Leveling Intermittent Renewable Energy Production Through Biomass Gasification-Based Hybrid Systems

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The increased use of intermittent renewable power in the United States is forcing utilities to manage increasingly complex supply and demand interactions. This paper evaluates biomass pathways for hydrogen production and how they can be integrated with renewable resources to improve the efficiency, reliability, dispatchability, and cost of other renewable technologies. Two hybrid concepts were analyzed that involve coproduction of gaseous hydrogen and electric power from thermochemical biorefineries. Both of the concepts analyzed share the basic idea of combining intermittent wind-generated electricity with a biomass gasification plant. The systems were studied in detail for process feasibility and economic performance. The best performing system was estimated to produce hydrogen at a cost of $1.67/kg. The proposed hybrid systems seek to either fill energy shortfalls by supplying hydrogen to a peaking natural gas turbine or to absorb excess renewable power during low-demand hours. Direct leveling of intermittent renewable electricity production was proposed utilizing either an indirectly heated biomass gasifier or a directly heated biomass gasifier. The indirect gasification concepts studied were found to be cost competitive in cases where value is placed on controlling carbon emissions. A carbon tax in the range of $26–40 per metric ton of CO_2 equivalent (CO_2e) emission makes the systems studied cost competitive with steam methane reforming (SMR) to produce hydrogen. The direct gasification concept studied replaces the air separation unit (ASU) with an electrolyzer bank and is unlikely to be cost competitive due to high capital costs. Based on a direct replacement of the ASU with electrolyzers, hydrogen can be produced for $0.27 premium per kilogram. Additionally, if a nonrenewable, grid-mix electricity is used, the hybrid system is found to be a net CO_2e emitter. [DOI: 10.1115/1.4004788]

Introduction

Wind and biomass are two promising, domestic renewable resources. Each resource faces unique challenges to large-scale adoption. This paper explores several possible synergies represented by hybridization between wind power and thermochemical biomass processing with the goal of improving the economic promise or efficiency of both.

Of the domestic resources available for fuel production, biomass shows significant promise. Recent assessments have shown that excess of 400×10^6 tons of biomass are currently available per year in the United States [1]. Some estimates predict that as much as 1×10^9 tons of biomass could be available in the future with changes to land management and agricultural practices [2]. In addition to high availability, thermochemical biomass plants provide many opportunities for system integration.

Biomass can be converted to fuel and power via two main thermochemical conversion pathways. Pyrolysis is the thermochemical decomposition of biomass in the absence of oxygen. It produces a mixture of synthesis gas (syngas) and bio-oil at temperatures around 500 °C. Gasification uses partial oxidation of the feedstock to provide heat for the reactor and is typically run at temperatures above 800 °C. The higher temperature produces syngas with very little bio-oil (which is considered as an impurity or tar). Gasification is a particularly promising alternative for the production of second generation bio-fuels from nonfood, cellulosic biomass.

Contributed by the Advanced Energy Systems Division of ASME for publication in the Journal of Energy Resources Technology. Manuscript received May 27, 2010; final manuscript received July 18, 2011; published online October 3, 2011. Assoc. Editor: Sarma V. Pisupati.

Biomass gasification plants often require external power for operation when the plants are optimized for fuel production. The use of renewable sources of power for biorefineries further improves the environmental benefits of thermochemical biomass processing [3]; however, few studies have looked at how to directly couple intermittent, renewable power with thermochemical processing.

Wind turbines have quickly become a widely accepted, commercial source of renewable energy in the United States. Over the last 29 years, utilities in the United States have improved their knowledge and ability to manage intermittent electricity sources. In spite of this progress, there are two significant issues that remain if large-scale wind power is pursued in the United States [4]: location and intermittency. The vast majority of land-based wind resources are found in the rural areas of the middle United States. In order to successfully utilize these resources, electricity must be transported long distances to demand centers. Additionally, the intermittency of wind means installing too much capacity will create grid instability unless suitable grid leveling options are available.

Transportation of wind-generated power can be accomplished via the electrical grid or by converting the electricity to a transportable fuel. Using the electric grid to transport the power would require significant updates to the national infrastructure. Additional high voltage transmission lines would be needed in many locations to connect wind resources with urban areas [4]. Another option is to convert intermittent electricity into a fuel. Several studies have been done recently on using electrolyzers to create hydrogen from wind-generated electricity [5,6].

Portions of national wind resources lie in areas that also have biomass availability. Therefore, biomass could be used to create peaking power, or wind-generated electricity could be

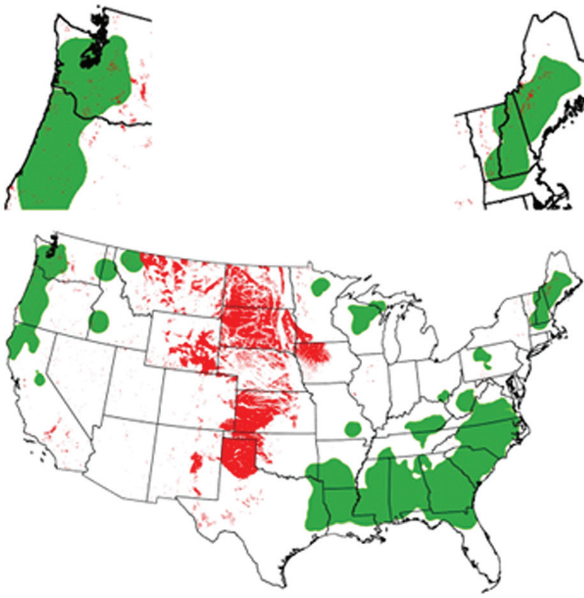

Fig. 1 Wind and woody biomass resources[2]

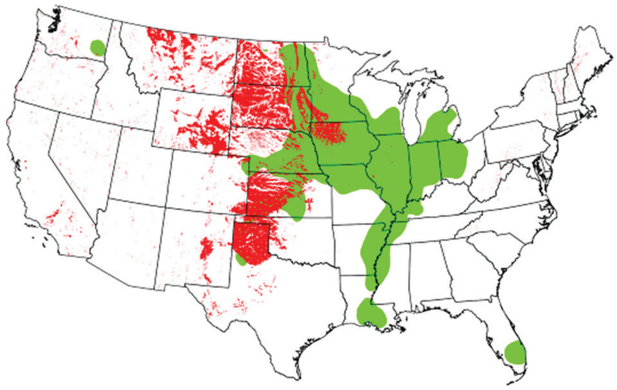

Fig. 2 Wind and agricultural biomass resources[2]

intermittently utilized by a properly designed biomass plant to create transportable fuel. The goal of this research is to determine the technical and economic viability of wind/biomass hybrid systems. ASPEN Plus thermodynamic simulation software was used in combination with time value of money economic analysis to explore the concepts presented.

Colocation Feasibility

For wind and biomass hybridization to be feasible, the two resources must be colocated. To confirm the possibility of colocation, maps were constructed that overlaid class 4 or higher wind resources onto biomass resources. Based on the U.S. Department of Energy's definitions of wind power classes, mapped resources have average wind speeds of greater than 5.6 m per second and an average wind power density of greater than 200 W/m^2 at a height of 10 m. Biomass availability data was taken from a previous study [1] and combined with wind resource information with the help of the National Renewable Energy Laboratory (NREL) geographic information systems (GIS) group. For both of the maps depicted in Figs. 1 and 2, the wind resources are shown in red and exclude potentially environmentally sensitive lands, wind on water features, and small isolated areas. The green shading on both maps indicate that greater than 2000 tons per day (TPD) of the specified type of biomass is available within an 80 km (50-mile) radius. Given the extent of green-area shading within these figures, any specific location within a shaded region is viable. The GIS maps do not account for competition for biomass resources (i.e., other biomass plants in the region). There are areas where the wind data are difficult to observe because the spatial resolution on the wind resources is much finer than the biomass,[1] so the areas of red can be difficult to distinguish.

