Final Report

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Project Objective:

This project is a research and development program aimed at furthering distributed wind technology. In particular, this project addresses some of the barriers to distributed wind energy utilization in Idaho.

Background:

At its core, the technological challenge inherent in Wind Energy is the transformation of a highly variable form of energy to one which is compatible with the commercial power grid or another useful application. A major economic barrier to the success of distributed wind technology is the relatively high capital investment (and related long payback periods) associated with wind turbines. This project will carry out fundamental research and technology development to address both the technological and economic barriers.

- Active drive train control holds the potential to improve the overall efficiency of a turbine system by allowing variable speed turbine operation while ensuring a tight control of generator shaft speed, thus greatly simplifying power conditioning.
- Recent blade aerodynamic advancements have been focused on large, utility-scale wind turbine generators (WTGs) as opposed to smaller WTGs designed for distributed generation. Because of Reynolds Number considerations, blade designs do not scale well. Blades which are aerodynamically optimized for distributed-scale WTGs can potentially reduce the cost of electricity by increasing shaft-torque in a given wind speed.
- Grid-connected electric generators typically operate at a fixed speed. If a generator were able to economically operate at multiple speeds, it could potentially convert more of the wind's energy to electricity, thus reducing the cost of electricity.

This research directly supports the stated goal of the Wind and Hydropower Technologies Program for Distributed Wind Energy Technology:

By 2007, reduce the cost of electricity from distributed wind systems to 10 to 15 cents/kWh in Class 3 wind resources, the same level that is currently achievable in Class 5 winds.

Tasks:

Task 1: Distributed Wind – Irrigator Nexus

According to the original Statement of Project Objectives, prepared in the spring of 2006, Task 1 was titled **“Tools to Improve Idaho’s Wind Resource Map and Assess Irrigation Potential”**. In August of 2006 our lead investigator on that proposed task, Paul Dawson, accepted a 1-year sabbatical in Europe, running through the summer of 2007. Coincidentally, grant reviewers at the National Renewable Energy Lab requested

that we incorporate one of their objectives – researching the wind-irrigators nexus – into our SOPO.

Responding to the internal staffing change and request from NREL, we changed the title of Task 1 to **Distributed Wind - Irrigator Nexus**, and developed the subtasks contained in this report. No significant change in the budget occurred due to this change in objectives.

Subtask 1.1 Coordinate with Idaho Energy Division on Wind-Irrigation Project

Boise State University researchers participated with the Idaho Office of Energy Resources (formerly the Energy Division of the Idaho Department of Water Resources) on a series of wind-irrigators workshops which occurred during 2007. Boise State University hosted the meeting on September 20, 2007.

Subtask 1.2 Research issues, barriers and potential solutions

Background

Two farmer/irrigators in southern Idaho agreed to participate in separate case studies. Each of these farmers operates high-lift irrigation pumps. Additionally the farmers have multiple anemometer towers on their farms, each with more than 1 year of data collected. The farmers agreed to make both wind and pumping data available for the case studies. One farmer, Leroy Jarolimek, agreed to fully disclose the data from his farm located near Burley, Id. The other farmer agreed to make data available as long as the studies do not specifically identify the farms. That farm will be described simply as being located in Southwestern Idaho.

The intent of the case studies is to determine what overlap (if any) exists between periods of wind speeds adequate for generating electricity and periods of large energy consumption for pumping. Technological solutions were examined, including: using wind turbines to pump water directly; pumping water during windy periods & storing it for use during the irrigation season; and generating electricity during windy periods and storing the energy for use during the irrigation season. Economic effects of existing policies were investigated. Additionally, idealized policies were investigated which may improve the systems' economic viability.

Methodology

Anemometer and pumping data from the two farms were analyzed using various techniques and software packages.

1. First, the amount of energy consumed was compared to the amount of energy available in the wind.
2. Then, an appropriate number of wind turbines was selected to capture the necessary amount of wind energy. The analyses assume use of GE 1.5MW turbines with 77-m rotor diameters. These turbines were selected because they are the most prevalent turbines used in Southern Idaho.

3. Using the selected number of turbines, economic analyses were run to determine if there was an economic benefit to using these turbines vs. continuing to pull energy from the grid.
4. Seasonal energy storage & water storage were investigated with a systems modeling approach using MATLAB™ software.

Southwest Idaho Project

On November 8, 2006, a site visit was performed at the Southwestern Idaho water project. That project consists of 4 different farms which all draw water from the same system. The water is pumped from a creek approximately 250' uphill (total head; total distance is greater than 300') to the plateau where the farms are situated. There are 3 separate pipelines, each with multiple pumps, carrying water up to the plateau. The water is then transported several miles by canal to the farms, where it is stored in various reservoirs which feed irrigation pivots. There are various pumps situated at the reservoirs which pressurize the water for the pivot systems. During the most intensive pumping months, electricity bills associated with pumping total about \$100,000 per month to lift the water to the plateaus and another ~\$100,000 to pressurize the water for the pivots¹. A 50-m and a 20-m anemometer have been collecting data since mid-2005. Anemometer data and pumping records were obtained for analyses.

Assuming use of GE 1.5 MW turbines, neglecting wake effects or turbine placement, a minimum of three turbines is required to generate more electricity than consumed by irrigation. See Figure 1.2.1.

Figure 1.2.1: SWI annual energy. Generation estimate assumes 3 GE 1.5MW, 77-m rotor diameter WTGs

As indicated in Figure 1.2.2, the irrigation consumption peaked in June, remaining greater than 2.5 million kWh through August, before dropping back down to about 1

¹ Based on 2006 irrigation season costs.

million kWh in September. The estimated electricity generation from three WTGs did not vary as greatly by month as did the irrigation consumption.

Figure 1.2.2 – production assumes 3 GE 1.5MW, 77-m rotor diameter wind turbine generators

Analysis - Southwest Idaho Project

PURPA

HOMER, a micropower optimization model developed at the National Renewable Energy Laboratory, was initially used to analyze the use of wind turbines to offset irrigation pumping costs. For the primary HOMER analysis, a 10.5 MW PURPA project was allowed, and it was assumed that the avoided cost rates were roughly the same as they are now. This optimization compared using 0, 1, 2 or 3 GE 1.5 MW, 77-m rotor diameter grid-tied wind turbine generators. Using these assumptions, it does not appear that PURPA wind projects will provide an economically feasible option for this irrigator to offset his pumping costs. After a sensitivity analysis was run, it was shown through HOMER that the points at which a PURPA project would be economically feasible are:

1. if the irrigators' price to purchase power increased to \$0.075/kWh
2. if the rate at which irrigators sell power to the utility increased to \$0.0675/kWh.

Net-Metering

Following the HOMER analysis of a PURPA project, it was decided to investigate the effectiveness of a net-metering contract. As it stands, Idaho only allows 100kW net-metering although some states do allow up to 2MW contracts. In this situation it was assumed that the utility would allow a 2MW net-metering power capacity. This would allow a single 1.5MW wind turbine to be used in the calculations. Under this contract, the total amount paid to the utility would be \$330,000. While this number is lower than the previous amount of \$431,191 paid in 2006, it does not include the capital costs of the turbine, which will be incorporated in the economics section.

Storage

It has been determined that there is no economically feasible option to connect the wind turbines to the grid under a PURPA contract; one might exist in net-metering; but additional storage options exist. There may be economically feasible options to generate, store and consume the wind power onsite and directly offset or eliminate the utility bills. The configurations investigated are: using wind energy to 1) pump and store water, 2) store energy in the form of compressed air, or 3) both.

For the implementation of wind power and energy/water storage at the farm, two scenarios exist:

1. *Storing Water*: Connecting the turbines directly to variable speed pumps and pumping water whenever the wind blows. In this respect the water is stored in canals / reservoirs until use.
2. *Storing Energy*: Implementing a compressed-air energy storage system. The turbines would be able to store energy in the form of compressed air, which could be converted into electricity when desired.

System Modeling - Southwest Idaho Project

Storing Water

In order to compare the amount of energy harnessed from the wind to the amount needed for irrigation, the actual volume of water that is needed had to be determined. Since the energy used per month was known, the following relationship was used to calculate average flow rate, Q :

$$Q = \frac{\dot{W}}{\rho g h} \eta_{\text{pump}}$$

where $\dot{W}$ is the average power usage throughout the month. This flow rate was then integrated over time to obtain the volume of water pumped for a given month. Actual met-tower data from the site was used, reported at 10-minute average intervals; this process was done for the duration of one year. Water is not allowed to be pumped during the winter months because of regulations and freezing conditions. Water can begin to be pumped from the stream in the spring. All timescales in this paper start from the end of the irrigation season October (month 1) to September (month 12). Although three turbines can produce enough energy from wind to meet the requirements for the year, because of the restriction on pumping water during the winter, this scenario requires two additional turbines to be able to cover the water demand for the year. Summing the volume pumped from the turbines and comparing to that pumped when the pumps were simply connected to the grid yields:

Figure 1.2.3 – Volume of water needed compared to amount available from wind for one year

In keeping with prior analyses, this model utilizes power curves from GE 1.5MW wind turbines to estimate the volume of water five such turbines would pump from the stream up the 250 foot head. The methodology was: given a wind speed, calculate the power produced at the turbine, scale by pump efficiency, calculate flow rate then integrate over time to obtain volume. A Matlab/Simulink model was created to run simulations for the duration of one year.

Figure 1.2.4 - Simulink model

Storing Energy

During the months that irrigation is not needed, it would be desirable to store the energy produced at the wind turbines for later use. While energy storage technologies are currently an active area of research, there are some feasible possibilities that could work in conjunction with a wind/irrigation system.

Compressed Air Energy Storage (CAES) is a proven technology with two successfully operating facilities in the world (Huntorf, Germany and McIntosh, Alabama)¹. These

facilities use surplus energy to compress air in large underground caverns. When energy is needed, the air is expanded at the surface through a turbine and electricity is created. Cavallo notes that "...with an installed capital cost of about \$890/kW, CAES is the least cost utility scale bulk storage system available."² If a CAES system is used, energy can be stored from the end of the irrigation season (October) until the pumps are needed to be operated in the spring.

Although CAES systems that use underground storage are inherently site specific, it is estimated that more than 80% of the U.S. territory, including most of Idaho, has geology suitable for such underground storage.⁴ CAES utilizes proven technology that can be optimized for specific site conditions and competitively delivered by various suppliers.

As in the water storage analysis, three turbines are not sufficient to generate *and store* enough energy to cover the demand. CAES systems have an efficiency of roughly 50%, therefore seven turbines were needed instead of three to generate and store adequate energy⁴.

Figure 1.2.5 - Energy needed for irrigation and available from wind

Results - Southwest Idaho Project

Store Water

In the previous analysis, the number of turbines in each scenario was decided to be the appropriate number to avoid any payments to the utility. In the water storage scenario, with five turbines, water is pumped from the stream at the beginning of spring and stored. When the irrigation season begins, that water is used for the next several months, being replenished as the wind blows. The level of the water storage in the system can be seen in the following figure.

Figure 1.2.6 - Water storage level over time.

Store Energy

To store enough energy to operate the pumps for the duration of the irrigation season, seven turbines were needed. Figure 1.2. shows the level of energy storage in the system for the entire year.

Figure 1.2.7 - Energy storage level over time.

Economics - Southwest Idaho Project

The configurations of storing energy/water both required the number of wind turbines to be the appropriate amount to avoid any payment to the utility for the year. The net-metering configuration does still require a certain amount of money to be paid to the

utility. Starting with the actual amount paid in the 2006 irrigation season of \$431,192, avoided costs are summarized in Table 1.

Amount paid to utility	
<i>Store Energy</i>	\$0
<i>Store Water</i>	\$0
<i>Net Metering</i>	\$330,000
Amount avoided to utility	
<i>Store Energy</i>	\$431,192
<i>Store Water</i>	\$431,192
<i>Net Metering</i>	\$101,192

Table 1. Amount of money paid and avoided to the utility.

In order to calculate a simple payback period for each of the above configurations, the capital costs associated with each need to be determined. Table 2 summarizes those costs for each configuration.

Capital Costs	
Storing Energy	
<i>Turbines (7)</i>	\$14,000,000
<i>CAES System</i>	\$135,000,000
<i>Total</i>	\$149,000,000
Storing Water	
<i>Turbines (5)</i>	\$10,000,000
<i>Additional</i>	
<i>Reservoirs</i>	\$30,000
<i>Total</i>	\$10,030,000
Net Metering	
<i>Turbines (1)</i>	\$2,000,000

Table 2 - capital costs for each configuration.

Each scenario has capital costs associated with the purchase of wind turbines, although the amounts differ because of the different number of turbines required for the different scenarios. From industry specialists, it was estimated that each 1.5MW wind turbine would have an approximate installed cost of \$2 million. It can be seen above that the capital cost for the CAES system is \$135 million. This amount was estimated from published figures through the Electric Power Research Institute⁴. If water is stored, the existing storage would not be sufficient to store the necessary amount. Therefore, additional reservoirs could be created on the farm, incurring an initial capital cost of roughly \$30,000.

Estimating the capital costs associated with each scenario, the simple payback period for each can be calculated. Table 3 shows these periods.

Simple Payback	
<i>Store Energy</i>	NA
<i>Store Water</i>	23
<i>Net Metering</i>	20

Table 3 - simple payback period in years. The payback period for storing energy exceeds the system's useful life; as such, it has no meaningful payback period.

