energy Feed-In Tariff [REFIT]) is the primary recommendation for achieving greater penetration of renewable energy. However, if certain goals of the REFIT recommendation are not achieved, the RPS would go into effect, as per the threshold requirements discussed below.

Policy Design

Goal: The aim of an RPS is for each investor-owned and public utility to provide 15% of its load using renewable energy resources.

Timing: Beginning in 2015.

Parties Involved: Investor-owned utilities, electric cooperatives, state government.

Other: The RPS recommendation is provisional, depending on the success of the REFIT recommendation, the primary policy for achieving greater penetration of renewable energy in Arkansas. The time frame for which the RPS would be triggered would follow the goals of ES-3b. For example, ES-3b states that by 2015, Arkansas will produce 500 megawatts (MW) of renewable energy. If the REFIT recommendation has not achieved 250 MW (half of the 2015 goal) by 2012, an RPS mandate will go into effect to ensure the 500-MW target is reached by 2015.

Implementation Mechanisms

The Arkansas Public Service Commission (APSC) will evaluate the potential cost impact on consumers. For utilities subject to the authority of the APSC, the APSC should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers. For utilities (e.g., municipal utilities) that are not subject to the authority of the APSC, the governing body for the utility should review any allocations that are subsidies coming from ratepayers, and ensure that there is not inappropriate cross-subsidization between classes of consumers.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Reductions in all GHG emissions from energy production and GHG emissions associated with process operational emissions and energy consumption.

Estimated GHG Reductions and Costs or Cost Savings

The results of this policy recommendation are summarized in Table H-3a-1, below. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table H-3a-1. Estimated GHG reductions and costs of or cost savings from the RPS

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$) 2015	2025	Total 2009–2025	Net Present Value 2009–2025 (Million $)	Cost-Effectiveness ($/tCO_2e$)
ES-3a	RPS	0.3	3.6	21.9	$548	$25.04

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- U.S. Department of Energy, Energy Information Administration. *Assumptions to the Annual Energy Outlook 2007: With Projections to 2030.* DOE/EIA-0554. April 2007. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf.
- Research and Development Solutions. *Cost and Performance Baseline for Fossil Energy Plants. Volume 1: Bituminous Coal and Natural Gas to Electricity*. DOE/NETL-2007/1281. Prepared for the National Energy Technology Laboratory. May 2007; revision 1, August 2007. Available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.
- Plant-specific Arkansas capacity addition data are based on Arkansas ES TWG input.

Quantification Methods:

See Annex 1 for the overall approach to the quantification of this and all other ES recommendations.

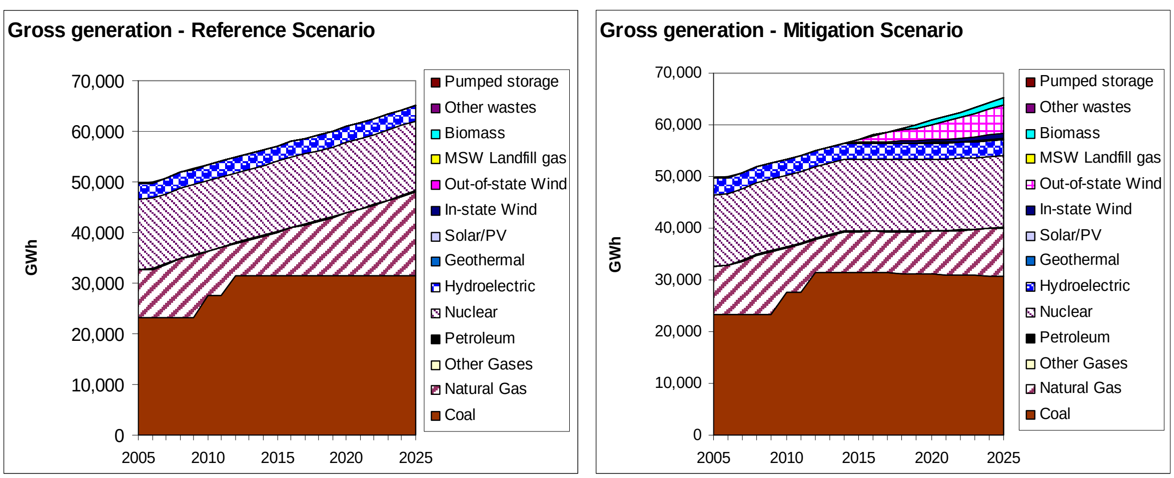
This policy recommendation requires that utilities and other load-serving entities supply a certain, generally fixed, percentage of electricity from eligible (e.g., low-GHG-emitting) renewable energy sources. The TWG has made the following key assumptions for the analysis of this recommendation:

- One reference scenario is modeled, assuming the Hempstead plant is built.
- The start year for the policy recommendation is 2015.
- Incremental renewable energy generation associated with the implementation of the RPS displaces marginal generation comprising 90% natural gas-fired and 10% coal-fired generation in each year new renewable capacity comes on line.

- The mix of new renewable resources to come on line would be modeled after the results of the U.S. Department of Energy, Energy Information Administration's *Assumptions to the Annual Energy Outlook 2007* for the Southwest Power Pool region, assumed to be a reasonable proxy for a least-cost renewable energy mix.
- 15% of all new wind capacity is reserved to be installed in high-wind resource areas in Arkansas; the balance is installed in high-wind resource areas in the surrounding region.
- Additional transmission capacity is built to accommodate all new wind energy resources.
- The capacity credit for intermittent renewables (i.e., wind and solar photovoltaic [PV]) is 15%. For these intermittent resources, spinning reserve is provided in the form of natural gas-fired combustion turbines.
- The cost of new renewables is compared to the average avoided cost of electricity expansion in Arkansas, as obtained from the RCI TWG (i.e., $58.3/MWh).

Figure H-3a-1 summarizes the impact of ES-3a on in-state gross generation. The incremental effect of the RPS by 2025 is about 7,984 gigawatt-hours (GWh), with 69% of this amount coming from out-of-state wind, 12% from in-state wind, 17% from biomass, and 2% from solar PVs. Displaced coal-fired generation in 2025 is 798 GWh, and natural gas-fired generation is 7,185 GWh.

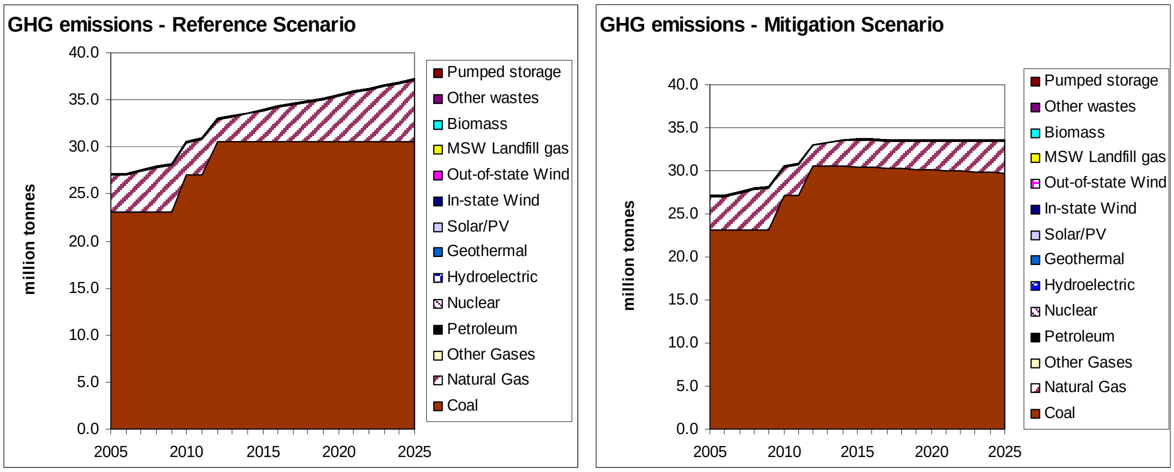
Figure H-3a-1. Effect of RPS on gross generation



RPS = renewable portfolio standard; GWh = gigawatt-hour; MSW = municipal solid waste; PV = photovoltaic.

Figure H-3a-2 summarizes the impact of ES-3a on CO_2-equivalent (CO_2e) emission reductions. The annual reductions due to the RPS by 2025 reach about 3.6 million metric tons (MMt) of CO_2e emission reductions. Cumulatively over the period 2015–2025, the RPS leads to a total of 21.9 $MMtCO_2e$ avoided.

Figure H-3a-2. Annual GHG reductions from the RPS



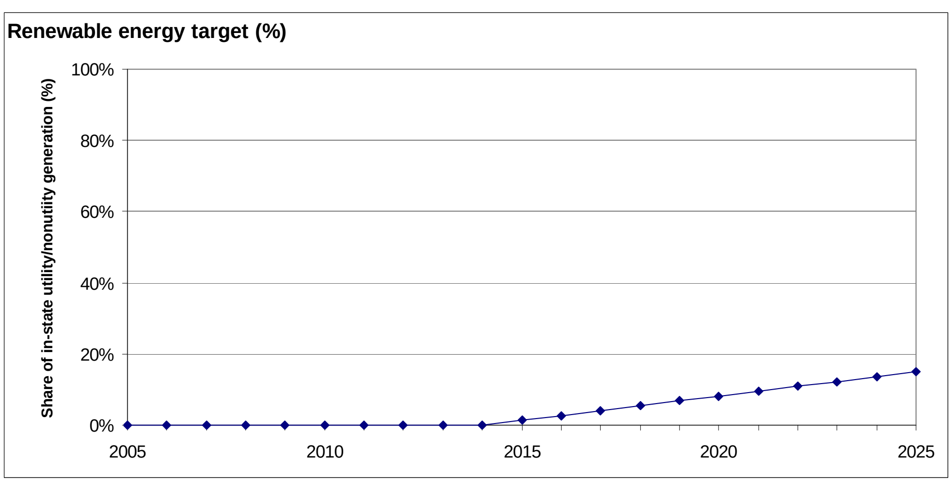
GHG = greenhouse gas; RPS = renewable portfolio standard; MSW = municipal solid waste; PV = photovoltaic.

Cost savings are associated with avoided capital, fuel, and operation and maintenance (O&M) costs. Incremental costs are associated with the capital, transmission, variable and fixed O&M, and fuel costs associated with the RPS. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The net present value (NPV) of the costs is $0.72 billion over the same period (2005$). The recommendation's cost-effectiveness is calculated as the quotient of the net present value (NPV) and cumulative GHG emission reductions. It is $32.8/tCO_2e (2005$) (i.e., $0.72 billion divided by 21.9 MMtCO_2e and multiplied by a conversion factor of 1,000).

Key Assumptions:

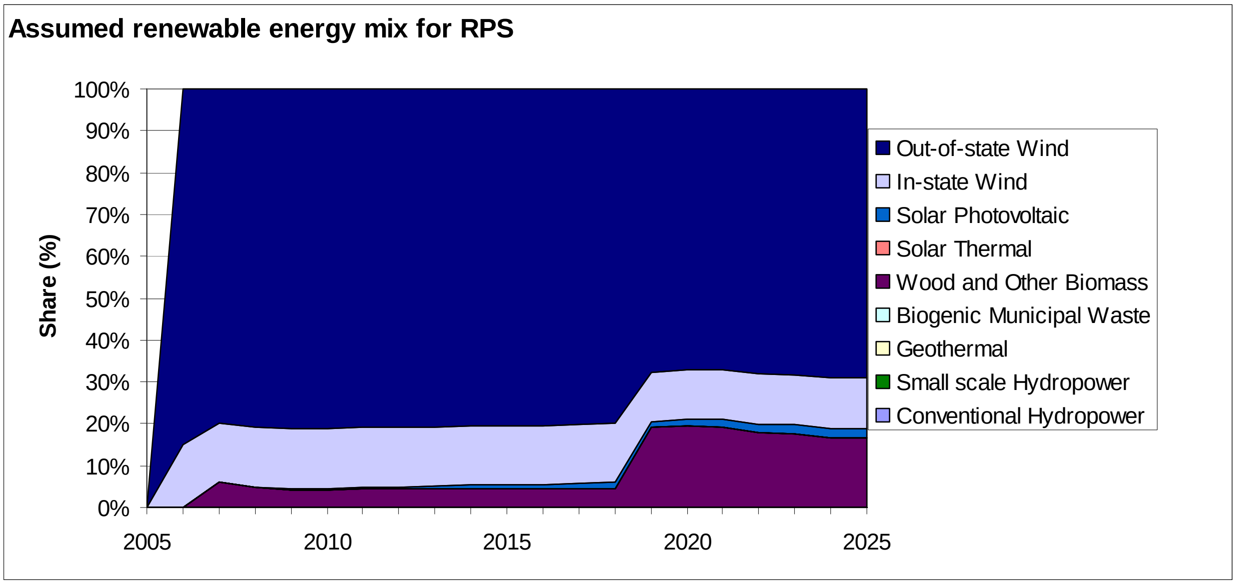
Renewable Energy Target—Defined as the percentage of in-state electricity production, the renewable energy target is summarized in Figure H-3a-3.

Figure H-3a-3. Assumed renewable energy target



Renewable Energy Mix—This is defined as the least-cost plan for the expansion of renewable capacity in the state and is summarized in Figure H-3a-4.

Figure H-3a-4. Assumed renewable energy mix



Assumed Cost and Performance Characteristics of New Capacity in Arkansas—These are obtained from the various sources indicated earlier and are summarized in Table H-3a-2.

Table H-3a-2. Assumed cost and performance characteristics of new capacity in Arkansas

	Cost component							
	Capital	Trans	Fixed O&M	Variable O&M	Cap factor	Heat rate		
	2005 $/kW	2005 $/kW	2005 $/kW-	2005 mills/kW	%	btu/kWh	Source	EPC Percenta
Hydroelectric	1,530	0	13.13	3.30	47%	10,107	EIA	2%
Geothermal	1,530	0	13.13	3.30	47%	10,107	EIA	2%
MSW	1,627	0	107.50	0.01	75%	13,648	EIA	2%
Landfill gas	1,627	0	107.50	0.01	75%	13,648	EIA	2%
Biomass	1,871	0	50.18	2.96	75%	8,911	EIA	2%
Solar	4,406	0	10.99	0.00	35%	10,280	EIA	2%
In-state Wind	1,845	80	28.51	0.00	35%	10,280	EIA	2%
Out-of-state Wind	1,845	80	28.51	0.00	35%	10,280	EIA+	2%

MSW = municipal solid waste; O&M = operation and maintenance; $/kW = dollars per kilowatt; Btu/kWh = British thermal units per kilowatt-hour; EIA = [U.S. Department of Energy] Energy Information Administration.