Figure 1 shows woody biomass resources overlaid on available wind. Woody biomass includes forest residues and mill residues. Mill residues include the bark and wood materials produced when logs are processed into lumber and wood scraps from factories such as furniture manufacturers. There are small pockets of the northwest and northeast where both class 4 or greater wind and sufficient woody biomass exist for a colocated, combined system.

Figure 2 shows agricultural (crop) residue biomass resources versus available wind. Crop residues considered included corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane, and flaxseed. Residue estimates were adjusted down to allow for soil erosion control, animal feed, bedding, and other existing farm uses consistent with Milbrandt [1]. There is significantly more overlap of agricultural biomass with wind than woody biomass and wind.

Both figures[2] show overlap of biomass resources and wind availability. The overlap of woody biomass and land-based wind is small. However, some of the areas may have access to sea-based wind resources that were not considered here and wind installations do exist in areas that have less than class 4 wind. Agricultural biomass and wind overlap in a large part of the Midwest. This result shows that wind/biomass hybridization could provide a useful service in some areas of the central United States. The concept will not generally be applicable outside of these areas.

Concept Selection

Increased penetration of wind power on the grid will result in unique challenges. These challenges include management of intermittency with electric power peaking units, and in the extreme case, finding use for electricity produced by wind when there is less demand than the energy produced. Managing intermittency will drive utilities to invest in additional peaking units and increase the need for interruptible customers, energy storage options, and dispatchable loads.

Direct integration between a thermochemical biomass plant and wind power could allow a hybrid system to manage local intermittency or capture stranded wind resources. The proposed hybrid systems are intended to fill wind energy shortfalls and/or absorb excess wind-generated power.

A literature review was undertaken to determine the current state of research with respect to biomass hybridization. The results of this literature review were used to refine ideas developed during the initial brainstorming phase. In general, each concept generated was ranked on criteria including green-house gas emissions, feedstock renewability and availability, reliability, cost, fuel production (syngas output per unit biomass), and the state of the technology. The details of the literature review, concept generation, and concept selection process are discussed in greater detail by Dean et al. [7].

Two competing fluidized-bed biomass gasification technologies were identified as the most promising for further analysis. These two types were chosen due to their relatively high state of technology readiness and because they provide multiple opportunities for integration of renewable electricity within a gasification plant. One concept involves direct grid leveling of intermittent wind

[1]Wind resources have a special resolution of 1/4° longitude by 1/3° latitude whereas biomass resource data was available at the county level.

[2]Maps created with the help of Donna Heimiller of the NREL GIS group.

power with an indirectly heated biomass gasification plant. The plant will produce both electricity and hydrogen fuel. The other concept uses an electrolyzer bank in place of an air separation unit (ASU) for a directly heated biomass gasifier for coproduction of fuel and power.

Analysis Objectives

The key research objectives were to (i) provide a high-level technical evaluation of integration options of wind-generated electricity with biomass gasification, (ii) quantify the amount of energy production or energy absorption possible with a 2000 TPD biorefinery, (iii) estimate the cost of hydrogen production for each hybridization option, and (iv) compare the economic results with other hydrogen production systems, such as steam methane reforming of natural gas.

A plant input capacity of 2000 TPD of biomass was selected for the analysis based on resource availability. Assuming an 80 km (50-mile) collection radius, multiple regions throughout the country were identified that could support this level of biomass requirement. At scales larger than 2000 TPD, the number of possible plant locations in the United States becomes severely limited [1]. Woody biomass was used as the plant feedstock for all the concepts studied. Biomass type was not varied due to limitations of the thermodynamic system model and concerns about the feasibility of feeding fibrous agricultural waste reliably. Pilot plants such as the IGT RENUGAS plant have clearly demonstrated the difficulty of feeding fibrous feedstock into a gasifier [8].

Based on a fixed biomass throughput, baseline directly heated and indirectly heated gasification plants were established. ASPEN Plus software was employed to determine the plant input and output parameters for each system. The baseline systems were optimized for hydrogen production using near term (~2012 timeframe) technologies. For the indirectly heated gasifier, a previously published system study was used as the baseline [9]. Since there was not an existing model available for the directly heated gasifier case, a model was constructed as part of this research. Detailed information about the ASPEN Plus models can be found in Ref. [10]. With indirectly and directly heated baseline cases in place, each plant was modified to incorporate the proposed hybrid concepts.

The models for all plants were steady-state. Control strategies and the dynamic effects of intermittent operation were not considered. Instead, the results of this study are intended to help inform the decision of whether the proposed systems deserve further consideration and dynamic simulation.

Indirect Gasifier Based Hybrid System

The first concept investigated is based on indirectly heated gasification architecture. The schematic of the plant layout is provided in Fig. 3. Indirectly heated gasification is a two-stage, fluidized-bed process where the heat needed for the reaction is produced by burning char in a separate chamber to heat sand. The hot sand is then circulated through the reaction chamber to drive reaction kinetics.

The biomass to hydrogen plant design proposed by Spath et al. [9] was used as the baseline design. Biomass entering the biorefinery is dried, then gasified to produce syngas in an atmospheric pressure, indirectly heated gasifier. Tar is thermally cracked in a catalytic tar cracker. The tar cracker must be heated because of the relatively low temperature (870 °C) of the syngas leaving the gasifier. Tar cracking temperatures typically exceed 900 °C [9,11]. Particulates and any tars remaining after the tar cracker are removed from the syngas using a wet scrubber. Sulfur is removed from the syngas in a two-step process of LO-CAT desulfurization followed by ZnO polishing beds. After sulfur has been removed, the carbon monoxide in the syngas stream is shifted towards hydrogen. Finally, the hydrogen is separated from the syngas via pressure swing adsorption (PSA) and the remaining (purge) gas is burned with a small natural gas trim to provide heat to the tar cracker.

Two possible changes to the biorefinery design were investigated. The first modification allows switching between fuel production and electricity production based on grid demand ("peaking"). This is accomplished by routing some or all of the syngas from the gasifier to a gas turbine instead of the fuel production reactors. The second modification allows the use of surplus electricity by the gasifier for heating ("sinking"). The conversion of wind-generated electrical energy to thermal energy within the gasifier effectively "sinks" the wind power into hydrogen fuel production. Both of these operating modes are discussed in further detail in the subsequent sections. Accordingly, analysis of each concept was separated into the peaking and sinking operating modes. The two modifications were analyzed individually to highlight their respective effect on plant performance and economics.

An ideal hybrid plant would continuously adjust both electricity use and fuel production to optimize plant economics. Electricity is produced instead of hydrogen when electricity is the more profitable product and vice-versa. Similarly, electricity is used for heating (or sunk) when electricity costs are low enough that the additional plant efficiency for hydrogen production offsets the cost of grid electricity.

Indirect Gasifier Peaking Modifications. Several modifications are required to allow the baseline biorefinery to alternate between hydrogen production and electricity production. These modifications include adding a gas turbine to the plant and the addition of several syngas routing provisions.

A general electric (GE) F class simple-cycle turbine was chosen for electricity production [12]. The F-class turbines can achieve a 20% increase in capacity when run on syngas (e.g., a turbine rated for 75 MW production on natural gas can produce up to 90 MW) depending on the syngas composition [12]. The higher power production is due primarily to higher mass flow through the turbine. When a nonstandard (low heating value) fuel is burned, a higher fuel feed rate is needed to provide the same amount of energy to the turbine. According to one GE technical paper [13], up to 14% deviation from catalogue flow rates can typically be achieved while avoiding compressor stall.

