Wind Electrolysis: Hydrogen Cost Optimization

Genevieve Saur and Todd Ramsden

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-5600-50408
May 2011

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

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Prepared under Task No. H271.3710

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1 Introduction and Key Findings

Wind-based water electrolysis is a viable approach to producing greener hydrogen, holding promise to better utilize domestic renewable energy sources for the energy needs of the transportation sector. A wind-based electrolysis system can reduce greenhouse gas emissions from the transportation sector while integrating larger percentages of renewable energy into the electric grid. To enable a greater penetration of renewable energy resources, hydrogen production from wind-based electrolysis must be cost competitive. As a vehicle fuel, this means competing with gasoline or other vehicle fuels; as energy storage for the grid, this means being cost competitive with other grid electricity technologies. Hydrogen could be produced for $4/kg or less at some high wind class sites, class 4 or higher, However a bigger issue is the capacity factor, which needs to be 44% or better along with relatively high wind speeds. Along with low production costs, however, delivery and storage costs will also factor into the final cost of hydrogen, which calls for investigating a wider range of wind class sites, where geographical elements such as distance from end use should also be considered. This report compiles information on a range of wind class resources to help identify elements that must be balanced.

This report describes a hydrogen production cost analysis of a collection of optimized central wind-based water electrolysis production facilities. The basic modeled facility includes a number of low temperature electrolyzers and a collocated wind farm of a number of 3-MW wind turbines that produce electricity for the electrolyzer units. Shortfalls of wind-based electricity to meet electrolyzer electricity requirements can be made up by purchasing electricity from the utility grid at market prices; conversely, excess electricity from the wind farm beyond the needs of the electrolyzer system can be sold to the utility grid at market prices, lowering the overall cost of hydrogen produced. The National Renewable Energy Laboratory (NREL) completed a series of scenario optimizations using hour-by-hour modeling (8,760 hours per year), considering both wind power output for various wind profiles and estimations of hourly electricity market prices.

The study was done as part of NREL and Xcel Energy's Wind2H2 project to characterize the technical and economic implications of a large-scale wind electrolysis system. The analysis considers the technical requirements of a water electrolysis system and optimized sizing of system components required for a particular hydrogen output based on wind availability and market costs for electricity. This latest cost study of hydrogen production via wind-based water electrolysis builds on the work of earlier cost studies. An earlier NREL study examined the costs of wind-based water electrolysis, but it did not consider the purchase of grid electricity during times of low wind, leading to a low utilization of the electrolyzer subsystem [1]. A 2009 independent review panel report on the state of low-temperature electrolysis analyzed hydrogen cost via wind electrolysis given recent advances in electrolyzer systems, though for costing purposes that analysis assumed that wind-based electricity would always be available to the electrolyzer system [2].

This study considers the optimal configuration of a water electrolysis production facility capable of producing a net 50,000 kg/day of hydrogen with a collocated wind farm as a renewable electricity source. Four wind farm sizing scenarios were considered, and hydrogen production cost modeling was conducted for two wind turbine capital cost cases: a low wind turbine cost case based on turbine costs from a 2006 NREL WindPACT study by Malcolm and Hansen [3], and a current cost case from a more recent 2009 wind turbine cost study, by Wiser et al. [4]. The independent review panel report on the state of low-temperature electrolysis supplied the electrolyzer costs, supplemented with costs from an H2A Production model case study of central hydrogen production from water electrolysis [2, 5, 6]. The latter, higher, wind costs better represent the costs of hydrogen production expected given the recent rise in wind turbine costs. The lower wind cost case, however, is comparable to the wind electricity costs assumed in the 2009 independent panel study, which concluded that hydrogen could be produced at a cost of $3/kg.

The cost analysis of these sets of optimized systems shows that wind-based water electrolysis systems could produce hydrogen for less than $3/kg assuming lower wind turbine costs. Figure 1 shows example results for one of the detailed scenarios that optimizes the size of the wind farm by balancing the grid electricity bought with the wind electricity sold. The low wind costs represent wind turbine costs from a period of low wind costs in 2002, which are included for comparison due to their inclusion in other wind reports; however, current wind costs (blue bars) represent more realistic wind turbine costs from 2008 and beyond, which incorporate higher material and construction costs. Each data set in Figure 1, current wind cost and low wind cost, is the aggregate of the same set of wind sites (128). The range of costs is a function of the spread of wind speeds and capacity factors embodied in each wind class. Costs in the low wind cost case range from $2.83/kg to $7.83/kg. In the current wind cost case, they range from $3.72/kg to $12.16/kg. All costs are presented in 2005 dollars (2005$). This reinforces the independent panel findings that wind-electrolyzed hydrogen could be produced for as little as $3/kg at good wind sites. Even considering higher wind turbine costs, hydrogen could be produced in some class 4, 5, and 6 wind areas for as little as $4/kg.

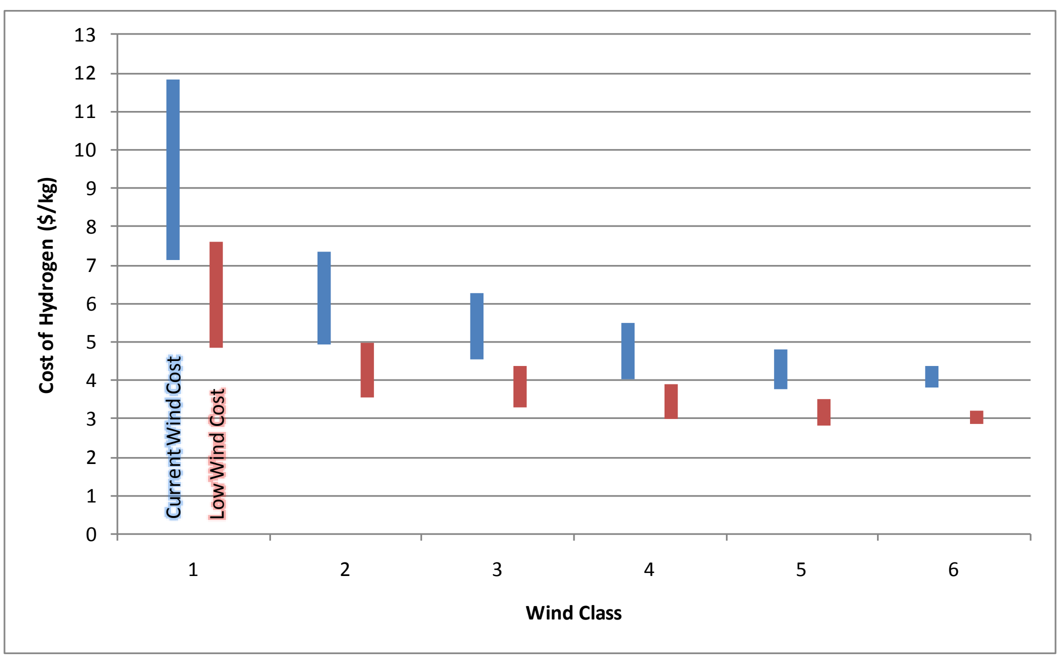

Figure 1. Range of costs for wind electrolysis hydrogen production for different wind classes from power-balanced optimization scenario

2 Background

NREL researchers developed an 8,760 hourly wind electrolysis optimization model based on the H2A Production and Fuel Cell Power models [6, 7]. The model can be configured to conduct technoeconomic analyses of different wind electrolysis facility configurations, each including a bank of low-temperature electrolysis units to produce hydrogen and a collocated wind farm comprising a number of 3-MW wind turbines. The basic functionality could also be accomplished by a system that was not entirely collocated as well. An 8,760 hourly grid pricing structure is included in the model based on six different daily and weekly charge rates— three summer and three winter to represent peak, partial-peak, and off peak time periods. The hour-by-hour analysis integrates the hourly wind profile with the hourly grid pricing structure to calculate the resulting hydrogen production costs of various wind electrolysis system configurations.

This initial analysis considers several grid-connected scenarios and an average hydrogen production rate of 50,000 kg/day, which is consistent with H2A Production model case studies for a central electrolysis plant [5]. The electrolyzers are relatively capital intensive, so this analysis assumes that they will be run at near maximum capacity with minimum avoidable downtime. Sustainable hydrogen production is met by using wind electricity for electrolysis when it is available and selling excess wind electricity to the grid to offset grid electricity that must be bought during times of low wind.

3 Model Configurations

3.1 Electrolyzers

The electrolyzer costs and assumptions used in this analysis come from the report on low-temperature electrolysis by an independent review panel for a central electrolysis production site of 50,000 kg/day capacity [2]. The plant design capacity is 51,020 kg/day with a 98% operating capacity factor for a net capacity of 50,000 kg/day. The electricity requirements of the system are 106 MW. Standard H2A assumptions were used for many of the economic assumptions [5, 8]. This includes a 10% internal rate of return and 40 year plant lifetime for a central production facility. Parameters adjusted to reflect the new study were total depreciable capital cost, electrolyzer efficiency, replacement time and costs, operating capacity factor, working capital, labor, production maintenance costs, other material costs, and land costs. Separating the total depreciable capital costs into direct and indirect costs reflected the independent review panel's capital cost estimate. Table 1 lists the relevant parameters and their baseline values.

Table 1. Electrolyzer Economic Parameters Based on the Independent Review Panel Report[a]

Parameter	Review Panel Baseline Value
Total Depreciable Capital Cost	$50.1 million[a]
Electrolyzer Efficiency	50 kWh/kg
Replacement Cost	25% of direct installed capital
Replacement Interval	7 years
Operating Capacity Factor	98%
Working Capital	5%
Other Material Costs	$0
Land Costs	$50,000/acre and 5 acres
Labor	10 full time equivalents
Production Maintenance Costs	2% of direct installed capital

[a] The review panel [2] gave a value of $50 million for total depreciable capital costs. The value listed reflects a close approximation that separated the costs into direct and indirect costs. See reference [2] for more information.

