ACHIEVING CALIFORNIA'S 33 PERCENT RENEWABLE PORTFOLIO STANDARD GOAL

Policy and Analysis Options

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ABSTRACT

Keystones of California's energy policy include strategies to ensure adequate energy resources, reduce energy demand, develop alternative energy sources, and improve the state's infrastructure. With the passage in 2006 of the California's Global Warming Solutions Act, reducing California's greenhouse gas emissions has become a critical policy goal. Increasing the use of renewable energy to 33 percent in 2020 is a significant step toward reducing emissions. To achieve this goal, California needs to evaluate policies that will best acquire renewable resources, examine the overall impacts of the resources acquired on overall system costs and, importantly, examine cost/risk interrelationships associated with this mandate. Although California's electric utility resource planning guidelines incorporate risk assessment and scenario analyses, the guidelines do not capture important cost/risk inter-relationships that dramatically affect estimated overall costs and risks associated with alternate portfolios of generating resources. To remedy this limitation, the report presents a new feed-in tariff approach that is modelled on successful forward capacity market auctions that are used by several regional transmission organizations. This approach reduces the risks of using the administratively determined market price referent values as the basis for feed-in tariff rates that do not achieve the renewable goal, or do so at a higher cost than necessary. A mean-variance portfolio theory is applied to create low risk, high return portfolios under various economic conditions. The results of the analysis indicate that compared to the projected 2020 California "business as usual" generating portfolio, there are other potential portfolios that have lower expected costs, less cost risk, and substantially reduced CO_2 emissions and energy import dependency. The analysis suggests that an optimal generating portfolio for California includes greater shares of renewable resource technologies, which may cost more on a stand-alone basis but reduce overall portfolio costs and risks because of their diversification effects.

KEYWORDS

Feed-in tariffs, portfolio analysis, generation mix, renewable energy, electricity planning, fuel prices, energy risks, auctions

TABLE OF CONTENTS

INDEX OF FIGURES

INDEX OF TABLES

EXECUTIVE SUMMARY

Keystones of California's energy policy include strategies to ensure adequate energy resources, reduce energy demand, develop alternative energy sources, and improve the state's infrastructure. With the passage in 2006 of the Global Warming Solutions Act,[1] reducing California's greenhouse gas emissions has become a critical policy driver. Increasing the use of renewable energy to 33 percent in 2020 is a significant step toward reducing emissions. There is little debate on the use of renewable generating technologies as an effective means for climate change mitigation. Policy makers, consumers, and companies, however, are wary because of the widespread perception that these technologies cost more than conventional alternatives so that increasing their deployment will raise overall electricity generating costs.

Although California's electric utility resource planning guidelines incorporate risk assessment and scenario analyses, the guidelines do not incorporate portfolio risk. Sensitivity analysis cannot replicate the important cost/risk inter-relationships that dramatically affect estimated portfolio costs and risks, and thus it is no substitute for portfolio-based approaches described in this report. For example, despite significant fuel price volatility, natural gas-fired resources continue to be added at levels that do not meaningfully reduce California's reliance on this fuel. This results in greater exposure to future electricity price risk and CO_2 risk for California electricity consumers. Renewable resources represent lower risk alternatives to natural gas-fired resources. However, because portfolio risk has not been incorporated into electricity generation long-term resource planning, the value of this risk reduction is not being fully considered in either the state's procurement or long-term planning processes.

Given this uncertain environment, it makes sense to shift electricity planning from its current emphasis on evaluating alternative technologies to evaluating alternative electricity generating portfolios and strategies. The techniques for doing this are rooted in modern finance theory – in particular mean-variance portfolio theory. Portfolio analysis is widely used by financial investors to create low risk, high return portfolios under various economic conditions. In essence, investors have learned that an efficient portfolio takes no unnecessary risk to its expected return. In short, these investors define efficient portfolios as those that maximize the expected return for any given level of risk, while minimizing risk for every level of expected return.

By applying these concepts, Bates White, LLC is able to evaluate the expected cost and, more importantly, the potential cost risk of California's projected 2020 "business-as-usual" (BAU)[2] electric generating mix, in an environment of uncertain CO_2 prices. These concepts are also applied to identify additional generation portfolios that had lower expected costs and less cost risk than the BAU mix. The resulting optimal portfolios represent various least-cost and risk combinations that can be used as a benchmark to evaluate other alternative generating strategies that will achieve the state's renewable energy goal of 33 percent in 2020 while simultaneously reducing CO_2 emissions.

