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Memo-Draft

To: Arkansas Agriculture, Forestry and Waste Management Technical Working Group

From: The Center for Climate Strategies

Subject: Assumptions for Agriculture, Forestry and Waste Management Policy Options

Date: June 6, 2008

This memo summarizes key assumptions used to estimate the GHG impacts and cost effectiveness for draft Agriculture Forestry and Waste Management policy options. The quantification process is intended to support custom design and analysis of draft policy options, and provide both consistency and flexibility. The purpose of this memo is to present the assumptions used as part of the quantification process in order to ensure consistency between options and between TWGs. Feedback on the assumptions is encouraged.

Quantifying reductions of GHG (particularly future reductions) is an inherently complex process and assumptions are important inputs into the quantification methodologies and models used to estimate policy costs and benefits. Models are representations of reality, and require the best available data on likely futures. An emphasis should be placed on using assumptions that are based on the best available data using local or regional data (when available) rather than national level data.

Unless directed otherwise by the Governor's Commission on Global Warming (GCGW), CCS will estimate the lifecycle GHG reductions for each policy option, where data and methods are available to do so. CCS also strives to estimate lifecycle reductions for policy options in the other sectors. It is important for the TWG and GCGW members to understand the ramifications of this. In the AR GHG Inventory and Forecast (I&F), the only sector for which consumption-based emissions data are provided is the electricity consumption sector. In all other sectors of the inventory, the GHG emissions are strictly those that occur within the state as a result of energy consumption or other GHG emission process (e.g. methane from landfilled waste). For example, for fuel combustion in the RCI and Transportation sectors, only the emissions associated with fuel combustion are provided, not those associated with the extraction, transport, processing, and distribution of each fuel. Similarly, for waste management, only emissions associated with waste management processes in AR are included in the I&F (e.g. landfilling, waste combustion), not those associated with production and transportation of the initial packaging or product that became a component of the solid waste stream.

Development of consumption-based emission estimates (including embedded GHG from lifecycle assessments) for all sectors of the inventory are beyond the scope of this process. Indeed, in many cases, these types of inventory estimates would involve significant technical and data availability challenges. However, for some policy options, lifecycle emission reductions can be estimated, and it should be recognized that the portion of emission reductions that occur out of state as a result of in-state policies are not captured in the I&F. Some might see these methodological differences in emissions and emission reductions accounting as a disconnect; however, CCS believes that the GCGW should consider taking credit for reductions that occur out of state as a result of actions taken within the state of AR. Some common examples of where this accounting occurs:

- Fossil fuel consumption: inventory estimates are based only on the GHG emissions associated with the combustion of each fuel; lifecycle emission reductions are estimated using GHGs from combustion plus the embedded GHGs from extraction, transportation, processing, and distribution;
- Solid waste management: landfill methane emissions or total GHG emissions are associated only with waste combustion and decomposition; lifecycle emission reductions include the landfill/waste combustion emissions plus those associated with production of the packaging or product (e.g. net difference of use of virgin materials versus recycled materials);
- Biofuels consumption: for fossil fuel displacement benefits, the inventory includes only GHGs from fossil fuel combustion; lifecycle emission reductions are estimated using the lifecycle gasoline/diesel emission factors compared to lifecycle biofuel emission factors (captures total GHGs from fuel production, processing, and distribution).

Biomass Supply

The table below indicates the biomass availability in Arkansas. The source/reference for the value is indicated in the notes section. The AFW TWG will work to refine this initial assessment during the process.

Biomass Resource	Annual Biomass Supply (10^3 dry short tons)	Heat Content (MMBtu/dry short ton)	Approximate Energy Available (MMBtu)	Notes
Forest Residue	5,265	9.96	52,448,370	Biomass availability from Annual Biomass Supply Study.[1] Heat Content from Biomass Heat Content Study.[2]
Mill Residue	3,239	9.96	32,263,679	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Urban Wood Waste	1,534	9.96	15,281,947	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Agricultural Residue	3,198	8.25	26,378,630	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.

[1] Arkansas Economic Development Commission, Annual Biomass Supply: Arkansas Biomass Resource Assessment, Arkansas http://arkansasedc.com/business_development/energy/?page=bioenergy

[2] U.S. Department of Energy, Energy Information Administration, "Average Heat Content of Selected Biomass Fuels," April 2008. Available at:

http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/table10.html.

Biomass Resource	Annual Biomass Supply (10^3 dry short tons)	Heat Content (MMBtu/dry short ton)	Approximate Energy Available (MMBtu)	Notes
Municipal Paper Waste	293	13.0	3,813,568	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Municipal Solid Waste (MSW) Fiber	TBD	9.95	TBD	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Used Cooking Oil	4	TBD	TBD	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Yard & Landscape Waste Debris	87	9.96	865,495	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study. Moisture contents from Wyoming study.[3]
Biosolids	41	TBD	TBD	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Energy Crops	TBD	TBD	TBD	Annual Biomass Supply Study. Heat Content from Biomass Heat Content Study.
Total Annual Biomass Supply	**13,661**	**N/A**	**131,051,689**	**Note that this does not include energy crops.**

Land Value and Conservation Easement Costs

The AFW options assume Conservation Reserve Program (CRP) annual payments as a proxy for easement costs.