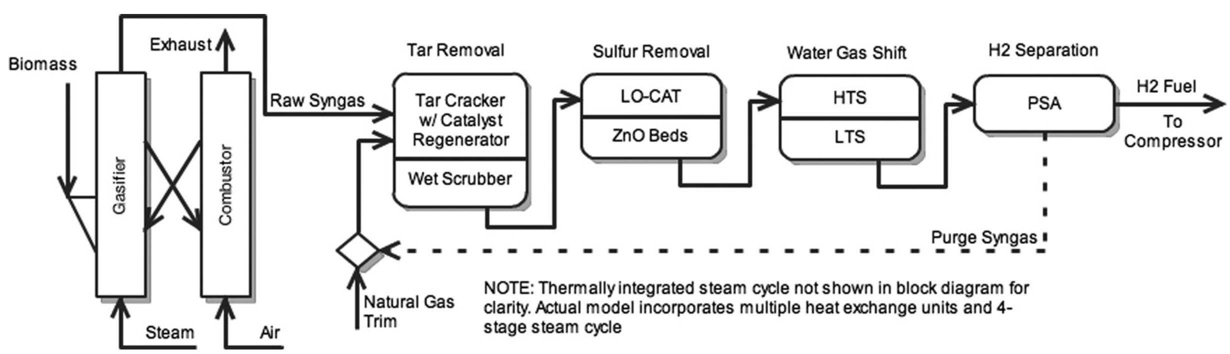

Fig. 3 Indirect gasifier baseline system

Cooling issues can arise with syngas combustion depending on its composition. Increased burner temperatures can shorten the service life of a turbine as well as significantly increasing NO_x and SO_x emissions. Based on data from general electric gasification projects [13] and previous research performed at the NREL [14], syngas compositions similar to the ones used in this study are typically humidified with steam before combustion to regulate the turbine inlet temperature. Steam was added to the syngas so that the final fuel gas was 20% water by weight. This corresponds to a lower heating value (LHV) of approximately 11 MJ/kg. The steam was available from the on-site steam cycle.

Syngas from the LO-CAT reactor is sent to the gas turbine during power generation. Tar reforming is required because tars are corrosive and could adversely affect the turbine combustor. In addition, the tar represents a significant portion of the chemical energy of the syngas, and removal (versus reforming) would result in a measurable decrease in plant efficiency. Therefore, directly after the tar reformer was the first possible location to split the syngas stream for combustion. However, by placing the turbine downstream of the bulk sulfur removal step, emissions of SO_x can be significantly reduced.

The system operates in a binary mode, meaning that it either produces power or hydrogen but not both at the same time. In addition to potential dynamic operational issues associated with switching between the two modes, there are several steady-state technical challenges due to the high degree of thermal integration in the base plant. Down stream water-gas shift (WGS) catalyst beds are extremely sensitive to air exposure and therefore syngas flow must be maintained or they must be sealed if shut down. In addition, the pressure swing adsorption off-gas from hydrogen production is burned to heat the tar reformer. This energy must be replaced when the PSA is not running during power production. Finally, the base design includes a thermally integrated steam cycle, which is partially fed by syngas cooling steps downstream of the split location. Loss of this heat energy to the steam turbine will adversely affect the plant power system.

The first two technical challenges were both addressed by diverting only a limited amount of syngas to the gas turbine when producing electricity. A slipstream of syngas is maintained through the water-gas shift reactors to avoid oxygen poisoning of the catalyst. After going through the water-gas shift reactors, the syngas is routed to the tar reformer and burned to replace the PSA off-gas that was previously burned to maintain temperature. This approach should keep the sensitive water-gas shift catalysts from air and also meet the energy demands of the tar reformer system. In addition, all base design systems are kept warm and active (except for the PSA unit) until peaking power is no longer needed.

In order to maintain the base plant steam system, a portion of the exhaust gases from the gas turbine are run through a heat exchanger. The heat exchanger exactly replaces heat loss from cooling steps downstream of the split location.

Table 1 summarizes the ASPEN Plus® simulation results for the peaking hybrid system. When making hydrogen fuel, the plant would have the major input and output variables shown in the H_2 production column. The power production column shows the input and output variables when the PSA unit is shut down.

Table 1 Peaking system input and output[a]

		H_2 production mode	Power production mode
Inputs (MW)	Biomass feed[b]	434	434
	NG feed[c]	23	—
	Electricity	10	—
Outputs (MW)	Electricity	—	77
	H_2[d]	232	—

[a]Where applicable, mass flows were converted to energy flows with the following lower heating values.
[b]A biomass LHV of 18.7 MJ/kg bone-dry wood was used [7].
[c]Natural gas LHV of 47.14 MJ/kg was used per HyARC database [23].
[d]Hydrogen LHV of 120.21 MJ/kg was used per HyARC database [23].

Table 2 Indirect gasifier capital costs

Plant area	Peaking	Sinking
Baseline indirect gasifier plant[a]	\$104.9 M	\$104.9 M
Turbine	\$32.2 M	—
Exhaust BFW preheater	\$0.25 M	—
Air duct heater and air blower	—	\$15.8 M
Total	\$137 M	\$121 M

[a]The baseline plant design and costs are based on Ref. [9].

The power production value of 77 MW represents the net power the plant could produce using a "rubber" turbine[3] with GE F-class efficiencies. The rubber turbine has a gross, assumed nameplate capacity of 80.6 MW but loses significant power due to plant parasitic needs. When running in a peaking capacity, the plant has a low total efficiency of 17.8%-LHV. This is compared to an efficiency of 49.7%-LHV when producing hydrogen and an expected stand-alone turbine efficiency of approximately 32%.

The extremely low power production efficiency is the result of multiple factors including the fact that 21% of the syngas stream is used to maintain the water-gas shift reactors and tar cracker at elevated temperature rather than for power production. In addition, a portion of the power output is used to serve auxiliary electrical loads within the plant.

Capital costs were estimated using numbers taken from Ref. [9] as a starting point. In 2005 dollars, the cost of a 2000 TPD biorefinery is estimated to be approximately $\$105 \times 10^6$. The cost of the gas turbine and additional heat exchangers were added to this cost for the hybrid case. The gas turbine costs were taken from Ref. [15] and then adjusted to \$2005 using the Chemical Engineering Plant Cost Index. Heat exchanger costs were calculated with the same scaling factors used in Ref. [9]. The additional capital costs for the turbine and exhaust boiler feed water (BFW) preheater are listed in Table 2.

Indirect Gasifier Sinking Modifications. Recent studies suggest that an indirectly heated gasifier will not produce enough char to maintain gasification temperatures; therefore, raw syngas must be diverted and combusted to supplement the heat delivered to the gasifier by the char combustor [16]. Therefore, during periods of low electricity demand (low purchase price), electric heaters could be used to add heat and partially replace the syngas recycle stream. Electric heating allows more hydrogen to be produced per ton of biomass feedstock, which increases plant production.

Supplementing the heat delivered to the gasifier by the char combustor with electrically generated heat rather than diverting and combusting syngas could be accomplished in multiple ways [10]. For this analysis, high-power, high-temperature electric air heaters were used. By preheating the combustion air used in the syngas and char combustors, more heat can be delivered to the sand per kilogram of char or syngas combusted, resulting in a reduced amount of syngas that must be recycled. The intention is to allow intermittent use of the combustion air preheaters, allowing the system to recycle syngas when electricity prices are high and add electric heat when electricity prices are low.

The ASPEN Plus® simulation results are summarized in Table 3 and appear to be promising. The amount of syngas that must be diverted is reduced by about 45% by combustion air preheating.

[3]The term "rubber" turbine refers to the fact that the turbine size was set to exactly match fuel stream mass and energy flow as opposed to using an existing, stock frame size.