Findings

A key finding of this report is that, compared to the projected 2020 California BAU electricity generating portfolio, there exist portfolios that are less risky, less expensive, and that substantially reduce CO_2 emissions and energy import dependency. The Bates White, LLC analysis suggests that an optimal generating portfolio for California includes greater shares of renewables technologies that may cost more on a stand-alone basis, but overall portfolio costs and risks are reduced because of the effect of portfolio diversification. Though counterintuitive, the idea that adding more costly renewables can actually reduce portfolio-generating cost is consistent with the basic finance theory. Optimal generating portfolio mixes also enhance California's energy security. The Bates White, LLC analysis further suggests that the optimal 2020 generating portfolios not only achieve California's 33 percent Renewable Portfolio Standard (RPS) goal but also reduce overall electricity generating cost, market risks and CO_2 emissions relative to the projected 2020 California BAU mix.

Perhaps the single most important lesson of the portfolio optimization analysis is that adding a non-fossil fuel, fixed-cost technology (such as wind energy) to a risky generating portfolio lowers expected costs at any level of risk, even if the non-fossil technology costs more when assessed on a stand-alone basis. This underscores the importance of policy-making approaches grounded in portfolio concepts as opposed to stand-alone engineering concepts. Of course, this does not mean that one can always increase the amount of renewable generation in a portfolio and continue to reduce portfolio risk. Portfolio risk depends critically on the overall mix of resources. Too much of any one resource, renewable or not, will tend to increase overall portfolio risk, because the portfolio becomes less diversified, just as the expression, "too many eggs in one basket," implies. As any generation portfolio becomes less diversified, overall risk tends to increase.

That said, it is important to recognize that the mean-variance portfolio approach has several important limitations with respect to generation planning. The portfolio optimization presented in this paper does not define any specific capacity-expansion plan. Such a plan would require far more detailed modelling and analysis. Furthermore, the report compares generation costs only, and does not include transmission costs needed to connect remote renewables or transmission costs necessary to connect conventional generation or to meet potential increases in load. The results presented here are largely expositional, but demonstrate the value of portfolio optimization approaches and suggest that capacity planning made on the basis of stand-alone technology costs will likely lead to economically inefficient outcomes.

CHAPTER 1: INTRODUCTION

Objectives

This report is divided into two parts, each addressing important topics. Chapter 1 through Chapter 3 apply the Capital Asset Price Model to the Market Price Referent and reviews the implications of finance theory for a market-based feed-in tariff design.

In Chapter 2, the risk-adjusted discount rates which have been used for calculating the Market Price Referent (MPR) by the California Public Utilities Commission (CPUC) for use in Renewable Portfolio Standard (RPS) solicitations is reviewed. Finance-oriented valuation principles, based on the Capital Asset Pricing Model (CAPM), are used to calculate MPR values. This approach differs from the approach currently used by the CPUC, which discounts all costs using the weighted average cost of capital (WACC) to establish MPR values.

Chapter 3 presents a new approach to developing so-called “feed-in tariffs”, which avoids having to calculate MPR values at all. Feed-in tariffs were first used in the guise of “avoided cost” payment schemes mandated as part of the US Public Utility Regulatory Policies Act of 1978 (PURPA). Under PURPA, US electric utilities were required to purchase all of the output from so-called “qualifying facilities” (QFs) at prices that reflected the utilities’ long-term avoided costs. Since there were no direct market prices that could be used, such as futures markets, avoided costs were administratively established and approved by state energy regulators, who typically relied on various forecast models to estimate future fossil fuel prices and electric prices. Like avoided cost rates set under PURPA, feed-in tariffs whose prices are set too high or that last too long will needlessly subsidize renewable resources and create welfare losses for society. Not only do such subsidies distort electric markets and reward inefficient renewable resource developers and operators, the subsidies adversely affect electricity consumers by unnecessarily raising electricity prices. This proposal is for an innovative two-part feed-in tariff, consisting of both a capacity payment and an energy payment that can be used to meet the state’s renewable resource goal. A two-part tariff design draws on the strengths of traditional feed-in tariffs, relies on market mechanisms, is straightforward to implement, and ensures installation efficiency and generation efficiency of renewable resources. This approach is modelled on forward capacity market designs that have been implemented by several regional transmission organizations in the USA to address needs for new generating capacity to ensure system reliability.

In Chapter 4 through Chapter 8, which makes up the bulk of this report, portfolio-theory concepts are applied from the field of finance to long-term electric generation planning to evaluate the expected cost and, more importantly, the potential cost risk of a “business-as-usual” (BAU) electric generating mix, in an environment of uncertain carbon prices. For this report, BAU is defined as a mix that incorporates 20 percent renewable energy, with the expectation of achieving all predicted energy efficiency from currently funded programs.

