A SCOPING-LEVEL STUDY OF THE ECONOMICS OF WIND-PROJECT REPOWERING DECISIONS IN CALIFORNIA

CONSULTANT REPORT

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Abstract

Many of California's wind power facilities are aging. Despite interest by policymakers in encouraging wind project repowering, as well as efforts by the state's utilities to contract with such projects, repowering activity has been somewhat slow.

This report addresses one of the primary barriers to wind repowering: the general lack of economic incentive to replace all but the most poorly functioning of the wind turbine fleet. In particular, the report provides a scoping-level analysis of the economic attractiveness of repowering to wind project owners. The study finds that aging wind facilities may often be more profitable, in the near term, in continued operations than they would be if they pursued repowering. In particular, the study finds that for a large number of existing wind projects, payment levels well above the 2007 market price referent and well above the presumed cost of a new wind project at a new site may be necessary to accelerate wind turbine replacement. If and when the production tax credit expires, this necessary payment level will increase further.

To encourage early repowering, it may be necessary to consider a more proactive state policy, one that offers an explicit financial incentive for the replacement of aging wind projects. If policy makers wish to encourage repowering, it may also be significantly less expensive to do so while the production tax credit is available. Even with such an incentive policy, however, a variety of other barriers will continue to thwart the replacement of aging wind projects; as such, it is unclear whether addressing the financial barriers will be sufficient to motivate significant repowering investments. Finally, the state should only develop a program to financially encourage repowering if it determines that the costs of doing so are worthwhile given the potential benefits.

Keywords: Wind power, repowering, economic analysis

Executive Summary

The California Energy Commission's (Energy Commission) *Integrated Energy Policy Reports* have concluded that little progress has been made to repower California's aging wind facilities to more efficiently use prime wind resources while potentially reducing avian mortality. About 1,320 megawatts (MW) of wind power was installed in California during the 1980s. These turbines are aging and often inefficient compared to current wind turbine technology, and repowering these turbines could result in a moderate amount of additional renewable energy delivered to the grid. Other potential benefits of wind project repowering include a reduction in avian mortality, reduced aesthetic concerns, potentially lower costs than new wind power or "greenfield" projects, improved turbine technology that better supports the state's electrical grid, and increased local and state tax base. As a result of potential benefits, the Energy Commission's *2007 Integrated Energy Policy Report* (IEPR) states, "The IEPR Committee encourages the repowering and expansion of existing wind energy sites to increase the efficient use of existing infrastructure and reduce environmental impacts."

Despite interest by the Energy Commission and California Public Utilities Commission in encouraging this repowering, and efforts by the state's investor-owned utilities to contract with such projects, repowering activity has been somewhat slow. For a variety of reasons, aging wind turbines are simply not being replaced with state-of-the-art wind technology at a rapid pace.

This report addresses one of the primary barriers to more-rapid wind repowering - the general lack of economic incentive to repower all but the most poorly functioning of the wind turbine fleet. In particular, this report provides a scoping-level analysis to determine whether repowering wind facilities is, in general, economically attractive to wind project owners in California, and assesses the conditions necessary to make turbine replacement economically desirable for wind project owners.

It should be noted that this analysis emphasizes the perspective of the wind project owner and the payment level that might be needed to encourage those owners to accelerate repowering decisions. The analysis informs, but does not directly address, other important stakeholders to repowering decisions, for example, the perspectives of utility purchasers, electricity ratepayers, or society at large.

The remainder of this report is structured as follows:

- Chapter 2 provides a general background on the wind repowering opportunity, including a list of the benefits and barriers to accelerated turbine replacement.
- Chapter 3 summarizes the method and assumptions used for the analysis developed in this report, as well as some of the key limitations to the analysis.

- Chapter 4 presents the key results of the scoping-level evaluation and highlights the conditions under which the study results show wind repowering to be economically viable.
- Chapter 5 offers some basic conclusions that emerge from the analysis.

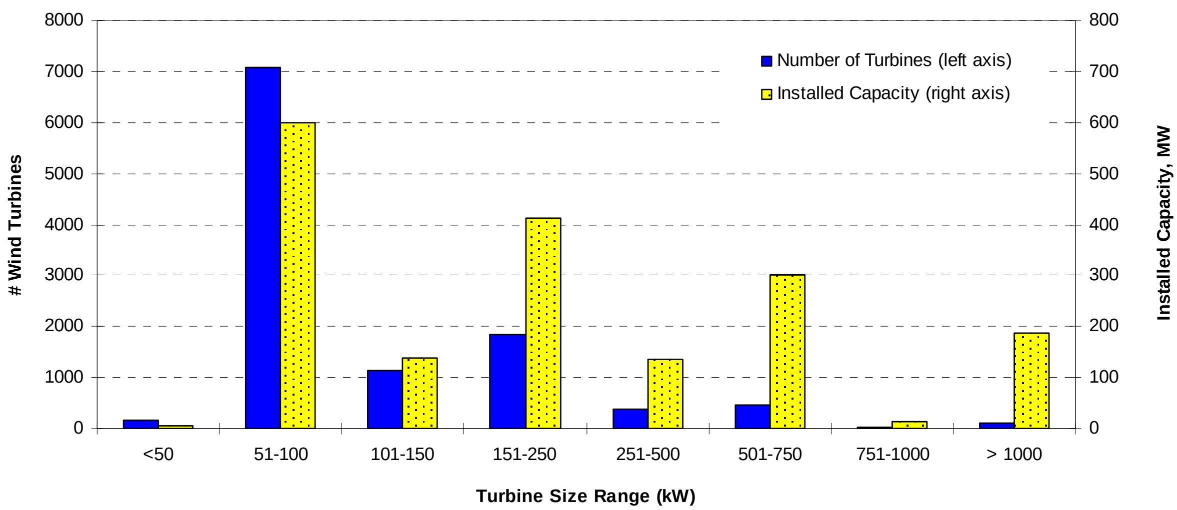
A detailed assessment of repowering potential and economics in California is beyond the scope of this analysis. As a result, this report is not intended to be the last word on this subject. The Energy Commission may wish to consider more detailed studies of the economic viability of, and market potential for, wind repowering in the state, as well as further assessment of whether the benefits of pursuing a more rapid pace of project repowering are worth the potential costs of doing so.