Table 3 Sinking system input and output[a]

		H_2 production mode	Sinking mode
Input (MW)	Biomass feed	434	434
	NG feed	23	28
	Electricity	10	57
Output (MW)	Electricity	—	—
	H_2	232	261

[a]Where applicable, mass flows were converted to energy flows with the same heating values given in Table 1.

Additionally, enough hot combustion products are still produced to dry the incoming biomass.

Unlike the peaking modification, which produced lower efficiency, adding electric heat to the plant increases the total plant efficiency (energy in/energy out) from 49.7% to 50.3%. Each additional unit of energy input as electricity produces 0.56 units of hydrogen energy output. Therefore, while providing a dispatchable load service to the local utility, the hybrid plant operates more efficiently.

The electric heater capital costs are based on a quote provided by a manufacturer [17] for their largest, high-temperature air duct heater. Based on that quote, a 2.2 MW air duct heater is estimated to cost $250,000 and has an electricity-to-heated air conversion efficiency of 90%. Since additional unit savings are not expected with increasing scale, a scaling factor of 0.9 was used. Finally, an installation factor of 2.47 was assumed for all cost estimates for consistency with other NREL hydrogen analyses (H2A) [9]. Based on these assumptions, the total additional capital costs for electrically heating the combustion air amounted to $15.8 million.

Direct Gasifier Based Hybrid System

Directly heated gasifiers typically have a single combustion/reaction chamber and burn a small portion of the biomass feed to generate the heat needed to drive the gasification reactions. A source of pure oxygen is required for combustion if the syngas is to be used for fuel production to avoid nitrogen dilution of the syngas. For large-scale oxygen production, the established method is to use a cryogenic ASU. Electrolysis could provide an alternative to an ASU with the added benefit of producing an additional pure hydrogen stream.

Recent research on the feasibility of combining electrolysis with gasification concluded that the economic feasibility of the combination was highly dependent on the price of available electricity [18]. The proposed hybrid system could directly address electricity price dependence by running the electrolysis system intermittently based on the cost of electricity.

A baseline gasification plant (see Fig. 4) and a hybrid plant were simulated in ASPEN Plus and were compared. Both the baseline and hybrid plants have the same general structure; biomass is gasified to produce syngas in a high-pressure, directly heated gasifier. Tars are removed and the syngas is cooled before entering a sulfur removal step. After sulfur has been removed, the carbon monoxide in the syngas stream is shifted towards hydrogen. Finally, the hydrogen is stripped from the syngas and the remaining gas is burned to generate power. Figure 4 shows the envisioned biomass to hydrogen pathway using the direct gasifier and a cryogenic ASU.

The bulk of the chemical processes operate at high pressure. The wet scrubber is run near atmospheric pressure, which requires cooling and recompression of the syngas before sulfur removal. The directly heated gasifier operating pressure selected in this study was 24 bar and represents the state of the art in fluidized-bed biomass gasification systems. It has been shown that higher gasifier operating pressure is generally preferred when considering gasifier efficiency and the heating value of the syngas [19]. However, the sensitivity of gasifier performance increases if pressure is rather low. For instance, a doubling of gasifier pressure only increases gasifier efficiency and heating value by 1–2% points [19]. A detailed exploration of the effect of gasifier operating pressure on the merit of the hybrid system proposed herein is beyond the scope of this analysis, but efficiency analyses and biorefinery performance using pressurized gasifiers are reported elsewhere [20]. Detailed discussion of the design assumptions and simulation are available in Refs. [7,10].

A cryogenic ASU is used to produce the oxygen for the baseline study. In addition to producing oxygen, a nitrogen stream is available as a byproduct from the ASU and is used as the inert pressurization agent for the lock-hopper system. To replace the ASU with electrolyzers, the LO-CAT/ZnO sulfur removal steps would need to be replaced with a two-stage Selexol plant. The sulfur removal change is driven by the need for an inert gas for feed pressurization. Since no nitrogen stream is available from the electrolyzer, carbon dioxide will be used for feed pressurization instead. Selexol can be configured to remove both sulfur compounds and carbon dioxide from the syngas [21].

To replace a single ASU unit for oxygen production, multiple electrolyzers are needed. The largest commercial electrolyzer is produced by StatoilHydro and produces a maximum flow rate of 174 kg/h of oxygen (43.6 kg/h of hydrogen). The StatoilHydro electrolyzer is an alkaline, low-temperature system [22]. While significant research is ongoing for high-temperature, advanced electrolysis systems, commercial technology was chosen for this analysis.

Based on ASPEN simulations, a 2000 TPD fluidized-bed, biomass gasifier with secondary oxygen injection would need approximately 27,800 kg/h of oxygen supplied. For this design, 160 electrolyzers would be needed to replace the ASU. This number

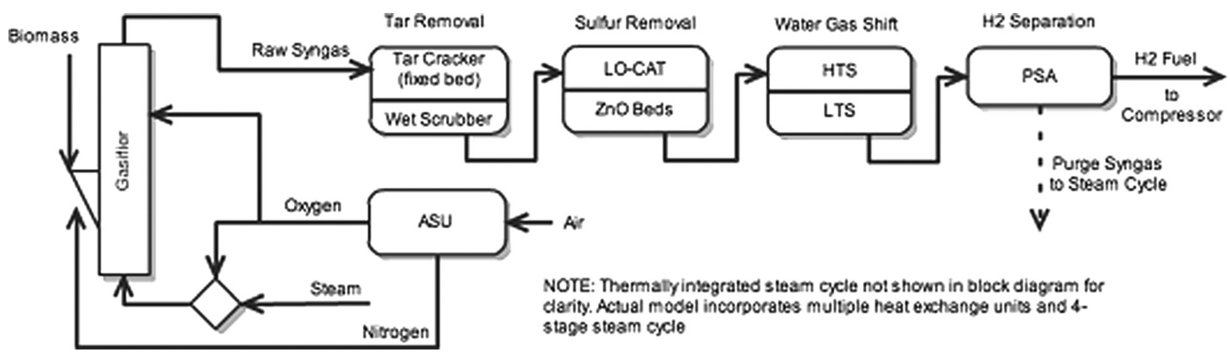

Fig. 4 Direct gasifier baseline system

Table 4 Direct gasifier input and output[a]

		Baseline plant	Hybrid plant
Input (MW)	Biomass feed[b]	411	411
	NG feed	—	—
	Electricity	—	342
Output (MW)	Electricity	15	—
	H_2	165	449

[a]Where applicable, mass flows were converted to energy flows with the same heating values given in Table 1.
[b]A biomass LHV of 17.7 MJ/kg bone-dry wood was used due to slightly different simulation feedstock [24].

assumes that all electrolysis units run at design capacity 100% of the time.

Input and output parameters from the electrolysis plant were determined from the published "Future Central Hydrogen Production from Grid Electrolysis" H2A case [23]. Based on ASPEN Plus simulations and the electrolysis H2A case, the plant input and output values for the hybrid system were estimated. The values for each individual plant and the hybrid case are given in Table 4.

The amount of electricity required to power the electrolyzer bank is extremely large when keeping the plant sized at 2000 TPD. Assuming a 35% capacity factor for installed wind, 970 MW of installed wind capacity would be needed to generate enough average electricity for a 2000 TPD plant. This is much larger than the total amount of installed wind power in some states. The large electricity needs render the idea of capturing stranded resources with this scale biorefinery plant problematic and ultimately infeasible. However, it is noteworthy that hydrogen production is also increased by 172% over the base plant with this hybrid concept.

While this study focuses on maintaining a 2000 TPD size biorefinery, if instead the plant design objective was to deliver 165 MW of hydrogen, then the biomass feed requirement could be lowered to approximately 920 TPD and the electricity demand reduced by 62%. The reduction in biomass feedstock requirements with this configuration is significant because it increases the number of geographic locations that could support wind/biomass hybrid systems and ultimately lowers the land area requirements for sustainable fuel production.