These concepts are applied to identify additional generation portfolios with lower expected costs and less cost risk than the BAU mix. The resulting optimal portfolios represent various least-cost and risk combinations that can be used as a benchmark to evaluate other alternative generating strategies that will achieve the state's 33 percent RPS goal in 2020 while simultaneously reducing carbon emissions.

Although California's electric utility resource planning incorporates risk assessment and scenario analyses, portfolio risk is not incorporated. Sensitivity analysis cannot replicate the important cost/risk inter-relationships that dramatically affect estimated portfolio costs and risks, and thus is no substitute for portfolio-based approaches described in this report. For example, despite significant fuel price volatility, gas-fired resources continue to be added at levels that do not meaningfully reduce California's reliance on natural gas. This results in greater exposure to future electricity price and carbon risk for California electricity consumers. Renewable resources represent lower risk alternatives to gas-fired resources. The value of this risk reduction is not captured in the state's current procurement or long-term planning processes.

Another potential problem is a failure to fully account for the benefits of generation portfolio diversification and renewables technology deployment. In deregulated markets, individual power producers evaluate only their own direct costs and risks in making investment decisions. These decisions do not reflect the overall market impacts of the individual generation technology investment decisions. Renewables investors, for example, may be unable to fully capture the risk-mitigation benefits produced for the overall portfolio, which leads to under-investment in renewables technology relative to levels that are optimal from society's perspective. By contrast, some investors may prefer the risk menu offered by fuel-intensive technologies such as combined-cycle gas turbines (CCGT), which have low initial costs. Regulated utilities are able to transfer fuel risks onto customers using fuel adjustment clauses. Thus, these investors do not bear the full risk effects imposed onto the generating mix, which may lead to over-investment in gas relative to what is optimal from a total portfolio perspective. All this suggests a rationale for economic policies, such as California's 33 percent RPS goal,[3] that favor technologies that bring diversification benefits.

The mean-variance portfolio analysis proposed in this report exemplifies how cost risk can be examined and incorporated into state policy decisions about future generating resources. Portfolio analysis may also enable California decision makers to assess potential changes to a portfolio's risks and costs brought about by adding specific renewable resources that have their own individual risk and cost profiles. The resulting risks and costs of alternative combinations of assets can then be quantified, allowing those portfolios that provide the best combinations of costs and risk to be identified along a curve. That curve is called the "efficient frontier." It represents portfolios that, for any given level of risk, are the least expensive. Conversely, for any given level of cost, there is an associated least-risk portfolio. Portfolio analysis allows for considering risk preferences in choosing among portfolios, as well as for examining different tradeoffs among various risks and costs.

Summary

There are several key findings of this report. First, compared to the projected 2020 CA-BAU electricity generating portfolio, there are portfolios that are less risky, less expensive, and that substantially reduce CO_2 emissions and energy import dependency. The analysis suggests that an optimal generating portfolio for California includes greater shares of renewables technologies that may cost more on a stand-alone basis, but overall portfolio costs and risks are reduced because of the effect of portfolio diversification. Though counter-intuitive, the idea that adding more costly renewables can actually reduce portfolio-generating cost is consistent with basic finance theory. Optimal generating portfolio mixes also enhance California's energy security. The analysis further suggests that the optimal 2020 generating portfolios not only achieve California's 33 percent RPS goal but also reduce overall electricity generating costs and market risks as well as CO_2 emissions relative to the projected 2020 CA-BAU mix. Second, adopting the recommended feed-in tariff design, either as a replacement for the state's RPS or as an adjunct to it, will encourage renewable resource development at the lowest cost, benefiting California consumers, businesses and industries. Moreover, adopting this feed-in tariff design approach obviates the need for the CPUC to establish feed-in tariffs administratively.

Organization

The remainder of the report is organized into two parts, as follows: Part 1, which includes this introductory chapter, continues with Chapter 2, which provides a brief discussion of estimates of the MPR, based on specific risk-adjusted discount rates, as opposed to discounting all costs at the WACC, an approach that CPUC currently adopts in calculating the MPR values. Next, Chapter 3 presents the feed-in tariff design approach, beginning first with a discussion of existing feed-in tariff mechanisms in use today, primarily in Europe, and concluding with a description of the market-based feed-in tariff approach. Part 2 of the report focuses on portfolio analysis. In Chapter 4, the main principles of a portfolio-based approach to electricity resource planning are set out. Chapter 5 describes the data needed for such an approach and specifies the data sources used in this report. Using these data, Chapter 6 identifies optimal CA electricity generating portfolios for 2020 and it presents key features of these *expository* portfolios. Chapter 7 provides a preliminary assessment of nuclear acceleration and promotion policies, and the effects of carbon pricing on generating portfolio mixes and CO_2 emissions for optimal mixes. Chapter 8 summarizes, concludes, and recommends future steps to further support California electricity planners' decision making processes.