Since only a simple payback period was calculated for the above configurations, these numbers are an underestimate of the actual duration to pay off the initial capital. Because of the costly CAES system, as well as other capital costs, all three configurations appear infeasible. However, the relationship between reduction in capital costs to the increase in annual payments to the utility can be explored. To reduce capital costs of the energy or water storing configurations, the number of wind turbines used could be adjusted. In these configurations, more money will be paid to the utility for electricity since fewer turbines are used, but initial capital is lower. To find the most effective way of using the stored energy/water, two different sub-scenarios will be examined:

1. Neglect running pumps as long as possible, use stored energy/water early in the season
2. Run pumps from grid in the beginning of the season, use stored energy/water during high cost months (July)

The two sub-scenarios (while storing either energy or water) were modeled using only three wind turbines. This allows the relationship between number of turbines and payback period to be investigated. Scenario (1) was modeled and can be seen in Figure 1.2.. Throughout the beginning of the year, energy is being produced at the wind turbines and stored. When irrigation is needed, power is drawn from the storage and it begins to deplete. Once the storage is depleted, the demand is met by the grid and what is immediately being produced at the turbines.

Figure 1.2.8 - scenario (1): Use stored energy early in the season

The second scenario can be seen in Figure 1.2.. It should be noted that the total amount of energy drawn from the grid in either case (scenario 1 or 2) is the same. The advantage and decision making process into when the stored energy should be used is not one based on minimizing the amount of energy pulled from the grid, but minimizing the cost associated with using that electricity. Additionally, by not drawing any power from the grid for roughly two months, the costly demand charges associated with peak power demand can be avoided.

Figure 1.2.9 - scenario (2): Use stored energy mid season

The three scenarios also need to be compared when storing water throughout the year. While the numbers are different, similar results are obtained as the energy storage configuration. The following two figures show those results from the two scenarios.

Figure 1.2.10 - scenario (1): Use stored water early in the season

Figure 1.2.11 - scenario (3): Use stored water mid season

The different methods of storing and using energy/water were paired with two economic scenarios:

1. Status Quo: cost of electricity and demand charges equal to those from 2006.
2. Time of Use Pricing: variation in cost of electricity over the course of the year. Base rate for nine months and a graduated rate for the three summer months.

The total amount paid to the utility for each configuration can be seen in Table 4.

		Status Quo	Time of use pricing
Store Energy	<i>Use storage early</i>	\$257,342	\$275,818
	<i>Use storage late</i>	\$239,276	\$237,879
	<i>Distribute storage evenly</i>	\$299,881	\$291,644
Store Water	<i>Use storage early</i>	\$173,354	\$170,462
	<i>Use storage late</i>	\$158,532	\$158,057
	<i>Distribute storage evenly</i>	\$197,532	\$201,181
Net Metering		\$330,000	
Original		\$431,192	

Table 4. Amount paid to utility for new scenarios

It can be seen that storing water and using it late in the season yields the lowest yearly cost for electricity. Looking under the scenarios of storing energy, the configuration that

would require the lowest yearly payment for electricity is to use the storage during the most expensive months of the year. Looking at the cost for electricity does not present the entire economic situation since a considerable amount of money must be spent for capital costs to be able to generate and store energy/water. For all the scenarios considered, there is going to be the capital cost of the wind turbines. If energy is to be stored, there are capital costs associated with the CAES energy storage system. In order to store the appropriate amount of water needed for the water storage configurations, additional reservoirs will still be needed. This will increase the capital costs associated with those scenarios. The summary of all capital cost estimates can be seen in Table 5.

Capital Costs	
Storing Energy	
<i>Turbines (3)</i>	\$6,000,000
<i>CAES System</i>	\$135,000,000
Storing Water	
<i>Turbines (3)</i>	\$6,000,000
<i>Additional Reservoirs</i>	\$30,000
Net Metering	
<i>Turbines (1)</i>	\$2,000,000

Table 5 - Capital costs ⁴

If the above capital costs were incurred, and the savings in electricity were as shown in Table 4, then the simple payback periods would be as shown in Table 6.

		Status Quo	Time of use pricing
Store Energy	<i>Use storage early</i>	NA	NA
	<i>Use storage late</i>	NA	NA
	<i>Distribute storage evenly</i>	NA	NA
Store Water	<i>Use storage early</i>	23	23
	<i>Use storage late</i>	22	22
	<i>Distribute storage evenly</i>	26	26
Net Metering		20	

Table 6 - simple payback period in years. The payback period for storing energy exceeds the system's useful life; as such, it has no meaningful payback period.

Jarolimek Farms

On December 12, 2006 a site visit was made to the Jarolimek Farms near Burley. Leroy Jarolimek is one of Idaho's wind energy pioneers. He has been using a grid-connected Jacobs 20-kW WTG for net-metering for several years. Data has been collected from 5 anemometer towers, starting in 2002. There are three 20-m tower, one 30-m and one 50-m towers, each with multiple instruments. Two 10-MW PURPA projects are scheduled to be built on his farms this year. The Jarolimek farms pump groundwater to pressurize the pivot systems. The five wells range in depth from 700' – 1000'. During the most intensive pumping months, electricity bills associated with pumping total about \$10,000 per month. Anemometer data and pumping records were obtained for analysis.

Assuming use of the same turbines, neglecting wake effects or turbine placement, a single turbine could generate approximately 92% of the electricity consumed by irrigation at Jarolimek Farms. See Figure 1.2.3. This annualized comparison utilizes 2002 actual irrigation data, which is the most recent data available; and 2004 50-m met tower data, which is the most dated wind data available. In the next quarter, correlations between the 2002 & 2004 wind and irrigation seasons will begin, to better understand the annual power consumption & generation needs.

Figure 1.2.12 – Consumption based on 2002 actual data; generation estimates based on 2004 anemometer data. Production assumes 1 GE 1.5MW, 77-m rotor diameter wind turbine generator.

As indicated in Figure 1.2.12, the irrigation consumption peaked in July, remaining greater than 400 MWh June through October. As with the Southwest Idaho Farms, the estimated electricity generation from three WTGs did not vary as greatly by month as did

the irrigation consumption.

Figure 1.2.13 – production assumes 2 GE 1.5MW, 77-m rotor diameter wind turbine generators

For the initial HOMER analyses, we have assumed that the PURPA issues described above have been resolved, allowing 10.5 aMW PURPA projects, and that the avoided cost rates are roughly the same as they are now. Using these assumptions, it does not appear that PURPA wind projects will provide an economically feasible option for irrigators to offset pumping costs.

Figure 1.2.14 – system optimization comparing 0-3 GE 1.5MW, 77-m rotor diameter wind turbine generators

Figure 1.2.14 is a screen-shot of one of the system configuration optimization analyses conducted for the SWI case. This optimization compared using 0, 1, 2 or 3 GE 1.5 MW,

77-m rotor diameter grid-tied wind turbine generators to offset irrigators' pumping costs by selling power via a PURPA contract. It indicates that the scenario using zero wind turbines is the best of these options. Similar analyses for Jarolimek Farms indicate the same.

HOMER has been used to attempt to determine the price points at which a PURPA contract would be an economically feasible pumping option. Sensitivity analyses have been run, using the current grid-connected option as a base case. In comparison, several different wind generation configurations, all using GE 1.5MW machines, have been generated and sensitivity analyses have been completed.

The sensitivity analysis results are illustrated graphically in figure 1.2.15. In that figure, the grey area indicates where the current grid-tied system is most economical and the green area indicates the area where one of the wind energy configurations is most economical. As the figure shows, the cross-over points (at which the wind energy systems become economical) are as follows:

- if the irrigators' price to purchase power increased to \$0.075/kWh; or
- if the rate at which irrigators sell power to the utility increased to about &0.0675/kWh.

HOMER was allowed to consider several wind energy configurations; it selected the single-turbine option as the most feasible, which was not expected. It was expected that a multi-turbine option would be more economical than a single-turbine, given economies of scale (crane costs, road construction, etc.).

Figure 1.2.15 – sensitivity analysis of Jarolimek Farms.

If there is no economically feasible option to connect the wind turbines to the grid, there may be economically feasible options to generate, store and consume the wind power onsite and directly offset or eliminate the utility bills. The primary configuration we have investigated is a hybrid compressed fluid system, illustrated in Figure 1.2.16.

Figure 1.2.16 – conceptual hybrid compressed fluid storage system.

While many technologies have been suggested to help mitigate grid impact of wind systems, we approach the problem with the premise that overall efficiency is maximized if the number of energy transformations is minimized. Hence we focus on mechanical energy storage (direct from the rotor), specifically hybrid compressed air & liquid working fluids. While we acknowledge the potential of other methods, we believe that this method holds the most promise because the technology required to implement it is readily available. Additionally, our current work in drive train technology is a perfect fit with this mechanical energy storage solution. We are continuing to develop and analyze this system, at least to the extent of determining feasible configurations such as energy storage capacity, power transfer capacity, and costs.

Analysis - Jarolimek Farms

PURPA

HOMER was initially used to analyze the use of wind turbines to offset irrigation pumping costs. For the primary HOMER analysis, a 10.5 MW PURPA project was allowed, and it was assumed that the avoided cost rates were roughly the same as they are now. This optimization compared using 0, 1, 2 or 3 GE 1.5 MW, 77-m rotor diameter grid-tied wind turbine generators. Using these assumptions, it does not appear that PURPA wind projects will provide an economically feasible option for this irrigator to offset his pumping costs.

Net-Metering

Following the HOMER analysis of a PURPA project, it was decided to investigate the effectiveness of a net-metering contract. As it stands, Idaho only allows 100kW net-metering although some states do allow up to 2MW contracts. In this situation it was assumed that the utility would allow a 2MW net-metering power capacity. This would allow a single 1.5MW wind turbine to be used in the calculations. Under this contract, the total amount paid to the utility would be \$19,200. While this number is lower than the previous amount of \$171,690 paid in 2006, it does not include the capital costs of the turbine.

Storage

It has been determined that there is no economically feasible option to connect the wind turbines to the grid under a PURPA contract; one might exist in net-metering; but additional storage options exist. There may be economically feasible options to generate, store and consume the wind power onsite and directly offset or eliminate the utility bills. The configurations investigated are: using wind energy to 1) pump and store water, 2) store energy in the form of compressed air, or 3) both.

For the implementation of wind power and energy/water storage at the farm, two scenarios exist:

3. *Storing Water*: Connecting the turbines directly to variable speed pumps and pumping water whenever the wind blows. In this respect the water is stored in tanks until use.
4. *Storing Energy*: Implementing a compressed-air energy storage system. The turbines would be able to store energy in the form of compressed air, which could be converted into electricity when desired.

System Modeling - Jarolimek Farms

Storing Water

In order to compare the amount of energy harnessed from the wind to the amount needed for irrigation, the actual volume of water that is needed had to be determined. Since the energy used per month was known, the following relationship was used to calculate average flow rate, Q :

$$Q = \frac{\dot{W}}{\rho g h} \eta_{\text{pump}}$$

where $\dot{W}$ is the average power usage throughout the month. This flow rate was then integrated over time to obtain the volume of water pumped for a given month. Actual met-tower data from the site was used, reported at 10-minute average intervals; this process was done for the duration of one year. Summing the volume pumped from the turbines and comparing to that pumped when the pumps were simply connected to the grid yields:

Figure 1.2.17 – Volume of water needed compared to amount available from wind for one year. One wind turbine needed.

In keeping with prior analyses, this model utilizes power curves from GE 1.5MW wind turbines to estimate the volume of water one such turbine would pump from the well. The methodology was: given a wind speed, calculate the power produced at the turbine, scale by pump efficiency, calculate flow rate then integrate over time to obtain volume. A Matlab/Simulink model was created to run simulations for the duration of one year.

Figure 1.2.18 - Simulink model

Storing Energy

During the months that irrigation is not needed, it would be desirable to store the energy produced at the wind turbines for later use. While energy storage technologies are currently an active area of research, there are some feasible possibilities that could work in conjunction with a wind/irrigation system.

Compressed Air Energy Storage (CAES) is a proven technology with two successfully operating facilities in the world (Huntorf, Germany and McIntosh, Alabama)¹. These facilities use surplus energy to compress air in large underground caverns. When energy is needed, the air is expanded at the surface through a turbine and electricity is created. Cavallo notes that "...with an installed capital cost of about \$890/kW, CAES is the least cost utility scale bulk storage system available."² If a CAES system is used, energy can be stored from the end of the irrigation season (October) until the pumps are needed to be operated in the spring.

Although CAES systems that use underground storage are inherently site specific, it is estimated that more than 80% of the U.S. territory, including most of Idaho, has geology suitable for such underground storage.⁴ CAES utilizes proven technology that can be optimized for specific site conditions and competitively delivered by various suppliers.

In this case, a single turbine is not sufficient to generate *and store* enough energy to cover the demand. CAES systems have an efficiency of roughly 50%, therefore two turbines were needed instead of one to generate and store adequate energy⁴.

Figure 1.2.19 - Energy needed for irrigation and available from wind. Two turbines needed.

Results - Jarolimek Farms

Store Water

In the previous analysis, the number of turbines in each scenario was decided to be the appropriate number to avoid any payments to the utility. In the water storage scenario,

with one turbine, water is pumped from the wells and stored. When the irrigation season begins, that water is used for the next several months, being replenished as the wind blows. The level of the water storage in the system can be seen in the following figure.