For the direct costs, the uninstalled costs for the electrolyzer units were $384/kW ($800/kg/day and 50 kWh/kg) with an installation factor of 1.05 to reflect the relative ease of installing skid-mounted units. Table 2 shows all depreciable capital costs.

H2A-based analysis of central wind electrolysis using this estimated breakdown of depreciable capital costs yields cost results consistent with the findings of the independent panel [2]. Using the estimated depreciable cost breakdown in Table 2 together with a constant electricity cost of $0.045/kWh, consistent with the independent panel, and the other independent panel cost parameters listed in Table 1, we calculated a hydrogen production cost of $3.00/kg [2]. This matches the independent panel's results for the central wind electrolysis case; therefore, the capital cost assumptions are considered applicable for this detailed analysis.

We assumed a constant electrolyzer energy usage of 50 kWh/kg for this analysis. Although electrolyzers can be run at partial power with an effect on the overall system efficiency, the size of the system will generally necessitate 50 or more units run in combination. Therefore, for simplicity rather than any given unit running at partial power, the electrolyzer units would be sequenced on and off for more or less optimal efficiency. Additionally, the particular scenarios analyzed assume near-maximum operating capacity.

Table 2. Breakdown of Electrolyzer Depreciable Capital Costs

Parameter	Value
Uninstalled Direct Capital Cost	$40.8 million
Installation Factor	1.05
Direct Installed Capital Cost	$42.9 million
Site Preparation	1% of direct installed capital
Engineering and Design	5% of direct installed capital
Project Contingency	10% of direct installed capital
Up-Front Permitting Fees	1% of direct installed capital
Total Depreciable Capital Cost	**$50.1 million**

3.2 Wind Farm

Characterizing and modeling the costs of wind-based electricity production required obtaining wind turbine capital and operating costs, wind turbine performance, and wind profiles from several sources.

Two sets of assumptions for wind turbine costs were modeled based on low costs in the Malcolm and Hansen study [3] and on current costs from the report by Wiser et al. [4]. For both cases the wind farm was modeled as a number of 3-MW turbines using a fixed charge rate of 12.1% for the capital costs. The fixed charge rate includes a 10% internal rate of return, 35% federal tax rate, and 6% state tax rate. No production tax credits or other incentives are included. The costs were separated into turbine installed capital and operations and maintenance (O&M). The costs from the Malcolm and Hansen study for wind turbines appear to be consistent with the single-point wind-based electricity cost used by the independent panel on electrolysis, and are included to better compare results from this hourly optimization analysis to the hydrogen production cost results reported by the independent panel. The costs from the more recent Wiser et al. study are assumed to reflect the current state-of-the-industry costs for wind turbine installations today.

The overall resulting wind electricity costs of these wind turbine farms operating in particular wind locations can be characterized by wind class (Table 3) and capacity factor. In our analysis, the wind electricity cost is same for all modeled scenarios, being based on the same wind profile and cost assumptions for each scenario. Figure 2 and Figure 3 shows the electricity cost ranges under on different wind classes and capacity factors.

Table 3. Wind Class Definitions (at reference height of 10 m)

Wind Class	**Wind Density Minimum** (W/m^2)	**Wind Speed Minimum** (m/s)	**Wind Density Maximum** (W/m^2)	**Wind Speed Maximum** (m/s)	**Average Wind Speed** (m/s)
1	0	0.0	100	4.4	2.2
2	100	4.4	150	5.1	4.8
3	150	5.1	200	5.6	5.4
4	200	5.6	250	6.0	5.8
5	250	6.0	300	6.4	6.2
6	300	6.4	400	7.0	6.7
7	400	7.0	1000	9.4	8.2

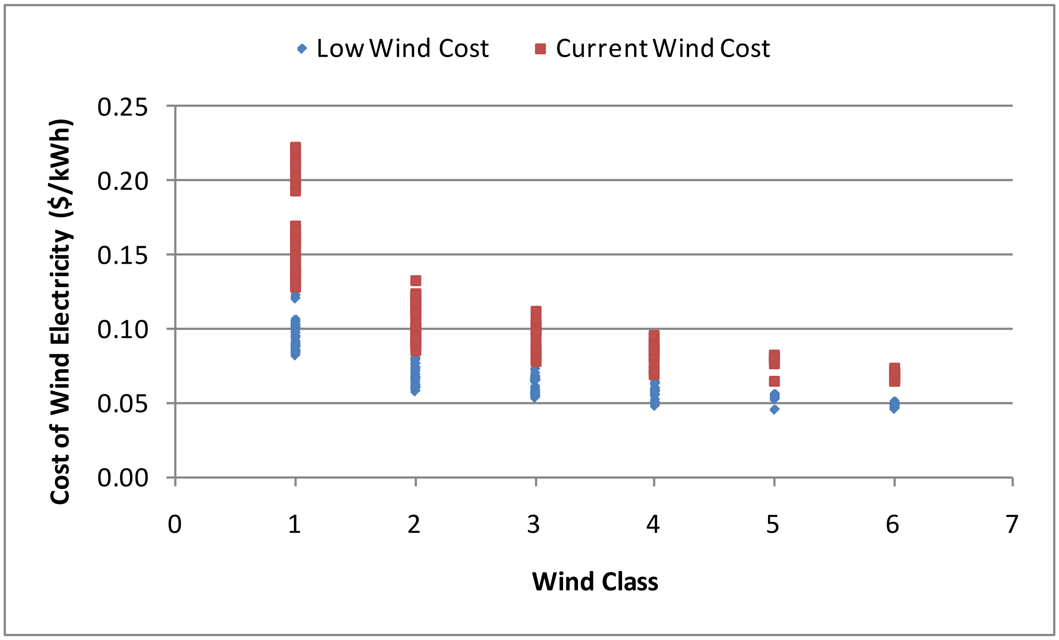

Figure 2. Wind electricity costs by wind class

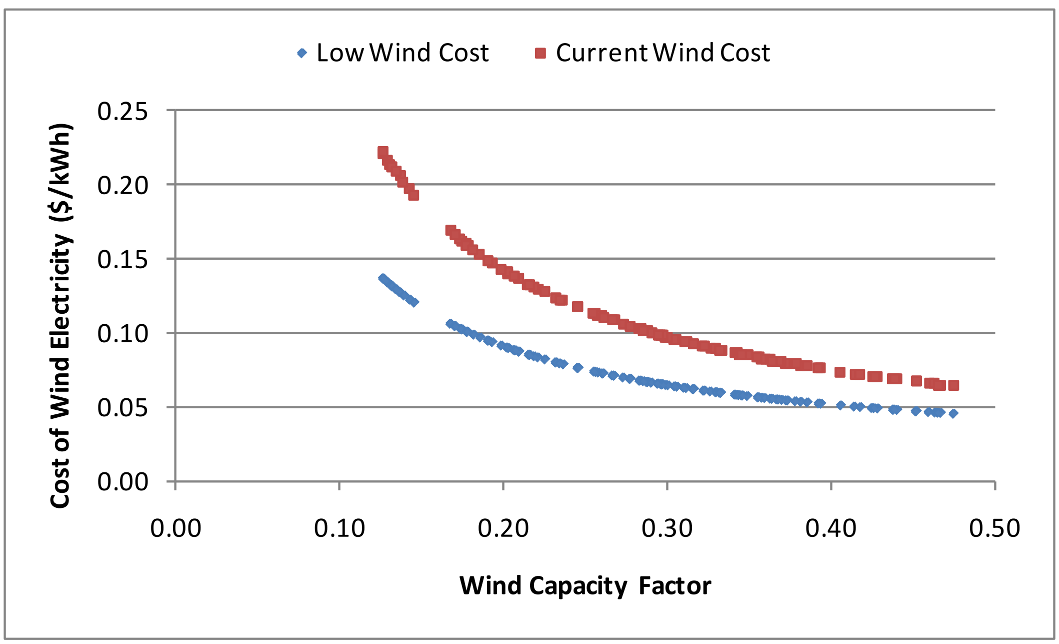

Figure 3. Wind electricity costs by wind farm capacity factor

3.2.1 Case 1—Low Wind Cost

Case 1 modeling used the study by Malcolm and Hansen [3]. The data for their study were collected between 2000 and 2002, now considered a period of very low turbine prices. These costs are included for comparison consistency with other studies and to demonstrate the effect of different wind turbine costs. Table 4 shows the model parameters used, which reflect a 3-MW turbine.

Table 4. Case 1 Wind Cost Parameters from the Malcolm and Hansen Study[a]

Parameter	Value (2005$)
Installed Turbine Capital Cost	$1148/kW
O&M (includes replacement costs)	$0.01234/kWh

[a]Reference [3]

3.2.2 Case 2—Current Wind Cost

The second case used a more current study [4], which reflects the most recent costs of wind turbine installations. These costs could be considered more consistent with the state of the industry for wind farms installed in 2009. Table 5 shows the parameters used depreciated to 2005$ using the U.S. Energy Information Administration (EIA) Gross Domestic Product (GDP) Implicit Price Deflator Table [9].

Table 5. Case 2 Wind Cost Parameters from the Wiser et al. Study[a]

Parameter	**Original Value** (2008$)	**Value** (2005$)
Installed Turbine Capital Cost	$2,120/kW	$1,964/kW
Total O&M	$0.008/kWh	$0.00741/kWh

[a] Reference [4]

3.2.3 Wind Turbine Performance

The wind turbines were based on a 3-MW turbine designed for a class 4 wind site, average annual wind speed 5.8 m/s at 10-m height. The height is adjusted to 100 m using the wind profile power law with standard 1/7 exponent. The power curve shown in Figure 4 was generated using a Rayleigh distribution curve using parameters in Table 6. The power conversion was used to estimate the power at different wind speeds in the 8,760 hourly analysis.

