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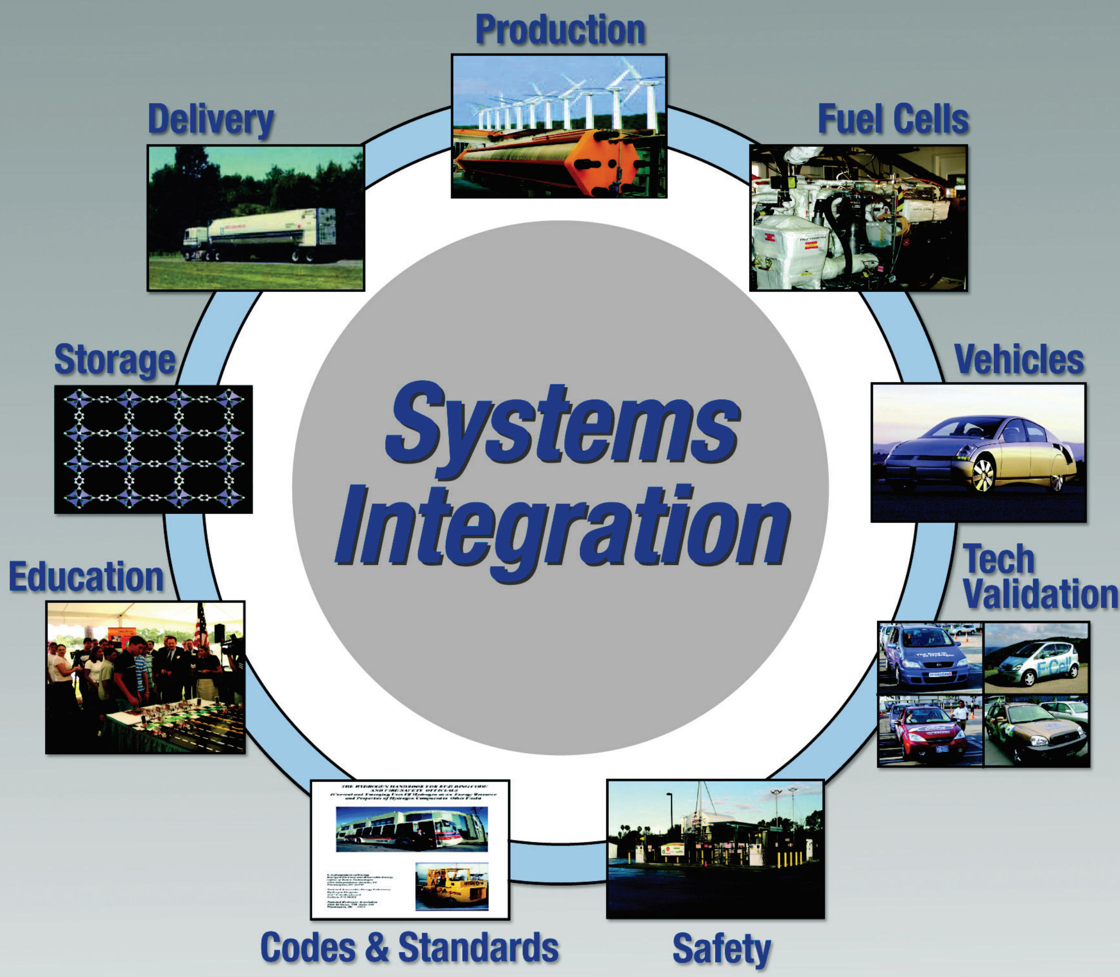
Hydrogen Production Cost Estimate Using Biomass Gasification



Independent Review

Published for the U.S. Department of Energy Hydrogen and Fuel Cells Program

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Independent Review Panel Summary Report

September 28, 2011

From: Independent Review Panel, Hydrogen Production Cost Estimate Using Biomass Gasification

To: Mr. Mark Ruth, NREL, DOE Hydrogen Systems Integration Office

Subject: Independent Review Panel Summary Report

Per the tasks and criteria of the Independent Review Charter November 9, 2010, this is the Independent Review Panel's unanimous technical conclusion, arrived at from data collection, document reviews, interviews, and deliberations from December 2010 through April 2011. All reported hydrogen levelized costs include a 100% equity financing with a real 10% internal rate of return on investments and are expressed in 2009 reference year dollars. Costs for a pioneer plant [a 1st plant with a capacity of 500 dry ton per day (dtpd) biomass] and Nth plant (with a capacity of 2000 dtpd) were evaluated.

Conclusions

The panel estimated the hydrogen levelized cost from a 1st plant producing 32,400 kg H_2/day to be $5.40/kg hydrogen (2009$). Single variable cases evaluated for capital expenditure (CapEx), feedstock price, and hydrogen yield showed the CapEx to be the most critical variable ($214 million for a 500 dtpd plant). Low CapEx cases resulted in levelized hydrogen costs of $4.80/kg; high CapEx cases were $6.10/kg.

Nth plant levelized costs for hydrogen production at 135,000 kg H_2/day were estimated to be $2.80/kg. Single variable studies for Nth plants showed feedstock and CapEx ($344 million for a 2000 dtpd plant) to be the most important variables. CapEx sensitivities resulted in levelized costs of $2.40–$3.40/kg (the methodology used did not separate out capital costs of sub-systems); varying feedstock costs gave a low sensitivity of $2.30/kg [$40/dry ton (dt)] and a high sensitivity $3.40/kg ($120/dt). Technology advances were not analyzed independently, but were assumed to be covered in the learning curve analysis applied to arrive at Nth plant costs.

The panel found the cost analysis methodology for hydrogen production costs to be generally sound. However, the panel felt that the H2A assumption of 100% equity financing with 10% annual return was unlikely and developed a more probable "base case" with 75% debt financing at a 10% interest rate, 25% equity financing at a 25% return on equity, and an accelerated 7-year depreciation schedule. The financing structure gives an effective return of 16% over a 20-year debt period and increases the 1st plant levelized hydrogen cost to $7.70/kg at $60/dry ton and $214 million for a 500 dry ton per day plant, and Nth plant levelized cost to $3.80/kg at $80/dry ton and $344 million for a 2000 dry ton per day plant).

Technology improvements may reduce the cost of producing hydrogen from biomass, but probably not enough to meet the 2017 goal of $1.10/kg.

Rationale

Publicly available information about hydrogen production comes from bench- and pilot-scale studies, so the panel looked to recent literature studies and current near-commercialization integrated biomass refinery projects for CapEx. Although some focused on liquid fuels, the panel was able to remove costs associated with liquid fuel production and add back estimated costs for hydrogen production.

To determine near-term feedstock costs, the panel gathered data from current biomass suppliers and ongoing integrated biomass refinery projects. For agricultural residues and wood, prices were consistently \$60–\$70/dt, so the panel extended these by \$10/dt to achieve an expected range of \$50–\$80/dt. Renewable Fuel Standard 2 is likely to drive biomass prices upward; advances in biotechnology may drive production costs down. The panel therefore used a broad range (\$40–\$120/dt with a base of \$80/dt) to capture this uncertainty for long-term hydrogen production. The DOE Biomass Program projects biomass costs ranging from \$62-\$75/dt so they are within the range chosen by the panel.[1]

The panel had no elaborate process models to carry out heat and mass balances, and so could not address issues such as the impact of electricity cogeneration and gasifier efficiency. The panel used a single variable sensitivity (with base values close to the current H2A model and other studies examined) based on overall hydrogen yield to examine efficiency effects.

This analysis ignores many variables and makes many assumptions. Many uncertainties are associated with costs for this process that is not yet in the pilot stage of development, and the panel had limited time and resources. The panel believes that its conclusions and concentration on the four areas that most affect the levelized cost of hydrogen are reasonable and constitute the best possible assessment of the technology.

George D. Parks (chair)

Maria Curry-Nkansah

Evan Hughes

George Sterzinger

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Mid-South Engineering
National Renewable Energy Laboratory
NewPage
POET
The Price Companies
TRI
UOP

Executive Summary

The Independent Review Panel reviewed the current H2A case (Version 2.12, Case 01D) for hydrogen production via biomass gasification and identified four principal components of hydrogen levelized cost:

- CapEx
- Feedstock costs
- Project financing structure
- Efficiency /hydrogen yield.

Projected Hydrogen Cost

1st plant (500 tpd)—**$5.40/kg**

Nth plant (2000 tpd)—**$2.80/kg**

The panel reexamined the assumptions around these components and arrived at new estimates and approaches that better reflect the current technology and business environments.

Capital Costs

The H2A estimate for CapEx for a 2000 dtpd biomass to hydrogen (BTH) plant is $155 million. This is an average of several engineering studies that used dated cost and performance data; thus, it needed to be updated.

The panel looked to two sources for new CapEx estimates:

- Recent publications for biomass gasification to hydrogen and other products
- Projected CapEx estimates for biomass gasification projects producing liquid fuels.

For projects producing liquid fuels, the panel removed those production costs (generally Fischer Tropsch synthesis) and replaced them with hydrogen production costs—water gas shift (WGS) reactor and pressure swing adsorption unit (PSA). The panel assembled cost data from three proposed commercial projects and seven case studies drawn from two publications. Purchased equipment costs were scaled to appropriate size (500 or 2000 dtpd) using a 0.6 scaling exponent. Total CapEx was then determined using a Lang factor of 4.0. The resulting costs were then averaged to arrive at CapEx (see Table ES-1). The standard deviation was 15%. The panel used learning curves for steam methane reforming (SMR) costs to adjust costs for the 1st and the Nth plants.

Table ES-1. CapEx

	CapEx ($ million)		
Scenario	**Base**	**Low**	**High**
1st plant, 500 dtpd	$214	$177	$267
Nth plant, 2000 dtpd	$344	$220	$514

Feedstock

The H2A case prices woody biomass at $38/dt. The panel had discussions with experts in agriculture and forestry and developers of early-stage advanced biofuels projects, studied numerous publications, and concluded that biomass prices for early-stage projects will be approximately $60/dt. The likely drivers for future biomass prices are:

- Advances in biotechnology that will produce high-yield, low-cost energy crops

- Competition for biomass resources, which will drive prices higher (the Renewable Fuels Standard 2 mandate of 21 billion gallons (79 million liters) of advanced liquid biofuels and cofiring for electricity generation under renewable portfolio standards).

The panel thus proposes a wide range for the long-term N^{th} plant but a narrow range for the near-term 1^{st} plant (see Table ES-2).

Table ES-2. Biomass Prices

	Biomass Cost ($/dt)		
Scenario	**Base**	**Low**	**High**
1^{st} plant	$60	$50	$80
N^{th} plant	$80	$40	$120

Financing

The panel identified several issues in the H2A case that drive the final calculation of levelized hydrogen costs and suggests modifications to standard H2A financing assumptions (see Table ES-3):

Table ES-3. Financing Modifications to Standard H2A Assumptions

	H2A	Panel Suggestion
Operational life	40 years	20 years
Depreciation schedule	20 years	7 years
Equity funding	100%	25%
Return on equity	10%	30%
Initial fixed O&M costs	Capitalized	Expensed

(For the H2A 100% case there is no construction loan in the calculations. For the panel base there is a single loan for all the debt over the total time period. The H2A $/gge results were lower than the panel base. The expected result was for the panel base to be lower than the 100% equity case. This anomalous result is a shortcoming in the way H2A performs the internal calculations.)

The panel used the H2A default values (100% equity, 10% after tax return, and 20-year depreciation) as a base case, but also added cases to assess the effects offinancing options that more accurately reflect the panel's view of the current investment climate. The panel calculated levelized hydrogen costs for the following options (Table ES-4).

