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"HVDC Transmission and Solar Power in the US Southwest"

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HVDC Transmission and Solar Power in the US Southwest

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Abstract

In this paper, we examine the economic viability of two new energy technologies when implemented in the US Southwest. The first technology of interest is a long distance high voltage direct current (HVDC) transmission link between Texas and Southern California that is constructed using a so-called "nanowire" technology. The second technology is grid-connected photovoltaic solar power. We investigate the potential value of these technologies by examining how profitable they would likely have been if they had been available in 2003.

1. Introduction

For a variety of reasons related to national security and environmental protection, public interest in alternative energy sources is rising. Ultimately, energy sources that are cleaner and more abundant than fossil fuels will become economically competitive. However, in today's marketplace, many renewable technologies are not cost competitive with fossil fuels in large-scale applications. In the case of solar, for example, materials costs are prohibitive relative to the energy savings when compared to fossil fuels. More generally, although renewable sources of energy, such as solar and wind, are often regarded as inexhaustible, in practice they require an input of limited resources. Limits on the number of suitable sites for solar or wind farms, as well as limited availability of the special materials that are required to produce solar panels or high performance wind generator blades, are some examples of resource constraints that even renewable energy sources face. Thus, the difference between "renewable" and "non-renewable" energy sources is subtle. The real issue is the relative costs of exploiting different energy sources taking all relevant externalities into account. Research into alternative energy technologies can ensure that the cost of an eventual transition to new energy sources is minimized, and is, thus, less disruptive to the economy.

Currently, hydroelectricity is the major renewable source of energy, but developed countries have limited options for adding to existing hydroelectric capacity. In several developing countries, there is substantial hydroelectric potential, but such sources are remote from major markets and would likely require improvements in long distance transmission technologies to make them competitive. Thus, incremental demand for energy in major markets will have to be met by fossil fuels or nuclear energy lest other alternative sources can emerge at competitive cost levels.

Advancements in wind power technology have made it the favored marginal source of renewable electricity supply. Wind potential worldwide is sufficient to allow wind power to supply a significant share of current electricity demand. Cost and reliability, however, are barriers to market entry. The intermittent nature of wind power makes it difficult to maintain system stability when wind constitutes a substantial fraction of generation capacity. Furthermore, additional backup generating capacity is needed to ensure that power can be supplied to meet system needs. The additional capital cost of such complementary capacity severely limits the competitiveness of wind power. Exacerbating the problem is the fact that many of the most promising sites for wind generation are remote from demand centers, thereby necessitating substantial investments in transmission capacity. Moreover, since the wind farms operate intermittently, the transmission capacity is often less than fully utilized, raising unit costs. In some areas, opposition to wind power is also growing, ironically enough, on environmental grounds. Objections have been raised to the visual blight of wind farms that are often located in scenic areas. Some have also expressed concern about the loss of bird life associated with wind generators, which are often located on ridges or in mountain passes where birds fly low to the ground.

Solar power is a promising renewable energy source that could feasibly supply a substantial fraction of current and projected electricity requirements at reasonable cost with few negative environmental effects. At present, only 0.1% of total world energy comes from solar. In the United States, where 6% of electricity comes from renewable sources, only 1% derives from solar power. The three biggest solar markets are Japan, the US and Germany, which together account for 88% of total solar installations worldwide. Japan leads the world in solar usage, with the size of the Japanese solar home market increasing 80% over the last decade. Japanese firms represent 70% of the world's Photovoltaic solar panel manufacturing capability. Generous government subsidies have made crucial contributions to the industry's growth within Japan.

If the cost of solar panels continues to drop, there is a reasonable chance that solar power could become competitive with natural gas, coal gasification or nuclear power in the not too distant future.[1] Furthermore, solar panels are amenable to mass production using relatively common techniques and materials, so increasing their supply should not greatly escalate the cost of production. In fact, there are likely to be considerable opportunities to lower production costs as panels are produced on a larger scale than is currently the case. As with wind power, however, the sites that are best suited for locating solar farms are often in locations remote from major demand centers.[2] Hence, extensive development of solar power, like wind power or new major hydroelectric resources, is likely to require reductions in the cost of long distance electricity transmission.

No matter which source of renewable energy we might pursue as a partial replacement for fossil fuel, improvements in electricity transmission technology will likely be needed. Moreover, improved electricity transmission technology would also facilitate wider use of nuclear power by allowing siting of facilities in areas that are remote from large population centers.

In fact, highly efficient long distance transmission reduces the need for local megawatt generation. Low cost transmission allows for a single plant to provide power to multiple locations with differential demand peaks. This not only improves the competitiveness of remotely located generation sources; it also provides system stability in the event of local plant outages.

Finally, as the August 2003 blackout in the US northeast and eastern Canada demonstrated, the North American electricity transmission grid is in need of upgrading. Improved electricity transmission technologies would greatly assist in producing a more efficient and reliable electricity supply system in North America regardless of the generation technologies that are used.

In this paper, we illustrate the potential benefits of new transmission and solar power technologies by evaluating a proposed project in the US southwest. We show that the project could be developed with minimal need for subsidy. The key idea is that revenue from arbitraging price differences between the Texas and California wholesale electricity markets would help cover a substantial fraction of the project costs including the costs of developing the new technologies. A major benefit of the proposed project is

[1] For more discussion, see the paper by Dagobert Brito also contained in this conference volume.

[2] An exception involves placing solar collectors on rooftops (or the windows) of residences and commercial buildings, where the power is used onsite.

that it would stimulate the development of alternative technologies that could make large-scale renewable energy competitive in a shorter time frame.

2. A new transmission technology

New high voltage direct current (HVDC) transmission capacity is the only feasible option for transmitting large amounts of power between California (which is in the WECC) and Texas (ERCOT).[3] Currently, the lack of synchronicity between these two NERC regions means that any capacity connecting the two regions must be direct current (DC) rather than alternating current (AC). Furthermore, a long distance link connecting Texas to Southern California would be necessary to support a large trade in electricity, which, due to transmission efficiency, favors HVDC over AC.

There is also some advantage in using HVDC to transmit the power generated by solar panels or wind generators from remote areas. In the case of solar panels, the source is DC and there would be no need to convert the power to DC before transmission. Moreover, since HVDC involves lower line losses, it increases the effective capacity of the solar panels to end-users. In the case of wind generators, output is generally transformed to DC before being converted back to AC because the frequency of the generated AC power does not necessarily correspond to the frequency of the grid to which it is connected. Transmission of power from a wind farm via a HVDC link would present a cost savings over AC transmission when the power is transported any considerable distance.

The calculations presented below assume that we have available a proposed new nanowire technology to use in the link. The Center for Nanoscale Science and Technology (CNST) at Rice University has been investigating single walled carbon nanotubes (nick-named “buckytubes”) as a possible source of radically new electrical transmission lines (nick-named “quantum wire”). When made with molecular perfection, these tubular fullerenes offer revolutionary electrical, thermal, and mechanical properties on the nanometer scale.

Experiments conducted at the CNST suggest that a quantum wire may have up to 10 times better conductivity than standard and proposed composite conductors. This is clearly a substantial advantage in long-distance electricity transmission. Furthermore, the

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[3] Currently, there is only limited direct current transmission capability between ERCOT and WECC. Due to a relatively small demand in New Mexico and Eastern Arizona, increasing capacity between the two NERC regions would likely only be cost effective if the link could connect major load centers.

quantum wire displays the improved conductivity at ambient temperatures and thus eliminates the need for the expensive cooling infrastructure of current super-conducting cables.

The experiments at CNST also suggest that the quantum wire is likely to have near-zero thermal expansion. This would eliminate the maintenance and reliability issues associated with sagging transmission lines in the existing transmission system . Many major failures, including the August 2003 blackout in the Northeast, originate when wires sag in hot weather thus increasing the risk of shorting out through contacting trees and other structures.

Other factors reinforce the potential cost savings. The experiments at CNST suggest that a quantum wire could be up to 30% lighter than standard and proposed composite wires of the same capacity. The lighter weight would reinforce the lower tendency to sag in allowing smaller transmission towers. In turn, smaller towers would not only reduce tower construction costs. They also would allow for a smaller right of way, the cost of which can be a substantial fraction of the overall cost of the project, particularly in countries such as Japan where land costs are high.

Finally, the CNST experiments have also indicated that a quantum wire is likely to have up to 10 times better tensile strength than standard and proposed composite wires of the same capacity. Greater tensile strength would allow for longer spans in the transmission line, which again would further lower the costs of construction by reducing the number of towers.

3. Why focus on the US Southwest?

We focused on a project in the US Southwest for four reasons. First, southern parts of the states of Arizona and New Mexico are the best parts of the US for harvesting solar energy. Not only do they have large amounts of incident energy per square meter, but the desert climate also means that there are few cloudy days, rendering the yield of a solar plant quite predictable.

