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Memo-Draft

To: Iowa Agriculture, Forestry and Waste Subcommittee

From: The Center for Climate Strategies

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

Date: May 23, 2008

This memo summarizes key assumptions used to estimate the GHG impacts and cost effectiveness for draft Agriculture Forestry and Waste 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 subcommittees. 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 ICCAC, 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 ICCAC members to understand the ramifications of this. In the IA GHG 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 IA 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 ICCAC should consider taking credit for reductions that occur out of state as a result of actions taken within the state of IA. 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 Iowa. 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 (dry tons)	Notes
Forest Residue	396,000	2005 NREL Report[1]. Estimated using USDA Forest Service's Timber Product Output database for 2002, includes logging residues and other removals.
Primary Mill Residue (Unused)	2,000	2005 NREL Report. Derived from the USDA Forest Service's Timber Product Output database for 2002, includes mill residues burned as waste or landfilled.
Secondary Mill Residue	32,000	2005 NREL Report. Includes wood scraps and sawdust from woodworking shops— furniture factories, wood container and pallet mills, and wholesale lumberyards. Estimated using number of businesses from the U.S. Census Bureau, 2002 County Business Patterns and assumptions on the wood waste generated.
Urban Wood Waste	353,000	2005 NREL Report. Includes MSW wood—wood chips, pallets, and yard waste; utility tree trimming and/or private tree companies; and construction/demolition wood. Data on the collected urban wood waste are not available; thus numerous assumptions were applied for estimation.

[1] *A Geographic Perspective On The Current Biomass Resource Availability In The United States*, A. Milbrandt, Technical Report NREL/TP-560-39181, December 2005, Prepared under Task No. HY55.2200.

Biomass Resource	Annual Biomass Supply (dry tons)	Notes
Agricultural Residue	26,003,000	2005 NREL Report. Estimated using 2002 total grain production, crop to residue ratio, moisture content, and taking into consideration the amount of residue left on the field for soil protection, grazing, and other agricultural activities.
Switchgrass		2005 NREL Report estimates a potential 11,297,000 tons of switchgrass could be grown on CRP lands.
Willow or Hybrid Poplar		2005 NREL Report estimates a potential 9,413,000 tons of willow or hybrid poplar could be grown on CRP lands.
Poultry Litter		
Municipal Solid Waste (MSW) Fiber		
Wood Pulp		
Yard & Landscape Waste Debris		
Total Annual Biomass Supply		

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 Iowa were $146.11 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.[2] The life-cycle fossil diesel GHG emission factor is 12.31 $MtCO_2e$/1,000 gallons.[3]

[2] 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.

[3] 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 avoided life cycle GHG emissions (i.e. emissions associated with the production, transport, and energy consumption during application) were taken from Wood and Cowie[4]. The estimate provided for the U.S. (taken from West and Marland, 2001[5]) was 857.5 grams (g) CO_2e per kilogram of nitrogen (kgN)[6] or 0.778 $MtCO_2e$ per ton of nitrogen (tN). This estimate was significantly lower than the estimates for European fertilizers (ranging from 5,339.9 to 7,615.9 gCO_2e/kgN). Wood and Cowie recognize that the estimate for the U.S. is low and suggested that part of this discrepancy could be explained by the exclusion of N_2O emissions from the US estimate, which are significant component of GHG emissions.

Renewable mix

The Clean Renewable (CRE) subcommittee has been requested to specify the mix of fossil and renewable technologies deployed to meet load growth. The table below from the IA Forecast shows the assumption that IA new build mirrors the MAPP region. This assumption will help inform the potential mix of technologies deployed on farms to meet renewable energy requirements under AFW-7. eg: 75% wind, 20% biomass, etc.

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	77%	78%	77%	76%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	77%	78%
Nuclear	11%	10%	10%	10%	10%	10%	10%	10%	9%	9%	9%	9%	9%	9%	9%	9%
Natural Gas	6%	2%	2%	4%	2%	2%	2%	2%	2%	2%	3%	3%	4%	3%	4%	4%
Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MSW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Biomass	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LFG	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wind	4%	6%	7%	7%	7%	7%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%
Hydro	2%	3%	3%	3%	3%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

4 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.

5 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.

6 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).

Emission Factors

Standard emissions factors for fuel feedstocks are calculated from the Iowa 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	0.0959
Natural gas	0.0539
Residual oil	0.0783
Diesel oil	0.0727
Petroleum coke	0.1003
LPG	0.0633
Refuse derived fuel (fossil)	0.0427
MSW (fossil)	0.0426
Refuse derived fuel (biomass)	0.0019
MSW (biomass)	0.0019
Wood, waste wood and sawdust	0.0020
Nuclear	0.0000
Landfill gas[7]	0.0000
Wind	0.0000
Solar/PV	0.0000
Other	0.0000
Oil	0.0734
Waste solvent	0.0734

The emissions factor for grid electricity was also taken from the Iowa inventory and forecast, derived by dividing total electricity consumption emissions in 2005 by electricity sales in 2005. This provided an Electricity Emissions Factor of 0.689 Metric Tons CO2-e per MWh.

Fuel Prices

The following table shows fuel prices for costs taken from Annual Energy Outlook 2008 (Early Release)[8].

	Crude Oil	Natural Gas	Coal
2009	13.31	6.56	1.29
2010	12.80	6.16	1.28
2011	12.31	5.85	1.25
2012	11.82	5.67	1.22
2013	11.35	5.48	1.20
2014	10.85	5.32	1.18

[7] Assumed to be biogenic.
[8] 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.htmlin the MAPP region from the *AEO* 2007.

2015	10.35	5.21	1.17
2016	9.85	5.17	1.16
2017	9.88	5.24	1.15
2018	10.03	5.31	1.14
2019	10.19	5.38	1.14
2020	10.32	5.29	1.14

Assumed cost of electricity is based on Future Mid-Continent Area Power Pool prices from the EIA Annual Energy Outlook (see http://www.eia.doe.gov/oiaf/aeo/supplement/index.html), illustrated below:

Mid-Continent Area Power Pool - 05	
Year	All Sector Average Electricity Price **(2005$** per kWh)
2008	0.060
2009	0.062
2010	0.064
2011	0.065
2012	0.064
2013	0.064
2014	0.063
2015	0.062
2016	0.062
2017	0.062
2018	0.063
2019	0.063
2020	0.063

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 CRE subcommittee prefers. Again, IA 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/kWh)
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.[9]

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. Also, the IA Renewable Energy Tax Credits under IA Code Chapters 476B/C provide tax incentives for renewable electricity.

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