Appendix C – GPRA07 Biomass Technologies Program Documentation

Background

This appendix discusses the assumptions and methods employed in the biomass benefits analysis, which is part of the fiscal year 2007 GPRA benefits analysis for all of the Department of Energy's Energy Efficiency and Renewable Energy (EERE) research and deployment programs. The biomass benefits analysis focuses on the benefits of future achievements by the Biomass Program and excludes retrospective benefits, as well as benefits resulting from industry's own initiative and funding.

The major program focus is to enable integrated biorefineries that produce ethanol as the main output and, where possible, limited volumes of coproducts such as chemicals, materials, and/or heat and power. Biorefineries process biomass into these products using biochemical processes (such as hydrolysis of biomass to sugars followed by fermentation of sugars to fuels and/or chemicals) or thermochemical processes (such as gasification of biomass to syngas followed by conversion of syngas to fuels or chemicals). Biorefinery configurations may vary as a function of site-specific conditions, including feedstock availability and price, local and regional market demand, and other factors. Heat and power produced within the biorefinery can be used for internal biorefinery power requirements, with excess electricity production sold externally.

As an interim step leading to future biorefineries, the program is working with corn ethanol production plants on near-term technologies aimed at increasing the ethanol production from traditional feedstocks (corn kernels) and enhancing the value of nonethanol coproducts such as animal feed additives. Only the starch portion of the corn kernels is currently converted to ethanol. Ethanol yield increases can be achieved with technology that converts the fibrous component of the corn kernels, which is composed of cellulosic material, to ethanol. This process also exposes the starch that is tightly bound by this fiber ("residual starch"), which is not currently available for conversion to ethanol in existing corn ethanol plants. A further benefit of this technology is the production of a higher-protein animal feed that may be more suitable for the poultry and swine markets. Cellulosic ethanol technology will be used to convert the fibrous component of kernels and expose the residual starch to fermentation. The advantage of introducing cellulosic ethanol technology into existing corn biorefineries is that the plants can utilize existing facilities for processing corn kernels, energy services, and fermenting and distilling ethanol, thus reducing capital expenditures and financial risks. Operators of corn biorefineries have expressed an interest in this technology as a means of expanding corn ethanol yields and increasing profits, and DOE has entered into partnership agreements with several plant operators. Positive experience with kernel fiber and residual starch conversion could facilitate the companies' decisions to investigate the possibility of converting additional cellulosic feedstock such as agricultural residues.

The GPRA07 benefits analysis is based on the concept that enhanced corn ethanol plants—with the added production of corn fiber ethanol, residual starch ethanol, and eventually stover-based ethanol—will lead to the development of mature stand-alone lignocellulosic ethanol plants.

Ligno-cellulosic biomass includes challenging feedstock such as corn stover, wheat straw, rice straw, woody forest wastes, and future energy crops, e.g., fast-growing trees such as hybrid poplars, and fast-growing grasses such as switchgrass. The time-based progression is as follows:

a. "Starch Biorefineries" (SBs) that use corn kernels or other grains to produce ethanol and a small volume of coproducts (chemicals and materials). Advanced starch biorefineries will convert some of the fiber in the corn kernels to ethanol using cellulosic ethanol technology.

b. "Cellullosic Biorefineries" (CBs) that use corn stover and/or other cellullosic biomass to produce ethanol.

A biorefinery industry is expected to result in biomass displacing petroleum feedstocks traditionally used in the production of fuels, chemicals, and materials. The biorefinery concept allows the cost of production to be reduced through synergies associated with feedstock handling and processing, and the allocation of capital and fixed operating and maintenance costs across multiple products. While the current analysis assumes that ethanol is the major output of biorefineries, future analyses could include additional fuels that the program may identify in the longer term.

When processing lignocellulosic biomass, the biorefinery will process the cellulosic portion of the biomass into ethanol and use the remaining lignin residues to generate electricity.[a] Excess electricity will be sold externally, thereby reducing the net ethanol cost. The program assumed the coproduction of a small quantity of nonfuel chemicals or materials in corn ethanol plants. These bio-based products were modeled as a "credit" that reduces the ethanol production cost. Analysts in EERE's Office of Planning, Budget and Analysis (PBA) used ethanol supply/demand data with biorefinery synergy credit—values for each year provided by the Office of the Biomass Program (OBP) —and "current law" tax incentives to estimate market penetration for ethanol.

A variety of chemicals and materials could potentially be coproduced at biorefineries. Sugar and starch products derived through fermentation and thermochemical processes include alcohols, acids, starch, xanthum gum, and other products. Some of these chemicals and materials represent end products, while others represent "intermediates" used in the production of other products. The potential target markets are even more diverse than the list of potential products. Therefore PBA analysts did not characterize or analyze specific target markets for bio-based products in this benefits analysis. Instead, this analysis represented the bio-based product as a "generic/composite" product. OBP assumptions for the "generic/composite" product were derived from several OBP-sponsored studies that assessed a wide range of possible bio-based products (polymers, solvents, etc.).

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[a] The structural materials that plants produce to form the cell walls, leaves, stems, stalks, and woody portions of biomass consists mainly of three biobased chemicals called cellulose, hemicellulose, and lignin. This composite material called lignocellulose is composed of rigid cellulose fibers embedded in a cross-linked matrix of lignin and hemicellulose that bind the fibers. Lignocellulose material is resistant to physical, chemical, and biological attack. In a biorefinery, the cellulose and hemicellulose can be broken down to produce fermentable, simple sugars through a process called hydrolysis. Cellulose is a very large polymer molecule composed of many hundreds or thousands of glucose molecules (polysaccharide).. Hemicellulose consists of short, highly branched, chains of sugars.