CHAPTER 2: USING THE CAPITAL ASSET PRICING MODEL APPROACH TO ESTIMATE THE MARKET PRICE REFERENT

2.1 Introduction

Finance theory provides direction on how to value investments and to analyze risks — and also how not to do it. It represents a major improvement over previous engineering-economics techniques that have been around since the beginning of the 20th century, but which fail to systematically include market risks and other investment realities. The principal underpinnings of modern finance theory include the Sharpe-Lintner Capital Asset Pricing Model (CAPM) and Markowitz's Mean-Variance Portfolio (MVP) Theory. These contributions were first reported a half-century ago and have since received the Nobel Prize. Both mechanisms provide powerful tools that significantly influence all aspects of investment analysis involving financial and non-financial (real) assets. In the case of electricity, a new, and to many, a surprising picture of the relative cost-effectiveness of conventional and renewable alternatives is presented. However, for a variety of reasons, energy planners are slow to incorporate them into their analyses. As a result, energy policy today is generally formulated on the basis of cost estimates that do not benefit from contemporary finance-oriented valuation principles that systematically accounts for market risks.

One way to account for risk, and therefore consider more fully the relative value of renewable versus fossil fuel generation is to use a Capital Asset Pricing Model (CAPM). This chapter describes how CAPM principles can be applied to develop better generating cost estimates for California's Market Price Referent (MPR). Another way of incorporating risk is described more fully in the subsequent Part II of this report on mean-variance portfolio analysis. It discuses how mean-variance portfolio (MVP) optimization can help planners create generating mixes that increase the share of wind and other renewables without increasing generating cost. This enhances energy security without sacrificing regulatory least-cost objectives.

California's RPS legislation requires the CPUC to calculate a MPR which serves as a standard of comparison for per kWh costs of renewable energy contracts. Renewable electricity contracts with levelized costs below the MPR are generally considered reasonable in cost, while proposed renewable contracts above the MPR result in above market costs that are covered by separate funds designed to support California's renewable goals.[4] The MPR is not a good standard of comparison because it is a stand-alone engineering calculation without consideration of risk, and, until recently, it did not include a carbon adder. For example, the CPUC's current method of determining MPR values generally involves evaluating (discounting) all project costs at the weighted average cost of capital (WACC), which is *inconsistent* with CAPM, a crucial part of modern finance theory. Finance-based approaches reflect market risk and thereby represent a significant improvement over WACC-based techniques. Specifically, a

CAPM approach relies on specific risk-adjusted discount rates for each project cost stream, as opposed to discounting all costs at the WACC, an approach that CPUC currently adopts in calculating the MPR values.

Since the analysis of the effects of a CAPM approach was completed, the CPUC has published its 2007 MPR values. These values include a carbon adder, based on analysis and methodology used in evaluating energy efficiency savings. While this adder makes the MPR come closer to a proper standard of comparison, the lack of any incorporation of risk still results in the undervaluing of renewable energy.

This chapter is organized as follows. The next section briefly explains the relationship between two finance-oriented valuation methodologies, i.e., CAPM and MVP approaches. Next, it explains the basis for risk-adjusted discount rates and shows why the proxy firm's weighted average cost of capital (WACC) is not appropriate for valuing generating costs. Then, it compares CPUC's WACC-based MPR values with the CAPM-based MPR values. In essence, using the CAPM shows how the countercyclical value of renewable generation increases the "break even" cost of those resources. In other words, because the value of renewable generation increases (and, hence, renewable generation's relative cost decreases)_when fossil-fuel costs increase, renewable generation can provide a resource cost "hedge," just as low "beta" investments can hedge a financial portfolio. (As is discussed in more detail in the next section, beta is the factor in the CAPM that measures the financial risk of an investment.)

2.2. Description of the CAPM

The CAPM is based on an observed linear relationship between portfolio risk and return. The model states that the expected return on any security is directly proportional to its risk *relative to the market as a whole*. The CAPM shows that investors need not concern themselves with the unique risks of individual securities because those risks can be eliminated through diversification. What this means is that investors do not require a higher expected return to cover a security's unique risk, but rather how the security's risk is correlated with overall variability in the market.