CHAPTER 1: The Repowering Opportunity

More so than any other state or country, California has a large number of aging wind turbines in use. Roughly 1,320 MW of wind power capacity was installed in the state during the 1980s,[1] and turbines remaining from this era are therefore at least 19 years old. No other state or country deployed wind power at this scale before 1990.

Figure 1 depicts the physical reality that, as of the end of 2005, most of California's existing wind turbines were old and of dramatically different scale than present industry standards. At the end of 2005, for example, the greatest concentration of wind turbines and capacity deployed in the state were in the 51-100 kW size range, 10-40 times smaller in nameplate capacity terms than current state-of-the-art technology. It was not until 2002 that California saw its first megawatt-class turbines, and even at the end of 2005, just 10 percent of the installed wind capacity in the state consisted of turbines of that size.

Figure 1. Number and Capacity of Wind Turbines in California, by Turbine Size

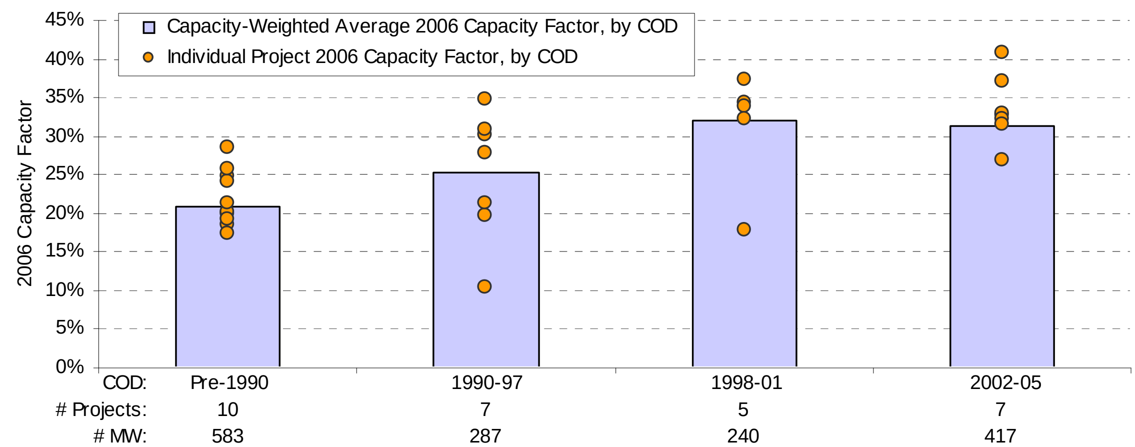


Source: California Energy Commission Wind Performance Reporting System, 2005

One of the key implications of these trends is that the average capacity factor of California's wind turbine fleet is well below what one expects to see in new wind power projects. Figure 2, for example, shows the average 2006 capacity factor for a *sample* of wind projects in California, binned by the date of installation. Though the resulting sample represents just 64 percent of the installed wind capacity in the state at the end of 2006, the figure nonetheless demonstrates the improved capacity factors for wind projects installed more recently.

Figure 2. Average 2006 Capacity Factor for California Wind Projects

[1] See: http://ewprs.ucdavis.edu/



Source: Berkeley Lab database

The potential benefits of repowering are multifaceted. Though there is disagreement on the magnitude or importance of these benefits, most would agree that the repowering of aging wind plants offers the following possible advantages:

- Avian mortality reduction that may occur due to the installation of a smaller number of larger wind turbines, with improved micro-siting practices.[2]
- Reduced aesthetic concerns to the extent that modern wind projects – even with higher tower heights – are deemed more visually appealing.
- Increased renewable energy production due to the higher average capacity factors typical of new wind facilities.[3]
- Use of existing infrastructure (for example, roads, substations), resulting in lower installed costs relative to new "greenfield" wind power projects.
- Use of newer wind turbine technology that can better support the state's electrical grid with better power quality.[4]
- Increased local and state tax base, and positive construction employment impacts.

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[2] For example, see some of the documents listed under the Energy Commission's Development of Statewide Guidelines for Reducing Wildlife Impacts from Wind Energy Development [http://www.energy.ca.gov/renewables/06-OII-1/documents/index.html].

[3] Assuming that new wind projects in the state achieve an average capacity factor of 34 percent, compared to 22 percent for projects that are not repowered, and assuming that an additional 1,000 MW of wind are repowered, then an increase in renewable electricity production of over 1,000 GWh/year would be possible, assuming that repowering does not increase nameplate capacity. Though this is a sizable addition, equivalent to 350 MW of new wind power capacity, it represents a relatively small proportion of the amount of additional renewable electricity required under the state's RPS.

[4] See, for example, Behnke, M. and W. Erdman. 2006. *Impact of Past, Present and Future Wind Turbine Technologies on Transmission System Operation and Performance*. CEC-500-2006-050. Sacramento, California: California Energy Commission. [http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2006-050.html]

In addition, although the 2-cent/kWh, 10-year federal production tax credit (PTC) is currently available through 2008 and is expected to be extended further, it is unlikely to be available indefinitely, and there may be advantages to accelerating the repowering process to take advantage of this federal tax benefit.

Despite the sizable opportunity for wind-project repowering in the state, as well as the possible benefits of pursuing that repowering, wind turbine replacement has not proceeded rapidly. Through the end of 2007, for example, roughly 365 MW of wind projects had been repowered in California.[5] If one defines the repowering opportunity to only include projects constructed before the end of 1994, and that are therefore more than 13 years old, then repowering to date has only managed to capture roughly 20 percent of the market potential of 1,640 MW.