The discussion in this section will focus on describing target markets and technical characteristics used in the analysis of the market penetration and benefits attributable to the three types of biorefineries referenced above.

Target Markets for Biorefineries

Corn ethanol plants, both dry mills and wet mills,[b] currently use corn kernels (no cellulosic feedstock) to produce ethanol and some coproducts such as animal feed additives (both dry and wet mills), or corn oil and high-fructose corn syrup (wet mills).

In 2004, U.S. ethanol fuel production reached approximately 3.4 billion gallons, an increase of 21% from the previous year. As of January 2006, the estimated 2005 production is 3.9 billion gallons. According to the Renewable Fuels Association, in January 2006, the operating ethanol plants in the United States had a total production capacity of 4.37 billion gallons, with an additional capacity of 1.75 billion gallons under construction or in expansion. Ethanol competes in transportation fuel markets for light-duty vehicles. In 2004, the U.S. prime supplier sales volume of motor gasoline was approximately 140 billion gallons.[1]

In 2004, approximately 99% of the ethanol consumed in the United States was for the gasoline additive market and 1% was for use as a gasoline substitute.[2] In 2004, the majority of the ethanol consumed was used as an oxygenate component for gasoline, and the remainder is used as a gasoline additive to improve octane in conventional gasoline. Within the oxygenate market, in early 2004, methyl-tertiary-butyl-ether (MTBE) and ethanol each provided approximately 50% of the volume. However, ethanol has taken a much larger share of this market, because MTBE has been or is being phased out in many states due to environmental concerns (see discussion of MTBE later in this section for additional detail).

The original Clean Air Act required a minimum level of oxygen content in both reformulated gasoline (RFG) and oxygenated gasoline. The Energy Policy Act of 2005 repealed the oxygen content requirement for RFG to take place 270 days after enactment. However, the GPRA 2007 analysis was completed prior to the approval of the Energy Policy Act of 2005 and was based on current law at the time of this analysis. RFG is required in ozone nonattainment areas, and oxygenated gasoline is required in carbon monoxide (CO) nonattainment areas. Ethanol competed with MTBE in both of these oxygenate market segments. Most of the MTBE (and an increasing share of ethanol) used are used in RFG, which is the most important market segment for oxygenates. The Energy Policy Act did not enact a nationwide ban on MTBE,[c] but many states have already banned the use of MTBE in gasoline sold within their states. In addition, several major refiners have since announced their intent to discontinue the use of MTBE. Some refiners have indicated that, because of ethanol's desirable properties and restrictions on MTBE use, they will continue using ethanol in a substantial portion of their RFG after the repeal of the RFG oxygen requirement.

[b] To learn more about these plants, see http://www.ethanolrfa.org
[c] MTBE is currently the subject of environmental concern in several communities, due to its leakage and contamination of groundwater. It imparts a turpentine odor to water at low concentrations.

Both ethanol and MTBE are used in the smaller oxygenated gasoline market segment, with ethanol being the dominant oxygenate. In a third market segment, ethanol is blended with conventional gasoline to make gasohol, which is primarily marketed in the Midwest. Gasohol consists of 90% gasoline and 10% ethanol by volume, with the ethanol serving as an octane enhancer and gasoline extender.

After adjusting for its Federal excise tax exemption, the price of ethanol has historically tracked with the price of gasoline, whereas MTBE has normally been priced at a premium relative to gasoline. MTBE had been the oxygenate of choice in RFG for most refiners outside the Midwest because of its wider availability, more favorable blending characteristics for summer Reid Vapor Pressure, and ease of distribution. When blended into gasoline, ethanol raises the vapor pressure of the mixture; adding MTBE to gasoline has only a minor effect on vapor pressure. Because ethanol absorbs water, which is typically present in small quantities in the U.S. petroleum products pipeline system, ethanol and ethanol blends are not routinely shipped via pipeline. Consequently, ethanol is shipped by rail, truck, and/or barge to distribution terminals, where it is blended into gasoline. MTBE is blended into gasoline at the refinery, and MTBE blends do not require any special handling compared with gasoline that has no MTBE.

The consumption of MTBE in 2002 was approximately 4 billion gallons, but MTBE consumption has been declining as California, New York, Connecticut, and other states transitioned from MTBE to ethanol. A national ban on MTBE would increase the demand for ethanol because ethanol, like MTBE, is a high-octane content, virtually sulfur-free additive that reduces toxic air emissions. Ethanol also will help solve the problem of fuel volume loss that would accompany an MTBE ban, because oxygenates such as MTBE (or ethanol or other oxygenates), when blended in gasoline, also are used by the automobile engine as a fuel. Reformulated gasoline containing MTBE typically contains 11% MTBE. Outside of California, reformulated gasoline containing ethanol typically contains 10% ethanol. In California, the current blend level is typically 5.7% ethanol.