Levelized Costs of New Renewable Capacity—These costs are computed using an annual inflation rate of 2.5%, a real discount rate of 5%, an after-tax weighted cost of capital of 9%, and a levelization period of 20 years and are summarized in Table H-3a-3 in units of 2005$/MWh.

Table H-3a-3. Assumed levelized costs of new renewable capacity

Capacity type	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Hydroelectric	59.9	0.0	3.1	3.3	0.0	66.3
Geothermal	40.4	0.0	3.1	3.3	0.0	46.8
MSW	27.1	0.0	16.2	0.0	0.0	43.2
Landfill gas	27.1	0.0	16.2	0.0	0.0	43.2
Biomass	31.1	0.0	7.5	2.9	22.0	63.6
Distributed solar PV	157.0	0.0	0.0	0.0	0.0	163.4
In-state Wind	65.7	2.9	9.2	0.0	0.0	77.8
Out-of-state Wind	65.7	2.9	9.2	0.0	0.0	77.8

MSW = municipal solid waste; O&M = operation and maintenance; PV = photovoltaic.

Levelized Costs for Natural Gas Combustion Turbine (NGCT) Used for Reliability Purposes— These are computed using the same financial parameters indicated above and are summarized in Table H-3a-4 in units of 2005$/MWh. Note that a 50% capacity factor is assumed in the calculation.

Table H-3a-4. Assumed levelized costs for NGCT used for reliability purposes

Capacity type	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total	Capacity factor (%)	Fuel factor (%)
CT	13.4	0.0	0.3	3.5	20.0	37.2	50%	25%

O&M = operation and maintenance; CT = combustion turbine; NGCT = natural gas combustion turbine.

Key Uncertainties

The costs of renewable energy technologies, the price forecast for natural gas and coal delivered to regional power stations, and the applicability of avoided costs over the planning period for both reference scenarios.

Additional Benefits and Costs

None cited.

Feasibility Issues

The functioning of the electric transmission network is somewhat analogous to the nation's system of roadways. High-voltage transmission lines were originally constructed to efficiently transport power from local utility bulk power plants, usually constructed in nearby rural areas, to large load centers in metropolitan areas. This has evolved over time to building transmission to even more remote baseload generation and interconnecting with neighboring utilities to take advantage of jointly owned generating stations and emergency assistance. Central station wind and solar have significant cost advantages over distributed resources, but prime locations are remote from Arkansas and in very rural areas without significant electric transmission infrastructure. If regional and national bulk electric transmission lines (the equivalent of the interstate highway system) are not built, access to significant and cost-effective renewable generation will be obstructed, and goals for such must be scaled back to levels reliably and economically achievable.

Status of Group Approval

Complete.

Level of Group Support

Majority (10 objections).

Barriers to Consensus

Ten of the 21 GCGW members present objected to this policy because (1) they do not agree with the mandatory requirement of the RPS if the REFIT policy has not achieved 250 MW (half of the 2015 goal) of renewables by 2012, and (2) the policy has a high associated cost.

ES-3b. Renewable Energy Feed-In Tariff (REFIT)

Policy Description

Renewable Energy Feed-In Tariff (REFIT) is a policy recommendation that provides guaranteed above-market rates for a given period to entities that install qualifying sources of renewable energy and sell energy back to the grid. The higher rate helps overcome the cost disadvantages of renewable energy sources and may be set at different levels for the various forms of renewable power generation. Utilities would be able to recover the cost of the program, plus a reasonable profit, from their ratepayer base. In cases where the entity does not have the capital available to finance the renewable energy installation, it can display this utility guarantee to a financial institute to aid in obtaining a loan for the purchase price of the installation.

"Renewable energy" is defined as energy from wind, solar (to include at least PVs and concentrating solar), advanced biomass (i.e., biomass other than corn-based ethanol), geothermal, and new hydroelectric installations, including additional generated power at existing installations. This definition puts no restriction on the size of a qualifying facility. The size of the installation should be taken into account by a sliding payment scale that gives smaller per-kilowatt-hour (kWh) payments to larger facilities (facilities having a larger maximum power output).

Some observers contend that Arkansas has significant amounts of such electricity-producing new renewable energy resources, while others contend that these resources exist only in insignificant amounts. It is partly for this reason that a mandated RPS is controversial and, for utilities, risky. By avoiding mandates, the REFIT avoids these controversies and risks, while maximizing investments in renewable energy sources. This type of program was pioneered by Germany during 1990–2000, and is behind the large growth in wind power in Spain, Germany, and Denmark. These countries now get 9%, 5%, and 20% of their electricity, respectively, from wind, and are beginning to branch out into solar PV and other forms of renewable electricity.

Policy Design

Goals:

- Require utilities to purchase electricity from individuals, municipal or local governments, or companies that own qualifying renewable energy facilities by means of a REFIT. The REFIT will stipulate government-set, above-market electricity rates and for a guaranteed 20-year period, for renewable electricity from approved sources. The rates should be high enough to provide an incentive for individuals or companies to install renewable energy systems.
- Establish a program that will encourage financing for such individuals or companies to install approved renewable electricity sources, and to allow utilities to recover the cost of this program (plus a reasonable profit) from their ratepayer base.
- Approved forms of renewable energy should include at least wind and solar, where "solar" should include at least PV and solar-thermal (often called "concentrating solar"). The above-market guaranteed rate is expected to be different for different forms of renewable energy.

The REFIT can be controlled by putting a limit on ratepayer impact, whereby an increase of 5% or less in rates is dedicated to the program.

Timing: Such a program should not take long to establish and could be in operation by perhaps 2010. It is difficult to say how many individuals or firms will want to take advantage of this incentive program, so it is difficult to predict the amount of electricity that might be generated renewably. A reasonable goal (which is not to be construed as a mandate) might be 500 MW by 2015, with at least 20 MW going to wind and 20 MW going to solar. The program might be expected to start small and to grow, depending on how viable wind and solar and other renewable forms of electricity turn out to be in Arkansas.

Parties Involved: Investor-owned utilities, electric cooperatives, state government.

Implementation Mechanisms

For utilities subject to the authority of the APSC, the APSC should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers. For utilities (e.g., municipal utilities) that are not subject to the authority of the APSC, the governing body for the utility should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Reductions in all GHG emissions from energy production and GHG emissions associated with process operational emissions and energy consumption.

Estimated GHG Reductions and Costs or Cost Savings

This policy recommendation was analyzed relative to several plausible scenarios regarding the efficacy of feed-in tariffs when applied to the Arkansas context. This was necessary insofar as there is limited literature on the transferability of the German and Japanese experiences with the use of feed-in tariffs for the stimulation of renewable energy development in other settings.

Following are three major assumptions regarding the transferability of the German and Japanese experiences with the use of feed-in tariffs. They have:

- Half the efficacy of the German experience.
- Three-fourths of the efficacy of the German experience.
- One-to-one transferability of the German experience. *This was the default assumption.*

In addition to these assumptions, different trajectories in the penetrations of renewable energy resulting in the application of the feed-in tariffs in Arkansas were assumed, as follows:

- Achieve the same level as the RPS (i.e., 15% of gross in-state electricity generation by 2025).

- Achieve renewable energy penetration in 2025 consistent with a rate impact of less than 5% of the projected retail electricity rate. *This was the default assumption.*
- Achieve a greater level than the RPS (i.e., 25% of gross in-state electricity generation by 2025.

The above combination of scenarios and sensitivities results in a total of 18 sets of results for this policy recommendation. However, only the results for the default assumptions for this recommendation are provided in Table H-3b-1, below. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table H-3b-1. Summarized results of policy recommendation ES-3b

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$) 2015	2025	Total 2009–2025	Net Present Value (Million $)	Cost-Effectiveness ($/t$CO_2e$)
ES-3b	REFIT	0.2	2.0	12.3	$398.7	$32.5

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/t$CO_2e$ = dollars per metric ton of carbon dioxide equivalent; RPS = renewable portfolio standard.

Data Sources:

- John Farrell. "Minnesota Feed-In Tariff Could Lower Cost, Boost Renewables and Expand Local Ownership." New Rules Project. January 2008. Available at: http://www.newrules.org/de/feed-in-tariffs.pdf.
- Friends of the Earth. "What Is a Feed-in Tariff and Why Does the UK Need One To Support Renewable Energy?" Briefing Note. April 2008. Available at: http://www.foe.co.uk/resource/briefing_notes/feedin_tariff.pdf.
- Paul Gipe. "Feed Law Powers Germany to New Renewable Energy Record." February 5, 2007. Available at: http://www.renewableenergyworld.com/rea/news/story?id=47322.
- All other data sources, including cost and performance assumptions as well as plant-specific Arkansas capacity addition data, are the same as assumed for ES-3a.

Quantification Methods:

See Annex H-1 for the overall approach to the quantification of this and all other energy supply policy recommendations.

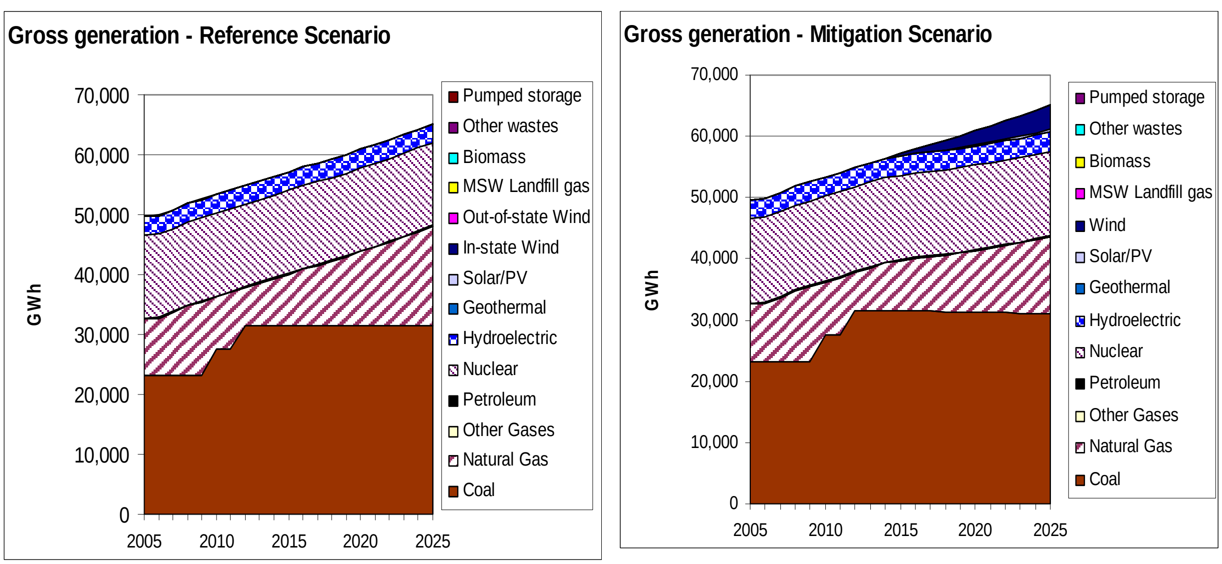
This is a policy recommendation to implement incentives available to residential, commercial, and industrial electricity customers to install renewable energy technologies. The TWG has made the following key assumptions for the analysis of this recommendation:

- One reference scenario is modeled, assuming the Hempstead plant is built.
- The start year for the policy recommendation is 2015 (500 MW minimum renewable capacity additions).

- Incremental renewable energy generation associated with the implementation of the feed-in tariff displaces marginal generation comprising 90% natural gas-fired and 10% coal-fired generation in each year new renewable capacity comes on line.
- The mix of new renewable resources to come on line is assumed to be wind and solar PV due to the fact that these resources were the ones for which data were available for the German experience.
- All new wind capacity is installed at demand sites in high wind resource areas in Arkansas.
- Additional transmission capacity will need to be built to accommodate new wind energy generation in excess of that needed to satisfy installer demand.
- No capacity credit for intermittent renewables is assumed (i.e., wind and solar PV), as the recommendation focuses on demand-side installation outside utility planning protocols.
- The cost of new renewable resources is compared to the average avoided cost of electricity expansion in Arkansas, as obtained from the RCI TWG (i.e., $58.3/MWh). This value was assumed to be applicable for all scenarios and sensitivities.

Figure H-3b-1 summarizes the impact of ES-3b on in-state gross generation. An additional 4,024 GWh of wind and 447 GWh of solar PV is achieved by 2025.

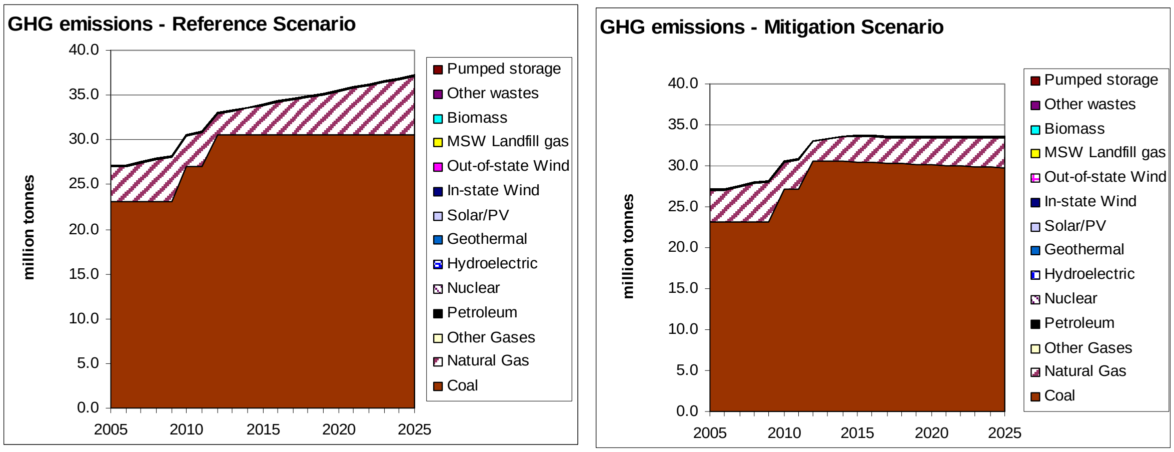
Figure H-3b-1. Gross generation



GWh - gigawatt-hours; MSW = municipal solid waste; PV = photovoltaic.

