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Energy Supply (ES)
Technical Work Group

Summary List of Pending Priority Policy Options for Analysis

Policy No.	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($\$/tCO_2e$)	Level of Support
		2015	2025	Total 2009–2025			
ES-1	Green Power Purchases and Marketing	*Transferred to RCI*					
ES-2	Technology Research & Development	*Not quantified*					Pending
ES-3A	Renewable Portfolio Standard (RPS)						Pending
	Scenario #1: Build Plum Point in 2010; do not build Hempstead plant	0.3	3.4	20.3	$664.7	$32.7	Pending
	Scenario #2: Build Plum Point in 2010; build Hempstead in 2012	0.3	3.6	21.9	$717.9	$32.8	Pending
ES-3B	Renewable Energy Feed-In Tariff (REFIT)						Pending
	Scenario #1: Build Plum Point only; half the efficacy of the German experience						Pending
	Sensitivity #1: Feed-in tariff set at a level to achieve same renewable energy generation as RPS	0.3	3.4	20.3	$405.2	$20.0	Pending
	Sensitivity #2: Feed-in tariff set at a level less than or equal to a 5% rate impact	0.3	3.2	19.3	$384.9	$20.0	Pending
	Sensitivity #3: Feed-in tariff set at a level to achieve 25% renewable generation by 2025	0.5	5.6	33.8	$675.3	$20.0	Pending
	Scenario #2: Build Plum Point only; three-fourths of the efficacy of the German experience						Pending
	Sensitivity #1: Feed-in tariff set at a level to achieve same renewable energy generation as RPS	0.3	3.4	20.3	$405.2	$20.0	Pending
	Sensitivity #2: Feed-in tariff set at a level less than or equal to a 5% rate impact	0.5	5.6	33.4	$667.1	$20.0	Pending
	Sensitivity #3: Feed-in tariff set at a level to achieve 25% renewable generation by 2025	0.5	5.6	33.8	$675.3	$20.0	Pending
	Scenario #3: Build Plum Point only; one-to-one with the German experience						Pending
	Sensitivity #1: Feed-in tariff set at a level to achieve same renewable energy generation as RPS	0.3	3.4	20.3	$405.2	$20.0	Pending
	Sensitivity #2: Feed-in tariff set at a level less than or equal to a 5% rate impact	0.8	8.8	52.6	$1,050.7	$20.0	Pending

Policy No.	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Level of Support
		2015	2025	Total 2009–2025			
	Sensitivity #3: Feed-in tariff set at a level to achieve 25% renewable generation by 2025	0.5	5.6	33.8	$675.3	$20.0	Pending
	Scenario #4: Build Plum Point & Hempstead; half the efficacy of the German experience						Pending
	Sensitivity #1: Feed-in tariff set at a level to achieve same renewable energy generation as RPS	0.3	3.6	21.9	$437.6	$20.0	Pending
	Sensitivity #2: Feed-in tariff set at a level less than or equal to a 5% rate impact	0.3	3.2	19.1	$381.3	$20.0	Pending
	Sensitivity #3: Feed-in tariff set at a level to achieve 25% renewable generation by 2025	0.5	6.1	36.5	$729.3	$20.0	Pending
	Scenario #5: Build Plum Point & Hempstead; three-fourths of the efficacy of the German experience						Pending
	Sensitivity #1: Feed-in tariff set at a level to achieve same renewable energy generation as RPS	0.3	3.6	21.9	$437.6	$20.0	Pending
	Sensitivity #2: Feed-in tariff set at a level less than or equal to a 5% rate impact	0.5	5.5	33.1	$660.7	$20.0	Pending
	Sensitivity #3: Feed-in tariff set at a level to achieve 25% renewable generation by 2025	0.5	6.1	36.5	$729.3	$20.0	Pending
	Scenario #6: Build Plum Point & Hempstead; one-to-one with the German experience						Pending
	Sensitivity #1: Feed-in tariff set at a level to achieve same renewable energy generation as RPS	0.3	3.6	21.9	$437.6	20.0	Pending
	Sensitivity #2: Feed-in tariff set at a level less than or equal to a 5% rate impact	0.8	8.6	52.0	$1,039.9	$20.0	Pending
	Sensitivity #3: Feed-in tariff set at a level to achieve 25% renewable generation by 2025	0.5	6.1	36.5	$729.3	$20.0	Pending
ES-4	Grid-Based Renewable Energy Incentives and/or Barrier Removal	TBD	TBD	TBD	TBD	TBD	Pending
ES-5	Approaches Benefiting From Regional Application	*Not quantified*					Pending
ES-6	Combined Heat and Power						Pending
	Scenario #1: Build Plum Point in 2010; do not build Hempstead plant	0.6	2.9	20.0	$886.1	$44.3	Pending
	Scenario #2: Build Plum Point in 2010; build Hempstead in 2012	0.6	2.9	20.0	$886.1	$44.3	Pending
ES-7	Geological Underground Sequestration for New Plants						Pending
	Scenario #1: Do not build new Hempstead plant	0.0	0.0	0.0	$0.0	$0.0	Pending

Policy No.	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/$tCO_2e$)	Level of Support
		2015	2025	Total 2009–2025			
	Scenario #2: Build Hempstead in 2012, with no mitigation or technology upgrade	–1.7	–1.9	–25.6	–$738.7	$28.9	Pending
	Scenario #3: Build Hempstead in 2012, with transition to carbon capture and storage (CCS) with CO_2 piped to MS for enhanced oil recovery	0.0	2.8	17.1	$582.3	$34.1	Pending
	Scenario #4: Build Hempstead in 2012, with transition to CCS with CO_2 stored in AR	0.0	2.8	17.1	$500.6	$29.3	Pending
	Scenario #5: Build Hempstead in 2012 as integrated gasification combined cycle (IGCC)	0.1	0.1	1.5	$334.0	$224.4	Pending
	Scenario #6: Build Hempstead in 2012, but with mitigation						Pending
	Scenario #6a: Build Hempstead in 2012, but with mitigation (natural gas combined cycle [NGCC] repowering)	2.3	2.3	31.8	$738.7	$23.2	Pending
	Scenario #6b: Build Hempstead in 2012, but with mitigation (offsets)	3.4	3.4	47.8	$394.8	$8.3	Pending
	Scenario #7: Do not build Hempstead; replace with expanded energy efficiency, renewable energy, and natural gas						Pending
	Scenario #7a: Do not build Hempstead; replace with expanded energy efficiency, renewable energy, and natural gas (energy efficiency & wind)	3.4	3.4	48.0	$1,440.7	$30.0	Pending
	Scenario #7b: Do not build Hempstead; replace with expanded energy efficiency, renewable energy, and natural gas (energy efficiency, wind, & NGCC)	2.9	2.9	40.4	$805.4	$19.9	Pending
ES-8	Transmission System Upgrades	TBD	TBD	TBD	TBD	TBD	Pending
ES-9	Nuclear Power						Pending
	Scenario #1: Build Plum Point in 2010; do not build new Hempstead plant						Pending
	Sensitivity #1: low-cost & performance assumptions	0.0	9.8	58.9	$1,329.4	$22.6	Pending
	Sensitivity #2: mid-cost & performance assumptions	0.0	9.8	58.9	$1,574.4	$26.7	Pending
	Sensitivity #3: high-cost & performance assumptions	0.0	9.8	58.9	$1,792.2	$30.4	Pending
	Scenario #2: Build Plum Point in 2010; build Hempstead in 2012						Pending
	Sensitivity #1: low-cost & performance assumptions	0.0	9.8	58.9	$1,329.4	$22.6	Pending
	Sensitivity #2: mid-cost & performance assumptions	0.0	9.8	58.9	$1,574.4	$26.7	Pending
	Sensitivity #3: high-cost & performance assumptions	0.0	9.8	58.9	$1,792.2	$30.4	Pending
ES-10	Carbon Tax	*Not quantified*					Pending

ES-11	Efficiency Improvements and Repowering of Existing Plants	2.3	2.3	31.8	$1,567.8	$49.3	Pending
	Sector Total After Adjusting for Overlaps	**3.2**	**21.5**	**149.7**	**$4,966**	**$33.2**	
	Reductions From Recent Actions	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	
	Sector Total Plus Recent Actions	**3.2**	**21.5**	**149.7**	**$4,966**	**$33.2**	

CCS = carbon capture and storage; GHG = greenhouse gas; IGCC = integrated gasification combined cycle; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent; NGCC = natural gas combined cycle; RCI = Residential, Commercial, and Industrial; RPS = renewable portfolio standard; REFIT = renewable energy feed-in tariff; TBD = to be determined.

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

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

* Note that the draft cumulative results shown on this row have not been reviewed by the TWG and will change based on GCGW and TWG comments. The cumulative results are based on the sum of the following:

- ES-3B (Renewable Energy Feed-In Tariff (REFIT)), Scenario #4, Build Plum Point & Hempstead; half the efficacy of the German experience, Sensitivity #1: Feed-in tariff level set at a level to achieve same renewabele energy generation as RPS
- ES-6 (Combined Heat and Power), Scenario #2, Plum point build in 2010; build Hempstead in 2012
- ES-7 (Geological Underground Sequestration for New Plants), Scenario #4, build Hempstead in 2012 with transition to CCS with CO2 stored in AR
- ES-9 (Nuclear Power), Scenario #2, Sensitivity #2: mid cost & performance assumptions
- ES-11 (Efficiency Improvements and Repowering of Existing Plants)

ES-1. Green Power Purchases and Marketing

Policy Description

[The Energy Supply (ES) Technical Work Group (TWG) recommends that this option be removed from the ES TWG list of policy options because it overlaps completely with Residential, Commercial, and Industrial (RCI) policy RCI-7, where it is more appropriately located.]

Green power purchasing refers to a variety of consumer-driven strategies to increase the production and delivery of low-greenhouse-gas (GHG) power sources beyond levels achieved through renewable portfolio standards and other mandatory programs. These programs provide consumers with information about alternative green sources that can be then be selected by the consumer, rather than the traditional, more carbon-intensive sources.

This policy should establish an Arkansas Green Power consortium, with participation from a variety of groups, including the electric utilities, in-state renewable energy producers, the Arkansas Department of Economic Development, and state universities' technology wings. The consortium should:

- Work to develop renewable energy production facilities in the state.
- Publicize, communicate, and market this power to consumers with a voluntary Arkansas Green Power fund.
- Establish a revolving loan pool to assist in the start-up costs for the program and re-invest the dollars in new and emerging technologies involving green power.

Policy Design

Goals:

- Electric facilities purchase green power to cover [x]% of their power needs by [year]. *[These remain unresolved by the ES TWG.]*
- Implement programs to provide consumers the option to purchase green power.

Timing: Consumer purchasing participation of green power by [year]. *[These remain unresolved by the ES TWG.]*

Implementing Parties: State facilities, electric utilities, renewable energy producers, electricity consumers, and buyers of energy-using appliances and equipment.

Other: None cited.

Implementation Mechanisms

None cited.

Related Policies/Programs in Place

A 2007 survey reports 44% of Arkansas residential consumers would be willing to pay more for electricity produced from renewable resources. While this survey was exclusively from electric cooperative members, the data could reasonably be expected to apply to all Arkansas consumers. Based on the data, a comprehensive marketing and communications strategy was developed, and the Electric Cooperatives of Arkansas (ECA) GreenPower voluntary program was launched in March 2008. Consumers could voluntarily purchase 100 kilowatt-hour (kWh) blocks of electricity at $0.05 per kWh, or $5.00 per block. ECA will escrow 100% of the funds and use the accumulated resources to build, acquire, or otherwise provide energy produced by new renewable resources to supplement the existing hydroelectric generation (average annual hydro production exceeds 500,000 megawatt-hours [MWh]). Alternatively the funds may be used to invest in energy efficiency efforts.