Multiple sources were used to estimate the capital costs associated with the directly heated gasifier concepts. All electrolyzer costs were calculated using the previously mentioned hydrogen analysis [23]. The majority of costs associated with the fluidized bed gasifier and feed preparation were taken from a recent publication by Jin et al. [25]. Gas cleanup costs were scaled based on previous systems studies completed at the NREL [9]. Selexol prices were based on Department of Energy estimates [26]. An overview of the capital costs can be found in Table 5. Detailed costing information for both systems is available in Refs. [7,10].

Based on the cost information summarized in Table 5, direct replacement of the ASU with an electrolyzer bank causes a 72% increase in the total capital investment required.

Table 5 Direct gasifier capital costs

Plant area	Baseline	Hybrid
Feed preparation, handling	\$27.9 M	\$27.9 M
Gasification, tar reforming, quench	\$22.7 M	\$22.7 M
ASU or electrolyzer bank	\$21.3 M	\$99.2 M
Gas cleanup	\$29.9 M	\$58.7 M
Shift and PSA	\$18.6 M	\$18.6 M
Steam and power generation	\$20.4 M	\$20.4 M
Water and other utilities	\$2.1 M	\$3.7 M
Buildings and structures	\$6.4 M	\$6.4 M
Total	\$149.3 M	\$257.6 M

Economic Model

The hybrid system concepts studied respond dynamically to fluctuations in the energy market, either absorbing or providing electricity on demand. To simulate this switching, a binary model was created for each proposed system based on a specified peaking or sinking duty. Duty is defined as the percent of hours per year where either sinking or peaking mode is used.

All concepts were assumed to be grid-connected for the analysis. The hybrid plants are intended to provide grid leveling services to a local utility that has intermittent wind resources. This arrangement allows for direct assessment of the market value of electricity and avoids inclusion of wind turbine capital costs in the cost of the system. For the directly heated gasifier hybrid system, the effect of stranded operation is discussed briefly in the economic results section of this paper.

Regional Transmission Organization (RTO) day-ahead prices were used for the cost-of-electricity when available. These prices represent the market value of electricity to the local utilities in an area on an hourly, averaged basis. The hybrid systems must be profitable at this low price point to cost effectively trade electricity on the energy market. When day-ahead market information was unavailable, load lambda data was used in its place. Load lambda data give the cost of producing one unit of electricity to the utility for each hour of the year. In all cases, costs were based on 2007 year-end data. Based on GIS research reported earlier (see Figs. 1 and 2), three general areas appear to have overlapping resources of both wind and biomass. These areas are served by the Northeast Independent System Operator (NE ISO), Midwest ISO (MISO), and Northwest Interchange (NW Int.). Cost of electricity values for each of these areas was used in the analysis.

To assess the economic potential of each of the proposed hybridizations, the yearly inputs and outputs for each plant, along with applicable capital costs, were entered into the H2A Analysis Tool developed by NREL [27]. The resulting cost of hydrogen produced (in dollars per kilogram) was compared to baseline plant results and also the published steam methane reforming results [28]. The analysis was performed in 2005 constant dollars for consistency with previous NREL studies [9,28].

The price of natural gas was held static for each of the regions studied. The 2009 Annual Energy Outlook report predicts regional variation of natural gas prices in the US of approximately three dollars per million Btu [29]. The predicted variation translates to approximately 10 cents per normal cubic meter. The sensitivity analysis for each of the hybrid plants shows the effects of a larger 30% variation in natural gas prices. The SMR base case is also sensitive to natural gas prices with a \$0.10 per normal cubic meter variation in price gas price causing a \$0.47 change in the cost of hydrogen produced [28].

The economic analysis makes several assumptions including that current electricity prices are representative of those at the time of actual plant construction and that sufficient market demand for hydrogen exists that all product can be sold. The major economic assumptions are summarized in Table 6. Additionally, values for rate of return and startup times for the plants are selected to enable comparison with other studies on hydrogen production from resources such as methane (see Tables 8 and 9). For this reason, all economic assumptions were taken directly from H2A defaults [27].

The effects of carbon costs on system results were taken into account separately as an adjustment to the H2A results. The amount of CO_2e per kilogram of hydrogen produced was tracked for all cases analyzed. The emissions for each hybrid system vary not only with the type of hybridization but also with the amount of time spent in each mode of operation. Values for these emissions are given with the economic results.

In addition to including the CO_2e emissions from the plant, there is a CO_2e credit associated with carbon emissions avoided due to the renewable nature of any fuel or electricity produced. Based on the regional average grid mix, anywhere from 483 to 724 kg of CO_2e are emitted per kilowatt-hour of electricity produced.

Table 6 Economic assumptions

Parameter	Value
Constant dollar value	2005
Internal rate of return (after-tax)	10%
Debt/equity	0%/100%
Plant life	40 years
Depreciation	Modified accelerated cost recovery system
Depreciation recovery period	20 years
Construction period	2 years
1st year	75% (25% for electrolysis)
2nd year	25% (75% for electrolysis)
Start-up time	12 months
Revenues	50%
Variable costs	75%
Fixed costs	100%
Working capital	15% of total capital investment
Inflation rate	1.9%
Total taxes	38.9%
Decommissioning costs	10% of depreciable capital
Salvage value	10% of total capital investment

Table 7 details the grid production mix and corresponding emissions for each location studied. The values shown in Table 7 are assumptions in so much as they are averaged values for large processes or regions. Table 7 is actually a calculation matrix. As an example, for the column "NE ISO" the calculation for the average greenhouse gas emission for each kilowatt-hour of energy produced is shown in Eq. (1).

$$0.150 \times 952.5 + 0.180 \times 893.1 + 0.300 \times 599.2 = 483 \tag{1}$$

One kilogram of hydrogen has the approximate energy equivalent of 1 gal of gasoline. However, because hydrogen can be used in fuel cells with much higher efficiency, 1 kg of hydrogen could actually offset about 2 gal of gasoline [30]. Burning 2 gal of gasoline produces 17.84 kg of CO_2e. These numbers were used as carbon credits for each kilogram of hydrogen or megawatt-hour of electricity produced by the proposed systems.

Economic Results

The proposed indirectly heated gasifier, peaking system switches between (1) hydrogen production and (2) electricity production (peaking) driven by the cost of electricity available on the grid. Based on discussions with Xcel Energy in Colorado [34], a peaking duty of 20% was used for the analysis. Table 8 summarizes the major model inputs by region for the system. A contract rate was used for any peaking electricity produced by the plant. This is common practice in the current electricity market and provides a premium price for dispatchable peaking assets. The cost of biomass feedstock was not varied regionally due to a lack of a reliable index or market basis upon which to base the variation.

Table 7 Greenhouse gas assumptions

	kg CO_2e per kW h[a]	NE ISO[b]	MISO[c]	NW Int.[d]
Coal	952.5	15.0%	75.6%	58.0%
Oil/petroleum	893.1	18.0%	0.1%	1.0%
Natural gas	599.2	30.0%	3.6%	19.7%
Nuclear	—	28.0%	15.1%	1.0%
Renewable	—	9.0%	5.6%	20.3%
Average kg CO_2e/kW h	—	483	743	679

[a]HyARC Energy Constants and Assumptions, H2A Analysis Tool [26].
[b]NE ISO energy sources report [31].
[c]Midwest ISO June monthly report [32].
[d]Approximation based on PacifiCorp 2008 integrated resource plan [33].