Since the enactment of the state's renewables portfolio standard (RPS) in 2002, the investor-owned utilities have signed 10 wind repowering contracts, for 124 MW to 161 MW of capacity in total. These include two Pacific Gas and Electric (PG&E) contracts for repowering in the Altamont pass (Diablo Winds and Buena Vista), and eight Southern California Edison (SCE) contracts for repowering in Tehachapi and San Gorgonio (CTV Power, Boxcar, Karen, Coram, Caithness I/II, and Ridgetop I/II). Roughly 100 MW of this capacity had been repowered by the end of 2007.[6,7]

Economic, legislative, regulatory, institutional, and financial considerations all have a direct bearing on repowering decisions, and a variety of barriers have contributed to the relatively slow rate of wind turbine replacement in California, including:[8]

- Environmental review and permitting challenges, which may delay construction and affect the operations of repowered facilities, especially in the Altamont Pass wind resource area.
- The federal PTC's "California fix", which effectively excludes from PTC eligibility any repowered wind project that remains on an existing qualifying facility (QF) contract (entered into before January 1, 1987).[9]

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[5] This figure is based on an AWEA/GEC wind project database updated to include repowering contracts signed under the California RPS. Separately, CalWEA has estimated that 340 MW of wind repowering has occurred in the state. The authors are unaware of a single, comprehensive and accurate source for repowered wind development.

[6] These data are based on the Energy Commission's tracking of RPS renewable energy contracts, which can be found at [http://www.energy.ca.gov/portfolio/contracts_database.html].

[7] PG&E has also gained approval to restructure contracts with a number of QF wind projects, which may facilitate future repowering.

[8] Many of these barriers have been discussed by CalWEA in various filings to the California Public Utilities Commission and the California Energy Commission, along with proposals on how to address them. To date, relatively few of CalWEA's suggestions have been accepted.

- The uncertain availability of the PTC and rising wind turbine costs, in combination with a lengthy and complicated contracting process, which may create incentives for delay.
- Lack of transmission availability for increased capacity in some resource areas, which may require transmission expansion to accompany repowered facilities, if those facilities lead to an increase in project capacity.[10]
- Additional requirements in new contracts, including collateral, performance requirements, and scheduling, that some project owners view as onerous.
- Lack of human resources to work on repowering opportunities, when demand for new greenfield projects is at an all-time high.
- Difficulty in gaining access to turbines in the present shortage environment, especially for repowered projects that tend to be relatively small.

And finally, it may simply be the case that owners of many existing, aging – but still well-performing – wind power projects are doing what is in their own best financial interest: continuing to reap significant cash flow from old, depreciated wind projects that receive qualifying facility (QF) prices. Such project owners may have little economic incentive to repower at this time, as repowering requires substantial new investment and potentially different and more onerous contract terms and pricing. This potential lack of economic interest is the topic of the remainder of this paper.

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[9] The repowered facility will be eligible for the PTC only if the existing standard offer contract is "amended" such that any wind generation in excess of historical norms is sold to the utility at short-run avoided cost, or if this excess generation is sold to a separate entity, or if the repowered project receives an entirely new contract from the purchasing utility (in lieu of the existing standard offer contract).

[10] Increases in generation, without an increase in nameplate capacity, would presumably not trigger the need for additional transmission investments.

CHAPTER 2: Method For Analysis

Method

Three cash-flow models are constructed to allow an economic comparison of a repowered wind facility with non-repowered existing wind facilities, as well as a new "greenfield" wind plant. The goal of this analysis is to determine the contract price (i.e., the levelized cost of energy, or LCOE) for a repowered facility that would be needed in order to make that project as profitable to its owner as continuing to operate the existing wind facility without repowering. [11] Achieving equivalent profitability of this form would likely be necessary to accelerate repowering decisions.[12] This price is then compared to the Market Price Referent (MPR),[13] to the calculated power price for a new greenfield wind facility, and to the levelized price of continued operations of the existing wind facility. A range of input assumptions are used to explore the conditions under which repowering might make economic sense for the project owner.

The analysis is performed as follows:

First, a cash flow model is created to evaluate the net present value (NPV) of continued operations of *existing* wind facilities in the state, without repowering. Given the sizable range in capacity factor and operations and maintenance (O&M) costs among existing California wind plants, the authors develop bounding scenarios including mid-, high-, and low-cost cases that accommodate variations in O&M costs and capacity factors. In addition, differences in contract status and pricing expectations are reflected in low-, mid-, and high-revenue scenarios. For each combination of cost/performance and revenue scenarios, the net present value of continued project operations is calculated, as well as the projected number of remaining years of positive cash flow (considered to be the project's remaining lifetime).

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[11] To some degree, the work presented here builds off of work conducted previously by the California Wind Energy Association. See, for example, California Wind Energy Association, 2006. Comments of the California Wind Energy Association in Reponse to the Scoping Memo and Ruling of Assigned Commissioner Filed August 21, 2006. Rulemaking 06-05-027. October 31. Unlike CalWEA, however, this work takes into account not only the profitability of the existing (non-repowered) wind plant under its existing QF contract, but also the expected future profitability of the existing plant after its current QF contract expires. In so doing, the authors find that higher revenue streams are needed to encourage accelerated repowering decisions.

[12] This is, of course, an approximation. If a repowered facility has a more-certain level of expected profitability, then a project owner may wish to pursue repowering even if the absolute level of expected profit is lower than that of continuing to operate the existing facility. On the other hand, continuing to operate the existing facility does not preclude the opportunity to repower at a later date. As such, accelerating the repowering decision may require an expected level of profitability that equals that of the continued operations of the existing plant plus any expected profit from repowering the facility at a later date.

[13] The market price referent is a value calculated by the California Public Utilities Commission and is intended to be a proxy for the cost of new gas-fired electric power generation.

Second, the cash flow model for the *repowered* wind facility is used to calculate the levelized power price needed to ensure that the repowered facility is as profitable (on an NPV basis) as continued operations of the existing plant (i.e., until that plant's operating profits become negative). This 20-year levelized price is then compared to:

- The 20-year levelized price from the repowered facility necessary to achieve a minimum nominal internal rate of return (IRR) of 10 percent.
- The 20-year levelized price from a new, greenfield wind project necessary to achieve a minimum IRR of 10 percent.
- The current 20-year Market Price Referent (MPR) for a flat block of power.
- The levelized price of receiving power from the existing facility, during the remainder of the project's life, without repowering.