What this means is that the expected return on any tradable security (e.g., stocks, bonds) can be estimated as the risk-free rate of return (typically what an investor can earn by owning a government issued bond), plus a risk-premium that is based on: 1) the overall expected return premium of the market over the risk-free rate, and 2) the volatility of the return on the individual security <u>relative</u> to the overall return in the market. Mathematically, the CAPM can be written as:

$$E(R) = R_f + \beta \, [\, E(R_m) - R_f \,] \qquad (2\text{-}1)$$

where: $E(R)$ = expected return on the security;

$E(R_m)$ = expected return on the market portfolio;

R_f = risk-free rate of return; and

β = "beta," which measures the volatility between market return and the return on the individual security.

Equation (2-1) states that, in equilibrium, every security is priced so it lies along a straight line, called the *security-market line*. Along this line, the required risk premium for any security equals the quantity of risk (as measured by beta) times the market price of risk (measured as the slope of the security-market line). E(R) equals the cost of equity to the firm, since it would represent the return expected by investors given the firm's level of non-diversifiable risk relative to the market as a whole. The CAPM is known as a "one-factor" model because expected return is a linear function of the equity risk premium. No other explanatory factors are included to determine expected returns.

Beta measures the risk of an individual security relative to the overall market portfolio, which theoretically includes all securities. For example, if the beta of a stock equals 1.0, then the stock has the same amount of non-diversifiable risk as the overall market and will exhibit volatility to the same degree as the market. If the market return increased by one percent, then the individual security's return should jump the same amount. Securities with beta values greater than 1.0 will tend to amplify movements in market returns. Securities with betas less than 1.0 will tend to dampen movements in market returns. A security with a beta of 0.5, for example, would tend to rise only half as much as the market when the market rises, and fall by half as much when the market falls.

The beta for a company's stock is estimated by regressing changes in the company's stock price versus changes in the overall price of the "market" portfolio. Rather than include every security in existence, which is the true definition of the "market" portfolio, a composite index, such as the Standard & Poor's (S&P) 500 is often used. Commercial firms, such as Value Line and Bloomberg commonly use five years' of weekly stock price data to estimate these regressions, which have the form:

$$\Delta P_{I,t} = \alpha_I + \beta_{\mathrm{RAW}} \Delta P_{M,t} + \varepsilon_t \qquad (2\text{-}2)$$

where: $\Delta P_{I,t}$ = the change in the price of stock I in month t;

$\Delta P_{M,t}$ = the change in the price of the stock market index in month t;

β = the estimated beta coefficient for stock I;

α_I = the estimated rate of price appreciation of the stock; and

ε_t = a random error term.

In addition to its application in financial markets to measure the value and returns on individual securities like stocks and bonds, as well as its use by many utility regulators to determine the return on equity for a regulated utility, the principles of the CAPM can also be applied to compare the costs of individual generating resources within an overall portfolio of resources. Specifically, using the principles of the CAPM, the appropriate discount rates to apply to different resources when developing "levelized cost" estimates can be determined. Using the principles of the CAPM, resources whose relative costs are at the lowest value when the cost of other resources is high, should be discounted at a lower rate than resources whose relative costs varies directly with the cost of other resources, can be shown.

For example, suppose a generating resource portfolio consisting of two resources is owned: a wind turbine and a natural gas combined-cycle plant. A simple question can be asked: when is the output from that wind turbine the most valuable? (By "value" means the net difference between market price and cost.) Alternatively, when is the wind turbine's relative cost the lowest can be asked? The answer is that, for this two-resource portfolio, the wind turbine's output is most valuable when the price of natural gas is highest and lowest when natural gas prices are low. In other words, there is an inverse relationship between the value of electricity produced by the wind turbine and the value of electricity produced by the gas combined-cycle plant. The electricity produced by the wind turbine helps to "smooth out" the cost volatility of the portfolio as natural gas prices fluctuate. Thus, the wind generation provides a "hedge" against cost fluctuations.

The question, therefore, is how to determine how valuable the cost hedge, provided by the wind generation is? The answer, as discussed below, is to use the CAPM to develop appropriate discount rates for renewable resources when estimating benchmark MPR cost values. The greater the hedge value of a renewable resource, the lower will be its "beta" value, and the lower the appropriate discount rate will be. The lower the discount rate, the higher will be the levelized MPR value. Thus, the greater the hedge value of a renewable resource, the higher the MPR can be set and still provide benefits to ratepayers.