Figure H-3b-2 summarizes the impact of ES-3b on CO_2e emission levels. The annual reductions due to the feed-in tariff reach about 2.0 MMtCO_2e by 2025. Cumulative emission reductions over the planning period total 12.3 MMtCO_2e.

Figure H-3b-2. GHG emissions



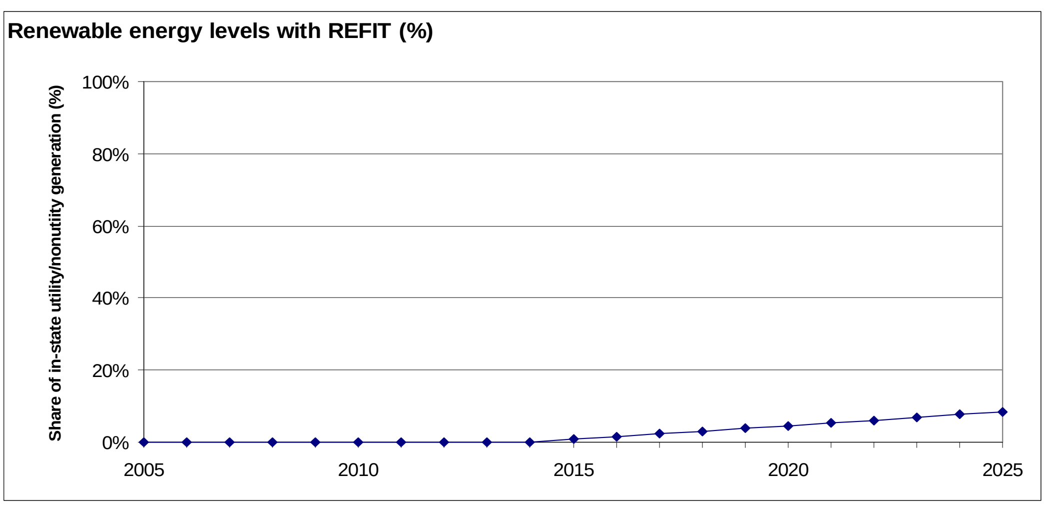
GWh - gigawatt-hours; MSW = municipal solid waste; PV = photovoltaic.

Cost savings are associated with avoided capital, fuel, and O&M costs. Incremental costs are associated with the capital, transmission, variable and fixed O&M, and fuel costs associated with the RPS. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The sum of the annual costs and annual benefits provides an estimate of the net costs of the feed-in tariff. The NPV of the costs is $0.51 billion over the 2015–2025 period (2005$). The cost-effectiveness of the various runs is calculated as the quotient of the NPV and cumulative GHG emission reduction and is equal to $41.7/MWh (2005$).

Key Assumptions:

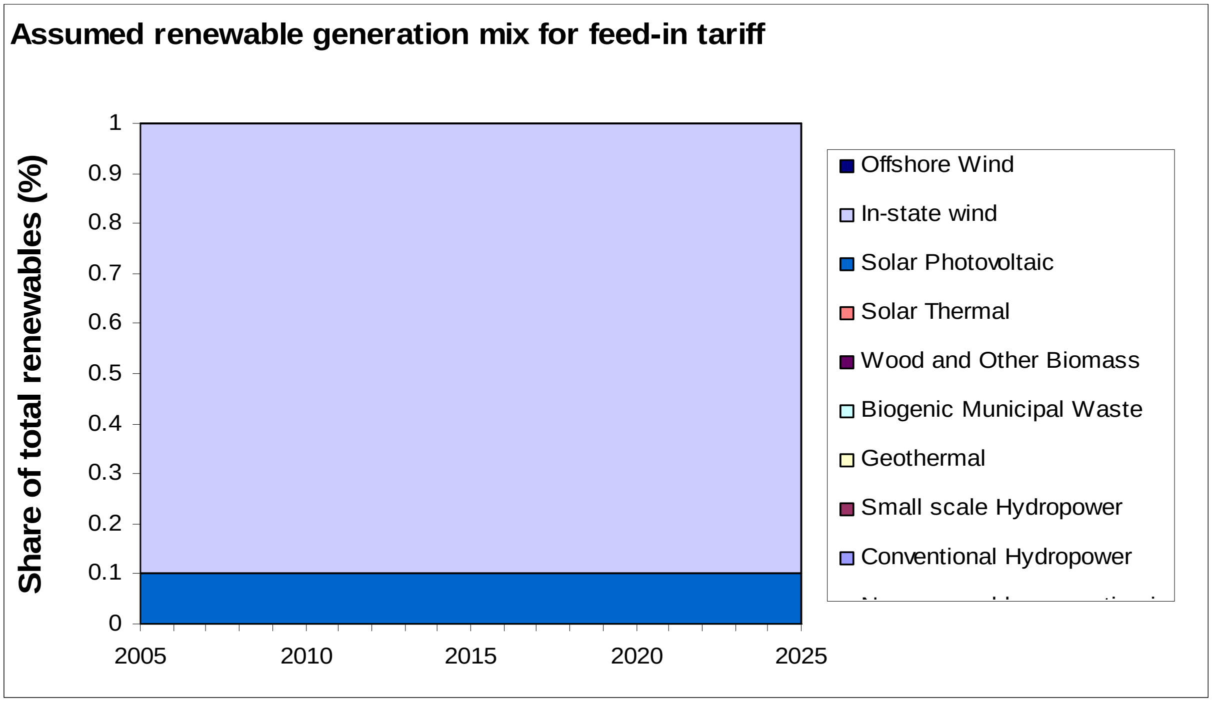
Renewable Energy Target—This is defined as the percentage of in-state electricity production, and is summarized in Figure ES-3b-3.

Figure H-3b-3. Assumed renewable energy target



Renewable Energy Mix—This is defined as the least-cost plan for the expansion of renewable capacity in the state, and is summarized in Figure H-3b-4.

Figure H-3b-4. Assumed renewable generation energy mix for REFIT



Assumed Cost and Performance Characteristics of New Capacity in Arkansas—These are obtained from the various sources indicated earlier, and are summarized in Table H-3a-2.

Levelized Costs of New Renewable Capacity—These are computed using an annual inflation rate of 2.5%, a real discount rate of 5%, an after-tax weighted cost of capital of 9%, and a levelization period of 20 years, and are summarized in Table H-3a-3.

Levelized Costs for NGCT Used for Reliability Purposes—As noted earlier, NGCT units are not assumed, given that much of the reliability needs are mitigated by the fact that these are demand-side options that do not need transmission and distribution (T&D) for meeting customer demand.

Key Uncertainties

The costs of renewable energy technologies, the price forecast for natural gas and coal delivered to regional power stations, the applicability of avoided costs over the planning period for both reference scenarios, and the reliability needs for dispatchable power under a REFIT regime.

Additional Benefits and Costs

None cited.

Feasibility Issues

The functioning of the electric transmission network is somewhat analogous to the nation's system of roadways. High-voltage transmission lines were originally constructed to efficiently transport power from local utility bulk power plants, usually constructed in nearby rural areas, to large load centers in metropolitan areas. This has evolved over time to building transmission to even more remote baseload generation and interconnecting with neighboring utilities to take advantage of jointly owned generating stations and emergency assistance. Central station wind and solar have significant cost advantages over distributed resources, but prime locations are remote from Arkansas and in very rural areas without significant electric transmission infrastructure. If regional and national bulk electric transmission lines (the equivalent of the interstate highway system) are not built, access to significant and cost-effective renewable generation will be obstructed, and goals for such must be scaled back to levels reliably and economically achievable.

Status of Group Approval

Complete.

Level of Group Support

Super Majority (4 objections).

Barriers to Consensus

Four of the 21 GCGW members present objected to this policy because of its high cost, and they believe an increase of 5% or less in rates is too high (the limit on ratepayer impact associated with REFIT should be in the 1%–2% range at most).

ES-4. Grid-Based Renewable Energy Incentives and/or Barrier Removal

Policy Description

Arkansas should enact tax incentives and innovative financing programs for residential and commercial utility users who develop or apply successful renewable energy systems. The tax and loan incentives should be proportional to the amount of renewable energy they are using, with the greatest incentives for those who use net metering and return energy to the grid for use by other utility customers. The Legislative Council, the Arkansas Department of Finance and Revenue, the Arkansas Development Finance Authority, the Arkansas Department of Environmental Quality, and the Arkansas Science and Technology Authority, in coordination with the GCGW and the appropriate legislative leaders, should research model programs in other states and countries and make recommendations on specific policies in time for the next legislative session. In addition, pilot and demonstration programs should be established to demonstrate the effectiveness of these policies as they are implemented. Alternative sources of funding, including foundations, utility companies, and others, should be sought to supplement state revenue for these policies.

This policy recommendation reflects financial incentives to encourage investment in renewable energy resources. Examples include: (1) direct subsidies for purchasing/selling renewable technologies, (2) tax credits or exemptions for purchasing renewable technologies, (3) tax credits for each kWh generated from a qualifying renewable facility, and (4) regulatory policies that provide incentives and/or assurance of cost recovery for utilities that invest in central station renewable energy systems. In addition, this recommendation would make it a priority for the legislature, the APSC, and other relevant state agencies to identify and rectify barriers to the development of renewable resources in the state.

Policy Design

Goals: The initial evaluation should include several different types of financial incentives to represent the range of opportunities.

- Offer tax credits or other incentives of $1,500 per kW-equivalent for small solar PV, micro-hydro, and small wind.
- Provide a subsidy to renewable energy generators of $0.01/kWh for electricity generated from a renewable resource, unless that electricity is used to meet a federal, state, or voluntary renewable energy standard.
- Offer low-interest loans for feasible and desirable biomass generation that meets exemplary environmental performance standards, with partial loan forgiveness for equipment that fails to perform to standard.

Timing: Tax credits beginning in 2010 and subsidies beginning in 2015.

Parties Involved: All power producers operating qualifying facilities for incentives other than tax credits, which would be available to any grid-connected customer.

Implementation Mechanisms

None specified

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Costs or Cost Savings

Table H-4-1. Estimated GHG reductions and costs of or cost savings from policy recommendation ES-4

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effectiveness ($/tCO_2e$)
		2015	2025	Total 2009–2025		
ES-4	Grid-Based Renewable Energy Incentives and/or Barrier Removal	*Not Quantified*				

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources: See ES-3a.

Quantification Methods: See ES-3a.

Key Assumptions: See ES-3a

Key Uncertainties

None cited.

Additional Benefits and Costs

Not applicable.

Feasibility Issues

None cited.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-5. Approaches Benefiting From Regional Application

Policy Description

The primary goal of this policy recommendation is to establish a mechanism that will allow Arkansas to adapt to and be prepared for a federally implemented cap-and-trade system and other federal climate policy. A cap-and-trade system is a market mechanism by which GHG emissions are limited or capped at a specified level, and those participating in the system are required to hold permits for each unit of emissions. Through trading, participants with lower costs of compliance can choose to overcomply and sell their additional reductions to participants for whom compliance costs are higher. In this fashion, overall costs of compliance are lower than they would otherwise be.

Policy Design

Goals: Not quantifiable.

Timing: Beginning as soon as possible.

Parties Involved: The GCGW or its designee.

Implementation Mechanisms

None cited.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Reductions in all GHG emissions from energy production in state and out of state associated with a carbon cap-and-trade system.

Estimated GHG Reductions and Costs or Cost Savings

The GCGW considers this policy recommendation as not quantifiable.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

None cited.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-6. Combined Heat and Power

Policy Description

Combined heat and power (CHP) refers to any system that simultaneously or sequentially generates electric energy and utilizes the thermal energy that is normally wasted. The recovered thermal energy can be used for industrial process steam, space heating, hot water, air conditioning, water cooling, product drying, or nearly any other thermal energy need in the commercial and industrial sectors. The end result is significantly increased efficiency over generating electric and thermal energy separately. In fact, many CHP systems are capable of an overall efficiency of over 80%—double that of conventional systems. Another significant advantage is the reduced T&D losses associated with centralized power generation.

Policy Design

Reports from the Energy Information Administration (EIA) show 16 distributed generation (DG) units in Arkansas with a capacity of 1–20 MW with a combined capacity of 126 MW. Annual energy production from these facilities exceeds 785 GWh, equivalent to less than 2% of retail energy sales. Though no assessment of the thermal efficiency is available, the units operate at a relatively high capacity factor, exceeding 70%. According to an assessment by the Electric Power Research Institute, the market adoption of CHP has been limited due to a confluence of barriers, including a lack of compelling savings and economics for end users and a lack of high enough margins for utility or third-party business models.

The combination of higher natural gas prices, the potential increased cost of all fuel-based energy production due to CO_2 restrictions, impediments to expanding the use of coal-based generation, the escalating costs for T&D facilities, and dramatic increases in the capital cost for all bulk power supply options will enhance the savings and economics for CHP. In addition to this natural market incentive for CHP, this policy recommendation proposes incentives in the form of payments to utilities, industries, individuals, or other entities that reduce CO_2 emissions by installing new CHP systems either to capture and use waste heat from electric power plants, or to generate electricity from waste heat produced in industrial processes. The incentives would be paid on a per-ton basis for each ton of saved CO_2, and would be accompanied by a 20-year guarantee of payment for future avoided CO_2 emissions, paid on a declining scale to phase out in 20 years (see example below under “Goals”). The purpose of the incentives is to encourage small generating facilities to be located next to industries that can use their waste heat, to encourage industries that use process heat to use their waste heat to generate electricity or for other lower-temperature heating applications, and to encourage industries using process heat to locate their operations close enough to existing generating facilities so that they can use the waste heat from those facilities.