A second reason for focusing on the US Southwest is that it is relatively close to large electricity markets in both Texas and California. Furthermore, both Texas and California have fairly liquid wholesale electricity markets. These wholesale electricity markets can therefore be used to gauge how profitable the proposed project is likely to be under realistic market conditions without having to construct a detailed model of electricity supply and demand. From a commercial perspective, the availability of liquid wholesale markets for electricity reduces the risk of developing the project since derivative instruments could be used to mitigate such risks and enable market access at a predictable price.

A third reason for focusing on Texas and California is that there is a range of potential benefits from linking these markets through HVDC transmission regardless of whether solar or wind power is part of the project. California depends on both power and natural gas imports from surrounding states. Much of the power imported into the state originates as hydroelectric power in the Pacific Northwest and coal generated power in the Rocky Mountains. When there is a drought, as was the case in the California power crisis of 2001, California must rely more heavily on natural gas to meet its power generation needs. However, there are currently physical constraints on the amount of natural gas and power that can be imported into the state. The possibility of importing power from Texas would provide another option for emergencies by increasing the effective reserve margin to the state. The amount of reserve capacity in Texas is quite favorable relative to the situation in California, suggesting that Texas might be able to provide emergency power in California. There is no presumption, however, that all the trade would be from Texas to California. The ERCOT system is only weakly connected to the rest of the North American power grid. Emergency reductions in power supply in Texas drive up prices in the state, and there are limited opportunities to moderate them via power imports. Increasing connections to California could, therefore, permit some moderation of price movements within Texas as well as California. This would likely be most evident in daily and seasonal load variations, which can be significant across the two states. For example, a time difference of two hours means that peak daily demands in the two states occur at different times.[4] From a commercial perspective, the option to arbitrage price differences resulting from differential peaks between the two states could help pay for the cost of the transmission line. By contrast, the major interstate power lines entering California from the Pacific Northwest come from regions that are in the same time zone as California, so arbitrage opportunities arising from differential peaks are limited.

A fourth reason for connecting Texas and California via a high voltage link is that it would assist with the development of wind power in West Texas. There are substantial

[4] A peculiar feature of the way time zones have been assigned in the US is that the time difference between California and Texas is quite large relative to the physical distance between the two states, and hence the costs of connecting them.

opportunities to generate wind power in West Texas but further development is hindered by the lack of sufficient capacity to transmit the power to the major markets in East Texas. It is expensive to supply transmission capacity for wind power alone, however, since it typically will be used at considerably less than full capacity. HVDC transmission capacity linking California and Texas could pass through the West Texas wind farm region and enable more of those resources to be developed at competitive cost.

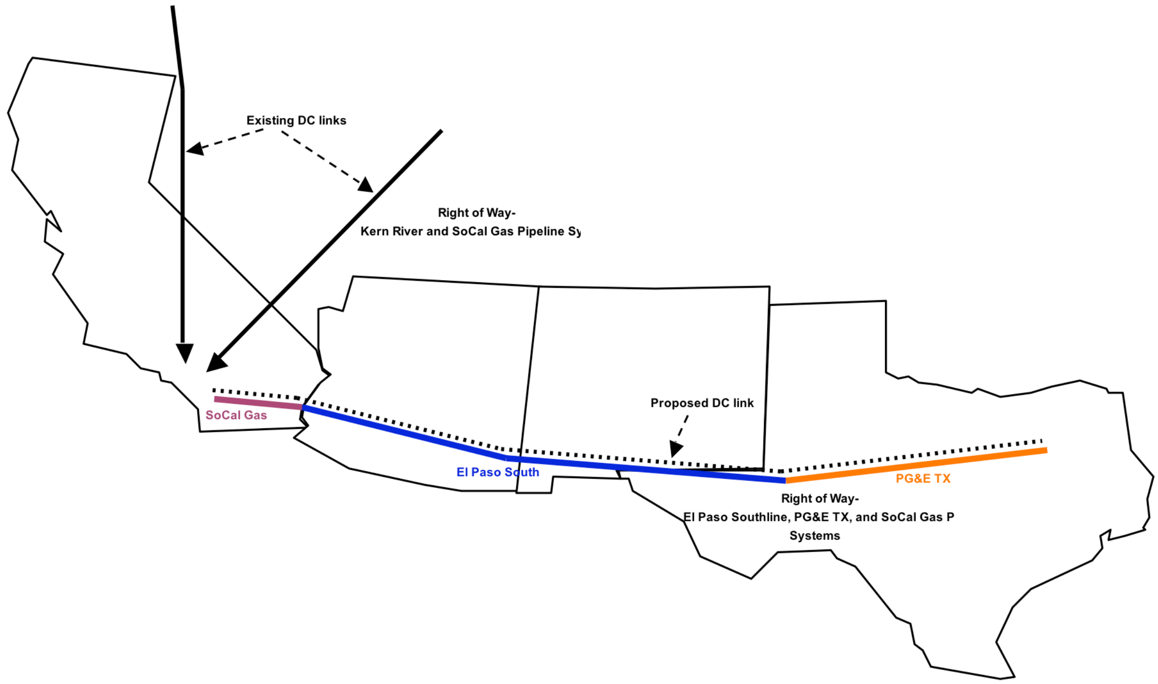

Figure 1: Proposed HVDC link route

Figure 1 illustrates the route for the proposed HVDC link. The key feature of the proposal is that it uses existing rights of way associated with gas pipelines. This should reduce development costs to the extent that the right-of-way need not be negotiated or land purchased for the project to move forward.

4. Methodology

To evaluate the profitability of the proposed link, one could construct a detailed structural model of the current California and Texas electricity supply systems. This would then be augmented to allow for planned additions to capacity in each state along with planned retirements of existing plants and prospective growth in demand. The model could be further elaborated to allow additional capacity to be brought on-line beyond the current planning horizons of suppliers in each state. Building such an elaborate model is, however, beyond the scope of this paper.

As a preliminary alternative, we collected wholesale electricity prices in North Texas and Southern California for every hour in 2003. These prices are then used to investigate the potential profits that could have been earned in 2003 if HVDC transmission capacity between the two markets had been available. If 2003 were representative of the likely opportunities over the life of the project, the resulting profit could be used to indicate the potential net present value of the investment opportunity over its anticipated lifetime.

The presence of HVDC transmission capacity would likely alter prices and the quantity of spinning reserves in each state at any time. An increase in demand in one of the states would encourage greater utilization of the transmission link, which would serve to raise prices in the supplying region and mitigate the increase in prices where the demand surge occurred. Indeed, one of the anticipated public benefits of the project would be that it would reduce price fluctuations in response to emergencies in either state.

We allow for price changes in response to utilization of the proposed HVDC transmission link by estimating a function relating wholesale prices in Southern California and North Texas to each region's load. The estimated functions were then used to alter prices in response to an arbitrage sale of power. For example, to take advantage of a price in California that exceeds the price in Texas, power is purchased in Texas, raising the load on the Texas system and hence the Texas price. Conversely, when the power is sold in California, it will reduce the California price. If we did not take these price responses into account, the net profits from line utilization would be overstated.

A potential complication of this econometric approach to estimating the price effects of load changes is that load and price may be determined simultaneously. Thus, the coefficient estimate may reflect the response of load to the wholesale price in addition to, or instead of, the response of wholesale prices to variations in the load.[5] In the market environments in both California and Texas in 2003, however, most of the load could not respond to prices in real time. Retail prices in both states were regulated to some extent and few customers in either state possessed meters capable of measuring (and charging

[5] Technically, the regressor would be correlated with the error term leading to bias in the estimated coefficient.

for) electricity consumption at different times of the day. The California Energy Commission began its a real-time metering program in May 2001, but by 2003 only the state's largest electricity consumers were using real-time meters. Similarly, a 2004 report[6] by the Texas Energy Planning Council (part of the Texas Railroad Commission) noted that at the time the report was written "demand response programs [did] not exist except at the wholesale market level for the very largest customers [with over one megawatt of demand]." In summary, high frequency price and quantity movements in 2003 should primarily reflect the price elasticity of the supply curve at different levels of overall system load at particular times of the day. The estimated regression coefficient on system load should therefore provide a reasonable estimate of how small changes in system load associated with arbitrage activity are likely to alter wholesale prices.

Our analysis ignores the fact that HVDC transmission capacity between Texas and California would provide potential opportunities to supply ancillary services in either state. In effect, the capacity of the transmission line could be offered to supply emergency power even in periods where the price differential is too small to use the link for profitable arbitrage. If an emergency does not occur, the link could earn a return merely for remaining on standby. If an emergency does occur, the link will be called upon to supply power at short notice, but, since such an emergency would be associated with elevated prices in the state where generating capacity is short, it would be profitable to ship power and exploit the arbitrage opportunity. An HVDC link may be particularly useful for supplying ancillary services since it can often assist with providing frequency as well as voltage control in the AC system.

5. Measuring arbitrage opportunities

In Figure 2, we graph the difference between the North Texas and Southern California wholesale electricity prices for every coincident hour in 2003.[7] The mean difference was \$6.01/MWh (calculated as Texas price minus California price), with a standard deviation of \$45.07/MWh. The minimum difference was –\$848.69/MWh, while the maximum was \$901.93/MWh. The distribution is also noticeably positively skewed (the skewness measure is 6.16, while the Texas price was larger for about 55% of the

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[6] The report is available at http://www.rrc.state.tx.us/tepc/092404presentations/bobking.pdf.