Third, because the low-, mid- and high-O&M-cost and performance assumptions for existing wind plants are intended to represent bounding cases, the authors also conduct sensitivity analysis around the mid-case input assumptions, including incremental variations in capacity factors and O&M costs. Because of the importance of the federal production tax credit, the authors also assess the additional payment that might be necessary to induce repowering were that credit not available.

Finally, the authors consider the current wind turbine shortage environment. In such an environment, it may be necessary for the profitability of a repowered wind facility to not only exceed that of an existing (non-repowered) facility, but also that of a new, greenfield wind project that would otherwise receive the turbines in question.

Input Assumptions

Input cost, performance, and financing assumptions for existing, repowered, and greenfield wind projects – presented in Table 1 – were developed using multiple sources. In particular:

- The Energy Commission's cost of generation report was used to inform the estimated installed cost of a new greenfield wind facility in the state; the initial O&M costs for greenfield and repowered wind projects; and expected property tax expenditures.[14]

[14] California Energy Commission, 2007. *Comparative Costs of California Central Station Electricity Generation Technologies*. Final Staff Report. CEC-200-2007-011-SF. Sacramento, California. [http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF]. Note that installed costs were increased by $100/kW from what was reported by the Energy Commission to account for the continued upward trend in wind project costs.

- The U.S. Department of Energy's *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*[15], and the data underlying that report (as evaluated by the authors), was used to estimate the original installed cost of existing projects in the state; the differential in cost between greenfield and repowered wind projects; the range of O&M and capacity factors among the existing fleet of wind projects in California; and annual O&M escalation rates.
- A consulting report prepared for the Energy Commission was used to estimate the cost of operating collateral for repowered and greenfield wind projects, a cost that is assumed to not apply to existing facilities.[16]

In all cases, the authors assume that repowered and greenfield projects are operational on January 1, 2009, and the analysis period therefore starts at the beginning of 2009 and runs for 20 years in these cases. For the existing facility, the analysis period also begins in 2009, and runs for the duration of the calculated remaining economic lifetime of the facility (i.e., as long as operating revenues exceed operating costs). The authors assume that each project is of equivalent size (25 MW), even though a new greenfield project may often be larger (therefore benefiting from economies of scale), while a repowered project may sometimes be larger than the existing project that it replaces. A minimum nominal return on investment of 10 percent is assumed for repowered and greenfield projects, and an independent power producer (IPP) project ownership arrangement is used. Use of existing infrastructure results in lower installed costs for a repowered facility than for a new greenfield project.

Low-, mid-, and high-cost scenarios are developed for O&M expenditures and capacity factors for the existing project to reflect the wide variation in these input parameters. The input parameters for these scenarios were developed after a review of actual O&M costs and capacity factors from a subset of existing wind projects in California. The low- and high-cost scenarios are intended to be bounding scenarios, and therefore reflect a considerable range of O&M and capacity factor assumptions. Additional data would be needed to better assess the actual distribution of O&M costs and capacity factors among California's wind fleet. Similar sensitivities are not developed for the repowered or greenfield project, in part to simplify the analysis and in part because variation in these parameters is not as significant for new projects as it is for the aging, existing wind generators in the state. Other input assumptions are as specified in Table 1.

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[15] Wiser, R. and M. Bolinger, 2007. *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*. LBNL-62702. Washington, D.C.: U.S. Department of Energy.

[16] O'Connell, R., and R. Wiser. 2006, *The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement*. Consulting Report. CEC-300-2006-014. Sacramento, California.

Table 1. Project Cost, Performance, and Financing Assumptions

Input Variable	Existing Project			Repowered Project	Greenfield Project
	low cost	mid cost	high cost		
Project size (MW)	25				
Ownership	IPP				
Project capital structure	100% equity				
Discount rate/minimum equity IRR (nominal)	10%				
Original installed cost (2007$)[a]	$2,500/kW			$1,880/kW	$2,040/kW
Initial O&M expense (2007$)[b]	$40/kW-yr	$60/kW-yr	$90/kW-yr	$30/kW-yr	
Real O&M escalation rate	4%/yr			0%/yr	
Property tax[c]	1.07% of depreciated cost				
Capacity factor (CF)	30%	22%	16%	34%	
Remaining project life	until operating profit is negative			20 years	
Federal income tax rate	35%				
State income tax rate	8.84%				
Tax depreciation	None			97% 5-yr MACRS; 3% 15-yr MACRS	95% 5-yr MACRS; 5% 15-yr MACRS
PTC (2007$)[b]	$0			$20/MWh	
Power sales price	see Table 2			calculated	
Contract duration	Indefinite			20 years	
Nominal inflation rate	2%/yr			2%/yr	
Annual cost of operating collateral (letter of credit)	None			2% of annual revenue	

[a] The installed cost for existing projects is used only for property tax calculations.

[b] Increases at nominal rate of inflation.

[c] Installed cost depreciated in straight line (by 5 percent per year) to 20 percent by year 17, and resulting property tax is escalated at 2 percent per year as per Proposition 13 limit.

Source: KEMA

Low-, mid-, and high-case assumptions are also required for expected contract pricing terms for existing wind facilities (see Table 2). For the remaining duration of standard offer QF contracts (shown in Row 1 of Table 2), or through 2011 (whichever comes first), energy prices are assumed to be the average of PG&E's and SCE's most recent five-year offers (Row 2), escalating at 1 percent per year (Row 3). For any project whose standard offer contract expires after 2011, and therefore for which the current five-year fixed energy prices no longer apply, energy prices after 2011 are assumed to equal the values shown in the second-to-last row of Table 2. Capacity payments during the entire remaining period of QF standard offer contracts (2009, 2012, or 2015) are assumed to have an effective range of $13/MWh to $21/MWh, with a mid-case of $17/MWh.[17] Projects are assumed to expect continued payments after their standard offer contracts expire that equal, conservatively, 70 to 95 percent of the 2007 market price referent, or $65 - 89/MWh (last row of Table 2).