Funding for the incentives should come from the utility’s customer base, overseen by the APSC, or from tax money appropriated by the legislature.

The state should expand on EIA survey data to determine the number of existing DG projects that have CHP potential, assessing the energy reductions achievable with forecasted escalating energy costs.

Goals: Reduce use of fossil fuel from industrial sources through the employment of new CHP applications incentivized by payments for CO_2 emission reductions. A typical incentive might be a 20-year guaranteed payment of $40 per ton of avoided CO_2, with the amount to decline in increments over time, phasing out at the end of 20 years. For example, the amount might decline to $30 per ton after 5 years, $20 per ton after 10 years, and $10 per ton after 15 years. It is hoped that this would reduce the direct use of natural gas in Arkansas by 10%, and would also increase the average energy efficiency of electric power plants by 10% (e.g., from 40% to 50%).

Timing: The incentives should be introduced right away, beginning in 2010.

Parties Involved: State government and regulators, electric utilities, and renewable energy and CHP industry.

Implementation Mechanisms

For utilities subject to the authority of the APSC, the APSC should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers. For utilities (e.g., municipal utilities) that are not subject to the authority of the APSC, the governing body for the utility should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

CO_2e reductions from avoided electricity production and avoided on-site fuel combustion less additional on-site CO_2e emissions from fuel used in CHP systems.

Estimated GHG Reductions and Costs or Cost Savings

Table H-6-1. Estimated GHG reductions from and costs of or cost savings from CHP

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value Net Present Value 2009–2025 (Million $)	Cost-Effectiveness ($/tCO_2e$)
		2015	2025	Total 2009–2025		
ES-6	CHP	0.6	2.9	20.0	$886	$44.30

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per metric ton of carbon dioxide equivalent.

Data Sources:

- U.S. Department of Energy, Energy Information Administration. "Electrical Power Annual 2006—State Data Tables." Form EIA-906: 1990–2006 Fossil Fuel Consumption for Electricity Generation by Year, Industry Type, and State. October 26, 2007. Available at: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.
- Minnesota Planning Minnesota Environmental Quality Board. *Inventory of Cogeneration Potential in Minnesota*. August 2001, page iv. Available at: http://www.eqb.state.mn.us/pdf/2001/CogenInventory.pdf
- U.S. Department of Energy, Energy Information Administration. *Assumptions to the Annual Energy Outlook 2007*. DOE/EIA-0554(2007). April 2007. Available at: http://www.eia.doe.gov/oiaf/archive/aeo07/assumption/index.html
- Spreadsheet entitled "Arkansas CHP 7-17-08.xls." Received July 17, 2008, from Katrina Pielli, Clean Energy Program Manager, U.S. Environmental Protection Agency (EPA).

Quantification Methods:

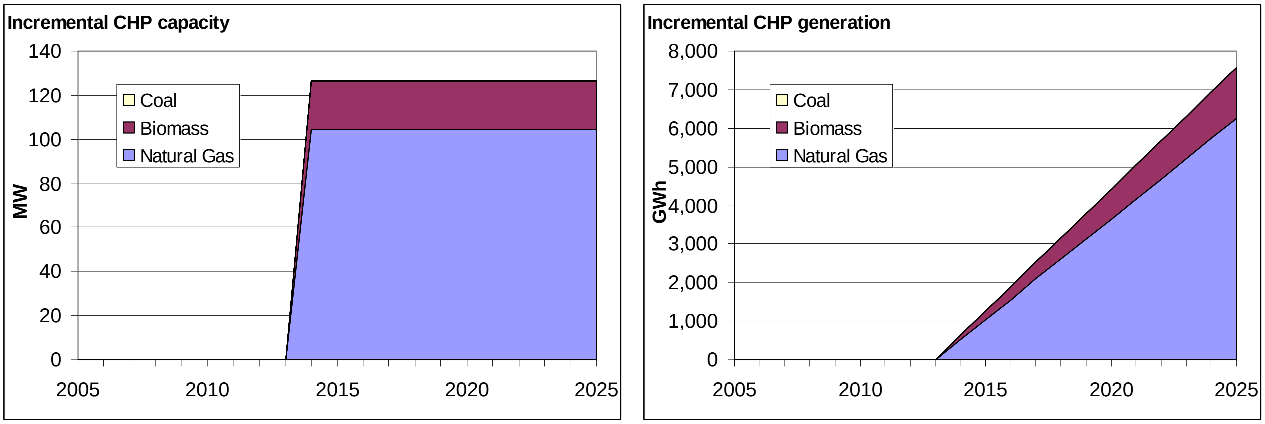
See Annex H-1 for the overall approach to the quantification of this and all other energy supply recommendations.

This policy recommendation requires increased used of highly efficient CHP facilities in Arkansas. The TWG is making the following key assumptions for the analysis of this recommendation:

- One reference scenario is modeled, assuming the Hempstead plant is built.
- The start year for the policy recommendation is 2013.
- Incremental electricity generation provided to the grid from new CHP systems displaces marginal generation comprising 90% natural gas-fired and 10% coal-fired generation in each year new renewable capacity comes on line.

Regarding incremental CHP capacity and corresponding electricity generation, the following capacity trajectory in Figure H-6-1 was assumed based on a recent study by the U.S. Environmental Protection Agency regarding the maximum achievable potential of CHP systems in Arkansas.

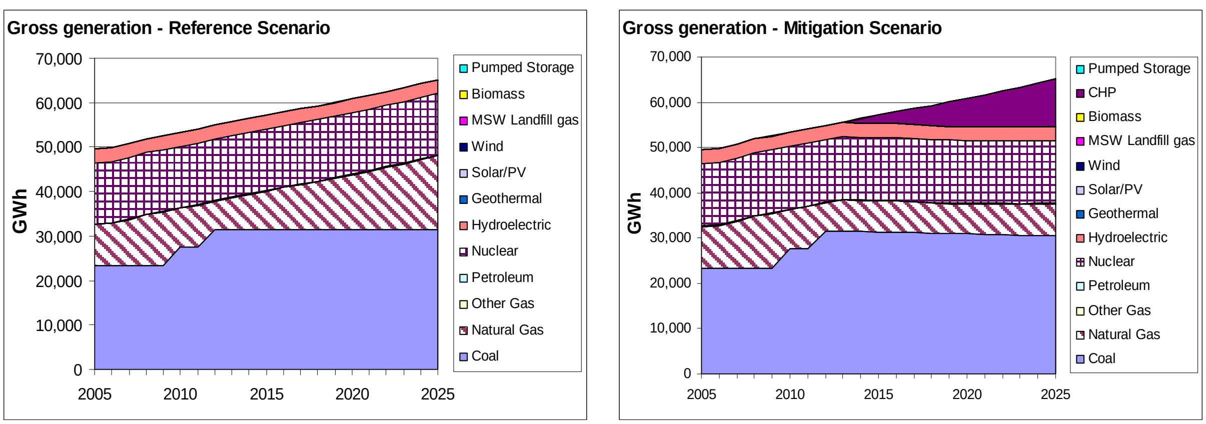
Figure H-6-1. Assumed CHP capacity trajectory in Arkansas



MW = megawatts; GWh = gigawatt-hours; CHP = combined heat and power

Figure H-6-2 summarizes the incremental impact of CHP on gross generation. The incremental effect of CHP by 2025 is about 7,574 GWh, with 83% of this amount coming from natural gas and the balance from biomass. After accounting for avoided T&D losses, displaced coal-fired generation in 2025 is 1,055 GWh, and natural gas-fired generation is 9,494 GWh.

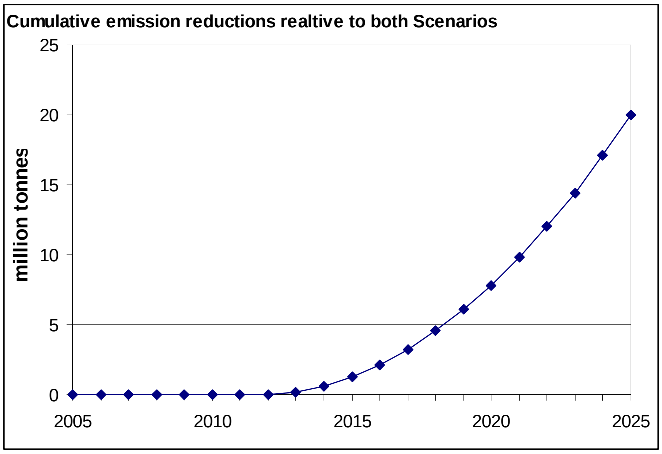
Figure H-6-2. Incremental impact of CHP on gross generation



GWh = gigawatt-hours; CHP = combined heat and power; MSW = municipal solid waste; PV = photovoltaic.

Figure H-6-3 summarizes the impact of this policy recommendation on cumulative CO_2e emission reductions. The cumulative reductions due to new CHP facilities reach about 20.0 $MMtCO_2$e avoided emissions by 2025.

Figure H-6-3. Cumulative emission reductions with CHP



Cost savings are associated with avoided capital, fuel, and O&M costs. Incremental costs are associated with the capital, transmission, variable and fixed O&M, and fuel costs associated with new CHP facilities. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The sum of the annual costs and annual benefits provides an estimate of the net costs of the policy recommendation. The NPV of the costs is \$0.89 billion over the 2015–2025 period (2005\$). The recommendation's cost-effectiveness is calculated as the quotient of the NPV and cumulative GHG emission reductions and is \$44.3/tCO_2e (2005\$) (i.e., \$0.89 billion divided by 20.0 MMtCO_2e and multiplied by a conversion factor of 1,000).

Key Assumptions:

Table H-6-2. Existing CHP in Arkansas

Application	Sites	MW
SIC 20: Food Processing	3	18.7
SIC 24: Wood Products	2	22.5
SIC 26: Paper	4	423.5
SIC 4952: WWTP	1	1.7
SIC 8060: Healthcare	1	8.5
SIC 8220: College/Univ	1	4.1
Total	12	479.0

CHP = combined heat and power; MW = megawatts.

Table H-6-3. CHP potential at existing industrial and commercial/institutional facilities, 2003: within-the-fence thermal and electric

	100 kW to 1 MW		1 MW to 5 MW		5 MW to 20 MW		> 20 MW		**Total**	
	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	**MW**
Industrial	509	79	222	322	57	499	5	206	793	**1,105**
Commercial	2,001	220	109	117	13	73	0	0	2,123	**410**
Total	2,510	298	331	439	70	572	5	206	2,916	**1,515**

CHP = combined heat and power; kW = kilowatts; MW = megawatts.

Table H-6-4. CHP cost and performance

Parameter	NG	Biomass	Coal
Average full-capacity-equivalent hours of operation	5,000	5,000	5,000
Fraction of new capacity	90%	5%	5%
Average net heat rate by fuel (btu per kWh)	10,000	13,000	12,000
Useable cogenerated heat output (% energy input)	40%	40%	40%
Fraction useable heat output replacing space/water/process heat	90%	90%	90%
Average overnight installed captial costs by fuel type (2005$/kW)	$2,000	$2,500	$2,500
CHP transmission cost (2005$/kW)	$0	$0	$0
Economic life of system (years)	20	20	20
Fixed O&M costs (2005$/kW)	0	0	0
Variable O&M costs (2005 $/MWh)	16.00	20.00	20.00

Btu = British thermal unit; CHP = combined heat and power; kW = kilowatts; kWh = kilowatt-hours; MWh = megawatt-hours; NG = natural gas; O&M = operation and maintenance.

Table H-6-5. Industrial sector energy costs in West South Central Region (2005$/MMBtu)

	2005	2010	2015	2020	2025	Source
Distillate Fuel	14.00	15.58	13.82	14.38	14.84	AEO2007 for West North Central region
Natural Gas	7.87	6.47	5.42	5.60	6.00	AEO2007 for West North Central region
Steam Coal	1.48	1.82	1.88	1.93	1.97	AEO2007 for West North Central region
Biomass	2.50	2.50	2.50	2.50	2.50	AEO2007 for West North Central region
electricty	20.01	20.46	18.55	18.59	18.98	AEO2007 for West North Central region

$/MMBtu = dollars per million British thermal units

Key Uncertainties

The costs of new CHP units, integration into electric system, projected fuel prices, available markets for heat production, and CHP potential in Arkansas.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-7. Geological Underground Sequestration for New Plants

Policy Description

This policy refers to the capture of CO_2 from fossil fuel-fired power plant emissions and its sequestration in geologic formations, including oil and gas reservoirs, coal seams that cannot be mined, and deep saline reservoirs. Broadly, three different types of technologies exist: post-combustion, pre-combustion, and oxyfuel combustion. After capture, the CO_2 must be transported to suitable storage sites; this is often accomplished via pipeline.

Policy Design

This policy affects all new coal-fired power plants, both those that are currently under construction and those that have not yet received full approval for construction in Arkansas. Plants currently under construction (including the Plum Point plant) should install and employ post-combustion carbon capture and storage (CCS) as soon after the plant's opening as the technology becomes available. Plants that have not yet received full approval for construction (including the Hempstead plant) should employ CCS as soon as they begin operations. All other new coal-fired generating plants should employ state-of-the-art pre-combustion CCS as soon as they begin operations.

This policy implies that, except for the already-permitted Plum Point plant, there will be no new coal-fired generating plants in Arkansas until sequestration is ready. Until that time, the electricity that would have been generated by new plants should be replaced with expanded energy efficiency, renewable energy, and, as a last resort, natural gas combined-cycle (NGCC) technology.

Goals: Capture 80%–90% of CO_2 emissions from new power plants.

Timing: Reductions achieved beginning in 2020.

Parties Involved: Large, new, coal-fired power plants.