Vehicle fleets provide additional demand for ethanol fuel. These include alternative-fuel vehicles that have been either modified or manufactured to accommodate the use of E85, i.e. 85% ethanol and 15% gasoline (the number of E95 vehicles is negligible at this time). The E85 vehicles are flexible-fuel vehicles that can use either gasoline or E85. The vehicle fleet market is dominated by government agencies, but also includes fleets owned by corporate entities and other organizations (taxi cabs, utilities, airport authorities, etc.). The use of green fuels in Federal Government fleets is driven largely by the alternative-fuel vehicle requirements under the Energy Policy Act (EPACT) of 1992.

The market penetration of E85 has been much lower than for E10 because (1) only a limited number or vehicles can use E85 (and fleet rules under EPACT do not necessarily require the use of alternative fuels in these vehicles), (2) E85 has generally been more costly than gasoline on an energy-equivalent basis, (3) the availability of E85 refueling stations is limited, and (4) the required investment for refueling infrastructure is greater for E85 than for E10. In the longer term, once production technology improvements achieve cost parity between ethanol and gasoline, ethanol will compete directly with gasoline in broader automotive fuel markets.

Baseline Technology Improvements

The degree to which this technology would progress in the absence of EERE's biomass R&D has not been studied in detail. Instead, EERE adopted the methodology recommended by the National Research Council (NRC) to estimate how EERE RD&D funding would accelerate technology improvements.[3] The NRC recommended using an N-year rule, in which technology deployment would be accelerated by N years with EERE R&D, or conversely delayed by N years in the absence of EERE R&D. PBA used a multitiered approach to recognize differences between shorter- and longer-term goals. PBA analysts assumed that without Federal investment in RD&D, technological advances would be delayed 7 years for corn fiber/recalcitrant starch, 12 years for bio-based products technologies for dry mills, and 15 years for ethanol production technologies using cellulosic feedstock.

<u>Compared to the program case, PBA assumed a delay of 7 years is used for baseline parameters for dry mill, plus corn fiber and residual starch conversion</u>. The reason for a moderate delay is that industry has shown interest and willingness to cost-share R&D in this area, and the estimated development time is short compared to that for lignocellulosic ethanol technology. OBP has already catalyzed work in this area, as indicated by several projects that are underway. It seems reasonable that, absent any further OBP involvement, industry would continue to build on work already accomplished, albeit at a slower rate. The rationale for assuming a 15-year delay for stand-alone cellulosic ethanol biorefineries is industry's reticence to underwrite cellulosic ethanol research, because of its greater risk and cost.

Baseline Market Acceptance for Ethanol Biorefineries

Gasoline is a mix of both high- and lower-value petroleum-based components, with the high-value components comprising only a small fraction of the total volume. With current ethanol tax incentives and ethanol's value to refiners due to its environmental and octane characteristics, corn-based ethanol is competitive with the small fraction of high-value petroleum-based constituents of gasoline that give gasoline acceptable octane and emissions levels. Therefore, a small amount of ethanol (10% or less) can be blended with 90% or more gasoline to produce a fuel that is competitive with conventional gasoline. Blending ethanol with gasoline in higher concentrations becomes less competitive, because a gallon of ethanol has only two-thirds the energy of a gallon of gasoline, which historically has made it difficult for ethanol to compete with gasoline on an energy-equivalent basis. In 2005, however, the price of oil reached new highs, and the cost of producing corn ethanol compared favorably with the cost of producing gasoline on an energy equivalent basis. Production capacity constrains the amount of ethanol that can enter the market, and the current production capacity for ethanol is much less than that of gasoline.

Ethanol is already widely used in gasoline and accepted as a component of transportation fuel in the target market. As the technology for producing cellulosic ethanol matures in the longer term, the retail value of cellulosic ethanol will become competitive with gasoline on an energy basis. At that point, fuel markets will likely accept nearly pure ethanol such as E85,because of its environmental characteristics and indigenous supply basis. In Brazil, for example, both E22 and

E100 are readily available,and most new cars sold are flex-fueled vehicles that can use either fuel. Increases in market penetration for ethanol will also be affected by competition from other alternative transportation fuels and success in overcoming the lack of an established nationwide E85 transportation and distribution infrastructure. Eventually, increases in market penetration may be constrained by the availability of feedstock, rather than market demand.

Biomass Program Technology Outputs for Corn Ethanol Biorefinery

Table C-1 summarizes ethanol production cost targets for corn ethanol dry mill biorefineries.

Table C-1. EERE Ethanol Production Costs - Targets in 2003$ per Gallon for Dry Mills Before Adding Feedstock Costs