The specific discount rates that are applied are called "risk-adjusted" discount rates. Essentially, the modified equation (2-1) is as follows:

$$R_D = R_f + \beta\,[\,E(R_m) - R_f\,] \qquad (2\text{-}3)$$

where R_D is the appropriate discount rate to use when determining a "break-even" levelized cost. For example, if a renewable generating resource has a beta value of zero, the appropriate discount rate to use for this resource when calculating the MPR would be the risk-free rate, R_f, because the second term on the right-hand side of equation (2-3) is zero, implying $R_D = R_f$.

Why Using the WACC Distorts Results

The WACC measures investors' assessment of their required rate of return — i.e. how much compensation is needed for money at risk in a project or firm. However, in the context of establishing "least-cost" resource portfolios, regulators will want to know two things: first, how much will a given portfolio cost, and second, how volatile will those costs be? The risks associated with generating cost streams, which form the basis for valuing these costs, are significantly different from the risks associated with the returns on utility debt and equity, which form the basis for the WACC. And while many think that sensitivity analysis properly handles the issue of risk, the fact of the matter is that it does not. No amount of sensitivity analysis can rehabilitate defective cost estimates.

Utility planners are used to the idea of valuing (discounting) all generating cost streams using the WACC, even though this produces unreliable results — it is like using the wage history of tailors in Hong Kong to estimate the firm's future O&M costs. Using the WACC in this manner makes little sense. It is also contrary to modern finance theory, which values uncertain future cash flows using CAPM-based rates that reflect the market-price of risk for fuel costs and other cash outflows.

The example in Table 1 illustrates the somewhat absurd results that occur when a single discount rate is used to evaluate alternative investments of different risk. Yet this is precisely how energy technologies are valued by engineering models – with a single arbitrary discount rate – even though the risk of each technology alternative is different. The Table shows the promised annual payment from a 15 percent low grade or "junk bond" and a government bond paying a 5 percent coupon. Let's also assume that both bonds are trading at $1000.

Table 1: Promised Annual Payment from Two Bond Investments

Year	Junk Bond with 15% Annual Payment	Government Bond with 5% Annual Payment
1	$150	$50
2	$150	$50
3	$150	$50
4	$150	$50
5	$150	$50
Present Value @ 7% Discount Rate	$615	$205

Both bonds require the same initial investment cost of $1000, so that the focus remains on the annual income streams. Using an arbitrary 7 percent discount rate, the present value of the junk-bond payments is $615 versus only $205 for the government bond. Does this analysis mean that the junk bond is a better investment and that all investors should buy only junk bonds? No, because this type of analysis fails to incorporate the default risk associated with the bond.

Unfortunately, this is how engineering cost models typically compare high-risk fossil to low-risk renewable resource alternatives. By using the same discount rate for all resources, the volatility those different resources contribute to a resource portfolio's overall cost, as well as the hedging value of renewable technologies, are not accounted for. As a result, lower engineering-cost fossil fuel resources will always be preferred to higher engineering-cost renewables, much as the results of Table 1 would mean the junk bond alternative is always chosen.

2.3 The Relationship between CAPM and Mean-Variance Portfolio Approaches

CAPM-based cost models tell a simple story: when the effects of market risk are included, the risk-adjusted generating costs may be significantly higher or lower than the costs estimated using stand-alone, engineering-oriented calculation that rely on a single discount rate. Widely reported engineering-oriented kWh costs — the dominant industry benchmark for 50 years — show levelized gas-fired generating kWh costs that do not reflect market risks. Even though gas prices have risen sharply and fluctuated wildly, and in spite of the fact that the financial performance of gas-based generators in the US has been dismal, it is difficult for people to shake these figures and accept the more reliable CAPM results.

Mean-variance portfolio (MVP) models tell this story in a different way that provides a more robust tool to policy makers and other industry participants. MVP theory predicts that when fixed-cost renewables are added to a fossil generating mix, overall generating cost and risk can be lowered, even where the *stand-alone* costs are higher. MVP models therefore suggest that wind and other fixed-cost renewables are economic, even on the basis of widely believed traditional engineering-oriented cost estimates. Using such conventional costs, MVP models show that it is possible to add more expensive renewable resources to a lower-cost fossil fuel mix and *reduce* – not increase – expected overall generating cost and risk.

The next section explains the CAPM approach to estimating risk-adjusted discount rates and shows why the proxy firm's weighted average cost of capital (WACC) is not appropriate for valuing generating costs.