Table 2. Assumed Contract Pricing Terms for Existing Facility

Contract Pricing Terms	PG&E	SCE	Report Assumptions
Last year of Standard Offer QF pricing terms (low, mid, high)	Varies	Varies	2009, 2012, 2015
1st year fixed energy price under Standard Offer contract (nominal $)	$64.50/MWh	$61.50/MWh	$63/MWh (2007)
Energy price escalation under fixed energy-price Standard Offer contract	1%/yr	1%/yr	1%/yr
Maximum fixed energy price duration under Standard Offer contract	5 years	5 years	5 years (through 2012)
Capacity value under Standard Offer contract (low, mid, high; nominal $)	Varies	Varies	$13/MWh, $17/MWh, $21/MWh
Energy price after 5-year fixed period above, if Standard Offer remains in effect (low, mid, high; nominal $)*	Unknown	Unknown	$55/MWh, $65.6/MWh, $70/MWh
Total payment after fixed capacity prices end (low, mid, high; nominal$)**	Unknown	Unknown	$65/MWh, $80/MWh, $89/MWh

* Midpoint reflects fixed energy price in 2012; low and high prices reflect conservative bound of uncertainty

** Roughly 70%, 85% and 95% of 2007 MPR for 10-year contracts, with 2010 facility on-line date

Source: KEMA

Using these basic, yet highly uncertain, assumptions, three bounding scenarios were developed for revenue expectations. Under the "low-revenue" scenario, the authors assume standard offer contract expiration after 2009, and the low range of future contract pricing shown in Table 2. Under the "high-revenue" scenario, the standard offer contract is assumed to remain in effect through 2016 (though energy pricing changes in 2012, because the current 5-year fixed energy pricing under standard offer contracts will expire on this date), and the high end of the range of future revenue expectations in Table 2 is used. The "mid-revenue" scenario uses an end-of-2012 standard offer contract expiration date and the mid-range of contract pricing. Figure 3 presents the resulting assumed revenue stream under the low-, mid-, and high-case scenarios. Note that these assumed price streams show a wide range, but all are below the 2007 MPR for a flat-block of power. In effect, these price

[17] These values were generated from a review of PG&E and SCE's FERC Form 1 filings.

assumptions reflect what an existing wind project owner might *conservatively* estimate as its uncertain future revenue stream.

Figure 3. Aggregate Sales Revenue Assumptions for Existing Wind Facility

Source: KEMA

Limitations

Before presenting the results of the analysis, a number of caveats and limitations to the methodology should be noted.

- First, the purpose of this analysis is simply to provide a scoping-level assessment of the economics of repowering decisions in California for wind project owners; the input data are not of sufficient quality to do anything that resembles a project-specific analysis.
- Second, the analysis does not consider the possibility that a repowered facility may be either larger than, or perhaps even smaller than, the existing project that it replaces, in nameplate capacity terms.[18]
- Third, though the analysis considers uncertainty and variability in some input parameters, the authors do not conduct a full sensitivity analysis on all inputs.
- Fourth, the analysis is based on NPV calculations, but does not directly consider economic *risk*. To the extent that existing (non-repowered) facilities shoulder greater O&M, project failure, and revenue risks, then the NPV calculations that follow may underestimate the economic potential for near-term repowering.

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[18] In later analysis, it may be useful to explore scenarios in which the repowered facility is larger than the existing facility that it replaces. In this instance, the NPV of the existing (non-repowered) facility would be allocated across a larger number of repowered project MWhs, leading to a potentially lower payment (in $ per MWh terms) needed to accelerate repowering.

- Fifth, the authors assume that a repowered facility would need to achieve equivalent expected profitability as continued operations of the existing (non-repowered) facility. Continuing to operate the existing facility, however, does not preclude repowering at a later date. As such, accelerating the repowering decision may require an expected level of profitability that equals that of the continued operations of the existing plant plus any above-normal expected profit from repowering the facility at a later date. This factor may lead the authors to overstate the economic potential for repowering.
- Sixth, the analysis assumes that a repowered facility will prefer a new, 20-year power sales contract over continuing to sell under the pre-existing standard offer contract.

Finally, as noted earlier, this analysis emphasizes the perspective of the project owner, and the payment level that might be needed to encourage accelerated wind project repowering. The analysis informs, but does not directly address, other important stakeholders to repowering decisions, for example, the perspectives of utility purchasers, electricity ratepayers, or society at large. Further analysis would be needed to fully evaluate these perspectives.

CHAPTER 3: Analysis Results

Economics of Repowering Decisions: Bounding Cases

This section presents the results of the bounding analysis, considering three different cost and performance assumptions (low, mid, and high – see Table 1) for the existing (not repowered) wind facility and three different sets of revenue expectations (also low, mid, and high – see Figure 3) for such a facility. Although the authors focus on the mid-case results in further analysis that follows, the nine scenarios resulting from the various cost and revenue assumptions presented here cover the full diversity of circumstances in which existing wind facilities in California may fall.

Table 3 shows the results from this analysis, in terms of the NPV and remaining lifetime of each possible existing (not repowered) project. Project lifetime is calculated as the number of years until operating profit turns negative.

Table 3. Economics of Existing Wind Projects

		O&M Cost and Capacity Factor Assumption*		
		Low-Cost ($40/kW, 30% c.f.)	**Mid-Cost** ($60/kW, 22% c.f.)	**High-Cost** ($90/kW, 16% c.f.)
Revenue Assumption	**Low**	NPV: $12,687	NPV: $3,526	NPV: $22
		Life: 23	Life: 10	Life: 1
	Mid	NPV: $17,511	NPV: $6,186	NPV: $121
		Life: 26	Life: 14	Life: 2
	High	NPV: $20,477	NPV: $7,909	NPV: $302
		Life: 28	Life: 16	Life: 4

NPV is in $000, remaining project life is in years.

*These scenarios vary O&M costs and capacity factors, with the low-cost case assuming the highest capacity factor and the high-cost case assuming the lowest capacity factor. See Table 1 for the specific assumptions for each case.

Source: KEMA

Projects with low O&M costs and high capacity factors ("low-cost" case) have high present values and many remaining years of positive revenues, under the assumptions used here.[19] This is true regardless of which revenue assumptions are applied. Owners of projects with these characteristics are not likely to be interested in repowering any time in the near future, unless the expected revenue generated from such repowering is quite high.

[19] In reality, it seems likely that catastrophic technology failure (or increased O&M cost escalation) would not allow even these projects to continue operations for the full 23 to 28 years calculated here, but the analysis does not account for such a possibility.