3.2.4 Wind Profiles

Ten-minute interval wind profiles for 136 random sites in California from 2006 were obtained through NREL's Western Wind Dataset [10]. Average wind speeds at 100 m ranged from 2.4 m/s to 9.4 m/s, which covers class 1 to class 6 wind sites. The 10-minute interval data were averaged each hour to create an 8,760 hourly/year wind profile for each site. Wind profiles do vary year to year, but for this analysis using a snapshot of real wind data was appropriate. More detailed analysis of an individual site might also include effects of yearly variation, which were not performed here.

Table 6. Wind Turbine Power Conversion Parameters for a 3-MW Turbine

Parameter	Value
Mean Wind Speed at 10 m (m/s)	5.8
Rated Power (kW)	3,000
Rotor Diameter (m)	99
Wind Reference Height (m)	100
Hub Height (m)	119
Air Density (kg/m^3)	1.225
Rotor C_p	0.50
Cut-In Speed at Hub (m/s)	3
Cut-Out Speed at Hub (m/s)	28.9
Power Law Shear Exponent	0.143
Mean Wind Speed at Hub Height	8.3
Rated Wind Speed	11.1
Net Annual Energy Production	88%
Availability	95%
Blade Soiling Losses	2%
Array Losses	5%

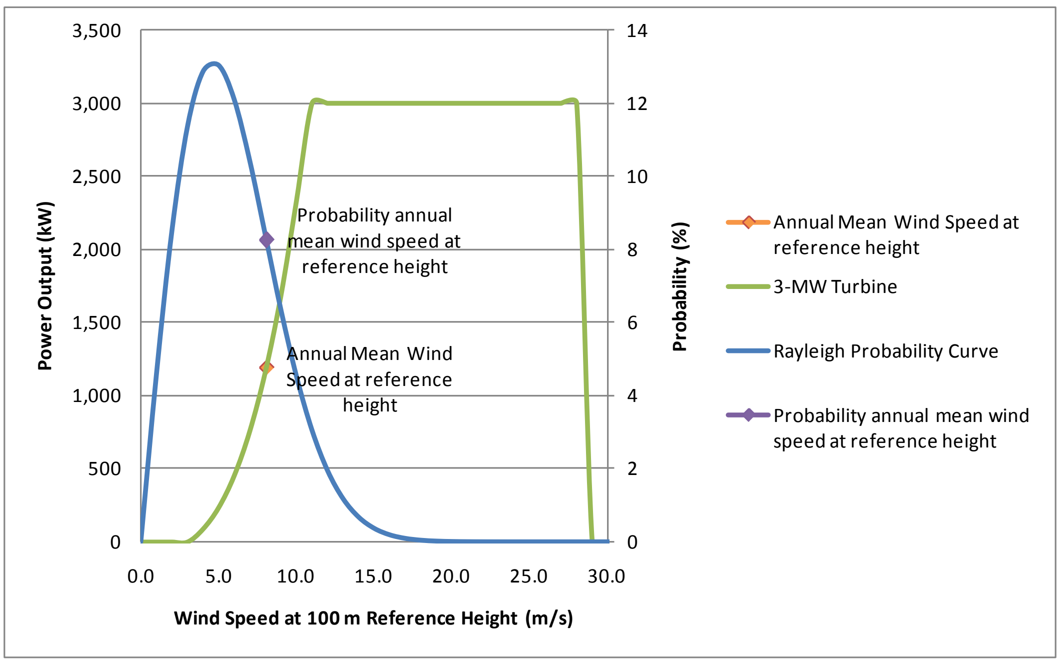

Figure 4. Three-megawatt wind turbine power curve

The range of sites for each wind class can be seen in the range of capacity factors shown in Figure 5. A variety of sites were analyzed to show a range of hydrogen production costs in different wind locations. Of the original 136 sites, 8 were removed because of very low capacity factor (<0.11) and would be marginal for wind production even under the best of circumstances. Using a large range of sites helps show the trade-offs that might be expected between lower wind production sites and better ones. In a fuller analysis, the distance of a site from the hydrogen demand would also play a factor in the final economic analysis. Our intention here, however, is to isolate only one element, wind electrolysis production of hydrogen.

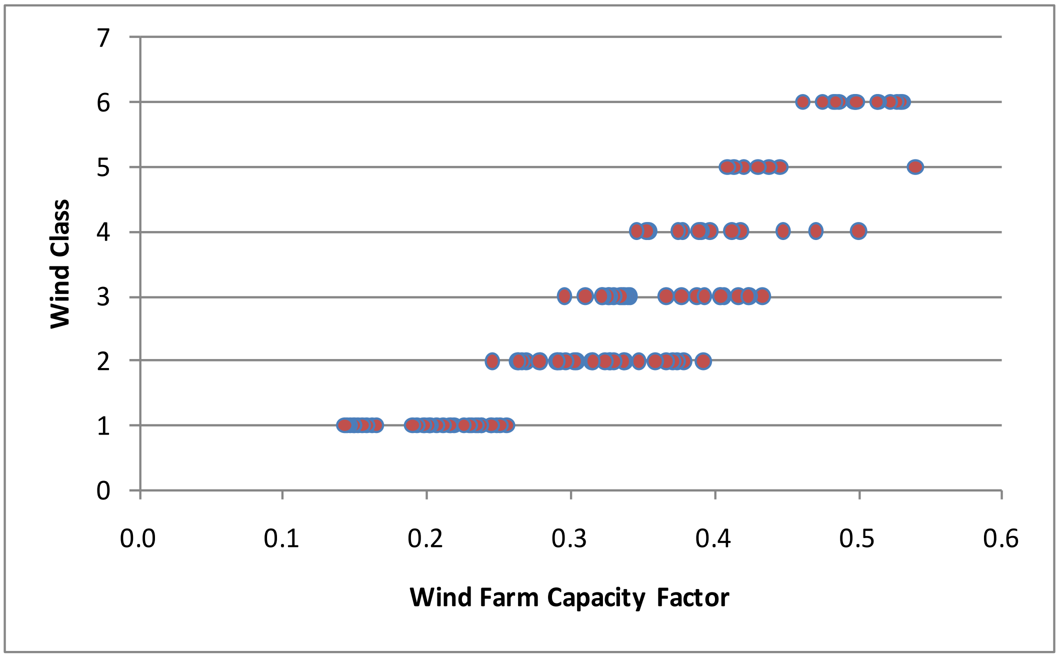

Figure 5. Range of wind sites used in study by wind class and capacity factor

3.3 Grid Pricing Structure

For modeling purposes, we developed an 8,760 hourly electricity pricing estimate for a grid pricing structure adopted from the Fuel Cell Power model [7, 11]. This estimate was based on a pricing structure that projected electricity prices on a per kilowatt-hour basis using six price tiers: summer peak, summer near-peak, summer off-peak, winter peak, winter near-peak, and winter off-peak. The base electricity price was set to $0.055/kWh, consistent with EIA price projections for average industrial electricity rates in 2005. The variance from this base for the six price tiers was based on actual hour-ahead pricing in the Southern California Edison ISO market, based on using actual price reports for typical summer and winter days. Figure 6 gives the six tiers. Similarly, the six tiers for each hour in a typical week were assigned based on actual costs reported for the California ISO hour-ahead market, seen in Figure 7. The actual hour by hour rates resulted in an average electricity price of $0.053/kWh. These rates reflect an approximated electricity demand.

Usage Charges		Rate Type	Rate ($/kWh)	Rate % of Base Rate
Summer rates ($/kWh)	Peak	4	0.099	180
	Partial peak	5	0.061	110
	Off-peak	6	0.039	70
Winter rates ($/kWh)	Peak	1	0.061	110
	Partial peak	2	0.050	90
	Off-peak	3	0.039	70

Figure 6. Charge rates for six tiers of grid pricing (structure adapted from Fuel Cell Power model [11])

Summer Rate (Hour)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Sunday	6	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6
Monday	6	6	6	6	6	6	6	6	5	5	5	5	5	4	4	4	4	4	4	5	5	5	5	6
Tuesday	6	6	6	6	6	6	6	6	5	5	5	5	5	4	4	4	4	4	4	5	5	5	5	6
Wednesday	6	6	6	6	6	6	6	6	5	5	5	5	5	4	4	4	4	4	4	5	5	5	5	6
Thursday	6	6	6	6	6	6	6	6	5	5	5	5	5	4	4	4	4	4	4	5	5	5	5	6
Friday	6	6	6	6	6	6	6	6	5	5	5	5	5	4	4	4	4	4	4	5	5	5	5	6
Saturday	6	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6

Winter Rates (Hour)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Sunday	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2
Monday	3	3	3	3	3	2	2	2	2	2	1	1	1	2	2	2	2	2	1	1	1	2	2	3
Tuesday	3	3	3	3	3	2	2	2	2	2	1	1	1	2	2	2	2	2	1	1	1	2	2	3
Wednesday	3	3	3	3	3	2	2	2	2	2	1	1	1	2	2	2	2	2	1	1	1	2	2	3
Thursday	3	3	3	3	3	2	2	2	2	2	1	1	1	2	2	2	2	2	1	1	1	2	2	3
Friday	3	3	3	3	3	2	2	2	2	2	1	1	1	2	2	2	2	2	1	1	1	2	2	3
Saturday	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	2	2	2

Figure 7. Weekly rate structure (structure adapted from Fuel Cell Power model [11])

3.4 Scenarios

We chose four scenarios for our wind-based water electrolysis analysis. The aim of the analysis was to determine the optimal wind electrolysis facility configuration for each scenario resulting in the lowest cost for production of hydrogen. A consideration in creating the scenarios was to not create situations in which wind subsidizes the cost of hydrogen by selling more and more wind electricity to the grid, thereby using the profits to drive down the cost of the hydrogen. The scenarios show some approaches to balancing the different products of the system. The electrolyzer facility was sized consistently to have an average output of 50,000 kg/day of hydrogen. Because of the capital intensity of electrolysis, we assumed that electrolyzers would be operated at maximum capability with a minimum of downtime for maintenance. The wind farm was then sized to meet the scenario requirement. All scenarios assumed that grid electricity could be purchased during times of low wind availability and wind electricity could be sold at the current grid rate when the output of the wind farm exceeds electrolyzer demand, except where specified. Selling wind electricity at the current grid rate has several implications: 1) this does not reflect a power purchase agreement for which the wind is purchased at a certain set price, 2) the wind selling price also does not include a production tax credit (PTC) or any other incentive, and 3) it may mean that wind electricity is sold at a rate below the cost. Each of these factors has an effect that this report does not address, but it is mentioned it for clarity. The following four scenarios represent different approaches to optimization and sustainable hydrogen production:

- Scenario a: cost balanced—the cost of the grid electricity that is purchased is balanced to the wind electricity sold at grid rate.
- Scenario b: power balanced—the amount of grid electricity purchased (in megawatt-hours) is balanced with the amount of wind electricity sold.
- Scenario c: same as scenario a, cost balanced, but no grid electricity is purchased during summer peak periods.
- Scenario d: same as scenario b, power balanced, but no grid electricity is purchased during summer peak periods.