Year	Operating $/gal EtOH	Capital $/gal EtOH	Denatured Ethanol Yield gal/bu	DDG Yield Lb/bu	DDG Enrichment Factor	Electricity Usage kWh/gal	Natural Gas Usage MMBtu/gal	Bio-based Product Credit $/gal EtOH
2007	$ 0.220	$ 0.152	2.80	18.50	1.00	0.77	0.03	$ -
2008	$ 0.220	$ 0.151	2.80	18.50	1.00	0.77	0.03	$ -
2009	$ 0.219	$ 0.151	2.81	18.50	1.00	0.77	0.03	$ -
2010	$ 0.219	$ 0.151	2.81	18.50	1.00	0.76	0.03	$ (0.01)
2011	$ 0.219	$ 0.151	2.82	18.50	1.00	0.76	0.03	$ (0.01)
2012	$ 0.218	$ 0.149	2.89	17.41	1.06	0.76	0.03	$ (0.02)
2013	$ 0.218	$ 0.146	2.96	16.43	1.13	0.75	0.03	$ (0.03)
2014	$ 0.218	$ 0.144	3.03	15.56	1.19	0.75	0.03	$ (0.03)
2015	$ 0.217	$ 0.142	3.10	14.78	1.25	0.75	0.03	$ (0.04)
2016	$ 0.217	$ 0.140	3.17	14.07	1.31	0.74	0.03	$ (0.05)
2017	$ 0.217	$ 0.138	3.24	13.43	1.38	0.74	0.03	$ (0.05)
2018	$ 0.216	$ 0.136	3.31	12.85	1.44	0.73	0.03	$ (0.06)
2019	$ 0.216	$ 0.134	3.38	12.31	1.50	0.73	0.03	$ (0.06)
2020	$ 0.215	$ 0.134	3.39	12.31	1.50	0.73	0.03	$ (0.07)
2021	$ 0.215	$ 0.133	3.39	12.31	1.50	0.73	0.03	$ (0.08)
2022	$ 0.215	$ 0.133	3.40	12.31	1.50	0.73	0.03	$ (0.08)
2023	$ 0.214	$ 0.133	3.40	12.31	1.50	0.72	0.03	$ (0.09)
2024	$ 0.214	$ 0.133	3.41	12.31	1.50	0.72	0.03	$ (0.10)
2025	$ 0.214	$ 0.132	3.41	12.31	1.50	0.72	0.03	$ (0.10)
2030	$ 0.212	$ 0.131	3.44	12.31	1.50	0.72	0.03	$ (0.14)
2035	$ 0.210	$ 0.130	3.47	12.31	1.50	0.71	0.03	$ (0.17)
2040	$ 0.209	$ 0.129	3.50	12.31	1.50	0.71	0.03	$ (0.20)
2045	$ 0.207	$ 0.128	3.53	12.31	1.50	0.70	0.03	$ (0.20)
2050	$ 0.205	$ 0.127	3.55	12.31	1.50	0.69	0.03	$ (0.20)

Source: John Jechura , *Adv Dry Mill Curve 8-25-2005 - DA changes.xls* , National Renewable Energy Laboratory

Dry mills process corn into ethanol, distillers dried grain solubles (DDGS), and carbon dioxide (CO_2). DDGS is sold into the animal feed market. Some dry mill operators are able to sell their CO_2 production, but the CO_2 market is limited and therefore not considered in this analysis. As dry mill plants begin to deploy the technology to convert the fiber and residual starch to ethanol, the yield of the weight DDGS coproduct decreases, but the protein component (weight) in the

DDGS remains constant. DDGS is valued in the marke place primarily for its protein. The relative protein content of the DDGS is computed by multiplying the DDGS weight by the DDGS enrichment factor, both of which are shown in the table. Most of the DDGS is now used in the cattle feed market, but it is expected that the higher-protein (percent) DDGS will be suitable for the poultry and swine markets.

The operating costs in the table do not include the energy costs. The table lists the per-gallon energy requirements for natural gas and electricity separately. NEMS and MARKAL use their endogenously computed energy prices to calculate the energy costs to produce corn-based ethanol (unit price of energy times energy consumption per gallon of ethanol). The Biomass Program assumed a bio-based coproduct credit of 1 cent per gallon of ethanol beginning in 2010, increasing gradually to 20 cents per gallon by 2040 for a dry mill processing corn kernels. The coproduct credit represents a generic bio-based product coproduced with ethanol and was provided by the National Renewable Energy Laboratory (NREL). The program's draft Multi-Year Program Plan of August 31, 2005, was not yet available when this analysis was conducted. PBA analysts assumed that commercialization of technologies for the conversion of corn kernel fiber and recalcitrant starch would begin in 2012, based on preliminary planning information developed by NREL. The successful technology will cause the industry-wide ethanol yield (gallons of ethanol per bushel of corn) to increase by 23% between 2012 and 2050(2).

Rather than assuming "instantaneous" deployment by all dry mills, the corn fiber and recalcitrant starch technology was assumed to be deployed by 100% of the dry mills by 2050, with a ramp-up beginning in 2012. The conversion of the corn fiber and recalcitrant starch was modeled as an increase in the conversion efficiency in terms of gallons of ethanol per bushel of corn. The ramp-up includes technology improvements and an estimate of the overall rate of adoption by ethanol plant operators, as shown in Denatured Ethanol Yield Column in Table C-1.

References:

John Jechura (NREL) provided the cost and conversion targets in an EXCEL spreadsheet titled *Adv Dry Mill Curve 8-25-2005 - DA changes.xls*. NREL report: *Evaluating progressive technology scenarios in the development of the advanced dry mill biorefinery,* Kelly Ibsen (NREL), Robert Wallace (NREL), Sue Jones (PNNL), Todd Werpy (PNNL), 3/04/05

Biomass Program Technology Outputs for Cellulosic Ethanol Biorefinery

Table C-2 summarizes ethanol production cost targets for cellulosic ethanol biorefineries as originally submitted to OMB as part of the original budget submission for the Biomass Program in October 2005. These targets represent an assumption of level funding for the Biomass Program, reflecting the level of funding experienced in recent budget cycles.