Table ES-4. Financing Sensitivity Cases

	H2A DOE Reference	Panel Base	Panel Low	Panel High
Equity financing	100%	25%	20%	40%
After tax equity return	10%	25%	30% (1^{st}) 20% (N^{th})	40% (1^{st}) 35% (N^{th})
Debt financing	0%	75%	80%	60%
Interest rate for debt	N/A	10%	5%(1^{st}) 8% (N^{th})	12%
Depreciation	20 years	7 years	7 years	7 years

Efficiency/Hydrogen Yield

Ideally, the panel would have conducted a rigorous process model-based analysis to optimize hydrogen yield and factors such as cost and cogeneration of electricity. Limited resources prevented this, so the panel examined hydrogen yield as an independent variable without considering the increases in CapEx and operating costs (OpEx) that would likely occur (see Table ES-5).

Table ES-5. Hydrogen Yields

	Hydrogen Yield (kg/dt biomass)		
	Base	**Low Cost**	**High Cost**
1st plant, 500 dtpd	72	76	68
Nth plant, 2000 dtpd	75	80	70

Operating Expenses

OpEx is not a highly significant variable, but the panel varied the H2A estimate by +30% and –20%.

The tornado plots in Figure ES-1 and Figure ES-2 show hydrogen production costs for cases using the low and high values described above.

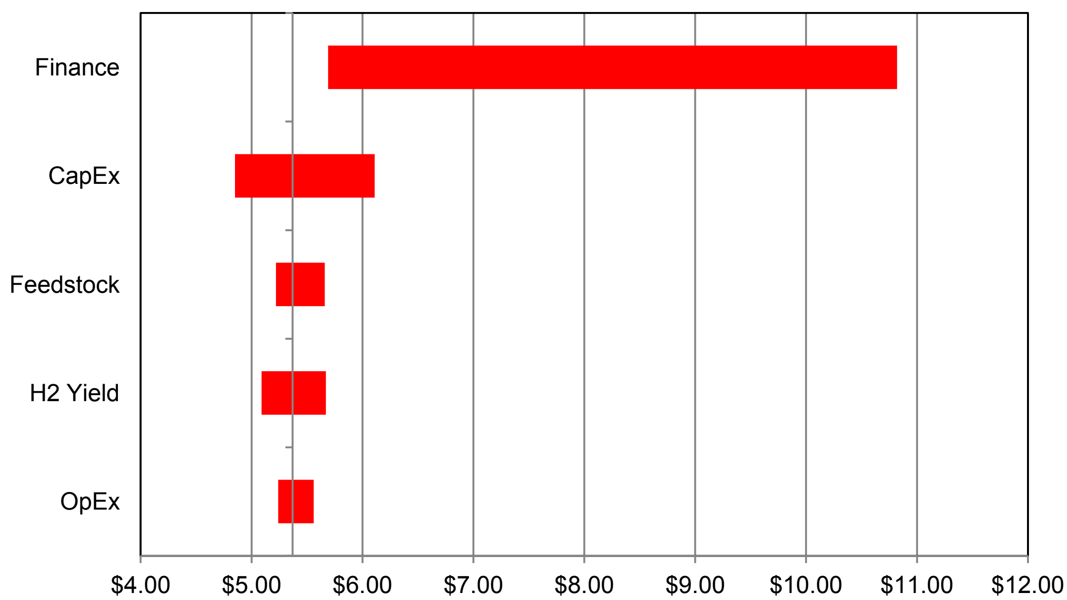

Figure ES-1. 1st plant levelized hydrogen costs

($/kg, base = $5.40/kg)

(The financing cases in the tornado chart does not cross the DOE reference case because the panel's cases do not include the DOE reference case parameters. For a more complete explanation of reasons for the divergence see the section on finance.)

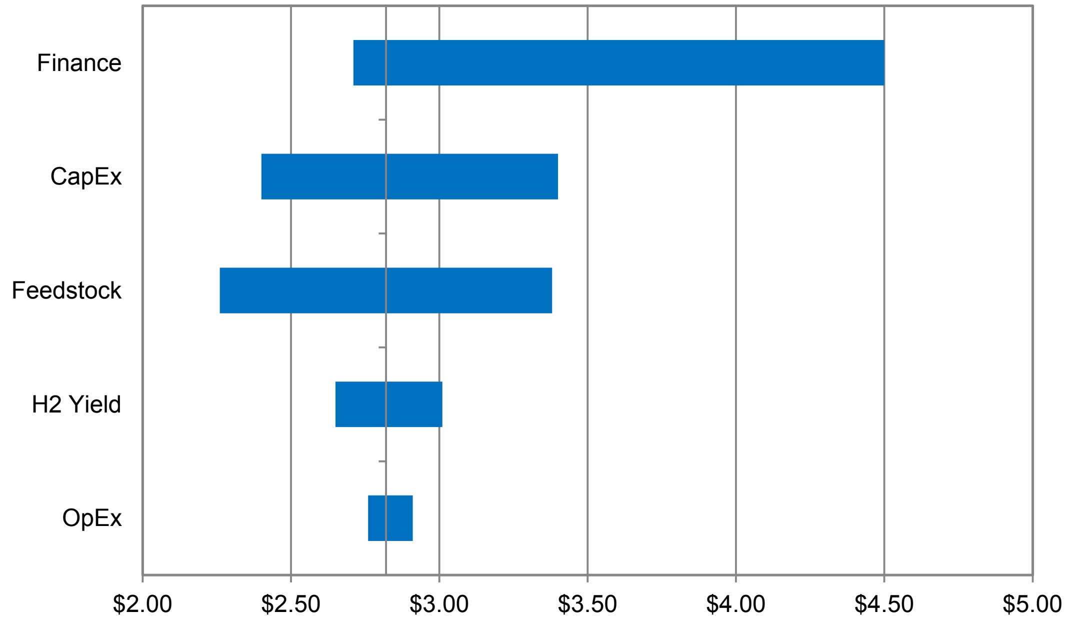

Figure ES-2. Nth plant levelized hydrogen costs

($/kg, base = $2.80/kg)

Results

The panel used these assumptions to calculate levelized hydrogen production costs of $5.40/kg for a 1st plant (500 dtpd) and $2.80/kg from an Nth plant (2000 dtpd). For comparison, the H2A version 2.1.2 DOE reference case projects a Nth plant levelized hydrogen production cost of $1.61/kg (in 2005$), which converts to $1.67/kg (in 2009$) (the year dollars used throughout this report). Figure ES-3 shows a breakdown of total 1st plant costs; Figure ES-4 shows a breakdown of total Nth plant costs from this study. Table ES-6 summarizes the breakdown for the DOE reference case and the panel's two cases.

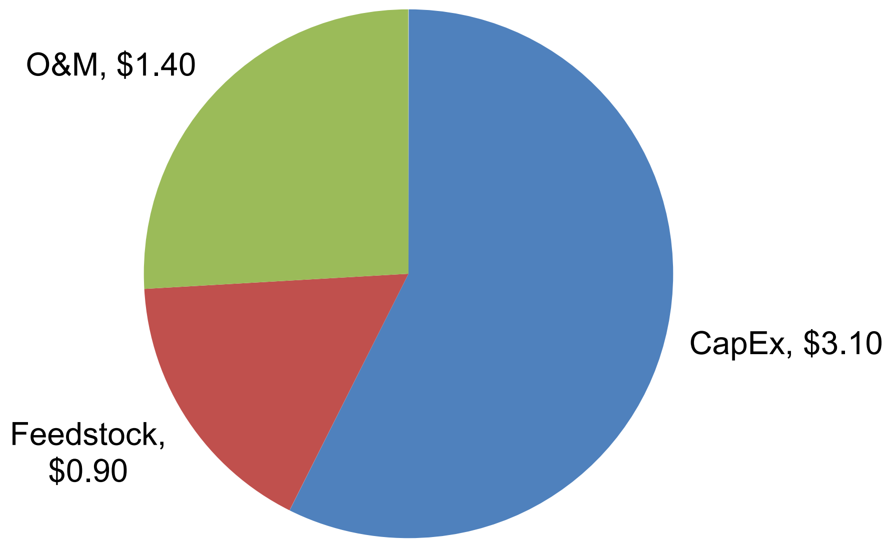

Figure ES-3. 1st plant levelized costs
($5.40/kg total)

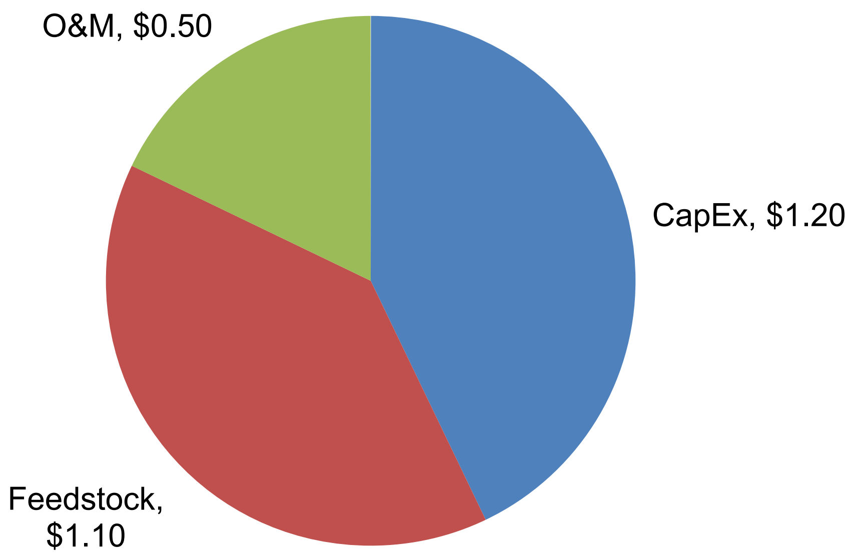

Figure ES-4. Nth plant levelized costs
($2.80/kg total)

Table ES-6. Levelized Hydrogen Cost Breakdown ($/kg H_2)

Case	CapEx	Feedstock	O&M	Total
DOE Reference Case	$0.59 33%	$0.55 34%	$0.53 33%	$1.67*
Panel 1st Plant	$3.10 57%	$0.90 17%	$1.40 26%	$5.50
Panel Nth Plant	$1.20 43%	$1.10 39%	$0.50 18%	$2.80

* Cost adjusted from 2005$ levelized cost of $1.61.

Other variables could be investigated and selected for additional runs of the H2A model, and other assumptions could have been made. This process is not yet at the pilot stage of development; as a result, many uncertainties are still associated with the costs. However, the panel believes that its conclusions and concentration on the four areas that most affect the levelized cost of hydrogen are reasonable and constitute the best possible assessment of the technology.

Acronyms and Abbreviations

ASU	air separation unit
BCAP	Biomass Crop Assistance Program
BTH	biomass to hydrogen
Btu	British thermal unit
CapEx	capital expenditure
DOE	U.S. Department of Energy
dt	dry short ton
dtpd	dry short ton per day
FT	Fischer-Tropsch
gge	gasoline gallon equivalent (approximately 1 kg—these terms are used interchangeably in this report)
gpy	gallons per year
HHV	higher heating value
HTWGS	high temperature water gas shift
IRR	internal rate of return
ISU	Iowa State University
kg	kilogram
LHV	lower heating value
LTWGS	low temperature water gas shift
MACRS	Modified Accelerated Cost Recovery System
MJ	megajoule
MMBtu	million British thermal units
MW	megawatt
NREL	National Renewable Energy Laboratory
OpEx	operating expenditures
O&M	operation and maintenance
PSA	pressure swing adsorption
R&D	research and development
RFS2	Renewable Fuel Standard 2
scf	standard cubic feet
tpy	tons per year
SMR	steam methane reformer, steam methane reforming
WGS	water gas shift

Contents

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Tables

Can Biomass Gasification Compete with Central Natural Gas?

The panel would like to briefly address the issue of whether production of hydrogen from biomass can compete with producing hydrogen via steam methane reforming (SMR). Table 1 shows a cost breakdown for SMR costs from a 2009 SRI report.[2] The plant described here produces 100 million scf (234,000 kg) of hydrogen per day. The price of natural gas is $5/MMBtu. Levelized hydrogen cost is $1.25/kg.

Table 1. SMR Levelized Cost Breakdown

Resource	Cost Contribution ($/kg Hydrogen)
Natural gas	$0.89
Catalysts	$0.01
Net utilities	$0.06
Labor and supplies	$0.08
Other costs	$0.33
Net costs	$1.25

SMR is a mature technology. It uses natural gas, which has a well-defined, nonvarying composition and is delivered via pipeline.