Figure 1.2.20 - water storage level over time.

Store Energy

To store enough energy to operate the pumps for the duration of the irrigation season, two turbines were also needed. Figure 1.2. shows the level of energy storage in the system for the entire year.

Figure 1.2.21 - energy storage level over time.

Economics - Jarolimek Farms

The configurations of storing energy/water both required the number of wind turbines to be the appropriate amount to avoid any payment to the utility for the year. The net-metering configuration does still require a certain amount of money to be paid to the utility. Starting with the actual amount paid in the 2001 irrigation season of \$170,690, avoided costs are summarized in Table 1.

Amount paid to utility	
<i>Store Energy</i>	\$0
<i>Store Water</i>	\$0
<i>Net Metering</i>	\$19,200
Amount avoided to utility	
<i>Store Energy</i>	\$171,690.00
<i>Store Water</i>	\$171,690.00
<i>Net Metering</i>	\$152,490.00

Table 7 - amount of money paid and avoided to the utility.

In order to calculate a simple payback period for each of the above configurations, the capital costs associated with each need to be determined. Table 2 summarizes those costs for each configuration.

Capital Costs	
Storing Energy	
<i>Turbines</i>	\$4,000,000
<i>CAES System</i>	\$135,000,000
<i>Total</i>	\$139,000,000
Storing Water	
<i>Turbines</i>	\$2,000,000
	>
<i>Water tanks</i>	\$135,000,000
	>
<i>Total</i>	\$137,000,000
Net Metering	
<i>Turbines</i>	\$2,000,000

Table 8 - capital costs for each configuration.

Each scenario has capital costs associated with the purchase of wind turbines, although the amounts differ because of the different number of turbines required for the different

scenarios. From industry specialists, it was estimated that each 1.5MW wind turbine would have an approximate installed cost of \$2 million. It can be seen above that the capital cost for the CAES system is \$135 million. This amount was estimated from published figures through the Electric Power Research Institute⁴.

If water is to be stored, tanks would need to be constructed to accommodate the desired level of water storage. From Figure 6 it was shown that roughly 600 million gallons are needed to be stored for the entire irrigation season. If 150,000 gallon water tanks were used, four thousand would be needed to store the appropriate amount of water. This equates to a capital cost of over \$500 million. If the number of tanks was adjusted to maintain similar capital costs as the CAES, over one thousand tanks would still be needed. Simulating the irrigation demand with a more feasible number of tanks, twenty, yielded results that essentially contained no water storage at all.

Knowing the capital costs associated with each scenario, the simply payback period for each can be calculated. Table 3 shows these periods.

Simple Payback	
<i>Store Energy</i>	NA
<i>Store Water</i>	NA
<i>Net Metering</i>	13

Table 9 - simple payback period in years. The payback period for storing energy & water both exceed the system's useful life; as such, they have no meaningful payback period.

Since only a simply payback period was calculated for the above configurations, these numbers are an underestimate of the actual duration to pay off the initial capital. Because of the costly CAES system and required infrastructure for storing water, storing energy or water appear to be infeasible. However, the relationship between reductions in capital costs to the increases in annual payments to the utility can be explored. To reduce capital costs of the energy storing configurations, the number of wind turbines used could be adjusted. In these configurations, more money will be paid to the utility for electricity since fewer turbines are used, but initial capital is lower. To find the most effective way of using the stored energy, two different sub-scenarios will be examined:

3. Neglect running pumps as long as possible, use stored energy early in the season
4. Run pumps from grid in the beginning of the season, use stored energy during high cost months (July)

The two sub-scenarios were modeled using only one wind turbine. This allows the relationship between number of turbines and payback period to be investigated. Scenario (1) was modeled and can be seen in Figure 1.2.. Throughout the beginning of the year, energy is being produced at the wind turbines and stored. When irrigation is needed, power is drawn from the storage and it begins to deplete. Once the storage is depleted, the demand is met by the grid and what is immediately being produced at the turbine.

Figure 1.2.22 -scenario (1): Use stored energy early in the season; assumes one turbine.

The second scenario can be seen in Figure 1.2.. It should be noted that the total amount of energy drawn from the grid in either case (scenario 1 or 2) is the same. The advantage and decision making process into when the stored energy should be used is not one based on minimizing the amount of energy pulled from the grid, but minimizing the cost associated with using that electricity. Additionally, by not drawing any power from the grid for roughly two months, the costly demand charges associated with peak power demand can be avoided.

Figure 1.2.23 - scenario (2): Use stored energy mid season

The different methods of storing and using energy were paired with two economic scenarios:

3. Status Quo: cost of electricity and demand charges equal to those from 2001.
4. Time of Use Pricing: variation in cost of electricity over the course of the year.
Base rate for nine months and a graduated rate for the three summer months.

The total amount paid to the utility for each configuration can be seen in Table 4.

		Status Quo	Time of use pricing
Store Energy	<i>Use storage early</i>	\$72,814	\$77,027
	<i>Use storage late</i>	\$72,818	\$76,909
Store Water		\$0	
Net Metering		\$19,200	
Original		\$171,690.00	

Table 10 - amount paid to utility for new scenarios

It can be seen that storing water and using it earlier in the season yields the lowest yearly cost for electricity. Looking under the scenarios of storing energy, the configuration that would require the lowest yearly payment for electricity is to use the storage during the most expensive months of the year. Looking at the cost for electricity does not present the

entire economic situation since a considerable amount of money must be spent for capital costs to be able to generate and store energy/water. For all the scenarios considered, there is going to be the capital cost of the wind turbines. If energy is to be stored, there are capital costs associated with the CAES energy storage system. In order to store the appropriate amount of water needed for the water storage configurations, additional reservoirs will still be needed. This will increase the capital costs associated with those scenarios. The summary of all capital cost estimates can be seen in Table 5.

	Capital Costs
Storing Energy	
<i>Turbines</i>	\$2,000,000
<i>CAES System</i>	\$135,000,000
Storing Water	
<i>Turbines</i>	\$2,000,000
<i>Water tanks</i>	> \$135,000,000
Net Metering	
<i>Turbines</i>	\$2,000,000

Table 11 - capital costs⁴

If the above capital costs were incurred, and the savings in electricity were as shown in Table 4, then the simple payback periods would be as shown in Table 6.

Simple Payback Period (years)		Status Quo	Time of use pricing
Store Energy	<i>Use storage early</i>	NA	NA
	<i>Use storage late</i>	NA	NA
Store Water		NA	
Net Metering		13	

Table 12 - simple payback period in years. The payback period for storing energy & water both exceed the system's useful life; as such, they have no meaningful payback period.

Conclusions – Subtask 1.2

While using wind power in conjunction with an irrigation system is not a new idea, there are methods associated with analyzing the system that can provide valuable information to its applicability prior to installation. By inputting actual anemometer data, these techniques can reasonably reflect the individual site's performance of such a system. Furthermore, by having access to detailed electricity bills and pumping data, the examination between supply in the wind and demand for irrigation can be investigated. The methods described allow the freedom of examining the interaction of the wind with the pumps and storage facility throughout the duration of a year.

Although none of the scenarios examined appear economically advantageous to purchasing power from the grid, some at least appear feasible. At SWI, given the extensive canal & reservoir system already in place, the options of storing water have payback periods in the mid-twenty year range. This is not an economically attractive option in the current environment, but it could become more attractive as utility rates increase. At Jarolimek farms, neither storing energy nor water is economically feasible. However, the payback period for net-metering would be 13 years, if policies were modified to allow 2 MW systems as in some states.

One general conclusion that might be drawn from these case studies regarding energy storage is that cycle-time matters. That is, it may make economic sense to operate a CAES plant such as Huntorf or McIntosh, given the energy will be stored for less than a day before being sold to the utility. In the cases examined here, however, the energy would need to be stored for an irrigation season. It can be seen that the levelized cost of energy from storage systems is inversely proportional to number of charge/discharge cycles that occur for any given period of time.

References – Subtask 1.2

¹ Mears, L., H. Gotschall, and H. Kamath, *EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications*. 2003, Electric Power Research Institute: Concord, CA.

² Cavallo, A; Controllable and affordable utility-scale electricity from intermittent wind resources and compressed air energy storage (CAES); *Energy*; Vol 32; pp120-127; 2007

³ Succar, S. Williams, R.; *Compressed Air Energy Storage: Theory, Resources, And Applications For Wind Power*; Energy Systems Analysis Group, Princeton Environmental Institute; Princeton University; 2008.

⁴ *Energy Storage Handbook*; Electric Power Research Institute; 2006.

Subtask 1.3 Host Irrigator-Wind Energy Workshops

Boise State University researchers participated with the Idaho Office of Energy Resources (formerly the Energy Division of the Idaho Department of Water Resources) on a series of wind-irrigators workshops which occurred during 2007. Boise State University hosted the meeting on September 20, 2007.

Subtask 1.4 Present Case Study Results at Workshops

Todd Haynes and Xander Harmon presented preliminary case study results at the final meeting on September 20, 2007. Haynes was scheduled to present more complete results at the November 8, 2007 Idaho Wind Working Group meeting; however, the meeting ran over-schedule and Haynes' presentation was cut from that day's agenda.

Task 2: Active Drivetrain Control for Distributed Wind Applications

Subtask 2.1 Code assessment

There are many codes available through the National Renewable Energy Laboratory created uniquely for use with horizontal-axis wind turbines (HAWTs). Initially, one such code, SymDyn, was used to perform the aerodynamic simulation but was later changed to FAST. This code performs an aeroelastic analysis of HAWTs with implementation features into Matlab/Simulink.

Subtask 2.2 Drivetrain model

Active drivetrain control was researched on parallel tracks both at Boise State University and at Colorado School of Mines (CSM), a subcontractor to this project. Multiple models were created and updated at Boise State University using Matlab/Simulink. Initially the NREL CART turbine was modeled. The subcontractor at CSM based its research on the AOC 15/50. In order to facilitate direct comparisons between the two tracks, Boise State researchers also modeled the Entegriy EW 15/50 (formerly known as the AOC 15/50).

A MATLAB™ model containing an aerodynamic model of the NREL CART turbine was initially created. The model contains a kinematic model of the differential continuously variable transmission (DCVT) and a simple induction generator model. Figure 2.2.1 shows the block diagram overview of the model.

Figure 2.2.1: Block diagram of the dynamic model of the DCVT operation

The DCVT is shown schematically in Figure 2.2.2 and demonstrates the operation of the proposed system.

Figure 2.2.2: The Differential Continuously Variable Transmission

In the simulation, the ring gear of the second stage is driven in a manner to achieve improved performance of the system. As discussed in section 2.3, two different control laws were formulated and section 2.4 demonstrates simulation results.

None of the modeling efforts included gear train dynamics (specifically rotary inertias of the gears and compliance of the gear teeth in mesh). It is clear that the dynamics of the gear box must be taken into account, particularly since we are proposing a configuration that is new to the application.

As a first step in that direction, we have started developing a Matlab-based model of the gear box in the Micon 108 turbines at the Lewandowski wind farm. Figure 2.2.3 shows a photograph of the gearbox taken on the ground at the Lewandowski farm.

Figure 2.2.3: Photograph of the Micon 108 gearbox

Using direct measurement and solid modeling methods, we have developed a computer model of this gear box. Figure 2.2.4 shows the SolidWorks model of this transmission.

Figure 2.2.4: SolidWorks model of Micon 108 transmission

In addition, a 9th order linear model of the transmission dynamics has been developed. Figure 2.2.5 shows the schematic diagram of the gearbox with the significant components and variables labeled. The dynamic state equations are also shown.

Figure 2.2.5: Schematic diagram of the Micon 108 gearbox.

State Equations:

$$\dot{w}_1 = \frac{1}{J_1} T_1 - \frac{1}{J_1} F_1 R_1$$

$$\dot{w}_{2,3} = -\frac{1}{J_{2,3}} F_1 R_2 - \frac{1}{J_{2,3}} F_2 R_3$$

$$\dot{w}_4 = \frac{1}{J_4} T_4 - \frac{1}{J_4} F_2 R_4$$

$$\dot{w}_g = -\frac{1}{J_g} T_4 - \frac{1}{J_g} T_{load}$$

$$\dot{T}_1 = k_o (w_{in} - w_1)$$

$$\dot{T}_4 = k_4 (w_g - w_4)$$

$$\dot{F}_1 = k_1 (R_1 w_1 + R_2 w_{2,3})$$

$$\dot{F}_2 = k_2 (R_3 w_{2,3} + R_4 w_4)$$

State Equations in Matrix Form:

$$\begin{bmatrix} \dot{w}_1 \\ \dot{w}_{2,3} \\ \dot{w}_4 \\ \dot{w}_g \\ \dot{T}_1 \\ \dot{T}_4 \\ \dot{F}_1 \\ \dot{F}_2 \end{bmatrix} = \begin{bmatrix} 0 & 0 & 0 & 0 & \frac{1}{J_1} & 0 & -\frac{1}{J_1}R_1 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & -\frac{1}{J_{2,3}}R_2 & -\frac{1}{J_{2,3}}R_3 \\ 0 & 0 & 0 & 0 & 0 & \frac{1}{J_4} & 0 & -\frac{1}{J_4}R_4 \\ 0 & 0 & 0 & 0 & 0 & -\frac{1}{J_g} & 0 & 0 \\ -k_o & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & -k_4 & k_4 & 0 & 0 & 0 & 0 \\ k_1R_1 & k_1R_2 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & k_2R_3 & k_2R_4 & 0 & 0 & 0 & 0 & 0 \end{bmatrix} \begin{bmatrix} w_1 \\ w_{2,3} \\ w_4 \\ w_g \\ T_1 \\ T_4 \\ F_1 \\ F_2 \end{bmatrix} + \begin{bmatrix} 0 & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & -\frac{1}{J_g} \\ k_o & 0 \\ 0 & 0 \\ 0 & 0 \\ 0 & 0 \end{bmatrix} \begin{bmatrix} w_{in} \\ T_{load} \end{bmatrix}$$

Investigation of different CVT configurations

The subcontractor at Colorado School of Mines carried out a parallel research track based on a belt/pulley CVT system. The CSM system has been modeled using input files for the 50kW AOC 15/50 WTG. In order to facilitate a direct comparison between the 2-stage planetary CVT modeled at Boise State and the belt/pulley CVT modeled at CSM, it is necessary to use the same input files. As such, we have begun working with input files for the 50kW Entegriy EW 15/50, which is a later version of the AOC. (Entegriy purchased AOC and changed the name; we are aware of no significant changes in the turbine's design.)