Despite an aggressive marketing campaign (including print, magazine, radio, bill stuffers, internet marketing, direct mail, and special event marketing), response to the program has been less than enthusiastic. However, the program is only 2 months old.

ECA's experience is consistent with that of most electric utilities that have introduced consumer-driven green power programs. One of the more successful U.S. programs, the North Carolina Green Power program, has been marketing renewables for over 2 years and has not passed the 1% participation rate.

Encouraging a higher participation level may be achieved by linking the development of renewable resources with economic development and more effective promotion.

Type(s) of GHG Reductions

Not applicable (quantified by the RCI TWG).

Estimated GHG Reductions and Costs or Cost Savings

Not applicable (quantified by the RCI TWG).

Data Sources: Not applicable.

Quantification Methods: Not applicable.

Key Assumptions: Not applicable.

Key Uncertainties

Not applicable (quantified by the RCI TWG).

Additional Benefits and Costs

Not applicable (quantified by the RCI TWG).

Feasibility Issues

Not applicable (quantified by the RCI TWG).

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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 could be targeted to increase collaboration among existing institutions in the state 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; 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 evaluation study for [specific alternative] energy potential in Arkansas. *[These remain unresolved by the ES TWG.]*
- Complete a least one high-visibility R&D demonstration to showcase alternative energies.

Timing: Establish funding in the [year] legislative session. Study finished in [year]. First request for proposals issued [month, year]. *[These remain unresolved by the ES TWG.]*

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

Other: None cited.

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 ES TWG considers this policy option 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

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

ES-3A. Renewable Portfolio Standard (RPS)

Policy Description

A renewable portfolio standard (RPS) is a requirement that utilities must supply a certain, generally fixed percentage of electricity from an eligible renewable energy source(s). An environmental portfolio standard (EPS) 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. For application in Arkansas, the state's current definition of renewable energy sources should be used in defining eligible sources for an RPS.

Policy Design

Goal: Each investor-owned and public utility should be able to provide 15% of its load using renewable energy resources.

Timing: Beginning in 2015.

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

Other: None cited.

Implementation Mechanisms

The Arkansas Public Service Commission (APSC) will evaluate the potential cost impact on 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 option are summarized in Table ES-3A-1, below. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table ES-3A-1. Estimated GHG reductions and costs of or cost savings from an RPS under Reference Scenarios #1 and #2

Scenario No.	Scenario Description	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Level of Support
		2015	2025	Total 2009–2025			
#1	Build Plum Point in 2010; do not build Hempstead plant	0.3	3.4	20.3	$665	$32.74	Pending
#2	Build Plum Point in 2010; build Hempstead plant in 2012	0.3	3.6	21.9	$718	$32.79	Pending

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $/t$CO_2$e = 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 is based on Arkansas ES TWG input.

Quantification Methods:

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

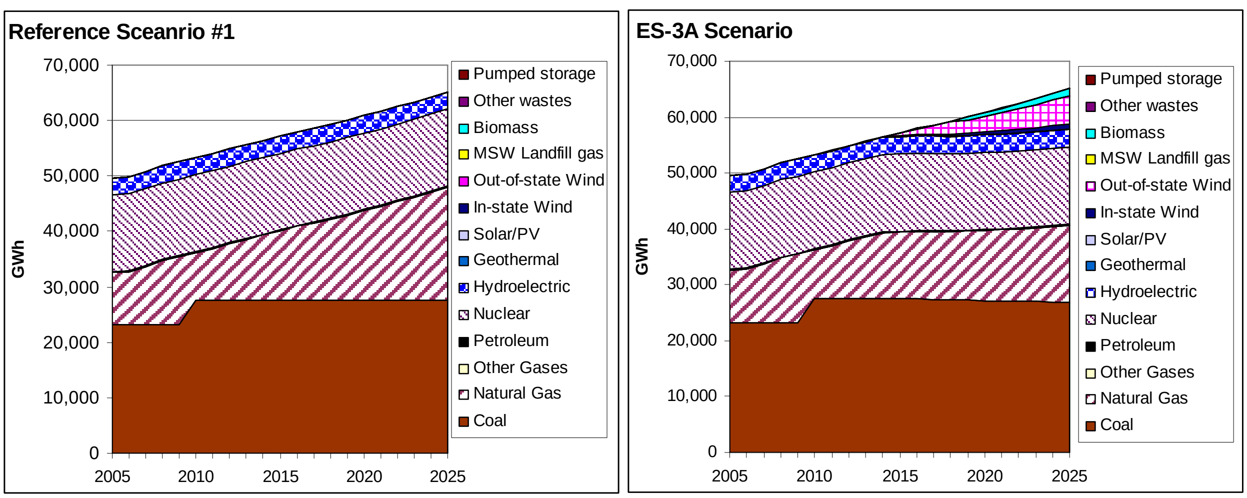
This policy option would require utilities and other load-serving entities to supply a certain, generally fixed, percentage of electricity from eligible (e.g., low-GHG-emitting) renewable energy sources. The TWG has made the following key assumptions for the analysis of this option:

- Two reference scenarios to be modeled, one assuming the Hempstead Plant (i.e., Reference Scenario #1) is built, one without the Hempstead plant (i.e., Reference Scenario #2).
- The start year for the option is 2015.
- Incremental renewable energy generation associated with the implementation of the renewable portfolio standard (RPS) displaces marginal generation comprising 90% natural gas-fired and 10% coal-fired generation in each year new renewable capacity comes online.
- The mix of new renewable resources to come on line would be modeled after the results of AEO2007 for the Southwest Power Pool (SPP region), assumed to be a reasonable proxy for a least-cost renewable energy mix.

- 15% of all new wind capacity would be reserved to be installed in high wind resource areas in Arkansas; the balance would be installed in high wind resource areas in the surrounding region.
- Additional transmission capacity will need to be built to accommodate all new wind energy resources.
- The capacity credit for intermittent renewables (i.e., wind and solar photovoltaics [PV]) was assumed to be 15%. For these intermittent resources, spinning reserve will be 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 Arkansas Residential, Commercial, and Industrial (RCI) sectors TWG (i.e., $58.3/megawatt-hour [MWh]). This value was assumed to be applicable for both reference scenarios.

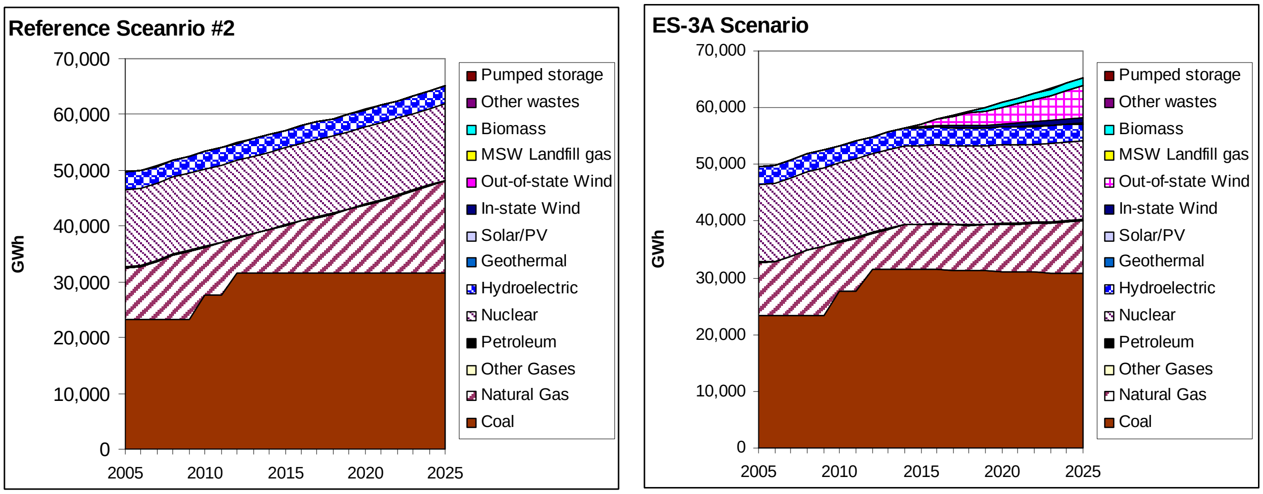
Regarding in-state gross generation, the impact of ES-3A is summarized in Figures ES-3A-1 and ES-3A-2 below for the reference scenarios. The incremental effect of the RPS by 2025 is about 7,984 gigawatt-hous (GWh), with 69% of this amount coming from out-of-state wind, 12% from in-state wind, 17% from biomass, and 2% from solar PV. Displaced coal-fired generation in 2025 is 739 GWh and 798 GWh in Reference Scenarios #1 and #2, respectively (6,653 GWh and 7,185 GWh for natural gas-fired generation, respectively in 2025).

Figure ES-3A-1. Effect of RPS on Reference Scenario #1 (with Hempstead plant built)



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

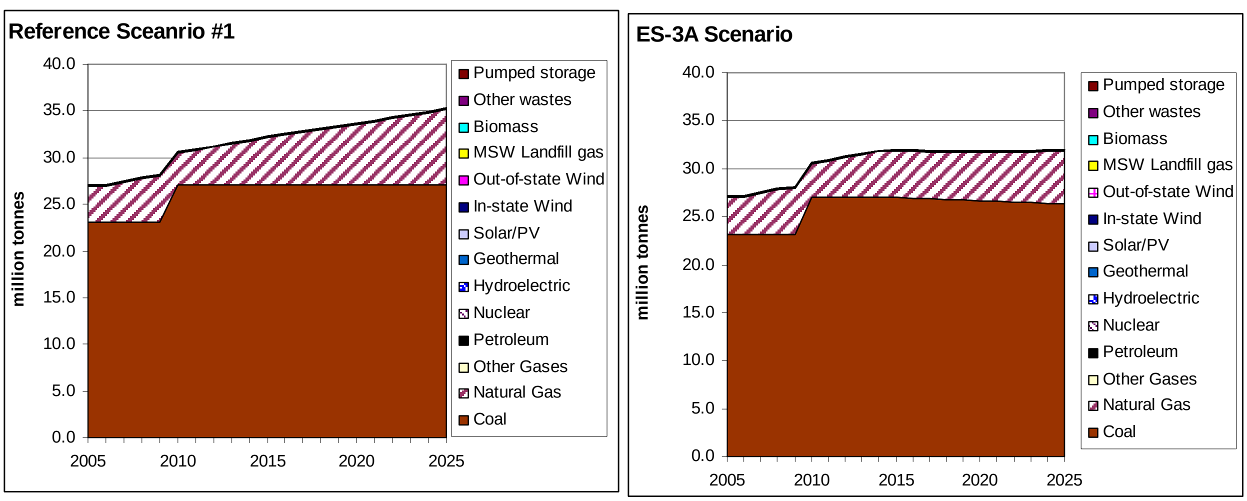
Figure ES-3A-2. Effect of RPS on Reference Scenario #2 (without Hempstead plant built)



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

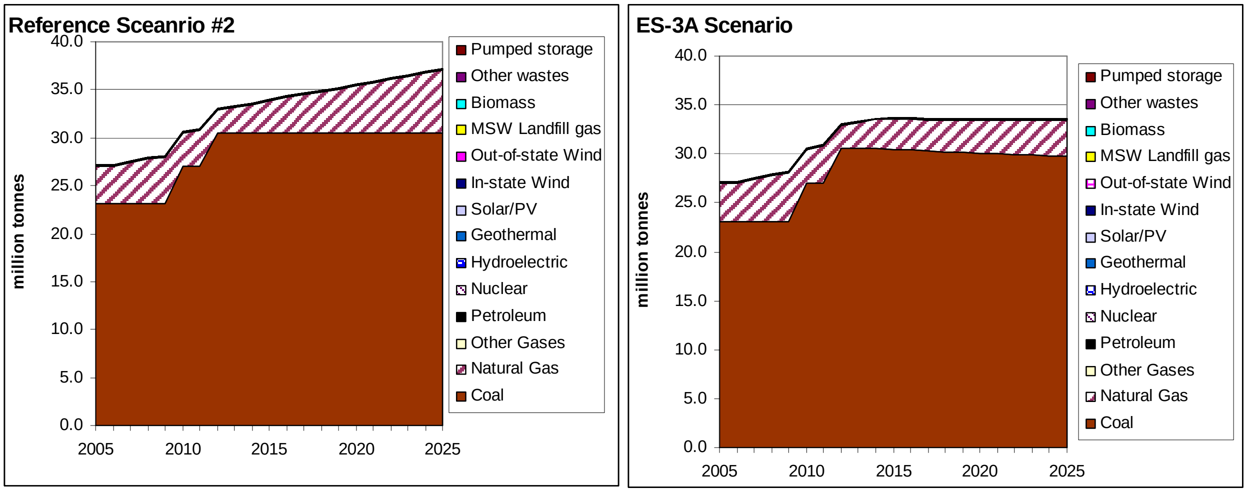
Figures ES-3A-3 and ES-3A-4 summarize the impacts of the RPS on carbon dioxide-equivalent (CO_2e) emission reductions. The annual reductions due to the RPS by 2025 reach about 3.4 million metric tons (MMt) of CO_2e for Reference Scenario #1 and about 3.6 $MMtCO_2e$ for Reference Scenario #2. Cumulatively over the period 2015–2025, the RPS leads to a total of 20.3 $MMtCO_2e$ avoided for Reference Scenario #1 and 21.9 $MMtCO_2e$ avoided for Reference Scenario #2.