CapEx for the natural gas SMR plant described is around $168 million. CapEx for a biomass facility will always be much higher because of pretreatment costs, solids handling, syngas cleanup, etc. For instance, CapEx for pretreatment in a biomass plant is $50–$70 million. Operating costs (OpEx) will also be higher because of materials handling costs. Thus, nonfeedstock costs will always be higher for biomass plants. (See Appendix A for details.)

In the 2009 Multi-year Program Plan,[3] the U.S. Department of Energy (DOE) targets a 2017 biomass cost of $0.15/kg hydrogen. At an optimistic hydrogen yield of 80 kg/dt biomass, this equates to a biomass cost of $12/dt. DOE presumably expects innovations in plant biology and harvesting to drive production costs down. This may happen, but the crucial parameter is biomass price—not cost—because demand for renewable liquid fuels (which is dictated by law) will drive biomass prices up. Additional price pressure may come from cofiring biomass with coal to reduce the carbon dioxide (CO_2) footprint of electricity plants. North American biomass prices are already $60–$70/dt. Spot prices for wood chips in Europe are approaching $100/dt.[4] At current prices of $60/dt, cost contribution from feedstock is already $0.75/kg hydrogen. KiOR quotes $72.30/dt in its Security and Exchange Commission filing, which means the feedstock contribution is $0.90/kg—equivalent to natural gas. The panel's project price of $80/dt yields a feedstock contribution of $1/kg.

In summary, all the costs inputs for biomass to hydrogen (BTH) are at least as high as those for hydrogen from natural gas, which currently produces hydrogen at a levelized cost of ~$1.25/kg. The only way for hydrogen from biomass to be equivalent to the levelized cost of hydrogen from natural gas would be for biomass to drop in price to a point where it is low enough to overcome the increased capital and operating costs of biomass plants.

Background

The mission of the DOE Hydrogen Program is to research, develop, and validate fuel cell and hydrogen production, delivery, and storage technologies. Hydrogen from diverse domestic resources can then be used cleanly, safely, reliably, and affordably in fuel cell vehicles and stationary power applications. The Hydrogen Program measures progress against the research and development (R&D) technical targets it established in conjunction with industry partners. It also commissions independent verifications of progress made toward meeting key technical targets. These provide an unbiased view of the program's progress that is based on the input of independent technical experts. As such, they improve confidence in the results and conclusions that DOE and other stakeholders referenced in technical and program publications, announcements, Congressional testimony, and other arenas. Understanding this unbiased information is critical to program decision making; budget planning; and prioritization of research, development, and demonstration activities. The verifications help to ensure the quality, objectivity, utility, and integrity of information disseminated to the public.

The DOE Hydrogen, Fuel Cells and Infrastructure Technologies Program Manager tasked the National Renewable Energy Laboratory (NREL) Systems Engineering & Program Integration Office (Systems Integrator) to commission an independent review to estimate the 2009 state-of-the-art levelized hydrogen production cost using biomass gasification to provide guidance on the direction of future R&D funding. The NREL Systems Integrator is responsible for conducting independent reviews of progress toward meeting that program's technical targets.

The panel used the current H2A model version 2.1.2 (available at www.hydrogen.energy.gov/h2a_analysis.html) to examine the production at pioneer (500 dtpd 1st plant) and mature (2000 dtpd Nth plant) stages of gasification technology (see Appendix A). DOE is updating the H2A model.

This report provides the results of the Independent Review Panel's examination of the potential of centralized facilities to meet BTH cost targets. It also provides perspective on the cost of hydrogen with current production technology. The key cost drivers for BTH production will be CapEx and feedstock costs. Financing structure will also be crucial.

Introduction

There is no silver bullet to solve the problems of greenhouse gas emissions and the nation's dependence on foreign oil. Advanced technologies and alternative fuels are integral parts of a multifaceted solution. In his March 31, 2011, Georgetown University speech, President Obama announced a 30% reduction goal by 2021 in the 11 million barrels per day of U.S. foreign oil imports. Hydrogen fuel cell vehicles can help the nation achieve this goal, and renewable hydrogen production is an important technology for reducing greenhouse gas emissions. DOE is thus collaborating with industry and academia to develop and commercialize renewable hydrogen. This report reviews and assesses the technical and economic feasibility of gasifying biomass to produce hydrogen.

Renewable hydrogen will likely be produced from nonfood biomass resources such as municipal solid waste; energy crops; short rotation woody crops; forestry, mill, and wood wastes; and agricultural residues such as corn stover. Gasification uses heat to convert biomass into a low to medium calorific syngas intermediate, which is then cleaned and processed into hydrogen.

Gasification Technology

The three main types of biomass gasification processes are:

- Fixed bed (downdraft and updraft)
- Fluidized bed (bubbling fluidized bed, circulating fluidized bed)
- Entrained flow gasifiers.

Each type can use one or a combination of gasification agents, including steam, air, and oxygen, to promote conversion. Gasification is an endothermic process and requires a heat source to promote reaction. If thermal energy is supplied to the gasifier via the combustion of the gasification mixture, this is *direct gasification*. If the gasification heat comes from heat transfer from an external source (a hot solid such as sand or olivine circulating between the gasifier and the char combustor), it is *indirect gasification*. Indirect gasification typically uses steam and direct gasification uses high-pressure air or oxygen as agents.

Indirect gasifier temperatures are 1380°–1650°F (750°–900°C) and produce syngas, char, and tars. One disadvantage of this approach is that a char combustor, a steam reformer, and an extra compressor are needed to boost the syngas pressure before the acid gas is cleaned up.

During direct gasification, biomass under pressure in the presence of oxygen and steam produce medium thermal energy syngas and heat via an exothermic process. The heat is captured in the gasifier and combined with oxygen to maintain temperatures of 1560°–2010°F (850°–1100°C). One disadvantage of this process is that it needs an expensive air separation unit (ASU) for oxygen supply.

DOE Gasification Targets

Table 2 and Table 3 (Table 3.1.8 and Table 3.1.8A from the April 2009 DOE Multi-year Research Development and Demonstration Plan for Hydrogen Fuel Cell Technology) show that the 2012 and 2017 hydrogen levelized cost targets are \$1.60/gge and \$1.10/gge, respectively, at 300 psi at the plant gate.[5] The report also shows the same time period's target capital investment costs of \$150 million and \$110 million, respectively.

Table 2. Technical Targets: Biomass Gasification/Pyrolysis Hydrogen Production

Characteristics	Units	2005 Status	2012 Target	2017 Target
Hydrogen cost (plant gate)	$/gge	<$2.00	$1.60	$1.10
Total capital investment	$ million	$194	$150	$110
Energy efficiency	%	>35%	43%	60%

Table 3. Biomass Gasification H2A Example Cost Contributions

Characteristics	Units	2005	2012	2017
Capital cost contribution	$/gge	$0.70	$0.50	$0.30
Feedstock cost contribution	$/gge	$0.30	$0.20	$0.15
Fixed O&M cost contribution	$/gge	$0.30	$0.20	$0.15
Other variable cost contribution	$/gge	$0.30	$0.30	$0.25
Total hydrogen cost	$.gge	$2.00	$1.60	$1.10

This technoeconomic evaluation assesses the BTH cost. It investigates the influence of the following factors on levelized hydrogen production costs:

- CapEx
- Feedstock prices
- Hydrogen yield
- Financing.

The panel examined a 500 dtpd 1st plant and a 2000 dtpd Nth plant, where multiple plants have operated for many years and generated learning curve benefits.

Results

The panel calculated hydrogen production costs of $5.40/kg for a 1st plant (500 dtpd) and $2.80/kg from an Nth plant (2000 dtpd). The H2A DOE reference case projects a Nth plant hydrogen production cost of $1.67 (in 2009$ adjusted from cost of $1.61/kg in 2005$). Figure 1 and Figure 2 show results of single variable sensitivity studies for the two cases. The assumptions used for base, high, and low cases are given in the respective sections for H2A Methodology, CapEx, Hydrogen Yield, and Feedstock. OpEx cases were taken directly from the DOE H2A reference case.

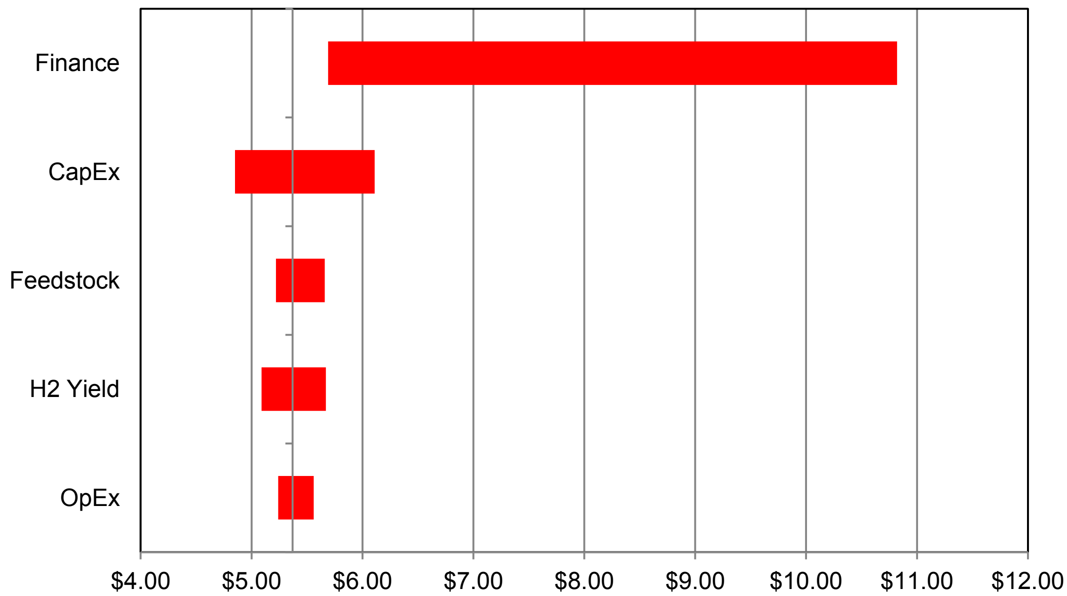

Figure 1. 1st plant levelized hydrogen costs

($/kg, base = $5.37/kg)

Note: The financing cases in the tornado chart do not cross the DOE reference case because the panel's cases do not include the reference case parameters. For a more complete explanation of reasons for the divergence see the section on finance.

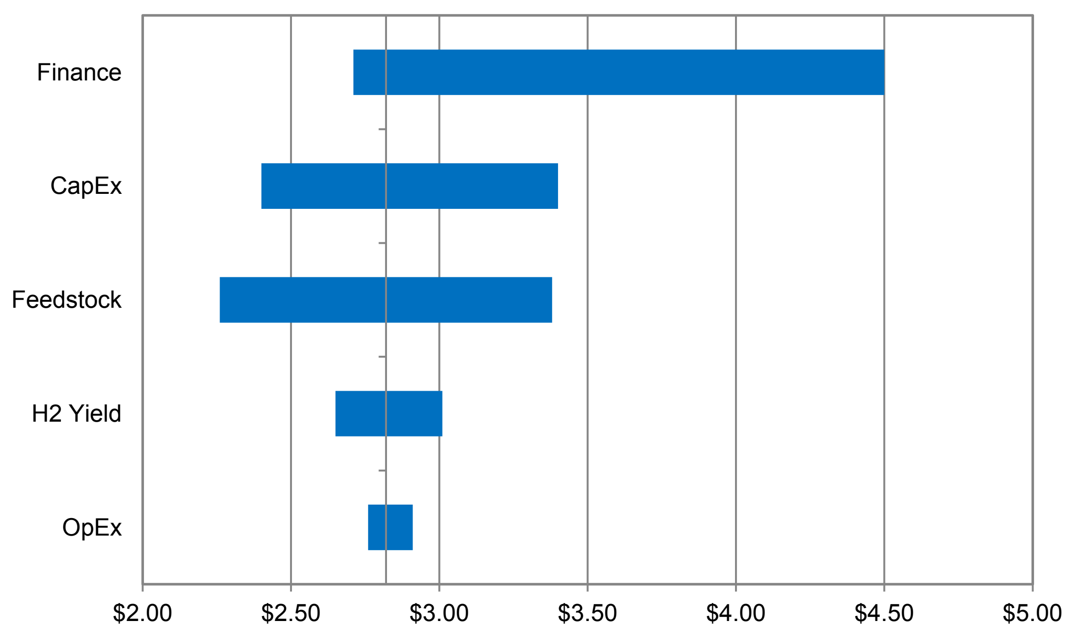

Figure 2. Nth plant levelized hydrogen costs

($/kg, base = $2.82/kg)

Figure 3 and Figure 4 show breakdowns of total levelized hydrogen costs from 1st and Nth plants.