Table C-2. Cellulosic Ethanol Production Costs and Conversion Efficiency Targets. Costs are in 2003$ per Gallon and do not Include Feedstock Costs

Year	Operating $/gal EtOH	Annualized Capital $/gal EtOH	Ethanol Yield gal/ton	Electricity Usage kWh/gal	Nat Gas Usage MMBtu/gal
2018	$ 0.45	$ 0.46	83.8	-3.70	0
2019	$ 0.39	$ 0.44	86.8	-3.69	0
2020	$ 0.34	$ 0.43	89.8	-2.08	0
2021	$ 0.32	$ 0.42	89.9	-2.07	0
2022	$ 0.31	$ 0.41	90.1	-2.06	0
2023	$ 0.30	$ 0.40	90.2	-2.06	0
2024	$ 0.29	$ 0.39	90.3	-2.05	0
2025	$ 0.28	$ 0.38	90.5	-2.04	0
2030	$ 0.23	$ 0.34	91.2	-2.01	0
2035	$ 0.19	$ 0.30	91.9	-1.97	0
2040	$ 0.15	$ 0.27	92.6	-1.94	0
2045	$ 0.13	$ 0.24	93.3	-1.91	0
2050	$ 0.10	$ 0.22	94.0	-2.03	0

Source: John Jechura , *Adv Dry Mill Curve 8-25-2005 - DA changes.xls* , National Renewable Energy Laboratory

Conversion of corn stover to ethanol is assumed to begin in 2018, based on preliminary planning information developed by NREL.(3). NREL supplied the non-feedstock capital and operating costs on a per gallon of ethanol. A real capital cost recovery factor of 15% is used to calculate the per-gallon capital costs. Cellulosic ethanol plants combust the lignin portion of the lignocellulosic feedstock to produce heat and electricity. The plants produce excess electricity that is sold into the grid. The negative numbers in the electricity use column represent the sale of the excess electricity. The electricity credit is computed by multiplying the price of electricity times the excess electricity production. Electricity prices are determined endogenously in NEMS and MARKAL.

Reference:

The methodology used for the cellullosic cost estimates was documented in NREL Report *Determining the Cost of Producing Ethanol from Corn Starch and cellulosic Feedstocks*, NREL/TP-580-28893, Andrew McAloon, Frank Taylor, Winnie Yee, Kelly Ibsen and Robert Wooley, October 2000. John Jechura of NREL provided the cost and conversion targets in an EXCEL spreadsheet titled *Adv Dry Mill Curve 8-25-2005 - DA changes.xls*. NREL report: *Estimated Ethanol Cost Curves from Advanced Dry Mills to 2050,* John Jechura, 6/2/05

Corn ethanol growth is based on our latest assessment of the industry that was done prior to the enactment of the Renewable Fuels Standard. For cellulosic ethanol based on corn fiber conversion, a near-term technology being developed by the program and industry partners, we assumed success for dry mills only. While the other type of ethanol plants, wet mills, may also succeed in deploying this technology, the benefits from wet mills are not considered in order to make the estimates more conservative. The volume of cellulosic ethanol from corn fiber includes the ethanol resulting from converting the fiber in the corn kernel and the residual starch that can be converted once liberated from the fiber. The total increment in ethanol output would equal 20% of the current dry mill's ethanol output. As previously stated, future biorefineries are assumed to use cellulosic biomass such as corn stover and energy crops, and not the corn kernel or its fiber as feedstock. The cellulosic ethanol estimates from corn stover, other cellulosic wastes, and energy crops resulted from market equilibrium analyses that compete ethanol with petroleum constituents in the low-blend fuel market (E10) and versus corn ethanol.

Technical Characteristics - The cellulosic biorefinery analysis is based on a plant whose main product is fuel ethanol with coproduction electricity. Excess electricity is sold to the grid and is modeled as a reduction in the cost of producing ethanol. The analysis is for a biorefinery with a total throughput of 2,000 dry metric tons of feedstock per day and with a conversion efficiency increasing from approximately 83 gallons of ethanol per dry U.S. ton of feedstock in 2018 to 94 in 2050, as a result of technological advances. Corn ethanol plants produce a more uniform sugar stream. Therefore EERE is targeting these plants for the production of new, high-valued, bio-based products that will compete favorably with petroleum product counterparts. The market for these products is limited compared to the fuels market, and the final choice of which products will be produced is still in the formative stages. Consequently, the economics of new bio-based products are represented as credits to the corn biorefineries, similar to the way credits for animal feed co-products are handled.

Technical Potential - The biomass feedstock resources discussed here do not include wood waste and black liquor waste from paper mills, an important but captive resource—these resources are typically used within the forest and paper products industry. Under favorable R&D outcome and market scenarios, the upper bound for ethanol supply from U.S. biomass is estimated at 35 billion gallons per year from cellulosic feedstock and 15 billion gallons per year from starch crops. The farm-gate price and supply relationship for biomass used in the market analysis are presented in **Table C-3**.

While forest residues and some of the "other wastes" may not be optimal for sugar-based ethanol production, we recognize that future syngas-based fuels production may use forest residues and certain "other wastes" as feedstock. Therefore, this analysis is not deemed to be overly optimistic, in spite of the assumption that biorefineries are sugar-based.