In the scenarios, the optimization comes from sizing the wind farm to meet the requirements of the scenario. The electrolyzer is set up to use wind electricity from the collocated wind farm first, then grid electricity as required to meet the electrolyzer system's needs. Excess wind electricity above the electrolyzer's requirements can be sold to the utility grid at the current grid rate during times of high wind production. For power-balanced scenarios the amount of electricity purchased from the grid (on a megawatt-hour basis) is balanced with the amount of wind electricity sold to the grid. In the cost-balanced scenarios, the hourly power purchased or sold is multiplied by the current grid rate and the yearly sum balanced between the amount purchased from the grid and the wind sold. Thus, in these optimization scenarios, the size of the wind farm is what changes.

Scenarios c and d were developed to explore the implications of not purchasing grid electricity during summer peak hours when the demand on the electric grid is greatest. In certain regions this might have significant economic and emissions implications for grid operators where peaking plants are both less efficient and more polluting. The system is designed with an average output of hydrogen per day, which is met with wind and grid electricity combined. During summer peak hours, because grid electricity is not to be used, the system runs at partial load using available wind electricity only; therefore the some hydrogen output may be unmet in comparison to the design average.

4 Results

The two different wind cost cases represented are case 1 using the Malcolm and Hansen study [3] and case 2 using the Wiser et al. study [4]. The four scenarios for each case show several ways in which the system might be configured and the resulting hydrogen cost from these configurations.

For optimization of the wind farms, an upper limit of less than 1 GW was set. The modeling restriction was put in place to eliminate eight sites with very low capacity (<11%) at low wind speed (class 1) from consideration because they were very marginal for wind electricity production. Therefore, the aggregate results describe 128 sites.

For the scenarios in which no summer peak electricity is bought, the unmet hydrogen is about 600,000 kg/yr to 1,000,000 kg/yr. Because the summer period is 122 days long, from June 1 to Sept 30, this corresponds to an unmet daily demand in the summer only of approximately 5,000 kg/day to 8,200 kg/day.

If a minimum of 50,000 kg/day of hydrogen production is required, systems restricting the use of summer peak electricity could be modeled with a higher nominal production capacity, possibly in combination with hydrogen storage, such that a minimum of 50,000 kg/day of hydrogen is produced even during summer peak electricity demand days with lower production capacity utilization. We have not yet conducted such an analysis.

4.1 Case 1—Low Wind Cost

The hydrogen costs for the four scenarios ranged from $2.83/kg to $7.83/kg. These costs assume current electrolyzer technology costs reduced by mass production (see section 3.1) and wind costs lower than would be expected today because of a recent trend of rising wind turbine costs. The costs of the wind electricity in this case ranged from $0.046/kWh to $0.138/kWh depending on wind site. The lower cost of this range is near, however, to the wind electricity cost assumed by the independent panel that analyzed the cost of central wind electrolysis [2]. This low-cost electricity was reached at a class 5 wind site with the highest capacity factor of any site, though not the highest annual average wind speed. It was for scenario d, which balanced the megawatt hours of wind bought and sold but did not purchase summer peak grid electricity.

Figure 8 and Figure 9 show the cost of hydrogen relative to a site's cost of wind electricity. For the cost-balanced scenarios, not purchasing summer peak electricity reduces the cost of hydrogen. The effect is more significant for the cost-balanced scenario, but also is seen in the power-balanced scenario. This is because the system operator no longer purchases the most expensive grid electricity, summer peak; however, the consequence is that some of the hydrogen demand may be unmet because the system is not running at full capacity during those summer peak hours when wind does not meet the electrolyzer energy needs. The system always uses available wind electricity for hydrogen up to the electrolyzer capacity.

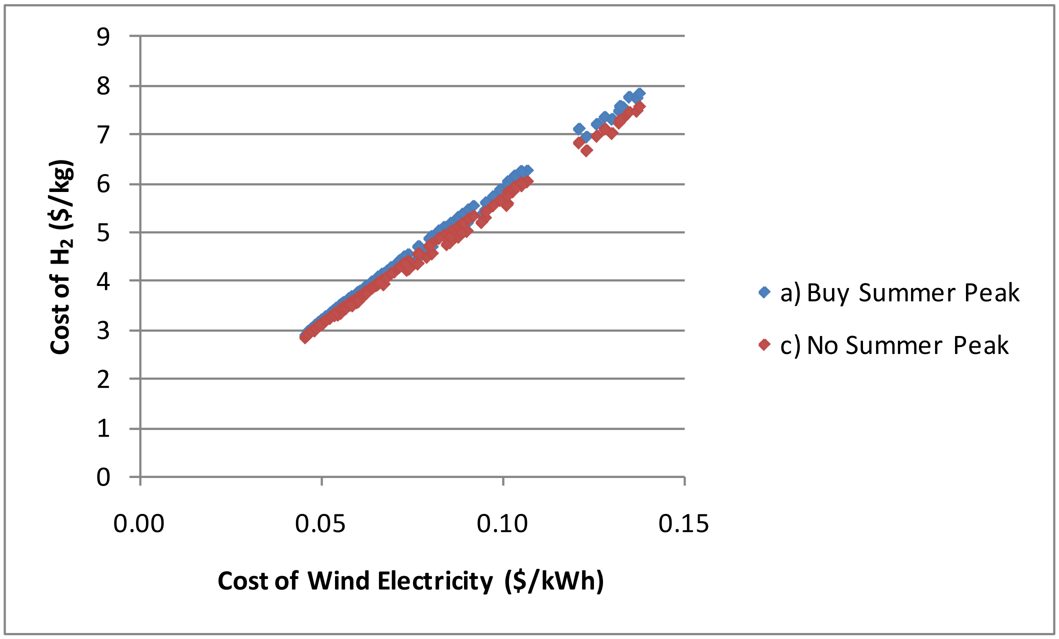

Figure 8. Cost of hydrogen for case 1 (low-cost wind), cost-balanced scenarios a and c

The power-balanced scenarios shown in Figure 9 have a smaller effect on the cost of hydrogen. In both scenarios, the amount of electricity bought and electricity sold are still balanced, but the size of the wind farm and therefore its production is adjusted. There is still some unmet hydrogen demand for the case where summer peak electricity is not purchased.

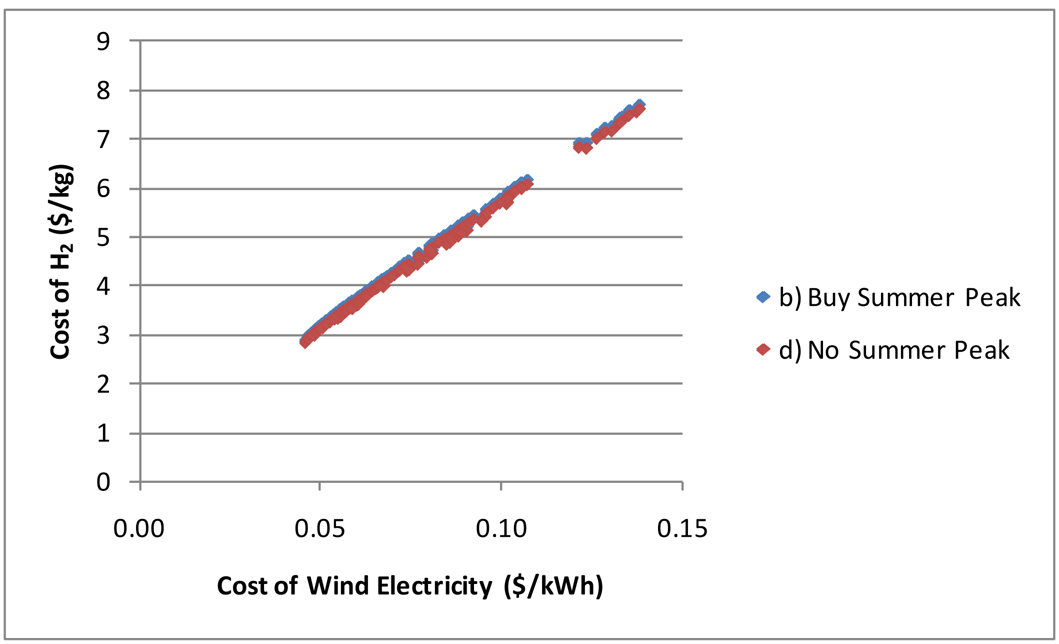

Figure 9. Cost of hydrogen for case 1 (low-cost wind), power-balanced scenarios b and d

Although we expect the costs of hydrogen production in case 2 to be more accurate given the current costs for wind turbines, the results of this lower cost case are a good companion to the production costs presented by the independent panel for electrolysis [2]. The panel projected central wind electrolysis production costs of $3.00/kg, but their projection (which focused on the state of technology for electrolyzer systems) used a rough assumption that wind-based electricity would always be available at a cost of $0.045/kWh. The cost optimization presented in this case shows that when slightly lower wind turbine costs are assumed, a wind electrolysis system using wind electricity produced in some class 4, 5, or 6 wind areas can produce hydrogen for a little less than $3/kg, as predicted by the independent panel.