When implementing a unique design for a gearbox into a wind turbine model, it is necessary to have a reliable, substantiated aerodynamic model for the turbine to begin with. There are many different options available when performing aerodynamic simulations. However, there are many codes available through the National Renewable Energy Laboratory created uniquely for use with horizontal-axis wind turbines (HAWTs). Initially, one such code, SymDyn, was used to perform the aerodynamic simulation but was later changed to FAST. This code performs an aeroelastic analysis of HAWTs with implementation features into Matlab/Simulink. After careful examination of how FAST works and of the inputs/outputs a verification study was required. A 15-meter, 50kW, 3-bladed Entegriy wind turbine was modeled and input into FAST. It was believed that if the power curve for this turbine could be re-created, then the legitimacy of the model would be established. Since the power curve from the manufacturer is taken from actual, real world data, corrections to the airfoil data would have to be made to correct for 3-dimensional spanwise flow (as well as other aerodynamic inconsistencies). Figure 2.2.6 shows plots of the power curve developed using FAST and the manufacturer's power curves on the same axes.

Figure 2.2.6: EW 15/50 power curves, one from manufacturer and one developed with FAST.

The power curve developed using FAST is a reasonably good approximation to that provided by the manufacturer. With some minor modifications, we are now ready to use EW 15/50 inputs to directly compare the 2-stage planetary and belt/pulley CVT systems.

Subtask 2.3 Develop variable drivetrain control laws

A graduate student supported on the project, Nathaniel Haro, completed his research and contributed significant results regarding the effectiveness of the DCVT in wind turbine applications. Following are typical results.

For wind speed changing in a step-wise fashion, the following figures show the response of the turbine in three different operating modes. The first mode (shown in black lines) shows the response expected from a fixed gear ratio gearbox turbine. The second (shown in blue) is the response predicted with the DCVT controlled to maintain a constant generator speed. Finally, the red line shows the predicted behavior if the DCVT is used to maintain a constant tip speed ratio (TSR).

Figure 2.3.1: Rotor shaft speed of simulated turbine in response to step-wise changes in wind speed.

Figure 2.3.2: Generator shaft speed in response to step-wise changes in wind speed

Figure 2.3.3: Shaft speed of ring gear (control input) for the turbine under step-wise changes in wind speed.

Subtask 2.4 Assess control law stability and usability

Stability of the ensuing control schemes is a crucial issue. With the completion of a functional simulation model, suitable control schemes have been developed.

A standard proportional integral derivative controller was chosen to aid in controlling the system. In order to determine appropriate controller constants, the system was first modeled in state-space form. To aid in this transformation Matlabs *linmod* function was utilized. This function “extracts the continuous- or discrete-time linear state-space model of a system around an operating point.” By using *linmod* to control the ring gear of the second stage planetary gear train around the operating point, the tip speed ratio, the following state-space model was returned.

$$\begin{bmatrix} \dot{\theta}_r \\ \dot{\omega}_r \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ -0.4989 & 0 \end{bmatrix} \begin{bmatrix} \theta_r \\ \omega_r \end{bmatrix} + \begin{bmatrix} 0 \\ 0.0578 \end{bmatrix}$$

Equation 1

$$\lambda = \begin{bmatrix} 0 & 1.167 \end{bmatrix} \begin{bmatrix} \theta_r \\ \omega_r \end{bmatrix}$$

Equation 2

From this set of equations the output λ is independent of its position and is only dependent on the input speed of the ring gear. This is what should be expected since the power generated by a wind turbine is a function of its rotational speed and torque rather than the position of the blades. However, this position is used within the model by SymDyn when calculating the torque generated by the turbine blades, taking into consideration the blade position when determining tower shadow. Tower shadow affects

how the wind flows around the turbine tower, usually slowing down the wind in front of it, which in turn reduces the torques associated with the blade in front or behind it.

Since these are the state-space matrices for the system without the PI controller the matrices will be the same if one was to use the generator torque as the input. From these equations λ for the undamped system can now be represented as:

$$\lambda = \frac{0.0963}{s + 0.4989} \omega_r \quad \text{Equation 3}$$

which is a first order system with a single pole. Once we add the PI controller, an additional pole, located at the origin and an additional zero are added to the system. It is the placement of the additional zero that determines how the PI controller will operate. When adding a PI controller into the Matlab model the signal is modified and can be represented in the form of:

$$\lambda = \left(\frac{K_D s^2 + K_P s + K_I}{s} \right) \left(\frac{0.0963}{s + 0.4989} \right) \omega_r \quad \text{Equation 4}$$

In the preceding equation K_P , K_I , and K_D are the constants associated with the PI controller.

Constant Generator Speed Pole and Zero Location

The PI controller for the constant generator speed model was designed so that the variation in the generator speed was minimized with a change in wind speed. This was accomplished by placing the location of the controller defined zero far to the left of the two poles, along the real axis. This position produces the root locus plot shown in Figure 2.4.1. The point where the loci return to the real axis is the point where, for the given zero location, the system produces the quick response time as well as reducing the oscillations produced by the controller. It was determined that a zero located at $-20+0i$ was adequate for this system, producing minimal variance in the generator speed, and yielding an equation for the PI controller in the following form:

$$G_c(s) = K_G \left(\frac{s + 20}{s} \right) \quad \text{Equation 5}$$

At this point the controller gain, K_G , was read off of the root locus plot of the controlled system, shown to be 79 in Figure 2.4.1 below.

Figure 2.4.1 Damped Constant Generator Speed System

Comparing the coefficients of Equations (4) and (5) would then yield the values for the controller coefficients. In the case used in the system, and shown above they were as follows:

Constant Generator Speed Controller Coefficients	
K_P	79
K_I	1580

This process was repeated several times, implementing the new PI controller values for each zero location until the results produced a controller that was favorable, which are the results shown above.

Constant Tip Speed Ratio Pole and Zero Location

In a similar fashion, the pole location for the constant λ controller was placed at

$$G_c(s) = K_G \left(\frac{s + 0.75}{s} \right) \quad \text{Equation 6}$$

producing the following root locus plot and controller coefficients.

Figure 2.4.2 Damped Constant Tip Speed Ratio System

Constant Tip Speed Ratio Speed Controller Coefficients	
K_P	1.87
K_I	1.4

It is relevant to mention that the PI controller for the constant λ is slower than the controller for the constant generator model. Since the dynamic response of the rotor is much slower than that of the generator, due to its large mass, a controller with the same response time is not necessary. In fact, if a controller with a similar response time is used the controller is then used to increase and decrease the rotor shaft speed, instead of allowing the wind to do so.

FAST aerodynamic model

A more sophisticated aerodynamic model known as FAST has been incorporated into the drivetrain model. Previously, a model was created for the CART turbine using SymDyn for aerodynamic calculations. FAST is an improvement over SymDyn for the nonlinear aerodynamic modeling of a wind turbine. This improved product generates a solution of higher fidelity than its predecessor according to NREL's included documentation. In addition to utilizing an improved aerodynamic model, the turbine parameters have been altered to reflect the EW 15/50 rather than the CART turbine. With these changes, the following objectives were established:

1. Develop a drivetrain model to interact with the FAST aerodynamics model
2. Strategically introduce a controller to the model and verify its operation with temporary controller parameters
3. Compare the power production of the model controlled for optimal tip speed ratio with the uncontrolled turbine over region 2, that portion of the power curve between cut-in and rated power
4. Alter the default FAST initialization script such that batch simulations with varying parameters are possible
5. Linearize the model using MatLab's built-in subroutines
6. Use linearization data at multiple operating points to determine if one set of control parameters will suffice or if a lookup table ought to be generated
7. Optimize the controller parameters for operating points based on findings from (6)
8. Add spring-mass-damper models to every moving part in the drivetrain to achieve more accurate system dynamics
9. Add a complex model of both control and production generators to replace the current simple models
10. Re-iterate the controller optimization procedure having added (8) and (9)

Figure 2.4.3 - Base Level SimuLink Model

Figure 2.4.3 shows the FAST model embedded within the EW 15/50 wind turbine system model which includes the drivetrain with a simple induction generator. The blade pitch and the yaw position inputs to the FAST model are set to zero in order to focus completely on the effects of a variable speed transmission.

Figure 2.4.4 - Drivetrain Block from SimuLink Model

Figure 2.4.4 shows the contents of the Drivetrain block from Fig. 2.4.3. Here the tip speed ratio (TSR) is calculated and fed into the controller. The controller, located at the second stage ring gear, applies a torque which is transmitted throughout the drivetrain in the Drivetrain Equations block. Using equations for the gears and the induction generator, all speeds and torques are found and sent to a Measurements block where the data is stored for later retrieval. In addition, the low speed shaft torque and speed are combined and form the feedback loop to FAST.

Figure 2.4.5 - Drivetrain Equations Block from SimuLink Model

Each of the three blocks in Fig. 2.4.5 contains the gearbox and generator equations. These equations have been rearranged compared to the work done with the previous CART SimuLink model in order to reflect a change in controller output. Where the previous models used the speed at the second stage ring as an output, this model uses torque. This provides a more realistic model and prepares for the addition of frictional and compliance losses at each shaft and gear mesh. When those losses are added, inertias and elastic compliance will also be added because while they do not change the energy lost in the drivetrain, they do affect the dynamic behavior of the system and therefore may have an effect on the optimal controller parameters.

Controller optimization is one of the primary goals of this effort. The primary input to the controller for this WTG is the tip speed ratio. It was known that there is an ideal tip speed ratio that will capture the most power out of the wind. We sought to determine what this tip speed ratio was, and how it varied with wind speed.

Modifying the FAST model, the generator was “disconnected” and the turbine was free to spin, uncontrolled. The initial rotor speed was started at zero while the wind was fixed at a certain value (in this case 5, 10, or 15 m/s). We anticipated the rotor speeding up well past stall while the torque should increase to a maximum, then decrease. After the simulation was run, the tip speed ratio, λ , and power coefficient, C_p , were calculated.

$$\lambda = \frac{\omega R}{U} \quad \text{Equation 7}$$

$$C_p = \frac{P}{1/2 \rho A U^3} \quad \text{Equation 8}$$

Figure 2.4.6 – Rotor Speed vs. time

Figure 2.4.7 – Aerodynamic torque vs. time

Figure 2.4.8 – Power coefficient vs. time

As can be seen in Figure 2.4.6, the rotor speed increases slowly, then dramatically, then slowly again as the entire blade is stalled. Figure 2.4.7 illustrates that the torque increases until a maximum is reached then quickly decreases. When these two are related through tip speed ratio and power capture (equations 7 and 8), the relationship can be seen in the Cp-TSR curve, Figure 2.4.8. What was unexpected is that while rotor speed and torque differ for each wind speed (both in the maximum value and rate at which they change), the percent of power captured from the wind remains the same. Thus, while the turbine is generating more power at higher winds, it is still only taking roughly 30% out of the power available in the wind. The theoretical maximum that could be achieved is 59%, the Betz limit. From this analysis, it can be seen that the controller should attempt to regulate the turbine to always be operating at a tip speed ratio of roughly 5.5 regardless of wind speed. The TSR of 5.5 is optimal only for the given aerodynamics of this rotor blade; a change in aerodynamics would affect the optimal TSR.

Figure 2.4.9 – Graphical Output from a Simulation with Controller Enabled

After only a handful of trial and error simulations, temporary PID parameters were chosen to facilitate a working, controlled model. Figure 2.4.9 shows how for a given windspeed the controller reacts to the turbine's tendency to rotate faster than is optimal. The control motor changes its torque and consequentially it's speed as well, which changes the steady state speed of the turbine to one that corresponds to the optimal tip speed ratio of 5.5.