[7] The California ISO determines prices every 10 minutes, while ERCOT does so every 15 minutes. To minimize the amount of data, we averaged the prices to hourly intervals.

hours). Thus, we observe a higher average price in Texas, despite a higher capacity reserve margin.

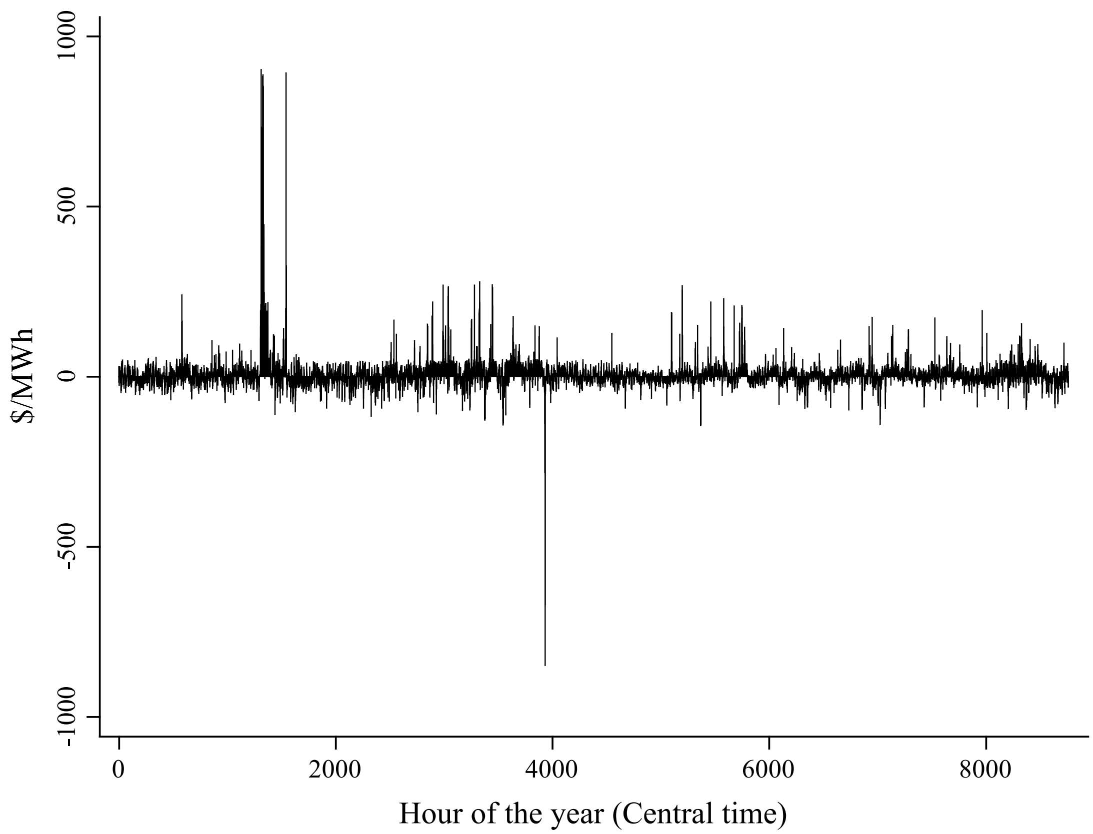

Figure 2: Texas minus California wholesale electricity price, 2003

There are a number of possible explanations as to why wholesale prices in Texas are, on average, higher than in California. First, as noted above, California has greater access to hydroelectricity, not only within the state, but also as imports from the Pacific Northwest. Figure 3 illustrates the supply stacks for both Texas and California, normalized on sales and adjusted for import capacity.[8] The relatively large capacity of

[8] The ratio of Texas sales to California sales in 2003 was about 1.35. Thus, we multiply the California supply stack by 1.35 so that it can be more readily compared to the supply stack for Texas. The import capacity adjustment was done by assuming the type of fuel at the receiving end of the capacity link. For example, the link from the Pacific Northwest to California is assumed to ship hydro-generated power, which serves to increase total hydro capacity in California. Likewise, the tie from the Southwest to California is assumed to ship coal-generated power, and all other ties are assumed to ship natural gas generated power. Texas, on net, is an exporter of power, so no adjustment is made to the Texas supply stack to account for interstate trade. This graphic is not exact (indeed the supply stack will vary over the year as a result of scheduled maintenance for example) and is for illustrative purposes only.

low variable cost sources of electricity in California will result in off-peak prices being generally lower in California than in Texas. However, during peak demand periods, the large capacity of high-efficiency natural gas units in Texas results in prices being generally lower. Variability in imports to California and load-following behavior of hydro capacity can serve either to exacerbate or mitigate these price differences.

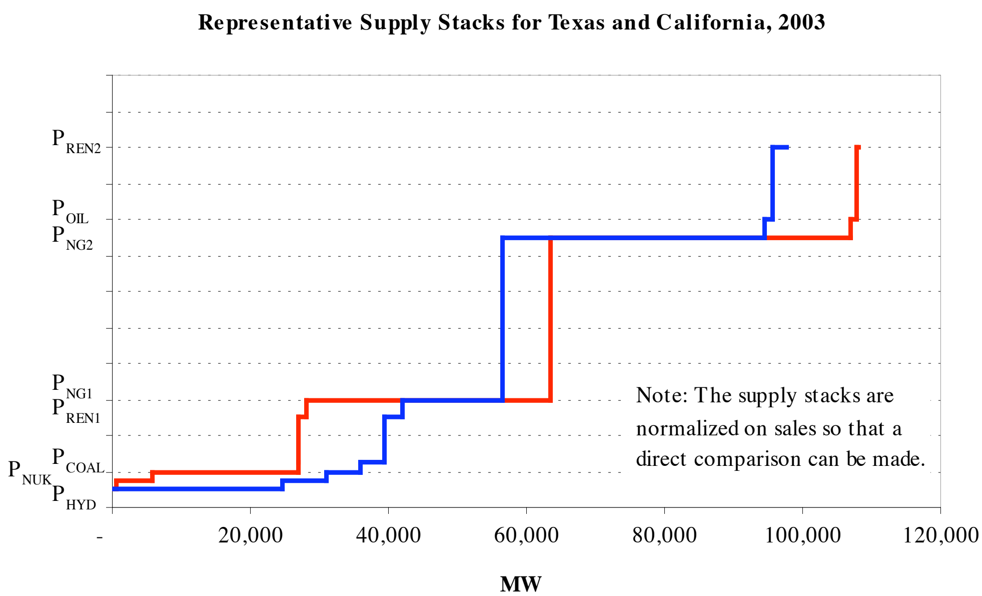

Figure 3: Representative Supply Stacks for Texas and California, 2003

Figure 3 indicates some of the arbitrage opportunities that could be realized on a daily basis from the construction of HVDC transmission capacity. Other opportunities will be available as a result of the time difference and the non-coincident daily peaks. On a longer time scale, differences in seasonal loads will also lead to predictable price differentials that can be exploited. Finally, variations in climate will also provide opportunities for profitable trades over periods longer than one year. For example, drought during the summer of 2001 limited hydroelectric output and contributed to a shortage of supply in California. An HVDC link would have provided much needed system flexibility and mitigated the increase in price that occurred due to the realization of capacity constraints.

Another possible explanation for the observed price difference in Figure 2 is that the two markets differ institutionally. The Texas market is a market for balancing energy, where market participants are expected to arrange trades through long-term contracts and then submit balanced energy supply and demand schedules to ERCOT. Power can then be bought and sold in day-ahead markets in order to accommodate deviations from the balanced schedules.

The philosophy reflected in the original California power market was quite different from that in ERCOT. All power producers were required to sell through the short-term power pool and long-term contracts were prohibited. Following the California power crisis of 2001, however, the market rules were changed. Market participants were allowed to trade electricity using both short- and long-term contracts, thereby enabling them to reduce exposure to unexpected variations in demand and supply. Most of the state's electricity now is traded through these contracts prior to being scheduled on the California Independent System Operator (CAISO) grid. The CAISO market for supplemental energy now operates more like the balancing energy market in Texas.

In order to account for the much greater sensitivity of the wholesale price to changes in load when the load on the system is greater we estimated non-linear supply curves of the form

$$p_t = \alpha_0 + \alpha_1 \ell + \alpha_2 \ell^2 + \alpha_3 \ell^3 + \sum_{i=1}^{J} \varphi_i I_{it} + u_t \tag{1}$$

where p is the hourly average price, ℓ is the average hourly load on the system in GW, the I_{it} are a set of (40) indicator variables for the time of day, day of the week and month and u_t is a random error term. The indicator variables are included since we want to measure the marginal effect on prices of a small change in either supply or demand given the prevailing levels of both anticipated and actual system demand. Market participants would be aware of predictable patterns in system load and prices, and they would make different plants available according to these expectations. For example, annual maintenance of base load facilities is generally scheduled during the months of lowest system-wide demand. Hence, the *effective* supply curve representing the marginal cost of generation varies with expectations of market participants and therefore will vary with season, day of week and time of day. This is precisely why capacity constraints can become binding in short-term intervals despite the existence of idle capacity. In effect, we have modeled expected demand using a set of indicator variables to measure daily, weekly and monthly patterns of demand.