4.2 Case 2—Current Wind Cost

For case 2 using the higher, more current, wind costs from the Wiser et al. study [4], the range of hydrogen costs for all scenarios was $3.72/kg to $12.16/kg. This was a direct result of higher wind electricity costs, which ranged from $0.064/kWh to $0.222/kWh. It should be noted these wind costs do not include any wind PTC or other incentive.

The lowest cost of hydrogen was found for a class 5 wind site with the highest capacity factor in scenario c, which balanced cost and did not buy summer peak electricity.

Figure 10 and Figure 11 show the cost of hydrogen related to a site's cost of wind electricity. Similar results are found as for case 1 but with slightly higher costs of hydrogen. In fact, the cost of hydrogen is fairly linear relative to the cost of the wind electricity, other parameters held static.

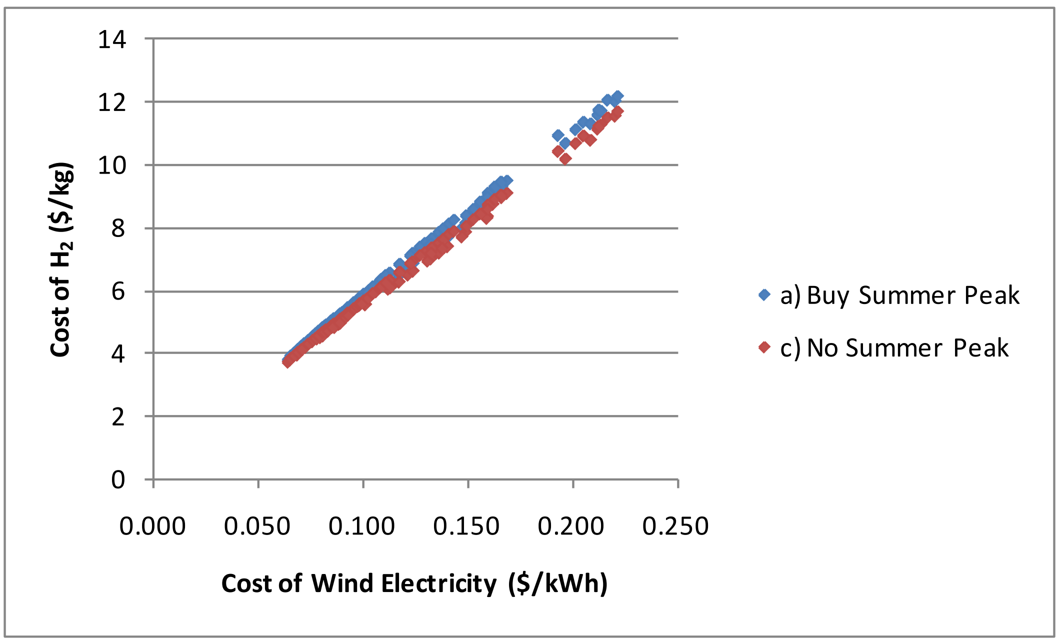

Figure 10. Cost of hydrogen for case 2 (current wind cost), cost-balanced scenarios a and c

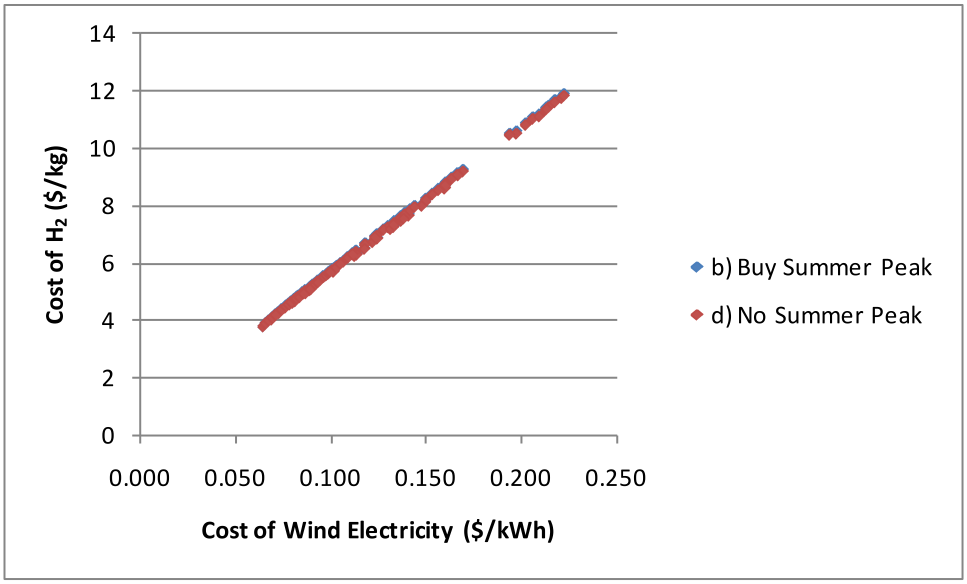

Figure 11. Cost of hydrogen for case 2 (current wind cost), power-balanced scenarios b and d

As with case 1 for the cost-balanced scenarios (Figure 10), not purchasing summer peak electricity slightly reduces the cost of hydrogen. Unmet hydrogen for the scenarios where summer peak electricity is not bought falls in the same range, from 600,000 kg/yr to 1,000,000 kg/yr.

The higher wind costs do produce higher costs of hydrogen, but a quick look at the wind sites that produced hydrogen at costs less than $4/kg (in 2005$) are informative to get a better idea of where low-cost hydrogen can be produced. Nine sites collectively produced low-cost hydrogen in at least some of the scenarios. All nine sites produced hydrogen at less than $4/kg in scenario c, which was cost balanced without buying summer peak electricity. Eight of the sites did such in scenario d, power balanced, and not buying summer peak electricity. Scenarios a and b had five sites each. Of the nine sites, seven were wind class 6, one was wind class 5, and one was wind class 4. They all had wind farm capacity factors of 44% or better, an average wind speed of 9.1 m/s at 100 m, and an average wind electricity cost of $0.067/kWh.

4.3 Scenario Details—Current Wind Cost

Looking more closely at the ramifications of the different scenarios analyzed reveals some interesting trends and points to take away in designing green hydrogen wind electrolysis systems. Whether or not to purchase summer peak electricity has implications beyond adding to peak load during the time of annual highest demand. The scenarios have an effect on the size of the wind farm and the cost of hydrogen. Additionally there is a distinct effect on cost of hydrogen and quantity of hydrogen unmet based on whether or not the green hydrogen is made by balancing cost or amount of electricity. For this, current wind costs from the Wiser et al. study [4] are used; however, similar results are found for lower cost wind as well, but in smaller ranges.

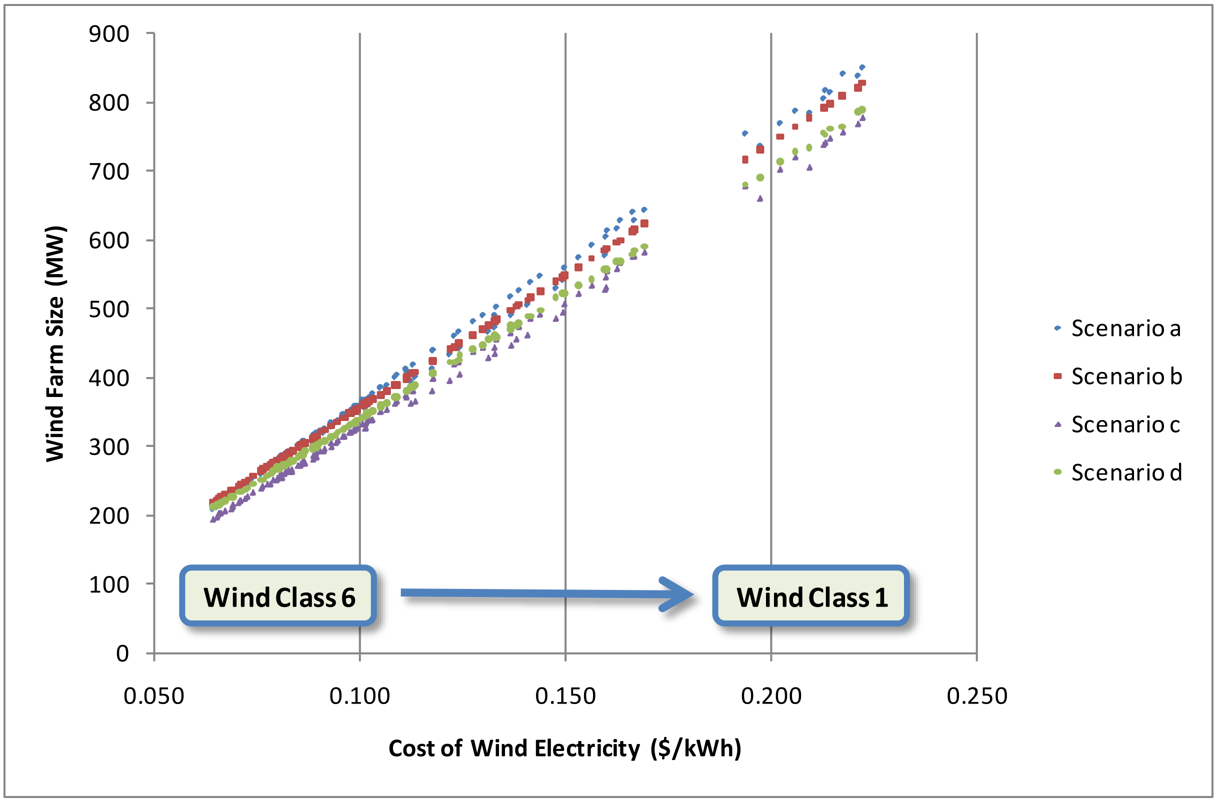

Figure 12. Wind farm size required to produce 50,000 kg/day H_2 and cost of electricity at each site for each scenario

The size of the optimized wind farms varies depending on the scenario. As stated before, all scenarios were set up to meet a 50,000 kg/day hydrogen rate. The electrolyzers were sized to meet that with their expected maintenance downtime taken into account. The wind farms were then sized based upon the scenario criteria in discrete multiples of 3-MW turbines. Figure 12 shows trends for the different scenarios. The cost of electricity is a function of the average wind speed and capacity factor of each site which are roughly conveyed by a wind class. Each particular wind site is shown in proxy as a cost of wind electricity which incorporates the average wind speed and unique wind profile. The four vertical data points show the different wind farm size optimizations for that unique site based upon the scenario constraints. There is a strong linear trend based on the cost of the wind electricity produced at a given site. In general, higher cost wind electricity means lower wind class sites and lower capacity factors, i.e., worse sites for wind production in general. Better wind sites produce lower cost electricity and require smaller sizes to meet the hydrogen demand. This is unsurprising.