Figure ES-3A-3. Annual GHG reductions from the RPS for Reference Scenario #1



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

Figure ES-3A-4. Annual GHG reductions from the RPS for Reference Scenario #2



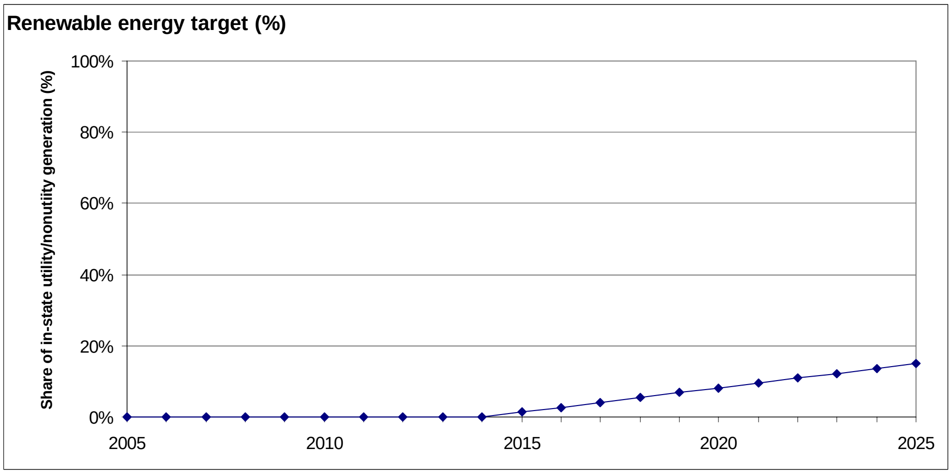
GHG = greenhouse gas; RPS = renewable portfolio standard; MSW = municipal solid waste; PV = photovoltaic.

Cost savings are associated with avoided capital, fuel, and operation and maintenance (O&M), and incremental costs are associated with capital costs, transmission costs, variable and fixed O&M costs, 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 RPS. For Reference Scenario #1, the net present value of the costs are $0.66 billion over the 2015–2025 period (2005$). For Reference Scenario #2, the net present value (NPV) of the costs is $0.72 billion over the same period (2005$). Regarding the cost-effectiveness of the option, it is calculated as the quotient of the NPV and cumulative GHG emission reductions. For Reference Scenario #1, it is \$32.7/tCO_2e (2005$) (i.e., $0.66 billion divided by 20.3 MMt and multiplied by a conversion factor of 1,000); for Reference Scenario #2, it is \$32.7/tCO_2e.

Key Assumptions:

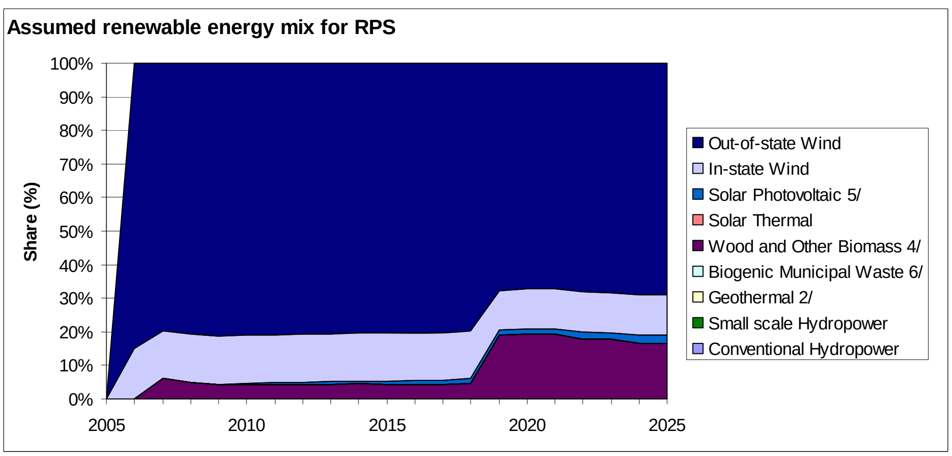
Renewable Energy Target—Defined as the percentage of in-state electricity production, the renewable energy target is summarized in Figure ES-3A-5.

Figure ES-3A-5. 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 ES-3A-6.

Figure ES-3A-6. 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 ES-3A-2.

Table ES-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 ES-3A-3 in units of 2005$/MWh.

Table ES-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	160.5
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 ES-3A-4 in units of 2005$/MWh. Note that a 50% capacity factor is assumed in the calculation.

Table ES-3A-4. Assumed levelized costs for NGCT used for reliability purposes

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

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

Transmission capacity will need to be available for the renewable sources.

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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

Policy Description

Renewable Energy Feed-In Tariff (REFIT) is a policy option 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 rate-payer 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 photovoltaics 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-kWh payments to larger facilities (facilities having a larger maximum power output).

Some observers argue that Arkansas has significant amounts of such electricity-producing new renewable energy resources, while others argue 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 photovoltaics (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 200 megawatts (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.

Other: None cited.

Implementation Mechanisms

None cited.

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 option 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 exists 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.

In addition to the two reference scenarios (i.e., with and without the Hempstead plant), there were three major assumptions regarding the transferability of the German and Japanese experiences with the use of feed-in tariffs, as follows:

- Half (50%) the efficacy of the German experience;
- Three-fourths (75%) of the efficacy of the German experience; and
- One-to-one (100%) transferability of the German experience.

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 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; and

- 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 option. Table ES-3B-1 summarizes the results for this option. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table ES-3B-1. Summarized results of policy option ES-3B

			GHG Reductions (MMtCO2e)			Net Present Value	Effectiveness	
Run	Analysis Scenario	Description	2015	2025	Total 2009-2025	(Million $)	($/tCO$_2$e)	Level of Support
	Scenario #1	Build Plum Point only; half the efficacy of the German experience						
1		*Sensitivity #1: Feed-in tariff level set at a level to achieve same renewable energy generation as RPS*	0.3	3.4	20.3	$405	$20.0	Pending
2		*Sensitivity #2: Feed-in tariff level set at a level less than or equal to a 5% rate impact*	0.3	3.2	19.3	$385	$20.0	Pending
3		*Sensitivity #3: Feed-in tariff level set at a level to achieve 25% renewable generation by 2025*	0.5	5.6	33.8	$675	$20.0	Pending
	Scenario #2	Build Plum Point only; three fourths of the efficacy of the German experience						
4		*Sensitivity #1: Feed-in tariff level set at a level to achieve same renewabele energy generation as RPS*	0.3	3.4	20.3	$405	$20.0	Pending
5		*Sensitivity #2: Feed-in tariff level set at a level less than or equal to a 5% rate impact*	0.5	5.6	33.4	$667	$20.0	Pending
6		*Sensitivity #3: Feed-in tariff level set at a level to achieve 25% renewable generation by 2025*	0.5	5.6	33.8	$675	$20.0	Pending
	Scenario #3	Build Plum Point only; One-to-one with the German experience						
7		*Sensitivity #1: Feed-in tariff level set at a level to achieve same renewabele energy generation as RPS*	0.3	3.4	20.3	$405	$20.0	Pending
8		*Sensitivity #2: Feed-in tariff level set at a level less than or equal to a 5% rate impact*	0.8	8.8	52.6	$1,051	$20.0	Pending
9		*Sensitivity #3: Feed-in tariff level set at a level to achieve 25% renewable generation by 2025*	0.5	5.6	33.8	$675	$20.0	Pending
	Scenario #4	Build Plum Point & Hempstead; half the efficacy of the German experience						
10		*Sensitivity #1: Feed-in tariff level set at a level to achieve same renewabele energy generation as RPS*	0.3	3.6	21.9	$438	$20.0	Pending
11		*Sensitivity #2: Feed-in tariff level set at a level less than or equal to a 5% rate impact*	0.3	3.2	19.1	$381	$20.0	Pending
12		*Sensitivity #3: Feed-in tariff level set at a level to achieve 25% renewable generation by 2025*	0.5	6.1	36.5	$729	$20.0	Pending
	Scenario #5	Build Plum Point & Hempstead; three fourths of the efficacy of the German experience						
13		*Sensitivity #1: Feed-in tariff level set at a level to achieve same renewabele energy generation as RPS*	0.3	3.6	21.9	$438	$20.0	Pending
14		*Sensitivity #2: Feed-in tariff level set at a level less than or equal to a 5% rate impact*	0.5	5.5	33.1	$661	$20.0	Pending
15		*Sensitivity #3: Feed-in tariff level set at a level to achieve 25% renewable generation by 2025*	0.5	6.1	36.5	$729	$20.0	Pending
	Scenario #6	Build Plum Point & Hempstead; One-to-one with the German experience						
16		*Sensitivity #1: Feed-in tariff level set at a level to achieve same renewabele energy generation as RPS*	0.3	3.6	21.9	$438	$20.0	Pending
17		*Sensitivity #2: Feed-in tariff level set at a level less than or equal to a 5% rate impact*	0.8	8.6	52.0	$1,040	$20.0	Pending
18		*Sensitivity #3: Feed-in tariff level set at a level to achieve 25% renewable generation by 2025*	0.5	6.1	36.5	$729	$20.0	Pending

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; \$/tCO$_2$e = 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 1 for the overall approach to the quantification of this and all other energy supply options.