Implementation Mechanisms

None cited.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Costs or Cost Savings

This policy recommendation was analyzed relative to the scenario described below:

- In place of the 2012 date for bringing the Hempstead plant on line, introduce expanded demand-side energy efficiency, renewable energy (wind), and NGCC units to replace the power that would have been generated by the Hempstead plant.
- In 2020, build the Hempstead plant (pulverized coal) with post-combustion (i.e., chemical absorption with monethanolamine) CCS technology and in-state sequestration. Export power generated to SPP and SERC regions.
- In 2020, add post-combustion CCS technology (i.e., chemical absorption with monoethanolamine) and in-state sequestration to the Plum Point plant.

The results for the analysis of the above scenario are summarized in Table H-7-1. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table H-7-1. Estimated GHG reductions from and costs of or cost savings from ES-7

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value (Million $)	Cost-Effectiveness ($/t$CO_2e$)
		2015	2025	Total 2009–2025		
ES-7	Geological Underground Sequestration for New Plants	2.9	5.6	36.8	$1,801	$31.9

$/$CO_2e$ = dollars per metric ton of carbon dioxide equivalent; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Data Sources:

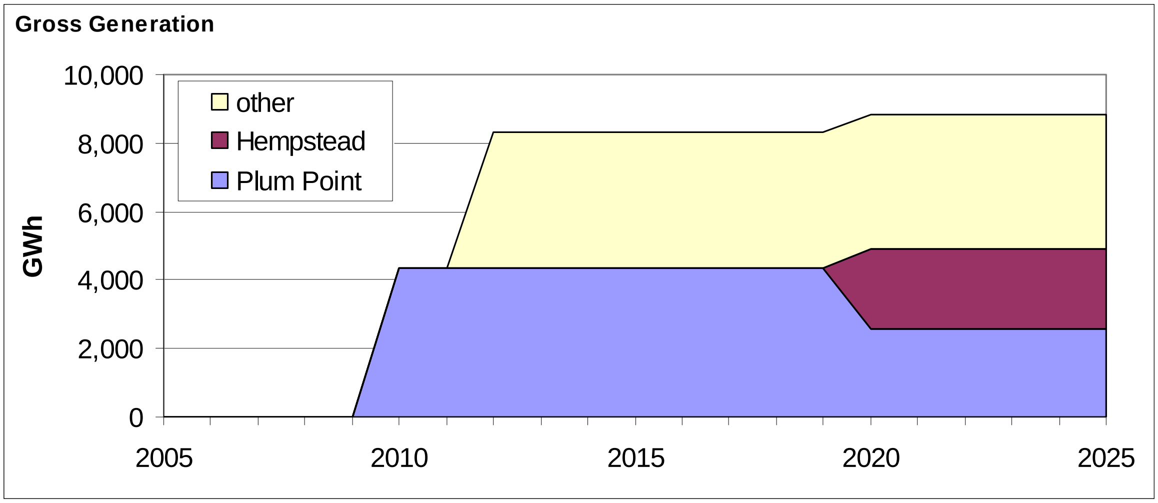
- U.S. Department of Energy, Energy Information Administration. *State Electricity Profiles 2005*. DOE/EIA-0348(01)/2. March 6, 2007. Available at: http://tonto.eia.doe.gov/ftproot/electricity/stateprofiles/05st_profiles/062905.pdf.
- Other renewables for CHP units are from U.S. Department of Energy, Energy Information Administration. Table 5. State Renewable Electric Power Industry Net Generation, by Energy Source. Derived from Form EIA-906: Power Plant Report and EIA-920: Combined Heat and Power Plant Report. Available at: http://www.eia.doe.gov/cneaf/solar.renewables/page/state_profiles/rspt05ar.xls.
- Spreadsheet entitled GenY06-summary.xls, obtained from Arkansas ES TWG detailing 2006 annual generation for electric production facilities in Arkansas.

Quantification Methods:

Regarding in-state gross generation, the impact of this recommendation on the Plum Point and Hempstead plants is summarized in Figure H-7-1. The incremental effect of the recommendation on the Plum Point plant shows that during 2020–2025, the period post-combustion carbon capture technology is operational, generation decreases by about 1,800 GWh due to derating associated with the retrofit. During 2012–2019, a combination of demand-side efficiency, wind, and NGCC generation are added to compensate for the deferral of the online year for the Hempstead plant. These resources are assumed to continue in the 2020–2025 period, when the

Hempstead plant comes on line. During this period, annual generation for the Hempstead plant is 2,326 GWh, after accounting for derating from the installation of post-combustion carbon capture technology.

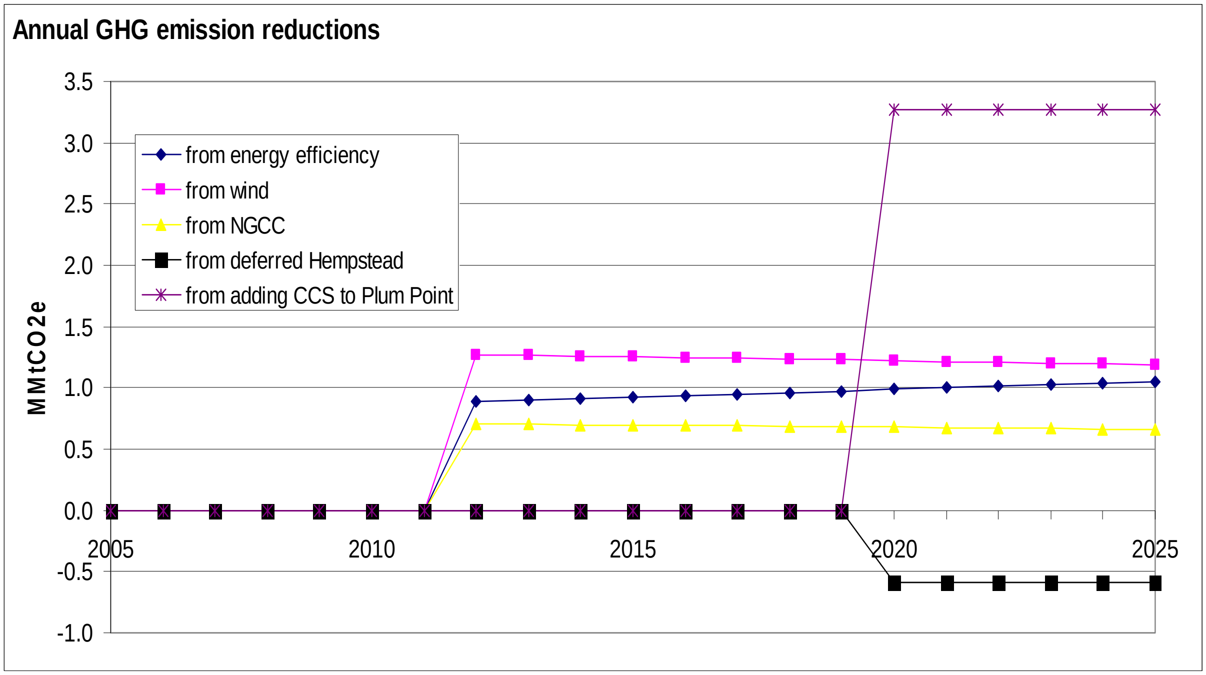
Figure H-7-1. Generation profile



GWh = gigawatt-hours.

Regarding CO_2-equivalent (CO_2e) emission reductions, the impact of this policy recommendation is summarized in Figure H-7-2 on a production basis. By 2025 the policy results in annual emission reductions of about 5.9 $MMtCO_2e$. This is made up of reductions of 3.33 $MMtCO_2e$ (from adding carbon capture to the Plum Point plant), reductions of about 3 $MMtCO_2e$ (from energy efficiency, wind, and natural gas-fired generation to offset Hempstead generation), and an increase of 0.6 $MMtCO_2e$ (from additional emissions associated with construction of the Hempstead plant, whose generation is exported. On a cumulative basis, the recommendation leads to reductions of 56.5 $MMtCO_2e$.

Figure H-7-2. GHG emission reduction profile



CCS = carbon capture and storage; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; NGCC = natural gas combined cycle.

Cost savings are associated with avoided capital, fuel, and O&M costs for coal and natural gas facilities from the additional demand-side efficiency measures. Incremental costs are associated with capital, transmission, variable and fixed O&M, and fuel costs associated with the new wind, NGCC stations, and CCS technology. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The sum of the annual costs and annual benefits provides an estimate of the net costs of the policy recommendation. The NPV of the costs is $1.8 billion over the 2012–2025 period (2005$). The policy's cost-effectiveness is calculated as the quotient of the NPV and cumulative GHG emission reductions. For the central estimate of cost and performance, it is $31.9/$tCO_2e$ (2005$) (i.e., $1.8 billion divided by 56.5 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions:

Tables H-7-3, H-7-4, and H-7-5 summarize key assumptions used in the analysis.

Table H-7-3. Real levelized costs for new power supply (2005$/MWh)

Capacity type	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total
Pulverized coal	24.6	0.0	3.2	4.6	12.1	44.4
IGCC	30.9	0.0	4.8	6.2	12.4	54.4
Natural Gas CC	8.9	0.0	1.3	1.3	54.9	66.4
IGCC/CCS (low)	42.3	0.0	5.2	6.2	17.1	70.8
IGCC/CCS (mid): out-of-state	47.5	0.0	5.2	6.2	15.2	74.1
IGCC/CCS (high)	51.8	0.0	5.2	6.2	13.4	76.5
Wind	65.7	2.9	9.2	0.0	0.0	77.8

CC = combined cycle; CCS = carbon capture and storage; IGCC = integrated gasification combined cycle; MWh = megawatt-hour; O&M = operation and maintenance.

Table H-7-4. Real levelized costs for retrofitting existing coal stations with CCS technology (2005$/MWh)

	Capacity	Transport in-state	Transport out-of-state	Fixed O&M	Variable O&M	Fuel	Storage	Monitoring	Total
MEA	29.3	1.5	13.3	0.0	11.9	10.2	13.3	6.2	85.9
Oxy-firing	19.1	1.5	13.3	0.0	15.9	8.0	13.3	6.2	77.4

CCS = carbon capture and storage; MEA = monoethanolamine; MWh = megawatt-hour; O&M = operation and maintenance.

Table H-7-5. Real levelized costs NGCT for reliability associated with intermittent renewables (2005$/MWh)

Capacity type	Capacity	Transmission	Fixed O&M	Variable O&M	Fuel	Total	Capacity factor (%)	Fuel factor (%)
CT	13.4	0.0	0.3	3.5	20.0	37.2	50%	25%

NGCT = natural gas combustion turbine; O&M = operation and maintenance.

DSM measure costs: $30/MWh (average).

Key Uncertainties

Costs and availability of post-combustion CCS technology, availability of suitable CO_2 storage sites in Arkansas, price forecast for natural gas and coal delivered to regional power stations, reliability needs for wind power, and uncertainty about potential liability and insurance issues associated with CCS.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Complete.

Level of Group Support

Majority (10 objections).

Barriers to Consensus

Ten of the 21 GCGW members present objected to this policy because it recommends that construction of the Hempstead (Turk) coal plant be delayed until 2020, the Hempstead plant will be the cleanest and most efficient coal plant built to date, it is uncertain if CCS technology can be demonstrated to be commercially viable and cost-effective by 2020, potential cost issues are associated with relying on renewables and other resources that may not be able to fulfill baseload demand that otherwise would be fulfilled by a coal plant like Hempstead, and the APSC is requiring the Southwestern Electric Power Company to review annually all carbon sequestration and capture technologies as available in the future.

One GCGW member objected on the basis that this would be de facto retroactive policymaking. Industry has a right to presume that the rules will not change in midstream on projects once they are begun. If the Commission wants to draw a line in the sand on the issue of coal-fired power plants, that must be done in the future and must not impact plants in which significant investments have already been made under a current policy structure.

ES-8. Transmission System Upgrades

Policy Description

Measures to improve transmission systems to reduce bottlenecks and enhance throughput may be required to satisfy long-term electricity demands, improve the efficiency of operations, and allow for delivery of diverse and renewable energy sources located outside of the state. Opportunities may exist to substantially increase transmission line carrying capacity through the implementation of new construction and retrofit activities on the transmission grid, including incorporating advanced composite conductor technologies, capacitance technologies, and grid management software. Siting new transmission lines can be a difficult process, given their cost and their local impact on the environment and on the use, enjoyment, and value of property.

Policy Design

A primary goal of this policy recommendation can be to provide incentives to utilities to upgrade existing transmission systems and reduce barriers to siting new transmission lines to provide access to new energy sources often far from existing transmission lines and load centers.

Another goal of this policy can be to reduce T&D line losses. Utilities use a variety of components throughout the T&D system to manage losses. Increasing the efficiency of these components can further reduce losses and associated GHG emissions. For example, Vermont offers a rebate to encourage the installation of energy-efficient transformers. Regulations, incentives, and/or support programs can be applied to achieve greater efficiency of T&D system components.

A third goal can be the general distribution of generation support (interconnection rules, net metering, etc.). Well-designed interconnection rules will ensure that distributed power products meet minimum requirements for performance, safety, and maintenance, while at the same time significantly advance the commercialization of these technologies.

Goals:

- Achieve a 5% effective improvement in energy efficiency through reduced T&D system losses (i.e., losses reduced from 6.5% to 6.2%).
- Achieve a 5% increase in renewable energy sources through improved transmission access to these sources.

Timing: Phased in, beginning in 2013, with the established goal achieved by 2018.

Parties Involved: APSC, investor-owned utilities, generation and transmission electric cooperatives, municipalities, representatives of environmental and economic development organizations, the Federal Energy Regulatory Commission, and transmission owners and operators.

Implementation Mechanisms

None cited.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Not applicable.

Estimated GHG Reductions and Costs or Cost Savings

Table H-8-1. Estimated GHG reductions from and costs of or cost savings from ES-8

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/t$CO_2e)
		2015	2025	Total 2009–2025		
ES-8	Transmission System Upgrades	*Not Quantified*				

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/t$CO_2$e = dollars per ton of carbon dioxide equivalent.

Data Sources: See ES-3a.

Quantification Methods: See ES-3a.

Key Assumptions:

A) The program begins in 2013 and continues through 2018.