Table 8 Peaking system H2A inputs

	NE ISO	MISO	NW Int.
Peaking duty	20%	20%	20%
Peaking electricity value (¢/kW h)	14.0	12.0	11.5
Utility electricity cost (¢/kW h)	5.92	3.62	3.69
Utility natural gas cost ($/nm^3)	0.32	0.32	0.32
Cost of biomass ($/ton)[a]	48.83	48.83	48.83

[a]Value taken from the Biomass 2009 Multi-Year Research, Development and Demonstration Plan (EERE 2009). The 2012 target value is $50.70 per ton of dry woody biomass in 2007 dollars. Taken to 2005 dollars with 1.09% inflation this yields $48.83 per ton.

Instead, the effect of biomass feedstock cost was investigated as part of the sensitivity analysis.

Based on the economic inputs above, and the plant inputs and outputs previously discussed, the cost of hydrogen production in each area was calculated. The results are shown in Table 9 along with the cost of hydrogen production for a baseline, nonhybridized biomass to hydrogen plant and a SMR plant.

The additional capital costs of hybridization cannot be justified today in any of the locations studied. There is a $0.20 to $0.24 per kilogram premium on hydrogen produced by the proposed hybrid system compared with a nonhybrid biomass to hydrogen gasification plant. Areas with higher priced electricity move this hybridization closer to economic feasibility with the best results found in the Northeast.

When the hybrid plant is producing electricity, the plant uses no natural gas or electricity whereas when the plant is producing hydrogen, natural gas is used for balancing the heat duty of the plant and electricity is required to run compressors. Taking the differences in carbon emissions into account, a value of $37–40 per metric ton of CO_2e makes the cost of hydrogen for the proposed hybrid system equal to that of SMR depending on the location. This comparison was made assuming that both the hybrid plant and SMR plant are subject to the same natural gas cost at a given location.

It is important to note that the baseline biomass to hydrogen plant only requires $23–25 per metric ton of CO_2e value to be cost competitive with hydrogen produced by SMR. This means that peaking hybridization will only be economically promising when there is some value placed on the additional functionality of dual mode operation.

In order to characterize the effect of various technical and economic assumptions, a sensitivity analysis was performed for the gas turbine peaking system. Figure 5 shows the results for the cost of hydrogen in tornado chart format. Capital costs, the cost of biomass, and the price which peaking electricity can be sold for are the key inputs. Capital costs, when varied ±30% cause the cost of hydrogen to vary $0.25. The cost of biomass was varied from $40 to $60 per ton based on projections in Ref. [35] and causes the cost of hydrogen to vary by less than $0.20. The price of peaking electricity and the plant capacity factor also cause fluctuations of less than $0.20. Changes in the cost of electricity bought by the plant, the cost of natural gas, peaking power output, and turbine peaking duty cause hydrogen costs to vary less than 5%.

The proposed sinking system switches between (1) hydrogen production with syngas recycling for gasifier heat and (2) hydrogen production with electrical heating (sinking) to decrease the

Table 9 Peaking system results

$/kg H_2	NE ISO	MISO	NW Int.
SMR	1.40	1.40	1.40
Biomass to hydrogen baseline	1.64	1.64	1.64
Gas turbine hybrid system	1.84	1.86	1.88

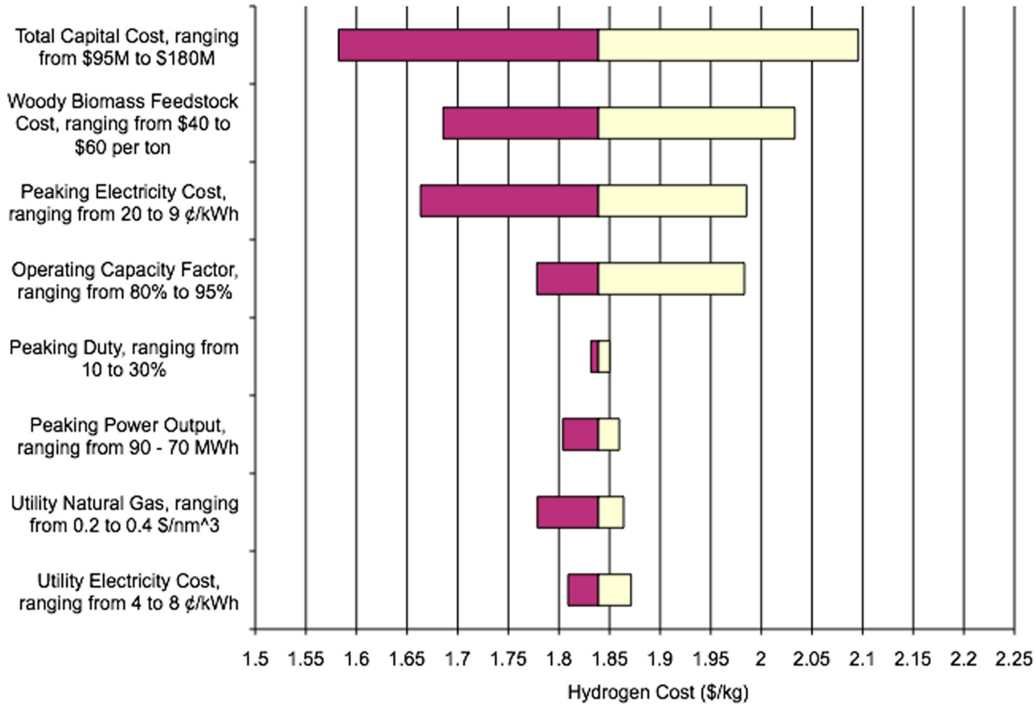

Fig. 5 Peaking system sensitivity (NE ISO)

syngas recycle. This sinking ability can best be described as a dispatchable load or demand from the viewpoint of the grid.

Based on discussions with Xcel Energy, the utility will pay to have wind-generated electricity used at times (the electricity has a negative cost) and having a dispatchable load would provide a valuable service to the utility [34]. Xcel Energy is required by Colorado's renewable portfolio standard to accept renewable energy when it is available. The requirement to accept wind electricity regardless of grid demand is not universal and therefore negative cost wind electricity may not be available in other states.

No similar system was found for comparison; therefore, a sinking duty of 20% was used as a starting point for the analysis. Table 10 summarizes the major economic model inputs by region. Unlike peaking electricity, where a contract rate is used for electricity produced by the plant, the sinking analysis simply uses the average cost-of-electricity for the cheapest 20% of hours as the sinking electricity cost. The utility electricity cost is the average of the remaining 80% of the hours. These costs-of-electricity would be valid if a plant operator used accurate day-ahead energy market forecasts to schedule plant operation.

Given the economic inputs in Table 10, the cost of hydrogen production in each area was calculated. The results are shown in Table 11 along with the cost of hydrogen production for a baseline, nonhybridized biomass to hydrogen plant and a steam methane reforming plant.

There is a \$0.03 to \$0.11 premium on hydrogen produced by the proposed hybrid system compared with a nonhybrid biomass to hydrogen gasification plant. The additional capital costs of the sinking hybridization are not fully offset by additional revenue in any of the locations studied. However, the marginal costs found are small enough that it is difficult to draw any definitive conclusion. Areas with lower cost electricity move this hybridization closer to economic feasibility with the best results found in the Northwest.

Because the premium is small (about 5%) it may be acceptable in the long term. Recent studies have shown that there is inherent value added, or welfare effects, for electricity storage capacity [36]. Whether similar value is added by the proposed sinking hybrid is unknown. A more likely parallel would be the idea of "interruptible customers" which get discounted electricity rates in return for intermittent power supply. A similar contractual agreement could be envisioned for the proposed hybrid where discounted electricity rates would be provided in return for intermittent demand.