Total continuous CRP land annual payments for Arkansas were $68.04 per acre as of March 2008. This payment includes annual incentive and maintenance allowance payments, but not one-time signing and practice incentive payments or payment reductions, such as for lands enrolled less than a full year and lands hayed or grazed (see http://www.fsa.usda.gov/Internet/FSA_File/mar2008.pdf).

Land Use

The reduction in fossil diesel fuel use from changing land use from intensive agriculture to alternative land use or practices is estimated at 3.5 gallons/acre.[4] The life-cycle fossil diesel GHG emission factor is 12.3 $MtCO_2e$/1,000 gallons.[5]

[3] Moisture contents for paper waste (5%) and yard waste (40%) from: Wyoming Business Council, *Municipal Solid Waste*. Available at: http://www.wyomingbusiness.org/pdf/energy/Biomass_MunicipalWaste.pdf.
[4] Reduction associated with less intensive land use (e.g. fewer passes). The estimate is based on conservation tillage compared with conventional tillage, at http://www.conservationinformation.org/Core4Brochures/CTBrochure.pdf, accessed May 2008.
[5] Life-cycle emissions factor for fossil diesel from J. Hill et al., "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences*, 103(30):11206–11210. From the assessment used to evaluate U.S. soybean-based biodiesel life-cycle impacts. See http://www.pnas.org/cgi/content/full/103/30/11099

Fertilizer

The following fertilizer cost information is taken from U.S. Department of Agriculture, Economic Research Service's U.S. fertilizer use and price information (see http://www.ers.usda.gov/Data/fertilizeruse/).

Month/Year	Average U.S. farm prices of selected fertilizers					
	Anhydrous ammonia	Nitrogen solutions 30%	Urea 45-46% nitrogen	Ammonium nitrate	Sulfate of ammonium	Average
Apr 2007	523	277	453	382	288	385

The assumed emissions factor for nitrogen applied is 4.70 kg CO2e / kg N applied (on-farm). This is obtained from the inventory and forecast. The avoided life cycle GHG emissions (i.e. emissions associated with the production, transport, and energy consumption during application) were taken from Wood and Cowie[6]. The estimate provided for the U.S. (taken from West and Marland, 2001[7]) was 0.858 kilograms (kg) CO_2e per kilogram of nitrogen (kgN)[8]. This provides a total emissions factor of 5.55 kg CO2e / kg N applied.

Emission Factors

Standard emissions factors for fuel feedstocks are calculated from the Arkansas GHG Emissions Inventory and summarized below (note that these emission factors include CH4 and N2O emissions in addition to CO2 emissions)

Feedstock	(tCO2e/mmbtu)
Subbituminous coal	0.096
Natural gas	0.054
Residual oil	0.078
Diesel oil	0.073
Petroleum coke	0.100
LPG	0.063
Refuse derived fuel (fossil)	0.043
MSW (fossil)	0.043
Refuse derived fuel (biomass)	0.002
MSW (biomass)	0.002
Wood, waste wood and sawdust	0.002
Nuclear	0.000

6 Sam Wood and Annette Cowie (2004) *A Review of Greenhouse Gas Emission Factors for Fertiliser Production* Research and Development Division, State Forests of New South Wales, Cooperative Research Centre for Greenhouse Accounting.

7 West, T. O. and Marland, G. 2001. *A Synthesis of Carbon Sequestration, Carbon Emissions and Net Carbon Flux in Agriculture: Comparing Tillage Practices in the United States.* Agriculture, Ecosystems and Environment 1812, 1-16.

8 These emission factors provide an estimate of the typical life cycle GHG emissions (including resource extraction, the transport of raw materials and products, and the fertilizer production processes) per unit weight of fertilizer produced (i.e., gCO_2e/kg fertilizer).

Landfill gas[9]	0.054
Wind	0.000
Solar/PV	0.000
Other	0.054
Oil	0.078
Waste solvent	0.073

The emissions factor for grid electricity was also taken from the Arkansas inventory and forecast, derived by dividing total electricity consumption emissions in 2005 by electricity sales in 2005. This provided an Electricity Emissions Factor of 0.592 Metric Tons CO2-e per MWh.

Fuel Prices

The following table shows fuel prices (in $/MMBTU) for costs taken from Annual Energy Outlook 2008 (Early Release)[10].