Figure 2.4.10 – Power Comparison - Controlled vs. Uncontrolled

Finally, Fig. 2.4.10 shows the current comparison of the controlled and uncontrolled models. As expected, this graph indicates that the current uncontrolled model is well designed to run at a near optimal TSR over a quite useful range of wind speeds. Here the performance between 8 and 10 m/s is very close to optimal, but the 4 to 8 m/s range experiences a reduction in power efficiency. At these lower wind speeds it is not surprising to see that the uncontrolled turbine deviates from the ideal TSR while the controlled turbine maintains maximum efficiency. How useful these gains are will depend upon the later additions of controller optimization and gear train inefficiencies (which are currently missing from both models). At the present time, however, the added power capture appears to be significant, particularly in locations where the wind is more likely to fall in the lower half of region 2 much of the time.

Linearization

If a PI controller is chosen, optimization requires that the FAST model be linear. Since the aerodynamic torque is nonlinear with respect to wind speed and rotor speed, it is not surprising to find that the FAST model is nonlinear as well. An operating point was chosen such that the TSR would be 6.1 with a wind speed of 6 m/s. Three linearization methods were attempted, two of which produced results.

The unsuccessful method involved utilizing SimuLink's built-in methods of block linearization. It appears that the solver used in SimuLink's linearization process is incompatible with the FAST block and after much effort this method was abandoned.

The second method allowed FAST to run its own linearization routine. By changing some of the runtime parameters and executing FAST from the command line, a linear state space model can be generated based on given operating point values for wind speed and rotor speed. Recall that rotor speed is directly proportional to TSR when the wind speed is constant and therefore specifying a rotor speed is effectively the same as specifying the TSR.

The final method involved small manual perturbations of the state variables and inputs, rotor speed and controller torque respectively, while observing the output (rotor acceleration). This was accomplished using the SimuLink model, making small changes to the operating point conditions and plotting the changes. Presently, the results from the two methods do not agree well. Future work will attempt to reconcile these two methods.

A concurrent task was to develop three dimensional data relating rotor aerodynamic torque to rotor speed and wind speed. This is the very same relationship that is being linearized in the preceding discussion. If a good surface fit can be found for this data, then gain scheduling may be utilized so that the controller can operate optimally at more than a single wind speed (the operating point value used for linearization). This data has now been generated with sufficient resolution to provide accurate gain scheduling. Once a linearization method is chosen, controller gains can be generated for many combinations of rotor speed and wind speed which will further improve the overall efficiency of the turbine in region two.

Previous efforts at linearization produced results that were inconsistent. Further investigation revealed errors in two of the methods that, once corrected, now agree with the third method. The most accurate of the three used FAST's built-in linearization routines, but was also the slowest. However, it was discovered that the linearization routine's batch file could be called using a MatLab script and the new looping capabilities made this the best method for obtaining linearization parameters for a wide range of wind speeds. Using this method, the turbine's aerodynamic model was linearized at wind speeds between 4 and 9 m/s.

Analysis of the linearized system revealed that many of the important parameters varied significantly with the changing wind speed, meaning a single set of controller gain values may not perform well compared to gain scheduling based on wind speed and rotor speed. The problem with this gain scheduling approach is that it is difficult to accurately measure the wind speed near a working turbine. It is not clear whether gain scheduling with uncertain wind speed values would prove more effective than a midrange setting of controller gain that works reasonably, while not optimally, at all wind speeds.

Further complications arise when realistic, time-varying, wind data is used instead of the constant or stepped wind used to for linearization and other early analysis. With

controller gains that seemed to work well with small incremental changes in wind speed the time-varying wind causes the turbine to respond too aggressively. Lowering the proportional gain and integrator gain lets the controller respond slower which is better for structural components, but tends to allow the tip speed ratio to wander significantly from its optimal value. Simulations show that up to a certain point, relaxing the controller doesn't seem to have a drastic negative effect on the power gained by the variable speed operation of the gear train, but the loads are significantly reduced. This is because even when the controller is responding too aggressively, it still does not manage to keep the TSR at 6.1. There is no feasible way for a turbine to adjust its speed to account for wind gusts as the stresses experienced by the system due to inertia would far exceed the maximum allowed. Instead, the best that can be accomplished is to follow the average wind speed and we discovered that lower controller gains accomplish this quite well. Figures 2.4.11 and 2.4.12 show the results of a 200 second test with time varying winds with a mean speed of 6 m/s. The average power gained through variable speed operation is 5.58 percent.

Figure 2.4.11 – Power splitting with varying wind and mean speed of 6 m/s

Figure 2.4.12 – Tip Speed Ratios with varying wind and mean speed of 6 m/s

The turbine model was modified to include control generator parameters that can be changed to reflect realistic values (see Fig. 2.4.13). This allows control generator size to be an additional parameter to help determine appropriate gear ratios in the epicyclic gear train (EGT). Tests were carried out to investigate the power split between the two generators at various wind speeds and gear ratios, the results of which can be seen in Figs. 2.4.15 – 2.4.18. An additional fixed speed gear on the shaft connecting the control generator and the second stage ring gear will allow for a smaller generator as it allows the power sent to the control generator to be a combination of speed and torque that matches the performance limits of the generator. Notice that with the present set of gear ratios the control generator must carry about 10-30 percent of what the main generator does. In this case, of course, the control generator is actually acting as a motor. It may be preferable to select gear ratios that allow it to act as a generator through much of region two so that less power will flow through the transmission and both power losses and mechanical fatigue will be reduced. A method has yet to be developed to select optimal values for the gear ratios.

Figure 2.4.13 – Drive train with additional control generator parameters

Figure 2.4.14 – Stepped wind speed schedule for controlled turbine power split test

Figure 2.4.15 – Power splitting for controlled turbine

Figure 2.4.16 – Gear train speeds for controlled turbine

Figure 2.4.17 – Gear train torques for controlled turbine

Figure 2.4.18 – Tip speed ratio for controlled turbine

Conclusion – Task 2:

As is often the case when a research project winds up, as many new questions remain as have been answered. That said, the work of this task leaves us with a significant contribution to the body of knowledge regarding wind turbine transmission. Through this project, we have proposed an innovative technique to achieve the benefits of continuously variable transmission through the use of fixed-mesh gear trains. In addition, we have developed a set of tools that enable us to analyze the benefits achieved and, at least as important, develop the control laws that will be required to implement these approaches.

This work will continue beyond the life of the current contract. We have submitted subsequent proposals to governmental agencies and have had discussions with a wind turbine manufacturer for which this technology is particularly attractive. Finally, we are preparing several scholarly papers for publication with the goal of placing these results in the archival literature.

Task 3: Turbine Rotor Design for Distributed Wind Application

Subtask 3.1

A team of undergraduate mechanical engineering students performed this task. The undergraduate researchers worked with two Boise State engineering professors – one fluid mechanics expert and one expert in solid mechanics, materials and dynamics.

The team of mechanical engineering students narrowed its focus to the 20-100 kW power range. This is due in part to the need for replacement blades on re-conditioned machines which are being taken offline at older windfarms, such as those in California. While many components are available for re-conditioning, our industry partners have indicated that replacement blades are scarce.

The team selected 100-kW as its target power rating so that if new blades were built they could be installed on one of the windturbines at Lewandowski Wind Farm for direct comparisons to existing Micon 108 rotors.

Subtask 3.2 Review Aerodynamic Codes

The team investigated the NREL wind turbine design codes, WTperf, Aerodyne, PropID and FAST. The Blade Element Momentum theory, the foundation for the aerodynamic content in these codes, was reviewed and preliminary calculations performed based upon the NREL S809 airfoil to compare with results from these codes to ensure their proper use. The codes have been previously verified and in cases certified for wind turbine design. Airfoil profiles and associated aerodynamic data for wind turbine applications are being collected.

Subtasks 3.3 & 3.4 Blade Profile Selection & Aerodynamic Design

A variety of Airfoil families were selected from the NREL database and evaluated based upon their ability to produce high torque and low drag near the hub in 100 kW turbine applications.

Aerodynamic Evaluation – Airfoil input data files were formatted and executed in the program WT Perf (wind turbine performance). This program uses blade element theory to perform an aerodynamic performance analysis. Two output files show overall turbine performance (power, torque, pressure, etc. vs. wind speed) as well as performance data for individual blade segments. Preliminary results indicate substantial improvement in performance over the pre-existing Micon blades at the Lewandowski Wind Farm.

The following airfoil was selected:

- Style: **NREL S-818**
- Stall Angle: **12.5°**
- Zero Lift Angle: **-5.31°**

Subtask 3.5 Rotor Structural Design

Material/Structural Evaluation – Power and rotational speed requirements were used to calculate an approximate force distribution along the blade. A structural analysis was then carried out using a cantilever beam analysis, with the help of COSMOS Finite Element software, see Figure 3.5.1.

The FEA yielded the following results.

- Max Stress: **19 MPa**
- Mean Wall Thickness: **0.25"**

These results will allow the use of less expensive materials which will reduce the overall cost of the blade.

Figure 3.5.1 - Finite Element Analysis

Subtask 3.6 Design Analysis and Review

The rotor blade previously developed based on the S-818 airfoil was further analyzed. The original blade, developed by a team of undergraduate students, did not have any twist to its profile. The profile has been refined to include a twist, and an analysis of its performance compared to the original has begun. Figure 3.6.1 plots normalized power curves of the blade with and without twist.

Figure 3.6.1 – Normalized power curve comparing originally proposed blade without twist to a blade with 5° twist.

Of primary interest was determining which blade shape will increase torque at wind speeds up to rated speed. To investigate this, a series of analyses investigated which blade section contributed most to torque at a given wind speed and rpm. For a given wind speed, this was analyzed for a series of rotor rotational speeds; then another wind speed was chosen and the analysis is repeated. These results of these analyses are demonstrated in Figures 3.6.2 and 3.6.3.

Figure 3.6.2 – Torque distribution as a function of blade length for various rotational speeds with wind speed = 15 m/s

Figure 3.6.3 – Tangential Force as a function of blade length for various rotational speeds with wind speed = 15 m/s

Through research it has been found that modeling a wind turbine's performance does not accurately replicate real-world test data. While there are many factors that contribute to this, one in particular is that the aerodynamic model does not consider 3D flow effects. In the FAST model used, lift and drag coefficients for each blade section were taken from empirical data (wind tunnel testing). These numbers are representative of 2D flow only. In reality the flow has a spanwise component which causes different performance for the blade element: a different effective cross-section as seen by the wind leads to a different effective chord and different flow characteristics over that area. If this difference in performance is significant, the model must be modified to account for it.

As air flows over a rotating blade, there is a component in the spanwise direction. Using Fluent™, a Computational Fluid Dynamics program, the modified performance of the blade can be estimated. The methods associated with this study were as follows:

1. Model the geometry of the turbine blade in SolidWorks™
2. Obtain 2-D cross sections at a certain point along the blade at various angles.
3. Using Gambit, create mesh files around the airfoil and computational domain
4. Import mesh files into Fluent™ and run the simulation
5. Perform data analysis/postprocessing of Lift and Drag forces/coefficients in MS Excel

Once the simulation is run for different cross section angles of the blade, at different angles of attack, its performance can be estimated.

Figure 3.6.4 – Illustration of spanwise flow

Figure3.6.5 – close up of quadrilateral mesh surrounding airfoil

Figure 3.6.6 - 10 degree cross section Velocity contour

Figure 3.6.7 - 20 degree cross section Velocity contour

Figure 3.6.8 - 20 degree cross section Velocity vectors

Figure 3.6.9 – Comparison of lift coefficients at different effective air- flow directions over the blade due to spanwise flow effects.

It has been concluded that in order to accurately model the wind turbine's real-world performance, the effects of spanwise flow must be considered. Currently there are several correction models available that relate theoretical models to empirical data. NREL distributes an Excel program, AirfoilPrep, which not only prepares airfoil data tables for input into their modeling codes, but comes equipped with a 3-D correction factor as well. Thus, it was decided to use AirfoilPrep to create the airfoil tables to be used in this model. Nine files were made in order to smoothly blend the changing airfoil cross sections.

In completing Task 3, investigation of spanwise flow effects has been identified as an area for further research. Spanwise flow investigation falls outside this project's scope. No further research was conducted on Task 3 or any of its subtasks as part of this project.

Task 4: Electric Generators for Distributed Wind: Novel and Innovative Designs

The main goal of this task was to investigate viable non-conventional electric generators for wind energy generation. New criteria for selecting generators involve size/price/power and the ability to run at multiple speeds when connected to a grid. We began by looking at two promising technologies: three-phase written-pole generators and wound-rotor induction generators that can be reconfigured into series-connected induction generators.

The task involving written pole generators was obviated. The primary reason is that the manufacturer of written-pole machines was not interested in designing and building written-pole generators that would run at several discrete speeds. All of our efforts focused on wound-rotor induction machines which can be reconfigured as series-connected induction machines. These machines can essentially run at two different speeds with the same sets of stator and rotor windings reconnected externally through slip rings. Slip ring technology is advanced enough not to create high maintenance issues for small machines in a range less than 100 kW.

Subtask 4.1 Assess availability and applicability of written-pole technology for distributed wind energy

This task was obviated and not considered. The primary reason is that the manufacturer of written-pole machines is currently not interested in designing and building written-pole generators that would run at several discrete speeds.

The manufacturer told us that a three-phase written-pole generator would be built using three conventional stator windings and a concentrated stator exciting coil in addition to a continuous layer of permanent magnetic material on the surface of the rotor. The stator currents influence the rotor magnetic layer and provide a hysteresis torque.