The proposed system is not a direct competitor with storage systems such as pumped hydroelectric or compressed air energy storage (CAES). Energy storage systems attempt to profit by market arbitrage (selling electricity back to the grid at a higher price than it was bought) whereas the proposed hybrid system sinks cheap electricity into transportation fuel. Sinking low cost electricity into fuel could be considered cross-market arbitrage and the most similar system to this would be electrolysis. Compared to electrolysis, the proposed system is significantly less expensive and has the added benefit of running without electric heat when electricity costs are too high.

Assuming that all sinking electricity is renewable and taking the additional differences in carbon emissions into account, a value of \$26–32 per metric ton of CO_2e makes the proposed hybrid cost competitive depending on the location of the system.

Table 10 Sinking system H2A inputs

	NE ISO	MISO	NW Int.
Plant capacity factor	90%	90%	90%
Sinking duty	20%	20%	20%
Sinking electricity cost (¢/kW h)	4.35	2.20	2.18
Utility electricity cost (¢/kW h)	7.05	4.87	4.69
Utility natural gas cost ($/nm^3)	0.32	0.32	0.32
Cost of biomass ($/ton)	48.83	48.83	48.83

Table 11 Indirect sinking system results

$/kg H_2	NE ISO	MISO	NW Int.
SMR	1.40	1.40	1.40
Biomass to hydrogen baseline	1.64	1.64	1.64
Electric air heater hybrid system	1.75	1.67	1.68

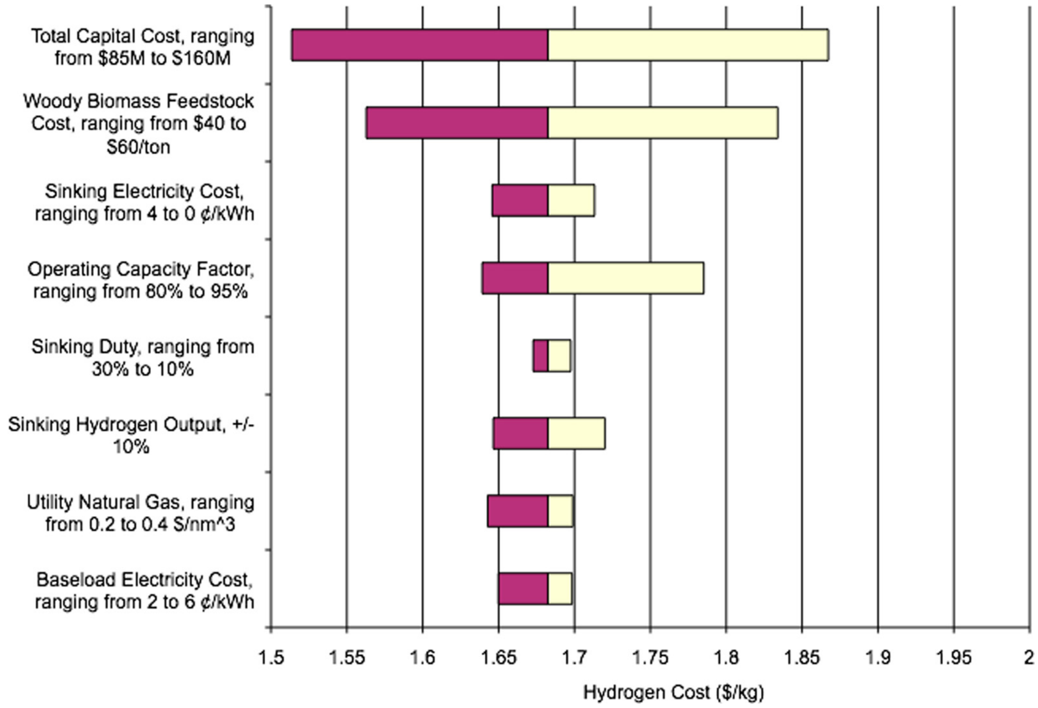

Fig. 6 Sinking system sensitivity (NW Int.)

At $27 per metric ton of CO_2e, the combustion air-heater hybridization becomes cost competitive with a methane steam reforming plant in the Northwest assuming both the hybrid plant and SMR plant are subject to the same natural gas cost.

In order to characterize the effect of various technical and economic assumptions, a sensitivity analysis was performed for the sinking systems (Fig. 6). The sensitivity analysis shows that capital costs, the cost of biomass, and the plant capacity factor for are the key inputs. Capital costs, when varied $\pm 30\%$ cause the cost of hydrogen to vary $0.18. The cost of biomass was varied from $40 per ton to $60 per ton and causes the cost of hydrogen to vary by less than $0.15. Changes in the sinking duty, the added hydrogen production due to sinking, the cost of natural gas, and the cost of electricity cause hydrogen costs to vary less than 3%.

From the sinking duty sensitivity analysis, it appears that an increased sinking duty would be preferable to the 20% assumption made. Minimum hydrogen production prices occur when the electric heating systems are run approximately 40% of the time. Running the electric heaters for more time increases plant hydrogen production and decreases plant green house gas emissions.

The proposed directly heated gasifier hybrid system replaces the ASU with an electrolyzer bank. An H2A analysis was completed to determine the baseline cost of hydrogen produced by a directly heated gasification plant that uses electrolysis regardless of electricity cost and the cost of hydrogen for a directly heated gasification plant that uses a traditional ASU. Table 12 summarizes the major model inputs. The plant was assumed to be located in the Midwest ISO region. The results of the analysis, along with the associated carbon emissions, are listed in Table 13. Costs for production of hydrogen via SMR and for an electrolysis plant only are also shown for reference purposes.

As shown in Table 13, hydrogen produced by a direct gasifier-electrolyzer hybrid plant is significantly more expensive than that produced by SMR. Electricity costs account for 37% of the overall cost of hydrogen produced (or about $0.86). Therefore, if the cost of electricity could be halved by intermittent operation during off-peak hours, the savings would bring the cost of hydrogen to $1.89 per kilogram of hydrogen. At this price, the hybrid system could compete with hydrogen produced by a standard direct gasification plant. It is important to note that these costs are approximately 15% higher than the $1.64 per kilogram of hydrogen estimated for the indirectly heated baseline gasification plant used for comparison of the indirect hybrid analysis (see Table 11).

The original concept called for the electrolyzer bank to be directly coupled with stranded wind resources. Typical capacity factors for wind-generated power are in the 30–35% range [37]. The effect of intermittent operation on the cost of hydrogen production was investigated using electrolyzer duties of 20%, 35%, and 50%. The smaller the duty, the larger the number electrolyzers needed to produce the same amount of oxygen per year.

The effect of reduced electrolyzer duty on the cost of hydrogen is shown in Fig. 7. Two curves are plotted. The first assumes a constant electricity price of $4.33/MWh regardless of the electrolyzer duty. This assumption would represent the scenario if the electrolyzers were directly coupled with a stranded wind resource. The second curve uses Midwest ISO market data so that the cost of electricity fluctuates with duty. These numbers do not consider the cost of oxygen storage, as these costs are assumed small compared to the increased electrolyzer capital costs and are identical for similar duty.