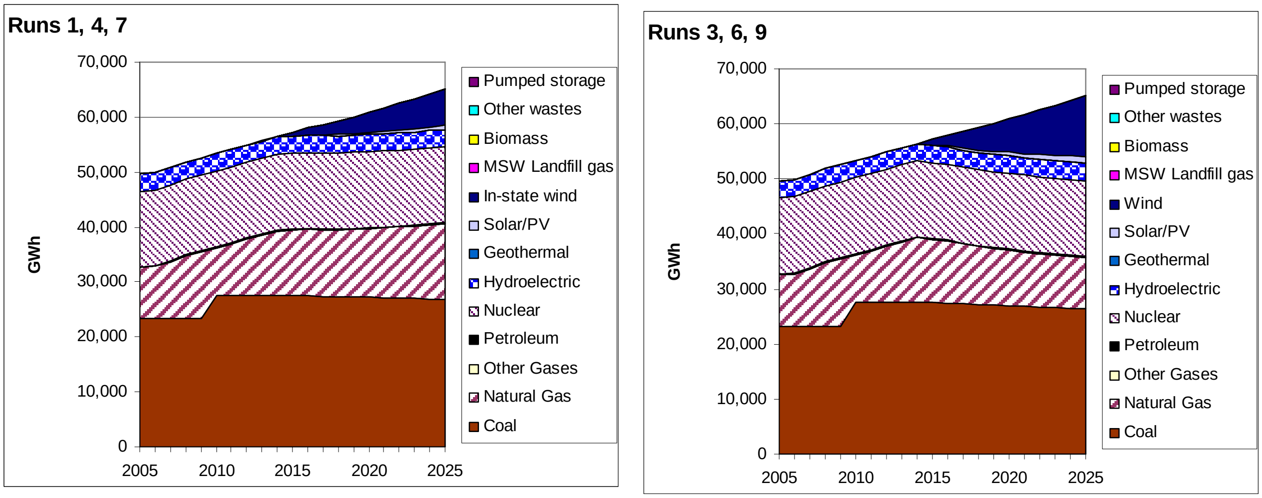
This option is a policy to implement incentives available to residential, commercial, and industrial electricity customers to install renewable energy technologies. The TWG has made the following key assumptions for the analysis of this option:

- Two reference scenarios to be modeled, one assuming the Hempstead plant (i.e., Reference Scenario #1) is built, one without the Hempstead plant (i.e., Reference Scenario #2).
- The start year for the option is 2015.
- The incremental renewable energy generation associated with the implementation of the REFIT displaces marginal generation comprising 90% natural gas-fired and 10% coal-fired generation in each year new renewable capacity comes online.
- 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 policy option focuses on demand-side installation outside utility planning protocols.
- 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). This value was assumed to be applicable for all scenarios and sensitivities.

Reference Scenario #1 (Without the Hempstead Plant)

Regarding in-state gross generation for Reference Scenario #1, the impact of the policy option on gross generation is the same for all sensitivities associated with the 15% and 25% renewable penetration targets, as summarized in Figure ES-3B-1.

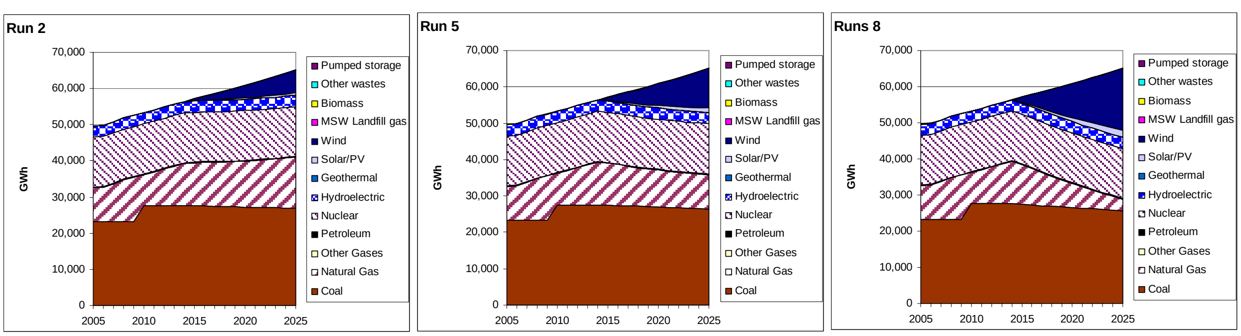
Figure ES-3B-1. In-state gross generation—runs 1, 4, 7 (15% penetration) and runs 3, 6, 9 (25% penetration)



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

Regarding in-state gross generation for Reference Scenario #1, the impact of the option on gross generation varies considerably for sensitivities associated with keeping renewable energy penetration in 2025 consistent with a rate impact of less than 5% of the projected retail electricity rate. Figure ES-3B-2 shows that, depending on the assumption regarding the transferability of the German experience (i.e., 50%, 75%, or 100% efficacy), penetration of wind and solar generation resulting in less than a 5% rate impact ranges from 11% to 29% of total in-state electricity generation.

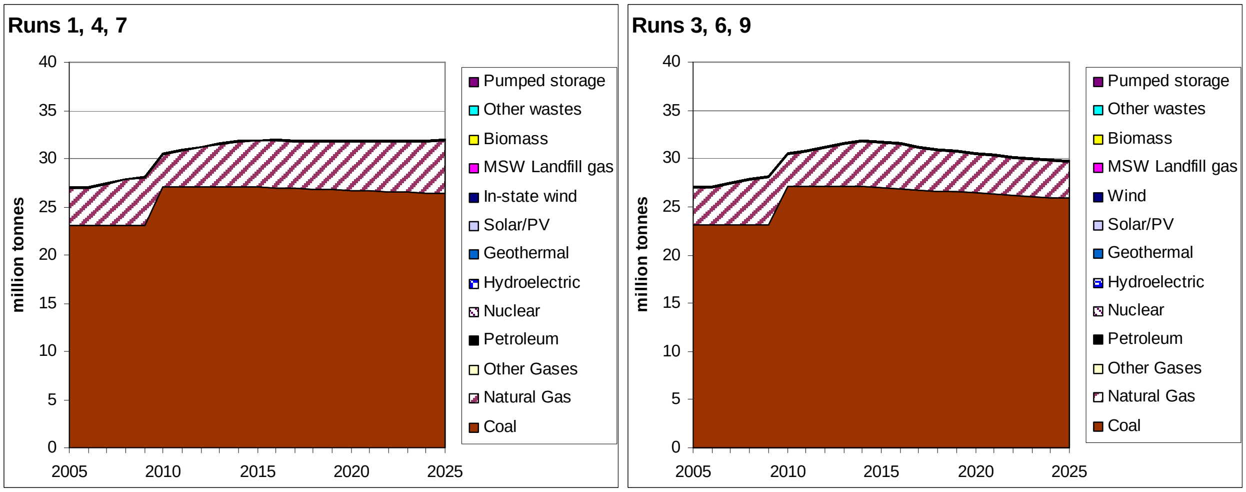
Figure ES-3B-2. In-state gross generation—runs 2 (50% efficacy), 5 (75% efficacy), and 8 (100% efficacy)



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

Regarding CO_2e emissions for Reference Scenario #1, the impact of the option on emission levels is the same for all sensitivities associated with the 15% and 25% renewable penetration targets, as summarized in Figure ES-3B-3. The annual reductions due to the REFIT set to achieve the same penetration levels as the RPS by 2025 reach about 3.4 MMtCO_2e for Runs 1, 4, and 7 and about 5.6 MMtCO_2e for Runs 3, 6, and 9. Cumulatively over the period 2015–2025, the REFIT leads to a total of 20.3 MMtCO_2e avoided for Runs 1, 4, and 7 and 33.8 MMtCO_2e avoided for Runs 3, 6, and 9.

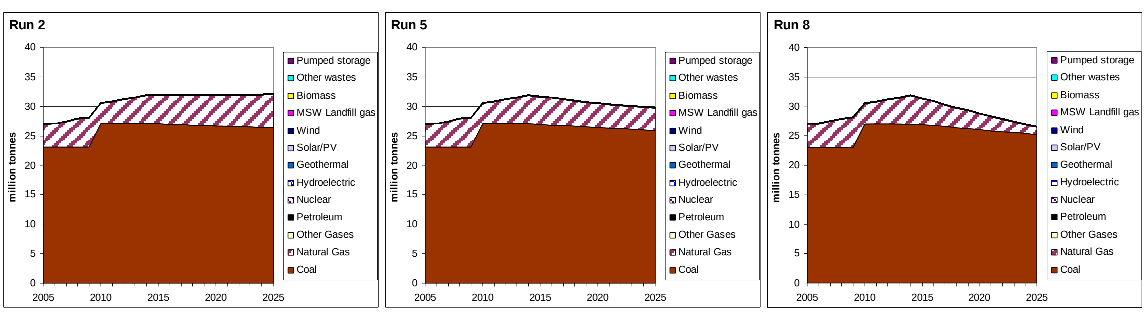
Figure ES-3B-3. CO_2e emissions—runs 1, 4, 7 (15% penetration) and runs 3, 6, 9 (25% penetration)



MSW = municipal solid waste; PV = photovoltaic.

Regarding CO_2e emissions for Reference Scenario #1, the impact of the option on emissions varies considerably for sensitivities associated with keeping renewable energy penetration in 2025 consistent with a rate impact of less than 5% of the projected retail electricity rate. Figure ES-3B-4 shows that, depending on the assumption regarding the transferability of the German experience, CO_2e emissions range from 10% to 25% below Reference Scenario #1 emissions. On a cumulative basis, CO_2e emission reductions amount to 19.3, 33.4, and 52.6 $MMtCO_2$e by 2025 for Runs 2, 5, and 8, respectively.

Figure ES-3B-4. CO_2e emissions—runs 2 (50% efficacy), 5 (75% efficacy), and 8 (100% efficacy)



MSW = municipal solid waste; PV = photovoltaic.

Cost savings are associated with avoided capital, fuels, and O&M, and incremental costs are associated with capital costs, transmission costs, variable and fixed O&M costs, and fuel costs associated with the REFIT. 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. For Reference Scenario #1, the NPVs of the costs are:

- $0.41 billion over the 2015–2025 period (2005$) for Runs 1, 4, and 7;

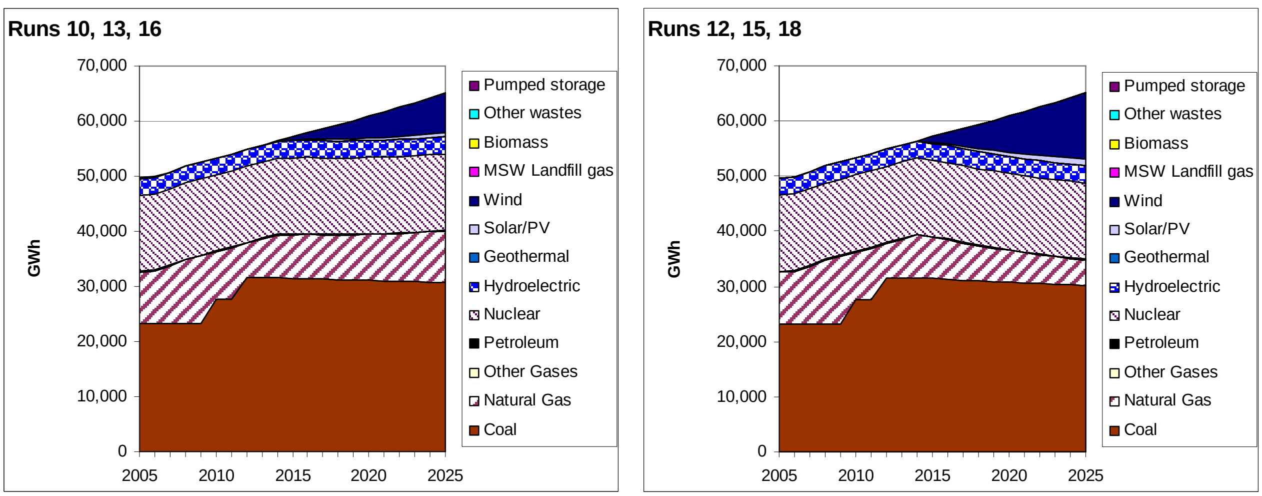
- $0.68 billion over the 2015–2025 period (2005$) for Runs 3, 6, and 9;
- $0.38 billion over the 2015–2025 period (2005$) for Run 2;
- $0.67 billion over the 2015–2025 period (2005$) for Run 5; and
- $1.1 billion over the 2015–2025 period (2005$) for Run 8.

The cost-effectiveness of the various runs is calculated as the quotient of the NPV and cumulative GHG emission reductions. The results are the same for each option, as would be expected, and equal to $20.0/MWh (2005$).