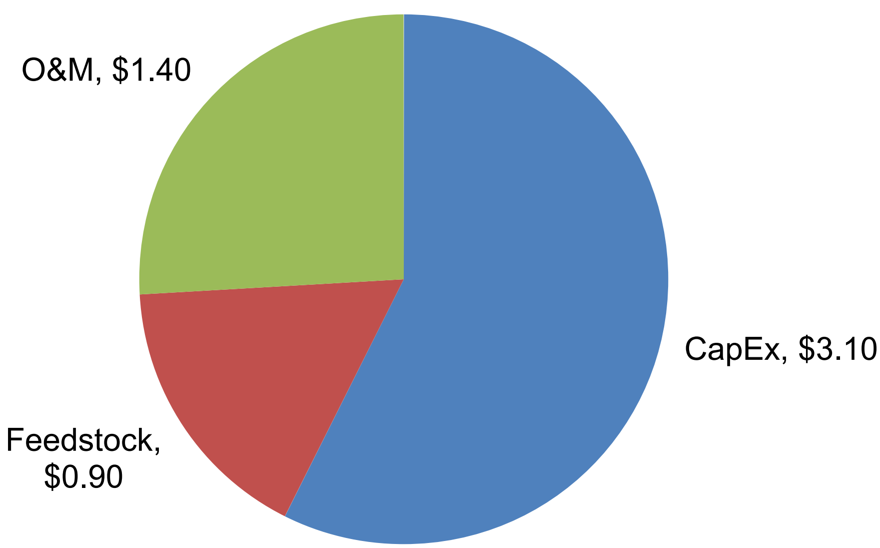

Figure 3. 1st plant costs
$/kg hydrogen produced

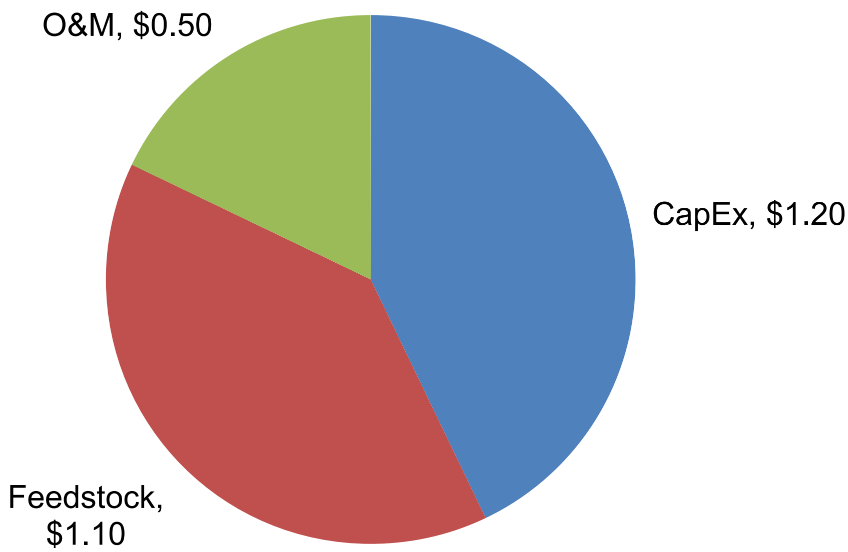

Figure 4. Nth plant costs
$/kg hydrogen produced

Table 4 summarizes the breakdown for the DOE reference case and the panel's two cases.

Table 4. Levelized Hydrogen Cost Breakdown ($/kg H_2)

Case	Capex	Feedstock	O&M	Total
DOE Reference Case	$0.59 33%	$0.55 34%	$0.53 33%	$1.67*
Panel 1st Plant	$3.10 57%	$0.90 17%	$1.40 26%	$5.40
Panel Nth Plant	$1.20 43%	$1.10 39%	$0.50 18%	$3.80

* Cost adjusted from 2005$ costs of $1.61.

Analysis Approach

The panel used this methodology:

- **Phase I.** Information gathering
    - Literature survey
    - Questionnaire distribution to industry, government, and academia
    - Phone interviews and follow-ups
    - Participation in biomass integrated biomass refinery annual project reviews
- **Phase II.** Current and future technology status assessment
- **Phase III.** H2A model methodology and key assumptions assessment
- **Phase IV.** Multiple scenario analysis for hydrogen pricing
- **Phase V.** Report preparation with key findings.

After reviewing the information, the panel decided to focus on four variables that have the greatest impact on hydrogen production costs: CapEx, feedstock costs, hydrogen yield efficiency, and project financing. The panel used the H2A model for this evaluation.

Estimating Capital Expenditures

Accurately estimating total project CapEx is critical to arriving at a levelized hydrogen production cost. The panel found a wide range of CapEx estimates, mostly because no BTH plants have been built. In fact, large-scale biomass gasifiers are still rare. Other factors contributing to this difficulty include:

- The quality of estimates varies widely.
- Many publications do not clearly describe methods for converting purchased equipment costs to total CapEx.

The current H2A case and many DOE reviews are based on cost estimates for an indirect gasifier based on the Battelle Columbus Laboratories 1980s pilot plant and operational data. No direct gasifier costs were used. To obtain estimates with more up-to-date information about the technology status and issues, the panel looked for studies that used more recent cost estimates and systematically contacted several advanced biofuels projects that use a gasification platform to produce liquid fuels.

Redoing the bottom-up estimation of unit operations, stream flows, equipment costs, and total investment used in the H2A version 2.1.2 required a scope and resources beyond that available to the panel; therefore, the panel used a different methodology. The panel contacted about 30 producers and operators of gasification equipment, but obtained detailed information from only 9. With few exceptions, they considered CapEx information to be proprietary or were unwilling to share their information for other reasons.

The panel used two sources to search for reasonable up-to-date CapEx estimates:

- Recent publications that have used realistic estimates to adopt a ground-up approach
- Projected project costs (adjusted for hydrogen production) for publicly announced biomass gasification projects.

All projects were scaled to 500 or 2000 dtpd biomass input using a 0.6 scaling exponent.

Publications

A recent publication from Iowa State University (ISU), NREL, and ConocoPhillips uses current information for processes and industrial standard methods to estimate indirect costs and contingencies and determine costs of producing Fischer-Tropsch (FT) liquid fuels via biomass gasification (N^{th} plant).[6] Costs for parts of the plant involved in FT synthesis and wax cracking were clearly listed so they could be removed from the estimate.

The panel also identified a 2002 study from Utrecht University that considered five distinct BTH configurations: three direct and two indirect gasifier cases.[7] This study was especially valuable, as it considered hydrogen production specifically.

Total CapEx varied widely between the studies, primarily because different methods were used to adjust purchased equipment costs to total project cost. To place these studies on a common basis, the panel:

1. Adjusted costs back to purchased equipment CapEx (the ISU study used a 3.02 multiplier; the Utrecht study used a 1.86 multiplier).

2. Subtracted equipment costs associated with liquid fuels production in the ISU study from the total purchased capital and added $60 million in equipment costs for syngas reforming and hydrogen purification (described below).
3. Multiplied purchased equipment costs by a factor of 4.0 (Lang factor) to estimate project costs. Given the critical nature of this factor, the panel looked to industry experts and the literature to arrive at a reasonable value. The panel believes that 4.0 is a conservative (low) value. For example, the ISU study, which included input from process engineers at ConocoPhillips, uses a Lang factor of 5.4 to fully account for installation, indirect costs, and owners' costs. Peters and Timmerhaus (a standard chemical engineering text) recommends a value of 4.87.[8]
4. Adjusted costs to 2009 basis using the Chemical Engineering Plant Cost Index.

To estimate hydrogen production costs, the panel examined publications describing hydrogen production via SMR and had discussions with industrial gas companies with extensive hydrogen production experience. The estimated the costs for additional components (WGS reactor and PSA) are $30 million (155,000 kg on a hydrogen per day scale). This value is probably low because an SMR might be required for some cases. This number was added back to the total project CapEx estimate after FT costs were subtracted to attain final project CapEx.

Direct Versus Indirect Gasifiers

Direct gasifiers typically have higher capital costs than indirect gasifiers, so an oxygen plant costs more. In the cases examined by the panel, total CapEx was almost identical (see Appendix B). Much of this is due to lower expenses for gas cleanup and compression for direct gasifiers, as they operate at higher temperatures and pressures than do indirect gasifiers.

Projects

The panel selected three publicly announced projects with high-level estimates of project costs and obtained cost breakdowns from two. Commercial Project One provided total project costs, which were used without modification (except for scaling and adjustments to convert from liquid production to hydrogen production). Commercial Project Two provided purchased equipment costs, which the panel adjusted using the appropriate Lang factors. Commercial Project Three disclosed total costs only, and the panel estimated costs for liquids production for this project to be 25% of total project costs. This was subtracted from total cost and hydrogen production CapEx was added in. The total CapEx was then scaled to size the plant appropriately.

Nth Plant Versus 1st Plant

The panel used SMR learning curve data to relate 1st and Nth plant costs. Schoots et al. analyzed cost data for SMR plants built from 1940 to 2007 and determined a learning rate of 11% $\pm$ 6%.[9] The learning rate is the amount that CapEx decreases with each doubling of installed capacity. So a 11% learning rate implies that the cost for a second plant (of identical size to the first) would be 89% of the first plant, the fourth plant CapEx would be 79%, etc.

After considering site availability, likely fuel cell vehicle penetration rate, and competing technologies, the panel chose to use a 10th plant to evaluate Nth plant costs. Using the 11% learning rate the panel calculated that 10th plant costs would be about 68% of 1st plant costs. Except for the ISU study, all the cases were 1st plants, so their CapEx was reduced by 68% to estimate Nth plant costs. For the ISU study, Nth plant costs were multiplied by 1.47 (1/0.68) to arrive at 1st plant costs. The panel used this approach and publicly available data to determine realistic CapEx for biomass gasification plants (see Appendix B).

Despite the wide variation in technologies included, the costs are remarkably consistent (the standard deviation for the base case CapEx was about 14%) among the technologies the panel examined. CapEx cases are listed in Table 5.

Table 5. CapEx Cases

		CapEx ($ million)		
Case	**Size**	**Base**	**Low**	**High**
1st plant	500 dtpd	$214	$188	$269
Nth plant	2000 dtpd	$334	$310	$420

Sensitivity Studies:

To assess the effects of individual variables on CapEx, the panel chose high and low values of the Lang factor, learning rate, and levelized hydrogen production costs (see Table 6).

Table 6. CapEx Sensitivity Values

Variable	Base	High	Low
Lang Factor	4.0	5.4	3.0
Learning Rate (relative Nth plant cost)	11% (68%)	5% (84%)	17% (54%)
Hydrogen Production CapEx	$30 million	$45 million	$15 million

Table 6 also shows the results used in the H2A sensitivity runs (see Figure 1 and Figure 2).

Weakness of the Method

Feedstock Effects

CapEx associated with feedstock preparation varies somewhat for different feedstocks. The ISU study assumes a switchgrass feedstock with handling and preparation CapEx of $44.5 million. The panel talked with Price Companies and Mid-South Engineering, which specialize in wood lots for the pulp and paper industry. They estimated $52.1 million and $70 million for CapEx for a 2000 dtpd wood lot. Wood lot technology is relatively mature, so the price would not be expected to drop significantly from 1st to Nth plants.