B) 90% of reductions in electricity production will come from coal and 10% from natural gas.

C) Effective improvements in energy efficiency through reduced T&D line losses occur at a rate of 0.5% per year in 2013 and 2014. The rate increases to 1% per year between 2015 and 2018.

D) The expected annual cost of line upgrades is $30 million.

E) The escalation rate for gross generation and associated CO_2e emissions beyond 2025 is 0.51%.

F) The rate at which costs are discounted annually is 5%.

G) NPV is calculated in 2008 dollars.

Key Uncertainties

See the Feasibility Issues section.

Additional Benefits and Costs

None cited.

Feasibility Issues

The functioning of the electric transmission network is somewhat analogous to the nation's system of roadways. High-voltage transmission lines were originally constructed to efficiently transport power from local utility bulk power plants, usually constructed in nearby rural areas, to large load centers in metropolitan areas. This has evolved over time to building transmission to even more remote baseload generation, and interconnecting with neighboring utilities to take advantage of jointly owned generating stations and emergency assistance. Central station wind and solar have significant cost advantages over distributed resources, but prime locations are remote from Arkansas and in very rural areas without significant electric transmission infrastructure. If regional and national bulk electric transmission lines (the equivalent of the interstate highway system) are not built, access to significant and cost-effective renewable generation will be obstructed, and goals for such must be scaled back to levels reliably and economically achievable.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-9. Nuclear Power

Policy Description

Nuclear power has historically been a low-GHG source of electric power. However, no new nuclear power plants have come on line in the United States since 1996 due to high capital costs. Long-term disposal of nuclear waste and public safety are public policy concerns with nuclear power. With the national pricing of the GHG cost of fossil fuel generation, with either a cap-and-trade system or a carbon tax, nuclear power will be more cost-competitive.

The Energy Policy Act of 2005 included provisions encouraging the construction of new nuclear units. There are currently nine applications for a new plant on file with the Nuclear Regulatory Commission (NRC). The one nearest to Arkansas is adjacent to the existing Grand Gulf unit in Port Gibson, Mississippi; it has been accepted for docketing by the NRC. As new nuclear power plants come on line in the future in the Arkansas region, they will offer Arkansas electric utilities an alternative to the construction of fossil fuel generation units.

Nuclear plant relicensing allows an existing plant to extend the life of the facility for 20 years past its original 40-year license terms. The two existing nuclear units in Arkansas have already completed this process. Thus, no further reductions in current GHG emissions can be achieved through the relicensing process.

Policy Design

Given the uncertainty of when new nuclear generating capacity will be on line in this region, the GCGW does not recommend a reduction goal achievable with this action. However, the GCGW does go on record supporting the construction of new nuclear power plants.

Goal: One new 1,500-MW nuclear plant operating at 95% capacity factor.

Timing: Operational in 2020.

Parties Involved: APSC.

Implementation Mechanisms

None cited.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Costs or Cost Savings

Table H-9-1 summarizes the results of this policy recommendation. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table H-9-1. Estimated GHG reductions and costs or cost savings from ES-9

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$) 2015	2025	Total 2009–2025	Net Present Value 2009–2025 (Million $)	Cost-Effectiveness ($/$tCO_2e$)
ES-9	Nuclear Power	0.0	9.8	58.9	$1,574	$26.7

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/$tCO_2e$ = dollars per ton of carbon dioxide equivalent.

Data Sources:

- California Public Utilities Commission. "New Nuclear Generation Resource, Cost, and Performance Assumptions." November 2007. Available at: http://www.ethree.com/GHG/25%20Nuclear%20Assumptions%20v2.doc.
- Upstream carbon emissions for nuclear, coal, and natural gas-fired generation are from Arthur D. Little, Inc. *Guidance for Transportation Technologies: Fuel Choice for Fuel Cell Vehicles—Final Report*. February 2, 2002. Available at: http://www.eere.energy.gov/hydrogenandfuelcells/ pdfs/fuel_choice_fcvs.pdf.
- Plant-specific Arkansas capacity addition data are based on Arkansas ES TWG input.
- U.S. Department of Energy. *Energy Technologies and the Environment: Environmental Information Handbook*. Report DOE/EH-077, Washington DC, 1988.
- R.A. Bradley, E.C. Watts, and E.R. Williams, eds. *Limiting Net Greenhouse Gas Emissions in the United States. Volume —Energy Technologies*. Report DOE/PE-0101-Vol.1. Washington, DC, 1991.
- Coal production statistics derived from U.S. Department of Energy, Energy Information Administration. "Annual Coal Report 2003 Data Tables." Available at: http://www.eia.doe.gov/cneaf/coal/page/acr/acr_html_tabs.html.

Quantification Methods:

See Annex H-1 for the overall approach to the quantification of this and all other energy supply recommendations.

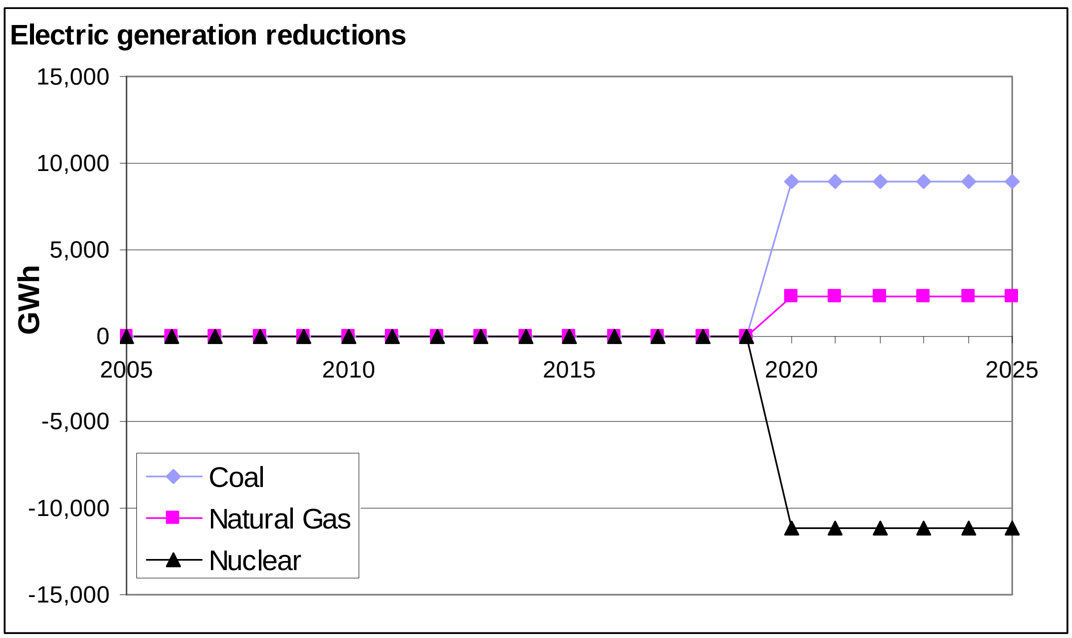
The analysis of this policy recommendation examines the installation a one nuclear power station during the planning period. The following key assumptions were used for the analysis of this recommendation:

- One reference scenario is modeled, assuming the Hempstead plant is built.
- The start year for the policy recommendation is 2020.

- Incremental renewable energy generation associated with the installation of the nuclear station displaces 80% coal-fired and 20% natural gas-fired generation in each year the nuclear station is operational.
- The cost of new nuclear power is compared to the average avoided cost of electricity expansion in Arkansas, as obtained from the RCI TWG (i.e., $58.3/MWh).
- Full fuel-cycle GHG emissions are considered.
- Three sensitivities are considered for cost and performance assumptions for nuclear stations, low, mid, and high estimates. *The mid estimate is the default assumption.*

Figure H-9-1 summarizes the impact of this policy recommendation on in-state gross generation. The incremental effect by 2025 is an additional 11,169 GWh of new nuclear generation over the period 2020–2025, leading to reductions of 8,935 GWh of coal-fired generation and 2,234 GWh of natural gas-fired generation.

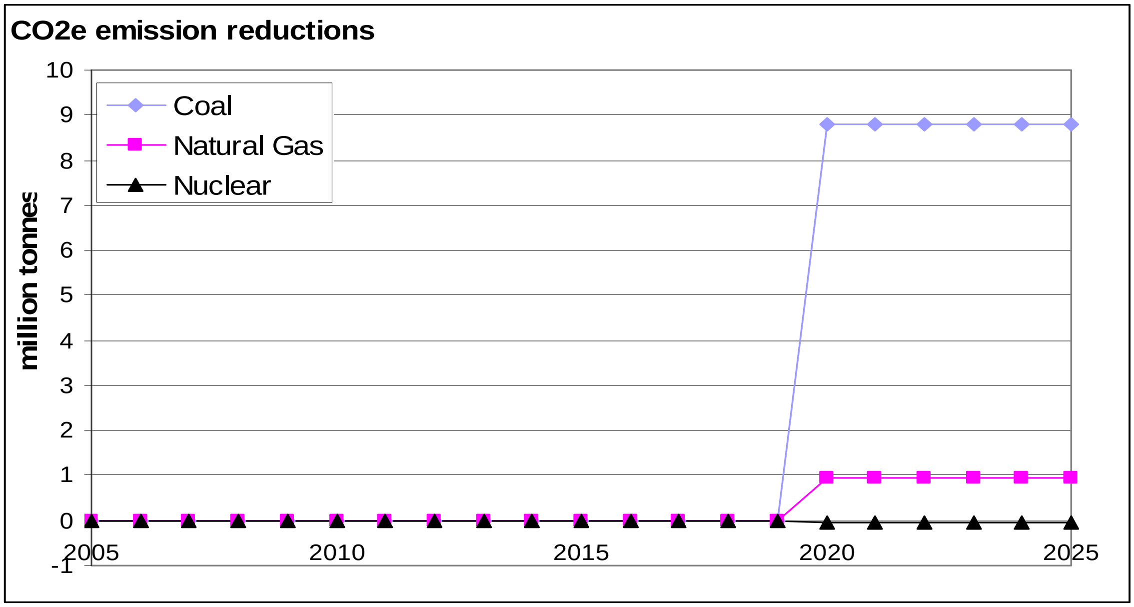
Figure H-9-1. Effect of ES-9 on in-state gross generation



GWh = gigawatt-hour.

Figure H-9-2 summarizes the impact of the recommendation on CO_2e emission reductions across the full fuel cycle. The annual effect of the recommendation by 2025 results in about a 9.82 $MMtCO_2e$ emission reduction across the full fuel cycle. This is made up of reductions of 8.93 $MMtCO_2e$ from less coal-fired generation, reductions of 0.93 $MMtCO_2e$ from less natural gas-fired generation associated with domestic supplies of natural gas, and an increase of 0.04 $MMtCO_2e$ from upstream emissions associated with nuclear power generation. On a cumulative basis, the recommendation leads to emission reductions of 8.9 $MMtCO_2e$.

Figure H-9-2. Effect of ES-9 on CO_2e emission reductions across the full fuel cycle



CO_2e = carbon dioxide equivalent.

Cost savings are associated with avoided capital, fuel, and O&M costs for coal and natural gas facilities. Incremental costs are associated with the capital, transmission, variable and fixed O&M, and fuel costs associated with the new nuclear station. The annual product of real levelized costs and displaced generation is an estimate of the annual costs. The sum of the annual costs and annual benefits provides an estimate of the net costs of the recommendation. For the central estimate of cost and performance, the NPV of the costs is $1.57 billion over the 2020–2025 period (2005$). The recommendation's cost-effectiveness is calculated as the quotient of the NPV and cumulative GHG emission reductions. For the central estimate of cost and performance, it is $26.7/t$CO_2$e (2005$) (i.e., $1.57 billion divided by 58.9 MMtCO_2e and multiplied by a conversion factor of 1,000).

Key Assumptions:

Tables H-9-2 through H-9-7 summarize the key assumptions used in the analysis of this policy recommendation.

Table H-9-2. Assumed coal fuel cycle inputs for power generation

Coal (GJ input per GJ of coal deliverd to the power station)	Extraction	Beneficiation and processing	Transport	Generation	**Fuel Chain**
Feedstock-INCLUDING ALL LOSSES					
Natural gas	-	-	-		**-**
Petroleum	-	-	-		**-**
Hydrogen	-	-	-		**-**
gasoline	-	-	-		**-**
Diesel	-	-	-		**-**
heavy fuel oil	-	-	-		**-**
Coal	1.0000				**1.0000**
electricity (end use)	-	-	-		**-**
Total-feedstocks	1.0000	-	-		**1.0000**
Fuels					
Natural gas	0.0001	-	-		**0.0001**
petroleum	0.0051	-	-		**0.0051**
Coal	0.0006	-	-		**0.0006**
gasoline	0.0002	-	-		**0.0002**
diesel	0.0039	-	0.0088		**0.0128**
heavy fuel oil	0.0005	-	-		**0.0005**
Biomass	-	-	-		**-**
electricity (end use)	0.0017	-	-		**0.0017**
Total-fuels	0.0122	-	0.0088		**0.0210**
Total-fuel & feedstock losses	**1.0122**	**-**	**0.0088**	**-**	**1.0210**

GJ = gigajoule.

Table H-9-3. Assumed domestic natural gas fuel cycle inputs for power generation

Natural Gas (GJ input per GJ of NG deliverd to the power station)	Extraction	NG Processing	NG Transport	**Fuel Chain**
Feedstock-INCLUDING ALL LOSSES				
Natural gas	1.00000	-	-	**1.00000**
Petroleum	-	-	-	**-**
Hydrogen	-	-	-	**-**
gasoline	-	-	-	**-**
Diesel	-	-	-	**-**
heavy fuel oil	-	-	-	**-**
Biomass	-	-	-	**-**
electricity (end use)	-	-	-	**-**
Total-feedstocks	1.00000	-	-	**1.00000**
Fuels				
Natural gas	0.02253	0.02467	0.00367	**0.05088**
petroleum	-	-	-	**-**
Coal	-	-	-	**-**
gasoline	0.00022	-	-	**0.00022**
diesel	0.00245	0.00024	-	**0.00269**
heavy fuel oil	0.00022	-	-	**0.00022**
Biomass	-	-	-	**-**
electricity (end use)	0.00022	0.00072	-	**0.00095**
Total-fuels	0.02564	0.02564	0.00367	**0.05496**
Total-fuel & feedstock losses	**1.02564**	**0.02564**	**0.00367**	**1.05496**

GJ = gigajoule; NG = natural gas.