Reference Scenario #2 (With the Hempstead Plant)

Regarding in-state gross generation for Reference Scenario #2, the impact of the option on gross generation is the same for all sensitivities associated with the 15% and 25% renewable penetration targets, as summarized in Figure ES-3B-5.

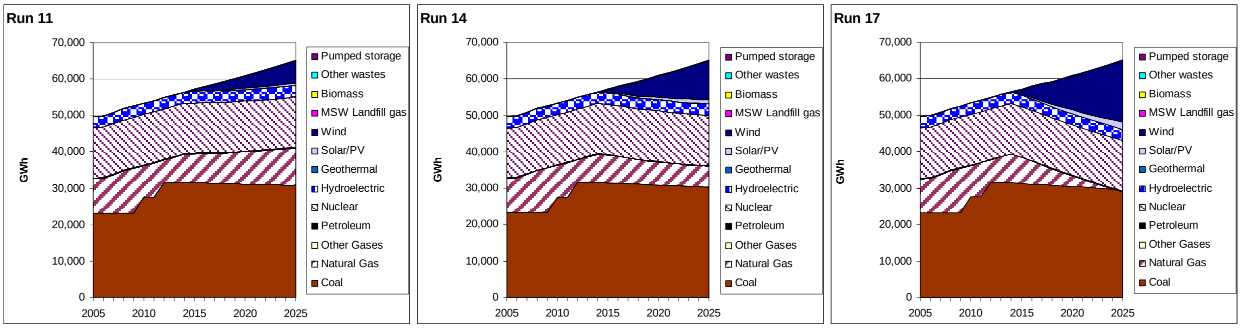
Figure ES-3B-5. In-state gross generation—runs 10, 13, 16 (15% penetration) and runs 12, 15, 18 (25% penetration)



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

Regarding in-state gross generation for Reference Scenario #2, the impact of the option on gross generation varies considerably for sensitivities associated with keeping renewable energy penetration in 2025 consistent with a rate impact of less than 5% of the projected retail electricity rate. Figure ES-3B-6 shows that, depending on the assumption regarding the transferability of the German experience, penetration of wind and solar generation resulting in less than a 5% rate impact ranges from 11% to 29% of total in-state electricity generation.

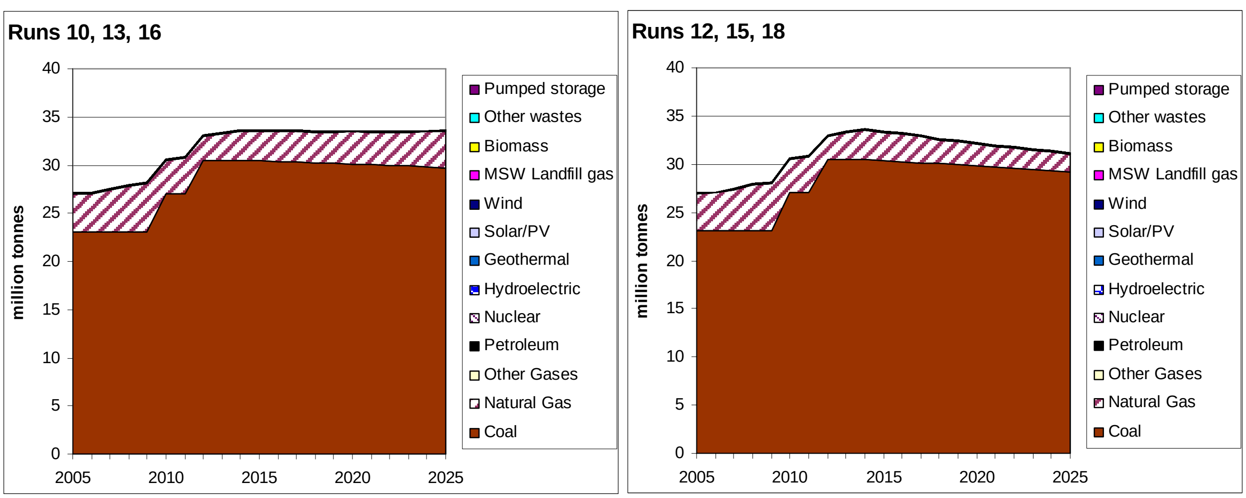
Figure ES-3B-6. In-state gross generation—runs 11 (50% efficacy), 14 (75% efficacy), and 17 (100% efficacy)



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

Regarding CO_2e emissions for Reference Scenario #2, the impact of the option on emission levels is the same for all sensitivities associated with the 15% and 25% renewable penetration targets, as summarized in Figure ES-3B-7. The annual reductions due to the REFIT set to achieve the same penetration levels as the RPS by 2025 reach about 3.6 $MMtCO_2e$ for Runs 1, 4, and 7 and about 6.1 $MMtCO_2e$ for Runs 3, 6, and 9. Cumulatively over the period 2015–2025, the REFIT leads to a total of 21.9 $MMtCO_2e$ avoided for Runs 1, 4, and 7 and 36.5 $MMtCO_2e$ avoided for Runs 3, 6, and 9.

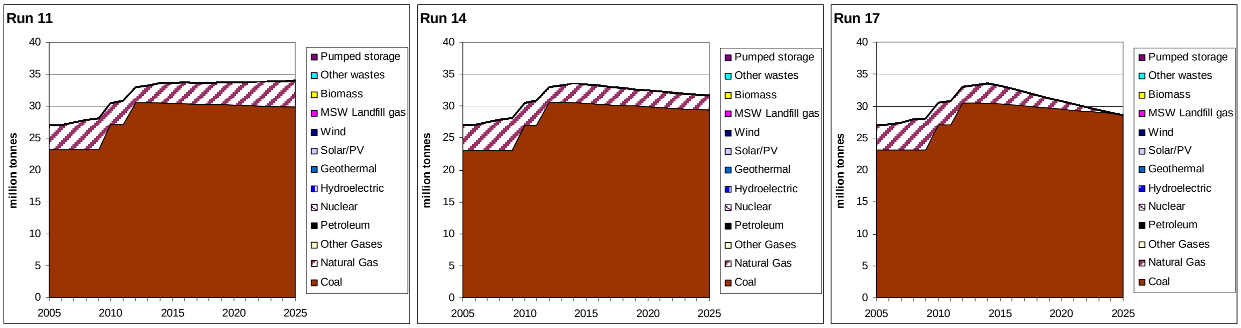
Figure ES-3B-7. CO_2e emissions—runs 10, 13, 16 (15% penetration) and runs 12, 15, 18 (25% penetration)



MSW = municipal solid waste; PV = photovoltaic.

Regarding CO_2e emissions for Reference Scenario #2, the impact of the policy option on emissions varies considerably for sensitivities associated with keeping renewable energy penetration in 2025 consistent with a rate impact of less than 5% of the projected retail electricity rate. Figure ES-3B-8 shows that, depending on the assumption regarding the transferability of the German experience, CO_2e emissions range from 10% to 25% below Reference Scenario #2 emissions. On a cumulative basis, CO_2e emission reductions amount to 19.3, 33.4, and 52.6 $MMtCO_2e$ by 2025 for Runs 11, 14, and 17, respectively.

Figure ES-3B-8. CO_2e emissions—runs 11 (50% efficacy), 14 (75% efficacy), and 17 (100% efficacy)



MSW = municipal solid waste; PV = photovoltaic.

Cost savings are associated with avoided capital, fuel, and O&M costs, and incremental costs are associated with capital costs, transmission costs, variable and fixed O&M costs, and fuel costs associated with the REFIT. 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. For Reference Scenario #2, the NPVs of the costs are:

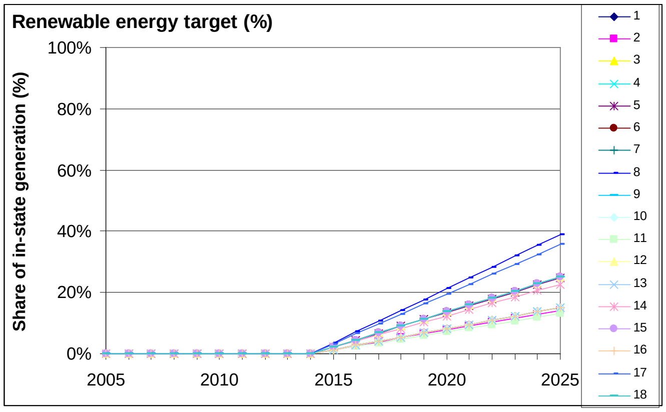
- $0.44 billion over the 2015–2025 period (2005$) for Runs 10, 13, and 16;
- $0.73 billion over the 2015–2025 period (2005$) for Runs 12, 15, and 18;
- $0.38 billion over the 2015–2025 period (2005$) for Run 11;
- $0.66 billion over the 2015–2025 period (2005$) for Run 14; and
- $1.0 billion over the 2015–2025 period (2005$) for Run 17.

The cost-effectiveness of the various runs is calculated as the quotient of the NPV and cumulative GHG emission reductions. The results are the same for each option, as would be expected, and equal to $20.0/MWh (2005$).

Key Assumptions:

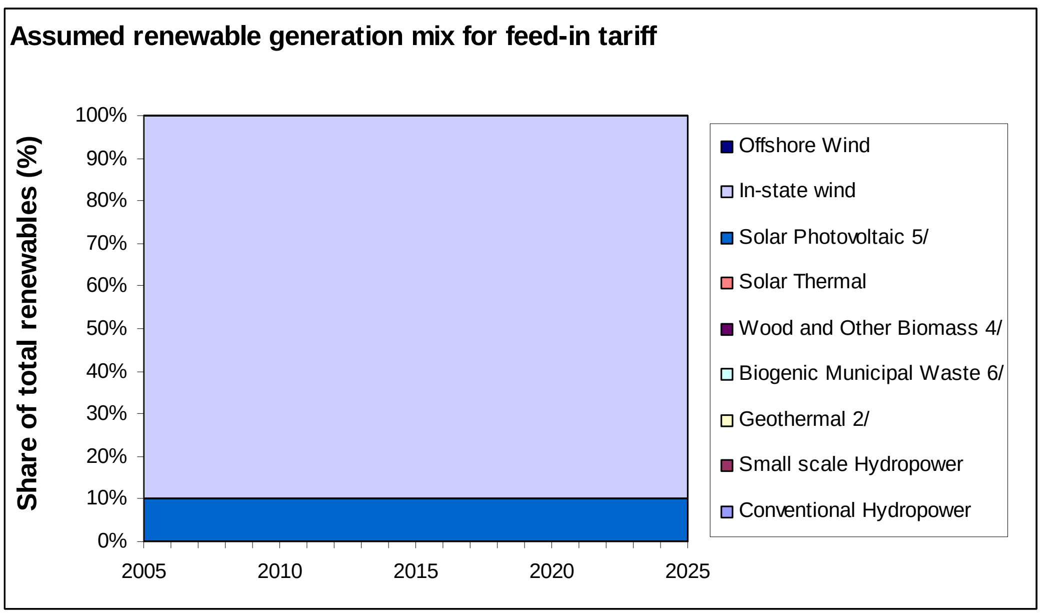
Renewable Energy Target—This is defined as the percentage of in-state electricity production, and is summarized in Figure ES-3B-9.

Figure ES-3B-9. 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 ES-3B-10.

Figure ES-3B-10. 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 ES-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 ES-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

None cited.

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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. 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 Governor's Commission on Global Warming (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 option 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 option 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.

Other: None cited.