Table 1 summarizes the estimation results for equation (1). The cubic term in load was not found to be statistically significant for Texas, so it was eliminated from the equation. In particular, the estimated short-run supply response in Texas did not become steeper at high load levels as happened in California. As we noted above, Texas had a greater reserve margin than California in 2003, so it could respond to large increases in load without needing to call upon generators with a higher marginal cost. Figure 4 graphs the original data and the fitted values as a function of the level of load on the system.[9] The R^2 statistics in Table 1 show that the time effects and system load leave substantial variations in prices over the year unexplained.

Table 1: Estimated relationships between load and price

	California		*Texas*	
variable	*coefficient*	*standard error*	*coefficient*	*standard error*
ℓ	33.6742	3.1700	10.8674	0.5064
ℓ^2	–0.90924	0.10951	–0.09068	.006565
ℓ^3	0.008702	0.001247		
	$R^2 = 0.3632$		$R^2 = 0.2615$	
H_0: All coefficients = 0	$F_{43,8714} = 115.60$		$F_{42,8716} = 73.48$	
H_0: All $\varphi_i = 0$	$F_{40,8714} = 86.45$		$F_{40,8716} = 52.65$	

Since the coefficients on the indicator variables are not the main focus, they are given in an appendix. Most of them are statistically significant and F-tests indicate that, as a group, the indicator variables are highly significant. This is an indication that there are strong time effects on system loads and prices.[10]

[9] Some data points in Texas that were outside the range plotted have been omitted from the plot (but were included in the statistical analysis). Both states also experienced negative prices on occasion. These arise because some generators (such as run-of-river hydroelectric plants) can supply power regardless of the price and bid a negative price to ensure that they are scheduled to operate. Other base load plant are expensive to stop and start and also will bid a negative price to supply additional energy. If the marginal demand is very low, the highest bid price can be negative.

[10] The signs on the time indicator variables are generally negative in periods when overall system load is greater. This is an indication that the elasticity of supply is greater in the long run than in the short run. Specifically, the coefficients on the indicator variables reflect the effect of time variation on prices *holding the system load fixed*. Thus, they indicate the price effects of the predictable portion of daily load variations. Conversely, the coefficients on the system load terms reflect the effect on prices of short run variations of load around the predictable seasonal pattern. Price spikes occur when unexpected variation in load results in a short run constraint on system capacity. Hence, the indicator variables for high demand periods are estimated to have negative signs because the price increases in such periods are below what they would have been if the load increases had been unexpected. Generators can be scheduled to meet the

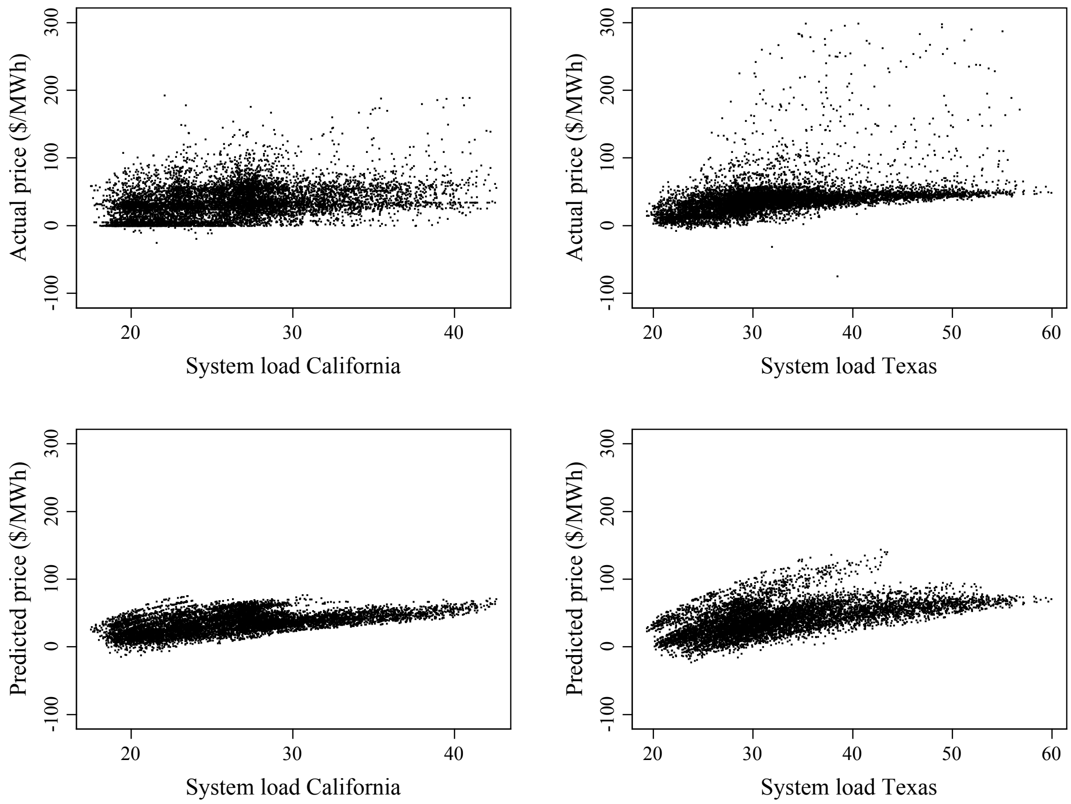

Figure 4: Actual and predicted relationships between load and price in 2003

Using the estimated parameters, we can calculate the effect of a short run change in supply or demand on the price by

$$\frac{dp}{d\ell} = \alpha_1 + 2\alpha_2 \ell + 3\alpha_3 \ell^2 \tag{2}$$

where a purchase in a given state is interpreted as an increase in ℓ while a sale results in a decrease in the load on the remainder of the system and hence a reduction in ℓ.

predictable pattern of load variation over time at lower costs than when unexpected fluctuations in demand or unplanned outages occur. In particular, factors such as unplanned outages of generators, congestion on transmission lines, and the need to maintain system stability, change the marginal supplier at a given level of system load. In effect, the supply stacks illustrated in Figure 3 above are not static, as the actual amount of capacity available for any generation type can vary through time. Nevertheless, generating plants are usually dispatched according to cost and overall system load is the primary determinant of how much costs will change in response to marginal variations in system load.

6. Valuing the transmission line

We consider a line with capacity to deliver 1GW of power to the state with the higher price. It is possible, however, that a smaller trade than 1GW could maximize profits, leaving the link less than fully utilized. In addition, transmission losses mean that the buyer will have to purchase more power than is actually going to be consumed. The distance between Dallas and Los Angeles is very close to 2,000km. A recent paper by Clerici and Longhi[11] implies that losses on an optimized[12] HVDC line with these parameters and using current technology would be approximately 12% with an additional 0.6% lost in each converter station. Taking an optimized quantum wire to be about ten times more efficient, total losses would be around 2.4%, consisting of 0.6% in each converter station and 1.2% line loss. In order to sell Q GWh, therefore, $Q/0.976$ GWh would need to be bought. If the current selling price is p_s, and buying price is p_b, we assume that the new prices will be[13]

$$p_s - \frac{dp_s}{d\ell}Q \text{ and } p_b + \frac{dp_b}{d\ell}\frac{Q}{0.976} \tag{3}$$

and transmission of amount Q would yield net revenue equal to[14]

$$R(Q) = \left(p_s - \frac{dp_s}{d\ell}Q\right)Q - \frac{Q}{0.976}\left(p_b + \frac{dp_b}{d\ell}\frac{Q}{0.976}\right) \tag{4}$$

A trade Q would maximize the arbitrage revenue (4) if

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[11] "Competitive Electricity Transmission as an Alternative to Pipeline Gas Transport for Electricity Delivery", available at http://www.worldenergy.org/wec-geis/publications

[12] Altering characteristics of the wire, such as its composition or diameter, can reduce resistance losses. These changes, however, raise other costs. An optimized line balances out the resistance losses against the remaining costs in order to achieve a lowest overall cost.

[13] Since the estimated coefficients on the second order terms are negative, the approximation (3) may tend to overstate the amount of adverse price adjustment. The estimated price adjustment would, however, reflect the effect of deviations of load "on average". These adjustments could be less extreme than the price movements applicable in the situations most relevant to exploiting arbitrage opportunities where prices are likely to be extreme relative to average. In any case, overstating the amount of price adjustment would conservatively understate the potential revenue making the project appear less favorable.