Gasifier Type and Cleanup Technology Effects

CapEx differs significantly depending on gasifier type and gas cleaning technology. Air-blown, oxygen-blown, high-temperature, and low-temperature gasifiers all have different cost structures and hydrogen yields. Ideally, the panel could have conducted analyses to find the gasifier design and configuration that would produce hydrogen at the lowest cost, but given its limited resources, the panel used average costs over several gasifier types. The wide variation in cost estimates for single gasifier types justified this approach and gave reasonable CapEx values.

Nth Versus 1st Plant

Given the large uncertainty in the learning rate (11% $\pm$ 6%), adjustments of 1st plant costs to Nth plants and vice versa, are questionable. The ratio of Nth to 1st plant costs could be as high as 0.84 or as low as 0.54.

Feedstock Prices

The cost and availability of biomass feedstock are critical elements of BTH, particularly as they affect the Hydrogen Program's ability to meet target levelized hydrogen production costs. The literature review showed that current feedstock prices vary widely. The most recent H2A analysis used $38/dt; other reports for the Fuel Cell Program used $60/dt. A recent National Academy of Sciences report projected 2020 "willingness to accept" prices ranging from $55/dt for wheat straw to $151/dt for switchgrass.[10] The willingness-to-accept price or feedstock price is the long-run equilibrium price that would induce suppliers to deliver biomass to the processing plant. The Biomass Program uses values ranging from $62-$75/dry ton.[1]

Early-Stage Feedstock Prices

Panel members discussed feedstock cost and availability issues with David Kolsrud, a Minnesota corn-soy bean farmer who has extensive experience managing and investing in dry mill corn ethanol plants. Kolsrud also has experience harvesting, baling, and storing corn stover, primarily for use as an emergency feed for cattle and hogs. He estimated the costs for delivering agricultural residues to the edge of the field at $45/dt to $60/dt. He also noted that year-to-year production would vary greatly depending on the harvest-to-frost window, making assured availability a major risk factor. The panel contacted the plant manager of the McNeil Generating Station, a 60-MW wood-fired plant that has operated for more than 25 years. Its price and availability for wood chips were sensitive to competing feedstock demands. McNeil reports paying $28–$30/ton for wood delivered by truck with a 20% additional added for railcar deliveries.[11] Assuming the wood contains 50% moisture, this would equate to $56–$60/dt.

The panel also obtained data and perspectives from eight commercial ventures who are developing advanced biofuels projects. Biomass feedstock prices are generally expected to average around $60/dt. This is not an average of numbers given by the project personnel. It is rather the biomass feedstock cost that the personnel thought would be an average cost for the feedstock supplies expected for their projects, a value that virtually all felt comfortable with as a nominal average value. KiOR's recent Initial Public Offering filing gives its expected biomass cost (southern yellow pine, clean chip mill chips) as $72.30/dt. These estimates are being used as part of project planning and financial analysis, so the panel used them as the base for the 1st plant projects with a relatively tight band for high to low estimates ($50–$80/dt). The high end of the range at $80/ton came from a case where the average of dozens of sources for a project was approximately $40/dt, but with the "BCAP" (Biomass Crop Assistance Program) accounting for paying farmers who supply corn stover an amount equal to what the plant was paying them, making this effectively $80/dt as the average that the suppliers were willing to accept. The low end of the range adopted for the 1st plant came from a situation in California where a very low cost of only $20/dt in 2010 was expected to be $50/dt in 2015 because:

- The BCAP would no longer be available to pay 50% of the amount the biomass supplier could collect for supplying a biomass power plant. The panel estimated this would cause the cost to double, from $20/dt to $40/dt.
- New power plants expected to come on line in the same biomass fuel supply region would nearly double the demand. The panel estimated this would account for the other 25% in cost increases.

Nth Plant Feedstock Price

Biomass price drivers for Nth plants will differ from those for 1st plants. The range of costs for the Nth plant is much wider than for the 1st plant. Increased biomass demand for liquid biofuels is likely to drive prices higher; advances in high-yield energy crop technologies should drive production costs down.

The 2007 Renewable Fuels Standard 2 (RFS2) mandates production of 21 billion gpy of advanced biofuels, and the number of biomass electricity generation facilities is projected to increase. This trend will be accelerated if the U.S. Environmental Protection Agency designates biomass cofiring as a Best Available Control Technology for greenhouse gas reductions at coal-fired electricity plants. All these factors will increase biomass demand. The annual biomass feedstock demand for the advanced biofuels and biomass electricity generators could exceed the 2017 Biomass Multi-year Program target feedstock availability by more than 35% (334 million dt demand versus 250 million dt supply). These uses would be mandated by law or regulation, so they would likely take precedence over biomass for hydrogen production. Thus, the price of biomass feedstocks for hydrogen, in the absence of major federal policy changes, will presumably exceed $80/dt.

As policy drives biomass demand increases, acreage devoted to biomass will likely increase, and new technologies will emerge that will increase yields and decrease costs. So although demand would suggest that prices will increase, technology advances in crop species breeding and selection, crop genetics, harvesting, storage, and delivery could lower biomass prices. For example, between 1947 and 2008, corn yields increased from 29 bu/acre to 150 bu/acre.[12] If similar increases could be achieved for nonfood, nonfeed biomass crops, increased yields could lead to lower biomass prices. Higher yields of food crops and reactivation of land that has dropped out of crop production could augment the energy crop yield increases as a means of reducing biomass feedstock costs. There are, of course, reasons why these lands have dropped out of crop production, and because these are "marginal" croplands, achieving large yield increases will be a greater challenge.

To estimate the effect of biomass feedstock demands on the cost of feedstock to a BTH facility, the panel looked at several biomass supply curves that predict biomass prices as a function of demand.

Khanna et al. updated the DOE/U.S. Department of Agriculture "billion ton study" by adding a supply curve (see Table 7).[13]

Table 7. Supply Curve

Demand (million dt)	Cost ($/dt)
240	40
350	43
400	46
470	50
600	60
700	80
800	110

The base, low and high values chosen for the N^{th} plant reflect the greater range possible for longer term estimates and have a high value, $120/dt, which was used in the National Academy of Science America's Energy Future report.[8] The base value, $80/dt, was chosen to be at the high end of the near-term range and reflects the rise in cost expected as more biomass is demanded. The low end of the range, $40/dt, was chosen for its agreement with low-cost biomass feedstock today, its agreement with the $38/dt of the H2A Case 01D, and for the possibility that continuing and expanded efforts to produce and deliver biomass at lower costs will be successful. Appendix C presents additional supply curves which show that the high-demand end often indicates a cost that is two or three times the low-demand end of the curve. The panel's selected range of $40–$120/dt gives a factor of 3. Thus, biomass feedstock costs could be driven upward by high demand or downward by the incentive to improve yields and reduce costs. The panel adopted the following feedstock pricing values (Table 8):

Table 8. Feedstock Pricing Values

	Base	Low	High
1^{st} plant	$60/dt	$50/dt	$80/dt
N^{th} plant	$80/dt	$40/dt	$120/dt

Results of H2A sensitivities using the low and high feedstock costs are reported in Figure 1 and Figure 2.

Hydrogen Yield

Hydrogen yield will significantly affect its levelized cost. Ideally, the panel could have evaluated detailed process models to examine tradeoffs in CapEx, hydrogen yield, cogeneration of electricity, etc., but instead looked to the literature for hydrogen yields. The panel focused on the hydrogen yield parameter (mass hydrogen out/mass biomass in). This ignores any electricity or other energy products that might be generated or consumed, and that would have to be included in a calculation of net overall efficiency. Hydrogen yield is treated as an independent variable for examining its effect on levelized hydrogen costs.

Table 9 shows hydrogen yields from the open literature.

Table 9. Hydrogen Yields From Open Literature

Case	Yield (kg/dt)
H2A 01D	70.4
Utrecht Case 1	45.8
Utrecht Case 2	67.7
Utrecht Case 3	46.2
Utrecht Case 4	79.1
Utrecht Case 5	38.9
GTI*	76.3

*Bowen[14]

Yields the panel chose to model are given in Table 10.

Table 10. Hydrogen Yields Modeled by Panel

	Daily Capacity (kg Hydrogen) *(Hydrogen Yield [kg/dt Biomass])*		
	Base	**Low Cost**	**High Cost**
N^{th} plant, 2000 dtpd	150,000 *(75)*	160,000 *(80)*	140,000 *(70)*
1^{st} plant, 500 dtpd	36,000 *(72)*	38,000 *(76)*	34,000 *(68)*

These yields may be somewhat optimistic, but they fit comfortably within those reported. They are shown again in Table 11 along with “Gross BTH Efficiencies,” which express the energy content of the hydrogen produced divided by the energy content of the biomass fed to the plant (lower heating value or LHV). Additional energy inputs and outputs are not included.

Table 11. Reported Hydrogen Yields

Case	Capacity (dtpd)	Hydrogen Production (kg/d)	Hydrogen Yield (kg/dt)	Gross BTH Efficiencies
H2A Default	500	35,329	70.7	47.8%
1st High-Cost	500	34,000	68.0	46.0%
1st Base Case	500	36,000	72.0	48.8%
1st Low-Cost	500	38,000	76.0	51.5%
Nth High-Cost	2000	140,000	70.0	47.4%
Nth Base Case	2000	150,000	75.0	50.8%
Nth Low-Cost	2000	160,000	80.0	54.2%

Hydrogen LHV = 113,839 Btu/kg and Biomass LHV = 8,405 Btu/lb

In addition to the complications of introducing electricity and natural gas into the biomass input or accounting for exports of power or heat, the difference between the LHVs and the higher heating values (HHVs) of the biomass input can be a 3%–10% effect on the number cited as the efficiency. (The even larger difference between the LHVs and HHVs of hydrogen is well known in hydrogen energy evaluations where the difference is an 18% effect.) For the four biomass feedstocks named in the Pacific Northwest National Laboratory Hydrogen Resource Center conversions calculator, the difference between LHV and HHV of biomass types is 3.5%–10%: LHV = HHV/Ratio where Ratio = 1.035 to 1.1. For "farmed trees" the ratio was 1.035 (8,852 Btu/lb over 8,406 Btu/lb.

Financing Calculations

The panel used the H2A model to calculate the levelized cost of a gasoline gallon equivalent ($/gge) of hydrogen and is structured to allow for the evaluation of several extremely different technological processes with correspondingly varying costs and efficiencies. The model does this by solving for a price ($/gge) that yields a target internal rate of return (IRR) for a given set of inputs. The three overarching questions for the H2A review are:

- Is the model internally consistent?
- Does the model's operation reasonably reflect how a commercial project would approach the economics of a project?
- Do selected input values reflect a realistic policy framework?

The H2A model assumptions should reflect how an actual commercial project would raise capital to cover investments, generate revenue from product sales, use revenues to cover OpEx, and recover capital, including a profit. Some input values will change as the sensitivity of the base results is gauged. The panel took the following steps to understand this process:

1. Studied basic energy policy scenarios.
2. Gauged how the scenarios would affect certain input values.
3. Examined active and stalled energy policy frameworks to develop input values.
4. Used the values to test the sensitivity of H2A results.
5. Linked that sensitivity to selected input values to the scenarios.

Internal Model Structure

The panel examined the model's internal logic, structure, and calculations. The panel agreed with the internal structure, with three caveats:

- The hydrogen price, in this case $/kg, is usually given by forces outside the project's control; i.e., $/kg is an exogenous. In H2A, it is a dependent variable that is solved in the model operation to produce a specified target IRR. H2A seems to handle this variance correctly, however, assuming the IRR forces the H2A model to estimate a nontransparent value.
- With certain inputs the project operation will likely generate negative income taxes in its early years. For a commercial project, negative taxes can be treated in two ways:
    - If investors have no taxes to offset, the taxes can be carried forward.
    - If investors have taxable income that can be offset by negative taxes, those taxes will be a source of cash; i.e., the project is "tax efficient." H2A is apparently limited to this assumed tax efficiency. This limitation will probably be relatively minor and not seriously limit the model's usefulness.
- H2A does not correctly calculate and treat interest during construction costs, possibly due to the base assumption that projects are funded with 100% equity. If the H2A model is operated under the assumption that the capital structure is leveraged; i.e., it is composed of debt and equity contributions, interest costs will be incurred during the construction period. The nearly universal practice is to capitalize these costs over the construction

period and add them to the total CapEx once construction is finished and the project begins operating.