Implementation Mechanisms

TBD – [as approved by the TWG]

Related Policies/Programs in Place

TBD – [as needed and approved by the TWG]

Type(s) of GHG Reductions

TBD – [as approved by the TWG]

Estimated GHG Reductions and Costs or Cost Savings

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

Policy No.	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/tCO_2e$)	Level of Support
		2015	2025	Total 2009–2025			
ES-4	Grid-Based Renewable Energy Incentives and/or Barrier Removal	*Not Yet Quantified*					Pending

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: [TBD, as approved by the TWG]

Key Uncertainties

TBD – [as needed and approved by the TWG]

Additional Benefits and Costs

TBD – [as needed and approved by the TWG]

Feasibility Issues

TBD – [as needed and approved by the TWG]

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

ES-5. Approaches Benefiting From Regional Application

Policy Description

The primary goal of this policy option is to establish a program that will allow Arkansas to adapt to and be prepared for a federally implemented cap-and-trade system. 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 in [year] *[This remains unresolved by the ES TWG.]*

Parties Involved: Target entities.

Other: None cited.

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 ES TWG considers this option 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

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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 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 option 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.

Other: None cited.

Implementation Mechanisms

None cited.

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 ES-6-1. Estimated GHG reductions from and costs of or cost savings from CHP under Reference Scenarios #1 and #2

Scenario No.	Scenario Description	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effectiveness ($/tCO_2e$)	Level of Support
		2015	2025	Total 2009–2025			
#1	Build Plum Point in 2010; do not build Hempstead plant	0.6	2.9	20.0	$886	$44.30	Pending
#2	Build Plum Point in 2010; build Hempstead plant in 2012	0.6	2.9	20.0	$886	$44.30	Pending

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:

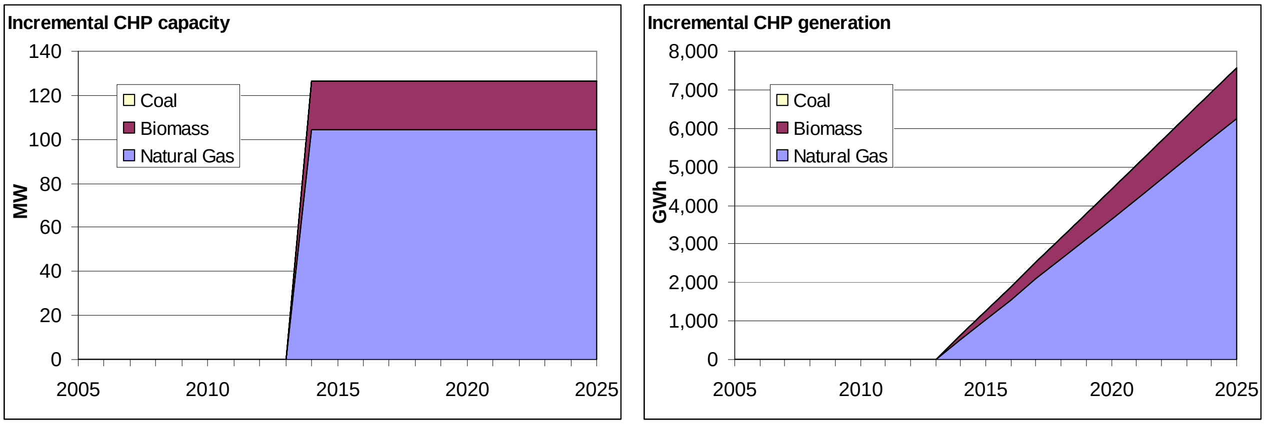
See Annex 1 for the overall approach to the quantification of this and all other energy supply options.

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

- Two reference scenarios to be modeled, one assuming the Hempstead plant is not built (i.e., Reference Scenario #1), and one assuming the plant is built (i.e., Reference Scenario #2).
- The start year for the option 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 online.

Regarding incremental CHP capacity and corresponding electricity generation, the capacity trajectory in Figure ES-6-1 was assumed based on a recent EPA study regarding the maximum achievable potential of CHP systems in Arkansas.

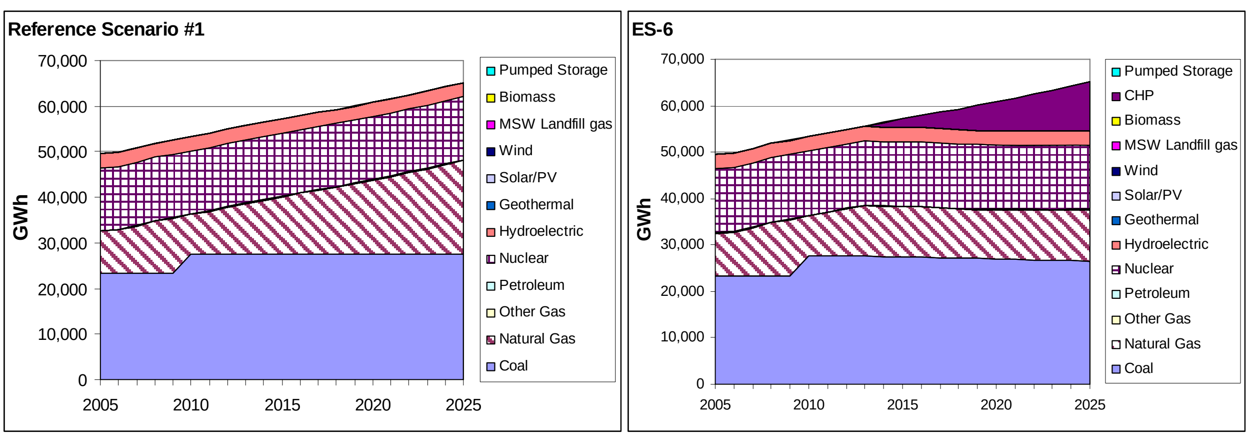
Figure ES-6-1. Assumed CHP capacity trajectory in Arkansas



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

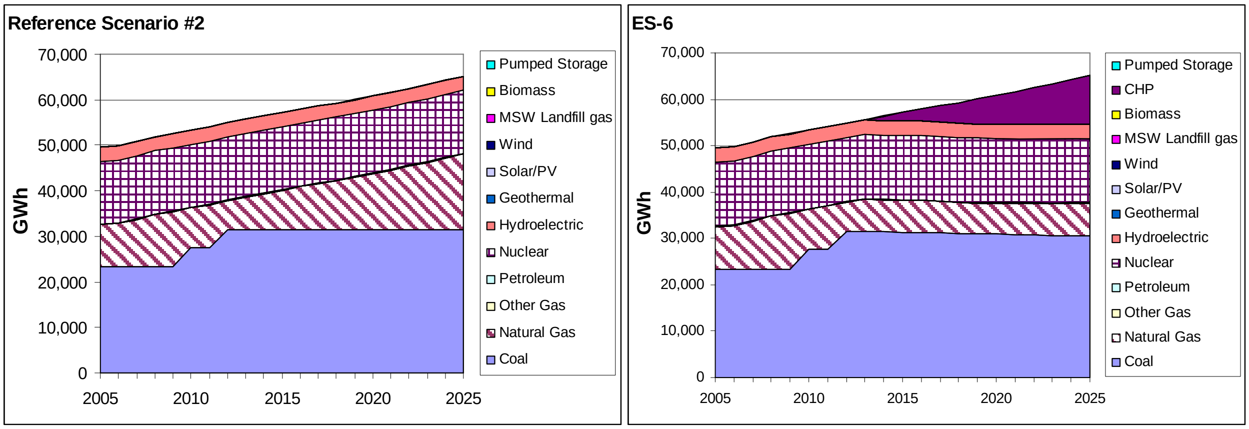
Regarding the contribution of incremental CHP to the overall electric mix of resources, the impact of the option is summarized in the Figures ES-6-2 and ES-6-3 for the two reference scenarios. The incremental effect of CHP by 2025 is about 7,574 GWh, with 83% of this amount coming from natural gas and 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. These levels are the same, regardless of the reference scenario.

Figure ES-6-2. Impact of CHP under Reference Scenario #1 (without Hempstead plant)



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

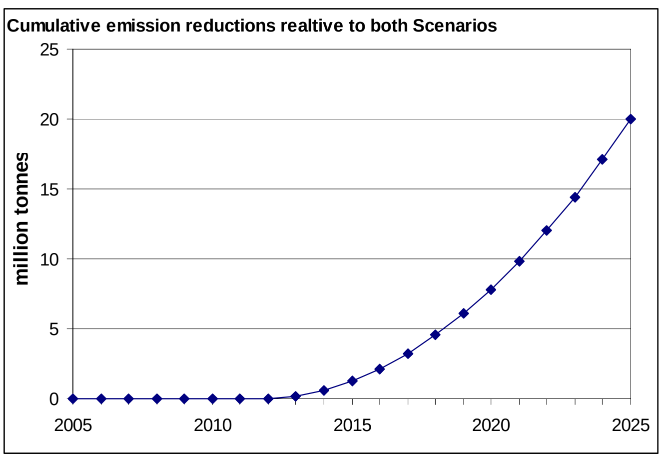
Figure ES-6-3. Impact of CHP under Reference Scenario #2 (with Hempstead plant)



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

Figure ES-6-6 summarizes the impact of this policy option on CO_2e emission reductions. The cumulative reductions due to new CHP facilities by 2025 reach about 20.0 $MMtCO_2e$ avoided relative to each reference scenario.

Figure ES-6-4. Cumulative emission reductions with CHP under both reference scenarios



Cost savings are associated with avoided capital, fuel, and O&M costs, and incremental costs are associated with capital costs, transmission costs, variable and fixed O&M costs, 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 this policy option. The NPV of the costs is $0.89 billion over the 2015–2025 period (2005$) relative to each reference scenario. The cost-effectiveness of the option is calculated as the quotient of the NPV and cumulative GHG emission reductions. For both reference scenarios, the cost-effectiveness is $44.3/$tCO_2e$ (2005$) (i.e., $0.89 billion divided by 20 MMt and multiplied by a conversion factor of 1,000).

Key Assumptions:

Table ES-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 ES-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 ES-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; O&M = operation and maintenance.

Table ES-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

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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, unminable coal seams, 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 done by pipeline.

This policy affects all new coal-fired power plants, both those that are currently under construction and those that have not yet received complete approval for construction in Arkansas. Plants currently under construction 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 complete approval for construction 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.

Policy Design

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

Timing: Reductions achieved beginning in 2018.

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

Other: None cited.

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 option was analyzed relative to a total of eight plausible alternative scenarios regarding the geological underground sequestration of CO_2 for new plants when applied to the Arkansas context. For the purpose of the analysis of this option, Reference Scenario #1 was considered the business-as-usual (BAU) case, and Reference Scenario #2 was treated as a plausible alternative scenario. In addition, sensitivity analysis was explored for two of the scenarios.

Table ES-7-1 summarizes the description of the scenarios and sensitivities undertaken thus far in the analysis.

Table ES-7-1. Scenarios and sensitivities undertaken in the analysis

Scenario #1	no build of new Hempstead plant BAU **(THIS IS THE BAU)**
Scenario #2	build Hempstead in 2012 with no mitigation or technology upgrade
Scenario #3	build Hempstead in 2012 with transition to CCS with CO2 piped to MS for enhanced oil recovery
Scenario #4	build Hempstead in 2012 with transition to CCS with CO2 stored in AR
Scenario #5	build Hempstead in 2012 as IGCC
Scenario #6	build Hempstead in 2012, but with mitigation
	Sensitivity 6(a) - NGCC-repowering
	Sensitivity 6(b) - Offsets
Scenario #7	no build of Hempstead, replaced with expanded energy efficiency, renewable energy, and natural gas
	Sensitivity 7(a) - displacement by energy efficiency and wind
	Sensitivity 7(b) - displacement by energy efficiency, wind, and NGCC
Scenario #8	build Hempstead in 2020 with transition to CCS with CO2 stored in AR

AR = Arkansas; BAU = business as usual; CCS = carbon capture and storage; CO_2 = carbon dioxide; IGCC = integrated gasification combined cycle; MS = Mississippi; NGCC = natural gas combined cycle.