[14] Observe that equation (4) implies that the resistance loss has a quadratic effect on the revenue from arbitrage. A higher resistance loss requires additional power to be bought in order to deliver 1GWh, and a higher purchase quantity in turn places more upward pressure on buying prices. This emphasizes the benefits of having a line with lower resistance losses.

$$Q = \frac{p_s - \dfrac{p_b}{0.976}}{2\left(\dfrac{dp_s}{d\ell} + \dfrac{1}{0.976^2}\dfrac{dp_b}{d\ell}\right)} \tag{5}$$

If the solution to (5) is greater than the capacity of the line (1GW), however, then the trade would be 1GW at the selling end. The arbitrage revenue per hour obtainable from buying in the low price region and selling to the high price region would then be given by (4) with Q equal to the minimum of the solution to (5) and 1GW.

We evaluated revenue (4) for every hour in 2003 using the observed wholesale hourly prices in California or Texas for the selling and buying prices, p_s or p_b (depending on which was larger). The marginal effects on buying and selling prices of the arbitrage trade were evaluated using (2) at the estimated parameter values in (5) and (4).

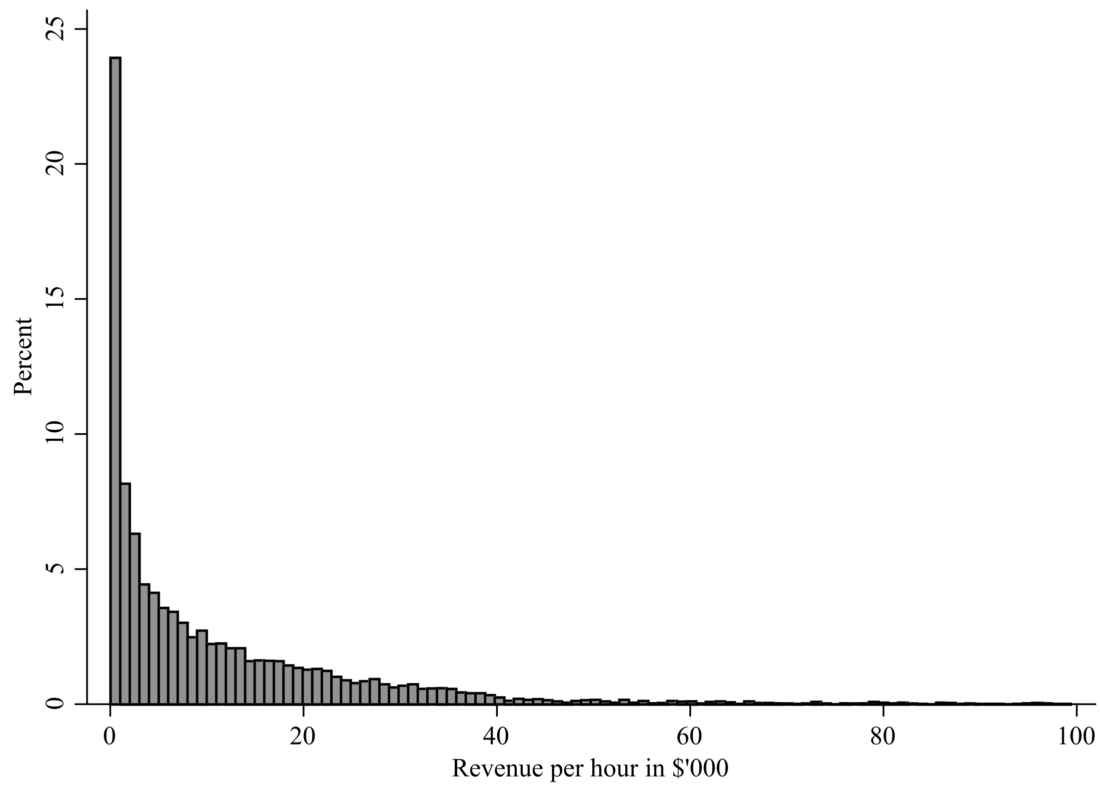

Figure 5: Distribution of hourly revenue for hours where it is less than $100,000

We found that the average arbitrage revenue earned per hour in 2003 would have been $15,096, with a standard deviation of $38,531. Figure 5 graphs the distribution of hourly revenue for all hours where it was less than $100,000. Figure 6 gives the hourly revenue for each hour of the year ordered from hour 1 (midnight to 1 am central time January1 2003) to hour 8760 (11 pm to midnight central time December 31 2003). For the observed 2003 prices, the maximum hourly revenue that could have been earned if the link had been available would have been $892,605. For about 9.5% of the hours, the revenue would have been less than $100, and for about 23.5% of the hours, it would have been less than $1,000. For slightly more than 25% of the hours, the line would have been fully utilized transmitting power from California to Texas, since the profit maximizing arbitrage trade actually exceeded the capacity limit of 1GW. Similarly, for almost 16% of the hours, the revenue maximizing transmission from Texas to California exceeded the line capacity of 1GW.

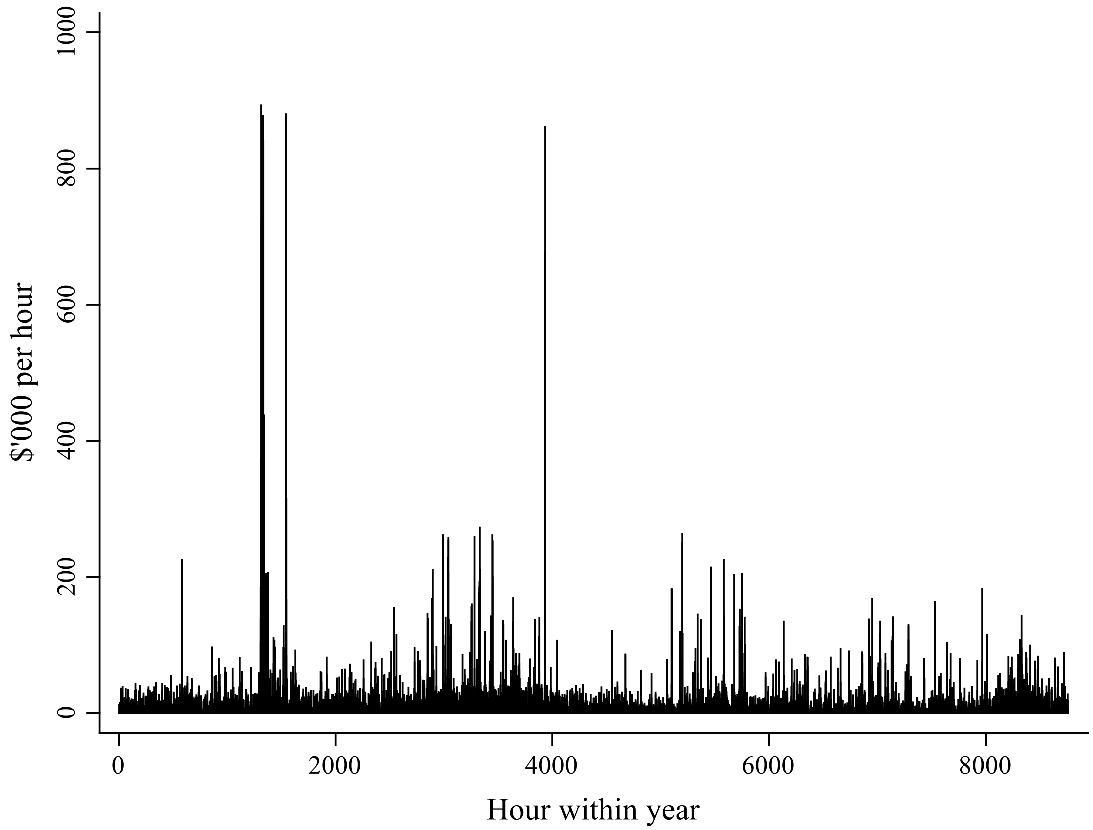

Figure 6: Hourly revenue for each hour of 2003

If we compound the hourly revenue stream forward at an effective discount rate of 7% (real) annually, the end-of-year value is $137.2 million. For a project life of 30 years, the present value of such an annual income stream at 7% would be $1,703 million. It is unknown, however, if this would be sufficient to cover the cost of constructing the link since the cost would depend on many unknown factors including, not least, the expense of producing a quantum wire cable.

To obtain an understanding of the role of resistance losses, it is useful to compare the above calculations with the result one obtains using currently available HVDC technology, where the losses would be closer to 13% as we noted above. We therefore repeated the calculations replacing 0.976 by 0.87 (which represents that rate for conventional HVDC).

With the higher losses of conventional HVDC, the average arbitrage revenue falls to $12,602 from $15,096. The standard deviation of revenue also declines slightly to $38,059. If we compound the revenue stream for conventional HVDC forward to the end of the year at an interest rate equivalent to 7% per annum, end of year revenue totals around $114.5 million. Although this is substantially below the $137.2 million calculated for the quantum wire, it is probably still sufficient to make the project viable. Revenue of $114.5 million for 30 years discounted at 7% yields a present value of $1,422 million.