Figure 12 shows other trends in which cost of wind electricity is used as a proxy for an individual wind site. Each scenario is designed for a peak hydrogen demand of 50,000 kg H_2/day. The size of the wind farm required meet constraints, however, is linear and differentiated by scenario. For instance, scenario c, balancing cost and not buying summer peak grid electricity, required the smallest wind farms at all sites and scenario d, balancing power and not buying summer peak grid electricity, also required smaller wind farms than both scenarios that buy summer peak electricity. The range in wind farm sizes designed to meet the different scenarios at a wind site that produced electricity for $0.10/kWh was about 333 MW to 369 MW; a site with

$0.15/kWh needed wind farms between 507 MW and 561 MW. The range of wind farm sizes across scenarios narrows as the cost of wind electricity decreases because of being at better production wind sites. As noted previously, the sites range from wind class 1 to class 6. Many of the lower class sites with high cost of wind electricity would probably not be developed unless wind turbine costs dropped significantly more than projected. We include them to show a full range of analysis results.

Scenarios c and d, which did not purchase summer peak grid electricity, also had lower hydrogen costs than the corresponding scenarios a and b, which did buy summer peak grid electricity. The vertical axis in Figure 13 shows the cost difference found by subtracting the scenario a cost of hydrogen at a site minus the site's corresponding cost in scenario c; also shown is the cost of hydrogen scenario b minus scenario d. The resulting cost difference is always greater than zero, signifying that the cost of hydrogen was lower for scenarios that did not buy summer peak electricity compared to the optimization for scenarios that did. There was a hydrogen cost penalty for buying summer peak electricity, though it is offset by an unmet hydrogen demand in the scenarios that did not purchase summer peak grid electricity. This analysis, however, suggests that this unmet demand could be met with small adjustments yielding very small production cost effects. Oversizing the electrolyzer results in hydrogen production cost differences of only less than $0.06/kg when the wind farms are optimized for that; however, that does not account for potential storage costs, which could be about $1.00/kg for bulk storage of 5,000 kg in compressed tanks [12]. This solution would approximately cover the 50,000 kg/day summer demand, but would still result in higher average production in the winter. This kind of seasonal variation might not be desired, but further investigation is left as a future exercise.

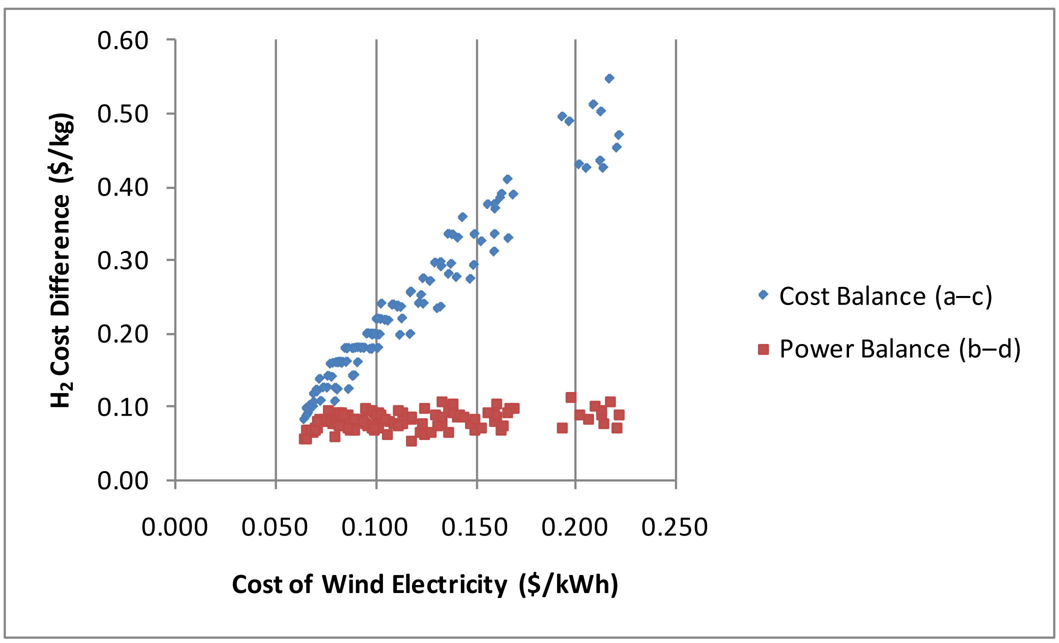

Figure 13. Difference in cost of H_2 between similar scenarios that do or do not buy summer peak

The scenarios that purchase summer peak electricity all had higher hydrogen costs than the scenarios that did not purchase summer peak electricity. Understanding this can help researchers design better, more cost-effective systems and scenarios in the future. Figure 13 shows the change in hydrogen cost between scenarios that bought summer peak electricity and those that did not. The trends are separated between the cost- and power-balanced scenarios, but scenarios a and b had higher hydrogen costs demonstrated in the figure by all cost differences being positive between their corresponding scenarios which did not buy summer peak electricity. The results shown are based on the cost of the wind electricity that serves as a proxy for individual wind sites; lower wind costs are found at more suitable wind resource locations.

Figure 13 shows that the cost difference increases greatly for the cost-balanced scenarios as wind electricity cost increases, and the power-balanced scenarios remain more level and wind cost insensitive. The range of the hydrogen cost difference for the cost-balanced scenarios is $0.08/kg to $0.55/kg, and for the power-balanced scenarios the range is much smaller, between $0.05/kg and $0.11/kg. For the cost-balanced scenarios, Figure 12 shows that the size of the wind farms is significantly smaller for scenario c in which summer peak grid electricity is not bought than scenario a in which it is bought. Therefore, consider that both scenarios include the same electrolyzer demand, so the smaller sized wind farm is buying more grid electricity, which has an average annual cost rate of $0.053/kWh, and selling less wind electricity. As the wind electricity cost increases, the system is using less wind and more of the cheaper grid electricity in the cost balanced scenarios. Therefore, the cost of hydrogen produced in the no summer peak electricity scenario is less; less of the expensive wind electricity is bought, more cheap grid electricity is needed because of smaller wind farm size, and less of the wind electricity is sold resulting in increasingly lower hydrogen costs as wind electricity cost increases. The power balanced scenarios also show that the scenario d in which summer peak grid electricity is not purchased results in lower costs of hydrogen. In these cases, however, it is less dependent on the cost of the wind electricity because only the power not purchased must be normalized. This still results in slightly smaller wind farm sizes, seen in Figure 12, because less grid electricity is purchased requiring less wind electricity to be sold on a power basis. Not purchasing the more expensive summer peak electricity results in a lower cost of hydrogen that is less dependent of the costs of electricity at different sites.

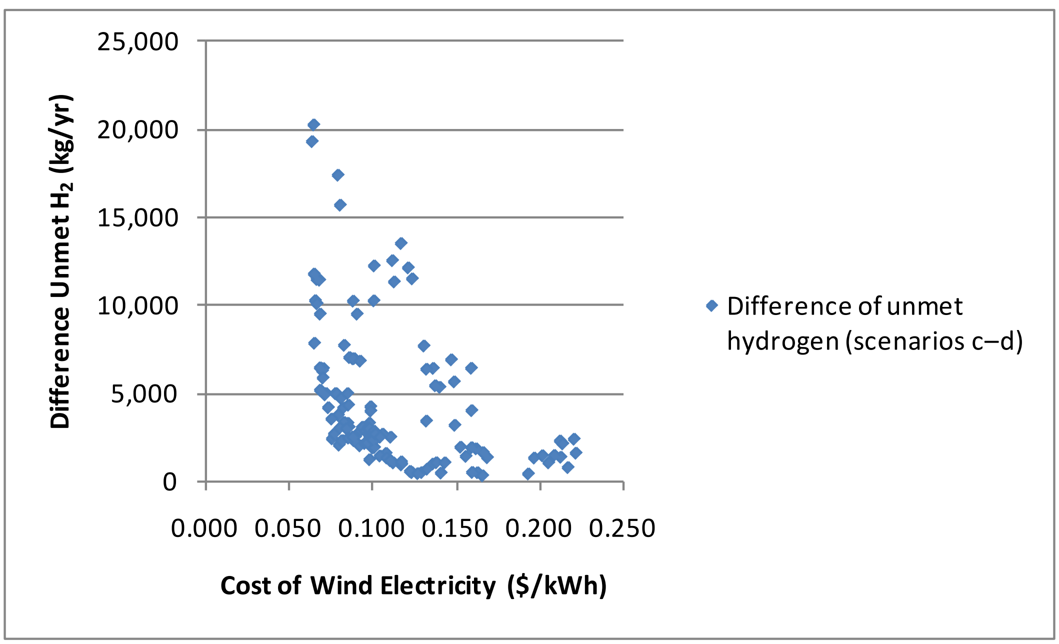

Figure 14. Difference in unmet hydrogen among scenarios

Another detail to examine is the effect on unmet hydrogen demand in the scenarios in which summer peak electricity is not purchased (scenarios c and d). In Figure 14, in which unmet hydrogen per year in scenario d is subtracted from that in scenario c, scenario c results in slightly more unmet hydrogen than scenario d in all cases examined. This can be partly explained as a result of the sizes of wind farms shown in Figure 12 in which scenario c has slightly smaller wind farms than scenario d. This difference results in less hydrogen being produced during summer peak time when grid electricity is not used to supplement the wind.