Table C-3. Farm-gate Biomass Quantities Supplied vs. Price Range Excluding Mill Residues and Black Liquor Near Term (million dry tons per year)

Feedstock	up to $21.20/dt	up to $31.80/dt	up to $42.40/dt	up to $53.00/dt
Forest Residues	0	12	20	70
Agricultural Crops Residues	0	1	65	80
Potential Energy Crops	0	0	80	187
Other Wastes	0	17	25	35
Total	0	30	190	372

Transportation costs ranging from $7.50 to $15.0 per dry ton (depending on hauling distance) were added to farm-gate prices to account for hauling to the biorefinery, assuming no difference between the case without EERE and the case with EERE (this assumption will be improved in future analyses). After adding these costs and applying the factors shown in Table 5, the near-term supply as a function of price per dry ton at the biorefinery gate is shown in Table 6. Because the models do not represent all competing uses of biomass, e.g., for biopower or fiber uses which are competitors to OBP's biorefineries. The fraction of the total feedstock assumed to be available to biorefineries is used as a proxy for reserving some of feedstock for competing uses. The fractions in **Table C-4** are assumed values.

Table C-4. Fraction of Total Feedstock Assumed To Be Available To Biorefineries

Feedstock	Fraction
Forest Residues	0.70
Agricultural Crops Residues	0.70
Potential Energy Crops	0.66
Other Wastes	0.60

Table C-5. Biorefinery-gate Quantities Supplied vs. Price Range Excluding Mill Residues and Black Liquor Near Term (million dry tons per year)

Feedstock	Up to $29.15/dry ton	Up to $42.40/dry ton	Up to $55.65/dry ton	Up to $68.90/dry ton
Agricultural Crops Residues	0	0.7	45	56
Potential Energy Crops	0	0	53	123
Forest and Other Wastes	0	15	23	49
Total	0	16	121	228

The annual quantity available for ethanol production, at up to $68.90 per dry ton (including costs of transportation to the biorefinery), has been reduced from 372 million to 228 million dry tons after applying the reduction factors from **Table C-5.** In the longer term (2040, for example), crop yields increasing at the rate of 1% per year will result in additional feedstock as shown in **Table C-6,** assuming no difference between the case without EERE and the case with EERE (this assumption will be improved in future analyses).

Table C-6. Long-term Biorefinery-Gate Supply vs. Prices Excluding Mill Residues and Black Liquor, Year 2040 (Million dry tons per year and 2000$. Costs include transportation costs from farm to biorefinery)

Feedstock	Up to $29/dry ton	Up to $42/dry ton	Up to $56/dry ton	Up to $69/dry ton
Agricultural Crops Residues	0	1	68	83
Potential Energy Crops	0	0	78	184
Forest and Other Wastes	0	19	29	70
Total	0	20	175	337

At approximately 93 gallons of ethanol per dry ton of feedstock, the potential supply in the long term is 31 billion gallons in 2040. This potential would increase significantly with appropriate incentives such as those aimed at increasing feedstock availability.

Expected Market Uptake - This analysis was done prior to the enactment of the Energy Policy Act of 2005 and was limited to policies existing at that time. We will include the biofuel specific policies in Energy Policy Act of 2005 in the GPRA08 analysis. The GPRA07 analysis did not include the RFS enacted in the Energy Policy Act. Corn ethanol is projected to continue to expand in GPRA07 as a result of various states' phase-outs of MTBE, but only to approximately 4 billion gallons/year by 2012 compared with an RFS requirement of 7.5 billion gallons/year in 2012. Although GPRA07 did not include the RFS, the impact on benefits estimates is mitigated by the fact that in the longer term, where most of the program benefits accrue, ethanol consumption easily exceeds the RFS requirement. Future cellulosic ethanol capacity will slowly replace corn ethanol capacity as the new technology becomes more competitive relative to corn ethanol. The tables show corn ethanol continuing at a fairly constant level through 2050.

The Biomass Program estimates that, beginning in 2012, corn ethanol plants will deploy the technologies for processing corn fiber, a cellulosic feedstock, into ethanol. This would be in addition to their continuing production of ethanol from corn starch. Beginning in 2018, a number of the ethanol plants will also convert corn stover to ethanol if R&D is successful.

NEMS and MARKAL were used to estimate ethanol market penetration for cellulosic ethanol from corn stover, energy crops, and other cellulosic residues; but excluding corn fiber and residual starch. The market penetration of corn fiber and residual starch-based ethanol, small quantities in comparison with the other cellulosic ethanol, were modeled as increases in the ethanol yield per bushel of corn in corn ethanol plants. The following section describes ELSASBioref and its use for this analysis.

Methodological Approach - Biomass ethanol market penetration analysis was accomplished through the integration of the results of various analyses conducted primarily by national laboratory personnel and their subcontractors. NEMS and MARKAL served as the integrating tools.

Cellulosic Feedstock Supply - Oak Ridge National Laboratory (ORNL) developed cellulosic feedstock supply curves with the aid of BIOCOST,[4] POLYSYS,[5] and other regionally detailed models. The feedstock supply-curve information shows quantities of different categories of cellulosic feedstocks available at different prices and time periods. The current GPRA case uses ORNL data reported by Arthur D. Little Inc.[6] These data were modified, based on more recent ORNL work on agricultural residue availability and cost[7].

Cellulosic feedstock costs are adjusted to include transportation charges from the farm gate to the conversion facility, and feedstock supplies are allocated among different competing uses as described above in the Technical Potential section. In addition, the analysis assumes that agricultural residues and bio-energy crops will increase at an annual rate of 1% during the analysis period, due to increasing agricultural productivity. This assumption yields a total U.S. feedstock supply in 2040 approaching 337 million dry tons of agricultural residues, forest wastes, energy crops and other biomass wastes, after excluding potential competing uses.