This problem emerged when the first alternative runs were conducted. Two had 10% composite costs of capital (defined in Reviews and Recommendations, Issue 3). One was done under the 100% equity case and the other under a leveraged debt/equity composite that resolved to 10%. The anomaly arose because in an early test H2A run the 100% equity case produced a lower levelized cost than the composite case ($5.36/kg versus $5.72/kg). All other things being equal, a 100% equity capital structure will be more expensive than a leveraged capital structure because equity returns are after tax. Debt returns of interest costs are before taxes. The immediate return of these interest costs as negative cash flows in the –1 and –2 operational years results in the leveraged case, requiring a higher levelized cost to yield the same IRR. The impact of this treatment will vary directly with the length of the construction period: the longer the period the greater the impact, and vice versa. There appears to be no fix for this problem.

Baseline Assumptions

The assumptions and input values selected to drive the model did not seem to reflect a reasonable approximation of how a commercial project would be designed. These flaws arose for two reasons:

- The selection of critical values seemed to be driven by a desire to use similar assumptions across extremely different technology options.
- Some values were either unrealistic or could not produce the expected results.

Panel members had discussions with DOE and NREL personnel connected with the development and use of the H2A model. When H2A was developed, a high-level decision was made to treat all hydrogen production technologies with a consistent set of assumptions. This obviously did not apply to input values such as CapEx and OpEx, but covered such financing assumptions as project life, depreciation schedule, cost of capital, and tax treatment. It was intended to produce a fair or neutral hydrogen cost from the various technologies.

On the surface, consistent modeling assumptions appear to produce a neutral evaluation of various technologies, because each technology faces identical conditions. However, technology options vary considerably by CapEx versus OpEx. For example, hydrogen production via electrolysis is likely to have lower initial CapEx but higher OpEx. Hydrogen from syngas produced from biomass gasification will have much higher upfront CapEx and lower OpEx. Capital structure, project life, accelerated depreciation, and operations and maintenance (O&M) treatments are all likely to vary depending on cost inputs.

Risk also affects variables such as acceptable rates of return. For example, investors will accept a low rate of return for a mature technology such as SMR where there is little risk. For a novel technology such as BTH, investors will demand a much higher projected rate of return. Project contingencies will also be significantly higher for novel technologies.

Forcing consistency across all technologies can put options such as those offered by biomass gasification into a financial straightjacket that neither reflects favorably on the technology nor indicates how it would likely be treated in a commercial project.

Policy Scenarios

The panel calculated the levelized hydrogen cost that will produce the target IRR on project investment for 1st plants and Nth plants. That assessment reflects initial assumptions about costs, efficiencies, and the financial model. These single point calculations are surrounded by many possible runs that reflect how the selected inputs might vary.

Alternative or sensitivity cases can be constructed by varying important input values; e.g., feedstock price and the CapEx of major equipment. This will certainly produce many results, but many alternative sensitivities do not indicate how the results are likely to change.

Part of the BTH project assessment requires that the sensitivity of the base case results to alternative input values be determined and their likelihood examined. For each base case assessment, a range of alternatives was evaluated to reflect the sensitivity of the results to (1) the possible policy frameworks that will affect important input values; and (2) the probable range of input values given the quality of the base case cost estimates.

Energy policy will affect continued access to loan guarantees, pilot stage cost sharing grants, and continued support for the mandated annual production goals of the RFS2. For example, advanced biofuels receive supports that are intended to assist early-stage technology commercialization:[15]

> Cellulosic ethanol receives federal support through a combination of incentives, including regulatory mandates, tax credits and depreciation allowances, grants, loan and guarantee arrangements, and biomass crop programs. These federal incentives are contained in several pieces of legislation, such as the Energy Policy Act of 2005, the Energy Independence and Security Act of 2007 and the 2008 Farm Bill.

The RFS2 mandates that all U.S. fuel suppliers blend advanced biofuels with standard fuels. If the technology to produce these fuels is successful, it could help BTH conversion by commercializing gasifiers and gas cleanup technologies. However, hydrogen and advanced biofuels are aimed at transportation, so hydrogen is seriously disadvantaged by not being qualified as a biofuel. If hydrogen is not so qualified, BTH could be supported to supply it to refineries to replace SMR with natural gas. This would then become a major technology option for lowering the CO_2 footprint associated with fossil fuel refining.

According to Energy Information Administration data, domestic refineries use about 6.839 million tonnes (7.5 million short tons) of on-purpose hydrogen per year, and estimates that about 40% of that, or 2.732 million tonnes (3 million short tons) are produced on site. A recent SRI Consulting report estimates that use will increase 40% in five years to refine increasingly sour crude.[16]

Using the 40% figure, domestic refineries produce about 2,723 million kg of hydrogen on site. Using the BTH yields from the open literature, a 500 dtpd BTH plant would produce about 14 million kg/yr hydrogen; a 2000 dtpd plant would produce more than 4 times that because of increases in conversion efficiencies. A program to replace even one eighth of the onsite hydrogen would provide a market of 340 million kg/yr, which would provide a market outlet for four 1st plants and five Nth plants.

A list of input values that will likely be influenced by the policy framework follows. The quality of the base estimate can be assessed to approximate the high and low ranges.

Financial Model Variables

- **Interest rate and percent of CapEx covered by debt.** Overall policy development active: The loan guarantee program is likely to be continued. This will allow a project to be financed with a debt/equity composition of 80%/20% with an interest rate of approximately 4%.
- **Cash grants for early-stage projects.** Overall policy development active: Cash grants for early-stage projects are possible. This assessment is based on treatment offered for advanced biofuels projects.
- **Modified Accelerated Cost Recovery System (MACRS) qualification; e.g., 7-, 5-, or 1-year depreciation.** Accelerated depreciation has been used in several cases to accelerate private capital flowing into chosen technologies. In a few cases, 1-year depreciation was allowed.

Review and Recommendations

The panel found the cost analysis methodology for hydrogen production costs to be mostly sound; however, the panel took several exceptions. Following are issues the panel found regarding methodology and parameters used within H2A.

Issue 1: Operating Life

The decision to assume a 40-year project life is tied to a desire to use modeling assumptions for biomass gasification technologies consistent with those used for nuclear technology options. This may confuse the assumption about allowed operating life with an ability to obtain financing. A 40-year operating life for the initial biomass gasification technology package seems unlikely. Thus, 40-year financing would probably not be available. It may be possible over 40 years to engage in major capital repairs or retooling efforts that would extend the project life. In that case, however, the salient CapEx would be financed at that time and treated accordingly. The panel recommends 20-year financing.

Issue 2: MACRS Schedule

MACRS allows qualified equipment to depreciate rapidly. The H2A model assumes a 20-year MACRS in conjunction with the assumed 40-year financing. Accelerated depreciation provides multiple benefits. Depreciation is a deduction from earnings before income tax, depreciation, and amortization or taxable income and will lower taxes payable, thereby lowering the pretax revenue and the $/kg required to meet the required profit level. Depreciation is also a noncash expense, which means that depreciation carved from taxable income will be available for distribution as free cash. The quicker the depreciation of project CapEx, the greater the benefits and the lower the $/kg required to meet the target IRR. The panel did not review tax law to determine whether the equipment in the biomass gasification package qualified for MACRS. The technology package is not commercially available, so it probably has not been addressed in tax law. For this purpose, the panel assumes a 7-year MACRS, which is the depreciation allowed for biomass to fuel projects under current tax law. The panel recommends 7-year MACRS linked with 20-year project life.

Issue 3: Composite Cost of Capital

Perhaps the most critical financial assumption used to evaluate the biomass gasification option centers on the assumed capital structure for the project. To compare different financing options, the panel has used the concept of composite cost of capital, which is calculated using a weighted average of a firm's costs of debt and classes of equity. The H2A model assumes 100% equity at a real return of 10% or an actual return of 12.2%. Most large-scale energy projects of this magnitude use a leveraged capital structure consisting of a combination of debt (loans) and equity. The precise percentage or ratio of debt to equity will vary, but federal law allows the DOE loan guarantee program to guarantee loans that cover as much as 80% of the total CapEx of a project.

The 100%/12.2% case was apparently used as a surrogate for a more realistic capital structure. The 100% equity represented an unrealistically high figure, and the 10% or 12.2% return was unrealistically low. On balance, the 100%/12.2% could be equivalent to a leveraged capital structure of 80%/20%, where the weighted average of interest on debt and equity would approximate the 100%/12.2% used in H2A. There are two problems with this approach:

- Simply doing the math on a composite cost of capital for an 80%/20% project (assuming a loan guarantee to cover project debt at 5% interest rate) compared to the 100%/12.2% would yield equity returns higher than 40% on equity to produce the composite cost of 12.2%.
- The interest payments on project debt are tax deductions and reduce taxable income and taxes. With a 100% equity financing, these deductions are lost. This bias will penalize high CapEx projects such as biomass gasification much more than low CapEx projects such as electrolysis.

The $/kg is calculated to provide a 12.2% IRR based on annual cash flow. The derivation of the 10% return simply subtracts annual escalation from the real return. Escalation in contracts is a commonly added figure and is meant to make the hydrogen $/kg mimic the expected escalation in competitive fuels, in this case gasoline. The return of 12.2% to equity, not the 10% figure, should be used as the project IRR. The panel recommends an 80%/20% leveraged capital structure. The cost of debt can be taken from a standard commercial interest rate for a AA commercial project and as a sensitivity run for an assumed loan guarantee.

Issue 4: Tax Efficiency

If H2A is run using a 20-year project life, a 7-year MACRS depreciation, and an 80%/20% composite capital structure, the project will likely show negative taxes in the first five years, when the MACRS annual depreciation is at a maximum and the interest payments on the 80% debt are highest. These two factors are likely to reduce taxable income to a negative level and result in a tax loss. Two options are available:

- **Capture the tax loss.** This requires equity investors who expect to have taxable income. Their tax losses are swept out and become a source of return to equity. The project is usually designed beforehand to attract tax equity investors.
- **Carry forward the tax loss.** If there are no equity investors with a tax appetite, the tax losses can be carried forward to reduce future tax payments.

In either case, using negative taxes will help enable the biomass gasifier project to reach the target IRR with a minimum $/kg.

H2A apparently considers only a tax-efficient option, which probably does not have a major impact on the calculated $/kg.

Issue 5: Expensing Operations and Maintenance

In the H2A runs, the depreciation schedule on the cash flow worksheet shows that:

- Depreciation is taken for 40 years rather than 20.
- The sum of the annual depreciations exceeds the initial depreciable capital by about $50 million due to assumptions regarding how replacement costs are considered depreciable capital.

These results arise from capitalizing annual O&M expenses rather than expensing them in the year they occurred. There is no basis for doing this. Capitalizing and depreciating O&M will result in a higher $/kg revenue requirement. The panel recommends expensing O&M.

Appendix A: Gasification Technology

Gasification converts biomass to syngas intermediates that can be used to produce value-added products.