Table H-9-4. Assumed nuclear fuel cycle inputs for power generation

Nuclear (GJ input per GJ of nuclear fuel deliverd to the power station)	Mining & milling	Conversion & transformation	Enrichment	fuel fabrication	Fuel Chain
Feedstock-INCLUDING ALL LOSSES					
Natural gas	-	-	-	-	**-**
Petroleum	-	-	-	-	**-**
Uranium	1.00000	-	-	-	**1.00000**
gasoline	-	-	-	-	**-**
Diesel	-	-	-	-	**-**
heavy fuel oil	-	-	-	-	**-**
Biomass	-	-	-	-	**-**
electricity (end use)	-	-	-	-	**-**
Total-feedstocks	1.00000	-	-	-	**1.00000**
Fuels					
Natural gas	-	-	-	-	**-**
petroleum	-	-	-	-	**-**
Coal	-	-	-	-	**-**
gasoline	-	-	-	-	**-**
diesel	0.00077	0.00077	0.00326	0.00004	**0.00483**
heavy fuel oil	-	-	-	-	**-**
Biomass	-	-	-	-	**-**
electricity (end use)	0.00000	0.00000	0.00002	0.00000	**0.00002**
Total-fuels	0.00077	0.00077	0.00328	0.00004	**0.00485**
Total-fuel & feedstock losses	**1.000765**	**0.000765**	**0.003284**	**0.000041**	**1.00485**

GJ = gigajoule.

Table H-9-5. Key assumptions for new nuclear station

Online year	2020	
Size	1,500	MW
Capacity factor	85%	
Generation (GWh)	11,169	
Technology	light water reactor using enriched uranium fuel	

GWh = gigawatt-hour; MW = megawatt.

Table H-9-6. Cost and performance assumptions for new nuclear station

	Min	Max	Central
EPC assumption	50%	50%	50%
Base generation capital cost (2005$/kW)	3,066	3,999	3,533
Total capital cost (2005$/kW)	4,599	5,999	5,299
Variable O&M (2005$/MWh)	$0.51	$0.51	0.51
Fixed O&M (2005$/kW-yr)	$63.29	$82.55	72.92
Nominal Heat Rate (BTU/kWh)	10,400	10,400	10,400
Capacity factor (%)	80%	90%	85%
Fuel (2005$/mmbtu)	1.0	1.0	1.0

Btu = British thermal unit; kW = kilowatt; kWh = kilowatt-hour; MWh = megawatt-hour; $/MMBtu = dollars per million British thermal units.

Table H-9-7. Full fuel cycle emission factors (tCO_2e/MWh)

Coal	1.0109
Natural gas	0.43751
Nuclear	0.00367

tCO_2e/MWh = metric tons of carbon dioxide equivalent per megawatt-hour.

Key Uncertainties

Nuclear fuel availability; nuclear waste storage and disposal; security requirements; changes in federal policy (e.g., NRC relicensing, long-term waste repository); technology and economics of new units; industry-wide developments.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Complete.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

ES-10. Carbon Tax

Policy Description

The primary goal of this policy recommendation is to establish a mechanism that will allow Arkansas to adapt to and be prepared for a federally implemented carbon tax and other federal climate policies.

A carbon tax sets a fee, or tax, for the release of carbon to the atmosphere. It does not set a limit, reduce, or otherwise control the tons of carbon released. The tax raises the cost of carbon-based emissions and, therefore, encourages investment in low-carbon or no-carbon alternatives. It also generates revenue for the government, which could be directed toward energy efficiency, the development and use of renewable energy, climate change adaptation investments, and other measures to mitigate or address the impacts of climate change. Many proposals also have options to rebate the tax back to the ratepayer, particularly low-income ratepayers. A carbon tax could be implemented as a tax on fossil fuels according to the amount of CO_2 emitted by their combustion. One of the benefits is that the tax can be more easily applied across all sectors. To achieve the stated goal, the amount of the tax must be high enough to trigger financial and behavioral decisions toward conservation or a shift to lower-emitting fuels.

Several examples exist where carbon taxes have been implemented. In 1990, Finland became the first country to adopt a carbon tax, setting its level at about $1.45 per metric ton of CO_2, which was raised to $8.34 in 1995. Other countries, such as Denmark, Holland, and Sweden, followed suit. In North America, several examples exist. In November 2006, Boulder, Colorado, passed the first-ever municipal "carbon tax," a tax on electricity consumption (utility bills) that funds programs by the City of Boulder to reduce GHG emissions. In February 2008, British Columbia announced its intention to implement a $10/metric ton carbon tax beginning in July 2008. And in May 2008, the Bay Area Air Quality Management District, which covers nine counties in the San Francisco Bay Area, passed a carbon tax of 4.4 cents per metric ton.

Additionally, many businesses and others have opted for what amounts to voluntary carbon taxes through participation in voluntary offsetting programs, such as Native Energy and TerraPass. For example, many online travel companies give customers the option of paying into these programs to offset the carbon costs of their travel. Such a program could be designed in Arkansas with utility bills to help implement many of the carbon capture projects discussed elsewhere in this report.

Policy Design

- Arkansas should only consider carbon tax programs that are national in scope, and in conjunction with other carbon tax and “cap-and-trade” programs that are proposed. The state should opt for national programs that use revenue sharing back to state government for purposes of implementing state initiatives on global warming. The state should promote a national carbon tax that does not put Arkansas at a competitive disadvantage with other states.

- Arkansas should make the cost of inefficient or higher CO_2-emitting activities more expensive than alternatives, thereby creating a financial incentive to discourage activities that result in CO_2 emissions. The amount of revenue that the carbon tax generates annually should depend on the facilities subject to the tax. The amount of the tax should be high enough to contribute to the reduction targets specified in a statute. From a competitive perspective, one advantage of a carbon tax is that it is constant and predictable, making a business case more stable than some alternatives.
- A carbon tax should include options to rebate the tax back to the ratepayer, thus creating a true cost of carbon but keeping ratepayers from paying more on their utility bills. This should include rebates on income and payroll taxes, particularly for low-income ratepayers.
- Voluntary carbon offset programs should be established in Arkansas through utility bills and other mechanisms.

Goals:

- Integrate a carbon tax program in correlation with a national cap-and-trade system.
- Work with surrounding states to establish a market-base value and standard that include Arkansas-specific opportunities based on economic and environmental benefits.
- Integrate a low-income credit initiative that focuses on efficiency.
- Establish a program that will easily allow Arkansas to adapt to a federal cap-and-trade system.
- Establish a voluntary carbon offset program in Arkansas.

Timing: Beginning in 2009 and the system in place by late 2010, depending on the status of efforts at the national level.

Parties Involved: All entities included in all other Arkansas climate change processes.

Other: None cited.

Implementation Mechanisms

A carbon tax is both an incentive mechanism and a revenue-raising instrument. The tax should be structured in such a way as to shift the tax burden away from low-income households. This can be done by recycling the revenue back into the economy through corresponding reductions in personal income taxes or by altering the rate recovery regulations for electricity use.

Another option would be to create a voluntary check-off program on utility bills that would account for carbon tax costs of household bills, giving customers the option of offsetting it with a Native Energy or TerraPass type of program, only inside Arkansas. The state should work with the APSC and public utilities, and other stakeholders, in establishing such a voluntary program.

The state of Arkansas should work with the Arkansas congressional delegation and other parties on designing and implementing a carbon tax on a national level, working in conjunction with other similar goals, such as a national cap-and-trade system.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

The GCGW considers this policy recommendation as not quantifiable.

Estimated GHG Reductions and Costs or Cost Savings

The GCGW considers this policy recommendation as not quantifiable.

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Not applicable.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Complete.

Level of Group Support

Super Majority (4 objections).

Barriers to Consensus

Four of 21 GCGW members present objected to this recommendation in general, noting that this is a national issue because imposing a carbon tax on a local market will cause Arkansas to be uncompetitive with other states that do not choose to impose such a tax. One GCGW member objected to the roll-back provision to adjust income and payroll taxes to offset any tax increase associated with a carbon tax, believing this defeats the purpose of the tax, which is to provide an incentive to decrease energy use.

ES-11. Efficiency Improvements and Repowering of Existing Plants

Policy Description

Improving efficiency at existing plants refers to increasing generation efficiency through such improvements as more efficient boilers and turbines, improved control systems, or combined-cycle technology. This could also include switching to lower- or zero-emitting fuels at existing plants, or new capacity additions. Policies to encourage efficiency improvements and repowering of existing plants could include incentives and/or regulations. Although most economic improvements have already been made, existing power plants should be encouraged to reach specific energy efficiency goals before new plants are constructed.

Policy Design

Goals: Beginning in 2010, power plants should commence efficiency measures by improvement in heat rates from existing levels. The policy will include a linear ramp-up schedule until a maximum 10% efficiency obtainable is reached by 2020.

Timing: 5% improvement achieved by 2015; 10% achieved by 2020.

Parties Involved: Public/consumers, state and local governments, APSC.

Implementation Mechanisms

An estimated cost of carbon should be included to help drive further improvements in efficiency.

For utilities subject to the authority of the APSC, the APSC should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers. For utilities (e.g., municipal utilities) that are not subject to the authority of the APSC, the governing body for the utility should review any allocations that are subsidies coming from ratepayers and ensure that there is not inappropriate cross-subsidization between classes of consumers.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

Avoided emissions from fossil-fuel generation.

Estimated GHG Reductions and Costs or Cost Savings

Table H-11-1 summarizes the results of this policy recommendation. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table H-11-1. Estimated GHG reductions and costs of or cost savings from ES-11

No.	Policy Recommendation	GHG Reductions ($MMtCO_2e$) 2015	2025	Total 2009–2025	Net Present Value 2009–2025 (Million $)	Cost-Effectiveness ($/t$CO_2e$)
ES-11	Repower existing coal station with NGCC	2.3	2.3	31.8	$1,568	$49.33

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/t$CO_2e$ = dollars per ton of carbon dioxide equivalent; NGCC = natural gas combined cycle.

Data Sources:

- U.S. Department of Energy, Energy Information Administration. *Assumptions to the Annual Energy Outlook 2007.* DOE/EIA-0554. April 2007. Available at: http://www.eia.doe.gov/oiaf/aeo//pdf/.pdf.
- National Energy Technology Laboratory. *Cost and Performance Baseline for Fossil Energy Plants*. DOE/NETL-2007/1281. August 2007. Available at: http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf
- Plant-specific Arkansas capacity addition data are based on Arkansas ES TWG input.

Quantification Methods:

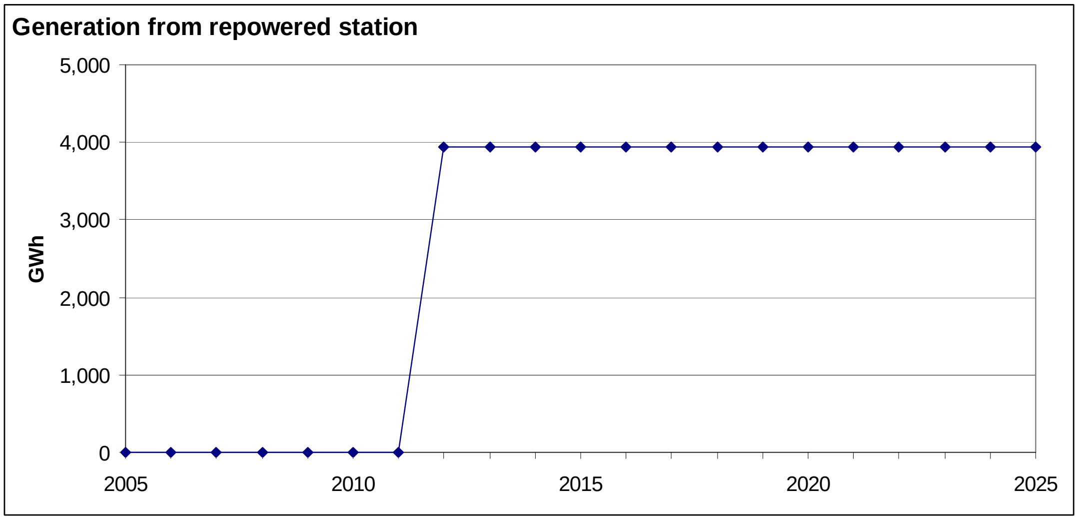
See Annex H-1 for the overall approach to the quantification of this and all other ES recommendations.

This policy recommendation would promote the identification and pursuit of cost-effective emission reductions from existing generating units by improving their operating efficiency and fuel changes, or by adding carbon capture technology. It has been modeled as the repowering of an existing pulverized coal station with NGCC technology. The TWG is making the following key assumptions for the analysis of this recommendation:

- The start year for the policy recommendation is 2012.
- One existing pulverized coal plant is repowered with an NGCC unit sized to provide equivalent annual power generation
- The coal station is be fully depreciated.

Figure H-11-1 presents the total generation associated with the repowered station.