2.4 Using the CAPM to Estimate the Cost of Electricity Generation

Cost-of-electricity estimates for various generating technologies are widely used in policymaking and in regulation. Managers and public policy makers want a simple means of determining what it will cost to generate a kilowatt-hour (kWh) of electricity using, for example, a wind turbine, over the next 20 years, as compared to generating a kWh of electricity using a combined-cycle gas turbine. Such comparisons help utilities and regulators establish investment plans under so-called “least cost” or Integrated Resource Planning (IRP) procedures that are used in many utilities. These procedures presume that if every new capacity addition is chosen through a “least-cost” competition, then the resulting total generation mix will also be “least-cost.” However, this presumption fails to include market risks and portfolio effects. As described more fully in Part II of this report, the stand-alone cost of a technology is not relevant. What counts is its cost contribution to the overall generating mix relative to its risk contribution to that mix. This needs to become the new valuation criteria.

In addition, the cost-of-electricity estimates need also to be adjusted for market risk, which distinguishes them from traditional, engineering-oriented estimates. Market risk is a cost — just like any other cost — that must be borne by electricity producers and their customers. Market risk can be quantitatively measured and included in electricity cost comparison models. The finance concept of risk is well understood by investors, although not as it relates to renewable energy technologies. Energy planners and policy makers, on the other hand, tend to understand renewables, but do not understand the important risk concepts that differentiate them from fossil alternatives. Any projected cost stream associated with a particular electricity resource contains some degree of risk. While projected fossil fuel costs clearly present the greatest risk, other cost streams, such as projected labor costs associated with O&M costs also carry an element of risk. Compared to traditional evaluation methods, the inclusion of risk tends to raise the electricity cost estimate for conventional technologies whose principal cost inputs are risky fuel and maintenance streams.

By contrast, the cost streams in the case of technologies such as wind, solar PV, and, to a lesser extent, other renewable technologies, are largely “sunk,” which makes them “systematically riskless,” or nearly so, in a finance sense. (In the language of the CAPM, this means the asset betas of capital-intensive renewables are close to zero.) Moreover, although the maintenance costs of renewables are just as risky as those of fossil technologies; generally it is so small that the contribution is little to overall project risk. By ignoring such risk differentials among technologies, traditional analyses tend to incorrectly overstate the costs of renewable technologies and – by the same token – systematically underestimate the costs of conventional fossil-fuel technologies.

2.5 Calculating Beta Values for MPR estimates

The approach used to develop betas follows the methodology described in Bollinger, Wiser, and Golove (2005).[5] To understand their approach, it helps to understand how to transform the typical calculation of beta values based on the returns of financial assets like stocks and bonds, to beta values that link fossil fuel costs and market returns.

To do this, suppose there is an “option” to purchase (say) natural gas at a fixed price of $3.00 per MMBtu. If the market price of natural gas is less than $3, then the option is worthless. However, as the market price of natural gas increases, so does the value of that option. The option is a financial asset; therefore the beta can be calculated. Typically, as fossil fuel prices like natural gas and crude oil increase, economic growth slows. The assumption is that economic growth can be represented using a proxy variable, such as returns in the stock market as a whole, as measured using a broad index of stocks like the S&P500. Thus, as natural gas prices increase, the value of the option increases, while returns in the stock market fall. Similarly, as natural gas prices fall, economic growth increases, the value of the market increases, but the value of the option decreases. This means that the value of the option and market returns are negatively correlated, and that the beta of the option is less than zero. In other words, holding an option to buy natural gas provides a hedge against adverse economic growth,

Next, suppose that, instead of owning an option to buy natural gas, a gas-fired generating plant is owned. In this case, as the price of natural gas increases, the value of the plant decreases. Even though the price of electricity may increase as well, it will likely increase proportionally less than the increase in the price of gas. Thus, the profitability of the gas-fired generating plant will decrease. Since higher natural gas prices also mean decreasing economic growth and decreasing market returns, the “return” earned from owning the gas-fired generating plant decreases, too. Therefore, the returns from the generating plant and the market are positively correlated, which means the “beta” value for the generating plant is greater than zero.

Finally, suppose a wind turbine is owned, and repeat the exercise. As the price of natural gas increases, the value of the electricity generated by the wind turbine will increase, too, and thus the returns earned from the wind turbine will increase. However, the returns in the market as a whole will decrease. Therefore, just like the gas-purchase option, returns from owning the wind turbine will be negatively correlated with returns in the market. In other words, the beta for the wind turbine will be less than zero.

Estimation Procedure

To determine the appropriate beta values for renewable resources like wind, the betas were calculated based on the changes in the prices of fossil fuels over time versus returns in the stock market. Since the returns on renewable resources are known to be positively correlated with the price of fossil fuels (i.e., higher fossil fuel prices implies higher returns from renewable resources), the changes in fossil fuel prices as a “proxy” for calculating renewable betas can be used. Equation (2-2) is applied to calculate those betas for coal, natural gas, and fuel oil, based on annual average price data of fossil fuels delivered to electric generating plants, between 1975 and 2005, as published by the U.S. Energy Information Administration (EIA).