A squirrel-cage is added under the magnetic layer for additional starting torque. The high resistance rotor cage is designed for 20% slip or more as the hysteresis torque brings the rotor to partial speed before the exciter coil is energized with alternating current at line frequency. A pole pattern is written on the rotor magnetic layer that is synchronous with the stator field. The phase relationship of the written poles and the rotating magnetic field causes the rotor to accelerate with maximum torque at synchronous speed. The exciter coil can be then turned off as the machine operates as a permanent-magnet synchronous machine.

A machine design with multiple discrete speeds would involve a separate set of three-phase stator windings and an additional exciter coil for each additional speed. This machine would be bulky for three or more discrete speeds and its advantages over similar multi-pole synchronous machines or induction machines are not clear at this point except for low starting currents, high starting torques, and high efficiencies.

Subtask 4.2 Theory and analysis of series-connected induction machines

A series-connected induction machine (SCIM) is a conventional three-phase wound-rotor induction machine (WRIM) with slip rings and which has been reconfigured by connecting its stator and rotor windings in series and with opposite phase sequence. For example, such a machine can be obtained by connecting the stator *phase a* winding in series with the rotor *phase a* winding, the stator *phase b* winding in series with the rotor *phase c* winding, and the stator *phase c* winding in series with the rotor *phase b* winding.

This machine has two modes of operation when connected to the grid: An asynchronous mode of operation like a conventional induction machine and a super-synchronous mode of operation like a synchronous machine. In the asynchronous mode of operation, the shaft speed is either below (motor regime) or above (generator regime) synchronous mechanical speed. In the super-synchronous mode of operation, the shaft speed runs at twice the synchronous mechanical speed. For example, the shaft of a two-pole 60-Hz machine would run at 7200 rpm; that of a four-pole machine at 3600 rpm, and that of a six-pole machine at 2400 rpm. As a standalone self-excited generator with capacitor banks in parallel with the series stator-rotor windings, the machine produces sinusoidal voltages and currents synchronized at half the electrical synchronous shaft speed. Thus, while a four-pole conventional self-excited generator running slightly above 1800 rpm would generate 60-Hz voltages and currents, the same machine reconfigured as a series-connected self-excited generator and running at about 1800 rpm would also generate 30-Hz voltages and currents. This SCIG would have to run at 3600 rpm to generate 60-Hz voltages and currents.

An immediate advantage as a standalone wind generator is that this machine is capable of running at two different speeds depending on whether it is connected as a conventional induction generator or a series-connected induction generator. Such a machine can easily be retrofitted to operate in either mode by modifying the stator and rotor connections.

The operation in the super-synchronous mode of operation is well understood in the current literature. In this mode, the machine can be viewed as a high reluctance synchronous machine. However, there is no current theory or equivalent circuit to explain the asynchronous mode of operation. Moreover, the stand-alone mode of operation as a self-excited machine cannot be easily explained and is also lacking a circuit model.

The goal of this subtask was to expand the theory of series-connected induction machines and to develop new circuit models to explain their different modes of operation. It was also hoped that these circuit models would shed new light on important parameters affecting the operation of this machine such as the stator-to-rotor turns ratios and the amount of capacitance needed for standalone self-excitation.

A new circuit model for an SCIM was successfully developed to explain the asynchronous mode of operation with such a machine connected to the grid. The dynamic modeling of the SCIM in the asynchronous mode of operation was extended

using an augmented dynamic model which, when averaged, explains the induction machine behavior of the SCIM in its asynchronous mode of operation. A formal presentation on this subject was delivered at the University of Illinois at Urbana-Champaign on March 26, 2007.

Subtask 4.3 Experimental self-excitation of series-connected induction generators

For standalone wind energy applications, a wound-rotor induction generator can be retrofitted to operate in an optimal fashion at two different wind speeds, the higher one being twice the lower speed. This is an advantage in areas where wind speeds vary over a wide range.

An experimental setup verified the optimal strategy for switching the induction machine from one configuration to another to take advantage of the changing wind speeds. All tests were conducted in-house using laboratory equipment. The wind turbines were replaced by prime-movers to substantiate the theoretical results.

Work focused on obtaining the above experimental saturation curve for our small laboratory induction machine. The nominal stator-to-rotor turns ratio is 2:1, meaning that the rotor windings are rated at 104 V whereas the stator windings are rated at 208 V line-to-line. Unfortunately, the experimental curve barely shows the beginning of the saturation region, see Figure 4.3.1. The purchase of a new induction machine was contemplated in order to generate a better experimental curve. Instead, we decided to use a standard saturation curve found in the literature to generate the synthetic data needed to verify the validity of the steady-state circuit model of a self-excited series-connected induction machine. This model was used to predict the voltage build-up of a series-connected induction machine when driven at a constant speed.

Figure 4.3.1 – Saturation Curve of Wound-Rotor Induction Machine

The comprehensive modeling of series-connected induction machines connected to the grid or operating as standalone self-excited machines was presented during a College of Engineering seminar series before an IEEE audience on December 4, 2007.

Task 5: Lewandowski Legacy Wind Farm Automation & Monitoring

Lewandowski Farms, Idaho's first commercial windfarm – comprised of 3 Micon 108 wind turbines, is located about 24 miles from the Boise State College of Engineering. At the commencement of this project, the wind farm was operational and selling electricity to Idaho Power Company via a PURPA contract. The wind turbines were refurbished and modified by the late Bob Lewandowski. The windfarm's current owners agreed to make the turbines available to the College of Engineering as a test bed for wind energy research projects. The turbines have no automation or remote monitoring capabilities.

Subtask 5.1 Assess current state of control panels

This task was largely completed in the project's first spring. The panels are each different from each other, and were not built in a professional manner. They were built sequentially by Mr. Lewandowski, who was a farmer and tinkerer. As such, many corners were cut in the purchase of equipment as well as in craftsmanship. The controls operate on relay logic, not Programmable Logic Controllers (PLC's).

A team of Electrical Engineering undergraduate students completed its capstone design project by modeling the solid state power electronics which control the Micon 108 induction generators. The model can be used to assist in creation of a laboratory mock-up, simulating the actual controls on the WTGs. Together, the model and the scaled mock-up can be studied and allow the project team to gain a deeper understanding of the induction motor control system. This information could be used installing and implementing the PLCs. On December 30, 2006, the undergraduate team visited the Lewandowski Wind Farm to gather pertinent data from the 3 (dissimilar) wind turbine control panels.

Subtask 5.2 Specify and order PLC's

Boise State University researchers had in discussions with the Kotzebue Electric Authority (KEA) in Kotzebue, Alaska, beginning in early December 2006. KEA owns and operates 15 Entegriety EW 15 WTGs. They had replaced the Automation Direct PLCs with newer controllers. We had discussed either purchasing the used PLCs or the possibility that they might donate the PLCs to Boise State University. The negotiations with KEA were unsuccessful. As such, we investigated purchasing new equipment.

In February and March 2007 local control systems experts toured the windfarm to gather information and prepare bids. We received a favorable bid from Diversified Control Systems of Boise, ID. That bid included 3 Allen Bradley MicroLogix PLC systems, materials to install the systems, controls engineering, software development, rebuilt electric panel boxes, and panel box drawings. During the prior quarter, efforts were made to finalize work scope and system price with DCS.

As part of the negotiations with DCS, a potential Conflict of Interest became apparent. The COI arose from Todd Haynes' dual roles as this research Project Manager and co-owner of the Lewandowski Wind Farm. Mr. Haynes' interests were fully disclosed to

Boise State University Administrators and to US DOE program coordinators. To proceed, Boise State legal counsel must define a conflict management plan for proceeding with the PLC procurement process.

Simultaneously, the Micon wind turbines at Lewandowski Farms were decommissioned on August 1, 2007. No attempt was made to move forward with PLC procurement while the windfarm owners attempted to resolve their long-term plan. This task's resources were reallocated to Task 1.

Subtask 5.3 Install and Program PLC's

This subtask has been eliminated.

Subtask 5.4 Develop experimentation protocols for turbines

This subtask has been eliminated.

Task 6: Project Management, Reporting and Outreach

Subtask 6.1 Coordinate with Idaho Wind Working Group

The Boise State University researchers involved in this project worked closely with the Idaho Wind Working Group during this project. Representatives attended each working group meeting, as well as the wind-irrigators-nexus technical working committee meetings. BSU researchers made presentations on progress at the final wind-irrigators meeting.

In 2008 Boise State was named one of six *Wind Application Centers* in the nation as part of **Wind Powering America's Wind for Schools** program.

Patents:

None

Publications / Presentations / Travel:

Presentations

Todd Haynes and Xander Harmon presented Task 1 preliminary case study results at the final meeting on September 20, 2007. Haynes was scheduled to present more complete results at the November 8, 2007 Idaho Wind Working Group meeting; however, the meeting ran over-schedule and Haynes' presentation was cut from that day's agenda.

Nathaniel Haro's work on Task 2 was presented in a poster at the American Wind Energy Association's Windpower 2007 Conference & Exhibition in Los Angeles.

Dr. Said Ahmed-Zaid delivered a formal presentation on Task 4 at the University of Illinois at Urbana-Champaign on March 26, 2007. Further results were presented at a Boise State University College of Engineering seminar series before an IEEE audience on December 4, 2007.

Publications

None

Travel

Various members of the Boise State University research team attended the American Wind Energy Association's Windpower Conference & Exhibitions in Pittsburgh (2006), Los Angeles (2007) and Houston (2008).

Todd Haynes attended the Wind Resource Assessment Workshop, sponsored by AWEA and CanWEA, held September 13 & 14, 2006, in Syracuse, NY.

Todd Haynes traveled to the two wind-irrigator case study sites as described in the Status section, Subtask 1.2. Travel dates were November 8 and December 12, 2006.

Todd Haynes and John Gardner attended the Center for the New West's Sun Valley Energy Roundtables in Sun Valley, Id., on November 30 and December 1, 2006. Travel dates were November 29 and December 3, 2006. The conference included presentations by key representatives of energy businesses and energy policy makers, including members of congress, U.S. senators and state and local political leaders from the western U.S.

James Ferguson and Anthony Paris attended the 45th AIAA Meeting and 27th ASME Wind Energy Symposium in early January, 2007.

On February 22, 2007, Todd Haynes (Boise State) visited Malad, Idaho and toured the area with the school district superintendent and Kurt Myers (Idaho National Lab) in an effort to locate the best site for a wind turbine. The Malad School District has secured a

used wind turbine which they intend to use to offset electric costs and educate students. The turbine is a Nordtank 65-kW which was taken offline from a windfarm in Southern California.

On February 23, 2007, John Chiasson, John Gardner and Todd Haynes visited the Idaho National Laboratory to discuss and explore collaboration opportunities.

Dustin Shively, graduate research assistant, attended the AIAA annual conference in Reno, NV in January 2008.

Project Schedule and Milestones Award No. DE-FC36-06GO86101

Task Number	Title or Brief Task Description	Task Completion Date				Progress Notes
		Original Planned	Revised Planned	Actual	Percent Complete	
1.0	Tool development to assess wind resource/irrigator needs	May-07	May-08	Dec-08	100%	Complete
1.1	Coordinate with Idaho Energy Division on Wind-Irrigation Project.	Aug-06	May-08	Nov -07	100%	Complete
1.2	Research issues, barriers and potential solutions associated with using wind energy for irrigation	Sep -06	Nov -08	Nov-08	100%	Complete
1.3	Host Irrigator/Wind Energy Workshop.	Dec-06	May-08	Sep -07	100%	Complete
1.4	Present results of this research and investigations at TWC meetings.	Dec-06	May-08	Sep -07	100%	Complete
2.0	Active drivetrain control for distributed wind applications	May-07	May-08	Jun -08	100%	Complete
2.1	Assess NREL design and modeling codes.	May-06		May-06	100%	Complete
2.2	Develop Matlab model of turbine, drivetrain and generator.	Oct-06	March-08	March-08	100%	Complete
2.3	Develop control laws for variable drivetrain.	Feb-07	May-08	Jun - 08	100%	Complete
2.4	Assess stability and usability of control laws.	May-07	May-08	Jun -08	100%	Complete
3.0	Turbine Rotor design for distributed wind applications	May-07	May-08	Mar-08	100%	Complete
3.1	Literature review, state-of-the art in small scale turbine rotor design.	Jun-06	May-07	Feb - 07	100%	Complete
3.1.a	Identify blade and rotor design problems specific to small scale distributed wind turbines.	Oct-06	Mar-07	Mar-07	100%	Complete
3.1.b	Select a turbine size for focus.	Dec-06	Jan-07	Mar-07	100%	Complete
3.1.c	Obtain representative C_p – wind speed curve for selected turbines.	Dec-06	Feb-07	Mar-07	100%	Complete
3.2	Review aerodynamic and structural software: NREL codes, RISO codes and other European codes.	Dec-06	Mar-07	Mar-07	100%	Complete

3.3	Blade profile selection: review and analyze available profiles from NREL and European agencies.	Mar-07	Dec-07	Dec-07	100%	Complete
3.4	Rotor aerodynamic design: number of blades; size of blades & rotor.	Mar-07	Dec-07	Dec-07	100%	Complete
3.5	Rotor structural design: stress levels and factors of safety (max wind gust); deflections.	Mar-07	Dec-07	Dec-07	100%	Complete
3.6	Design analysis and review: impact on cost of electricity.	May-07	May-08	Mar-08	100%	Complete
4.0	Electrical generators for distributed wind: Novel and innovative designs	May-07	May-08	Mar-08	100%	Complete
4.1	Assess availability & applicability of written pole technology for distributed wind energy.	May-06			0%	Eliminated
4.2	Theory and analysis of series-connected induction machines.	Dec-06	Feb-07	Mar-07	100%	Complete
4.3	Experimental self-excitation of series-connected induction generators.	May-07	May-08	Mar-08	100%	Complete
5.0	Lewandowski Legacy Wind Farm	May-07	Dec-07		100%	Complete
5.1	Assess current state of control panels.	Apr-06		May-06	100%	Complete
5.2	Specify and order PLC's.	Sep-06	Dec-07	Mar-08	100%	Complete
5.3	Install and program PLC's.	Oct-06	Mar-08		0%	Eliminated
5.4	Develop experimentation protocols for turbines.	Dec-06	May-08		0%	Eliminated
6.0	Project management, reporting and outreach	May-07	May-08	Nov -07	100%	Complete
6.1	Coordinate with Idaho Wind energy Working Group.	May-06	May-08	Nov -07	100%	Complete
6.2	Host Idaho Wind Working Group Meeting	Mar-07	May-08	Nov -07	100%	Complete

Appendix A – Status Reports from Colorado School of Mines

Subcontractor Quarterly Report

Project Title: Distributed Wind Energy in Idaho

Covering Period: July 1, 2006 to September 30, 2006

Date of Report: October 31, 2006

Award Number: [DE-FG36-06GO86101]

Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on September 30, 2006, the Colorado School of Mines PI finalized the CSM project team by hiring a graduate student Research Assistant (RA). The PI and RA performed a literature search to determine the existing research on innovative wind turbine drive trains, made contact with several knowledgeable researchers, and began the process of developing a model of a wind turbine with an innovative drive train.