	Crude Oil (in $/MMBTU)	Crude Oil (in $/barrel)	Natural Gas (in $/MMBTU)	Coal (in $/MMBTU)	Coal (in $/ton)
2009	13.3	77.2	6.56	1.29	26.8
2010	12.8	74.2	6.16	1.28	26.6
2011	12.3	71.4	5.85	1.25	25.9
2012	11.8	68.6	5.67	1.22	25.3
2013	11.4	65.8	5.48	1.20	24.9
2014	10.9	62.9	5.32	1.18	24.5
2015	10.4	60.0	5.21	1.17	24.3
2016	9.85	57.1	5.17	1.16	24.1
2017	9.88	57.3	5.24	1.15	23.9
2018	10.0	58.2	5.31	1.14	23.7
2019	10.2	59.1	5.38	1.14	23.7
2020	10.3	59.9	5.29	1.14	23.7
2021	10.5	60.7	5.17	1.14	23.7
2022	10.6	61.7	5.29	1.15	23.9
2023	10.8	62.6	5.41	1.15	23.9
2024	11.0	63.6	5.56	1.16	24.1
2025	11.2	64.7	5.69	1.16	24.1

[9] Assumed to be biogenic.
[10] Fuel cost (in $/MMBTU) come from Figure 1. Energy Prices 2006 dollars per million BTU From EIA AEO 2008. see http://www.eia.doe.gov/oiaf/aeo/prices.html.

Assumed cost of electricity is based on Future Southeastern Electric Reliability Council prices from the EIA Annual Energy Outlook (see http://www.eia.doe.gov/oiaf/aeo/supplement/index.html), illustrated below:

Southeastern Electric Reliability Council - 09	
Year	All Sector Average Electricity Price (2005$ per kWh)
2009	0.071
2010	0.072
2011	0.072
2012	0.071
2013	0.069
2014	0.068
2015	0.068
2016	0.068
2017	0.068
2018	0.069
2019	0.069
2020	0.069
2021	0.069
2022	0.069
2023	0.069
2024	0.069
2025	0.069

Capital costs and capacity factors

Estimates of capital costs and capacity factors for new generating capacity vary tremendously and the quantification process requires some guidance as to which estimates the ES TWG prefers. Again, AR specific estimates are preferred. The following table from the *Annual Energy Outlook* 2007 shows the capital cost and O&M costs used by the National Energy Modeling System (NEMS) model.

Table 39. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2006 ($2005/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2006[3] (2005 $/kW)	Variable O&M[5] ($2005 mills/kWh)	Fixed O&M[5] ($2005/kW)	Heatrate in 2006 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2010	600	4	1,206	1.07	1.00	1,290	4.32	25.91	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2010	550	4	1,394	1.07	1.00	1,491	2.75	36.38	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,936	1.07	1.03	2,134	4.18	42.82	9,713	7,920
Conv Gas/Oil Comb Cycle	2009	250	3	574	1.05	1.00	603	1.94	11.75	7,163	6,800
Adv Gas/Oil Comb Cycle (CC)	2009	400	3	550	1.08	1.00	594	1.88	11.01	6,717	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,055	1.08	1.04	1,185	2.77	18.72	8,547	7,493
Conv Combustion Turbine[5]	2008	160	2	400	1.05	1.00	420	3.36	11.40	10,807	10,450
Adv Combustion Turbine	2008	230	2	379	1.05	1.00	398	2.98	9.91	9,166	8,550
Fuel Cells	2009	10	3	3,913	1.05	1.10	4,520	45.09	5.32	7,873	6,960
Advanced Nuclear	2014	1350	6	1,802	1.10	1.05	2,081	0.47	63.88	10,400	10,400
Distributed Generation -Base	2009	2	3	818	1.05	1.00	859	6.70	15.08	9,500	8,900
Distributed Generation -Peak	2008	1	2	983	1.05	1.00	1,032	6.70	15.08	10,634	9,880
Biomass	2010	80	4	1,714	1.07	1.02	1,869	2.96	50.18	8,911	8,911
MSW - Landfill Gas	2009	30	3	1,491	1.07	1.00	1,595	0.01	107.50	13,648	13,648
Geothermal[6,7]	2010	50	4	1,790	1.05	1.00	1,880	0.00	154.92	36,025	30,641
Conventional Hydropower[6]	2010	500	4	1,364	1.10	1.00	1,500	3.30	13.14	10,107	10,107
Wind	2009	50	3	1,127	1.07	1.00	1,206	0.00	28.51	10,280	10,280
Solar Thermal[7]	2009	100	3	2,675	1.07	1.10	3,149	0.00	53.43	10,280	10,280
Photovoltaic[7]	2008	5	2	4,114	1.05	1.10	4,751	0.00	10.99	10,280	10,280

Source: Assumptions to the AEO 2007, p. 77.[11]

Renewable Incentives

Inclusion of the federal production tax credit (PTC) in the levelized cost estimates for renewables in the Policy Options needs to be considered. The federal Renewable Electricity Production Tax Credit has been around in some form since 1992 but seems to always be about to expire (currently December, 2008). The existing incentive for wind, closed-loop biomass and geothermal is 2.0¢/kWh. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources receives a 1.0¢/kWh credit.

[11] http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf