Transmitting 4,000 MW of New Windpower from North Dakota to Chicago:

New HVDC Electric Lines or Hydrogen Pipeline

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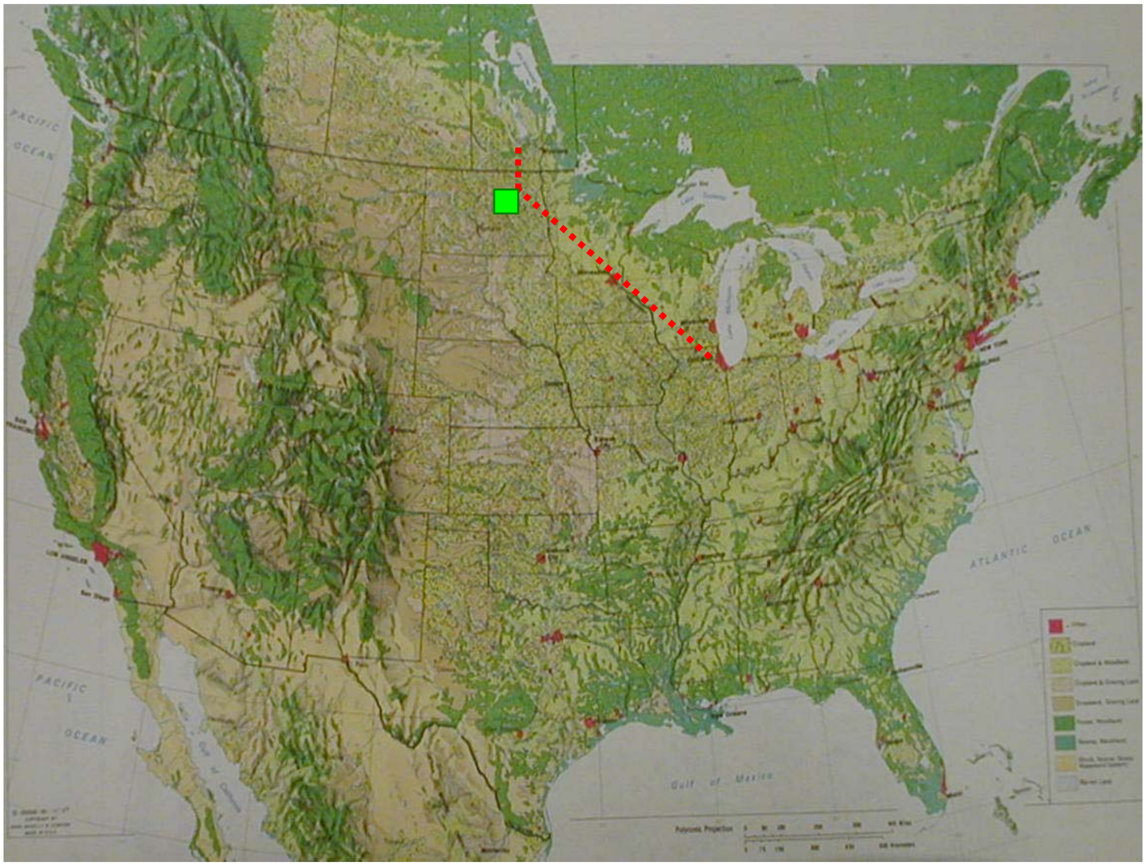
Figure 1-A.   Assumed location of large North Dakota windplant, transmission corridor to Chicago, and optional Manitoba Hydro HVDC interconnect at the Dorsey Substation, near Winnipeg



Executive Summary

We studied how the energy industry might profitably collect and transmit, at large scale, the vast, stranded renewable resources of the Great Plains to distant load center markets. We focused on windpower, mindful of its potential synergy with other energy sources. This energy might displace fossil and nuclear generation on the electricity grid, or might also be largely used to fuel vehicles, as electricity or as hydrogen.

We assumed a single 4,000 Megawatt (MW) generating capacity (nameplate; peak) windplant, on about 350 square miles in North Dakota, delivering its entire energy output to Chicago, as wholesale electricity or as gaseous hydrogen (GH2), via two alternative transmission systems: HVDC electric lines, or hydrogen pipeline.   See Figure 1-A. This 4,000 MW wind energy generation, conversion, transmission (GCT) module is large enough to:

a. Fully achieve economies of scale in manufacturing and installing both generation and transmission equipment;
b. Serve as a planning module, for modeling much larger systems, to approach harvesting the entire Great Plains potential of windpower, and perhaps other renewables.

However, 4,000 MW represents less than 2 per cent of North Dakota's wind energy potential.

We assumed technology and cost improvements likely in year 2010; all modeling is done in $US 2001.

Figure 1-B. Left powerline: The Pacific Direct Current Intertie (PDCI), near Bishop, CA. HVDC, 3,000 MW, +/- 500 kv bipole, 846 miles from Celilo, at The Dalles Dam, OR to Sylmar (NW Los Angeles, CA). Commissioned in 1970 as 1,500 MW line. The right powerline is conventional high voltage AC.

FINDINGS

We find from our Excel cost and profit-loss models that large-scale wind energy, generated in North Dakota and transmitted to a single delivery point in Chicago, via dedicated conversion-transmission system(s), will cost:

1. ***Delivered as electricity***
   - About $ .06 / kWh via HVDC transmission; competitive with generation by a new combined cycle combustion turbine (CCCT) if natural gas price is $4.30 - 5.30 per mmBtu.
   - About $ .14 - .18 / kWh via GH2 pipeline transmission, including conversion from electricity to GH2 in North Dakota and from GH2 back to electricity in Chicago.

2. ***Delivered as GH2***
   - About \$ .06 - .08 / kWh via GH2 pipeline transmission, including conversion from electricity to GH2 in North Dakota;
   - Competitive with GH2 made in Chicago from natural gas via steam methane reformation (SMR), a mature and widely-used industrial process, if natural gas price is about \$ 11.50 - 19.00 per mmBtu.

We also find:

1. Only one GCT case to be profitable, i.e. where revenues exceed costs, for delivering wholesale electricity in Chicago: HVDC transmission under these optimistic assumptions:
   a. Federal production tax credit (PTC) of ~ \$ 0.017 / kWh;
   b. Wind generator total installed capital cost is \$ 700 / kW
   c. Lines for both 2,000 MW HVDC systems are on a single set of towers, on one ROW;
   d. Chicago hourly wholesale electricity prices in 2010 are double the 1999 prices.
2. Energy storage in the GH2 pipeline is worth over \$100 million per year because Chicago electricity generation may be always on-peak. Consequently, we should investigate large-scale geologic storage along the pipeline route, to add more value via seasonal-scale GH2 storage.
3. Implications for optimum collection and transmission of all the diverse, diffuse, dispersed, renewable energy resources from the Great Plains to distant markets:
   a. seasonal synergy, for harvest, stockpiling, and dispatch;
   b. sharing transmission to improve its CF, thus project profitability.

We also find that low conversion-transmission system CF is a very large economic burden on delivered North Dakota wind energy because our study assumes that:

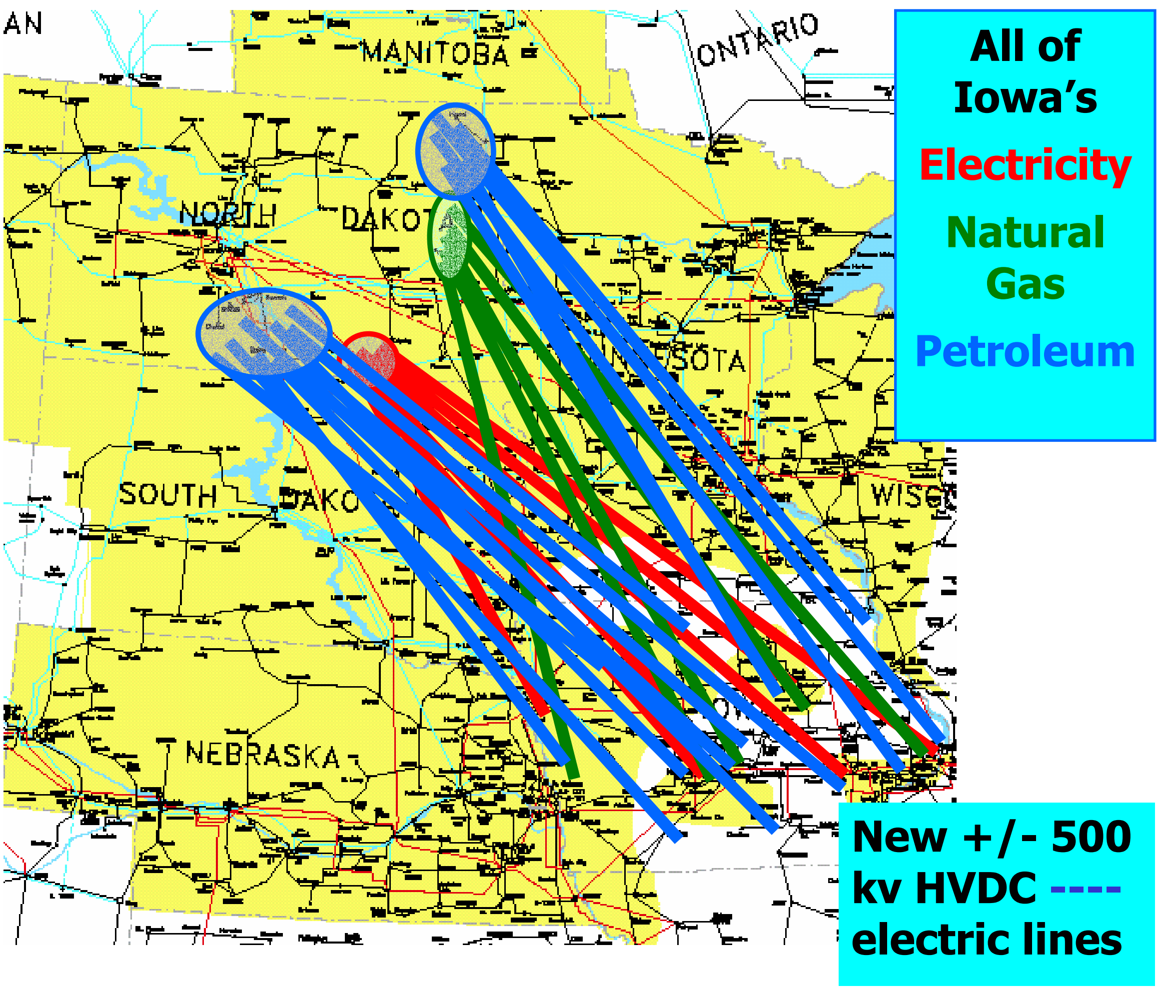
1. All conversion and transmission systems are exclusively dedicated to the windplant;
2. Peak capacity rating of the conversion and transmission components equals windplant peak generating capacity; the GCT module is not transmission-limited; wind generation is never deliberately curtailed;
3. The long-term average CF of the wind generators is 40%, reflecting the unusually-energetic North Dakota resource;
4. All collection, conversion, and transmission system components operate at the same CF as the windplant:
   a. In the HVDC scenario: AC-DC, DC-AC converters, and transmission line.
   b. In the GH2 scenario: primarily electrolyzers and compressors, because the pipelines can be "packed", for storage.

This low conversion-transmission system CF is a powerful incentive to share transmission with other energy sources-- other renewables and perhaps "really clean coal", i.e. requiring complete capture and use or sequestration of carbon (C) and carbon dioxide (CO_2). We also considered interfacing the 4,000 MW windpower GCT module with two Great Plains hydro systems, WAPA and MH[1], to “firm” windpower and improve transmission CF.

We suppose that GH2 pipeline transmission may offer important advantages over electric transmission, but only if a large number of circumstances favorable to GH2 are simultaneously satisfied, as discussed in “Prospects for GH2 Pipelines”, below.

This is a modest beginning study of a large and complex system optimization problem. We present a long list of recommended future technical and economic study, which is justified by the very large, potentially-synergistic, stranded renewable energy resources of the Great Plains.

Figure 1-C. Exporting 20% of North Dakota’s wind energy to Iowa would replace all of Iowa’s present energy sources, and would require 24 new HVDC electric transmission lines of largest-available size, replacing all Iowa’s present energy sources.   Graphic by Thomas A. Wind, Wind Utility Consulting, Jefferson, IA.



[1] Western Area Power Administration (WAPA) embraces the Missouri River system; Manitoba Hydro (MH) embraces Nelson River and others in Canada, and is a major exporter to USA.

1. Introduction

Repowering The Midwest, released Feb 01 by Environmental Law and Policy Center of the Midwest proposes 24,500 MW of new wind generation in the ten Midwestern states by year 2020.[2] However, despite significant cost reductions in wind generating equipment, with wind energy the lowest-cost renewable energy source, most of this energy is "stranded" for lack of available transmission capacity to bring it to markets in distant load centers.

Five Great Plains states have a combined available, harvestable, average annual wind energy potential of over 5,000 Twh.[3][4][5] North Dakota's estimated annual wind energy potential, alone, is over 1,200 TWh. For comparison, total USA electric energy consumption in year 2000 was about 3,500 TWh. Exportable Great Plains biomass will significantly increase the total annual renewable energy potential.

At 40 per cent windplant capacity factor (CF), over 300,000 Megawatts (MW) of peak (nameplate) installed windplant generating capacity would be required in North Dakota, to fully harvest this single state's wind resource. The largest practical long-distance electric transmission line is likely to remain a high voltage direct current (HVDC) line of about 3,000 MW capacity. Thus, about 100 large, new HVDC electric transmission lines would be necessary to export just North Dakota's wind energy; about 400 new electric lines to export the wind energy from the five windiest Great Plains states.

HVDC lines are generally more compact than HVAC lines. See Figure 1-B. However, routing, siting, and permitting these 400 new electric lines through many "back yards" will be costly, in dollars, permitting delays, and lasting public nuisance. See Figure 1-C, for an example.

Large, new gaseous hydrogen (GH2) pipelines, might offer greater long-term benefit - cost ratio than large, new HVDC electric lines. Installed underground, like natural gas pipelines, GH2 pipelines might be more acceptable to the public, easier to route and permit, and offer greater security from damage or attack.

A 36"-diameter GH2 pipeline, operating at 1,000 psi, has a continuous energy transmission capacity of about 6,000 MW, and the important benefit of energy storage capacity of about 120 GWh.

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[2] See reference 1: Environmental Law and Policy Center, Chicago, 2001. *Repowering The Midwest: The Clean Energy Development Plan for the Heartland*, released February 14, 2001.

[3] North Dakota, South Dakota, Kansas, Montana, Texas. See references 3, 4. About half the land area of each state has been withdrawn from the estimated wind resource base as unavailable or unsuitable: urban, airports, highways, water bodies, etc.

[4] These wind resource assessments are currently being revised by the National Renewable Energy Laboratory (NREL), continuously, as new state wind resource maps become available; an interim report to EIA, USDOE, is expected by Mar 03. A work-in-process; format of a new report, if any, TBD. (personal communication, Sept 02)

[5] TWh = 1 billion kWh. Total electric energy consumption in USA, in year 2000, was about 3,500 TWh.

Thus, instead of 400 new electric lines, 200 new GH2 pipelines would be needed to export the available wind energy from the five windiest Great Plains states. The key question remains: do we intend to deliver North Dakota wind energy to Chicago as electricity or as GH2?

The extant electric transmission system will accommodate only a very small fraction of the Great Plains wind resource. Although significant wind energy from North Dakota and other Great Plains states can be delivered by expanding and upgrading the existing electricity grid, bringing the far larger portion of this available wind resource to markets will require large, new, costly transmission systems. In some cases, this electricity grid expansion will be socially and politically very difficult: public opposition, regulatory processes, and vested interests. Several groups are studying, or advocating for, this grid expansion.[6]

The full cost of this new transmission must be included in the price for each kWh of wind energy delivered to end users, making wind energy delivered to Chicago very expensive, unless:

1. That new transmission is shared with other energy sources, to improve its capacity factor (CF) above the 40 percent expected for the best windpower plants, and / or
2. Transmission is undersized and windpower production is intentionally curtailed during long periods of high wind energy, to optimize return on investment for the complete GT system.

See Figures A and B: GCT system block diagrams, for the GCT scenarios we studied. See Figure 1-A, the assumed location of the GCT module.

Salient Assumptions

1. Capital equipment technology and costs likely for year 2010:
    a. Windplant total installed capital cost at both $950 / kW and $700 / kW (nameplate);
    b. Electrolyzers at both $300 and $200 per kWe (kW electrical input).
2. $ US 2001, without inflation adjustment;
3. 4,000 MW (nameplate) wind generating capacity in a single North Dakota windplant, to achieve the economies of scale expected for the GCT scenarios analyzed;
4. Simple capital recovery factor (CRF) rather than discounted cash flows, for cost and profitability models;
5. Transmission systems are dedicated exclusively to the windplant, and operating at the same CF, assumed to be 40 per cent;

[6] Wind On The Wires, www.windonthewires.org; American Wind Energy Association, www.awea.org; Western Area Power Administration, www.wapa.gov; Midwest Independent System Operator, www.midwestiso.org; National Electric Reliability Council, www.nerc.com; National Wind Coordinating Committee, nwcc@resolv.org, and others. ABB has been commissioned to study North Dakota transmission expansion.

6. Revenue from wholesale electricity sales in Chicago is modeled on:
    a. Actual hourly production from the extant Chandler, MN windplant;
    b. Corresponding actual hourly wholesale electricity prices in 1999, in the Chicago market;
    c. Doubling the prices in (b), to estimate year 2010 prices, for the model calculations.
7. Profitability is calculated both with and without the extant federal production tax credit (PTC) for wind generation, now about \$ .017 / kWh;
8. By year 2010, a market for GH2 will emerge in Chicago to completely consume the GCT system output, in the several GH2 transmission scenario cases;
9. In the GH2 transmission scenario, in all cases, the oxygen byproduct of electrolysis, at the North Dakota windplant, is sold to a presumed adjacent coal gasification plant at \$19.17 / ton.

Approach

Our study developed:

1. Cost and income Excel models, for nine transmission scenarios, with results calculated for year 2010 construction; we used simple capital recovery factor (CRF) rather than discounted cash flows
2. An extensive list of recommended future study and R+D that must be done before we consider design, finance, and build of high-capacity, long-distance, compressed-gas pipelines designed for transmitting and storing hydrogen from wind and other renewable sources, and perhaps also from "really clean" gasified coal;
3. An initial assessment of the potential for "firming" windpower with hydropower by energy interchange with nearby Western Area Power Administration (WAPA) and Manitoba Hydro (MH) systems.
4. The value of carbon emission taxes that would be required for each case to break even with the cost of electricity from new natural gas fired combined cycle combustion turbines (CCCT);
5. In the GH2 scenarios:
    a. Selling the oxygen (O_2) byproduct of hydrogen production to future "really clean" coal gasification plants, adjacent to the windplant, to improve project profitability;
    b. Seasonal-scale GH2 storage, probably in subterranean geologic formations or numerous, dispersed, manmade structures or vessels, as proposed by Dr. Bent Sorensen, Denmark[7], and discussed by W. Amos, NREL[8];

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[7] "Handling Fluctuating Renewable Energy Production by Hydrogen Scenarios", Prof Bent Sorensen, Roskilde Univ, Denmark, in Reference 73, http://mmf.ruc.dk/energy/

[8] Reference 72.

However, we did not consider, nor include in our economic analysis:

1. Estimating how much extant electricity transmission right-of-way (ROW) capacity can be increased, at "no net increase in perceived or actual public nuisance or danger"; at what cost;
2. Cost and topological optimization of infrastructure for energy gathering, at the North Dakota source, and for energy distribution in Chicago;
3. Estimating size and timing of markets for GH2 fuel in Chicago, for distributed generation of electricity (DG) and / or for vehicles;
4. Discounted cash flows: we used simple capital recovery factor (CRF) for the cost model, which drove the profitability model;
5. Effects of Title IX Energy, in the 2002 Farm Bill;
6. Many other cases based on different sets of assumptions

Prospects for GH2 Pipelines

The anticipated "renewables-hydrogen economy" features collection and transmission of large, diverse, dispersed, diffuse renewable energy sources, such as windpower, as pipelined GH2.

The salient differences between HVDC electric and GH2 pipeline transmission:

1. Energy storage: "packing" gas pipelines, by crowding more molecules into the pipe by increasing pipeline pressure, is commonly used in the natural gas transmission industry. Packing the 36" GH2 pipeline, assumed in several cases is this study, to 1,000 psi (~70 bar), then drawing down the pressure to 500 psi, provides ~ 120 GWh of storage: 2 days' supply at constant 2,500 MW drawdown.
2. Overhead vs. underground location: HVDC electric lines are usually, and most economically, located on towers or poles aboveground. HVDC can be transmitted for an unlimited distance underground or underwater, but at about ten times the cost of overhead. Gas pipelines are usually, and most economically, located underground, with consequent advantages of less aesthetic impact and increased protection from damage or attack.

Although we show, above, that GH2 transmission is economically unattractive, GH2 transmission might expedite large, new transmission capacity for multiple stranded Great Plains renewables, by avoiding the thicket of electricity transmission regulation via FERC, RTO's, ISO's, other established electricity industry interests, and permitting jurisdictions. However, energy pipelines are also subject to FERC and other regulation and permitting.

Properly built and well-maintained, steel pipelines have long service lives. Perhaps the energy industry should consider building all new natural gas transmission lines of "hydrogen-capable" line pipe. Then, as the methane is depleted, these pipelines can carry a "Hythane" mixture, increasingly enriched by GH2 from various sources, and eventually 100% GH2.

GH2 transmission may provide a larger long-term market for Great Plains wind than electric transmission ***IF*** several, or most, of the following occur:

1. A large market emerges for pure GH2 for fuel cell fuel, for transportation-- buses, cars, aircraft-- and for DG (distributed generation) of electricity-- especially in CHP (combined heat and power) installations; thus, wind energy is delivered as hydrogen gas to new terminals and load centers;
2. If wind-generated GH2 can compete in cost and market price, with GH2 from natural gas and gasified coal.
3. Electric transmission upgrade and expansion proves extremely difficult and costly because of public opposition and ROW acquisition cost;
4. GH2 transmission in underground pipelines is more acceptable to the public than overhead electric transmission;
5. ROW access and cost is favorable for H2 transmission in high-capacity, long-distance underground pipelines;
6. We learn, and demonstrate, how to build high-capacity, long-distance, underground, GH2 pipelines operating at variable pressure (at several-day time scale; at 2:1 pressure range). See "NHTTF", Section 8 of report. Hydrogen pipelines have been operated safely for decades, in North America and in Europe, by industrial gas and oil-and-gas companies, but generally are:
    a. Confined to established industrial plants and corridors;
    b. Operating at constant pressure, avoiding hydrogen embrittlement from cyclic fatigue, from varying pressure;
    c. Among relatively few acceptance and delivery points, or nodes.
7. Electrolyzers with high-pressure (> 1,000 psi) output, high-efficiency (> 90%), TICC (total installed capital cost) < $250 / kWe input, and low O+M cost (< $0.001 / kWh), in MW-scale modules, become commercially available by about year 2010;
8. GH2 can be stored, at low cost, in very large (seasonal) quantity in either or both:
    d. Underground geological formations along the H2 pipeline route; natural gas (NG, primarily methane, CH4) is widely stored underground, but the H2 molecule is far smaller and may leak away;
    e. Distributed, in storage vessels aboard vehicles and at stationary sites.
9. Windpower-biomass synergy develops to embrace:
    f. Seasonal counter-availability;
    g. Stockpiling and dispatching generation, on several-day to seasonal time scale;
    h. Ease of "distributed collection" from various sizes of biomass-to-hydrogen plants, at frequent intervals along the H2 pipeline route; a delivery node to an H2 pipeline would be simple and inexpensive, relative to HVDC access, and amenable to a wide range of capacity, probably 100 kW to 1,000 MW:

        i. A boss on the mainline pipe;
        ii. Shutoff valve (manual and automatic);
        iii. Delivered-gas quality monitoring and auto-shutoff system;
        iv. Meter;

v. Compressor, if required.

10. Synergy with coal, via "zero emissions" (which shall mean including C and / or CO_2 capture and permanent sequestration) coal gasification plants, develops so that:
    i. Coal gasification plus water-shift reaction is a major source of H_2 for commingling and pipeline transmission with wind-source H_2;
    j. The oxygen (O_2) byproduct of wind-generated hydrogen, via electrolysis of water, is sold to adjacent coal-gasification plants.
11. Natural gas (NG) price is $15 - 20 / mmBtu, without carbon-emission taxes (C-taxes);
12. C-taxes are applied, raising the effective prices of all fossil fuels;
13. A distribution network for pure H2 is in place at the major markets likely to be candidate destinations for GH2 transmission pipelines;
14. The "Hindenberg" effect, i.e. public apprehension about the safety of GH2 transmission and utilization, is allayed.

Since the world now has no GH2 pipeline systems, designed for collecting and transmitting energy at large scale from remote, diverse, dispersed, diffuse renewable energy sources, we will need a pilot-scale facility if we anticipate the convergence of multiple favorable factors, above. See "National Hydrogen Transmission Test Facility (NHTTF)", later in this report.

Conclusion

This is a modest beginning study of a large and complex system optimization problem. We present a long list of recommended future technical and economic study, which is justified by the very large, potentially-synergistic, stranded renewable energy resources of the Great Plains.

Perhaps neither HVDC nor GH2 transmission is adequate to the task, and we will need to wait for a higher-capacity mode such as the "continental supergrid", a combination of superconducting (SC) electric and liquid hydrogen transmission, as proposed by EPRI.[9] However, superconductive electric transmission may not be suitable for windpower, because of its time-varying power output at daily, even hourly scale; SC transmission has difficulty with changing current rapidly.

System Configurations: Block Diagrams

See system flowcharts and block diagrams in Appendix D; two simplified diagrams, Figures A and B, for the two principal scenarios investigated, appear below. See extensive technical discussion of "The Transfer of Electrical Energy to the Supply Grid", Chapter 4 of S. Heier.[10]

[9] References 61, 62, 63.

[10] See reference 71.

Figure A. Simplified "Electrical Transmission" Scenario

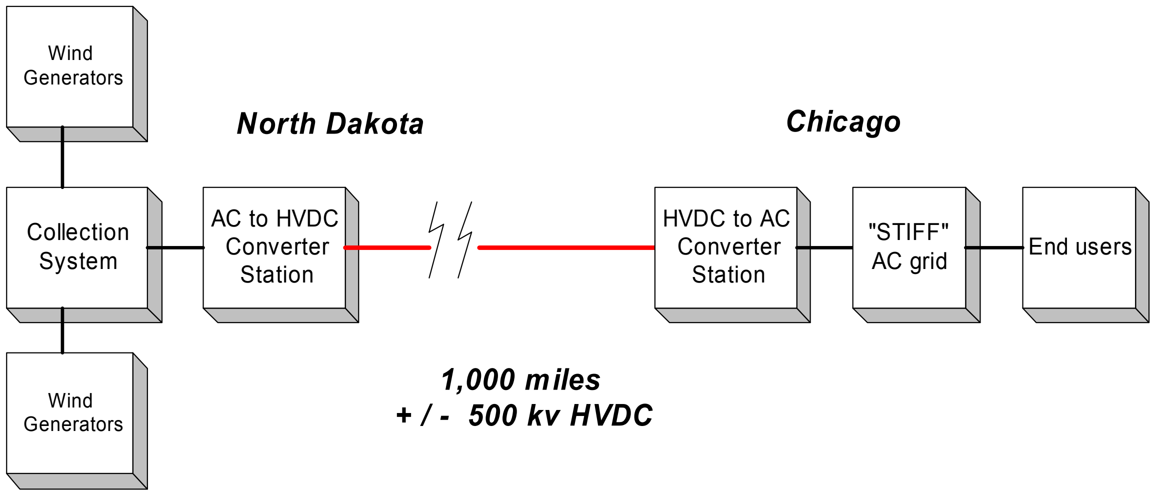
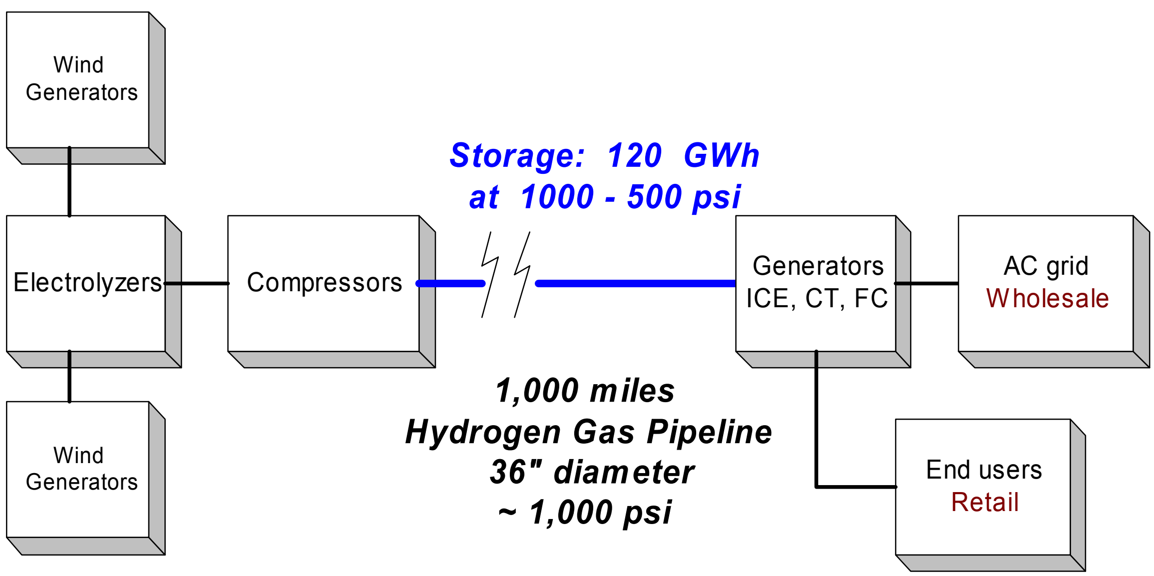


Figure B. Simplified "Hydrogen Transmission" scenario, delivering electricity in Chicago



We model the costs and revenues of three of these options; the hydro storage of wind energy we examine only conceptually. The first option listed above is especially attractive because the energy can be stored in the hydrogen pipeline for electricity generation during peak periods. The fourth option is attractive because DG and ground and air transportation in the Chicago area, both public and private, represent a very large potential future market for hydrogen fuel.

This project updates and expands an earlier paper comparing the provision of electricity to Chicago via a hydrogen pipeline versus electric transmission lines.[11] To expand this work we have collected additional information on pipeline and HVDC costs, considered the value of several benefits of the hydrogen pipeline scenario, and researched the viability of hydro storage of wind energy in the region. Important additional benefits of the hydrogen transmission scenarios we explore here are:

- The energy storage value of the pipeline, and
- The sale of byproduct oxygen from electrolyzers to coal-gasification plants.

Other potential benefits of hydrogen pipeline transmission not treated in this study are:

- Relative security of underground pipeline versus overhead wires;
- Greater public acceptance and lower cost permitting of a pipeline versus overhead high voltage power lines;
- Lower cost right-of-way (ROW) purchase or lease;
- Delivering hydrogen fuel to distributed generation, to displace retail-value electricity;
- Distributed collection, from various hydrogen sources along the route; and
- Sharing the transmission system with plants generating hydrogen from coal, while selling valuable electrolysis-byproduct oxygen to those coal plants.[12]

See section 8, Recommended Future Work, for further discussion of these issues.

1.1 Methodology

To compare the economics of the 4,000 MW-scale pipeline and HVDC transmission scenarios, we constructed two spreadsheet models, one for costs and the other for profit/loss. With these models we explored nine different scenarios for delivering wholesale electricity to Chicago: six scenarios including a hydrogen pipeline and three with HVDC power lines. All scenarios are assumed to be the year 2010, and we assume technology cost reductions (from current costs) based on this assumption. The pipeline scenarios are based upon:

1. A 1000-mile, 36-inch pipeline with low-pressure electrolyzers and separate compressors;

[11] See reference 2: Gibbs and Biewald, *Transmitting Windpower from the Dakotas to Chicago: A Preliminary Analysis of a Hydrogen Transmission Scenario,* prepared in conjunction with "Repowering the Midwest…" for Environmental Law and Policy Center, Chicago, Illinois, September 8, 2000. Available at: www.synapse-energy.com.

[12] For "zero-emissions" concepts, for coal and other carbon fuels, see: www.netl.doe.gov/scng/news/pdf/NGTworkshops.pdf, www.cleanenergysystems.com/WhatsNew/CorpUpdate.html, www.llnl.gov/llnl/06news/NewsReleases/2001/NR-01-05-11.html, www.llnl.gov/str/June01/Cooper.html, www.zest.org, and www.zeca.org.

2. A 1000-mile, 36-inch pipeline with high pressure (1,000 psi output) electrolyzers and no external compression; and
3. A 1000-mile, 18-inch pipeline with high pressure (1,000 psi output) electrolyzers and no external compression.[13]

Each of these pipeline scenarios is explored with two types of hydrogen-fueled electricity generation in Chicago (yielding the six scenarios):

1. A solid oxide fuel cell (SOFC) with a gas turbine operating on byproduct heat, and
2. A combined cycle combustion turbine (CCCT).

The HVDC scenarios developed for modeling purposes are:

1. Two full HVDC systems, including lines and converters, 2,000 MW each, installed on two sets of towers;
2. The same two systems installed on one set of towers; and
3. The same two systems installed on one set of towers, with the final 100 miles into Chicago installed underground.

The cost model is a simple summation of capital and operating costs collected from an array of literature and industry sources. Detailed information on scenario costs appears in Chapter 2. The revenue model is more complex. We model wind generation using actual hourly wind generation data for an entire year (1999) for both pipeline and HVDC scenarios. Based on the pipeline diameters in the different scenarios (and pressure limitations), we calculate pipeline storage capacity. To calculate revenues from electricity sales in Chicago, we use adjusted 1999 hourly marginal price information from the Commonwealth Edison system.[14]

To model the sale of electricity, we developed a heuristic to maximize revenues, taking into consideration: (a) pipeline pressure, (b) current and day-ahead electricity prices, and (c) a fixed generating capacity of 2,300 MW in Chicago.[15] We assumed electricity was sold into wholesale markets in Chicago.[16] The storage capacity of the pipeline allows

[13] Note that both pipelines and HVDC systems can simply be paralleled and proliferated to achieve the desired regional transmission capacity; this may strongly affect pipeline size, transmission economics and transmission mode choice.

[14] Because electricity markets in Chicago are not yet fully deregulated, we adjust this price data to simulate competitive market prices. These adjustments are described in Chapter 3.

[15] Note that this generating capacity limit is on equipment in Chicago, generating electricity from hydrogen – not on wind generating capacity in North Dakota. The 2,300-MW limit was selected based on iterative model runs to maximize revenue. The figure 2,300 seems a reasonable amount of capacity to service a 4,000 MW windfarm operating at an average 40 percent capacity factor with storage capability. However we have not attempted to optimize the amount of fuel cell or combustion turbine capacity in Chicago taking into account the cost of that capacity.

[16] We assumed this because a large energy generating and delivery system such as the one envisioned would be developed by a wholesale energy company (or companies), not by a retail user who could displace the cost of retail electricity. To gauge the cost of delivering Dakotas windpower to distributed generators in Chicago, see our cost estimates for hydrogen-only delivery to Chicago.

some portion of total kWhs to be stored from their actual generation hour to higher priced hours. In the HVDC scenarios, there is no energy storage; all electricity generated is sold instantaneously at the current hourly price.

In addition to these scenarios for electricity delivery, we assess the costs of delivering hydrogen gas to Chicago via the pipeline, as fuel for surface vehicles, aircraft, and DG. For this, we simply subtract the cost of electricity generating infrastructure in Chicago and calculate the delivered cost of hydrogen in each of the hydrogen scenarios. We compare this cost to the cost of generating hydrogen in Chicago via steam methane reformation (SMR) of natural gas, to determine the breakeven price for natural gas.

Annual revenues for each scenario are calculated by summing revenues in each hour of the year. Total annual costs are subtracted from total revenues to calculate an annual profit or loss for each scenario.

Our review of potential storage of wind energy in large hydro systems was limited to information collection from staff at two large Midwestern hydro systems: the Western Area Power Administration (WAPA) in the U.S. and Manitoba Hydro (MH) in Canada. We were prevented by time and budget constraints from modeling hydro storage scenarios.

2. Pipeline vs. Electric Lines – Cost Model

Our cost assumptions for each component of the wind generation, the hydrogen pipeline scenarios and the HVDC electricity scenarios are set forth in the table below, based on projected year 2010 installed capital costs. All costs are in 2001 US dollars.

Table 1. Capital Cost Assumptions for System Components

Component	Unit Cost
Wind generators	$950 and $700 per kW*
Electrolyzers	$200 – 300 per kW
HVDC converters, PCC, per pair	$130 per kW
HVDC transmission lines, 2 GW	$400,000 per mile
HVDC underground cable, 4 GW	$7.3 million per mile
Hybrid Fuel Cell Systems	$1,000 per kW
Combined-Cycle Combustion Turbines	$450 per kW

*We calculate total costs for systems assuming both $700 and $950 per kW for wind generators.

2.1 Wind Generation Costs

We assume 4,000 MW of wind generating capacity spread across an area of approximately 400 square miles in central North Dakota. We assume an average capacity factor of 40 percent for these generators, resulting in annual generation of approximately 14 million MWh (14 TWh) in an average year.

Our primary cost assumption for the capital cost of wind generators is a total installed cost of $950 per kW, with operating and maintenance (O&M) costs of $0.008 per kWh.[17] Total annual costs of wind generation using these figures are $567 million. We do not expect this figure to decrease significantly during the period 2001 to 2010.[18] However, to explore a case in which wind costs do decline significantly, we also calculate total system costs assuming wind turbine total installed capital costs of $700 per kW.

2.2 Pipeline Costs

There is much uncertainty about the cost of hydrogen pipelines. Currently, no hydrogen pipeline of the scale and purpose envisioned here exists; we found no recent research or design studies. Although industrial gas companies and oil and gas companies have safely and profitably operated hydrogen pipelines for decades, they are not optimized for large-scale, long-distance, renewable-source energy collection and transmission, nor for energy storage. We have constructed these costs estimates from literature (much of it from 1970's and 1980's), through discussions with experts in the gas pipeline industries, and hydrogen researchers.[19] Costs are presented here, and performance and revenue modeling is presented in Chapter 3.

[17] See reference 6: Malcolm and Hansen, *Results from the WindPACT Rotor Design Study*, presented at Windpower 2001, Washington, DC, June, 2001.

[18] Personal communication with D.J. Malcolm, November 2001.

[19] See references 8 - 33 and 46 - 49.

The best source of "benchmark" cost data is the new Alliance Pipeline, running from northeast British Columbia to Chicago, which began service on December 1, 2000.[20] This 36-inch natural gas pipeline, 3,200 kilometers in length, operates at a pressure of 1,740 psi. Its capacity is 1.5 billion cubic feet per day (Bcfd). Total capital cost, including gas gathering laterals, compressors and valves, meters and terminals, was $US 3.3 billion. We inferred that 1,600 km of this line (1,000 miles) would have cost $ 1.5 billion, to which we applied a 1.4 multiplier for the expected increased cost of a hydrogen-service pipeline of the same diameter, as approximated by Ogden, and others.[21] This 1.4 multiplier is an important assumption, which needs additional analysis. (See section 8, Recommended Future Work.)

Costs for each of the six pipeline scenarios, for delivering wholesale electricity in Chicago, are shown in Table 2. The first two scenarios include a 36-inch pipeline and the third includes an 18-inch line. The names of scenarios are made up of three pieces of information: pipeline diameter ("36" or "18"), the presence or absence of a compression system external to the electrolyzers ("C" or "NC") and the hydrogen-to-electricity generating technology: fuel cell ("FC") or combined-cycle gas turbine ("CT"). These names, with brief scenario descriptions, are shown in Table 2.

In the "NC" scenarios, $200 million is deleted from the all-inclusive cost of the pipeline, to back out the capital cost of compressors.

2.3 HVDC Costs

The second option we explore for transmitting Dakotas wind energy to Chicago is new HVDC power lines. Costs, benefits, and performance are from current public-domain studies, vendor literature and engineers, and researchers.[22] HVDC lines are much better suited to long distance, high capacity (1,000 MW and greater) electricity transmission than the ubiquitous high voltage alternating current (HVAC) power lines because:

- Energy losses over long distance are lower with DC lines;
- DC lines are inherently controllable and stable; they have no reactive power;
- Energy directional flow can be controlled, avoiding "power loops" on the grid;
- The converter stations can supply reactive power support to the HVAC grid; and
- Transmission line towers are smaller and less-obtrusive; less costly; require smaller ROW.

[20] See reference 32.

[21] See references 24 - 28.

[22] See references 35 - 40.

Table 2. Assumed Costs of Hydrogen Pipeline Scenarios ($ million)

Scenario	Capital Cost	Annual Cap. Cost	Annual O&M Cost	Total Annual Cost
36-C-FC (36" pipeline; low-pressure electrolysis with compression; 70% efficient SOFC fuel cells)				
Wind Generators	$3,800	$494	$112	$606
Pipeline	$2,300	$299	$35	$334
Electrolyzers	$1,200	$156	$36	$192
Fuel Cells	$2,300	$299	$42	$341
Compressors	(in pipeline)	(in pipeline)	$37	$37
Total	$9,600	$1,248	$262	$1,510
36-C-CT (36" pipeline; low-pressure electrolysis with compression; 60% efficient CC gas turbine)				
Wind Generators	$3,800	$494	$112	$606
Pipeline	$2,300	$299	$35	$334
Electrolyzers	$1,200	$156	$36	$192
CCCTs	$1,035	$135	$27	$162
Compressors	(in pipeline)	(in pipeline)	$37	$37
Total	$8,335	$1,084	$248	$1,331
36-NC-FC (36" Pipeline; high-pressure electrolysis; 70% efficient SOFC fuel cells)				
Wind Generators	$3,800	$494	$112	$606
Pipeline	$2,100	$273	$35	$308
Electrolyzers	$1,200	$156	$36	$192
Fuel Cells	$2,300	$299	$42	$341
Compressors	$0	$0	$0	$0
Total	$9,400	$1,222	$225	$1,447
36-NC-CT (36" Pipeline; high-pressure electrolysis; 60% efficient CC gas turbine)				
Wind Generators	$3,800	$494	$112	$606
Pipeline	$2,100	$273	$35	$308
Electrolyzers	$1,200	$156	$36	$192
CCCTs	$1,035	$135	$36	$171
Compressors	$0	$0	$0	$0
Total	$8,135	$1,058	$219	$1,277
18-NC-FC (18" Pipeline; high-pressure electrolysis; 70% efficient SOFC fuel cells)				
Wind Generators	$3,800	$494	$112	$606
Pipeline	$800	$104	$35	$139
Electrolyzers	$800	$104	$36	$140
Fuel Cells	$2,300	$299	$44	$343
Compressors	$0	$0	$0	$0
Total	$7,700	$1,001	$227	$1,228
18-NC-CT (18" Pipeline; high-pressure electrolysis; 60% efficient CC gas turbine)				
Wind Generators	$3,800	$494	$112	$606
Pipeline	$800	$104	$35	$139
Electrolyzers	$800	$104	$36	$140
CCCTs	$1,035	$135	$38	$172
Compressors	$0	$0	$0	$0
Total	$6,435	$837	$221	$1,058

HVDC systems require a costly converter terminal at each end of the line, but the DC lines are less costly than HVAC lines and suffer much lower losses. Thus, HVDC and HVAC system total cost, the sum of long-term capital and O&M costs, are equal at a "break-even distance" of about 400 to 600 miles. HVDC can also be transmitted long distances in underground or undersea cables, at no more loss than in overhead lines. Underground or undersea HVAC transmission losses become severe at more than about 10 to 30 miles. The contemplated transmission of 4,000 MW over 1,000 miles clearly favors the economics of HVDC over HVAC, with the added advantages of the other issues listed above.

Assessing the cost of HVDC lines is challenging at this time, because so few HVDC systems have been built, and because the state and economics of the art are rapidly improving.

We have costed and modeled three HVDC scenarios, named "HVDC-A" through "HVDC-C," as shown in Table 3 below. Again, costs are presented here, and performance and revenue modeling is presented in Chapter 3. All four scenarios assume two HVDC circuits and four power converter stations (one at each end of each circuit). In scenario HVDC-A the two circuits are mounted on separate sets of towers; in HVDC-B, the two circuits are installed on one set of towers. Less land is required for the ROW in HVDC-B, thus capital costs are lower. Maintenance costs are also lower for HVDC-B. Converter station costs are the same for both HVDC-A and HVDC-B.

In the HVDC-C scenario we assume that the final 100 miles of the transmission system is installed underground, because of line siting challenges in suburban Chicago areas. Permitting new overhead electric lines is increasingly difficult, costly, and time-consuming, especially in congested urban and suburban areas, where ROW cost is also very high. Installing cables underground may not forestall public opposition, but it is a reasonable option to consider if the HVDC lines are to be built. We assume, in HVDC-C, that both circuits are installed on one set of towers and that the final 100 miles are underground. The addition of the underground segment increases construction costs (included in capital costs) and reduces maintenance costs in this scenario relative to the non-underground scenarios. The costs for each of the HVDC scenarios are shown in Table 3 below. Annual capital costs are calculated using a 13-percent annual capital recovery factor.

Underground cables require only 20 to 50 feet of ROW width, while overhead lines require 150 to 200 feet. The O&M cost for underground cable is lower, as underground lines are relatively immune to weather and other hazards. However, underground cable costs four to eight times as much as overhead lines, installed (see figures in Table 3); this cost gap will close somewhat as new cable manufacturing processes (extruded solid polymer dielectric) become popular.

The present practical limit, and likely future limit, of HVDC underground cable system capacity is about 1,000 MW per circuit, at +/- 500 kV. Thus, four complete HVDC cable pairs are required: eight cables in a single trench. Each cable is about six inches in diameter and weighs about 20 pounds per foot.

Table 3. Assumed Costs of HVDC Scenarios ($ million)

	Capital Cost	Annual Cap. Cost	Annual O&M Cost	Total Annual Cost
HVDC-A (two sets of towers)				
Wind generators	$3,800	$494	$112	$606
Lines	$936	$122	$9	$131
Converters	$520	$68	$10	$78
Total	$5,256	$683	$132	$815
HVDC-B (one set of towers)				
Wind generators	$3,800	$494	$112	$606
Lines	$568	$74	$6	$80
Converters	$520	$68	$10	$78
Total	$4,888	$635	$128	$764
HVDC-C (one set of towers; underground final 100 miles)				
Wind generators	$3,800	$494	$112	$606
Lines	$1,211	$157	$6	$163
Converters	$520	$68	$10	$78
Total	$5,531	$719	$128	$847

3. Pipeline vs. Electric Lines – Profit Model

To calculate projected revenues and profit or loss, from each scenario, we developed an hourly energy production and sales model.[23] Key data elements in the model are a year's hourly wind data and wholesale market price data, for the year 1999. In addition, the model includes assumptions about the performance of each pipeline and HVDC system. The model's wind and market price data are described in section 3.1. Treatment of the pipeline and HVDC systems is described in sections 3.2 and 3.3.

3.1 Wind and Market Price Data

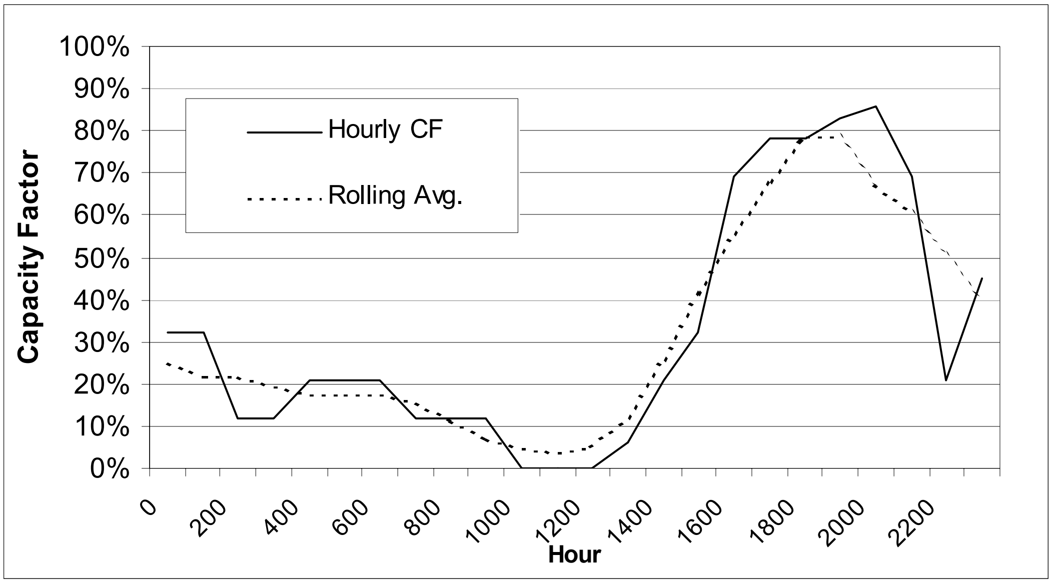
The wind data in the model is based on actual output data from a 100 MW windplant in Chandler, Minnesota. We have adjusted these data in two ways to simulate wind production from a 4,000 MW project in North Dakota. First, we have smoothed fluctuations in plant output slightly to account for the much larger land area of the Dakota project. This is based on the idea that, as land area increases, wind output becomes less variable. This is because wind activity will be considerably different across a 400 square mile area. Also, as a given weather system moves across a wind facility, it causes turbines at the facility to peak at different times.[24] The larger the facility, the more the energy of the wind is distributed in time, smoothing fluctuations in plant output.[25]

[23] See references 53 - 57.

[24] For an analysis of these dynamics, see: R. Hudson, B. Kirby and Y. Wan, *The Impact of Wind Generation on System Regulation Requirements*, Oak Ridge National Laboratory, Oak Ridge, TN.

[25] See reference 51: G. Czisch and B. Ernst, ISET, in Proceedings of Windpower 2001, American Wind Energy Association (AWEA), Washington, DC, June 4-7, 2001

Figure 2. Rolling Average Smoothing of Wind Data



To adjust the Chandler, MN data to represent a very large wind facility, we applied a five-hour rolling average to the hourly capacity factor of the windplant. Thus, each hourly capacity factor for the hypothetical Dakota project is the average of five Chandler data points. Figure 2 illustrates the effect of this adjustment on the Chandler data for a representative day.

The second adjustment we made was to increase the annual average capacity factor of the windplant from the actual average at Chandler, MN (36.2 percent) to 40 percent expected for the more energetic North Dakota wind resource, for year 2010 wind generators.[26] To increase the annual average capacity factor to 40 percent, we simply multiplied each hourly capacity factor by a factor of 1.105.

To develop a set of hourly wholesale prices for the Chicago area, we began with the 1999 hourly marginal costs from the Commonwealth Edison system in Chicago. Market-based wholesale electricity prices were not published for this region in 1999 (though we expect that a market with published prices will emerge there in the coming years). Thus, we have adjusted these hourly marginal costs in two ways, making sure that the result was consistent with projections for prices in competitive electricity markets in the Chicago area in 2010:

[26] Lessons Learned in the DOE-EPRI Wind Turbine Verification Program (TVP), EPRI, McGowin et al, 2001, p 8

- Increased the volatility of the Commonwealth Edison marginal costs to be consistent with volatility seen in competitive markets in New England and the Pennsylvania/New Jersey/Maryland (PJM) area.[27]
- Increased all hourly prices by a factor of two, making the annual average price consistent with the cost of energy from a new CCCT power plant ($38 to $42 per MWh). Several long-term price forecasts, including that of the Department of Energy in its *Annual Energy Outlook*, use this price as a proxy for long-term prices, based on the theory that long-term prices will reflect the cost of new capacity.[28] In addition this average price range is consistent with recent average prices in competitive electricity markets in the U.S. Statistical analysis of a large number of hourly price data sets was beyond the scope of this project, however, this analysis should be performed as one of the next steps building on this report.

We have made these adjustments to the hourly wind and price data in an effort to make actual data taken from operating systems better simulate the systems we seek to model. Even after these adjustments, we believe that actual wind variability is still well represented in the wind data, and patterns in daily and seasonal price variations are reflected in the wholesale price data. Most importantly, the same wind and price data are used in all modeling scenarios, so the adjustments we have made will not affect our comparisons of scenarios.

3.2 Pipeline Revenues

The six pipeline scenarios are constructed by altering different components of the pipeline system, including: the pipeline, the electrolyzers and the Chicago generating capacity. In the "36-C" scenarios, we assume a low-pressure electrolyzer and a separate compressor to bring hydrogen to 1,000 psi at pipeline input. Additional capital and O&M costs are put in the cost calculation for the compressor. In the "36-NC" and "18-NC" scenarios, we assume electrolyzers operating at 1,000 psi output, and thus no need for external compression. The fuel cells in the "FC" scenarios are assumed to be "hybrid" solid oxide (SOFC) units, with a combustion turbine operating on byproduct heat. Overall electrical efficiency is 70 percent. The combustion turbines in the "CT" scenarios are assumed to be large, combined-cycle gas turbines coupled with heat recovery steam generators operating at a total efficiency of 60 percent. The operating parameters in each of the three pipeline scenarios are shown in Table 4.

We model pipeline energy storage by allowing pipeline pressure to fluctuate between 500 and 1,000 psi. For the 36-inch pipeline, this provides approximately 122 GWhs of energy storage, and for the 18-inch pipeline, just over 30 GWhs. We developed a simple function to maximize revenues from electricity sales in Chicago taking into consideration

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[27] These are two of three fully deregulated power pools currently operating in the U.S. The third is ISO California, however prices have been much more volatile in this region than we expect them to be in 2010.

[28] See: U.S. DOE, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001), p. 75. Document available at www.eia.doe.gov/oiaf/aeo.

(a) pipeline pressure, (b) current and day-ahead prices and (c) a Chicago generating capacity limit of 2,300 MW.[29]

The use of day-ahead price information is consistent with information available to traders in competitive power markets. In short, the sales function sells as much electricity as possible during higher-priced periods, within the operating constraints of the pipeline and generating capacity. Revenues in every hour of the year are summed to calculate annual revenues. In the "18-NC…" scenarios, we also assume an electrolyzer efficiency of 90 percent, to develop a "most optimistic" case for hydrogen transmission. The 18-inch pipeline may be undersized, unable to continuously transmit 4,000 MW, perhaps requiring wind generation shedding – an economic optimization strategy not considered in this report.

Table 4. Operating Parameters of Pipeline Scenarios

Scenario	Pipeline Diameter (inches)	Capacity	Electrolyzer	Generator	System
36-C-FC	36	122	85%	70%	59.7%
36-C-CT	36	122	85%	60%	51.3%
36-NC-FC	36	122	85%	70%	59.7%
36-NC-CT	36	122	85%	60%	51.3%
18-NC-FC	18	30	90%	70%	63.0%
18-NC-CT	18	30	90%	60%	54.0%

For our modeling purposes, we include in total revenue figures for all pipeline scenarios, the value of the oxygen (O_2) byproduct of the electrolytic conversion of the wind energy to hydrogen. Coal gasification plants, like the zero-emissions steam technology (ZEST) design, would use this oxygen, plus water feedstock, to generate hydrogen, in synergy with wind.[30] Based on conversations with industry experts, we estimate this value at \$19.17 per ton O_2 delivered to the coal plant gate.[31] The windplant electrolyzers will produce about 3.1 million tons of byproduct O_2 in a typical year, worth \$60.1 million at the coal plant.

[29] Note that this generating capacity limit is on equipment in Chicago, generating electricity from hydrogen – not on wind generating capacity in North Dakota. The 2,300-MW limit was selected based on iterative model runs to maximize revenue. The figure 2,300 seems a reasonable amount of capacity to service a 4,000 MW windfarm operating at an average 40 percent capacity factor with storage capability. However we have not attempted to optimize the amount of fuel cell and combustion turbine capacity in Chicago taking into account the cost of that capacity.

[30] Alliance Pipeline information package: system maps with receipt and delivery points; System Update, May and Fall, 1997, Winter/Spring and Summer, 1998, Spring, 1999, 1st, 2nd, 3rd and 4th Quarter, 2000, Calgary.

[31] Estimated: Table ES-2, Parsons Corporation (recent) report, courtesy of Gary J. Stiegel, Product Manager, Gasification Technologies, National Energy Technology Laboratory, Pittsburgh, PA 15236, gary.stiegel@netl.doe.gov

3.3 HVDC Revenues

The three HVDC scenarios are much more similar to each other than the six pipeline scenarios, for delivering wholesale electricity in Chicago. The performance of the HVDC systems is exactly the same – the only difference is cost. Energy losses in the two converter stations are assumed to total 1.5 percent (two converter stations are required on each line). Energy losses in the lines are 0.4 percent per 100 kilometers, or 6.4 percent total line loss. Thus, overall system efficiency is approximately 92 percent.

While the pipeline can store energy, the HVDC system cannot; thus, each kWh generated at the North Dakota windplant is sold, via HVDC transmission, in Chicago, at the current market-clearing price. Revenues in every hour of the year are summed to calculate annual revenues.

4. Results

Below, we analyze cost and revenue data from the scenarios assessed in five different ways.

- In section 4.1 we assume that the pipeline projects deliver *electricity* to wholesale markets in Chicago. Under this assumption, the costs and revenues of the pipeline projects can be compared on equal terms to the HVDC projects. Under this assumption, we can also assess the value of energy storage in the pipeline, as some electricity is shifted from its time of generation in North Dakota to higher priced hours in Chicago (as described in section 3.2).
- In section 4.2 we assess the cost of delivering *hydrogen* to the Chicago area via the six pipeline scenarios. In this analysis we ignore the HVDC scenarios and compare pipeline project costs to the cost of hydrogen generated via SMR in the Chicago area.
- In section 4.3 we assess project costs and revenues without the federal production tax credit (PTC) of 1.7 cents per kWh for wind energy.
- In section 4.4 we assess the sensitivity of these results to the assumed cost of wind generation in 2010. We compare our original scenarios, based on total installed wind generator costs of $950 per kW, to scenarios with wind costs at $700 per kW.
- Finally, in section 4.5, we assess the cost of the pipeline scenarios in a retail context by assessing the total cost of electricity from small, distributed generators operating on pipeline hydrogen.

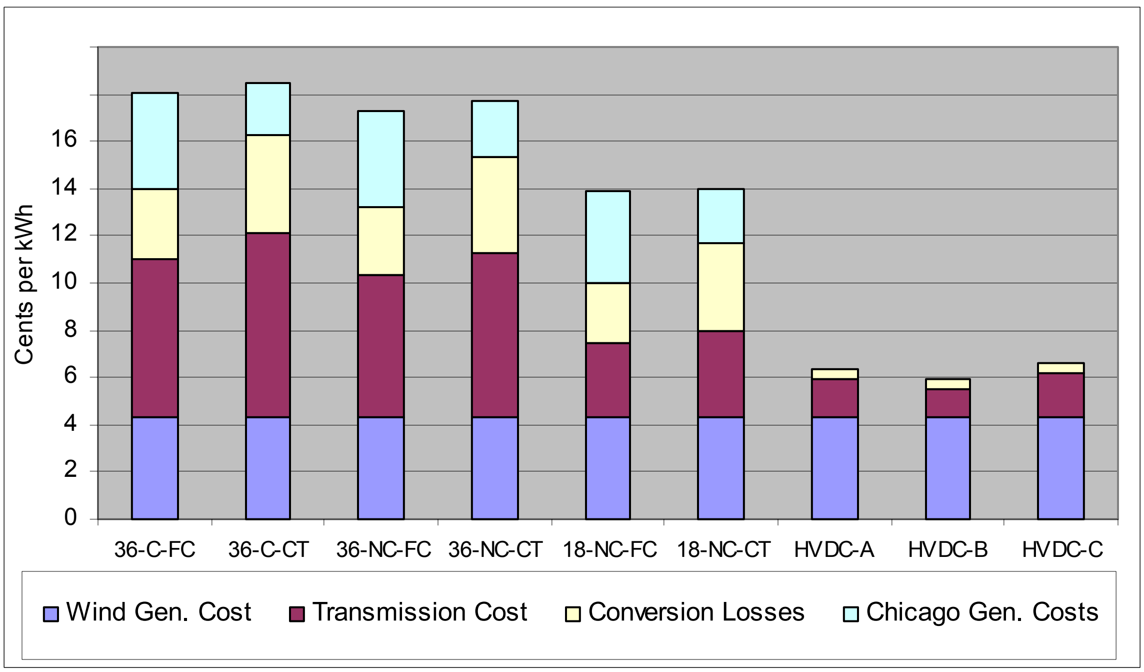
Note that, throughout Chapter 4, all calculations of revenues and profits/losses include the effects of the federal PTC, except in section 4.3, where results are shown without the PTC. No calculations of project costs include the PTC; it is viewed as a revenue stream.

4.1 Delivering Electricity to Chicago

The cost of delivering electricity to Chicago in each of the nine scenarios is shown in Figure 3. A further breakout of costs appears in Table 2, above. Electricity from the pipeline scenarios is extremely expensive. The *wholesale* cost of electricity from the pipeline scenarios, between roughly 14 and 18 cents per kWh, is well above year 2000 average *retail* rates in Chicago (8.8 cents per kWh).[32] The HVDC scenarios, all around six cents per kWh, are much less costly, but still well above wholesale market prices during most hours of the year in the Chicago area.

Note that here we value the energy conversion losses in each scenario and show them as costs in each bar. We do this in order to show the actual costs of the other components, such as wind generation and transmission. (In other words, the wind generation we model costs an average of 4.32 cents per kW when costs are spread across all kWhs generated, not across kWhs delivered to Chicago.)

Figure 3. Cost of Delivered Electricity in Pipeline and HVDC Scenarios

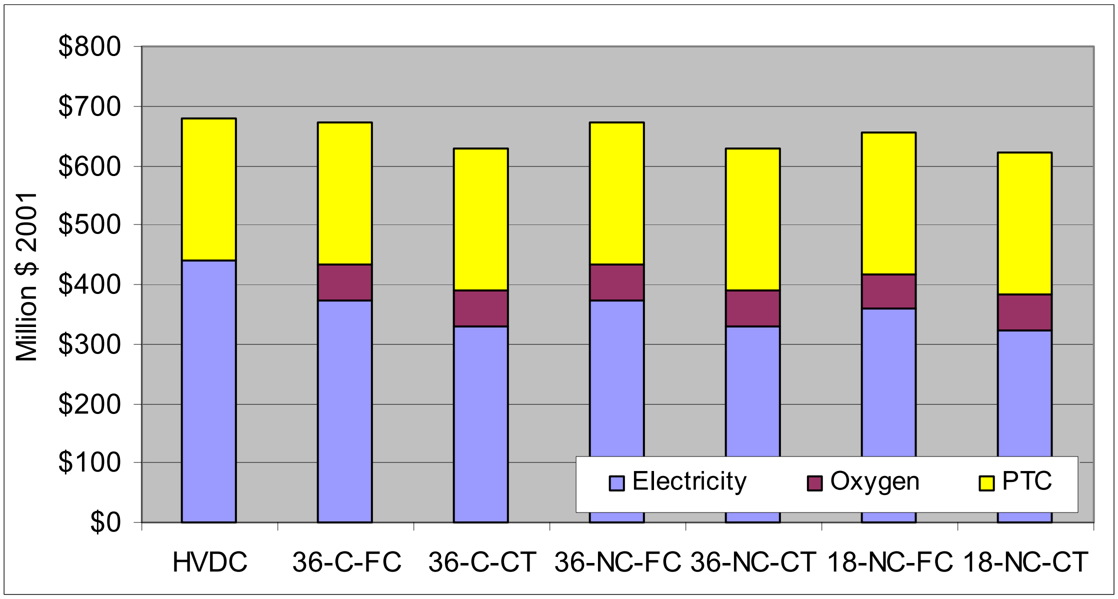


The annual revenues for each HVDC and pipeline scenario are shown in Figure 4, below. Note that revenues for all three HVDC scenarios are the same, because wind generation, conversion losses and energy sales are all the same; the only difference among these scenarios is costs (see Table 3). The HVDC scenarios provide the highest revenues of any scenario. This is primarily because energy losses are much higher in the pipeline scenarios due to the conversion of energy from electricity to hydrogen and back. Overall efficiency is 92 percent in the HVDC scenarios, and it ranges from 51 to 63 percent in the

[32] Wholesale electricity prices include only the cost of power generation. Retail prices also include the cost of transmission and distribution and other utility costs.

pipeline scenarios. Figure 4 illustrates the portion of revenues coming from electricity sales, oxygen sales and the PTC.[33]

Figure 4. Annual Revenues for All Scenarios, including PTC



However, revenue per MWh of electricity sold is higher for all pipeline scenarios than for the HVDC scenarios. This is because the storage capacity of the pipeline allows a higher percentage of electricity to be sold during high-priced periods than in the HVDC scenarios. Revenue per MWh for all scenarios is shown in Figure 5.

To estimate the value of the pipeline storage capacity in each of the pipeline scenarios, we first look at the difference in revenue per MWh between a given pipeline scenario and the HVDC scenarios, in which no storage was available. Next, for each pipeline scenario we multiple this difference by the total number of MWhs sold. In other words, we multiply the average premium per MWh due to storage by total MWhs sold. The results are shown in Figure 6. The value of pipeline storage ranges from $191 million in 18-NC-FC to $249 million in both 36-C-CT and 36-NC-CT.

Although the pipelines provide energy storage, and thus greater revenue per MWh, the high capital costs and energy losses of these scenarios are too great a burden. Combining costs with projected revenues shows that none of the projects is profitable. Figure 7 shows the annual losses that would be incurred by each project. With lower project costs and far smaller energy losses, the HVDC scenarios come closer to breaking even than the pipeline scenarios; however our HVDC scenarios would also post annual losses.

[33] The PTC provides 1.7 cents per kWh of energy produced by a windplant. Because wind generation is assumed to be the same for all scenarios (14,017,289 MWhs), revenues from the PTC are also the same for all scenarios – $283 million.

Figure 5. Revenue per MWh, including PTC

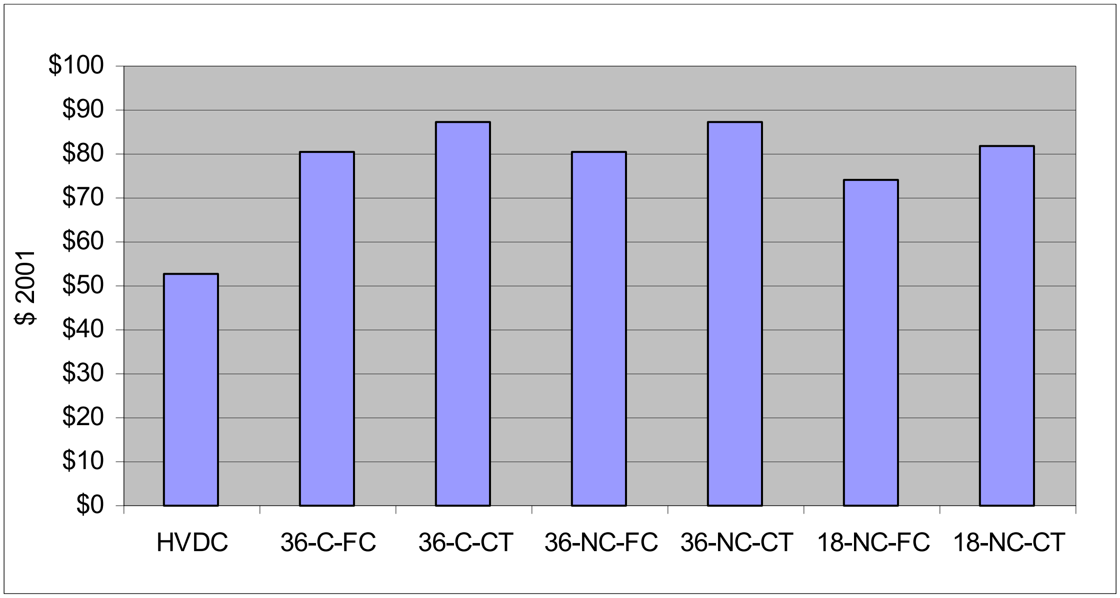


Figure 6. The Value of Pipeline Storage Capacity, including PTC

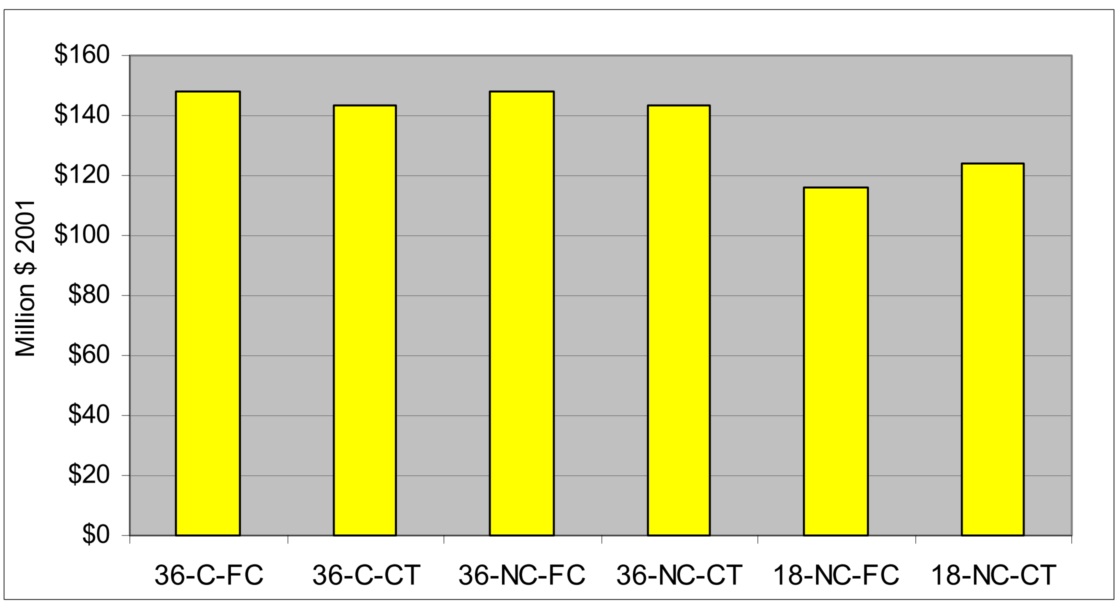
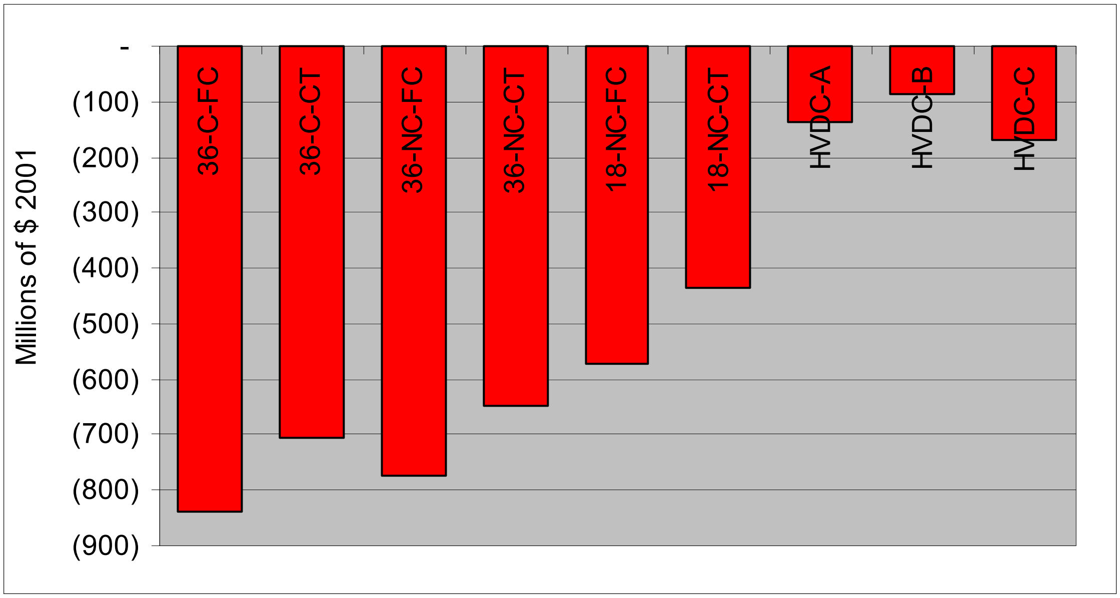


Figure 7. Annual Losses for Each Project Scenario, including PTC



Another way to put the costs of these scenarios in perspective is to compare them to the cost of the power generation technologies against which the scenarios would likely compete. The vast majority of the new power plants being constructed in the U.S. are CCCTs. These plants are also the wholesale price setters (the marginal plants) during many hours in most power control areas.[34] Thus, a CCCT provides an instructive comparison for this purpose.

The Department of Energy's *Annual Energy Outlook, 2001*, projects the cost of energy from a new CCCT in 2005 at 4.16 cents per kWh, assuming gas prices of $4.25 per mmBtu. This is well below the total electricity costs in most of our scenarios (ranging from 5.92 to 18.51 cents per kWh). However, two factors could change, causing the cost of electricity from a CCCT to rise without affecting the cost of our wind/hydrogen scenarios: natural gas prices could rise and/or mandatory CO_2 reductions could increase the cost of using all fossil fuels.

To see what kind of increase in gas prices would make our scenarios competitive, we increase the natural gas component (2.79 cents per kWh, or about 67 percent) of the total cost figure cited above for a new CCCT. Table 5 shows the gas prices at which electricity from each of our scenarios would break even with a new CCCT. Table 5 also shows the cost of carbon emissions (in terms of dollars per ton of CO_2) that would cause each scenario to be competitive with a new CCCT.

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[34] Recall that we checked to ensure that the wholesale prices in our pipeline model were in the range of the total cost per MWh of a new CCCT, on the theory that this plant type would set prices over the long term.

Table 5. Breakeven Natural Gas Prices and Carbon Taxes for Electricity from CCCT, and for Each Scenario, including PTC

Scenario	Breakeven Gas Price ($/mmBtu)	Breakeven Carbon Cost ($/ton CO_2)
36-C-FC	$22.90	$317.90
36-C-CT	$23.60	$329.90
36-NC-FC	$21.70	$298.10
36-NC-CT	$22.40	$310.10
18-NC-FC	$16.50	$209.70
18-NC-CT	$16.60	$211.30
HVDC-A	$5.00	$11.90
HVDC-B	$4.30	$1.50
HVDC-C	$5.30	$18.40

Predicting natural gas prices is extremely difficult. One undisputable fact is that prices were much higher and more volatile in 2000 and 2001 than in recent history. The annual average price in 2000 was $4.38 per mmBtu, and the average for 2001, based on data through August, was $5.12. A significant factor in the elevated average prices for 2000 and 2001 was the extreme run-up in prices in the Western U.S., associated with the power supply problems in California and the eventual bankruptcy of a major utility. (Monthly average prices in December 2000 and January 2001 were $8.23 and $9.47 per mmBtu respectively.) To put these prices in context, during the 25 years prior to 2000 annual average natural gas prices never rose above $3.70 per mmBtu.[35]

Most analysts agree that gas prices will remain more volatile in the future than they have been; however analysts do not agree on whether prices will be significantly higher on average. Year 2010 gas prices in the range of $5 to $7 per mmBtu – which would make the HVDC scenarios competitive – seem conceivable. However prices in the range needed to make the pipeline scenarios competitive – $19 to $26 per mmBtu – are unlikely.

The carbon tax prices needed to make the pipeline scenarios competitive seem more unlikely. Most documents that discuss carbon trading in the context of mandated CO_2 reductions envision prices in the range of $5 to $25 per ton of CO_2. In most CO_2 emission trades to date, prices have been under $5 per ton.

4.2 Delivering Hydrogen to Chicago

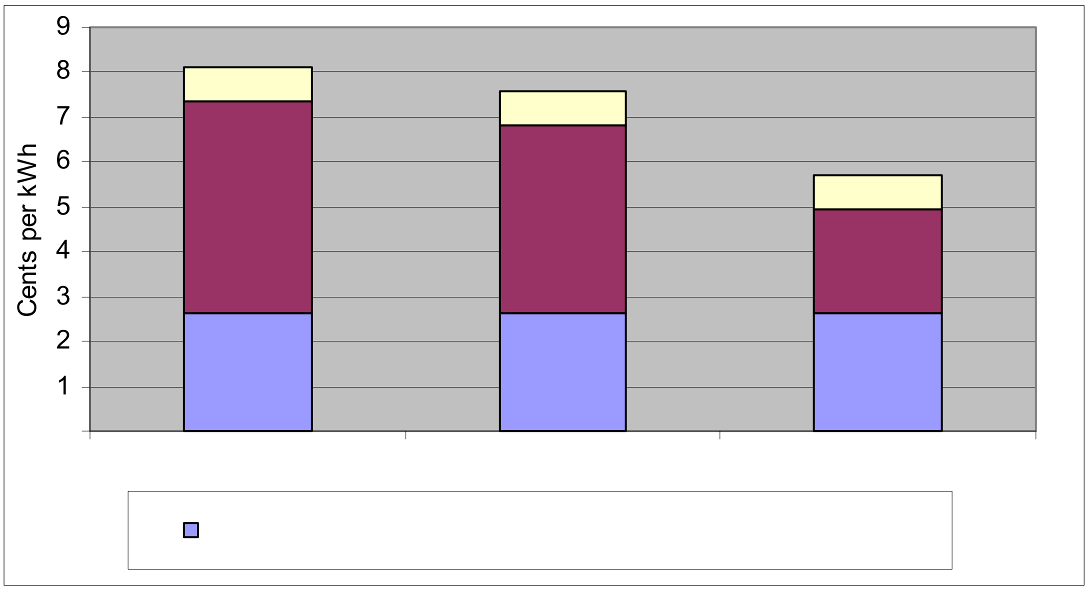
Given that the pipeline scenarios delivering wholesale electricity are far from profitable, we now investigate the costs of delivering hydrogen to the Chicago area. We assess the same six hypothetical pipeline projects described in Chapter 2, except we remove the costs and energy losses associated with electricity generation in Chicago. (This reduces the six scenarios to three.) The cost of delivering wind energy as hydrogen for each project is shown in Figure 8. Annual hydrogen production is total wind generation

[35] All prices cited here are for gas delivered to electric utilities. See: Energy Information Administration, *Monthly Energy Review, January 2002*, p. 133. Available at www.eia.doe.gov.

(14,017,289 MWhs) less electrolyzer losses. Note that in the more optimistic "18-NC…" scenarios we assume a more efficient electrolyzer (90 percent rather than 85 percent).

Note also that the cost of wind energy is lower (2.62 cents per kWh) in Figure 8 than in the cost charts in section 4.1 (4.32 cents per kWh), showing the total cost of delivering electricity to Chicago. This is because, in section 4.1, we calculated estimated revenues for each project, and we included the federal PTC as a revenue stream (see Figure 4). Because we will not calculate estimated revenues from hydrogen sales here, we include the federal PTC as a 1.7 cent per kWh credit to wind costs here.

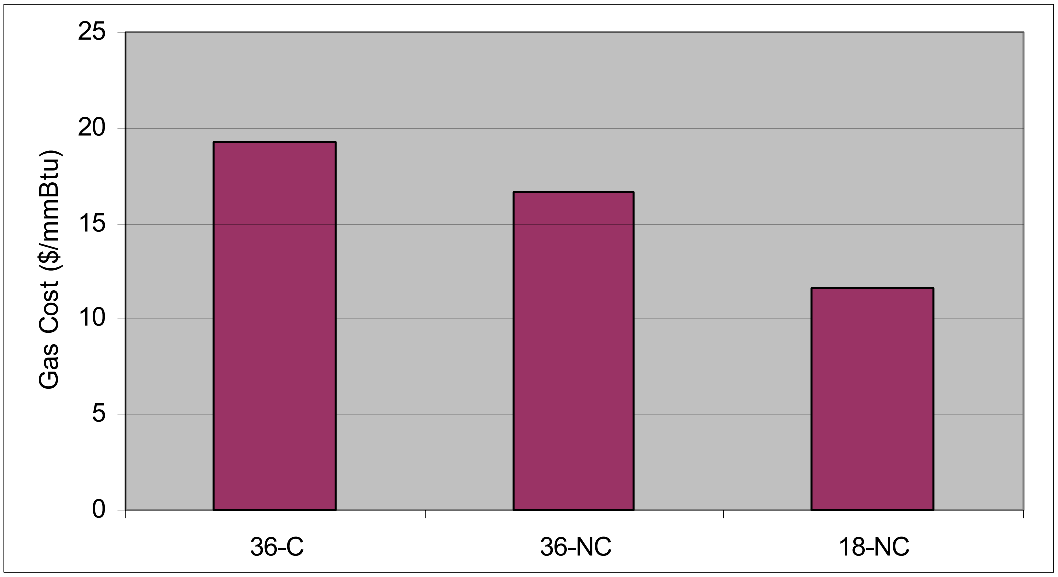
Figure 8. The Cost of Delivering Hydrogen via the Pipeline Scenarios, with PTC



It is far more difficult to project revenues from the sale of hydrogen than to project revenues from electricity sales, because today's markets for hydrogen, though large, are primarily confined to oil and gas processing facilities and to nitrogen fertilizer plants. Today's price of merchant hydrogen, usually made from natural gas, depends directly on the price of natural gas. Now, compare these delivered hydrogen costs to the cost of hydrogen from other sources: how does the cost of hydrogen from this paper's scenarios compare to the cost of the hydrogen against which it would be competing if large-scale demand emerged?

Currently the most cost effective method of large-scale hydrogen production is the steam methane reformation (SMR) of natural gas, producing hydrogen at roughly 1.88 cents per kWh (assuming gas priced at roughly \$4.00 per mmBtu). The natural gas input to this process is responsible for 88 to 98 percent of total costs, with larger SMR plants falling at the higher end of this range and smaller ones, at the lower. In order for the cost of SMR-hydrogen to rise to the cost of hydrogen from these pipeline scenarios, the cost of natural gas would have to rise significantly. Figure 9 shows the cost of natural gas that would produce SMR hydrogen costs equal to each scenario. These prices are quite similar to the prices that would make the electricity delivery scenarios competitive with a new CCCT power plant (see Table 5).

Figure 9. Natural Gas Costs to SMR Hydrogen Plants that Would Produce Hydrogen Costs Equal to Those in the Pipeline Scenarios, with PTC



4.3 Assessing the Projects without the PTC

Sections 4.1 and 4.2 present data assuming that the federal PTC for wind generation remains in effect. We now show results without revenue from the PTC. Figure 10 shows annual losses for each project delivering electricity to Chicago with and without the PTC.

Figure 10. Annual Losses from Projects, With and Without the Federal PTC

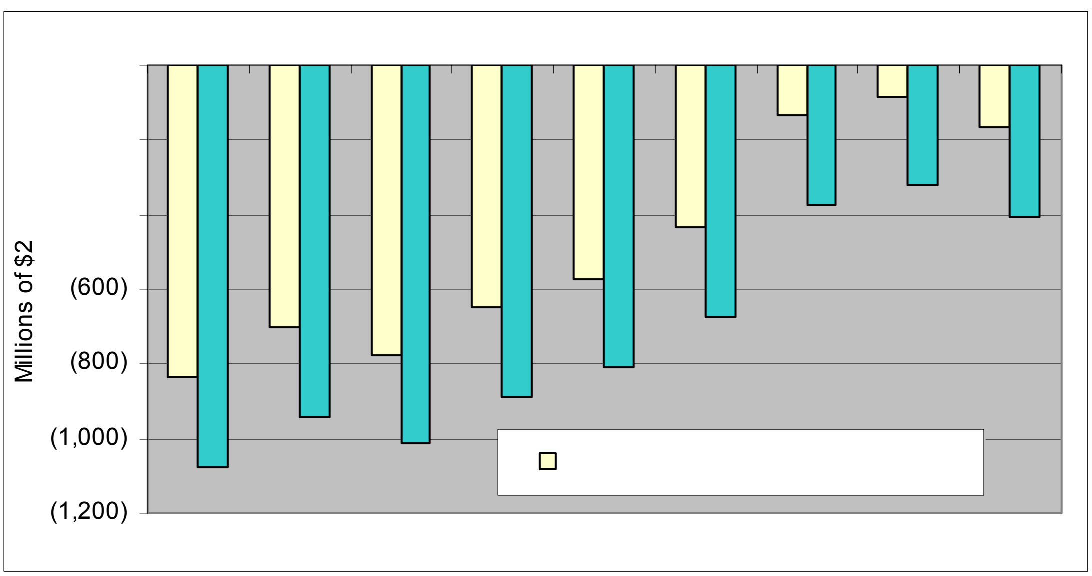


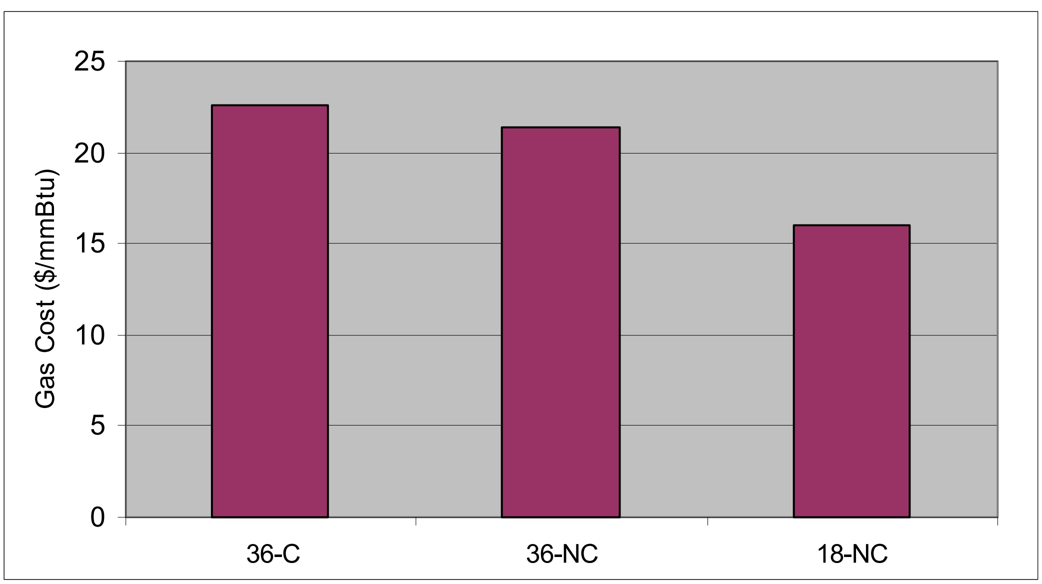
Table 6 follows the analysis laid out in Table 5, showing the natural gas prices and the carbon costs that would cause electricity from a new CCCT in the Chicago area to cost the same as electricity from our scenarios, but *without* the PTC. (The natural gas prices and carbon taxes shown here are not additive. Either the natural gas price or the carbon cost would cause our scenario to be competitive.)

Table 6. Breakeven Natural Gas Prices and Carbon Taxes, Without the Federal PTC

Scenario	Breakeven Gas Price ($/mmBtu)	Breakeven Carbon Cost ($/ton CO_2)
36-C-FC	25.40	$362.20
36-C-CT	26.20	$374.30
36-NC-FC	24.30	$342.50
36-NC-CT	25.00	$354.50
18-NC-FC	19.10	$254.10
18-NC-CT	19.20	$255.60
HVDC-A	7.60	$56.30
HVDC-B	6.90	$45.90
HVDC-C	7.90	$62.80

Figure 11 shows the natural gas costs to an SMR hydrogen plant that would result in hydrogen costs equal to our pipeline scenarios. Obviously, both the costs shown in Table 6 and Figure 11 are higher than those in section 4.2, where the effect of the PTC is included.

Figure 11. Natural Gas Costs to Steam Reforming Hydrogen Plants that Would Produce Hydrogen Costs Equal to Those in the Pipeline Scenarios, Without the Federal PTC



4.4 Assessing the Projects With Lower Wind Generator Capital Costs

Tables 4 through 6 above show data with the installed cost of wind generators at $950 per kW. Although we believe this to be a good prediction of wind costs in 2010,[36] some industry analysts expect significant additional cost reductions during this decade. Thus, we have also assessed the costs of all wind scenarios assuming that the total installed capital cost of wind turbines is $700 per kW. A breakout of project costs with wind costs at $700 per kW appears in Appendix A. As seen in Figure 12, the assumption of lower wind costs reduces annual project losses somewhat, but most projects are still far from profitable. One project, however, becomes profitable with lower wind costs.
The HVDC-B scenario (two HVDC systems installed on one set of towers) posts annual revenues of $45 million.

Figure 12. Annual Losses With Wind Capital Costs at $700 per kW, with PTC

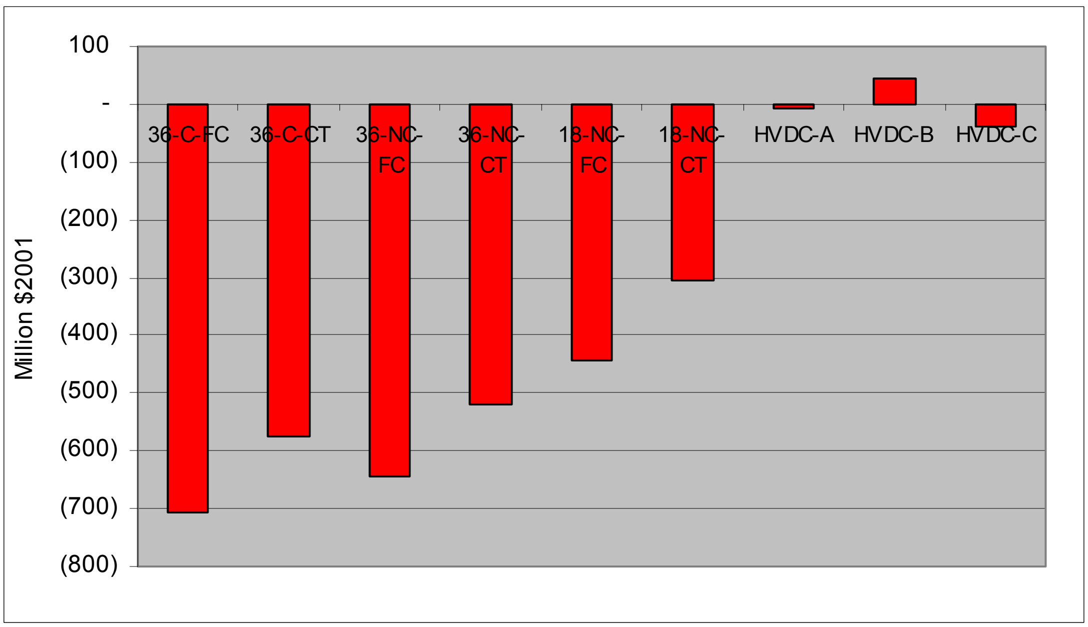


Table 7 shows the gas prices and the carbon costs that would cause electricity from a new CCCT in the Chicago area to cost the same as electricity from our scenarios, with wind at $700 per kW, with PTC. (Again, gas prices and carbon taxes shown here are not additive.) The gas prices necessary to make the HVDC scenarios are below likely future gas prices, and the carbon costs are negative. This tells us that each of these scenarios is projected to provide slightly cheaper electricity (assuming wind costs of $700 per kW) than a new CCCT. The breakeven prices and carbon costs for the pipeline scenarios remain unlikely.

[36] See references 6, 7.

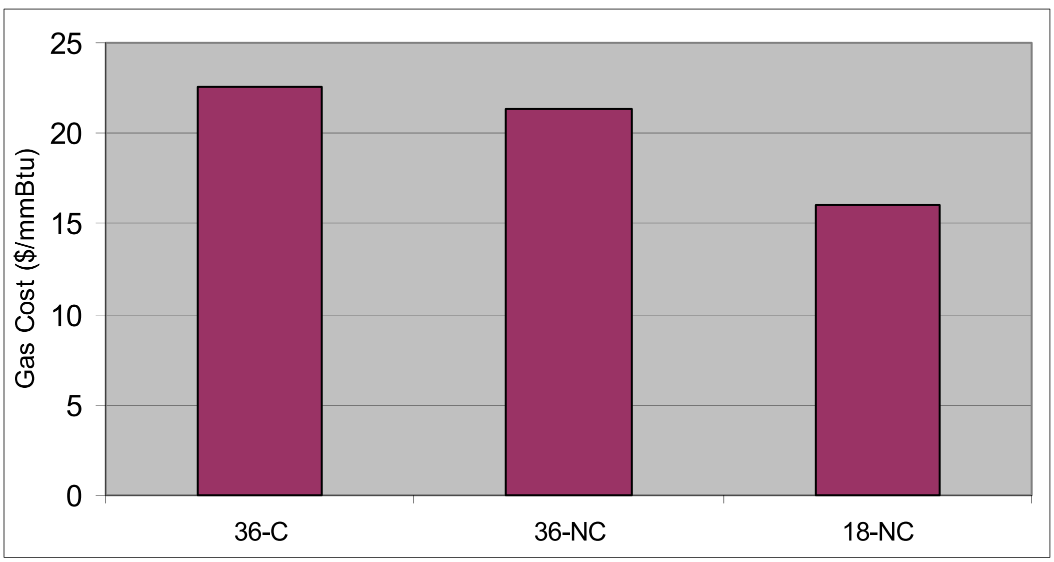
Table 7. Breakeven Natural Gas Prices and Carbon Taxes With Wind Capital Costs at $700/kW, with PTC

Scenario	Breakeven Gas Price	Breakeven Carbon Cost
36-C-FC	20.50	$277.30
36-C-CT	20.80	$282.80
36-NC-FC	19.30	$257.60
36-NC-CT	19.60	$262.90
18-NC-FC	14.30	$171.40
18-NC-CT	14.00	$166.50
HVDC-A	3.40	-$14.40
HVDC-B	2.80	-$24.80
HVDC-C	3.80	-$7.90

Looking at Figure 12 and Table 7, some readers may conclude that a new CCCT would not be profitable given the hourly prices we have used. After all, scenarios HVDC-A and HVDC-C are not profitable (as seen in Figure 12), and they produce electricity at lower cost per kWh than a new CCCT (shown in Table 7 by the negative breakeven carbon costs). However, this conclusion is probably incorrect, because it ignores the variability of the wind generation and the dispatchability of a CCCT. In other words, while the HVDC scenarios' cost per kWh are slightly lower than that of a new CCCT (with wind at $700 per kW), the CCCT's *revenues* would be much higher, because the plant would only operate during higher-priced hours. The wind/HVDC projects sell all electricity generated at the time of generation, at the current price. These projects sell electricity at a loss during many hours of the year when total project costs per kWh are considered. We did not model the profit/loss of a new CCCT, however based on the data in Figure 12 and Table 7, it appears that a new CCCT would either post small profits or small losses.

As seen in Figure 13, SMR hydrogen production is projected to be far less costly than our pipeline scenarios, even assuming wind costs at $700 per kW.

Figure 13. Natural Gas Costs to SMR Hydrogen Plants that Would Produce Hydrogen at Costs Equal to Those in the Pipeline Scenarios with Wind Capital Cost at $700 per kW, with PTC



4.5 The Cost of Electricity from Distributed Generation Using Hydrogen from These Projects

In section 4.1 above we present the costs of wholesale electricity delivered via the pipeline and HVDC scenarios. We compare these costs to the cost of electricity from a new CCCT power plant, and, in Table 5, we show that natural gas prices would have to rise to a range of $16 to $23 per mmBtu in order for electricity from the pipeline scenarios to be competitive. However, given the increasing interest in distributed generation (DG), it is useful to consider the implications of our pipeline cost estimates in a *retail* setting.[37] Part of the attraction of DG is that it avoids the transmission and distribution costs that are paid in retail rates. So, perhaps our pipeline projects would be more cost effective fueling DG units that are competing with retail electricity prices.

To make this comparison, we look again at the cost of hydrogen delivered to Chicago and add in the estimated total costs (in 2010) of operating selected DG technologies. Before making this comparison, however, an important caveat is necessary. The projects assessed in sections 4.1 and 4.2 are large-scale energy supply projects. It is common for developers of large energy resources, like oil fields or power plants, also to build the transmission infrastructure needed to deliver the energy to wholesale markets.

However, in the deregulated electricity industry of the future, one energy company will be very unlikely to develop a large-scale resource, a transmission infrastructure, *and* provide end-use customers with small-scale generating units or retail electricity. The wholesale and retail sides of this industry are being fully separated by regulators concerned about potential anti-competitive behavior of companies involved in both generating and delivering energy. Thus, today and in the future, DG units are likely to be owned by end users or “energy service companies,” power lines will be owned by transmission and distribution (T&D) companies, and generating resources will be owned by generating companies.

Thus, the total cost of operating a DG unit on hydrogen from these pipeline scenarios would probably be spread across at least three parties: the owner of the windplant, the owner of the pipeline project and the energy user or service company that purchases and operates the DG unit. The decisions about whether to install a DG unit and what fuel to use would be made by the owner of the DG unit. The pipeline hydrogen would be competing against natural gas and hydrogen from other sources to serve DG units. So the important comparison here is between the cost of hydrogen and natural gas or other fuels, a comparison similar to the one made in section 4.2 above. Here, we show the total costs of operating DG on pipeline hydrogen simply to gauge whether this scenario appears more competitive than the delivery of wholesale electricity (as in section 4.1) or hydrogen (as in section 4.2).

Figure 14 shows the cost of operating three DG technologies on hydrogen from our three pipeline scenarios. Costs for the pipeline scenarios are the same as those presented in section 4.2. The three DG technologies examined are an internal combustion engine (ICE), a microturbine and a fuel cell. Our cost assumptions for the DG technologies, detailed in Appendix B, are based on data in the Distributed Resources Emissions Model, developed by the Natural Resources Defense Council (NRDC).[38] We have adjusted data from that source to simulate cost reductions reasonably expected between now and 2010.

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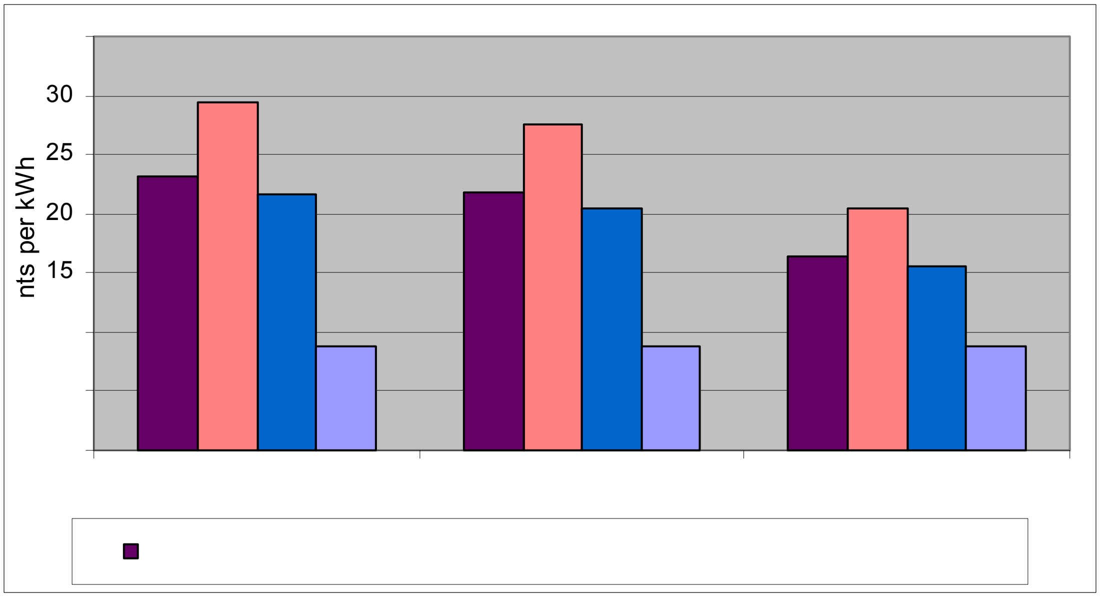
[37] The term “distributed generation” refers to small (less than one MW) generators located close to or at the point of electricity use, displacing retail-value electricity. Falling costs and advances in technologies such as microturbines and fuel cells have drawn substantial interest to DG and the reliability benefits it offers.

[38] Unpublished.

Figure 14. The Cost of Electricity from DG Units Operating on Pipeline Hydrogen from North Dakota Wind Energy

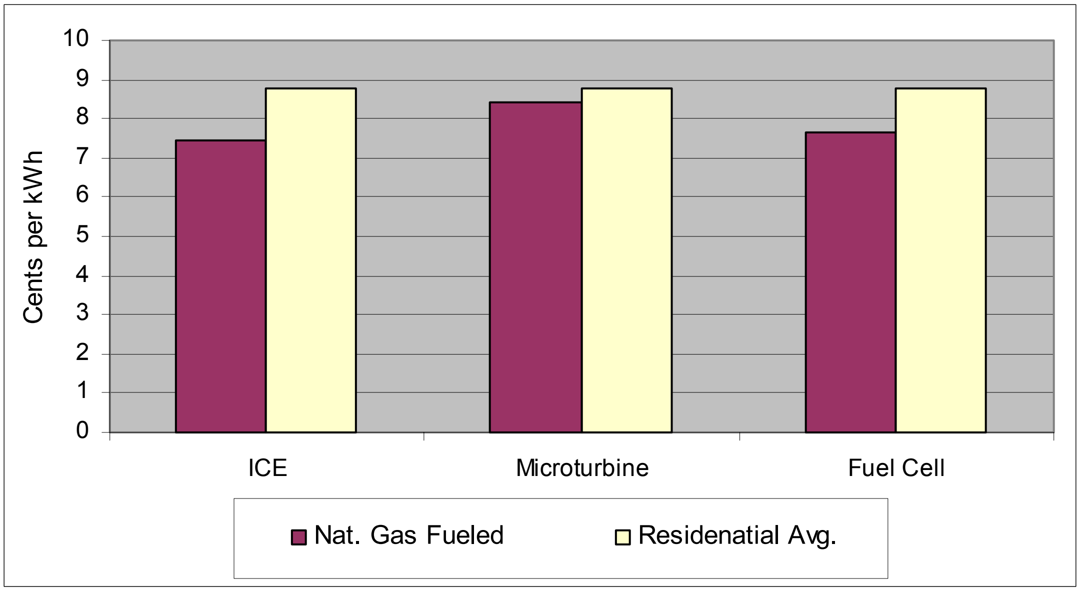


As Figure 14 illustrates, the total cost of operating DG on hydrogen from these pipeline scenarios is much higher than current retail rates in Illinois. For comparison, we show the average year-2000 retail rate paid by residential electricity customers in Illinois (8.8 cents per kWh).[39] Residential customers, of course, pay the highest retail rates of any customer class. The most competitive pipeline/DG scenario is a fuel cell operating on hydrogen from the 18-inch pipeline. Further, note that these pipeline/DG scenario costs are optimistic in that we have ignored the cost of hydrogen distribution infrastructure in Chicago to deliver the gas from the pipeline hub to the end-use site.

To distinguish between the impacts of the pipeline hydrogen costs and our cost assumptions regarding DG technologies, we present the cost of these technologies operating on natural gas in Figure 15. We use the same electricity generating cost data here as in Figure 14, and we assume a natural gas price of $4.50 per mmBtu. Note that our assumed 2010 DG costs are 5 to 15 percent lower than Illinois' average residential rates for 2000.

[39] Retail price figure is taken from the U.S. Energy Information Administration's publication, *Monthly Retail Rates*, available at: www.eia.doe.gov.

Figure 15. The Cost of Electricity from DG Units Operating on Natural Gas at $4.50 per mmBtu



5. The Hydro Firming Opportunity

While energy storage in a hydrogen pipeline is one option for "firming" intermittent wind generation, a firming arrangement with a large hydroelectric system represents another strategy. Under this type of arrangement, the windplant would deliver all or a portion of its output to the transmission system of the hydro company. The hydro company would use the energy to serve its customers in real time, and the windplant would be entitled to withdraw the same amount of hydroelectric energy at an agreed-upon time. In a sense, each wind kWh that the hydro company used to serve its load would allow it to generate less energy on its rivers or from its reservoirs. In this way, wind energy could be indirectly stored in the river.

Exactly when the windplant would be entitled to withdraw energy from the river would depend on the terms of the agreement. The windplant might simply want a commitment for firm, baseload energy out of the river – the sale of which would be more valuable than variable wind energy. Or, the windplant might want firm power during peak periods, the most valuable kind of power. If the hydro company were willing to enter into such an agreement, they would have to decide how much to charge the windplant for the "firming service." The hydro company would be receiving less valuable kWhs and delivering more valuable kWhs.

In one scenario, the hydro company might agree to provide firm energy for the windplant in an amount equal to the amount of wind energy they received. Here the hydro company would probably seek to receive a per-kWh charge on the firm energy delivered. In another scenario, the hydro company might require that kWhs be traded based on a ratio that provided them with similar value. For example, they might propose to provide three firm kWhs for every four intermittent kWhs received. These are simply two payment options for the same basic transaction.

Below, we discuss the issues likely to be considered regarding a hydro firming agreement.

5.1 Key Issues

Three categories of issues come up when thinking about using a hydroelectric system to "firm" intermittent energy resources such as wind. These categories are:

- The "capacity and energy" profile of the hydro system,
- Constraints on river operation,
- Transmission adequacy, and
- The economics of the transaction.

The first three categories include questions about whether the hydro system *can* provide firming service, and if so, how much energy it can firm. The fourth category deals with the terms under which the hydro system will be willing to provide the service (assuming it can).

The first category relates to the hydro system's current resource and load profile. If the system is "capacity constrained," it must acquire additional resources to meet its peak load commitments. It may be able to generate as much (or more) energy annually as its customers consume, but it does not have sufficient generating capacity to meet customer demand during peak periods. Such a system will have to purchase additional capacity for use during peak periods and/or purchase additional energy to meet peak load. In contrast, a system that is "energy constrained" may have enough capacity to meet peak loads with a substantial margin but not have sufficient water flows in the river to serve its customers' annual energy needs. This kind of system might purchase additional energy during off-peak periods to supplement the output of its dams.

A hydro system that is capacity constrained is not likely to be willing to enter into a firming agreement with an intermittent resource – at least not during its peak use seasons. In this case, the windplant would be providing energy, something the hydro system has enough of, and asking for capacity, something the hydro system is short on. An energy constrained hydro system is more likely to be interested in a firming arrangement. This type of a system could use the revenues from the arrangement to purchase additional energy (or simply use the net kWhs from a ratio trading deal).

Constraints on river operation is the second key factor in determining whether a hydro system can provide firming service. The first issue here is what kind of dams the hydro company has. "Run-of-river" or "low-head" dams do not store large amounts of water behind them; they simply capture the energy of the river at a certain point. "Impoundment" or "high-head" dams do store large amounts of water, and thus energy. A system with a large amount of impoundment capacity is likely to have more flexibility in when it generates power than a system with primarily run-of-river capacity. More flexibility in generation probably means an increased willingness to engage in a firming arrangement. But there are other constraints on river operation.

Companies that operate dams are subject to operational constraints that reflect the variety of competing uses of the river. The major constraints are in the areas of river navigation, flood control and environmental protection. Constraints adopted to meet goals in these three areas can leave power companies with little flexibility in how much water they move through dams during a given hour. In some instances, these constraints force power companies to move additional water through dams when they do not need the additional electricity or hold water back when they need electricity.

Persistent droughts can reduce the generating capabilities of hydro companies significantly. However, average water levels in large rivers change slowly in response to multi-year trends. Thus, uncertainty over water levels might prevent a hydro company from entering into a very long term contract (five to ten years), but water levels tend to be stable enough to allow for planning over the near to medium term.

The third question affecting the potential for hydro firming is the availability of transmission capacity to carry out the transaction. While insufficient transmission capacity is less prohibitive than mismatches in the first two areas can be, the cost of additional transmission capacity will affect the economics of a hydro firming agreement. In the extreme case, the need to construct new power lines could cause a windplant to abandon a potential hydro firming arrangement.

Finally, assuming that the hydro system can provide firming service, there is the question of terms. As noted, in a firming arrangement the hydro system is trading less valuable kWhs (variable energy) for more valuable kWhs (firm energy). A rough estimate of the value of the windplant's intermittent energy and the hydro system's firm energy, (or firm, on-peak energy) can be discerned in the wholesale power markets to which each system has access. The difference between the average short-term (spot market) energy price and the price of firm energy (or firm, on-peak energy if that is what the windplant wants) is the market value of the "firming service" the hydro system could provide.[40]

5.2 Firming Possibilities in North Dakota

For windplants developed in North Dakota, there are two large hydroelectric systems within reasonable transmission distance that could theoretically provide firming service. These are the Western Area Power Administration's (WAPA) Upper Great Plains system on the Missouri River in Montana and North and South Dakota, and Manitoba Hydro's (MH) resources in the Province of Manitoba. Both of these systems have substantial hydroelectric generating capacity (both have over 2,000 MW), and both have extensive transmission networks with which to move power.

Below, we describe our initial findings from discussions with WAPA and MH staff about their ability and interest in providing firming service.

5.2.1 Western Area Power Administration (WAPA)

- WAPA's primary resources in the Upper Great Plains (UGP) region are eight large dams on the Missouri River in Montana and North and South Dakota.[41] During periods of adequate precipitation, these dams total approximately 2,200 MW of generating capacity. WAPA's coincident peak load in this region is approximately 1,900 MW. This is a reserve margin of just under 14 percent. Thus, WAPA is not capacity constrained, but this is not a particularly large capacity margin. U.S. utilities have traditionally planned 15 percent capacity margins (although these margins are shrinking now).
- During non-drought years, WAPA is also an energy surplus system; during drought years, it can be energy constrained. WAPA purchases energy in drought years to meet customer needs and even purchases in surplus years because water releases do not always match load patterns. In year 2000, WAPA purchased 2,834 GWhs.[42]
- Although WAPA is usually neither capacity nor energy constrained in meeting the peak demand of its customers, it faces significant other constraints on the operation of its dams on the Missouri. WAPA operates the UGP dams in accordance with the "Master Water Control Manual," written by the Army Corp of Engineers. This

[40] Another way to think about this: the wholesale price of firm energy is the hydro company's opportunity cost – it is what they would lose by providing firm energy to the windplant. The hydro company would get the value of the intermittent wind energy. Subtracting the value of the intermittent energy from the firm energy leaves the increment that one would have to pay the hydro company to make the two transactions of equal value to them.

[41] The dams are actually operated by the Army Corps of Engineers.

[42] This figure is from WAPA's 2000 Annual Report on its website at: www.wapa.gov/geninfo/pppsmb.htm.

document is updated periodically, and is currently undergoing a major revision. The Master Manual lays out operating procedures designed to manage the river in a way that achieves goals in river navigation, flood control, environmental protection, irrigation, water quality, recreation and power production.

- Currently there is considerable uncertainty over what changes this round of revisions to the Master Manual will entail. In addition, litigation of the final revisions is a strong possibility, as several groups have already announced their intentions to sue if the revisions do not meet their goals.
- Staff at WAPA are familiar with the wind firming concept but feel that it would not be useful to explore the idea further until the Master Manual revisions are finalized. WAPA staff believe that, as a result of these revisions, they may have less flexibility in river operations than they have had in the past.
- Transmission capacity is not likely to be a limiting factor in a firming arrangement between North Dakota wind and WAPA. If 4,000 MW of wind capacity were sited in North Dakota, significant transmission upgrades would have to be made simply to interconnect the new capacity. If the concept of a hydro firming arrangement were considered as these transmission investments were made, new infrastructure could be deployed in a way that facilitated the arrangement, minimizing the amount of additional transmission needed. However a comprehensive transmission study would be required to discern the full transmission requirements of such an arrangement.

5.2.2 Manitoba Hydro (MH)

- MH is a Crown Corporation, owned by the Province of Manitoba. The utility has roughly 4,800 MW of hydro capacity at 12 dams. Nearly 80 percent of this capacity is in the northern third of the province, hundreds of kilometers from the load centers in the south, such as Winnipeg. Responding to this fact, the company built two 900-km HVDC lines from the north to the Dorsey Sub, within 26 km of Winnipeg. There are three converter stations.
- With the HVDC lines, MH is neither capacity nor energy constrained. In FY 2001, the company generated over 32,500 GWhs and sold only 20,100 GWhs to end users in Manitoba (an energy surplus of 38 percent). The company's capacity margin was extremely large as well – over 30 percent.
- MH is an active buyer and seller in wholesale power markets. The company exported over 12,000 GWhs (38 percent of its generation) from the province in FY 2001. Most of this energy was exported to the U.S., with a large amount going to the Minneapolis area. Much more than WAPA, MH sees wholesale power markets as a source of revenue, and the company commonly purchases electricity off-peak to conserve water for on-peak generation.
- Although MH is constrained by the same competing river uses as WAPA, the company has access to far more water than WAPA and thus appears to have more operational flexibility than WAPA. However, 86 percent of the company's hydro capacity is run-of-river. Because of the size of the rivers in question, the company

does have some ability to control the output of these facilities, but it has far less control over them than do companies with large impoundment dams.

- Transmission capacity would have to be enhanced significantly for MH to firm substantial amounts of wind energy from North Dakota. There are only three interconnections between Manitoba and the U.S. (all are HVAC lines):
  - One 230-kV line from Winnipeg to Grand Forks, ND,
  - One 230-kV line from Winnipeg to Duluth, MN, and
  - One 500-kV line from Winnipeg to Minneapolis, MN.

  Currently, these lines are heavily loaded a large portion of the time. During peak periods, the lines are heavily used for MH's exports to the U.S. Given MH's interest in U.S. wholesale power markets, one might expect the company to be willing to share the cost of new interties with other interested parties.

  Perhaps the North Dakota 4,000 MW windplant, in an electricity transmission scenario, might construct an HVDC line from the windplant to MH's Dorsey substation, southwest of Winnipeg, as part of the overall windplant transmission system, to exchange energy with the MH system and provide a new transmission path to market for MH hydro energy. An HVDC line to the Dorsey substation would increase the capacity factor of the windplant HVDC line to Chicago.

- Without significant transmission expansion, there appears to be the opportunity for MH to accept a limited amount (500 MW or less) of intermittent wind generation (perhaps delivered to MH customers in the U.S.) in return for firm, off-peak power. Currently, the company could deliver little additional energy to the U.S. during peak periods, due to transmission line loadings. Interties would have to be enhanced to expand potential wind firming possibilities with MH.
- Any expansion of MH hydro generating capacity will be controversial among Manitoba Native tribes and within the Upper Midwest environmental community.

5.3 Additional Analysis

Although neither hydro system we spoke to was willing to speculate about how much energy they might be able to firm, we can begin to explore this question in the following way. Consider the maximum demand that a firming agreement would place on the hydro partner: this would occur when wind output was at a minimum during the hours the hydro company had agreed to deliver firm energy. In this case, (assuming the wind output is zero) the hydro system would have to generate the energy to deliver the agreed-upon number of firm kWhs and meet its other commitments. In other words, during some periods of the year, the hydro system will have to generate the full amount of the firming deal on top of its other commitments. And the company would have to be able to do this during peak hours.

So how much additional firm capacity *could* each of these systems commit to? In 2000, WAPA had only 300 MW of capacity in excess of their peak load. In all U.S. electricity control areas, market participants are prohibited from taking on firm commitments equal to their peak load; all companies serving load must contract for capacity in excess of their firm load to contribute to the regional capacity reserve margin. Depending on the rules of the Mid-Continent Area Power Pool (MAPP), WAPA may currently have very little ability at all to firm intermittent energy.

This rough calculation is consistent with information from WAPA. WAPA staff noted that the flexibility to firm wind energy becomes extremely limited in drought years (such as the current period). Three of the six dams are fully loaded this winter, with virtually no operational flexibility.

MH clearly has more room to firm wind energy than WAPA. The company had 1,574 MW more capacity than it needed to serve its Manitoba customers in FY 2001. If the company also had 500-MW of firm commitments outside of Manitoba, this leaves roughly 1,000 MW of capacity. Leaving a 10 percent reserve margin, the company could commit to delivering some 500 MW of firm energy. However, arranging the transmission for a 500 MW firming arrangement could prove to be impossible without costly new lines. Again, this calculation is roughly consistent with the informal speculation of MH staff.

Major capacity upgrades to extant electric transmission systems in the Great Plains of USA and Canada may change this hydro-firming analysis in the short term; the magnitude of the total Great Plains wind resource dwarfs the potential for effective hydro-firming.

6. Summary of Findings

- None of the cases studied here is profitable, including the present federal PTC, to deliver electricity to the Chicago wholesale market or to deliver hydrogen gas to Chicago for distributed generation and vehicle and aircraft fuel.
- The cost of North Dakota wind energy delivered to Chicago as electricity, including all transmission costs, is far from competitive, at 6 to 18 cents per kWh. Natural gas prices would have to rise to a range of $16 to $23 per mmBtu to make electricity from the pipeline scenarios competitive with electricity from a new combined-cycle combustion turbine. Gas prices of $4.30 to $5.30 would make the HVDC scenarios competitive with a new combined-cycle combustion turbine.
- The cost of delivering hydrogen via the pipeline scenarios ranges from 5.8 to 8.1 cents per kWh. Natural gas prices would have to rise to a range of $11.50 to $19.00 to make this hydrogen competitive with hydrogen produced from steam methane reforming (SMR) of natural gas.
- The federal PTC for wind energy is a significant factor on project economics. Removal of the PTC increases project losses by 20 to 30 percent for pipeline projects and more than 100 percent for some HVDC projects.
- If total installed wind costs in 2010 are assumed to $700 per kW instead of $950 per kW, projected annual losses are reduced. The HVDC-B scenario becomes profitable under this assumption. The pipeline scenarios remain far from profitable even with reduced wind costs.
- The oxygen byproduct of hydrogen generation by electrolysis, in the hydrogen pipeline scenarios, is valuable if it can be piped a short distance to demand such as new "clean coal" plants in North Dakota.
- Much further study is needed to validate these study results. Further work is especially needed in the areas of hydrogen pipeline costs and HVDC costs.
- Hydrogen pipeline transmission for renewable energy sources faces several obstacles:
    1. High capital costs for electrolyzers (and compressors, if 1,000 psi electrolyzers are not available), and for the electricity generating systems at destination;
    2. Energy conversion losses in electrolyzers;
    3. Low capacity factor of the pipeline;
    4. Economic competition from HVDC electrical transmission and point-of-use hydrogen storage;
    5. Hydrogen embrittlement in high pressure, variable-pressure, steel hydrogen transmission pipelines providing cushioning and storage;
    6. Optimizing collection and conversion topology at sources; and
    7. Acceptance by the public, and by the insurance and finance industries.

7. Other Considerations

7.1 Energy Security

The Great Plains wind resource could supply a large part of the USA's total energy consumption, replacing a significant fraction of its imported oil and natural gas and significantly reducing its CO2 emissions.

However, economical collection, concentration, and transmission of wind and other renewable-source energy will necessarily result in new, large-scale electric transmission lines and / or hydrogen pipelines (or other systems) which are vulnerable, more or less, to sabotage, as Amory Lovins warns in "Brittle Power: Energy Strategy for National Security". [43]

Underground systems, such as the hydrogen pipeline or the superconducting "energy pipeline" [44] in 8.2.5, would probably be less vulnerable than overhead HVDC lines.

7.2 Biomass Synergy

Energy generation from biomass, as either electricity or hydrogen, at frequent points along the transmission route, may greatly improve the capacity factor of the transmission system. Both wind energy and biomass energy availability vary seasonally; perhaps they are complementary. Some biomass resources might be stockpiled, feeding generation plants dispatched to supplement wind energy fed to the transmission system. The biomass resource, along the 1,000 mile length of the transmission system, might rival the 4,000 MW peak wind capacity modeled here.

However, energy delivery nodes on an HVDC system will be costly at small capacity; HVDC equipment vendors suggest 500 MW as a minimum size, for low cost / kW for the converter stations. Energy delivery nodes on a large hydrogen gas transmission pipeline might be simple and economical, even at low capacity: a boss on the pipe, a valve, a meter, perhaps a compressor, and perhaps a small building.

7.3 Coal Synergy

New "clean coal" plants in North Dakota may produce either electricity (ZECA plant) or hydrogen (ZEST plant). Either plant may benefit from purchase of byproduct oxygen, in the hydrogen transmission scenarios, as discussed above. Coal plant output might synergistically share the transmission system with windplants, thus improving transmission capacity factor and lowering the cost per kWh for wind energy delivered to Chicago. Since coal plant output is probably difficult to adjust, hydrogen transmission may be more advantageous, because hydrogen can be compressed and stored in the pipeline, or in other media.

[43] See reference 42.

[44] See references 62 - 64.

7.4 Carbon Taxes and Internalizing Other Externalities

Large national and international taxes to discourage anthropogenic emissions of CO2 from fossil fuel combustion, and to internalize other externalities of fossil fuels, may be necessary to close the large market price gap, shown in this report, between Great Plains wind energy and fossil energy sources delivered to end-users.

7.5 International Collaboration

Several collaborative opportunities, especially with Japan, Germany, and Canada, for hydrogen transmission technical and economic study, should be pursued.[45]

7.6 Define "Renewables-Hydrogen Economy"

The hydrogen community and various renewable-source interest groups should collaborate to define, and estimate expectations for, a "renewables-hydrogen economy", especially pertaining to collection and transmission of diverse, dispersed, diffuse, remote renewables to distant markets. For example, shall Great Plains wind energy be transmitted as electricity or as hydrogen, to distant markets like Chicago?

[45] See reference 43.

8. Recommended Future Work

8.1 National Hydrogen Transmission Test Facility (NHTTF)

One salient feature of the nascent "renewables-hydrogen economy" is collecting energy from diverse, dispersed, diffuse, remote, renewable energy sources as hydrogen, and transporting it via high-capacity pipelines to distant markets, on regional, national, international, or intercontinental scales.

However, no GW-scale hydrogen pipeline system exists in the world. The Hydrogen Community does not know how to build such systems, optimized for energy collection from renewable sources, from very large land areas, and for storage, transmission, and delivery -- the backbone of the nascent "hydrogen economy" -- nor how to deal with hydrogen embrittlement in such large and complex systems.[46] A pilot-plant facility, a 10 to 100 MW scale transmission test facility, will be needed; it is on the critical path to deployment of 4,000 MW-scale systems as contemplated in this study. It will take several years and about $30-50 million[47] to build; the process should begin now.

Fully realizing the "renewables-hydrogen economy" opportunity requires pipelines that:

- Are capable of carrying pure hydrogen at high pressure and flow rate;
- Accommodate time-varying, somewhat unpredictable, inputs;
- Accommodate continuously-varying pressure, over a wide but limited range, providing valuable cushioning and energy storage;
- Overcome the severe hydrogen-embrittlement problem, [48] or establish strict operating limits and protocols for transmission components and systems; this may limit or defeat the storage value in 3, above;
- Accept hydrogen delivery at frequent (roughly 5-15 km) intervals along the source end, providing "distributed collection" from the "distributed generation" sources;
- Are fitted with compressors, meters, fittings, terminals, and safety systems optimized for hydrogen;
- Are proven safe, i.e. amenable to high-confidence monitoring, inspection, and repair, based on years of pilot-scale operating experience in typical field conditions;
- Are economically attractive in capital and O&M costs, competitive with high voltage direct current (HVDC) collection, transmission, and storage systems (hydro-firming);
- Can share capacity with hydrogen produced from "clean" coal gasification.

The "renewables-hydrogen economy" also requires:

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[46] See references 42, 43.

[47] A rule-of-thumb estimate for the installed cost of complete, large, natural gas (NG) pipeline systems is $25 per inch diameter per meter length. Thus, a small, 50-mile-long, 8" diameter NG pipeline would cost > $16 million. The "hydrogen service" multiplier of 1.4 increases this to > $22.4 million. The NHTTF would need other capital equipment and facilities, and perhaps a longer pipeline.

[48] See references 18, 19, 44, 45.

- Public acceptance of routing and permitting for hydrogen pipelines, installed in their "neighborhood", as part of the energy infrastructure upon which they depend;
- Optimized topology for energy generation, collection, and conversion -- typically from electricity to hydrogen in electrolyzers -- but also from thermal biomass, photolysis, and other renewable sources, and perhaps from coal gasification;
- Accurately estimating the costs of hydrogen collection and transmission systems for renewables, as total cost per MWh delivered via long-distance transmission;
- Insurance and finance industry acceptance and participation, which in turn will require safety and business standards and codes, and substantial successful field experience.

A pilot-scale research, development and demonstration facility, an NHTTF, will help to make clear the technical, institutional, business, and public perception challenges of hydrogen pipeline transmission, so that optimized "renewables-hydrogen economy" systems can be more effectively considered for adoption in the future.

Perhaps this should be an International Hydrogen Transmission Test Facility (IHTTF), built in the Midwest, in collaboration with Japan, Canada, Germany, and perhaps others.[49]

8.2 Modeling and Research

8.2.1 Modeling and Systems Study at GW scale

1. Build two models, for electricity and for hydrogen, to find the economic optimum (profit maximizing) ratio of nameplate (peak) wind generation capacity to rated transmission capacity, balancing enhanced transmission system capacity factor with energy production lost to generation shedding (to prevent overloading transmission). Both electricity and hydrogen systems, by nature, include allowed short-term overloads, but with very different time constants and other characteristics.
2. Build two models, for electricity and for hydrogen, for the source-end energy collection and conversion system interfacing wind generators to transmission, to minimize costs and energy losses, and to maximize wind generator capacity factor. Embrace both technology and topology of the collection-conversion system, including:
   - wind generator electrical generating system type; interface voltage, frequency, and possibility of using a voltage source converter (VSC) feeding the HVDC system;
   - number and spacing of entry points to the transmission system; geometric array of wind generators upon the land;

[49] See: W. Leighty, *National Hydrogen Transmission Test Facility (NHTTF): Concept and Rationale,* 15 Oct 2001

- electrolyzer size and location; output pressure and piping to transmission line.

3. Build a model, embracing both electricity and hydrogen, to find the economic optimum modular generation capacity for a Great Plains wind generation-transmission system. Include modeling for optimizing geographic positioning of 4,000 MW of wind generators upon the land.
4. Run the models used in this report under these conditions:
   - at 10 times and 100 times the generation scale considered in this report.
   - for other wholesale electricity markets: for example, Denver, northern California, southern California, Tokyo;
   - statistical analysis of a large number of hourly price data sets (see 3.1, Wind and Market Price Data, above)
   - with delivery point at Minneapolis - St Paul, as well as at Chicago.
5. Expand model to include integration of electricity and/or hydrogen from other sources:
   - other renewables: biomass, PV, light-driven molecular or cellular systems, geothermal, solar power satellite receiving stations, [50] and perhaps others.
   - Include diurnal and seasonal effects, and dispatchability of some renewables
   - generation, for smoothing aggregate power production, and increasing transmission capacity factor (CF);
   - "really clean" (including carbon sequestration and near-zero emissions) coal plants; and
   - cogeneration of electricity and hydrogen in new high-temperature, gas-cooled nuclear reactor designs, like the PBMR (pebble bed modular reactor).
6. Model renewables resource assessment and transmission planning, integrating all likely renewable sources, at continental scale, to include Canada and Mexico, and Alaska renewables.
7. Emulate the pan-European (including North Africa) wind energy study by ISET (51), to discover the smoothing effect of time-varying windpower output over very large catchment areas in North America, when integrated into the continental energy grid.
8. Update PNL-7789, *An Assessment of … Wind Energy Potential in the Contiguous United States,* 1991,[51] to improve its accuracy and relevance:
   - as suggested on p. 60 of the report;
   - with updated meteorological data;
   - with updated exclusionary criteria, and a wider range of exclusion scenarios.

[50] See reference 43.

[51] See reference 3.

9. Model transmission sharing, including wind, to improve transmission CF: for example, wind might use 40% of transmission capacity, paying 50% of cost; other sources use 40% of capacity, paying 50% of cost; 20% of capacity is unused and lost.
10. Model a shorter transmission path, for both electricity and hydrogen, perhaps with Minneapolis-St.Paul as destination.

8.2.2 Technology Developments Needed

1. For acceptable cost of energy conversion from electricity to hydrogen, we need MW-scale electrolyzers, at >90% efficiency, at <$300 / kW installed, at 1,000 psi output pressure, with very low long-term O+M cost. Proton Energy announced, in late 2001, a kW-scale, PEM electrolyzer with 2,000-psi output,[52] a step in that direction.
2. For credible consideration of long-distance, high-capacity transmission of renewable-source energy by hydrogen pipelines, and for the NHTTF, where high and fluctuating pressures will be required, we need absolute and complete confidence that hydrogen-embrittlement of steel can be prevented and detected.[53]
3. To lower pipeline capital cost and prevent hydrogen-embrittlement or other hydrogen service degradation, we need to investigate transmission pipeline materials other than steel: composites, including continuously-fabricated, in-situ method; include hydrogen-impermeable or hydrogen-storing internal pipeline coatings.
4. For HVDC electric transmission in urban areas, we need lower-cost underground cables at 500 kV, 1000 MW; extruded solid-polymer dielectric construction and economical, standardized installation procedures will help.
5. For HVDC transmission at the source end, we need VSCs of higher capacity, higher output voltage, lower energy conversion loss, and lower capital cost, to provide impedance matching, and VAR support and control, to diverse renewable electricity sources.

8.2.3 Hydrogen Transmission at GW scale

1. Consider other hydrogen transmission systems, as alternatives to a compressed hydrogen gas pipeline:
   - "Hythane": mixing hydrogen with natural gas, in extant natural gas transmission pipelines, at up to 20 % concentration by energy, as a short-term transition strategy; [54]

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[52] See reference 52.

[53] See references 19, pp 587-91; 44, 45.

[54] See reference 46.

- Closed-cycle chemical, via liquid pipeline(s): cyclohexane-benzene; methylcyclohexane-toluene; sodium borohydride, etc;
- Open-cycle chemical, via liquid pipeline: methanol, ethanol, hydrazine, etc.
- Liquid hydrogen, via cryogenic railcars or pipeline; a pipeline could contain a superconducting electric transmission line, as in 8.2.5, below.
- Closed-cycle solids: storage in particulate solids; transportation of the solids to destination(s), release of hydrogen gas, return of solid to source(s). [55]

2. Develop an Excel model, with Word text "design and operating manual" and assumptions, for designing and costing large-scale, long-distance hydrogen transmission pipeline systems, optimized for collection from diverse renewable energy sources:
   - Begin with fluid mechanics and hydraulic engineering equations;
   - Include capital and O&M costs for all components, including electrolyzers and compressors;
   - Include pipelines up to 56" diameter;
   - Include compression system design optimization and energy cost;
   - Make all variables accessible, well-cataloged and identified;
   - Include a variety of charting for model results: inputs and outputs;
   - Include an adjunct model for energy conversion and collection infrastructure: location and capacity of electrolyzers; size and cost of piping; feedwater supply system; optimum capacity and design of transmission entry points.
3. Run the model, in 2, to improve accuracy of the pipeline analysis in this report;
4. Investigate lowering wind-hydrogen transmission system long-term COE by integrating and optimizing wind turbine electric generating system (type and specifications) with electrolyzer: variable-speed; voltage and frequency; impedance matching. This is interactive with 5, below. (see 8.2.1.2, above; 8.2.4.3, below)
5. Run the model, in 2, with results of 4, to suggest optimum conversion and collection infrastructure topology and designs, to minimize long-term COE.
6. Estimate the distribution options and costs for end users of hydrogen in Chicago; consider several introduction scenarios and markets: ground vehicles, aircraft, DG.
7. Value the byproduct heat and distilled water from fuelcells producing electricity from hydrogen in Chicago; value byproduct heat from other prime-movers for converting hydrogen to electricity in Chicago.
8. Survey other hydrogen storage opportunities and estimate costs per kWh-day:
   - along the transmission route, especially geologic;

[55] See references 67 - 70.

- reversible fuel cells with associated distributed storage devices, and
- distributed storage in ground vehicle, aircraft, and DG on-site fuel tanks.

9. Begin the design process for an NHTTF, or International HTTF. (See 8.1, above)

8.2.4 Electric Transmission at GW scale

1. Develop a model to find optimum number and capacity of transmission entry points for large Great Plains windplants, for both HVAC and HVDC transmission systems, both PCC and VSC converters and FACTS controllers. [56]
2. Develop a model to optimize collection, conversion and transformation infrastructure, topology and design, connecting the wind generator array to electric transmission lines.
3. Consider and model (both technically and economically) VSC, as the source-end electric energy collection and conversion device, for HVDC systems. This will result in:
   - Multiple delivery points to the HVDC line, as the capacity of each VSC will be limited to about 500 MW, about one-fourth capacity of the HVDC line; this may help optimize topology design for the 4,000 MW source system;
   - Connecting the wind turbines to an AC bus of ideal voltage and frequency, with complete VAR control, to minimize complexity and cost of the individual wind turbine generating systems and control systems;
   - The wind turbines may be equipped with robust and low-cost squirrel-cage induction motors as the generators, with minimum power electronics;
   - Higher energy conversion losses, in the VCS than in phase commutated converter (PCC) of "conventional" HVDC transmission systems;
   - The introduction of mixed HVDC systems, with multi-terminal VSC at source end, and PCC at destination end.
4. Design a complete 4,000 MW HVDC transmission system, including the design options in this report, from a candidate North Dakota source area to candidate Chicago-area delivery point(s); calculate all capital and O+M costs.
5. Estimate capacity potential for upgrading extant electric transmission systems, in extant ROW corridors, for North Dakota, and for the entire Great Plains wind resource area. Consider HVDC, especially for long-distance, high-capacity wind energy. Consider "energy pipeline" (below). Estimate cost of several such upgrades especially beneficial to large-scale wind energy export; run the cost and profit models (37, 38).

[56] See reference 59.

8.2.5 "Energy Pipeline" Superconducting Transmission

Electric Power Research Institute (EPRI), Palo Alto, CA, has conceptually proposed superconducting cables for long-distance, high-capacity (100 GW) low voltage DC (LVDC) electric transmission. [57] With liquid hydrogen (LH2) coolant, this "energy pipeline" could also deliver energy as LH2. Combined electricity and hydrogen power capacity might be 100 GWe plus 100 GW as LH2, totaling 200 GW. Two such energy pipelines could accommodate the entire peak wind generation capacity of North Dakota.

However, such a pipeline has not been built; capital and O&M costs have been only roughly estimated. [58] Hysteresis energy losses may make such pipelines unsuitable for power levels varying at hourly time scale, as from windplants – even large ones spanning an entire state. [59]

Although steady state DC electric transmission energy loss in a superconductor is nearly zero, even over long distances, these energy pipelines will require refrigeration and vacuum-insulation systems, which will consume a fraction of the input energy.

These pipelines may best, or necessarily, be located in tunnels drilled in bedrock, for stability, security, and maintenance access. Such TBM-drilled tunnels cost approximately $300 per ft. [60]

These pipelines would apparently also suffer the adverse economics of CF limited to about 40%, if sized to equal windplant peak generation capacity. LH2 is incompressible, so provides no energy storage in the pipeline, as do the gaseous hydrogen (GH2) pipeline scenarios analyzed in this report. Liquefying hydrogen, from GH2 to LH2, consumes about one-third of the energy in the GH2 input – a very costly conversion. Much research, and pilot-scale projects, will be needed to commercialize this transmission technology, which may prove useful for export of Great Plains wind energy.

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[57] See references 61, p 4, 6, 28, 31; 62, 63.

[58] See references 62 - 64.

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Appendix A: Total Project Costs with Wind at $950 and $700 per kW*

Scenario	Total Annual Costs Wind at $950 per kW	Total Annual Costs Wind at $700 per kW	Percent Reduction
36-C-FC			
Wind Energy	$566,824,494	$436,824,494	22.93%
Pipeline	$334,000,000	$334,000,000	
Electrolyzer	$192,000,000	$192,000,000	
Fuel Cells	$340,853,157	$340,853,157	
Compressor	$37,300,000	$37,300,000	
Total	$1,470,977,651	$1,340,977,651	8.84%
36			
Wind Energy	$556,591,434	$426,591,434	23.36%
Pipeline	$334,000,000	$334,000,000	
Electrolyzer	$192,000,000	$192,000,000	
Fuel Cells	$161,888,787	$161,888,787	
Compressor	$37,300,000	$37,300,000	
Total	$1,281,780,222	$1,151,780,222	10.14%
36-NC-FC			
Wind Energy	$566,824,494	$436,824,494	22.93%
Pipeline	$308,000,000	$308,000,000	
Electrolyzer	$192,000,000	$192,000,000	
Fuel Cells	$340,853,157	$340,853,157	
Compressor	$0	$0	
Total	$1,407,677,651	$1,277,677,651	9.24%
36-NC-CT			
Wind Energy	$556,591,434	$426,591,434	23.36%
Pipeline	$308,000,000	$308,000,000	
Electrolyzer	$192,000,000	$192,000,000	
Fuel Cells	$170,522,089	$170,522,089	
Compressor	$0	$0	
Total	$1,227,113,523	$1,097,113,523	10.59%
18-NC-FC			
Wind Energy	$570,882,356	$440,882,356	22.77%
Pipeline	$139,000,000	$139,000,000	
Electrolyzer	$140,000,000	$140,000,000	
Fuel Cells	$343,185,262	$343,185,262	
Compressor	$0	$0	
Total	$1,193,067,617	$1,063,067,617	10.90%
18-NC-CT			
Wind Energy	$559,915,032	$429,915,032	23.22%
Pipeline	$139,000,000	$139,000,000	
Electrolyzer	$140,000,000	$140,000,000	
Fuel Cells	$172,432,202	$172,432,202	
Compressor	$0	$0	
Total	$1,011,347,234	$881,347,234	12.85%

*Figures shown are annualized costs. Annual wind costs are calculated as total installed costs multiplied by a 12-percent annual capital recovery factor, plus annual O&M costs.

Appendix B. Cost Assumptions for Distributed Generation

In section 4.5 we show total costs of operating distributed generation on hydrogen from the pipeline projects modeled here. The table below details our cost and efficiency assumptions for internal combustion engines (ICEs), microturbines and proton exchange membrane fuel cells (PEMFC) in 2010.

The 45% PEMFC efficiency shown includes the benefit of eliminating the hydrocarbon fuel reformer from the system, since the PEMFC is operating on pure hydrogen.

Table B-1. 2010 DG Cost Assumptions

Technology	Efficiency (%)		O&M	Total Non-Fuel Costs (
ICE	40	$700	2.50	3.63
Microturbine	30	$800	2.00	3.29
Fuel Cell	45	$2,000	1.00	4.22

Appendix C: Energy Conversion Factors for Hydrogen

Volume				
1 Nm3 =	35.315 cubic ft (scf)			
Pressure				
1 Mpa =	145 psi =	9.9 atm		
1 atm =	14.696 psi =	1.01325 bar		
1000 psi =	68.9 bar =	68.05 atm		
Power				
1 kW =	10.5 scf per hr			
1 MW =	10,500 scf per hr =	297.5 Nm3 per hr =	3.6 GJ per hr	
1 GW =	10.5 Mscf per hr =	297,500 Nm3 per hr =	3,600 GJ per hr	
1 TW =	10.5 Bscf per hr =	297.5 MNm3 per hr =		
1 Mscf per hr =	327 mmBtu per hr			
Energy				
1 GJ =	277.8 kWh =	2,915 scf =	75.36 Nm3 =	10^9 J
1 kWh =	10.5 scf =	0.298 Nm3 =	0.95 mmBtu	
1 MWh =	10,500 scf =	297.5 Nm3 =	3.6 GJ	
1 GWh =	10.5 Mscf =	297,500 Nm3 =	3,600 GJ =	3,430 mmBtu
1 TWh =	10.5 Bscf =	297.5 MNm3 =	3.6 PJ	
1 kg H2 =	11.08 NM3 =	128.8 MJ (HHV) =	135,100 Btu =	375.6 scf
10^6 scf =	343 GJ =	26,850 Nm3		
1 lb H2 =	5.04 Nm3 =	0.0585 GJ (HHV) =	16.26 kWh =	187.8 scf
1 Nm3 H2 =	0.09 kg =	3.361 kWh		
1 scf H2 =	343 kJ =	325 Btu (HHV)		
1 kWh =	3,410 Btu			
1 scf natural gas = 1,010 Btu				

Kilo = 10^3, Mega = 10^6, Giga = 10^9, Tera = 10^12, Peta = 10^15, Quad = 10^15, Exa = 10^18

Appendix D: Generation - Transmission Systems Flowcharts

D.1. Electricity Transmission (see also reference 71)

Figure D-1. Simplified "Electrical Transmission" Scenario

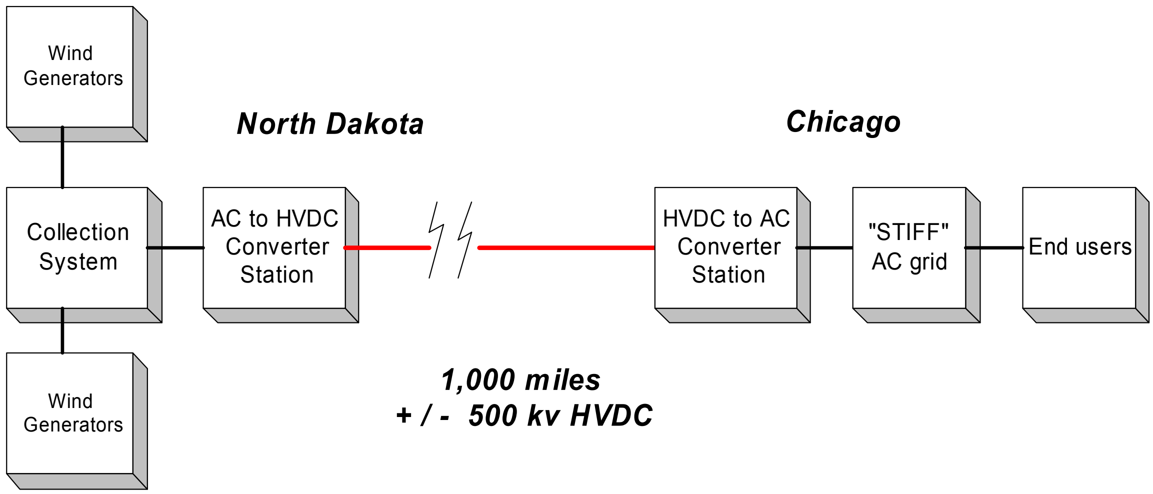


Figure D-2. "Electrical Transmission" Scenario HVDC-C, with eastern 100 miles underground, to facilitate permitting and ROW acquisition approaching Chicago urban area

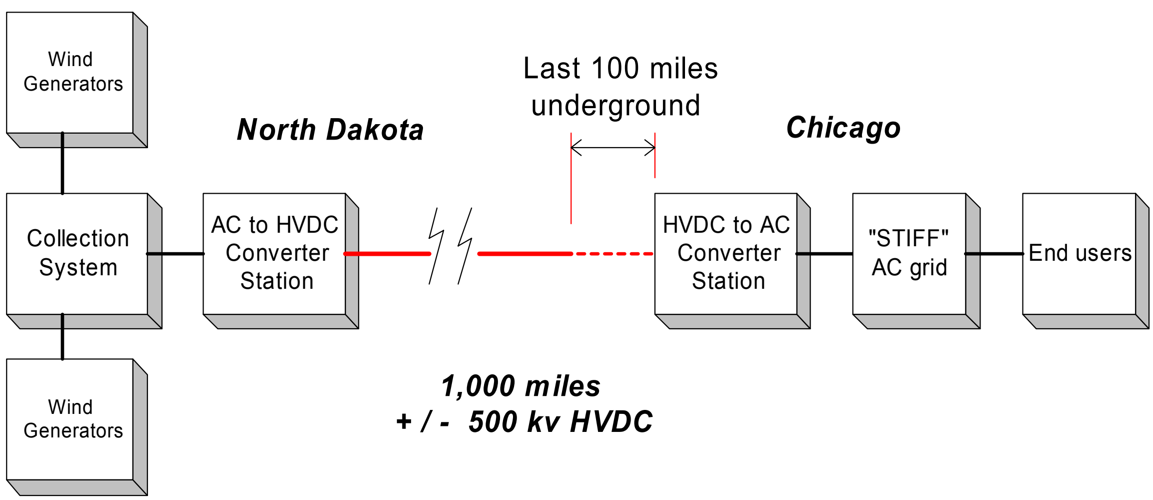


Figure D-3. "Electrical Transmission" Scenario requires two, parallel, 2000 MW circuits for 4000 MW total capacity; 3000 MW is the highest practical capacity for a single HVDC circuit.

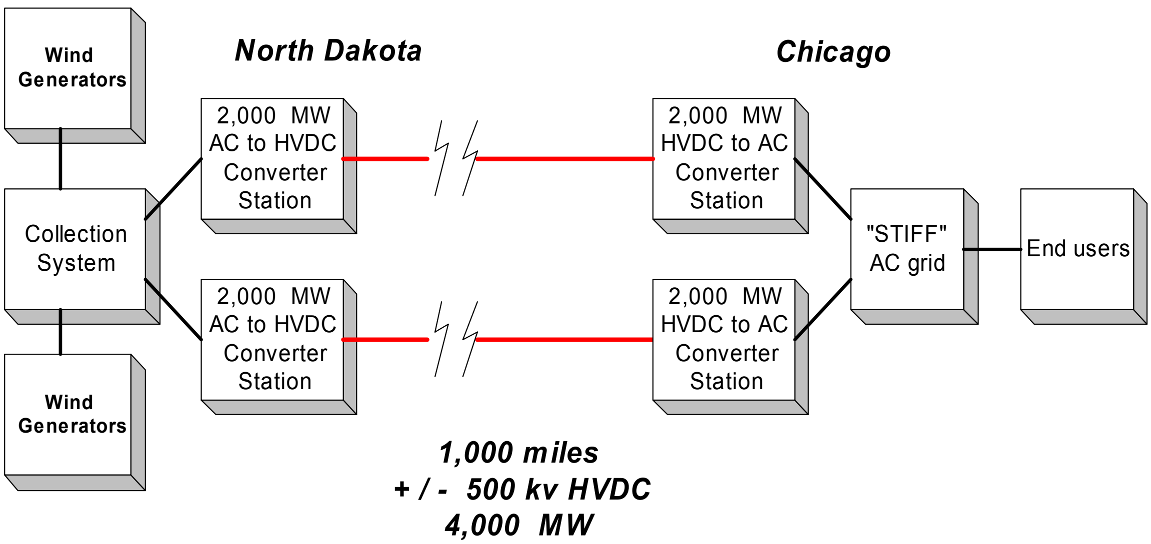


Figure D-4. "Conventional" HVDC bipole transmission detail. Line-Commutated Converters (LCC), 60 Hz collection buses in ND. Power Electronics control variable speed, power factor, and harmonics.

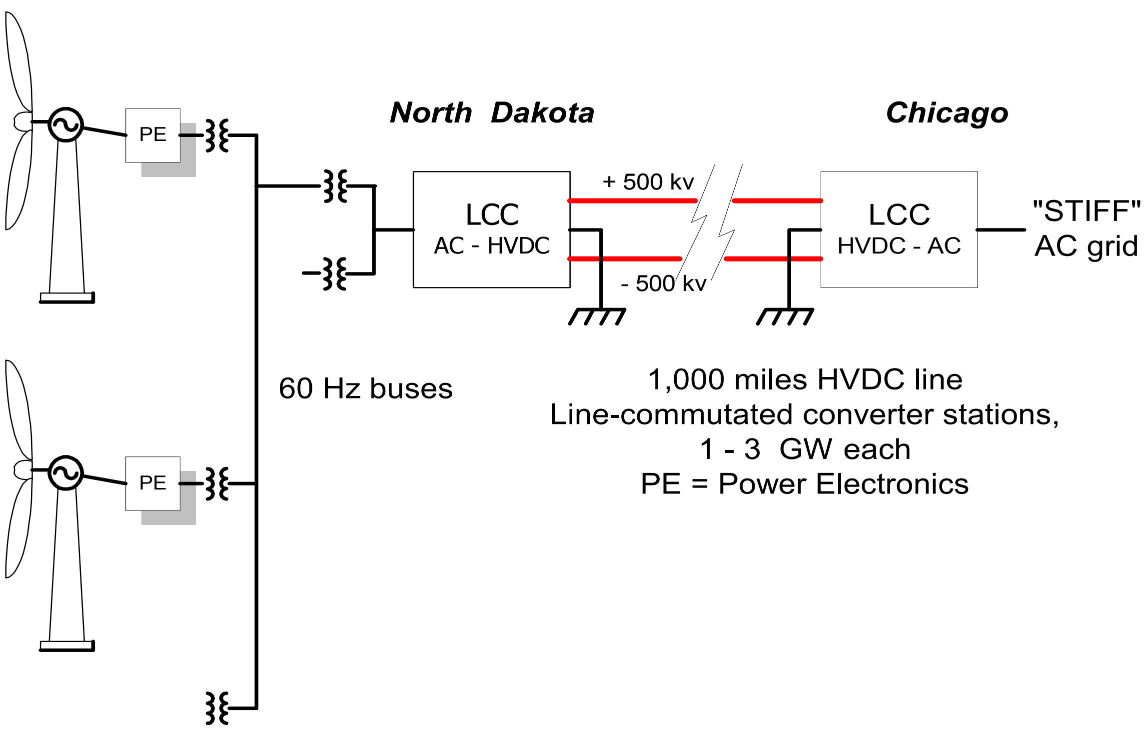


Figure D-5. "Conventional" HVDC Bipole transmission with multiple input nodes via multiple Line-Commutated Converter (LCC) stations.

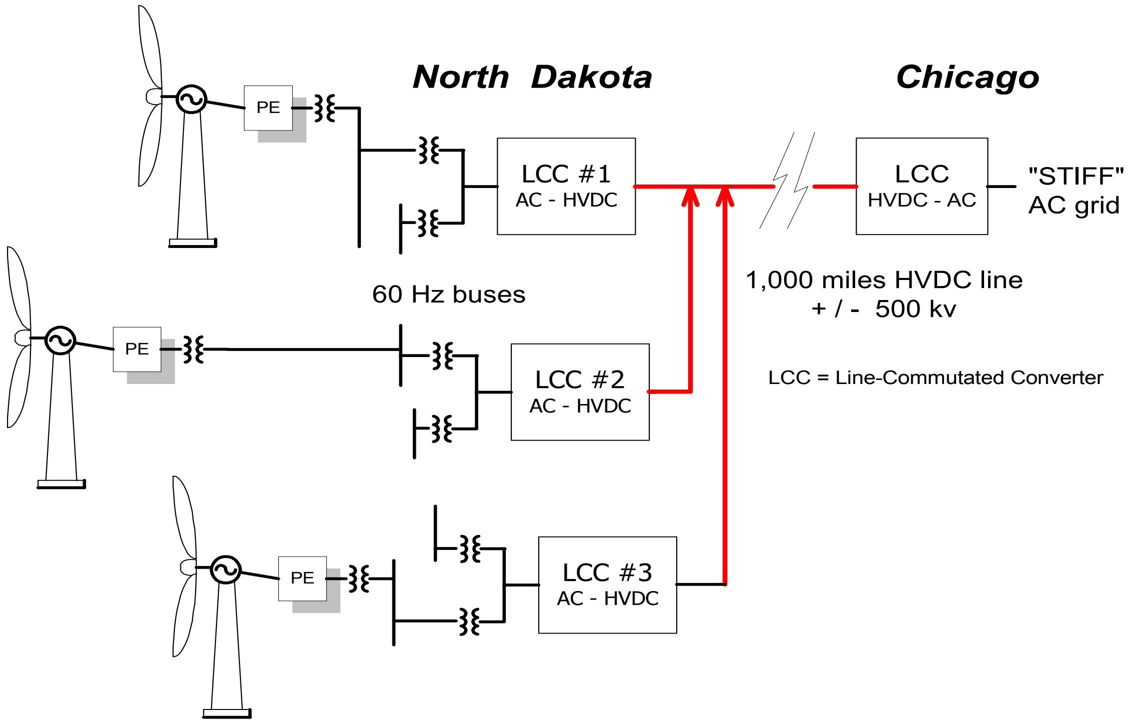


Figure D-6. Voltage-Source Converters (VSC) at ND source may allow wind generators to operate with simple squirrel-cage induction generators, without power electronics, grouped on independent variable voltage, variable-frequency buses

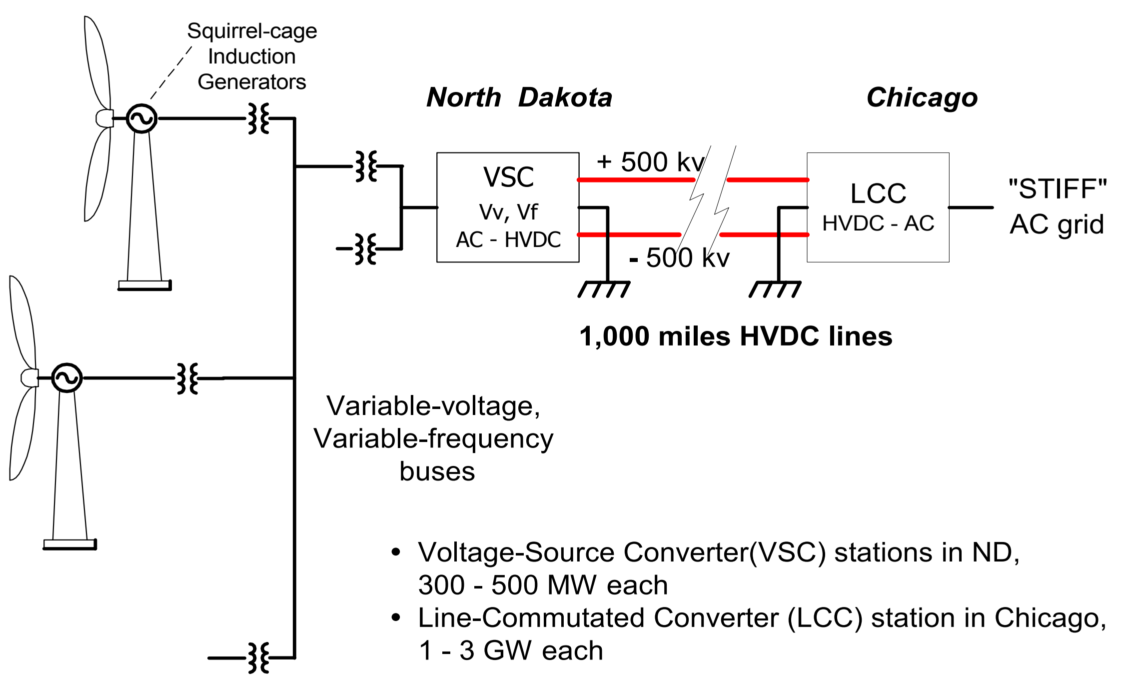
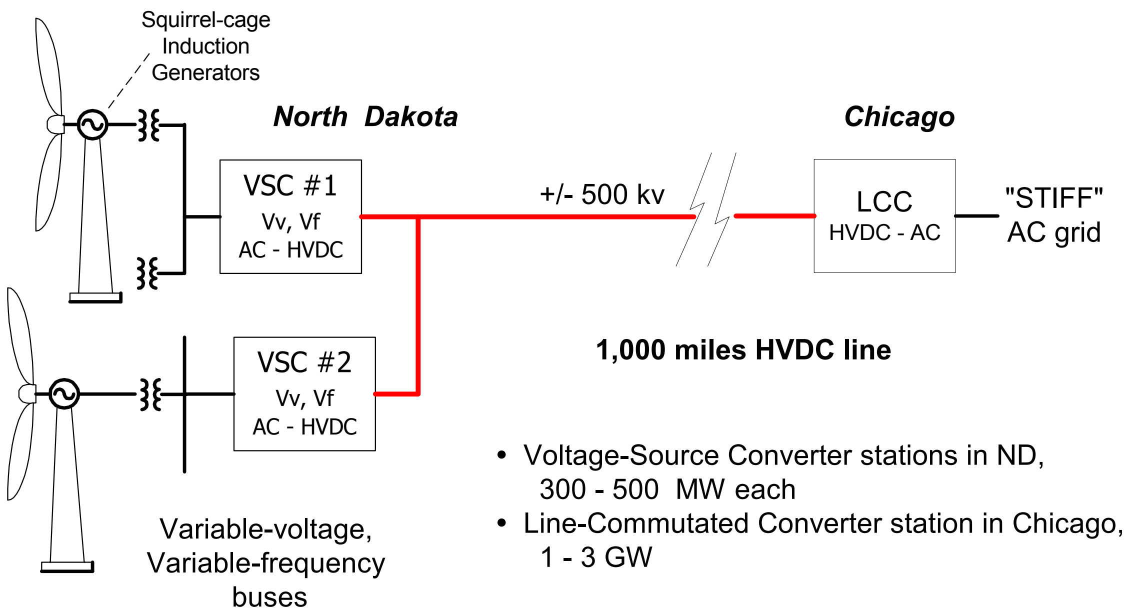


Figure D-7. HVDC Bipole transmission with multiple input nodes via multiple "VSC" Voltage-Source Converter stations in ND, feeding "conventional" LCC converter stations in Chicago.



D.2. Hydrogen Transmission

Figure D-8. Simplified "Hydrogen Transmission" scenario, delivering electricity in Chicago

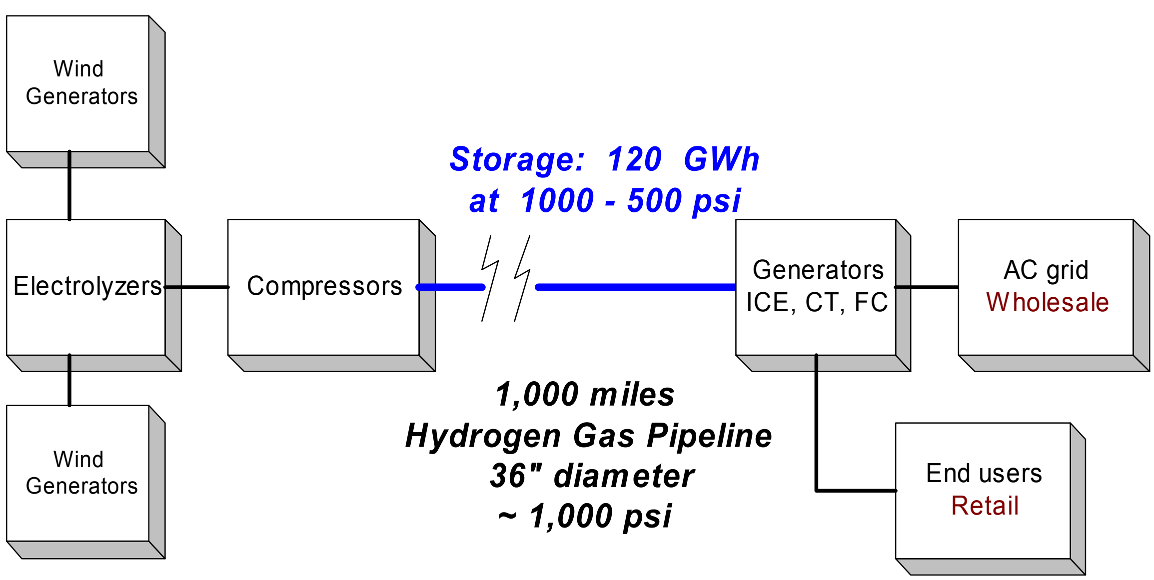


Figure D-9. Simplified "Hydrogen Transmission" scenario, delivering hydrogen in Chicago to various users

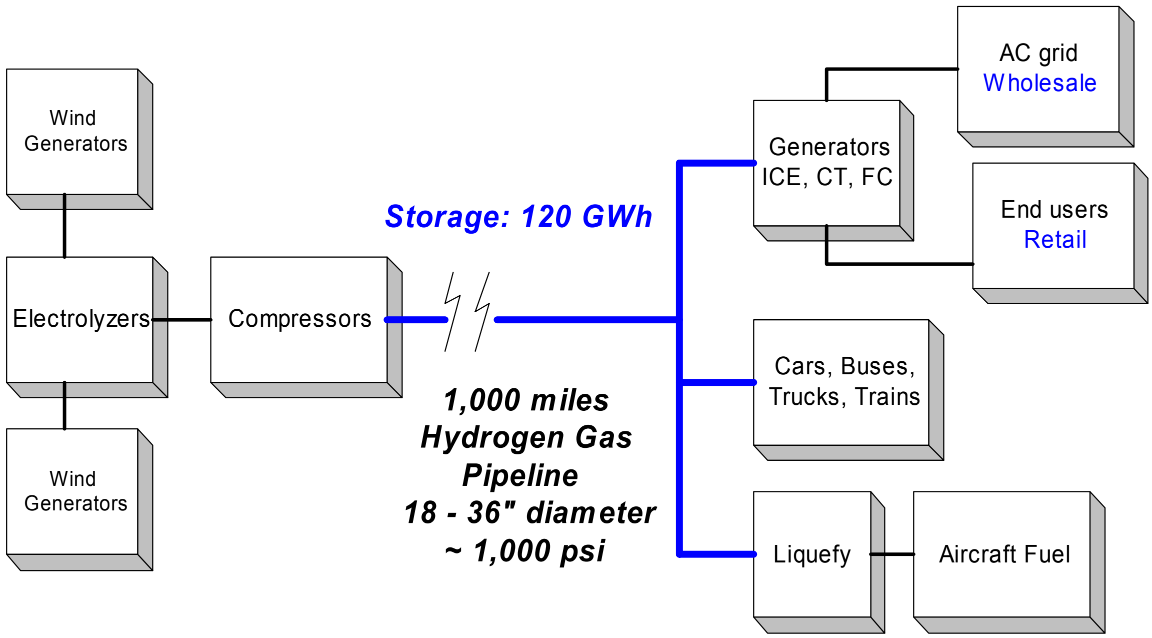


Figure D-10. "Hydrogen Transmission" scenario, delivering hydrogen in Chicago to various users, with several potential storage resources in addition to pipeline storage

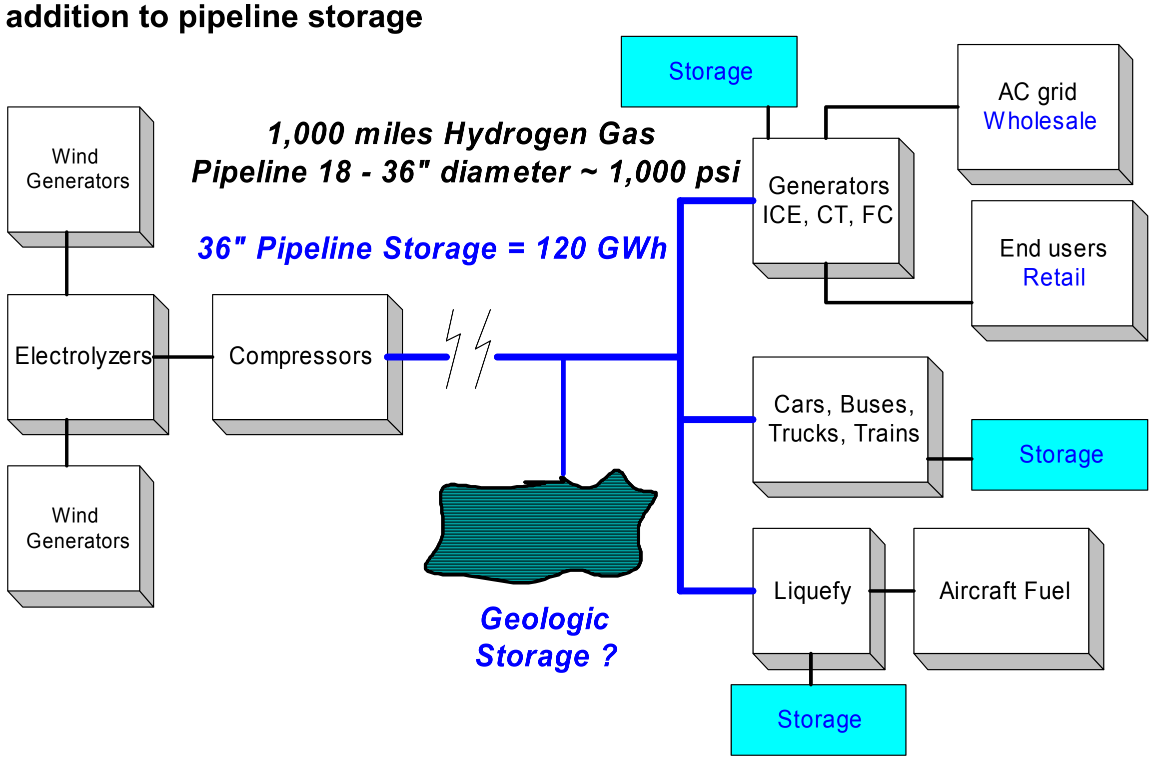


Figure D-11. "Hydrogen Transmission" scenario, synergy with coal gasification plants near wind energy source, using byproduct oxygen from electrolyzers

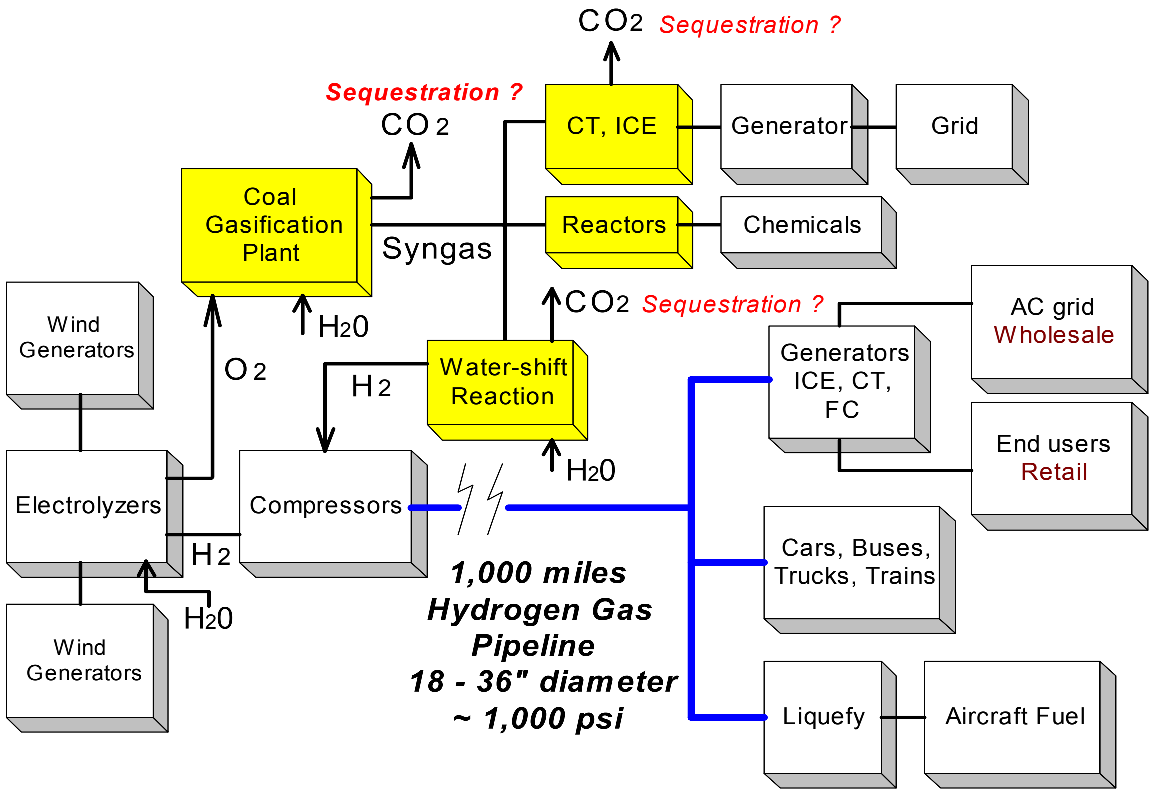


Figure D-12. High pressure output electrolyzers eliminate compressors at pipeline input, saving capital cost and energy. Mid-line compression may be required. This scenario shows electricity delivery in Chicago.

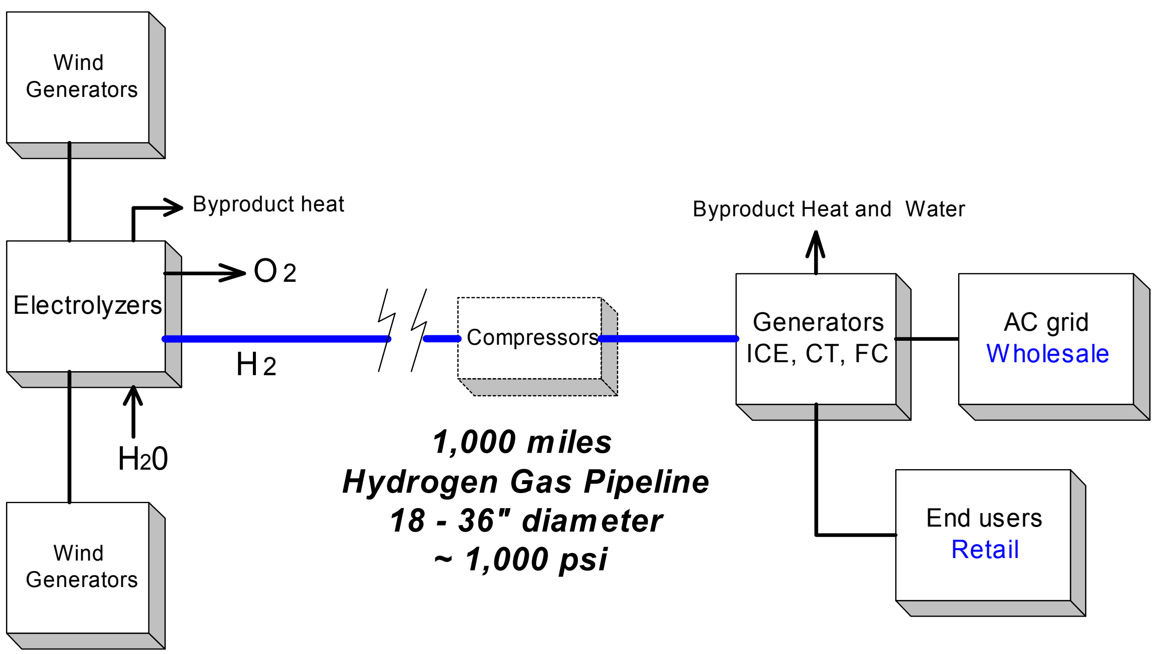


Figure D-13. In Hydrogen Transmission scenario, hydrogen may be delivered to the pipeline, anywhere along it, from numerous and varied sources, via nodes of widely varying capacity: perhaps 1 - 500 MW ea.

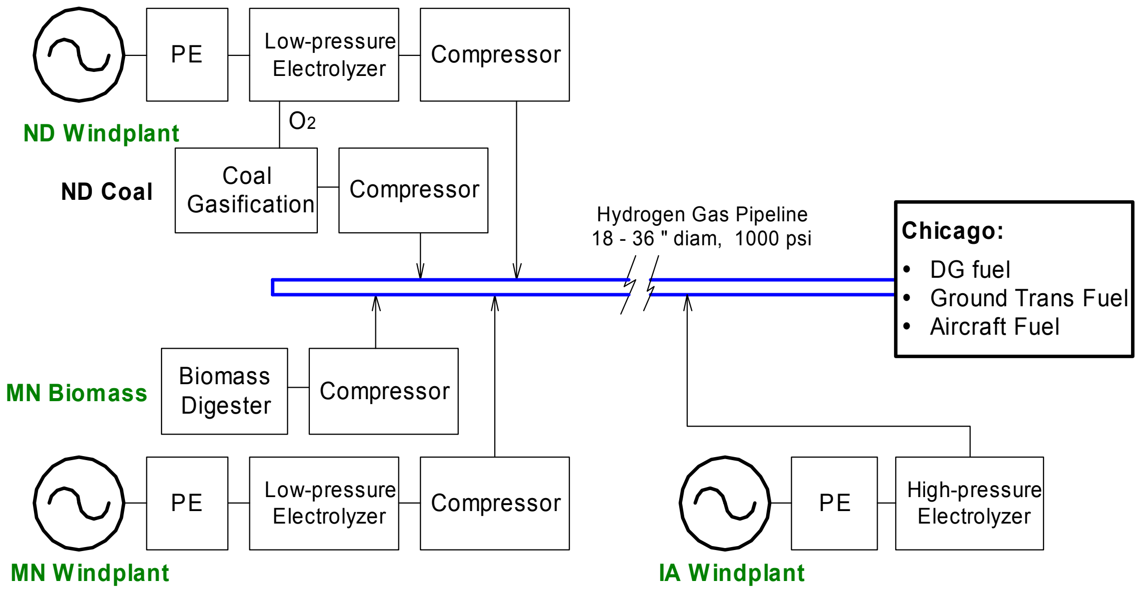


Figure D-14. Delivery nodes to hydrogen pipeline may be simple, of widely-varying capacity, located anywhere along the pipeline.

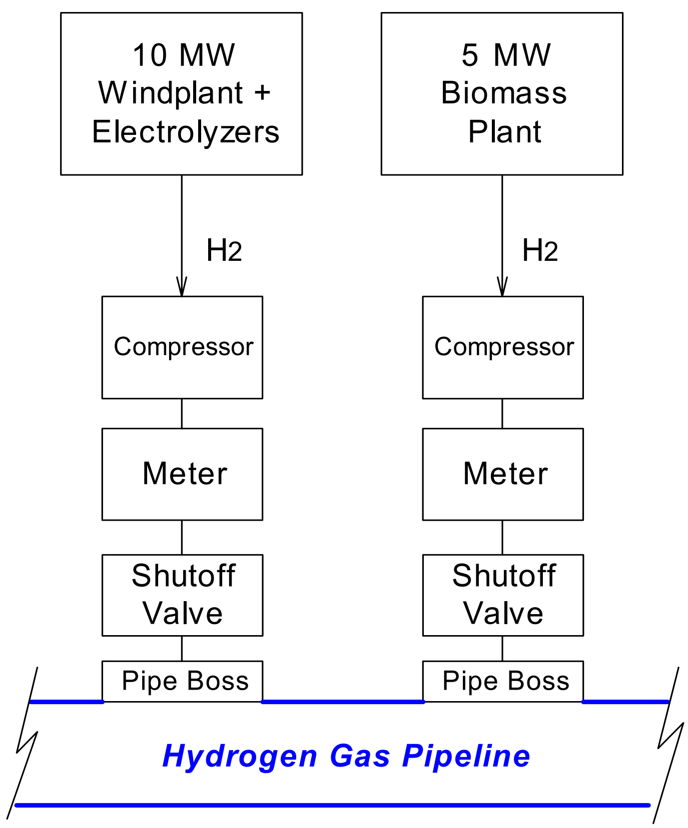


Figure D-15. Collection topology options for hydrogen transmission: a combination of electric wiring and piping for water, hydrogen, and oxygen (if latter is to be sold near windplants). Electrolyzers may be located at individual wind generators or grouped. Power electronics is required to rectify AC to DC required by electrolyzers.

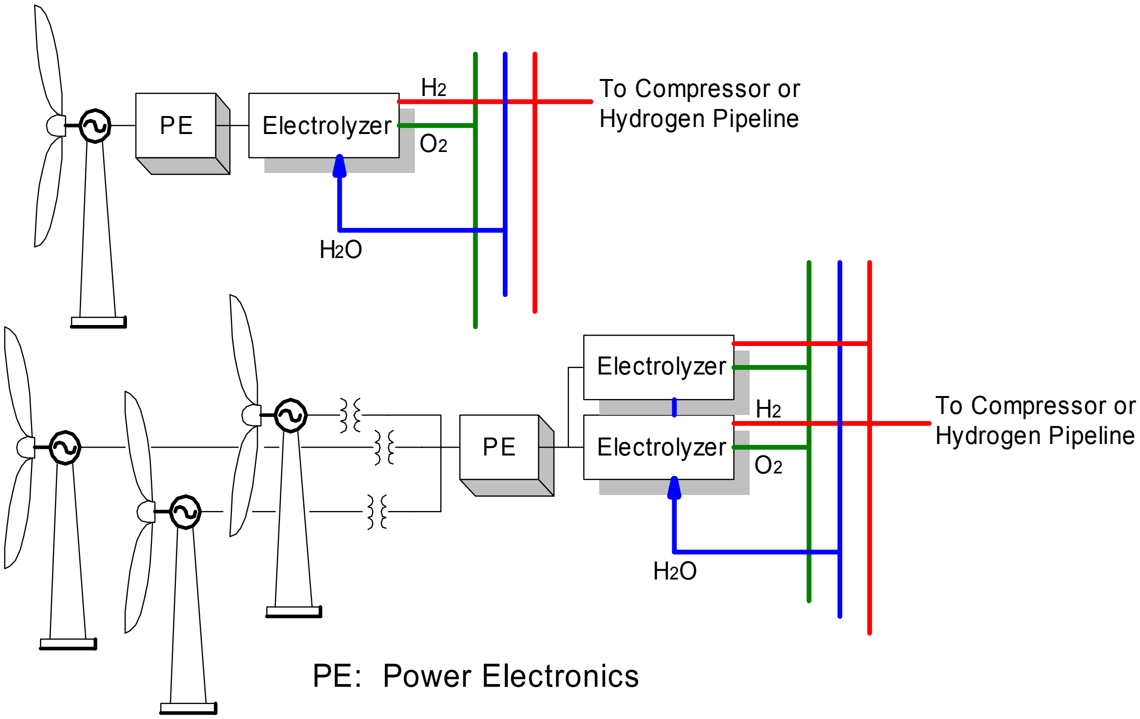


Figure D-16. Conceptually, energy may be stored as oxygen in geologic formations in North Dakota for use by coal gasification plants when windplant output is low. However, this has not been studied nor tested; oxidation of subterranean formations may quickly destroy the reservoir.