Figure 5 and Figure 6 show conceptual designs for direct and indirect BTH. Each has at least five basic process areas:

- Feed handling and drying (Area 100)
- Gasification (Area 200)
- Gas cleanup and conditioning (Area 300)
- Hydrogen reforming, shift, and hydrogen purification (Area 400).
- Auxiliaries/balance of plant

Conceptual Process Design Overview (configuration)

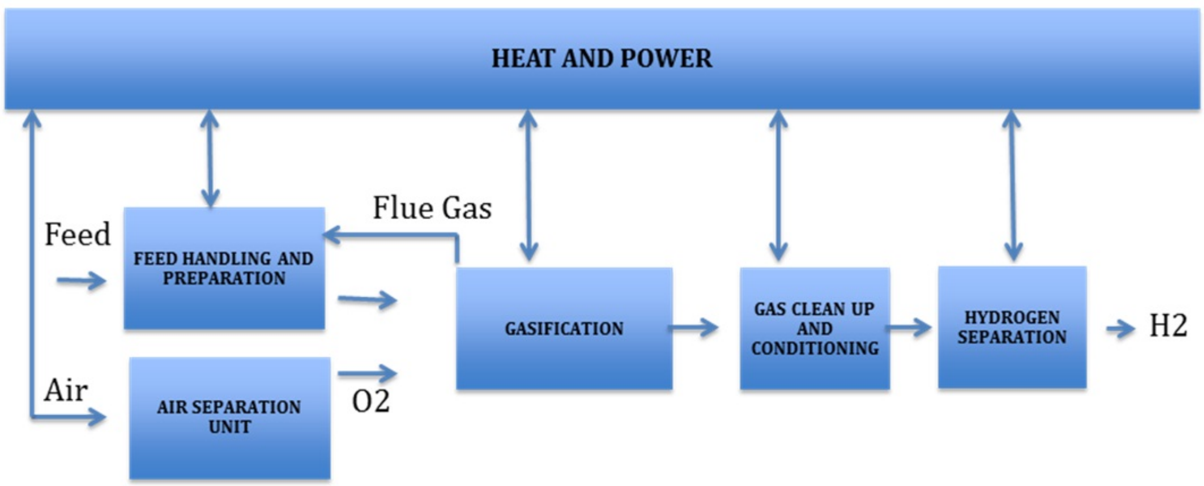

Figure 5. High-pressure oxygen blown direct gasification block flow diagram

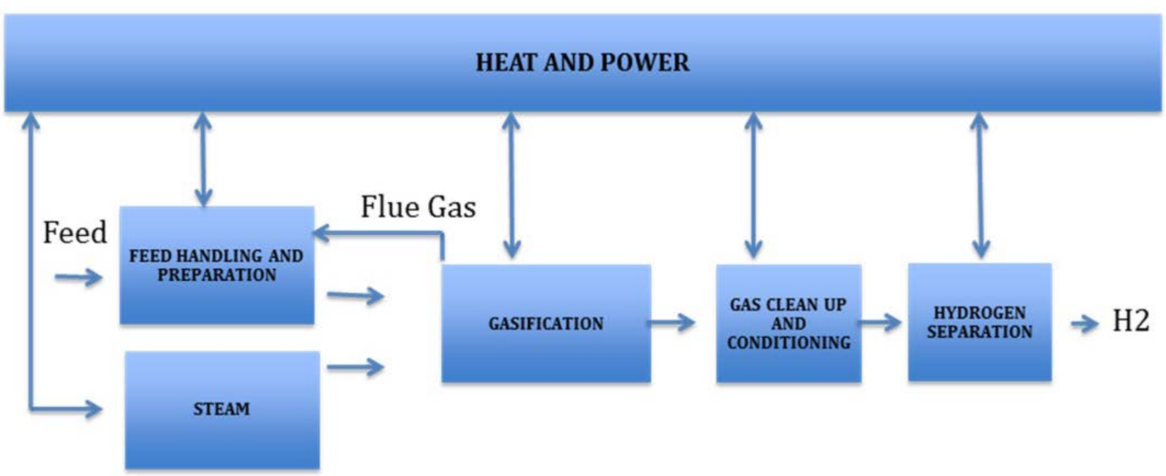

Figure 6. Indirect steam gasification block flow diagram

Feed Handling and Drying Technology – Area 100

The Feed Handling and Drying section includes biomass delivery (primarily by truck), storage, and preparation. For most gasifiers, certain specifications, including size and moisture content, are set for the feedstock. To meet these specifications, the as-received biomass may need to undergo several steps:

1. Once delivered, it is weighed, analyzed, and stored.
2. When needed, it is transported via conveyors to areas for proper sizing.
3. It may be hammer milled, chopped, shredded, pulverized, or pelletized to achieve a specified size.
4. It is transported on a drier feed screw conveyor to a rotary, steam, or cyclonic drier to achieve the stipulated moisture content. The heat source can be excess steam from the steam recovery system or hot flue gas from the char combustor, the tar reformer, or the PSA.
5. When needed, it is transported by conveyor to the lockhoppers or a pneumatic system, where it is introduced into the gasifier.

Potential feed handling technology efficiency and cost improvements include front end handling of feed additives and feed preparation research to prevent feed from tangling in screws.

Gasification – Area 200

There are three main types of biomass gasification processes:

- Fixed bed (downdraft and updraft)
- Fluidized bed (bubbling fluidized bed, circulating fluidized bed)
- Entrained flow gasifiers.

Each type can use one or a combination of gasification agents (steam, air, or oxygen) to promote conversion. Gasification requires a heat source to promote reaction. If the gasification mixture combusts to supply thermal energy, it is direct gasification. If the heat is transferred from a circulating hot solid such as sand or olivine between the gasifier and char combustor, it is indirect gasification, which typically uses steam.

Indirect Gasification

Indirect gasification includes the following steps:

1. A high-pressure lockhopper or pneumatic system typically transports the biomass to the gasifier.
2. CO_2 from the acid gas removal system pressurizes the lockhoppers.
3. The biomass enters the reaction vessel from the top and steam is introduced from the bottom.
4. Hot sand particles or other solids such as olivine provide heat for the endothermic gasification reactions. As a heat transfer agent, the hot sand circulates between the hot char combustor and the gasifier. Steam can provide heat and fluidization for the biomass bed. Temperatures are usually maintained at 1382°–1652°F (750°–900°C).
5. The biomass converts into raw syngas, which contains sulfur compounds, alkali metals, light and heavy hydrocarbons, residual sand, char, and other impurities. The crude syngas

is typically undiluted by nitrogen and has a heating value of about 15 MJ/m^3 (403 Btu/ft^3).

6. A two-stage cyclone system separates solids such as sand, char, and other particulates in the crude syngas.
   a. In the first stage, 99.9% of the sand and char are separated from the syngas and sent to the char combustor.
   b. In the second stage, 90% of the fine particulates are removed.
7. The char is broken down and provides flue gas exhaust and heat to the olivine, which can reach a temperature of 3270°F (1800°C).
8. Another two-stage cyclone system separates the solids from the char gases.
   a. Olivine is separated from the hot combustion gas via the primary combustor cyclone and then circulated to the gasifier, where it transfers heat.
   b. Ash and any other residual particles (99.9%) are removed for the char gas in the secondary combustor cyclone.
9. The residual sand and ash mixture is collected, cooled, and landfilled.
10. The gas from the secondary gasifier cyclone is sent to the bubbling fluidized bed tar reformer.
11. The low processing temperatures cause significant tar to be produced. Thus, the biomass must undergo conversion in a tar reformer, which is typically a bubbling fluidized bed reactor. Light and heavy hydrocarbons are converted to carbon monoxide and hydrogen; ammonia is converted to nitrogen and hydrogen.

Advantages include:

- HHV syngas is produced.
- It does not need oxygen, so expensive ASU and efficiency losses can be eliminated.
- Nitrogen dilution does not present a problem because air is not required.
- Some technologies such as TRI-biomass gasification use smaller downstream shift reactors to maximize hydrogen production to 3.5 to 1 hydrogen:carbon monoxide ratio. These may be less capital intensive for hydrogen production.

Disadvantages include:

- The gasifier design is more complex than that of a direct gasifier, so it may have higher maintenance and labor costs.
- The lower process temperatures produce more char and tar, so a char combustor and steam reformer may be required. These will add costs and reduce efficiencies.
- The additional downstream compressors that boost the syngas pressure for downstream acid gas removal process add costs and reduce efficiencies.

Potential areas for technology efficiency and cost improvements include:

- Research embedded gasifier catalysts to reduce the tar burden and improve the syngas yield.
- Eliminate the tar reformer to improve the syngas yield.

- Continue to research tar reformer catalysts to lengthen their lives and improve methane conversion. This will eliminate the need for an SMR.
- Improve engineering and operating expertise.

Direct Gasification

Biomass produces medium thermal energy syngas and heat under pressure in the presence of oxygen and steam. The generated heat is captured in the gasifier and maintains the necessary high temperatures (1560°–2010°F [850°–1100°C]). Direct gasification includes the following steps:

1. A high-pressure lockhopper or pneumatic system transports the biomass to the gasifier.
2. Nitrogen from the air separation unit or CO_2 from the acid gas removal system pressurizes the lockhoppers.
3. The biomass enters the reactor from the top and oxygen or air is introduced very close to the biomass entry point.
4. The air or oxygen combusts a portion of the biomass to provide the necessary heat. The rate and feed ratio of air or oxygen to bone dry biomass controls the temperature.
5. Steam fluidizes the bed and increases the reaction temperature. Direct gasifier temperatures are maintained at 1562°–2012°F (850°–1100°C).
6. The biomass, in the presence of oxygen and steam, produces medium thermal energy syngas and heat.
7. A two-stage cyclone system separates solids such as sand, char, and other particulates in the crude syngas.
    a. In the first stage, 99.9% of the sand and char are separated, collected, cooled, and disposed.
    b. In the second stage, 90% of the fine particulates are removed.

Advantages include:

- Some downstream compression can be eliminated to reduce costs and improve efficiency.
- Most tars are converted at high processing temperatures so the tar reformer is not needed.
- Only one, two-stage cyclone is needed to remove minerals and char.
- The process is simplified because it does not need to integrate tar and steam reformers.

Disadvantages include:

- It requires expensive ASU for the oxygen supply.
- It must have low-moisture (less than 20%), small particle feedstock to maintain the high process temperature. This adds substantial CapEx and reduces overall efficiency.
- It needs a secondary heat recovery system before gas cleanup to cool the high-temperature syngas that exits the gasifier.

Potential areas for improving direct gasification technology efficiency and cost include:

- Economies of scale can be reached by cofeeding biomass and coal (further research is recommended).
- ASU costs need a 30% reduction in CapEx and OpEx.

- Research on torrefaction is recommended to reduce CapEx.
- Improved thermal efficiencies could reduce upstream preparation costs.
- Improved engineering and operating expertise can help increase efficiency.

Syngas Cleanup and Conditioning – Area 300

Gas cleanup and conditioning are multistep processes. Cleanup for direct gasification is simpler because it the lacks the tar and steam reforming processes associated with indirect gasification. However, both processes include acid gas cleanup, WGS, and PSA hydrogen purification.

Syngas Scrubbing

Following direct gasification or tar reforming:

1. Heat exchangers and water scrubbing cool the syngas and remove residual impurities such as tars, particulates, and ammonia.
2. The cooled syngas is compressed and sent to the acid gas removal process to remove hydrogen sulfide, carbonyl sulfide, and CO_2. A high degree of sulfur removal is required because the downstream reformer and low-temperature WGS reactor catalysts have sulfur tolerances lower than 1 part per million by volume.
3. Elemental sulfur is collected and stored for future disposal and CO_2, which is a vented by-product.

Hydrogen Reforming, Shift, and Pressure Swing Absorption Purification – Area 400

Once the gas cleanup process is complete:

1. The syngas hydrogen content increases (indirect gasification) via syngas methane conversion and endothermic SMR forms carbon monoxide and hydrogen. Typical temperatures are 1500°–1600°F (816°–871°C); pressures are 218–435 psia (1500–3000 kPa). PSA offgas provides fuel; reformation is not typically needed.
2. The syngas is introduced into a two-stage exothermic WGS reaction, which combines carbon monoxide and water in the presence of steam to form hydrogen and CO_2. The temperature for the first-stage high-temperature water gas shift (HTWGS) is 570°–840°F (299°–449°C).
3. The gas leaves the HTWGS, is cooled to 392°F (200°C), and enters the low temperature water gas shift (LTWGS) reactor.
4. Once the carbon monoxide content of the LTWGS reactor is below 2%, a heat exchanger removes more water from the gas.
5. The gas is introduced into the PSA unit.