Figure 15 shows the totals of unmet hydrogen in scenarios c and d. The wide range is not easily described by comparing to the wind electricity cost, capacity factor, or wind class. The range is probably caused by site specifics that are related to the wind fluctuations and variability of the wind profile compared to the average wind speed. In the scenarios described in this analysis, however, the unmet hydrogen shortage is all accounted for in the summer months rather than spanning the whole year.

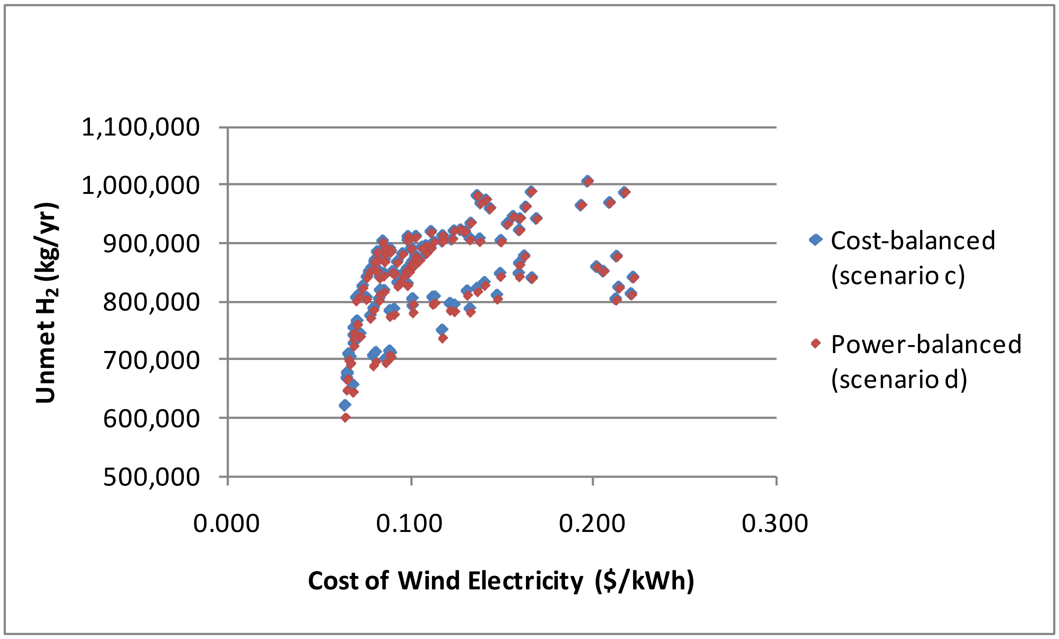

Figure 15. Unmet hydrogen in scenarios that do not buy summer peak electricity

4.4 Detail Case Site—Current Wind Cost

One particular site is selected for a more detailed analysis. The site has a class 5 wind with a capacity factor of 0.47. The average wind speed at 100 m is 8.52 m/s. The wind electricity cost is $0.064/kWh configured as for case 2, more current wind turbine costs. Figure 16, the wind profile of the site, shows a relatively steady wind production through the entire year.

Table 7 gives some of the results of the optimization. The grid utilization relates the maximum megawatt imported from grid to the maximum megawatt wind excess exported to grid; i.e., grid utilization = 100 × max grid MW import/max wind MW export. A grid utilization of less than 100% means that the maximum power of wind electricity exported to the grid was greater than the maximum power needed from the grid in any given hour. The maximum grid electricity needed will be the maximum power of the electrolyzer, 106 MW, for hours in which there is no wind.

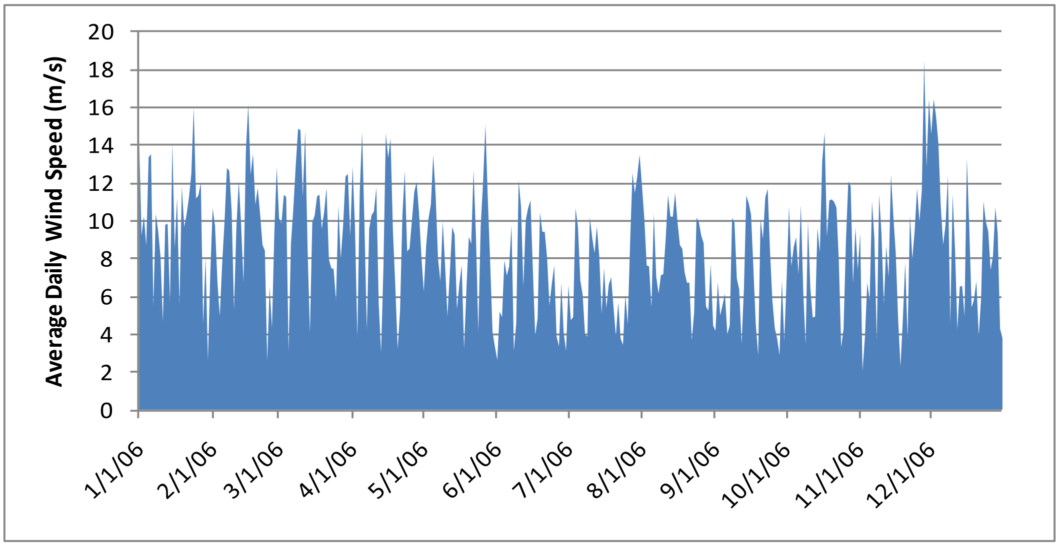

Figure 16. Example wind profile

Table 7. Detailed Example

Scenario	**Wind Farm Size** (MW)	**Number of 3-MW Turbines**	**Grid Utilization** (%)	**Unmet H_2 Production** (kg/yr)	**Cost of Hydrogen** ($/kg)
(a) Cost-Balanced—Buy Summer Peak	210	70	94	0	3.80
(b) Power-Balanced—Buy Summer Peak	219	73	102	0	3.82
(c) Cost-Balanced— No Summer Peak	195	65	100	622,000	3.72
(d) Power-Balanced—No Summer Peak	213	71	120	602,000	3.77

To see the difference between purchasing and not purchasing summer peak electricity, compare Figure 17 and Figure 18, which show the daily averaged power going to the electrolyzer and the grid for scenarios b and d (power balanced). For scenario b, Figure 17 shows a steady line at 106 MW. Figure 18, however, shows the averaged daily decrease in the summer months where there is some unmet hydrogen as compared to the expected average. In both figures, the area of excess wind should approximately equal the area in red, which is the power bought from the grid.