Ethanol Conversion Costs - NREL, which is partnering with industry and universities to develop competitive ethanol production technologies, provided estimates of cellulosic ethanol production costs (other than feedstock-related costs) on a per-gallon basis. The NREL estimate of the efficiency of converting feedstock into ethanol is input as a function of date, namely the number of gallons per dry ton of feedstock increases in the future as a result of R&D success. This allows the ORNL-provided feedstock costs to be presented on a per-gallon basis and added to the NREL non-feedstock costs to obtain the cost of producing a gallon of cellulosic ethanol. Corn mills may also produce other high value bio-based products from the sugar streams in addition ethanol and animal feeds. Because of the large number of potential products, each with relatively small markets, that have been identified, a detailed analysis of the markets for potential bio-based products was not feasible. Instead, NREL estimated a generic credit for bio-based product to corn ethanol mills. The GPRA analysis did include the extra demand for corn used to produce bio-based products in calculating the market price for corn.

Benefits Estimation - In both NEMS-GPRA07 and MARKAL-GPRA07, reductions in fossil energy use and carbon emissions attributable to EERE R&D (Program case) were calculated by computing the fossil energy use and carbon emissions in the Program and Bases cases, and taking their differences. Fossil energy use includes the fossil energy embedded in the final product, e.g., in gasoline, as well as the upstream fossil energy consumption, e.g., the fossil energy used to extract and transport oil, refine the oil into gasoline, and to transport the gasoline to retail service stations. Fossil energy requirements to produce both corn and cellulosic ethanol are input into NEMS-GPRA07 and MARKAL-GPRA07. Both models calculate carbon emissions by multiplying fossil fuel consumption by carbon emission factors, which depend on the fossil fuel type. Both models calculate energy costs endogenously in the process of solving for market equilibrium conditions.

For GPRA07, the analysis only considers reductions in fossil fuel use and carbon emissions from the production and consumption of ethanol. It does not include that benefits that accrue from bio-based products that displace petrochemical products, because the analysis assumes a generic bio-based product. As the amount of bio-based products that are produced is small compared with the amount of ethanol produced, the GPRA benefits estimates are not materially understated.

Update to the GPRA07 Inputs Based on President's Initiative

In his State of the Union Address, the president described new initiatives for developing alternative fuels that will break the nation's "addiction to oil." Among these was increased funding for the development of ethanol from cellulosic biomass as a substitute for gasoline. This led to a major rethinking of the goals of the Biomass Program.

Corn ethanol technology

The original inputs for Biomass involved improvements to corn ethanol production technology as well as inputs for introduction of cellulosic ethanol technology. In this revised set of inputs, we have made no changes to the assumptions about the impacts of the program on the existing corn ethanol technology.

Cellulosic ethanol technology

The president's new initiative for biomass accelerates cellulosic ethanol technology development—achieving a nominal ethanol selling price of $1.07 per gallon of ethanol in 2012. See **Figure C-1** for a comparison of the revised nominal cost trajectory for cellulosic ethanol.

The nominal selling price is a proxy for cost performance that reflects:

- A minimum rate of return of 10% on capital investment
- A nominal feedstock cost of $40 per dry U.S. ton
- A plant gate price (no costs for fuel distribution, marketing and taxes)

We interpret the goal of $1.07 in 2012 to reflect projected nominal cost of ethanol for technology that has been proven at the pilot scale. Therefore, we assume that fully commercially available technology at this nominal cost is available by 2015, allowing three years for commercial demonstration and design, construction, and start-up of a full commercial-scale facility.
In NEMS and MARKAL, we do not use the nominal cost, but rather, break this cost down into annualized cost of capital, operating expenses excluding feedstock cost, and a credit for excess electricity sold to the grid (**Table C-7**).

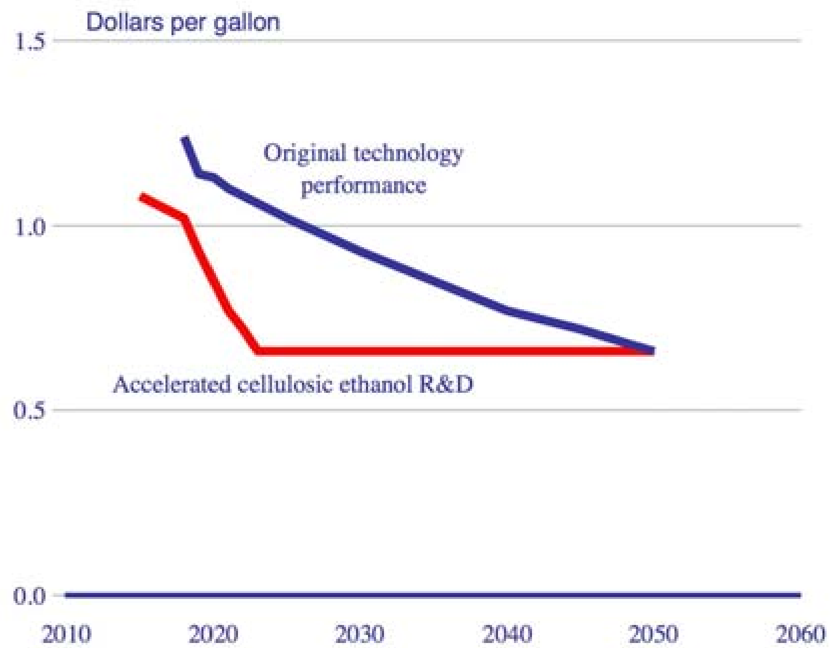

Figure C-1. Revised cost trajectory for nominal ethanol cost ($2003 per gallon of ethanol)