Intermittent operation significantly adds to plant capital costs. If the price of electricity available to the plant does not decrease

Table 12 Direct system H2A inputs

	MISO
Electrolyzer duty (%)	100
Utility electricity cost (¢/kW h)	4.33
Cost of biomass ($/ton)	48.83

Table 13 Direct system results

	$/kg H_2	Net $CO_2e/kg\ H_2$
SMR	$1.40	−6.8
Biomass gasification	$2.13	−19.6
Electrolysis	$2.59	14.5 (−17.8)
Electrolysis + gasification	$2.32	0.24 (−18.2)

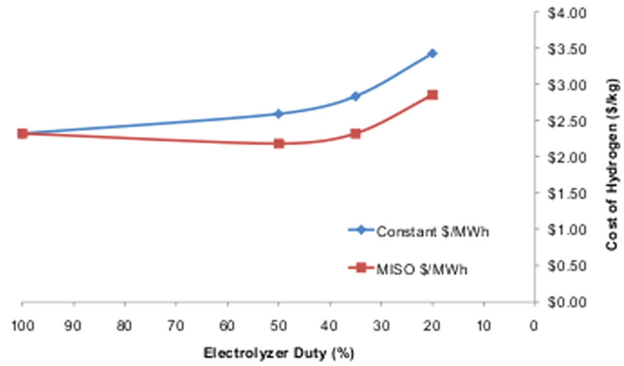

Fig. 7 Electrolyzer duty versus cost

with intermittent electrolyzer operation, then the cost of hydrogen increases by 22% for a 35% duty. However, if the cost of electricity can be reduced by intermittent operation then the analysis shows that intermittent operation may be preferable to 100% duty. This result means that the initial concept of capturing stranded resources is less favorable economically than a grid-connected sinking system.

If grid electricity is used, then carbon emissions actually increase relative to biomass gasification alone for this hybridization. If upstream emissions for electricity production are taken into account, electrolysis and this proposed hybrid are both net CO_2e emitters. This makes their justification by carbon value impossible unless only renewable electricity is used for operation (renewable energy values are shown in parentheses in Table 13). Since renewable wind energy is inherently intermittent, it is unreasonable to assume renewable electricity is used without adding the necessary equipment for intermittent operation. One renewable energy exception would be the use of hydroelectric power for the systems.

Similar to the other hybrid systems investigated, hybridization results in a price premium. There must be some additional justification for hybridization such as utility demands. The baseline biomass to hydrogen case with an ASU requires only $35 per metric ton of CO_2e to be cost competitive with SMR produced hydrogen assuming both the hybrid plant and SMR plant are subject to the same natural gas cost at a given location.

Electrolyzer-based hybrid system economics are extremely sensitive to the cost of electricity (Fig. 8). Fluctuations of $0.01 in the cost of electricity cause the price of hydrogen to fluctuate more than $0.25 per kilogram. If the price of electricity were to drop below $0.04/kW h, then the proposed hybrid system could economically compete with a nonhybrid biomass to hydrogen plant. However, this low price level is unlikely and any energy market fluctuations would have a dramatic effect on economic viability.

Conclusion

The two hybrid concepts analyzed involve coproduction of gaseous hydrogen and electric power from thermochemical-based biorefineries. Both of the concepts analyzed share the basic idea of combining intermittent wind-generated electricity with a biomass gasification plant. Wind availability overlaps biomass resource availability in three areas of the United States, making the use of locally produced wind electricity for gasification feasible. The proposed hybrid systems attempt to either fill wind energy shortfalls by burning syngas in a natural gas turbine or absorb excess renewable power during times of low-electricity demand.

None of the proposed hybrid systems produced hydrogen for less than a nonhybrid plant could. In all cases a premium was paid for hybridization that could not be offset by the increased functionality.

The indirectly heated gasifier hybrid system consists of two parts: (1) producing peaking electricity intermittently with a gas turbine and (2) sinking electricity into electric heaters intermittently to boost fuel production efficiency. Each of these parts was analyzed separately. The indirectly heated gasifier hybrid system is meant to be grid-connected and provide peaking electricity and dispatchable demand (e.g., an on demand load) to the local utility to help manage intermittent wind resources.

The indirect gasification concepts studied could be cost competitive in the near future as value is placed on controlling carbon emissions. Carbon values of just under $40 per metric ton of CO_2e make the systems studied cost competitive with steam

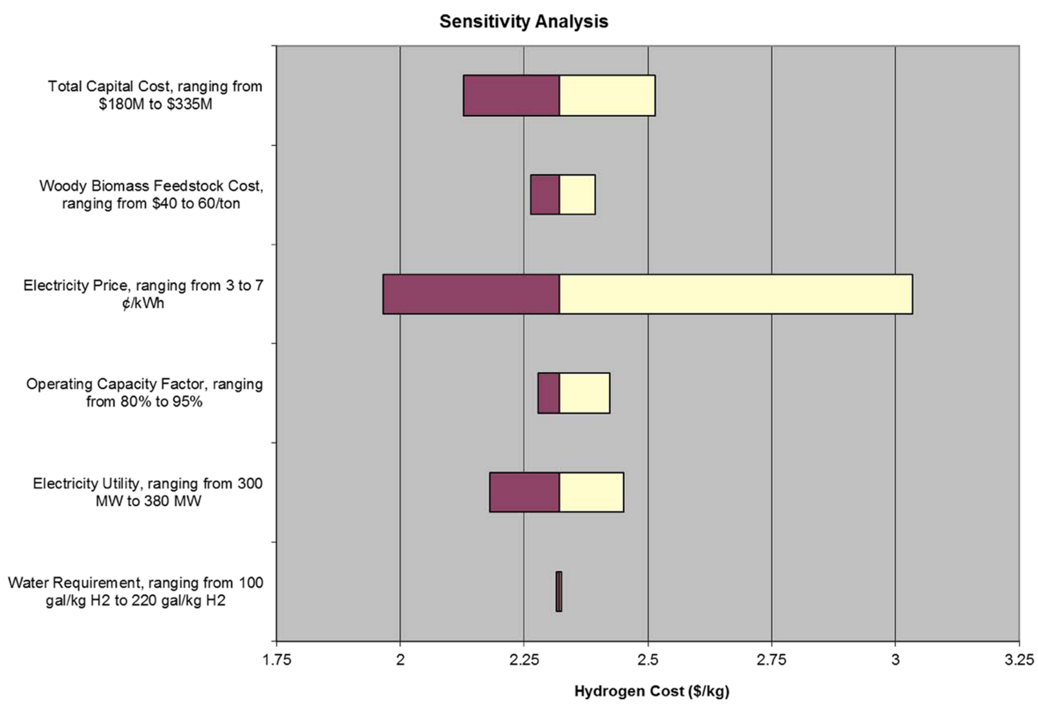

Fig. 8 Direct system sensitivity

methane reforming to produce hydrogen. However, a nonhybrid biomass to hydrogen plant will be more cost competitive in general so there must be additional operational value placed on peaking or sinking for these plants to be economically attractive. This additional value is likely to become a reality as additional intermittent renewable energy sources, such as wind, are added to the national grid.

The directly heated gasifier hybrid system involves replacement of the air separation unit with electrolyzers. This change allows for extra production of hydrogen and intermittent operation. The analysis for this system assumed direct replacement of the ASU without intermittent operation. Estimates of the effect of intermittent operation on plant economics were made. The electrolyzer bank could be either grid-connected to provide a dispatchable demand to the utility or it could be tied directly to a stranded wind source to convert wind into chemical fuel (H_2).

The direct gasification concept studied is unlikely to be cost competitive in the near future, but may eventually be attractive with lower-cost electrolysis and a smaller biorefinery plant size that is sized for a specific hydrogen demand. Intermittent operation and stranded operation were found to have worse economics than grid-connected systems. High electrolyzer capital costs make the possible electricity cost savings of intermittent operation difficult to justify. Based on a direct replacement of the ASU with electrolyzers, hydrogen can be produced for $2.32 per kilogram. However, using grid electricity, the hybrid system is a net CO_2e emitter. For the use of electrolysis to make sense in this setting, there must be a significant benefit to the ability to operate intermittently.

Acknowledgment

The authors would also like to acknowledge Dr. Bob Evans for conceiving the hybrid hydrogen production systems project and Donna Heimiller for performing the GIS mapping.

Employees of the Alliance for Sustainable Energy, LLC, under Contract No. DE-AC36-08GO28308 with the U.S. Dept. of Energy have authored this work. The United States Government retains and the publisher, by accepting the article for publication, acknowledges that the United States Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for United States Government purposes.

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