The above combination of scenarios and sensitivities results in a total of nine sets of results for this option. Table ES-7-2 summarizes the results for this policy option. The sections that follow describe the data sources, quantification approach, and key assumptions used in the development of these results.

Table ES-7-2. Summarized results of ES-7

		GHG Reductions (MMtCO2e)			Net Present Value		
Scenario	Description	2015	2025	Total 2009-2025	2009–2025 (Million $)	Cost- Effectiveness ($/tCO$_2$e)	Level of Support
Scenario #1	no build of new Hempstead plant						
Scenario #2	build Hempstead in 2012 with no mitigation or technology upgrade	-1.7	-1.9	-25.6	-$739	$28.9	Pending
Scenario #3	build Hempstead in 2012 with transition to CCS with CO2 piped to MS for enhanced oil recovery	0.0	2.8	17.1	$582	$34.1	Pending
Scenario #4	build Hempstead in 2012 with transition to CCS with CO2 stored in AR	0.0	2.8	17.1	$501	$29.3	Pending
Scenario #5	build Hempstead in 2012 as IGCC	0.1	0.1	1.5	$334	$224.4	Pending
Scenario #6	build Hempstead in 2012, but with mitigation						
Scenario #6a	*build Hempstead in 2012, but with mitigation (NGCC-repowering)*	2.3	2.3	31.8	$739	$23.2	Pending
Scenario #6b	*build Hempstead in 2012, but with mitigation(Offsets)*	3.4	3.4	47.8	$395	$8.3	Pending
Scenario #7	no build of Hempstead, replaced with expanded energy efficiency, renewable energy, and natural gas						
Scenario #7a	*no build of Hempstead, replaced with expanded energy efficiency, renewable energy, and natural gas (energy efficiency & wind)*	3.4	3.4	48.0	$1,441	$30.0	Pending
Scenario #7b	*no build of Hempstead, replaced with expanded energy efficiency, renewable energy, and natural gas (energy efficiency, wind, & NGCC)*	2.9	2.9	40.4	$805	$19.9	Pending
Scenario #8	build Hempstead in 2020 with transition to CCS with CO2 stored in AR	0.0	2.8	17.1	$1,021	$59.8	Pending

$/$CO_2$e = dollars per metric ton of carbon dioxide equivalent; AR = Arkansas; CCS = carbon capture and storage; CO_2 = carbon dioxide; GHG = greenhouse gas; IGCC = integrated gasification combined cycle; MMtCO_2e = million metric tons of carbon dioxide equivalent; MS = Mississippi; NGCC = natural gas combined cycle.

Data Sources:

- Petroleum data are from APSC.
- 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:

- This option explores alternatives to the construction of the Hempstead plant, including CCS, renewables, and other mitigation options.
- The start year for the alternatives varies, depending on the scenario analyzed. Table ES-7-3 summarizes the years the come are on line.
- Except for Scenario #2, all scenarios were compared to the Hempstead case.

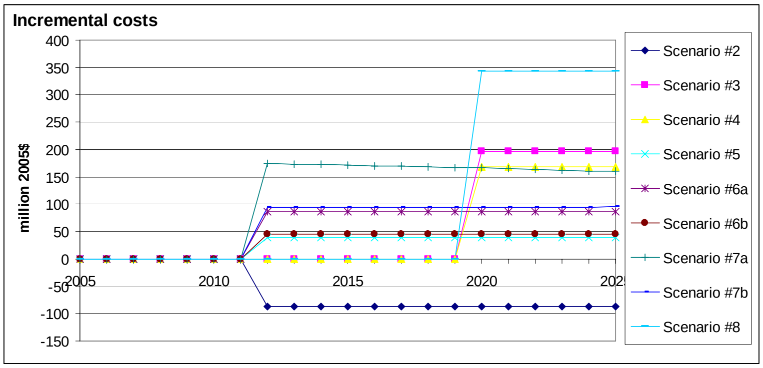
Table ES-7-3. Key assumptions for the scenarios under ES-7

Key Assumptions		Capacity (MW)	Type	Capacity factor (%)	Heat rate (btu/kWh) No CCS	Heat rate (btu/kWh) With CCS	Online year	Carbon capture (%)	Carbon capture online year
Scenario #1	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead	NA	NA	NA	NA	NA	2026	NA	NA
Scenario #2	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead	600	Pulv coal	75%	9,000	NA	2012	0%	NA
Scenario #3	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead	600	Pulv coal	75%	9,000	15,366	2012	83%	2020
Scenario #4	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead	600	Pulv coal	75%	9,000	15,366	2012	83%	2020
Scenario #5	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead replacement	600	IGCC	75%	8,922	NA	2012	0%	NA
Scenario #6a	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead replacement	600	NGCC	75%	7,200	NA	2012	0%	NA
Scenario #6b	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead replacement	600	CO2 offsets	75%	NA	NA	2012	0%	NA
Scenario #7a	Plum point	665	Pulv coal	75%	9,425	NA	2010	NA	1
	Hempstead replacement	600	EE & wind	NA	NA	NA	2012	NA	1
Scenario #7b	Plum point	665	Pulv coal	75%	9,425	NA	2010	NA	1
	Hempstead replacement	600	EE, wind, NG	75%	NA	NA	2012	NA	1
Scenario #8	Plum point	665	Pulv coal	75%	9,425	NA	2010	0%	NA
	Hempstead	600	Pulv coal	75%	9,000	15,366	2020	83%	2020

$/$CO_2e$ = dollars per metric ton of carbon dioxide equivalent; AR = Arkansas; CCS = carbon capture and storage; CO_2 = carbon dioxide; EE = energy efficiency; GHG = greenhouse gas; IGCC = integrated gasification combined cycle; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; MS = Mississippi; N/A = not applicable; NGCC = natural gas combined cycle; pulv = pulverized.

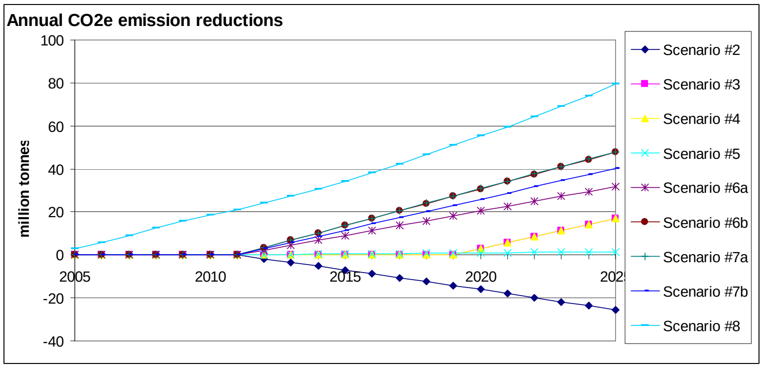
Regarding costs, each scenario displays sharply differing annual incremental costs due to the fact that the scenarios are differently configured, as illustrated in Figure ES-7-1.

Figure ES-7-1. Incremental costs of scenarios under ES-7



Each scenario displays similarly sharply differing annual CO_2e emission reductions, as illustrated in Figure ES-7-2.

Figure ES-7-2. Annual CO_2e emission reductions of scenarios under ES-7



CO_2e = carbon dioxide equivalent.

Key Assumptions:

Table ES-7-4. Assumed utility and non-utility capacity and generation in 2005

Coal	3,793	23,037	23,227	10,285	238.9
Natural Gas	6,468	5,804	5,851	8,020	46.9
Other Gases	0	0	0	0	0.0
Petroleum	23	163	164	10,869	1.8
Nuclear	1,834	13,690	13,802	10,352	142.9
Hydroelectric	1,387	3,086	3,111	9,928	30.9
Geothermal	0	0	0	0	0.0
Solar/PV	0	0	0	0	0.0
Wind	0	0	0	0	0.0
MSW Landfill gas	0	0	0	0	0.0
Biomass	0	0	0	0	0.0
Other wastes	0	0	0	0	0.0
Pumped Storage	28	20	20	10,500	0.2
Total	13,533	45,799	46,176		461.6

PV = photovoltaic; MSW = municipal solid waste.

Table ES-7-5. CHP capacity and generation in 2005

Coal	0	0	0	0	0.0
Natural Gas	228	204	206	9,910	2.0
Other Gases	0	15	15	0	0.0
Petroleum	0	44	44	6,818	0.3
Nuclear	0	0	0	0	0.0
Hydroelectric	1	-3	-3	0	0.0
Geothermal	0	0	0	0	0.0
Solar/PV	0	0	0	0	0.0
Wind	0	0	0	0	0.0
MSW Landfill gas	0	0	0	0	0.0
Biomass	298	1,735	1,749	7,961	13.9
Other wastes	0	0	0	0	0.0
Pumped Storage	0	0	0	10,500	0.0
Total	527	1,995	2,012		16.3

PV = photovoltaic; MSW = municipal solid waste.

Table ES-7-6. 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

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

Table ES-7-7. 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; MWh = megawatt-hour; O&M = operation and maintenance.

Key Uncertainties

Costs of 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.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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 option can be to provide incentives to utilities to upgrade existing transmission systems and reduce barriers to siting of 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 5% effective improvement in energy efficiency through reduced T&D system losses (i.e., losses reduced from 6.5% to 6.2%).
- Achieve 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.

Other: TBD – [as needed and approved by the TWG]

Implementation Mechanisms

TBD – [as approved by the TWG]

Related Policies/Programs in Place

TBD – [as needed and approved by the TWG]

Type(s) of GHG Reductions

TBD – [as approved by the TWG]

Estimated GHG Reductions and Costs or Cost Savings

Policy No.	Policy Option	GHG Reductions ($MMtCO_2e$)			Net Present Value 2009–2025 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Level of Support
		2015	2025	Total 2009–2025			
ES-8	Transmission System Upgrades	*Not Yet Quantified*					Pending

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) It is assumed that 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 .5% 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) Net present value is calculated in 2008 dollars.

Key Uncertainties

TBD – [as needed and approved by the TWG]

Additional Benefits and Costs

TBD – [as needed and approved by the TWG]

Feasibility Issues

TBD – [as needed and approved by the TWG]

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

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 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.

Other: None cited.

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

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

Scenario	Description	GHG Reductions (MMtCO2e) 2015	2025	Total 2009-2025	Net Present Value 2009–2025 (Million $)	Effectiveness ($/tCO$_2$e)	Level of Support
Scenario #1	Plum point build in 2010; no build of new Hempstead plant						
	Sensitivity #1: low cost & performance assumptions	0.0	9.8	58.9	$1,329	$22.6	Pending
	Sensitivity #2: mid cost & performance assumptions	0.0	9.8	58.9	$1,574	$26.7	Pending
	Sensitivity #3: high cost & performance assumptions	0.0	9.8	58.9	$1,792	$30.4	Pending
Scenario #2	Plum point build in 2010; build Hempstead in 2012						
	Sensitivity #1: low cost & performance assumptions	0.0	9.8	58.9	$1,329	$22.6	Pending
	Sensitivity #2: mid cost & performance assumptions	0.0	9.8	58.9	$1,574	$26.7	Pending
	Sensitivity #3: high cost & performance assumptions	0.0	9.8	58.9	$1,792	$30.4	Pending

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; $/tCO$_2$e = 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 ADL 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 1 for the overall approach to the quantification of this and all other energy supply options.