Conversely, projects with high O&M costs and poor performance ("high-cost" case) are found to gain relatively little value from continued operations (again, regardless of the revenue assumption), and the authors estimate that projects of this nature have only 1 to 4 years (from 2009) before they become uneconomic to maintain, depending on assumptions made for future revenue. Owners of these projects are most likely already planning for the repowering of these facilities.

Finally, for the existing wind projects that fit the mold of the "mid-cost" assumptions, remaining profitable project lifetimes of 10 to 16 years are calculated, depending on the revenue assumption made, with significant remaining value possible through continued operations. For projects of this nature – which presumably make up the majority of the existing wind power fleet in California – to replace their existing technology with new wind turbines will likely require that the repowered project achieve at least a similar level of expected profitability.

Next, the authors used the cash flow model for the repowered project to calculate:

- The 20-year levelized power price (i.e., levelized cost of energy, or LCOE) that yields an NPV equivalent to the NPV of the existing project under each of the nine scenarios shown in Table 3.
- The 20-year levelized power price that yields a "normal" 10 percent IRR (i.e., a NPV of $0 at the assumed 10 percent nominal discount rate).

Results from this analysis are shown in Table 4. Though the results show that a repowered project under the assumptions presented earlier would need a 20-year levelized revenue stream of $80/MWh to achieve a normal 10 percent IRR, additional revenue would be required under each of the nine scenarios examined to match the economics of continuing to maintain and operate the existing wind facility.

Specifically, a repowered project would require 20-year levelized revenue ranging from $80/MWh to $141/MWh in order to match the economics of not repowering. The upper end of this range compares poorly with the 2007 20-year Market Price Referent (MPR) of ~$97/MWh for a flat block of power, as well as the calculated 20-year levelized revenue requirement for a greenfield project of roughly $88/MWh.[20] Moreover, with few exceptions, the levelized revenue stream required to accelerate repowering decisions is also above the expected levelized revenue for continued operations of the existing, not-repowered facilities.

These comparisons lead to several tentative conclusions:

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[20] The greenfield revenue requirement of $88.4/MWh results from running the greenfield cash flow model under the assumptions presented in Table 1, and solving for the revenue that provides a 10 percent IRR (for example, NPV of $0 using a 10 percent nominal discount rate).

First, because existing wind facilities are often expected to remain profitable for some time, the levelized revenue stream required to accelerate repowering decisions can – in some cases – be sizable. The better-functioning the existing facility (lower O&M and/or higher capacity factors), the greater the required revenue stream will need to be to encourage project owners to accelerate the repowering process. For example, one can calculate the difference in revenue needed to ensure that the repowered facility receives not just a normal annual profit of 10 percent on investment, but is also as profitable in NPV terms as continued operations of the existing facility. Focusing on the mid-cost and mid-revenue cases, this extra revenue is sizable, at more than $18/MWh ($98.5/MWh - $80.0/MWh) over 20 years.

Second, the levelized revenue needed to accelerate project repowering can be viewed from several different perspectives. For example, in many cases, the results show that aggregate revenue for a repowered facility will need to be higher than the revenue required for a new, greenfield facility (assuming that the greenfield facility requires – and receives – a normal, 10 percent IRR). Under the mid-cost and mid-revenue assumptions, for example, the 20-year levelized additional revenue is found to equal roughly $10/MWh ($98.5/MWh - $88.4/MWh). New greenfield development may therefore be less costly, in some circumstances, than repowered facilities. Relative to the 2007 20-year MPR for projects with online dates of 2009, meanwhile, the extra revenue equals a more-modest levelized value of $1.5/MWh ($98.5/MWh - $97.0/MWh) under the mid-cost and mid-revenue assumptions. Finally, the revenue stream needed to encourage early repowering is, in many cases, substantially higher than the payments that would otherwise be made to existing facilities during those facilities' remaining project lives, on a $ per MWh basis.[21]

Third, the results show that the economic incentive to repower or to not repower is heavily dependent on input assumptions, and is therefore highly project specific. For existing low-cost projects (i.e., with low O&M costs, and high capacity factors), the authors calculate that a very lucrative contract of $118-141/MWh may be required to encourage immediate repowering. For high-cost existing projects, on the other hand, long-term contracts that involve repowering may be possible with levelized revenue streams of roughly $80/MWh, significantly below the 2007 MPR. For the majority of projects that fall within the middle of the range, aggregate 20-year revenue streams in the range of roughly $90-104/MWh may be needed, depending on the project's expectations for future revenues in the no-repowering case.

[21] Note, however, that repowered facilities are expected to have higher levels of annual electricity production (due to a higher capacity factor) and longer economic lives, making this comparison somewhat contrived.

Table 4. Economics of Repowered Wind Projects				
Existing Project Assumptions			**Repowered Project Results**	
Revenue	Annual O&M Cost and Capacity Factor	LCOE for Remaining Project Life	LCOE equal to Existing Project NPV	LCOE equal to $0 NPV (IRR=10%)
Low	**Low** ($40/kW, 30%)	$66.7 / MWh	$117.9 / MWh	$80.0 / MWh
	Mid ($60/kW, 22%)	$67.2 / MWh	$90.5 / MWh	
	High ($90/kW, 16%)	$77.2 / MWh	$80.0 / MWh	
Mid	**Low** ($40/kW, 30%)	$80.4 / MWh	$132.3 / MWh	
	Mid ($60/kW, 22%)	$80.6 / MWh	$98.5 / MWh	
	High ($90/kW, 16%)	$81.6 / MWh	$80.4 / MWh	
High	**Low** ($40/kW, 30%)	$88.6 / MWh	$141.2 / MWh	
	Mid ($60/kW, 22%)	$88.6 / MWh	$103.6 / MWh	
	High ($90/kW, 16%)	$87.0 / MWh	$80.9 / MWh	