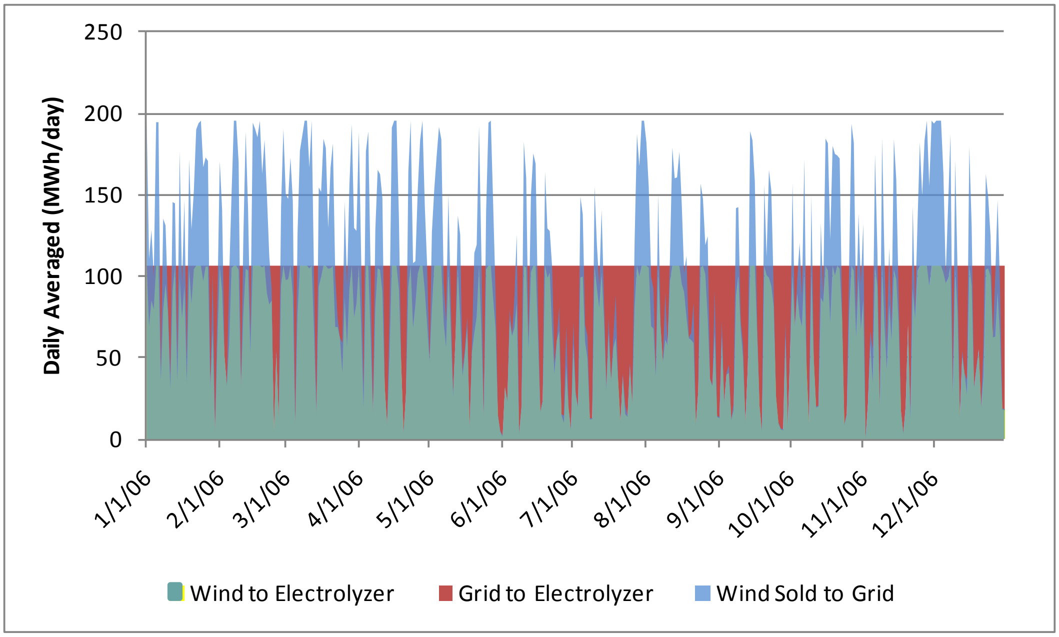

Figure 17. Example scenario b

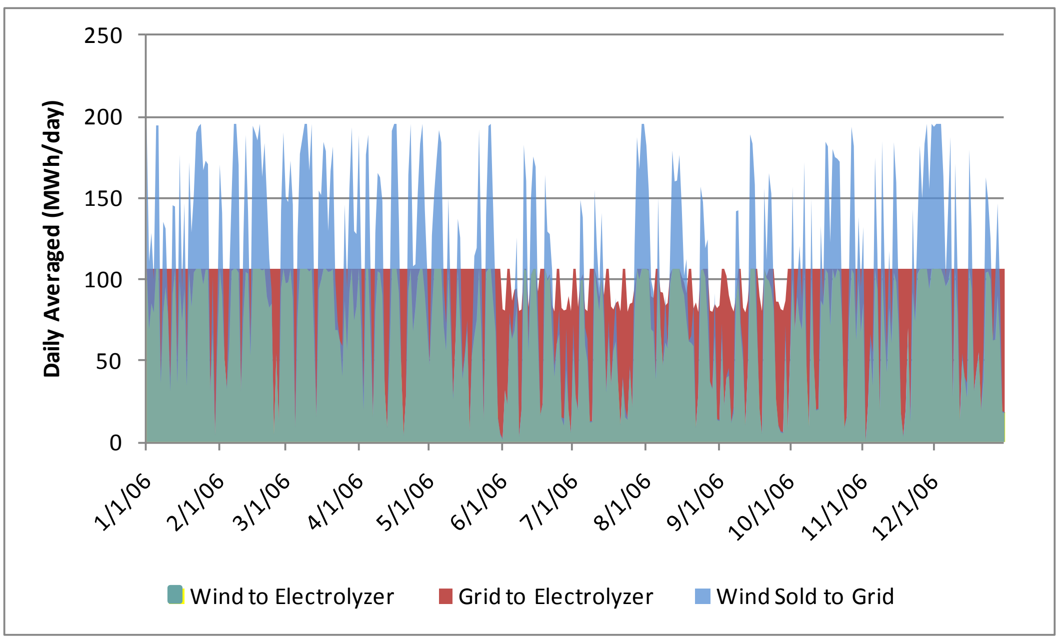

Figure 18. Example scenario d

4.5 Sensitivity Case Site—Current Wind Costs

Finally, the sensitivity to several variables is shown here. The costs and performance of both the wind turbines and the electrolyzers have been predicted, but it is important to show how different parts of the wind electrolysis system affect the final cost of hydrogen. How the technologies develop both in cost and performance has an effect on the system.

A sensitivity analysis was performed on five variables—wind turbine cost, wind farm availability, electrolyzer cost, electrolyzer energy usage, and electrolyzer capacity factor. The wind farm and electrolyzer sizes remained the same as the baseline optimization, then the variables were changed to find the new cost of hydrogen. This was done to show how an over, under, or incorrect performance prediction would affect the overall economics of the system. Figure 19 shows only one scenario; the other scenarios exhibited similar ranges around their respective baseline cost of hydrogen.

Table 8 lists the adjusted variables in the sensitivity analysis. The high and low values of the different variables were chosen as being representative, but are not intended to show definitive ranges. The wind turbine and electrolyzer capital costs were varied by –/+ 20%, the wind farm availability and electrolyzer capacity factor were varied by 2%, and finally the electrolyzer energy use (related to its efficiency) was given a high and low value corresponding to the independent review panel's values for a central production facility [2]. The wind turbine costs, electrolyzer efficiency, and cost have the largest effect on the overall cost of hydrogen. By comparison, the capacity factors of the wind farm and electrolyzers, which gauge the maintenance downtime required of the subsystems, have a much smaller overall effect. The wind turbine cost uncertainty can have a large effect on the economic viability of a wind electrolysis production facility.

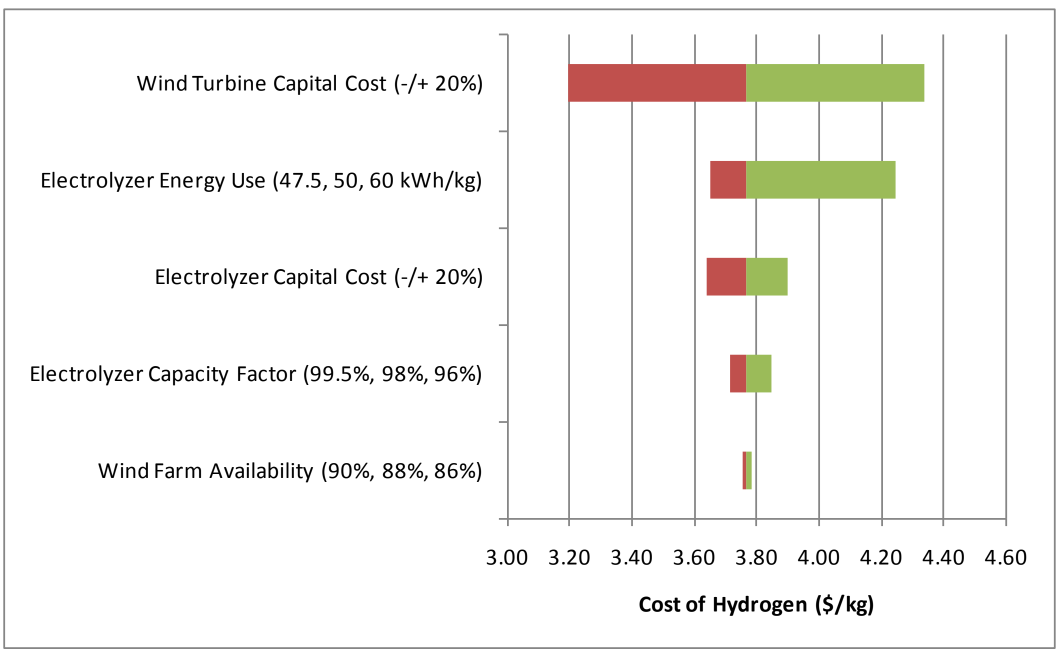

Figure 19. Sensitivity of cost of hydrogen for scenario d (power balanced, no summer peak)

Table 8. Sensitivity Values for High and Low Hydrogen Costs (2005$)

Variable Name	Base Case Value	Low Value	High Value
Wind Turbine Capital Cost ($/kW)	1,964	1,571	2,356
Electrolyzer Energy Use (kWh/kg)	50	47.5	60
Electrolyzer Capital Cost ($/kW)	384	307	461
Wind Farm Availability (%)	88	90	86
Electrolyzer Capacity Factor (%)	98	99.5	96

5 Conclusion

This analysis builds on the technical accomplishments of the NREL Wind2H2 program by examining the systems required for large-scale production of hydrogen via water electrolysis. By investigating lower cost and cost-optimized electrolysis production systems that use renewable wind energy, this analysis increases our understanding of how to develop green, sustainable hydrogen production systems. The model developed can be configured for different economic and technical parameters, allowing individual production sites and overall wind electrolysis trends to be analyzed.

This examination highlighted several economic and technical ramifications that should be considered. For instance, the scenarios in which peak summer grid electricity was not purchased generally resulted in lower costs of hydrogen, while not exacerbating peak demand during the summer. Those scenarios, however, also did not meet the average daily hydrogen production requirement during those peak summer days. These results must be considered when estimating hydrogen production if large demands for fuel cell electric vehicles or other renewable integration are to be met.

As expected, the cost of wind electricity is integral to the cost of the hydrogen from a wind electrolysis system, and higher wind costs yield higher hydrogen costs. The wind site capacity factor and the cost of the hydrogen, however, are highly correlated: higher wind capacity factors (that is, higher wind availability) correlate to lower hydrogen cost even at sites with lower average wind speeds. Class 4, 5, and 6 wind sites are capable of producing hydrogen for approximately $4/kg using current wind turbine costs.

6 Recommended Future Work

Several areas presented themselves as possibilities for future work, for example, examining model enhancements such as inclusion and effect of wind production tax credits or power purchase agreements. Also, alternatives to meeting a hydrogen production demand using oversized electrolyzers or some storage could warrant further work. Additional scenarios might include grid-independent or other coproduction models. GIS-related work might examine the effect of different regional electricity costs, or low and high variability of both electricity costs, or the balance points of different delivery and production cost based on distance from use. Future analysis could include wind site data over several years to show the effect of designing for a particular year or averaging over several years.

Our next steps are to examine the ramifications of some of the results in designing a wind electrolysis site, to identify key criteria for locating plants, to consider how costs might be reduced, and to develop cost sensitivities that might affect system design. This includes continued model validation and refinement. New scenarios could be developed to consider other aspects of a system. Continued use of the framework developed and analysis of results will help identify areas that need further work.

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REPORT DOCUMENTATION PAGE

Form Approved
OMB No. 0704-0188

1. REPORT DATE *(DD-MM-YYYY)*
May 2011

2. REPORT TYPE
Technical Report

3. DATES COVERED *(From - To)*

4. TITLE AND SUBTITLE
Wind Electrolysis: Hydrogen Cost Optimization

5a. CONTRACT NUMBER
DE-AC36-08GO28308

5b. GRANT NUMBER

5c. PROGRAM ELEMENT NUMBER

6. AUTHOR(S)
Genevieve Saur and Todd Ramsden

5d. PROJECT NUMBER
NREL/TP-5500-50408

5e. TASK NUMBER
H271.3710

5f. WORK UNIT NUMBER

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
National Renewable Energy Laboratory
1617 Cole Blvd.
Golden, CO 80401-3393

8. PERFORMING ORGANIZATION REPORT NUMBER
NREL/TP-5500-50408

9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)

10. SPONSOR/MONITOR'S ACRONYM(S)
NREL

11. SPONSORING/MONITORING AGENCY REPORT NUMBER

12. DISTRIBUTION AVAILABILITY STATEMENT
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

13. SUPPLEMENTARY NOTES

14. ABSTRACT *(Maximum 200 Words)*
This report describes a hydrogen production cost analysis of a collection of optimized central wind based electrolysis production facilities. the basic modeled wind electrolysis facility includes a number of low temperature electrolyzers and a co-located wind farm encompassing a number of 3 MW wind turbines that provide electricity for the electrolyzer units.

15. SUBJECT TERMS
wind electrolysis; hydrogen cost optimization; wind based water electrolysis; wind based electricity

16. SECURITY CLASSIFICATION OF: a. REPORT	b. ABSTRACT	c. THIS PAGE	17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
Unclassified	Unclassified	Unclassified	UL		19b. TELEPHONE NUMBER (*Include area code*)

Standard Form 298 (Rev. 8/98)
Prescribed by ANSI Std. Z39.18