Quarter details

Finalization of project team.

The CSM PI hired a graduate student with experience in both power systems/power electronics and controls to assist with the development of the turbine model. No further hiring is expected to be necessary before the end of the subcontract period (May 31, 2007).

Literature search and contacts with knowledgeable researchers

The CSM team conducted a literature search to investigate the existing research on innovative wind turbine drive trains. There is quite a bit of literature available on Continuously-Variable Transmissions (CVTs), but not many papers on wind turbines using CVTs. There are other innovative drive trains that are discussed in the literature, but a CVT will likely provide the most benefit, so the CSM team decided to focus on CVTs.

One report [1] on the economic feasibility of using CVTs in large (utility-scale) wind turbines details the results of a CRADA between the National Renewable Energy Laboratory's National Wind Technology Center (NWTC) and Motion Technologies (now Fallbrook Technologies). This report provides an economic feasibility analysis for three different types of CVTs. The discovery of this report led to a meeting with Jason Cotrell of the NWTC, who provided insight into the potential benefits of and barriers to incorporating CVTs into small wind turbines. In brief, the benefits include the potential to eliminate inverters and to operate the turbine at a higher aerodynamic efficiency. The barriers include problems of control and reliability.

At Mr. Cotrell's recommendation, the CSM team contacted Don Miller at Fallbrook Technologies to discuss the operation and modeling of the CVT. Mr. Miller was able to provide some information about CVTs and their capabilities, but due to intellectual property constraints was not able to provide a complete mathematical model of a CVT. A number of CVT models do exist in the open literature, so the modeling can proceed without more information from Fallbrook Technologies.

Model development

There are several different parts to the model that must be developed to study the effects of a CVT on a wind turbine drive train. First, the aerodynamic and structural properties of the wind turbine must be modeled. Second, a model for the drive train, including gear box and CVT, must be developed. Third, a model of the electrical system, including generator and electrical load, must be added to the overall model. During the first quarter, the CSM team investigated three different tools for modeling the wind turbine's aerodynamic and structural properties. These tools include

- using a look-up table in Matlab's Simulink ® to represent the power coefficient (C_p) surface for a wind turbine and a single degree of freedom model of the turbine dynamics based on the relationship between net torque, angular acceleration, and angular inertia ($\sum \tau = J\dot{\omega}$)
- using NREL's SymDyn [2] model for the turbine's aerodynamic and structural properties and adding a CVT model using Matlab's Simulink ®
- using NREL's FAST [3] model for the turbine's aerodynamic and structural properties and adding a CVT model using Matlab's Simulink ®

These modeling tools are listed in order of increasing model fidelity. However, an accurate model requires accurate knowledge of turbine parameters, which may or may not be available for the purposes of this research.

The CSM team has discussed modeling options with NREL's Jason Jonkman, one of the developers of FAST, and is confident that at least one of the listed modeling options will be suitable for the subcontract research.

Plans for next quarter

During the next quarter, the CSM team will develop one or more model(s) of a 50 – 100 kW using the available modeling tools. The team will also develop a model of a CVT using Matlab's Simulink ® and select a model for the generator and one or more load profiles.

References

- [1] Cotrell, J., "Motion Technologies CRADA CRD-03-130: Assessing the Potential of a Mechanical Continuously Variable Transmission," NREL Technical Report TP-500-36371, National Renewable Energy Laboratory, Golden, CO, 2004. Available at <http://www.nrel.gov/docs/fy04osti/36371.pdf>.
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- [3] Jonkman, J. and Buhl, M., "FAST User's Guide," NREL Technical Report TP-500-38230, National Renewable Energy Laboratory, Golden, CO, 2005. Available at <http://wind.nrel.gov/designcodes/simulators/fast/FAST.pdf>.

Subcontractor Quarterly Report

Project Title: Distributed Wind Energy in Idaho

Covering Period: October 1, 2006 to December 31, 2006

Date of Report: January 31, 2007

Award Number: [DE-FG36-06GO86101]

Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on December 31, 2006, the Colorado School of Mines team (PI and Research Assistant) worked on model development for the components of the wind turbine system on which they are focused. The primary components of this system are a wind turbine, a continuously variable transmission (CVT), and an electric generator.

Quarter details

Selection of FAST Wind Turbine Simulator

The CSM team considered three options for simulating wind turbine performance. A “look-up table” would have been the simplest solution, but it would also neglect the dynamic response of the electric output and of the turbine’s physical structure. Two aeroelastic simulators (that retain most of the major dynamics) are available from NREL. FAST was selected over SymDyn because of its higher fidelity, the availability of appropriate input files, and its widespread use in the wind industry.

Figure: FAST wind turbine simulator in Green

Ideally, a FAST input file based on the Micon 108 kW machines of the Boise State University team would be used at CSM. Unfortunately, no such input files are available from the NREL resources, the Micon 108 documentation doesn't have sufficient data for these file (the original machines have also been modified), and direct measurement of these parameters is cost and time prohibitive. Instead, CSM is using input files for a 50 kW machine, the AOC 15/50, which was among the sample input files that came with the FAST simulator. The AOC 15/50 was the closest available turbine to the modified Micon 108 turbines, which will likely be configured to run at less than 108 kW.

The FAST simulator can be run as a Simulink block once the necessary input file modifications, output selections, and initializations have been made. The drive train is typically included in the FAST model as a fixed gear ratio, while the goal of this project is to consider a variable gear ratio between the turbine rotor and the generator shaft. In order to accomplish this variable gear ratio, the CSM team has partially externalized the gear box. At this stage they are using the nominal gear ratio of the AOC 15/50 as the upper limit of the variable range, which is 28.25:1. Since the gear ratio in a CVT ranges from 0.5:1 to 4:1, the drive train is now being visualized as a two stage train: with a fixed gear ratio of 1:7 between the turbine and the CVT, and the CVT applying a gear ratio that maximizes the power coefficient of the wind turbine. The fixed 1:7 gear ratio is achieved inside the FAST model, and the variable ratio is achieved externally with Simulink blocks.

Modeling of the innovative drive train

The efforts of the CSM team to find CVT manufacturer willing to allow us to model their technology were not successful. Their intentions now are to use a simplified dynamic model found in "Nonlinear Control of a Continuously Variable Transmission (CVT) for Hybrid Vehicle Powertrain" by Setlur, et al [4]. The basis of this approach can be seen in the following equations from that paper.

Engine speed dynamics:

$$\dot{\omega}_L = \frac{1}{J_{wt}} [\tau_{wt} - \tau_{CVT,wt}]$$

(Where $\tau_{wt}(t)$ is the torque generated by the FAST wind turbine model, $\tau_{CVT,wt}(t)$ is the torque applied to the CVT by the wind turbine, and J_{wt} is the inertia of the wind turbine. The derivative of ω_L is the radial acceleration of the low speed shaft)

Transmission dynamics:

$$\tau_{CVT,gen} = [\tau_{CVT,wt} - J_t \dot{\omega}_L] v$$

$$\dot{v} = u$$

(Where $\tau_{CVT,gen}(t)$ is the torque applied to the generator by the CVT, J_t is the inertia of the transmission, $v(t)$ is the effective gear ratio, and $u(t)$ is the CVT control input)

The transient IG model applies a Park transformation, converting the three-phase quantities of the generator into a “two-phase primitive machines with fixed stator windings and rotating rotor windings to represent fixed stator windings (direct axis) and pseudo-stationary rotor windings (quadrature axis).” [5] The equations describing this transformation have been assembled in Simulink, as shown in the figure above. Generator parameters for their 4 pole, 50 kW Primeline induction generator were provided by Marathon Electric of Wassau, WI.

A quick explanation is in order to justify the inverter in the figure. One of the motivations for using the CVT is to eliminate the need for such power electronics. Exciting the IG model, though, cannot be accomplished with torque – it must be accelerated in motoring mode. A grid-connected inverter is being used for this purpose, and then is bypassed once the machine is brought up to speed. The CSM team is currently modeling a grid connection as the load rather than an isolated water-pumping network, which they hope to include once the model is effective in its current configuration.

Plans for next quarter

During the next quarter, the CSM team will integrate its system components into a complete system and design the controller to track the maximum power coefficient of their wind turbine model.

References

- [4] Setlur, P., Wagner, J.R., Dawson, D.M., and Samuels, B., “Nonlinear Control of a Continuously Variable Transmission (CVT) for Hybrid Vehicle Powertrains,” Proceedings of the 2001 American Control Conference. Volume 2, 25-27. June 2001, pp 1304-1309.
- [5] Simoes, M.G., and Farret, F.A., “Renewable Energy Systems: Design and Analysis with Induction Generators,” CRC Press. New York, NY, 2004.

Subcontractor Quarterly Report

Project Title: Distributed Wind Energy in Idaho
Covering Period: January 1, 2007 to March 31, 2007
Date of Report: April 30, 2007
Award Number: [DE-FG36-06GO86101]
Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on March 31, 2007, the Colorado School of Mines team (PI and Research Assistant) worked on model and control development for the wind turbine system with a continuously variable transmission (CVT). The primary components of this system are a wind turbine, a CVT, and an electric generator.

Quarter details

Simulation results from CVT wind turbine model

The CSM team has completed the CVT wind turbine model, developed PI control in order to track the ideal tip-speed ratio, and shown an improvement in energy capture in wind speeds up to ~ 15 m/s. Fatigue loading is also improved by the CVT-controlled wind turbine, as compared to fixed speed operation, for wind inputs that average 6 and 8 m/s. The fatigue improvements are demonstrated by a reduction in standard deviation of load torque in the range of 20-30%. At a higher wind speed of 10 m/s mean, however, fatigue loading increased by 87%. This may be due, in part, to the limits of the generator whose parameters are being used for our simulations. More study in this area is needed. The results are summarized in Table 7.

Table 7: Summary of results for wind turbine - CVT system with PI control

	Fixed Speed	CVT Controlled	Fixed Speed	CVT Controlled	Fixed Speed	CVT Controlled
Average Wind Speed (m/s)	6	6	8	8	10	10
Output Energy(kW*s)	576.2	752.8	1497.3	1691.7	2378.2	3324.6
% Improvement	n/a	+30.6%	n/a	+13.0%	n/a	+39.8%
Mean Load Torque (N*m)	52.6	76.7	123.1	132.2	191.3	205.2
Std. Dev. Load Torque	48.6	37.4	60.7	45.9	63.4	118.4
Change in Std. Deviation	n/a	-23.0%	n/a	-24.5%	n/a	+86.8%

The CVT wind turbine model integrates high-fidelity models of an induction generator and wind turbine with input/output equations representing the dynamics of a continuously variable transmission. The CVT is controlled by a rate-of-change input that uses a PI controller to process the wind speed error signal, and does so to track the ideal tip-speed ratio. Simulations of the system's performance in response to 3 turbulent wind input files show an improvement in the electric power output. A mitigation of fatigue loading is

also seen in response to wind files with light and moderate average speeds, but fatigue loading increases in high winds.

The high fidelity of this model is one of its strengths. The FAST wind turbine simulator is a well-known model that has been independently tested and certified, the transient induction generator is also an established model that has seen extensive use in research, and the continuously variable transmission provides simple relationships between input and output that are not committed to a particular flavor of this rapidly advancing technology. FAST's capability to model many different behaviors within a wind turbine system provide great flexibility for analysis and control, and the line currents available from the induction generator model allow for an integration of this system with various loads. The only load that has been tested so far by the CSM team is a direct connection to the utility grid.