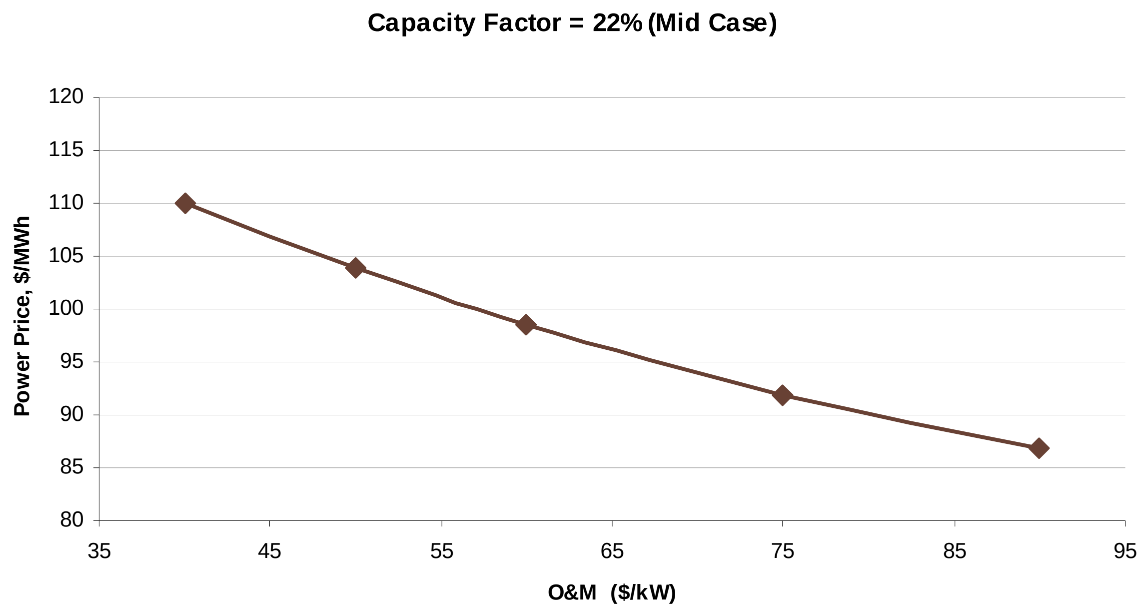
Source: KEMA

Economics of Repowering Decisions: Sensitivity Analysis

Based on the analysis presented above, it seems clear that assumptions about expected revenue have far less effect on the value of an existing (not-repowered) project than do O&M cost and capacity factor assumptions. For example, considering the mid-cost case, the low-revenue scenario required a repowered project to earn revenues of $90.5/MWh, while the high-revenue scenario required revenues of $103.6/MWh. Considering the mid-revenue case, however, a move from the low-cost to the high-cost scenario changed levelized payments more substantially, from $80.4/MWh to $132.3/MWh.

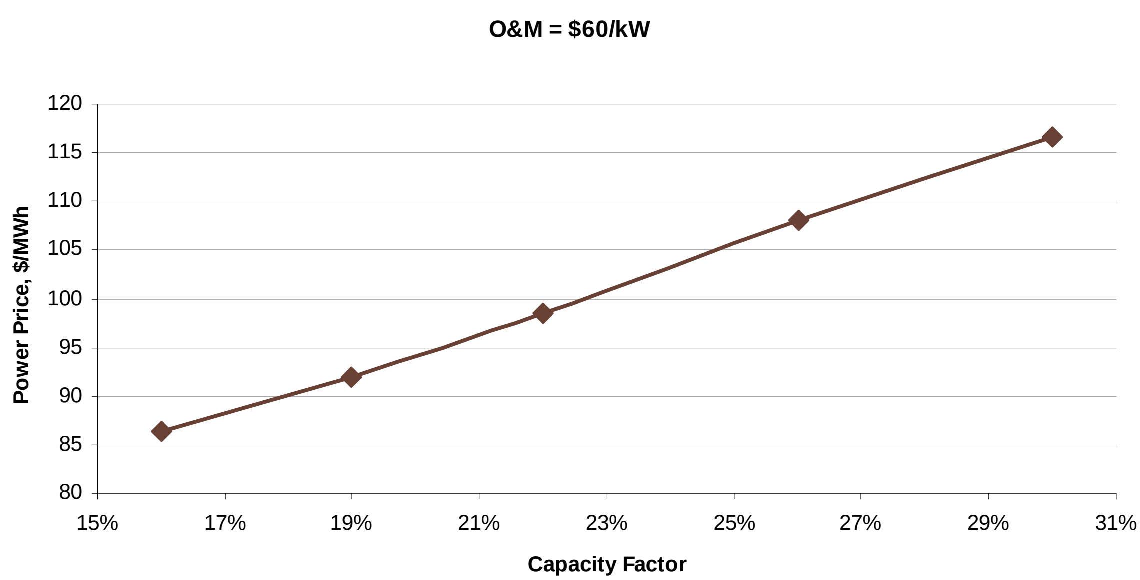
The analysis above, however, uses relatively extreme boundary cases for O&M costs and capacity factors. It also varies O&M costs and capacity factors together within each of the three cases, instead of allowing them to vary independently, making it difficult to determine whether the economics of the existing project – and hence the repowering decision – hinges more on O&M cost or capacity factor assumptions. Figures 4 and 5 explore this question by holding first capacity factor and then O&M costs constant at the mid-cost scenario assumptions, and allowing the other variable to vary over the full range of assumed values. As shown, the two variables appear to have a comparable impact on the levelized revenue stream needed to encourage accelerated repowering. More generally, it is clear that the levelized revenue stream necessary to encourage repowering is highly sensitive to each of these input parameters, again suggesting that the economics of repowering are highly project-specific.

Figure 4. Sensitivity of Repowered Revenue Requirement to Existing Project O&M Costs



Source: KEMA

Figure 5. Sensitivity of Repowered Revenue Requirement to Existing Project Capacity Factor



Source: KEMA

One of the potential advantages of repowering wind facilities in the near-term is that the federal PTC is currently available, allowing repowered facilities to earn a 10-year, $20/MWh (2007$) tax incentive. The federal PTC, however, may not be extended indefinitely. The previous analysis finds that, with the PTC available and with mid-cost and mid-revenue assumptions, a levelized payment stream of $98.5/MWh may be necessary to accelerate the repowering decision. Were the PTC not available, however, the authors calculate that this payment stream would increase to $126.6/MWh, $28/MWh higher than if the PTC is available. In other words, if and when the PTC expires, the necessary payment level required to encourage repowering will increase by a sizable amount of roughly $28/MWh. As such, if state policymakers wish to encourage wind project repowering, it may be significantly less expensive to do so while the PTC is available.