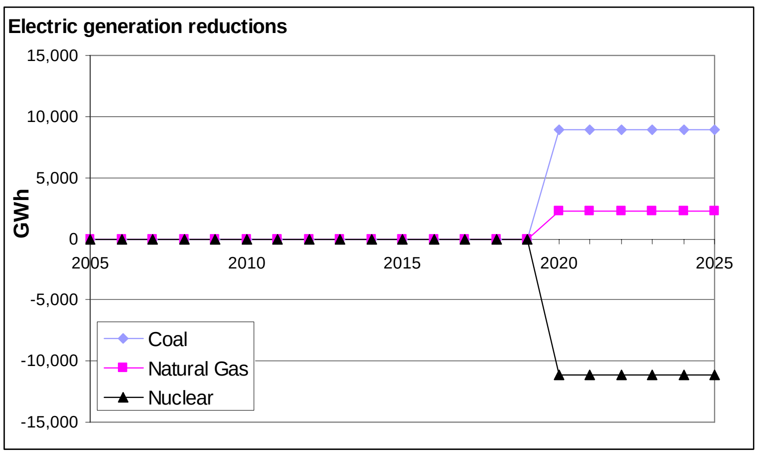
The analysis of this option examines the installation of one nuclear power station during the planning period. The TWG is in the process of making the following key assumptions for the analysis of this option, as follows:

- Two reference scenarios to be modeled, one assuming the Hempstead plant (i.e., Reference Scenario #1) is not built, and one assuming it is built (i.e., Reference Scenario #2).

- The start year for the option 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 Arkansas RCI TWG (i.e., $58.3/MWh). This value was assumed to be applicable for both reference scenarios.
- Full fuel-cycle GHG emissions are considered.

Regarding in-state gross generation, the impact of the option is summarized in the chart below for both reference scenarios. The incremental effect of the option 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.

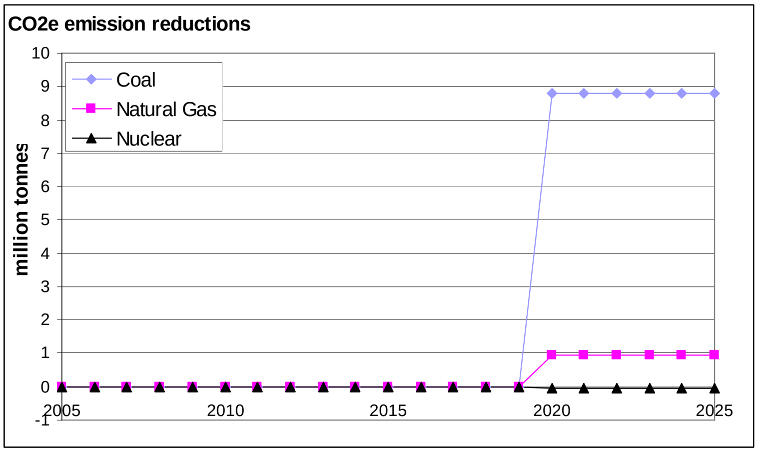
Figure ES-9-1. Effect of ES-9 on in-state gross generation under both reference scenarios



GWh = gigawatt-hour.

Figure ES-9-2 summarizes the impact of the option on CO_2e emission reductions across the full fuel cycle. The annual effect of the option by 2025 results in about a 9.82 $MMtCO_2e$ emission reduction across the full fuel cycle. This is made up by 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 option leads to reductions of 58.9 $MMtCO_2e$.

Figure ES-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, and incremental are costs associated with capital costs, transmission costs, variable and fixed O&M costs, 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 option. For the central estimate of cost and performance, the NPVs of the costs are $1.57 billion over the 2020–2025 period (2005$) for both reference scenarios. The cost-effectiveness of the option is calculated as the quotient of the NPV and cumulative GHG emission reductions. For both reference scenarios for the central estimate of cost and performance, the cost-effectiveness is $26.7/t$CO_2e$ (2005$) (i.e., $1.57 billion divided by 58.9 MMtCO_2e and multiplied by a conversion factor of 1,000).

Key Assumptions:

Figure ES-9-3. 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.

Figure ES-9-4. 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.

Figure ES-9-5. 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.

Figure ES-6. 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.

Figure ES-7. 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

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

Figure ES-8. 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., Nuclear Regulatory Commission 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

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

ES-10. Carbon Tax

Policy Description

A GHG tax is a tax on each ton of CO_2e emitted from certain sources. The tax could be imposed upstream and based, for example, on the carbon content of fuels (e.g., fossil fuel suppliers) or at the point of combustion and emission. Although taxed entities would pass some or all of the cost on to consumers, there would be competitive pressure to find cost-effective ways to lower (or offset) emissions. Consumers who see the implicit cost of GHG emissions in products and services could adjust their behavior to lower emissions and reduce cost. The program can be designed to be "revenue neutral" (not a net tax increase), for example, by offsetting with an income tax reduction; can fund policies and programs to assist with reducing GHG emissions; or can be directed to helping the competitiveness of industries or assisting communities affected by the tax.

Policy Design

- Set percentage limits for passing the rate cost on to customers, with the idea of opening up new renewable energy purchasing options to rate payers.
- Possibly consider a utility cap based on a regional system average rate, much like what's needed with the oil industry. The intent would be to put the pressure back on the business sector to adjust to the market instead of consumers' having no options. This would cross over with other sections of the GCGW's effort to give rate payers renewable options.
- A carbon tax would give an immediate option for funding the Arkansas Climate Change Institute and the programs and costs that come out of the GCGW's recommendations.

Goals:

- Integrate a carbon tax program in correlation with a regional 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 prepares Arkansas for federal standards and puts the state ahead of the game (instead of playing catch-up) and in a position that benefits ratepayers most in need (i.e., low-income customers).
- Establish a program that will easily allow Arkansas to adapt to a federal cap-and-trade system.
- After coordinating with a regional system, establish a recording/banking system that will put the South at an advantage—from financial, environmental, and adaptability perspectives—of being prepared for federal standards for a cap-and-trade program.

Timing: Beginning in 2009 and system in place by late 2009.

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

Other: None cited.

Implementation Mechanisms

None cited.

Related Policies/Programs in Place

None cited.

Type(s) of GHG Reductions

The ES TWG considers this policy option as not quantifiable.

Estimated GHG Reductions and Costs or Cost Savings

The ES TWG considers this policy option 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

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

ES-11. Efficiency Improvements and Repowering of Existing Plants

Policy Description

Efficiency improvements 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.

Other: None cited.

Implementation Mechanisms

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

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

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

		GHG Reductions (MMtCO2e)			Net Present Value		
Option	Description	2015	2025	Total 2009-2025	2009–2025 (Million $)	Effectiveness ($/tCO$_2$e)	Level of Support
ES-11	Reppower existing coal station with NGCC	2.3	2.3	31.8	$1,568	$49.33	Pending

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/tCO_2e$ = 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:

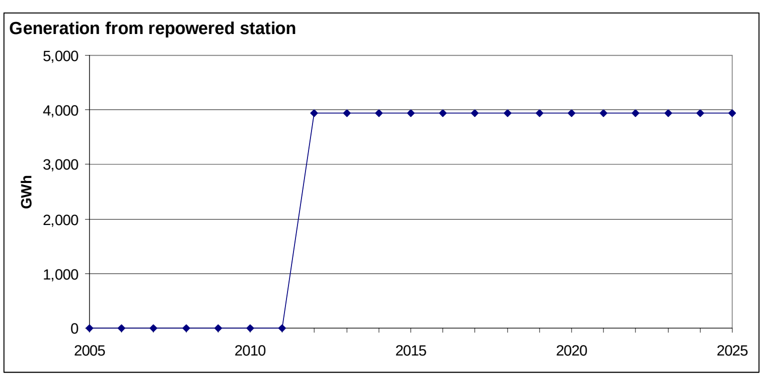
See Annex 1 for the overall approach to the quantification of this and all other energy supply options.

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

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

Figure ES-11-1 summarizes the total generation associated with the repowered station.

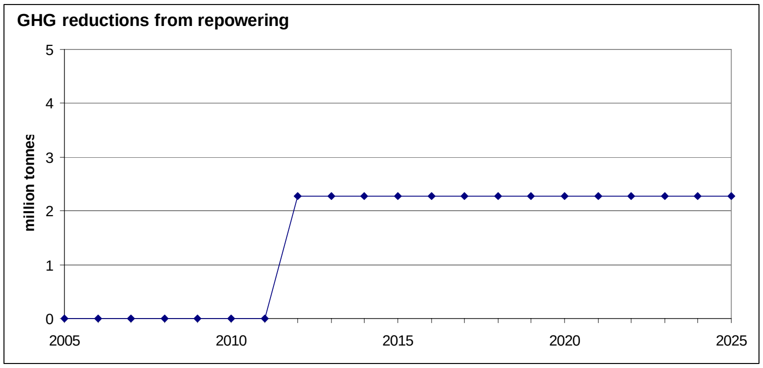
Figure ES-11-1. Generation from repowered pulverized coal plant



GWh = gigawatt-hour.

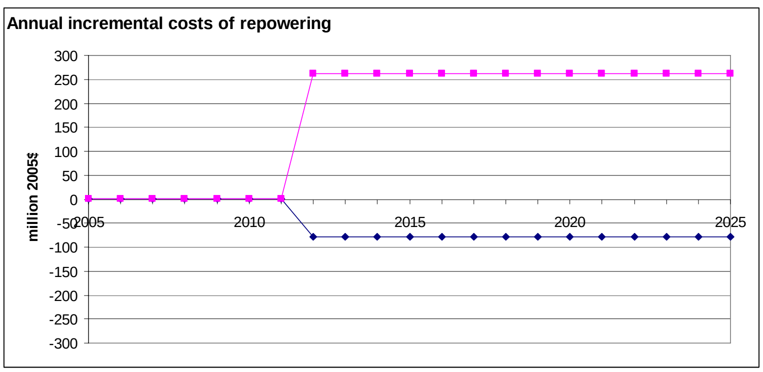
Figure ES-11-2 summarizes the annual CO_2e emission reductions associated with the repowered unit. The annual emission reductions in both 2015 and 2025 are 2.3 $MMtCO_2e$, and the cumulative emission reductions over the 2005–2025 forecast period are 31.8 $MMtCO_2e$.

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



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 the Figure ES-11-3. The coal station was assumed to be fully depreciated. The NPVs of these annual costs are $1.6 billion over the 2012–2025 period (2005$).

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



The cost effectiveness of this policy option 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 MMt 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

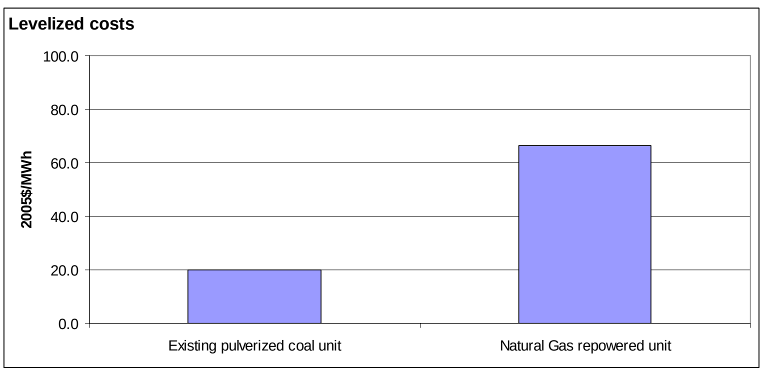
- Heat rate: 10,000 Btu/kWh
- Average annual capacity factor: 75%

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 ES-11-4 defines the levelized costs.

Figure ES-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 option may relate to a cap-and-trade proposal.

Additional Benefits and Costs

None cited.

Feasibility Issues

None cited.

Status of Group Approval

Pending – [until GCGW moves to final agreement at meeting #9 or #10]

Level of Group Support

TBD – [blank until GCGW meeting #9 or #10]

Barriers to Consensus

TBD – [blank until final vote by the GCGW]

Annex 1
Overall Quantification Approach for Energy Supply Options

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 TWG policy options 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 options, CCS would undertake the analysis. Where an ES TWG member offered to undertake the analysis of one or more options, 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 options.[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 options. 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 mitigation options 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.

[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 options with net costs; negative numbers represent options 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 proceeded 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 options, 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 option 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 options overlap with options being considered in other TWGs. The analysis for these options 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 onto 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 that 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.