The cost of constructing the link using currently available HVDC technology is likely to be between $800 and $900 million in present value terms. A recent World Bank publication ("High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper" by Rudervall, Charpentier and Sharma[15]) suggests the figure of $800 million. Another document available from the Energy Information Administration (CSA Energy Consultants, "Existing Electric Transmission and Distribution Upgrade Possibilities,"Arlington, VA, July 18, 1995[16]) gives the cost of a converter station as $215 million, although this cost may have declined somewhat in recent years as a result of technological advances. A conventional link on this route would use 795 kcmil wire[17] yielding a cost (excluding right of way) of $296,024 per mile or $444 million. Adding these together yields a total cost of $874 million.

A revenue stream with a present value over 30 years of $1,422 million compares very favorably to a capital cost of close to $900 million. The analysis of Clerici and Longhi cited above also suggests that a link using current HVDC technology should be competitive with incremental natural gas transportation over this distance. Natural gas is

[15] The paper is available at http://www.worldbank.org/html/fpd/em/transmission/technology_abb.pdf

[16] The paper is available at http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/table2.html

[17] A circular mil (cmil) is the area of a circle with a diameter of 1/1000 of an inch (often referred to as 1 mil).

already transported from the Permian basin in West Texas to Southern California with electricity generation comprising a large part of the demand. The alternative is to consume the gas to generate power closer to the production area so that electrons are shipped rather than gas molecules.

The higher revenue from a quantum wire link would allow it to have higher construction costs and still remain profitable. Even if the cost of the wire is higher, other factors would allow some cost savings. The lower losses on a quantum wire would also allow the line to have a lower capacity yet still deliver the same 1GW of maximum power. In addition, the higher tensile strength, reduced tendency to sag and lower weight of a quantum wire relative to a conventional wire of the same capacity should allow smaller towers and longer spans between them, thus reducing construction costs.

7. Solar plant in Arizona

Before we consider the benefits of adding a solar plant to the project, it is useful to examine the time profile of the trades between California and Texas using the proposed quantum wire link. These can be summarized by regressing the postulated flows against the time, day and month indicator variables. The resulting profile represents an average direction and quantity of flow for a given hour, day, and month.

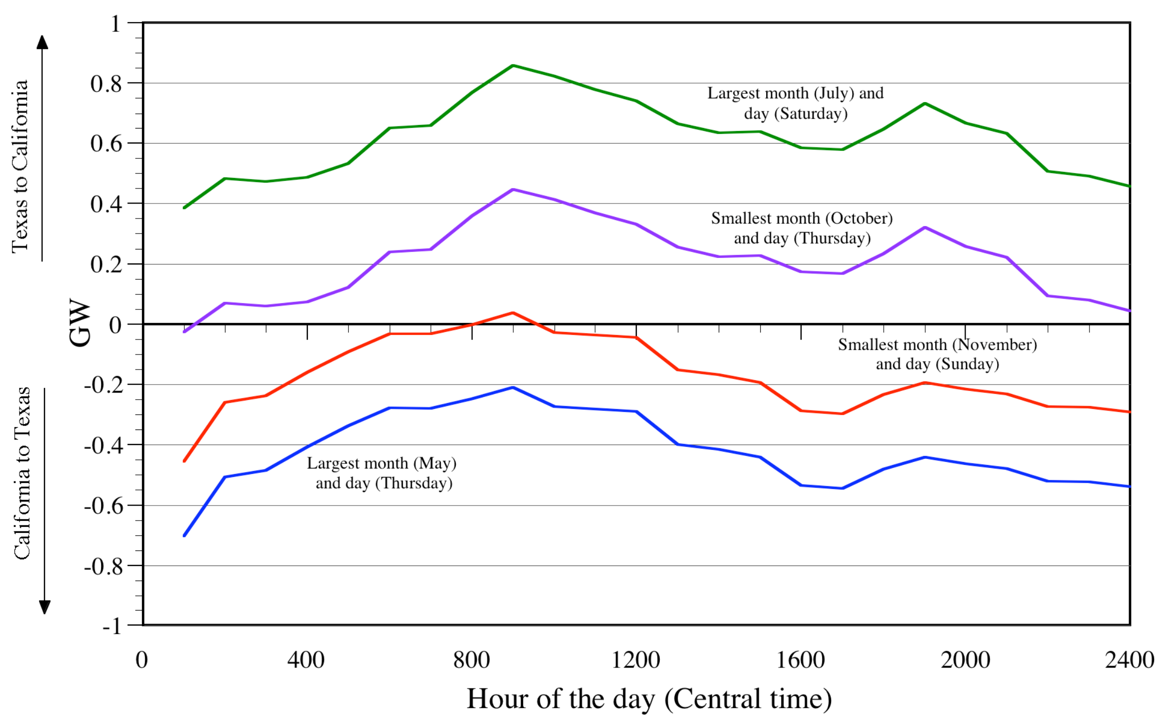

Figure 7: Average daily patterns of arbitrage flows

Figure 7 illustrates the range of profiles for trades over the proposed quantum wire. In general, power is more likely to flow to California from 7 am to noon Central time (5-10 am Pacific time), with a somewhat smaller peak around 7 pm Central time (5 pm Pacific time). It is most likely to flow to Texas from 10 pm to 3 am Central time (8 pm to 1 am Pacific time), with a somewhat smaller peak from 3-5 pm Central time (1-3 pm Pacific time). This general pattern is consistent with Figure 3, which indicates that California tends to have lower prices in the off-peak periods while Texas prices are more likely to be lower in the peak periods.

Arizona is in the Mountain time zone and hence is one hour ahead of California and one hour behind Texas. A solar plant in Arizona would generate power from around 8 am to 6 pm local time (9 am to 7 pm Central time). It thus would be well placed to sell power into the Texas morning peak and into California in the early afternoon. In fact, it is possible that the plant would sell power to both markets simultaneously.

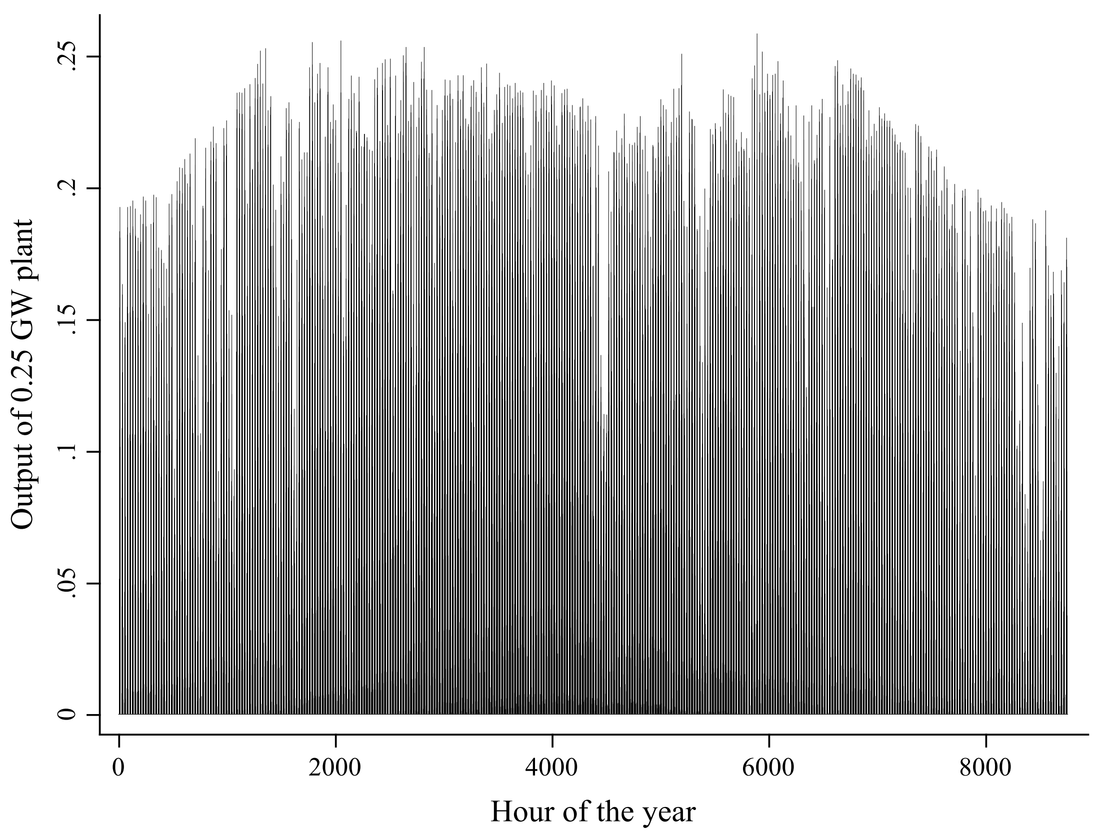

Figure 8: Simulated solar plant output using 1990 data

For our calculations, we assume that the proposed photovoltaic plant of 250 MW peak capacity, is in Tucson, Arizona. Using data from the National Renewable Energy

Laboratory (NREL) for 1990, we simulate electricity output for the solar plant. The NREL data actually allows one to simulate a number of different plants, but for this purpose, we assume the panels are fixed and tilted at an angle equal to the latitude minus 15°. Such a configuration yields a maximum output of around 1,102.5 Wh/m^2 compared with 1,067 Wh/m^2 for a horizontal panel. In addition, the output from the horizontal configuration is more concentrated in the hours around noon, but, given the time profile of the trades on the quantum wire, this configuration would likely not maximize the value of the plant in arbitraging the two markets. Figure 8 graphs the simulated output.