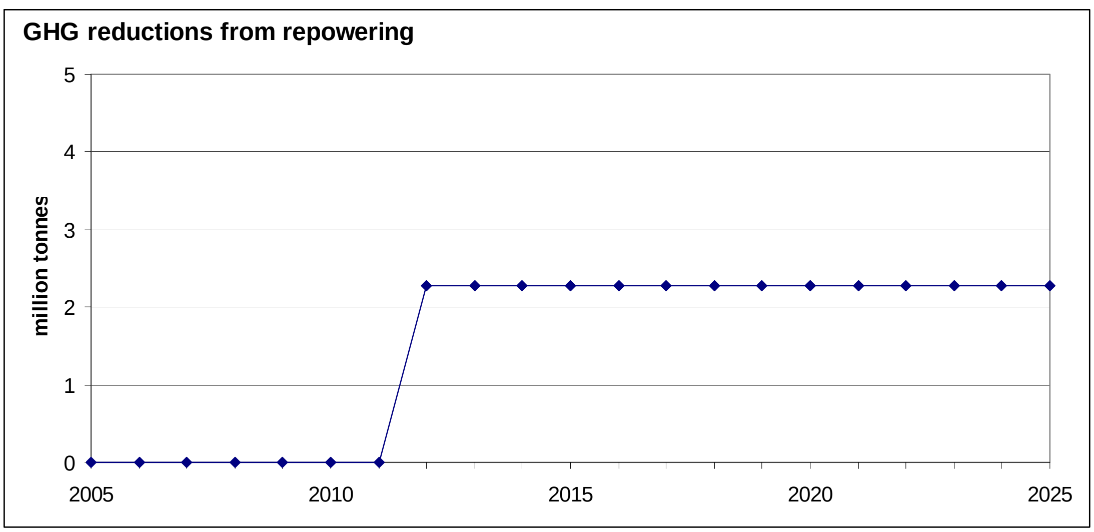
Figure H-11-1. Generation from repowered pulverized coal plant



GWh = gigawatt-hour.

Figure H-11-2 presents the annual CO_2e emission reductions associated with the repowered unit. The annual emission reductions in both 2015 and 2025 are 2.3 MMtCO_2e. The cumulative emission reductions over the 2005–2025 forecast period are 31.8 MMtCO_2e.

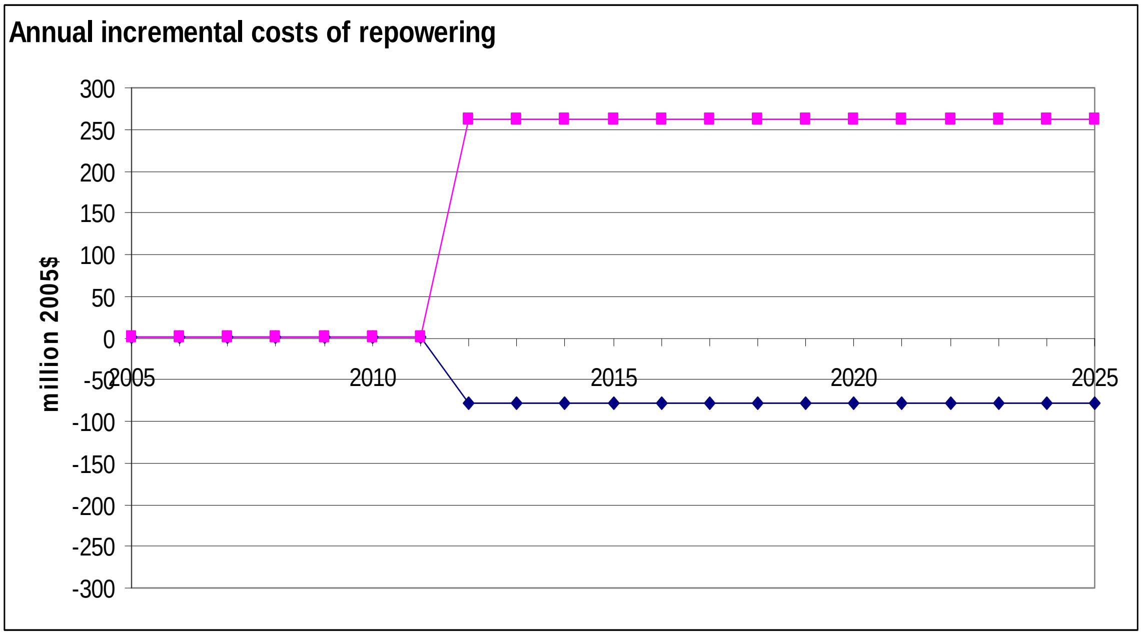
Figure H-11-2. Annual CO_2e emission reductions associated with the repowered unit



GHG = greenhouse gas.

There are incremental capital, O&M, and fuel costs from the NGCC unit and incremental fuel and O&M savings from coal, as summarized in Figure H-11-3. The coal station was assumed to be fully depreciated. The NPV of these annual costs is $1.6 billion over the 2012–2025 period (2005$).

Figure H-11-3. Annual incremental costs of repowering



The recommendation's cost-effectiveness was calculated as the quotient of the NPV and cumulative GHG emission reductions, or \$49.3/tCO_2e (2005\$) (i.e., \$1.6 billion divided by 31.8 MMtCO_2e and multiplied by a conversion factor of 1,000).

Key Assumptions:

Performance Characteristics of the Existing Coal Station—The existing pulverized coal plant to be repowered has the following characteristics:

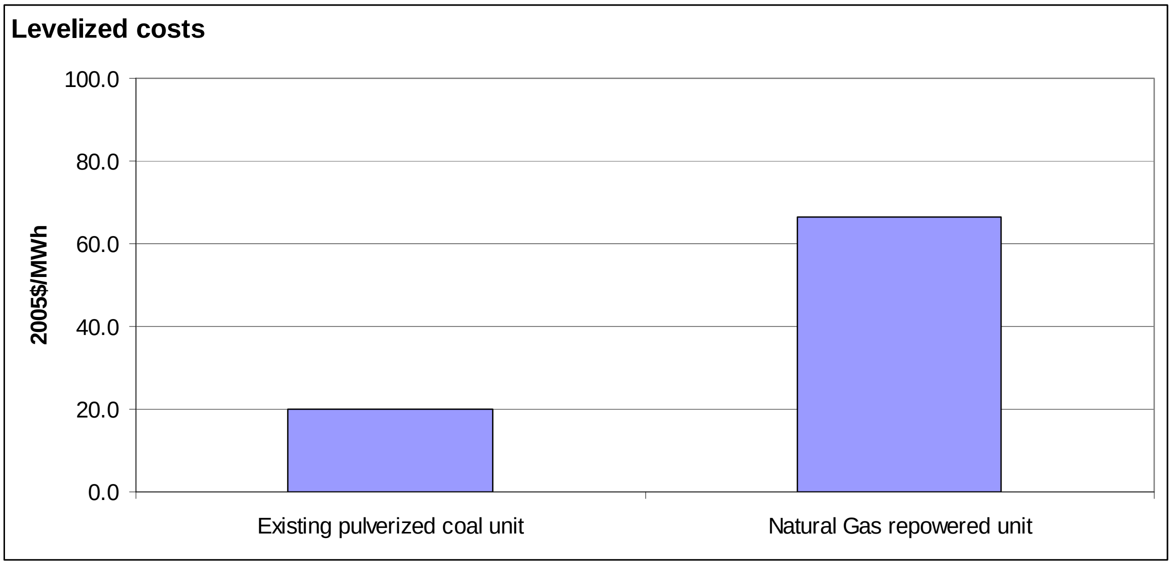
- Type: pulverized coal
- Age: 30+ years
- Size: 600 MW
- Heat rate: 10,000 Btu/kWh
- Average annual capacity factor: 75%

Performance Characteristics of the Repowered Unit—The repowered unit has the following characteristics:

- Type: natural gas combined cycle
- Size: 600 MW
- Heat rate: 7,200 Btu/kWh
- Average annual capacity factor: 75%

Levelized Costs—Figure H-11-4 defines the levelized costs.

Figure H-11-4. Levelized costs



MWh = megawatt-hour.

Key Uncertainties

Two key uncertainties have been identified: (1) whether and how the new source review provisions of the Clean Air Act would affect the promotion of plant upgrades, and (2) how this policy recommendation may relate to a cap-and-trade proposal.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Approved.

Level of Group Support

Unanimous.

Barriers to Consensus

Not applicable.

Annex H-1

Overall Quantification Approach for Energy Supply Policy Recommendations

This Annex outlines key elements of the quantification approach the Center for Climate Strategies (CCS) adopted for quantifying the greenhouse gas (GHG) impacts and costs for those policy recommendations that are considered amenable to quantification. The list of topics addressed in the memo is summarized below.

A. Premises

The analysis was based on a number of key premises, as briefly outlined below.

- *CCS role:* Unless a member of the Energy Supply (ES) Technical Work Group (TWG) offered to undertake an analysis of any of the recommendations, CCS prepared the analysis for review, comment, and revision by the TWG. Where an ES TWG member offered to undertake the analysis of one or more recommendations, CCS would provide analytical support (e.g., review and technical feedback) as needed.
- *Transparency:* Data sources, methods, key assumptions, and key uncertainties are clearly indicated for TWG review and comment.
- *Analytical approach:* The approach adopted was of cost-effectiveness (and net present value [NPV]) analysis, as widely applied to GHG mitigation policy recommendations.[1] Included were direct, economic costs from the perspective of the state as whole (e.g., avoided costs of electricity, rather than consumer electricity prices).
- *Bottom-up analysis:* A bottom-up approach was adopted, which was amenable to transparency and was capable of reflecting the costs (and cost savings) associated with individual policy recommendations. This was chosen in contrast to macroeconomic analysis, which aims to capture flows and interactions across all sectors of the economy. Potential macroeconomic impacts, cost, or benefits that fall disproportionately on specific groups or actors, as well external costs and benefits, should be noted qualitatively where studies or other information are available.

B. Outputs

The analysis of policy recommendations was organized so as to produce the following results:

- *Net GHG reduction potential* in million metric tons of carbon dioxide equivalent ($MMtCO_2e$) using Intergovernmental Panel on Climate Change 100-year global warming potential, reported annually for the years 2015, 2020, and 2025, and cumulatively for the period 2010–2025. Where significant additional GHG reductions or costs occur beyond the project period as a direct result of actions taken during the project period, these were indicated as appropriate.

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[1] For more discussion of various economic analysis approaches, see, e.g., Section 2.4 of: Intergovernmental Panel on Climate Change. *Climate Change 2007—Mitigation of Climate Change. Contribution of Working Group III to the Fourth Assessment Report of the IPCC.* Available at: http://www.mnp.nl/ipcc/pages_media/AR4-chapters.html.

- *NPV cost* (or cost savings) for the period 2010–2025 in 2007 constant dollars, using a 5% real discount rate.[2] Positive numbers represent recommendations with net costs; negative numbers represent recommendations with net cost savings.
- *Cost per metric ton of CO_2 equivalent* (tCO_2e) emissions reduced (or removed) in units of $\$/tCO_2e$. This figure represents the NPV cost divided by the cumulative emission reductions, both over the 2010–2025 period.

C. Methodology

As much as possible, the analysis preceded using simple spreadsheet modeling techniques in which assumptions were transparent and readily accessible to any TWG member for review and adjustment. To ensure consistent results across recommendations, common factors and assumptions were used for such items as:

- *Electricity avoided costs and emissions*—Common values ($/megawatt-hour [MWh] and tCO_2/MWh) were developed based on available studies. Each policy recommendation was first analyzed individually and then addressed as part of an overall integrated analysis.
- *Fuel costs and projected escalation*—Fuel cost estimates were based on common sources, wherever possible. For example, fossil fuel price escalations were indexed to U.S. Department of Energy (DOE) projections, as indicated in DOE's most recent *Annual Energy Outlook*.
- *Overlap with other TWGs*—Some ES policy recommendations overlap with policy recommendations analyzed by other Arkansas Governor's Commission on Global Warming TWGs. The analysis for these recommendations took place in close coordination with the assumptions and other inputs used in those TWGs.
- *Consumption-based approach*—This approach aims to reflect the emissions associated with electricity sources used to deliver electricity to consumers in Arkansas. It is distinct from a production-basis approach, which considers the emissions from Arkansas power plants, regardless of where the electricity is delivered.

D. Assumptions

As much as possible, the analysis sought to rely on data sources that are Arkansas-specific, and that TWG members were in a good position to obtain and provide. The success of this approach depended on how accessible the information was to TWG members and the timeliness in which it was provided to the CCS analytical team.

Where Arkansas-specific information could not be readily obtained, the analysis relied on published data from DOE, the National Laboratories, and other state climate change processes. Specific assumptions that were needed to undertake the analysis are outlined below. Some of these assumptions were obtained from non-Arkansas sources:

- Avoided costs associated with the most recent electric capacity expansion plans in Arkansas;
- New centralized renewable installation energy cost and performance assumptions;

[2] Capital investments with lifetimes longer than 2025 are represented in terms of levelized or amortized costs, in order to avoid "end effects."

- New centralized fossil power station cost and performance assumptions;
- Fossil fuel price forecasts to electric generators through 2025 (i.e., distillate, residual oil, natural gas, coal, biomass);
- Any studies that provide spatial and temporal (as appropriate) quantitative estimates of renewable resource potential in Arkansas (wind, solar, biomass, animal wastes);
- Any studies that provide an indication of the technical and economic potential of combined heat and power systems in Arkansas (both commercial and industrial applications);
- Any studies that provide the costs associated with integrating large amounts of intermittent renewable technologies into the system (where integration costs are expected to increase with increasing amounts of intermittent capacity);
- Any studies that examine alternative electric sector expansion plans in Arkansas that have considered decoupling profits from sales, lost revenue adjustments, inverted block rates for residential consumers, and/or use of carbon adders; and
- Any studies that examine the installation and operating costs of integrated gasification combined-cycle systems in Arkansas.

E. Cost Inclusion

Several types of costs were explicitly considered in the analysis, and several types were excluded, as summarized below.

- Sample costs included:
    - Capital costs levelized (amortized) where appropriate, e.g., for new energy supply facilities and associated infrastructure;
    - Operation and maintenance and other labor costs (or incremental costs relative to standard practice);
    - Fuel and material costs, e.g., for natural gas, electricity, biomass resources, water, fertilizer, material use, electricity transmission and distribution; and
    - Other direct costs (e.g., administrative) and other costs (where readily estimated), such as the grid integration costs for renewable energy technologies.

- Sample costs excluded:
    - External costs, such as the monetized environmental or social benefits/impacts (value of damage by air pollutants on structures, crops, etc.), quality-of-life improvements, or improved road safety or other health impacts and benefits;
    - Energy security benefits; and
    - Macroeconomic impacts related to the impact of reduced or increased consumer spending, shifting of cost and benefits among actors in the economy.