Potential areas for improving direct gasification technology efficiency and cost include:

- Detailed optimization studies are needed for hot gas cleanup to increase reliability and reduce complexity, and reduce CapEx and OpEx. This could lead to the removal of compression steps, replacement of expensive solvents, and elimination of some waste streams and oxidation steps.
- Research for customization of cold gas wash may lead to a more cost-effective approach to acid gas removal.

- WGS catalyst research is needed to improve lifetimes and conversion efficiencies.

Hydrogen Purification

If the shifted gas is at least 70 mol% hydrogen, it can be introduced into a pressure swing adsorption unit to remove any remaining impurities. The hydrogen recovery rate can be as high as 85%; its purity level can reach 99.99 vol%. The tail gas from the PSA unit is recycled upstream to heat the gasifier or reformer, or both.

A potential area for technology efficiency and cost improvements in hydrogen purification is further development of robust and inexpensive membrane separation systems.

Appendix B: Capital Expenditures

Base Case

There are numerous methods for adjusting purchased CapEx to total project costs. The panel started with purchased costs for major equipment and used Lang factors to adjust to full project costs. The panel examined methods that ranged from multiplying by 1.86 to 5.35 and assumed a base Lang factor of 4.0 so total project costs were 4 times the cost of purchased equipment. The standard learning curve adjustment of 0.68 (ratio of N^{th} plant CapEx to 1^{st} plant) was used along with a hydrogen production cost of $30 million (for correcting processes that produce liquids).

High Case

The ISU, NREL, ConocoPhillips paper used industry standard methods for CapEx. Total project costs were calculated to be ~5.4 times purchased CapEx. The panel used this Lang factor of 5.4 as a high case. The low learning rate was used, giving an N^{th} plant cost at 84% of a 1^{st} plant. Hydrogen production cost was set at $45 million.

Low Case

For the low CapEx case a Lang factor of 3.0 was used along with an N^{th} plant to 1^{st} plant cost ratio of 54% and a hydrogen production cost of $20 million.

Scaling

An 0.6 scaling exponent was used to scale project costs to 2000 dtpd; the Chemical Engineering Plant Cost Index was used to adjust project costs to a 2009 basis.

CapEx for FT synthesis and wax cracking were subtracted and $30 million added to the resulting project costs to account for hydrogen production.

Projects

Commercial Project One

Project one provided a detailed breakdown of CapEx, but did not include purchased equipment prices or Lang factor value. The total cost of installed capital was $207 million. Project one added 31% ($93 million) for indirect costs and an additional 25% for owner's costs. The panel subtracted the cost of the FT reactor and added the cost of hydrogen production after scaling and adjustment. The only adjustments for high and low cases were different costs for hydrogen production. These adjustments gave a project cost of $548 million.

Commercial Project Two

Project two gave the panel installed CapEx of $85.6 million and a Lang factor of 1.72. The panel converted CapEx back to purchased equipment costs (dividing by 1.72) and then scaled the project and used its standard Lang factor of 4 to calculate a project cost of $455 million.

Commercial Project Three

Project three stated total project costs only, so the panel subtracted 25% to account for FT synthesis and wax cracking and used this base case for all three cases. The only adjustment was to change the CapEx associated with hydrogen production.

Results from all the studies used are shown in Table 12.

Table 12. Basis for CapEx Estimates (All Values in $ Million)

Project/Study	Scale (dtpd)	Stage	Product	Scaled Purchased Equipment	Corrected CapEx*	1st	Nth
						(500 dtpd)	**(2000 dtpd)**
Indirect Gasifiers							
Commercial Project 1	1000	1st	FT		548	238	372
Commercial Project 2	500	1st	FT	114	455	198	310
Commercial Project Three	2000	1st	FT		432	188	294
Utrecht 4	2000	1st	hydrogen	128	542	236	368
Utrecht 5	2000	1st	hydrogen	134	565	246	384
					Average	**221**	**346**
					Standard Deviation	**26**	**41**
Direct Gasifiers							
ISU HT	2000	Nth	FT	102	331	212	331
ISU LT	2000	Nth	FT	84	250	160	250
Utrecht 1	2000	1st	hydrogen	152	638	278	434
Utrecht 2	2000	1st	hydrogen	111	474	206	322
Utrecht 3	2000	1st	hydrogen	132	559	243	380
					Average	**220**	**343**
					Standard Deviation	**44**	**69**

All values in this table are in 2009$.
Corrected CapEx is defined as the CapEx scaled to 2,000 dtpd and modified as if the plant produced hydrogen instead of FT liquids per the methodology described in the "Estimating Capital Expenditures" section. No adjustments for 1^{st} or N^{th} Plants have been made..

Appendix C: Feedstock

In the low-cost half of the supply curve, an estimate for one local region in a southeastern U.S. state came out as follows (see Table 13):

Table 13. Southeastern Biomass Supply Predictions

Million tpy	Cost ($/dt)
0.034	27.30
0.037	27.30
0.057	36.30
0.127	49.95
0.157	49.95
0.282	62.00

A woody biomass supply curve that indicates a substantial fraction of the total estimated supply can be at about half the high cost extreme is this, from an estimate for California and the 17 western states. The contractors developed the following supply curves for woody biomass ("forest biomass at roadside" as given in Table 8 of the report to the Western Governors Association by Kansas State University and the U.S. Forest Service—shown here as Table 14):[17]

Table 14. Western States Biomass Supply Predictions

California (Million tpy)	17 Western States (Million tpy)	Cost ($/dt)
1.27	4.96	10.00
3.37	9.27	20.00
3.97	11.60	30.00
4.05	12.19	40.00
4.10	12.57	50.00
4.26	20.47	75.00
4.27	20.59	100.00

And, in the same report by Kansas State University and the U.S. Forest Service (Appendix A on agricultural crop residues), these results are given for winter wheat straw in Idaho, Washington, and Oregon (Table 15):

Table 15. Western Agricultural Residues

Idaho (million tpy)	Washington (million tpy)	Oregon (million tpy)	Cost ($/dt)
0.783	0.398	0.185	30.00
0.965	1.365	0.241	35.00
0.971	1.520	0.400	40.00
1.003	1.526	0.443	45.00
1.003	1.526	0.453	50.00

Khanna et al. performed an analysis of the DOE/U.S. Department of Agriculture "billion ton study" by adding feedstock cost estimates and developing a supply curve (see Table 16).[7]

Table 16. Future U.S. Biomass Supply Curve

Demand (million dt)	Cost ($/dt)
240	40
350	43
400	46
470	50
600	60
700	80
800	110

Given that the total supply estimate was about 1 billion dt – 1.3 billion dt is the rounded-off result of the 2005 "billion ton study"[18]– Table 16 shows the high cost of $110/dt as the demand reaches a large fraction of the total estimated supply. The current (2010) use of biomass for energy in the United States is approximately 3.5 quads. At 15 MMBtu/dt this is 233 million dt, which is very close to the 240 million dt that are the supply at the $40/dt cost in Table 16. Therefore, the supply curve of Table 16 is suggesting that the biomass already in use for energy in the United States can be supplied at about $40/dt, and that if the demand were to approach the billion ton approximate limit the cost would rise toward about $110/dt, shown for an 800-million-dt/yr demand.

The California supply curve numbers in Table 15 suggest a similar conclusion: at about one third to one half the total supply, the cost of biomass feedstock is about one third the cost at the high end where demand presses toward the estimated total of the supply. (The $10/dt at the low cost end of the California forest biomass column above is for biomass at the roadside. The 100-mile distance truck-transport haul, which might be necessary for moving low-cost forest residues to large biomass power or fuel plants, would add $25/dt to the cost of delivered feedstock.

Another California estimate of biomass feedstock costs found that 2010 costs of only $20/dt would increase to $50/dt in 2015 because:

- BCAP would no longer be available to pay 50% of the amount that the biomass supplier could collect for supplying a biomass power plant. The panel estimated that this would cause the cost to double, from $20/dt to $40/dt.
- New power plants expected to come on line in the same biomass fuel supply region would nearly double the demand. The panel estimated that this would account for the other 25% in cost increases.

Appendix D: Sensitivity Runs

Table 17. 1st Plant Using H2A Default Financing

1st Plant 500 dtpd	$MM CapEx	$/dt Feed	kg/dt Hydrogen Yield	kg/d Hydrogen Design Capacity	Debt Period (years)	Interest Rate	Equity	After Tax Real IRR on Equity	Composite Cost of Capital	$MM Fixed O&M	2009$/kg Hydrogen Levelized Cost of Hydrogen
Base	$214	$60	72	36,000	NA	NA	100%	10%	10%	$7.21	**$5.37**
High CapEx	$267										**$6.15**
Low CapEx	$177										**$4.85**
High Feedstock		$80									**$5.66**
Low Feedstock		$50									**$5.22**
High Yield			76	38,000							**$5.09**
Low Yield			68	34,000							**$5.67**
Low Finance					20	5%	20%	30%	10%		**$5.69**
High Finance					20	12%	40%	40%	23%		**$10.82**
High OpEx										$9.37	**$5.56**
Low OpEx										$5.77	**$5.24**

Table 18. N^th Plant Using H2A Default Financing

Nth Plant 2000 dtpd	$MM CapEx	$/dt Feed	kg/dt Hydrogen Yield	kg/d Hydrogen Design Capacity	Debt Period (years)	Interest Rate	Equity	After Tax Real IRR on Equity	Composite Cost of Capital	$MM Fixed O&M	2009$/kg Hydrogen Levelized Cost of Hydrogen
Base	$344	$80	65	150,000	NA	NA	100%	10%	10%	$13.5	$2.82
High CapEx	$514										$3.40
Low CapEx	$220										$2.40
High Feedstock		$120									$3.38
Low Feedstock		$40									$2.26
High Yield			80	160,000							$2.65
Low Yield			70	140,000							$3.01
Low Finance					20	8%	20%	20%	11%		$2.71
High Finance					20	12%	40%	35%	21%		$4.50
High OpEx										$17.55	$2.91
Low OpEx										$10.80	$2.76

Table 19. 1st Plant Using Panel Financing

1st Plant 500 dtpd	$MM CapEx	$/dt Feed	kg/dt Hydrogen Yield	kg/d Hydrogen Design Capacity	Debt Period (years)	Interest Rate	Equity	After Tax Real IRR on Equity	Composite Cost of Capital	$MM Fixed O&M	2009$/kg Hydrogen Levelized Cost of Hydrogen
Base	$214	$60	72	36,000	20	10%	25%	35%	16%	$7.21	**$7.69**
High CapEx	$267										**$8.95**
Low CapEx	$177										**$6.81**
High Feedstock		$80									**$8.01**
Low Feedstock		$50									**$7.53**
High Yield			76	38,000							**$7.30**
Low Yield			68	34,000							**$8.13**
Low Finance					20	5%	20%	30%	10%		**$5.69**
High Finance					20	12%	40%	40%	23%		**$10.82**
High OpEx										$9.37	**$7.91**
Low OpEx										$5.77	**$7.54**

Table 20. N^th Plant Using Panel Financing

Nth Plant 2000 dtpd-	$MM CapEx	$/dt Feed	kg/dt Hydrogen Yield	kg/d Hydrogen Design Capacity	Debt Period (years)	Interest Rate	Equity	After Tax Real IRR on Equity	Composite Cost of Capital	$MM Fixed O&M	2009$/kg Hydrogen Levelized Cost of Hydrogen
Base	$344	$80	65	150,000	20	10%	25%	35%	16%	$13.5	$3.79
High CapEx	$514										$4.76
Low CapEx	$220										$3.08
High Feedstock		$120									$4.40
Low Feedstock		$40									$3.18
High Yield			80	160,000							$3.56
Low Yield			70	140,000							$4.05
Low Finance					20	8%	20%	20%	11%		$2.71
High Finance					20	12%	40%	35%	21%		$4.50
High OpEx										$17.55	$3.89
Low OpEx										$10.80	$3.72

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