Turbine Arbitrage in a Shortage Environment

Global demand for wind turbines has increased dramatically in recent years, and demand for wind turbines has out-stripped industry supply. In this turbine-limited environment, those developers that have access to new turbines will dedicate those turbines to the most-profitable wind projects in their pipeline.

This dynamic potentially introduces another consideration – the opportunity cost of new turbines – into the repowering decision. In other words, the choice facing an existing wind project owner may not simply be between continuing to operate the existing facility or repowering, as previously analyzed. Instead, the choice may really be between continuing to operate the existing facility and using the new turbines for a new greenfield facility, or repowering and thereby foregoing the opportunity to use the new turbines elsewhere. In such a case, a repowered facility must not only overcome the expected profitability (NPV) of the continued operations of the existing facility, but must also overcome the expected profitability (NPV) of a new greenfield project.

In an environment in which owners of greenfield facilities earn normal profits, assumed here at 10 percent, this additional complication is moot – greenfield projects in this instance, using a discount rate of 10 percent, would have an NPV of 0, so no additional NPV would need to be recovered by the repowered project, and the results presented previously would not change. In California and elsewhere, however, profits of above 10 percent for greenfield projects may be possible. In this instance, the NPV at a 10 percent discount rate would be positive and, arguably, would need to be recovered by the repowered project.

To evaluate this possibility, the authors consider a new greenfield wind project in California with the characteristics presented in Table 1, but that is able to sell its power under a 20-year contract at the 2007 MPR for baseload renewable resources (for example, $96.96/MWh). The results show that such a project has a positive NPV of $2.85 million, using a 10 percent discount rate. Considering only the mid-range of cost and performance assumptions for the existing facility, Table 5 presents the 20-year revenue stream necessary for a repowered wind facility to not only be economically attractive relative to continued operations of the existing facility (first column results, which match those previously presented in Table 4) but to also overcome the expected NPV of using those same turbines in the greenfield project selling at the MPR, as described above (second column results).

Table 5. Economics of Repowering in a Turbine Shortage Environment			
Existing Project Assumptions		**Repowered Project Results**	
Annual O&M Cost and Capacity Factor	Revenue	LCOE equal to Existing Project NPV	LCOE equal to Existing + Greenfield Project NPV
Mid Case ($60/kW, 22%)	**Low**	$90.5 / MWh	$99.06 / MWh
	Mid	$98.5 / MWh	$107.0 / MWh
	High	$103.6 / MWh	$112.2 / MWh

Source: KEMA

Though these results are crude, and heavily dependent on input assumptions, they show that in a turbine shortage environment, even more attractive pricing may be necessary to encourage near-term repowering. Under the assumptions presented here, for example, a comparison of the two columns in Table 5 shows that an additional payment of more than $8/MWh above and beyond the results presented earlier may need to be offered to the project owner to accelerate the repowering decision.

CHAPTER 4: Conclusions

Though many barriers continue to thwart rapid wind-project repowering, in this report the authors have found that a primary barrier is simply that many existing, aging wind facilities are more profitable, in the near term, in continued operations than they might be if they pursuing repowering with new wind turbines. In many instances, it appears as if project owners will only be motivated to pursue project repowering, in the near term, if levelized revenue of over $98.5/MWh is available. For existing wind projects that are better-functioning than the "mid-case" assumes, higher levels of payment may be necessary to accelerate the repowering process.

With recent increases in the MPR, it is possible that a greater number of wind projects will begin to explore repowering opportunities. The 2007 MPR for a flat block of power is only modestly below the $98.5/MWh figure provided above. As such, if wind project owners are able to earn contracts for repowered projects at roughly the MPR, then interest in repowering should increase. Nonetheless, for a large number of the (well-functioning) existing wind projects, payment levels of well above the 2007 market price referent and well above the presumed cost of a new greenfield project may be necessary to accelerate wind turbine replacement. Moreover, if and when the production tax credit expires, this necessary payment level will increase by a sizable amount.

To combat this economic barrier, and encourage early repowering, it may be necessary to consider a more proactive state policy towards repowering, one that would offer an explicit incentive for the replacement of aging wind projects, and therefore make repowering economically profitable for more project owners. Moreover, if state policymakers wish to encourage wind project repowering, it may be significantly less expensive to do so in the not-so-distant future, while the production tax credit is available. The analysis presented in this paper, however, suggests that a "one-size-fits-all" fixed incentive program is unlikely to be economically efficient given the wide range of financial conditions facing individual wind projects; a more nuanced program would be required.

Moreover, though the analysis presented in this report suggests an immediate, binary choice between repowering an aging facility or continuing to operate that facility, in fact the option to repower is one that is continuously available. The authors have shown that, if provided sufficient revenue to overcome the expected remaining value of the existing facility, and if required to make a one-time choice, a project owner may be willing to repower its facility. If given the option, however, and if the state offered an *ongoing* incentive to project repowering, such an owner may earn even more value by continuing to operate the existing facility until the operating profits go negative, and then repowering and accessing the state incentive at that point, thereby earning the value of continued project operations <u>and</u> the additional (time-discounted) value of a repowered facility. As a result, if the state wished to significantly *accelerate* the repowering decision, any available incentive may need to be provided on a one-time or declining basis, to encourage early replacement.

Of course, the state should only develop a program to financially encourage repowering if it determines that the costs of doing so are worthwhile given the potential benefits of repowered wind projects. The authors make no judgment on these tradeoffs in this report. In addition, it is important to recognize that financial considerations are only one of many barriers to wind repowering. The state would also need to address the multitude of other barriers that will continue to thwart wind repowering, including complex environmental review and permitting procedures, possible transmission limitations, and contracting barriers. Without addressing these issues, it is unclear whether addressing the financial barriers to repowering would be sufficient, by itself, to motivate significant new repowering investments.