The biggest drawback of this model is its slowness. At 8 hours per 70 s simulation, it would be an impractical tool to use for design tasks that require a large number of runs. Another drawback is the transient fluctuations seen in the load torque at the beginning of each simulation. The transient induction generator model is the source of this problem – most likely a consequence of an imprecise synchronization of the generator with the electric grid. For these reasons, the use of a simple induction generator model might be preferable for studies that do not require the line currents provided by the transient model.

The PI control used in the studies to date improved the energy capture of the wind turbine, but performance could be improved by utilizing more sophisticated control. One possible next step would be to pursue optimized control to reduce fatigue torque loading. Also, this study compared the energy output and fatigue loading of the controlled-CVT wind turbine to a fixed speed machine. It would be valuable to see similar comparisons made between different variable-speed technologies to do a more detailed cost-benefit analysis.

Plans for next quarter

During the next quarter, the CSM team will focus on publishing the existing results and investigating the benefits of more sophisticated controllers.

Subcontractor Quarterly Report

Project Title: Distributed Wind Energy in Idaho

Covering Period: April 1, 2007 to June 30, 2007

Date of Report: July 31, 2007

Award Number: [DE-FG36-06GO86101]

Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on June 30, 2007, the Colorado School of Mines team (PI and Research Assistant) has improved the wind turbine with CVT simulation tool and the CVT controller.

Quarter details

The main objectives for the quarter ending on June 30, 2007 were to improve the previously-developed simulation tool and to improve the CVT controller.

The simulation tool modeling a wind turbine with CVT (Figure 2) provides detailed data on the electrical and mechanical components of the system. Because of the level of detail, the original model required about 8 hours of computation time for a 70-second simulation. Thus, one of the objectives for this quarter was to find ways to speed up the model. One of the ways to decrease the simulation time is to replace the transient induction generator model with a steady-state model obtained from NREL's web site. We determined that the steady-state model is useful for analyses that do not require electrical signals such as the line currents supplying the loads.

Figure 2: Simulation model of a wind turbine system with CVT

Other changes to the simulation tool included incorporating the change in turbine speed due to changes in wind input into the net energy calculation and modifying some of the input files to improve the initial transient behavior.

During this quarter, our main focus on improving the CVT controller was to make it realizable. The previously-developed controller (Figure 3) requires a measurement of the input wind speed, which is used in the turbine speed error signal calculation. This error signal is the input to the previously-developed PID controller. A common controller in the wind industry involves setting the generator torque equal to a gain K times the rotor speed squared,

Figure 3: Block diagram for CVT Controller

$$\tau_c = K \cdot \omega_{rotor}^2$$

Letting the control torque be the CVT torque on the turbine side of the CVT, we can use the same control configuration in our model. The CVT control law, which computes the derivative of the CVT gear ratio $\dot{c}$, becomes

$$\dot{c} = \frac{1}{J_{gen} \cdot \omega_{CVT}} \left(\frac{K \cdot \omega_{CVT}^2}{N^3 \cdot c} - J_{gen} \cdot c \cdot \dot{\omega}_{CVT} - \tau_{gen} \right)$$

This control scheme results in a 4.8% improvement in energy capture compared to a fixed-speed turbine for the low-turbulence, 8 m/s average wind speed input file, which is slightly higher than the 3.9% improvement seen with the PID controller over the fixed-speed turbine using the same input file.

Plans for next quarter

During the next quarter, more analysis will be performed on the $\tau_c = K \omega_{rotor}^2$ controller to allow for a more complete comparison to the original PID controller. Also, a state-space-based controller and model will be developed to provide the groundwork for more extensive control modeling that can make use of the many signals available in the FAST model.

Subcontractor Quarterly Report

Project Title: Distributed Wind Energy in Idaho

Covering Period: July 1, 2007 to September 30, 2007

Date of Report: October 31, 2007

Award Number: [DE-FG36-06GO86101]

Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on September 30, 2007, the Colorado School of Mines team (PI and Research Assistant) improved the previously-developed standard torque controller and attempted to create an operational state-space based control model.

Quarter details

The main objectives for the quarter ending on September 30, 2007 were to improve the “standard torque controller” developed during the last quarter to allow for a more complete comparison to the original PID controller and to lay the groundwork for more sophisticated control by developing a state-space based controller.

Standard Torque Controller Improvements

The “standard torque controller” is given by $\tau_c = K \omega_{rotor}^2$, where τ_c is the generator (control) torque and ω_{rotor} is the rotor angular velocity. The parameter K is given by

$$K = \frac{1}{2} \rho A R^3 \frac{C_{p,max}}{\lambda_{ideal}^3},$$

where ρ is the air density, A is the rotor swept area, R is the rotor radius, $C_{p,max}$ is the maximum power coefficient, and λ_{ideal} is the tip-speed ratio at which $C_{p,max}$ occurs.

The Simulink model used in the standard torque control research is shown in Figure 4. The block *CVT v_dot control2* implements the torque control and contains the subsystem shown in Figure 5.

The net electric energy captured using this standard torque controller was calculated as the total electric energy minus the kinetic energy that was used as the turbine decelerated in slowing winds.

Figure 4. Simulink model used in standard torque control research. The block *CVT v_dot control2* has been modified from the model used during the previous quarter and includes the subsystem shown in Figure 5.

Figure 5. Simulink subsystem implementing the standard torque controller.

$$\begin{aligned} \text{Total Electric Energy} &= 1.8581\text{e}+003 \text{ kW*s} \quad (\text{with CVT}) \\ &\quad -132.2 \quad (\text{slowing rotor}) \\ &\hline &1.7259\text{e}+003 \end{aligned}$$

When the CVT ratio was held static (at 1), the energy captured was 1.6473e+003 kW*s. The wind turbine using the CVT captured 4.8% more energy that it did without the CVT, which is an improvement over the energy capture found using PI control, which only saw a 3.9% improvement over the simulation without a CVT.

State-space Controller Development

The second task undertaken during this quarter was to develop the infrastructure for a state-space based controller. In theory, state-space control will allow us to control many different degrees of freedom for the wind turbine and CVT in a coordinated fashion. The FAST wind turbine simulation can extract linearized representations of a nonlinear wind turbine, and these linearizations (the A , B , C , and D matrices of a state-space representation) can be used in the control design. Although progress was made in this area, we were unable to create an operational model within the time and budget allowances of the project.

Plans for next quarter

The next quarter will focus on completing a conference paper and a final report to disseminate the results of this project.

Subcontractor Quarterly Report

Project Title: Distributed Wind Energy in Idaho

Covering Period: October 1, 2007 to December 31, 2007

Date of Report: January 31, 2008

Award Number: [DE-FG36-06GO86101]

Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on December 31, 2007, the Colorado School of Mines team (PI and Research Assistant) wrote a conference paper and prepared a presentation to disseminate the results of the research to date.

Quarter details

The main focus of this quarter was the writing of the following paper, which will be presented at the 2008 AIAA Aerospace Sciences Meeting and Exhibit's AIAA/ASME Wind Energy Symposium in Reno, NV on January 7.

Rex, A.² and Johnson, K., 2008, "Model Development of a Wind Turbine System with a Continuously Variable Transmission for Design of Region 2 Speed Control," *Proceedings of the 2008 AIAA/ASME Wind Energy Symposium*, (electronic).

Note that this paper covers approximately the first $\frac{3}{4}$ of the research conducted for this project, and the final report and journal paper in progress will include the remainder of the work.

A presentation, which can be seen in the appendix below, was also created for the conference.

Plans for next quarter

The next quarter will focus on finalizing the state-space control, tying up loose ends, completing a final report, and writing a journal paper to disseminate the research results.

² Advisee

Appendix to subcontractor quarterly report, 1/31/08: Wind Energy Symposium Presentation

Model Development of a Wind Turbine System with a Continuously Variable Transmission for Design of Region 2 Speed Control

Andrew Rex
Kathryn Johnson

Fixed-speed and variable-speed operation

- Wind turbines operate most efficiently at variable speeds that maintain the turbine's ideal tip-speed ratio (λ).

$$\lambda = \frac{\omega_r R}{U}$$

- However, generators that are directly connected to a utility grid operate at a fixed speed.

2008 AIAA/ASME Wind Energy Symposium 2

The AOC 15/50 TSR Curve

- ω = wind turbine radial velocity
- R = wind turbine radius
- U = wind speed
- C_p = the power coefficient

2008 AIAA/ASME Wind Energy Symposium 3

Points of frequency conversion

2008 AIAA/ASME Wind Energy Symposium 4

Outline

- Motivation
- Continuously-Variable Transmissions
- Wind Turbine Model
- Controller Development
- Simulation Results
- Conclusions

2008 AIAA/ASME Wind Energy Symposium 5

What is a continuously-variable transmission (CVT)?

- A CVT enables an infinite range of gear ratios within its limited range
 - 1.0 - 3.5 for Nuvinci
 - 0.4 - 2.4 for Nissan

2008 AIAA/ASME Wind Energy Symposium 6

Generator model

- Transient induction generator model
- The steady-state 'transformer equivalent circuit model' neglects time variance of mutual flux linkages.
- Applies Park (d-q-0) transformation to convert 3-phase machine into a 2-phase representation
- Machine parameters from Marathon Electric induction generator: 4 pole, 50 kW

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CVT model

- Speed equations (C = CVT speed ratio)

$$\omega_{HSS} = C \omega_{CVT} \Rightarrow \dot{\omega}_{HSS} = C \dot{\omega}_{CVT} + \dot{C} \omega_{CVT}$$
- Torque equation

$$\tau_{CVT} = J_t \dot{\omega}_{CVT} + C(\tau_{HSS} + J_{gen} \dot{\omega}_{HSS})$$
 - CVT inertia lumped on the wind turbine side of the CVT.
 - Generator torque and acceleration of generator shaft geared through C .

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Outline

- Motivation
- Continuously-Variable Transmissions
- Wind Turbine Model
- Controller Development
- Simulation Results
- Conclusions

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CVT Control

- GOAL: Track ideal TSR (λ_{ideal}) to maximize power output.
- Error = $\lambda_{ideal} - \lambda$
- Error signal is input to a PID controller.
- Output of PID controller is the input to the CVT ($\dot{\omega}$).

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Problems with PID Tuning

- Traditional step response techniques have been shown to not identify optimized values for Region 3 wind turbine control.
- Systematic approach requiring high volume iterations impractical because simulation runtime is approximately 6 hours using the high-fidelity model.
- Compromise: low volume iterations.

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PID tuning process

- Tune k_p with k_I and k_D set to zero, select for maximum electric power output.
- Fix k_p at value determined in step 1, tune k_I with k_D set to zero.
- Fix k_p at value determined in step 1, tune k_D with k_I set to zero.

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Wind input file characteristics

- Wind files built with NREL's TurbSim code
- "A" is the most turbulent, "C" the least turbulent

File name	6C	6A	8C	8A	10C
Mean wind speed at hub height	6 m/s	6 m/s	8 m/s	8 m/s	10 m/s
Standard deviation	1.212	1.616	1.392	1.856	1.572

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Baseline simulation: fixed speed

- CVT speed ratio fixed at 1
- Turbulent 70s wind file.
- Relatively fixed wind turbine radial velocity.
- Power & torque fluctuations follow the wind speed.

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Comparison of results from PID gains

Comparison of Variable-Speed Controllers

Controller Type	Energy Capture (%)	Standard Deviation of Load Torque (%)
P Controller	4.10%	-27.20%
PI Controller	3.90%	-31.60%
PD Controller	4.10%	-
PID Controller	4.00%	-

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Summary

- An improvement in energy capture due to PI-controlled CVT is seen in all wind conditions.
- The CVT mitigates fatigue loading in 6 and 8 m/s, lightly turbulent winds.
- The CVT increases standard deviation in load torque, and thus likely fatigue loading, in highly turbulent winds at all 3 speeds.

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Ongoing work

- Develop an implementable controller, i.e., one that does not require a wind speed measurement
- Compare energy capture and loads to a baseline variable-speed case with power electronics

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Questions?

Subcontractor Final Report

Project Title: Distributed Wind Energy in Idaho
Covering Period: January 1, 2008 to March 31, 2008
Date of Report: April 30, 2008
Award Number: [DE-FG36-06GO86101]
Subcontract Principal Investigator (PI): Kathryn Johnson, Colorado School of Mines (CSM)

Quarter summary

During the quarter ending on March 31, 2008, the Colorado School of Mines team (PI and Research Assistant) wrote a journal paper based on the conference paper presented in January 2008 at the AIAA/ASME Wind Energy Symposium. The journal paper will be submitted to the ASME Journal of Solar Energy Engineering in May 2008.

Quarter details

The main focus of this quarter was the writing of the following paper, which will be submitted to the *ASME Journal of Solar Energy Engineering*.

Rex, A.³ and Johnson, K., “Methods for Controlling a Wind Turbine System with a Continuously Variable Transmission in Region 2,” in preparation for the *ASME Journal of Solar Energy Engineering*.

As an extension of the conference paper presented in January 2008, this journal paper incorporates the realizable (in the field) CVT controller based on the “standard” nonlinear region 2 torque controller, $\tau_c = K\omega^2$. Simulation results and energy capture data are shown and compared to the PID control scheme previously developed and presented.

A copy of the current draft of the journal paper is attached as a separate document.

Plans for next quarter

Since this project is complete, there will be no next quarter. However, the PI intends to pursue a follow-up project involving state-space control for the CVT to achieve multiple control objectives.

³ Advisee