The efficiency of the solar panels significantly affects the cost of the plant since it dictates how large an area of panels we need to generate 1GW. For example, for 10% efficiency, 250,000/(0.1×1.1025) = 2.268 million m^2 of panels will be needed. The efficiency of the panels, in turn, depends on the materials and the manufacturing process, which also affect the production costs. Rather than specify the efficiency of the solar panels, we calculate a trade-off between efficiency and the maximum production and installation cost per meter squared of the panels that, when combined with the balance of system costs, leads to a net present value for the project of zero.

Recall that the overall losses (on a quantum wire) from shipping power between Texas and California are assumed to be 2.4%. The overall distance is approximately 2,000km, with around 800km from Tucson to Southern California and 1200km from Tucson to North Texas. Allowing line loss to be proportional to distance, the line loss between Texas and Arizona is 150% of the loss between California and Arizona. Noting that the losses in a converter station are 0.6%, we therefore assume that the losses between Tucson and Southern California are 1.08% (2/5 times 1.2% plus 0.6%), while those between Tucson and North Texas (again including a converter station) are 1.33%. Thus, to sell Q GWh in California if the solar plant output is S GWh, the following amount needs to be purchased in Texas:

$$\frac{1}{0.9867}\left(\frac{Q}{0.9892}-S\right).$$

Conversely, to sell Q GWh in Texas, then at most the following amount needs to be purchased in California:

$$\frac{1}{0.9892}\left(\frac{Q}{0.9867}-S\right)$$

Let the price in California be p_C and in Texas be p_T. If California has the higher price, the revenue maximizing sales Q in California will solve

$$Q=\frac{p_C-\dfrac{p_T}{(0.9892)(0.9867)}+\dfrac{2S\dfrac{dp_T}{d\ell}}{(0.9892)\left(0.9867^2\right)}}{2\left(\dfrac{dp_C}{d\ell}+\dfrac{1}{\left(0.9892^2\right)\left(0.9867^2\right)}\dfrac{dp_T}{d\ell}\right)} \tag{6}$$

which exceeds the value implied by (5), the case without the solar plant, by the additional term in the numerator of (6). Since less power needs to be purchased in Texas, prices there will not rise as much, so a larger arbitrage sale in California will be optimal. Similarly, if Texas has the higher price, the revenue maximizing sales Q in Texas will solve[18]

$$Q=\frac{p_T-\dfrac{p_C}{(0.9892)(0.9867)}+\dfrac{2S\dfrac{dp_C}{d\ell}}{\left(0.9892^2\right)(0.9867)}}{2\left(\dfrac{dp_T}{d\ell}+\dfrac{1}{\left(0.9892^2\right)\left(0.9867^2\right)}\dfrac{dp_C}{d\ell}\right)} \tag{7}$$

Actual arbitrage sales will equal the amount given by (6) or (7) unless the resulting value of Q is greater than 1 or less than or equal to S, adjusted for transmission losses. In the former case, Q would equal the 1GW capacity of the line. In the latter case, if solar output is non-zero, it could still be sold for positive revenue. We would expect this situation to occur when the price differential between California and Texas is not very large, for otherwise Q would be positive. If the price differential between California and Texas is small, solar power would be sold in both states. If we let s be the solar output sold in California and $S - s$ the output sold in Texas, total revenue from solar sales alone would be

$$R=\left(p_C-\frac{dp_C}{d\ell}0.9892s\right)0.9892s+\left(p_T-\frac{dp_T}{d\ell}0.9867(S-s)\right)0.9867(S-s) \tag{8}$$

Revenue (8) would be maximized where

[18] Note that the final term in the numerator in (7) differs from the corresponding term in (6), but otherwise the expressions are identical. Also note that the expressions are identical if solar output, S, is zero, as the previous analysis would imply.

$$s=\frac{0.9892\,p_C-0.9867\,p_T+2\left(0.9867^2\right)S\dfrac{dp_T}{d\ell}}{2\left(0.9892^2\dfrac{dp_C}{d\ell}+0.9867^2\dfrac{dp_T}{d\ell}\right)} \tag{9}$$

If the solution to (9) is negative, all the solar output S would be sold in Texas, while if it is greater than or equal to S all the output would be sold in California.

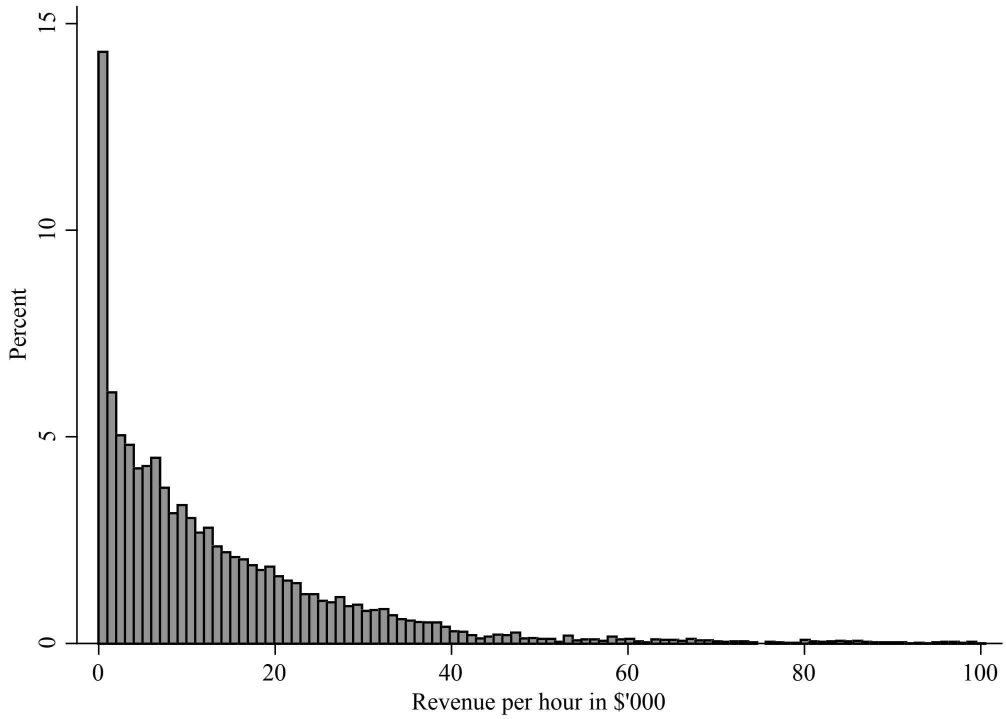

Figure 9: Distribution of hourly joint project revenue when it is less than $100,000

The average hourly revenue from the joint quantum wire/solar project is $17,348 with a standard deviation of $39,093. The maximum hourly revenue is now $895,547. Figure 9, corresponds to Figure 5 above, and indicates the distribution of hourly revenue for all hours where revenue is less than $100,000. Figure 10, corresponds to Figure 6 above, and indicates the hourly revenue for each hour of the year. Comparing Figures 9 and 10 with Figures 5 and 6, the addition of the solar plant generates positive revenue in many more hours of the year and allows the quantum wire to be more fully utilized. The proportion of hours where revenue is less than $100 declines to about 5.4%, while it is less than $1,000 for fewer than 14.5% of the hours. The proportion of hours during which the line would be fully utilized rises to almost 25.8% for flows from California to Texas and slightly more than 16.4% for flows from Texas to California.

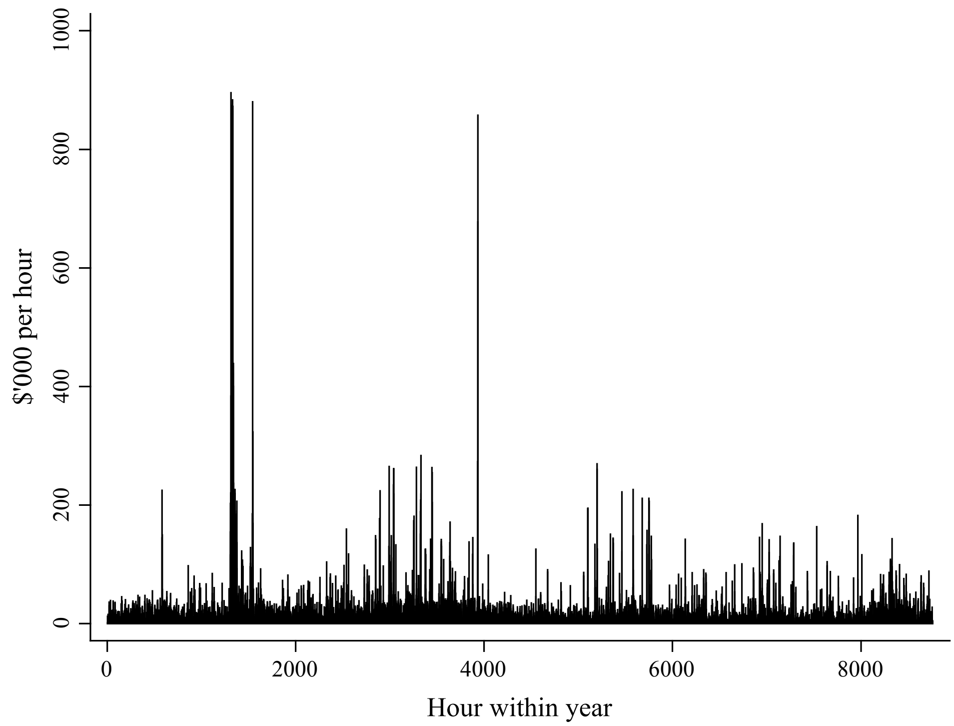

Figure 10: Hourly revenue from joint project for each hour of 2003

Now suppose that only the marginal increase in revenue for the solar project would be available to fund the construction of a solar photovoltaic plant. If we compound the revenue from both the transmission project and the solar plant forward to the end of the year, revenue now averages $157.7 million. The marginal contribution of the solar plant output is thus $20.5 million per year at end of year values. For a 30-year project life, and again discounting at 7% (real), this amounts to a present value increment of $253.9 million.