Table C-7. Revised Inputs to NEMS and MARKAL for Cellulosic Ethanol

Year	Annualized Cost of Capital ($2003/gal)		Non-biomass Operating Costs ($2003/gal)		Electricity Use (kWh per gal)		Ethanol Yield (Gal/ton)	
	Orig	Rev	Orig	Rev	Orig	Rev	Orig	Rev
2015		$0.41		$0.31		-2.06		90.10
2016		$0.40		$0.30		-2.06		90.20
2017		$0.39		$0.29		-2.05		90.30
2018	$0.46	$0.38	$0.45	$0.28	-3.7	-2.04	83.8	90.50
2019	$0.44	$0.34	$0.39	$0.23	-3.69	-2.01	86.8	91.20
2020	$0.43	$0.30	$0.34	$0.19	-2.08	-1.97	89.8	91.90
2021	$0.42	$0.27	$0.32	$0.15	-2.07	-1.94	89.9	92.60
2022	$0.41	$0.24	$0.31	$0.13	-2.06	-1.91	90.1	93.30
2023	$0.40	$0.22	$0.30	$0.10	-2.06	-2.03	90.2	94.00
2024	$0.39	$0.22	$0.29	$0.10	-2.05	-2.03	90.3	94.00
2025	$0.38	$0.22	$0.28	$0.10	-2.04	-2.03	90.5	94.00
2030	$0.34	$0.22	$0.23	$0.10	-2.01	-2.03	91.2	94.00
2035	$0.30	$0.22	$0.19	$0.10	-1.97	-2.03	91.9	94.00
2040	$0.27	$0.22	$0.15	$0.10	-1.94	-2.03	92.6	94.00
2045	$0.24	$0.22	$0.13	$0.10	-1.91	-2.03	93.3	94.00
2050	$0.22	$0.22	$0.10	$0.10	-2.03	-2.03	94	94.00

We have taken the numbers from Jechura's original analysis that correspond to $1.07 per gallon in 2022 and shifted those to start in 2015. In addition, we have taken remaining improvements that Jechura shows occurring through 2050 and accelerated them so that they reach their endpoint by 2020 instead of 2050. This corresponds to an aggressive R&D effort aimed at bringing the technology to its mature state more rapidly. After 2020, no further improvements in cost are assumed.

Biomass Supply Curves

Biomass supply curves have not been changed from the original inputs provided by the Biomass Program. Updated supply curves—currently used in the Biomass Transition Model—are available, but were not used in updating the GPRA models. This may have the effect of constraining biomass availability below the level available in the Biomass Transition Model. In the upcoming cycle for GPRA 08, we should consider updating the NEMS-GPRA08 and MARKAL-GPRA08 models to make them consistent with the Biomass Transition Model. In the case of NEMS, we will need to regionalize the supply curves.

Energy Markets

In the past, projections have changed little from year to year. Not so this year. The AEO 2006 projections were officially published in February 2006. They show what is nothing short of a "sea change" in EIA's perspective on energy prices. On average, for example, the new oil price projections are more than double the prices projected in AEO 2005.

The GPRA 07 benefits estimates are based on energy projections reported by the Energy Information Administration in their *Annual Energy Outlook 2005* (AEO 2005) report. The timing and level of effort involved in putting together the GPRA benefits forces us to use projections for energy markets that are roughly one year behind what is available by the time we publish our benefits estimates. While we realize that updating to AEO 2006 energy prices would make a big difference in projected market penetration of biomass technology and other energy efficiency and renewable energy technologies, we simply do not have time to completely redo the benefits estimates for the entire EERE technology portfolio. To remain consistent with the rest of the portfolio, the new inputs for the Biomass Program also use last year's lower energy prices.

Adjusting Industry Growth Constraints

In the NEMS-GPRA07 and MARKAL-GPRA07 models, we have increased the constraints on industry growth to make them consistent with assumptions in the Biomass Transition Model. Thus, bioethanol capacity now has a maximum growth rate of 25% per year, up to a limit of around 5 billion gallons per year of new capacity. These higher growth rates are based on historical data for growth of the existing corn ethanol industry and growth of U.S. gasoline refining capacity.

Sources

[1] Petroleum Marketing Annual 2004, U.S. Energy Information Administration, Table 48.
[2] Davis, S.C., and S.W. Diegel, "Transportation Energy Data Book." Oak Ridge National Laboratory, Edition 24, December 2004.
[3] *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000*, National Research Council, http://www.nap.edu/catalog/10165.html

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[5] Daryll E. Ray, Daniel G. De La Torre Ugarte, Michael R. Dicks, and Kelly H. Tiller, "The Polysis Modeling Framework: A Documentation." Agricultural Policy Analysis Center, University of Tennessee, May 1998, http://apacweb.ag.utk.edu/polysys.html
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[7] Graham, R.L, "Key Findings of the Corn Stover Supply Analysis," Oak Ridge National Laboratory, unpublished paper, October 15, 2003.