The costs of a photovoltaic plant include the panels, the balance of system, land and construction costs, and maintenance costs, all of which depend on the area of the panels. In turn, the area required for the solar plant depends upon the conversion efficiency of the panels. As we noted above, at 10% efficiency 2.268 million m^2 of panels will be needed. The area needed would be halved if the efficiency of the panels could be doubled.

Figure 11 expresses the results of the analysis in terms of the trade-off between panel efficiency and the present value of installation and maintenance costs per meter squared of panel area. For example, if panel efficiency were 16%, the project would have non-negative net present value for installation and maintenance costs up to around

$180/m^2$. Producers have not had sufficient experience with manufacturing solar panels in volume to enable one to judge the likelihood of achieving costs at or below the maximum level indicated in Figure 11. The largest existing grid-connected photovoltaic system (at Mühlhausen in Germany) has a peak DC capacity of only 6.3MW. Nevertheless, the allowable costs in Figure 11 are well within the range considered feasible using current technology. For example, an article available at Azom.com (*The A to Z of Materials*)[19] states that the baseline First Solar thin film technology, with 11% efficiency, currently has manufacturing costs of less than $100/m^2$ with $50/m^2$ possible as the technology is optimized for larger volumes. The US Department of Energy has set a combination of 15% module efficiency with a direct manufacturing cost of $50/m^2$ as a long-term goal for thin film modules, with the remaining installation and maintenance costs possibly doubling the overall cost of the system.

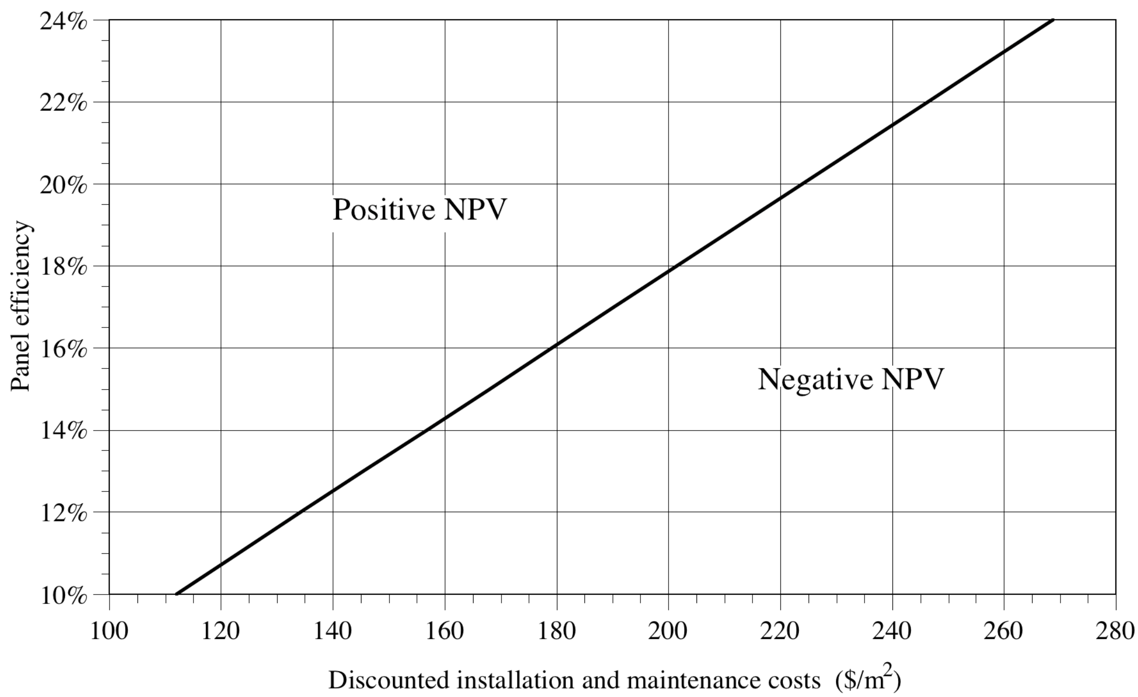

Figure 11: Installation and maintenance costs for zero net present value

8. Concluding remarks

Although the cost and revenue calculations in this paper are indicative, rather than definitive, they suggest that a moderately sized project could be placed in the US Southwest with minimal need for subsidy. The key idea is that a new transmission link

[19] See http://www.azom.com/details.asp?ArticleID=1167

between Texas and California would provide an opportunity to arbitrage price differences that reflect, in part, the differences in time zones and the different seasonal weather patterns in the two states. The arbitrage revenue would likely be sufficient to finance the construction and maintenance costs.

An additional advantage of the proposed system that we have not included in the calculations is that would allow substantial additional wind resources in West Texas to be developed. At present, electricity that could be generated from these resources is too expensive to provide to major markets in East Texas. The quantum wire would allow efficient access for the wind resource to both East Texas and markets farther west.

A major public benefit of undertaking such a project is that we would learn a great deal about the process of manufacturing and installing photovoltaic systems on a large scale. This may stimulate the development of associated technologies and advance the time when solar energy could be competitive with fossil fuels as a source for electricity generation.

9. Appendix

Table 2 reports the estimated coefficients on the indicator variables for time of day, day of the week and month of the year in equation (1).

Table 2: Estimated time effects

	California		*Texas*	
variable (Central time)	*coefficient*	*standard error*	*coefficient*	*standard error*
0200	-5.127881	1.488327	2.265469	2.828049
0300	-1.775732	1.564249	3.169377	2.838019
0400	-3.626914	1.633206	2.631301	2.845989
0500	-5.207557	1.679018	1.77067	2.841338
0600	-8.401042	1.681906	-3.258269	2.821547
0700	-12.43621	1.607141	-16.34919	2.830939
0800	-20.06236	1.49251	-13.20999	2.850823
0900	-31.69526	1.443163	-17.90536	2.87074
1000	-29.41759	1.450789	-18.40726	2.900285
1100	-28.54353	1.476092	-21.32628	2.928075
1200	-29.84746	1.50367	-24.26084	2.946028
1300	-26.236	1.522649	-23.8555	2.95796
1400	-25.18937	1.527161	-24.69684	2.970708
1500	-25.66844	1.53065	-24.21478	2.98087
1600	-20.49104	1.53446	-26.59408	2.9906
1700	-19.75602	1.53196	-28.41036	2.999753
1800	-22.1415	1.531498	-31.89773	3.011484

1900	-28.21904	1.546041	-31.68229	3.026036
2000	-30.93228	1.576782	-36.12296	3.017055
2100	-27.62318	1.579353	-37.99523	3.00196
2200	-26.38723	1.573415	-35.872	2.961831
2300	-20.30629	1.546987	-17.81465	2.892787
2400	-18.6514	1.482548	-10.81922	2.83476
Monday	-8.017	0.8603898	-5.50443	1.554835
Tuesday	-10.7151	0.8973218	-0.361334	1.555381
Wednesday	-9.555997	0.8934292	-5.016756	1.550503
Thursday	-11.38409	0.8906407	-4.321946	1.560046
Friday	-11.04135	0.8767071	-11.21517	1.556792
Saturday	-2.686987	0.7941822	-0.1294971	1.529846
February	15.43972	1.03877	43.17491	2.028992
March	15.01924	1.012339	34.75362	2.056917
April	0.1592841	1.019575	9.48505	2.015651
May	-9.337888	1.018516	-8.338293	2.036233
June	-18.13503	1.080949	-28.62566	2.133884
July	-17.36211	1.250696	-38.74669	2.22644
August	-24.21732	1.250009	-37.24311	2.294521
September	-22.85282	1.167444	-22.06089	2.026727
October	-15.59458	1.051992	1.917275	1.978604
November	-11.21062	1.02331	2.315205	2.013533
December	-14.18249	1.032515	1.976796	1.982734
Constant	-338.8182	30.22485	-184.8465	9.266886