Both “rolling” betas and cumulative betas were calculated. The cumulative betas fix an initial observation as the starting point, and keep introducing additional observations in the regression estimation, so the sample size is growing. In the analysis, a sample size of 10 (from 1975 to 1984) is initially used and gradually increased until it reaches the maximal sample size of 21 (from 1975 to 2005). Rolling betas, on the other hand, use the sample size (10 years of data), and drops the earliest observation when an additional recent observation is introduced into the sample. Thus, for the analysis, betas were initially calculated for the 10-year period between 1975 and 1984, then 1976 and 1985, and so forth, with the most recent sample data between 1996 and 2005. The betas for each of three fuels were calculated separately.

Results

Figure 1 reports the cumulative beta, the 95 percent confidence interval of the cumulative beta, and the rolling beta for coal. As can be seen in the figure, the rolling beta values are more volatile than the cumulative beta. However, the overall coal beta is small and slightly negative. What this means is that, as coal prices increase, returns in the market tend to decrease.

Figure 1: Historical Beta of Coal Delivered to Electric Generating Plants

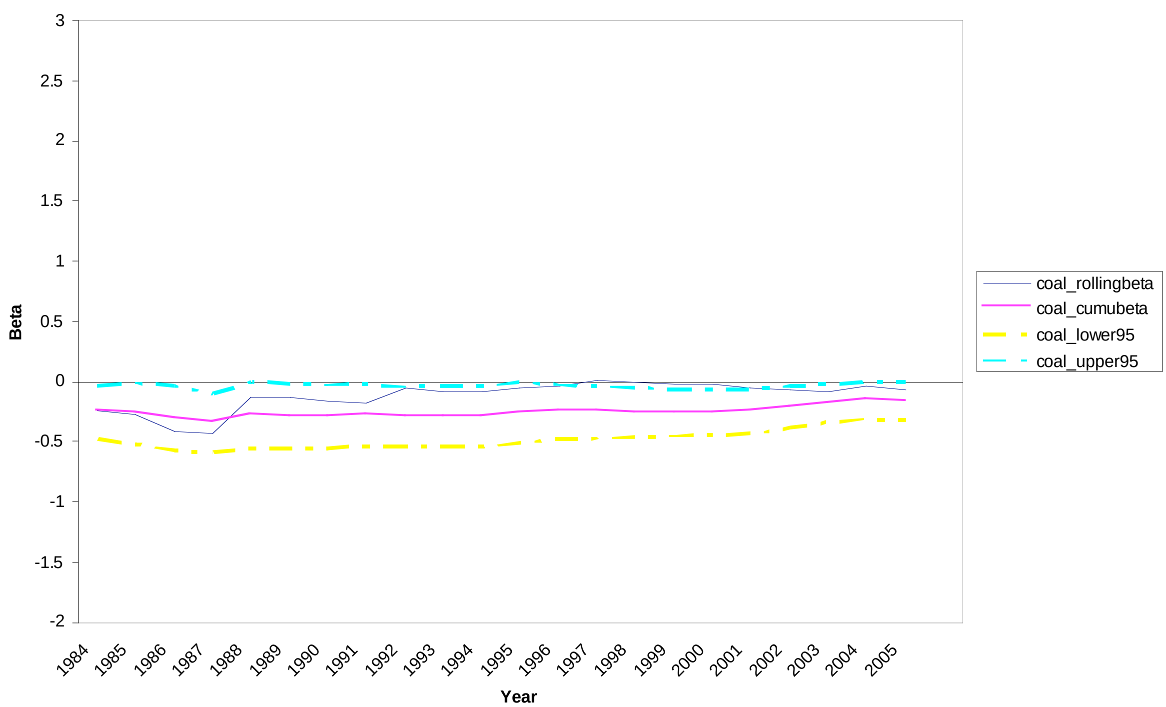


Figure 2 reports the cumulative beta, the 95 percent confidence interval of the cumulative beta, and the rolling beta for natural gas. Compared to coal, the natural gas beta values are more volatile. Even though the cumulative beta seems consistently negative, it is statistically insignificantly different from 0 because of the high volatility. Also the rolling beta changes from negative to positive between 1996 and 2002 (inclusive). Again, the calculations are consistent with the hypothesis that higher natural gas prices are linked to lower economic growth and market returns.

Figure 2: Historical Beta of Natural Gas Delivered to Electric Generating Plants

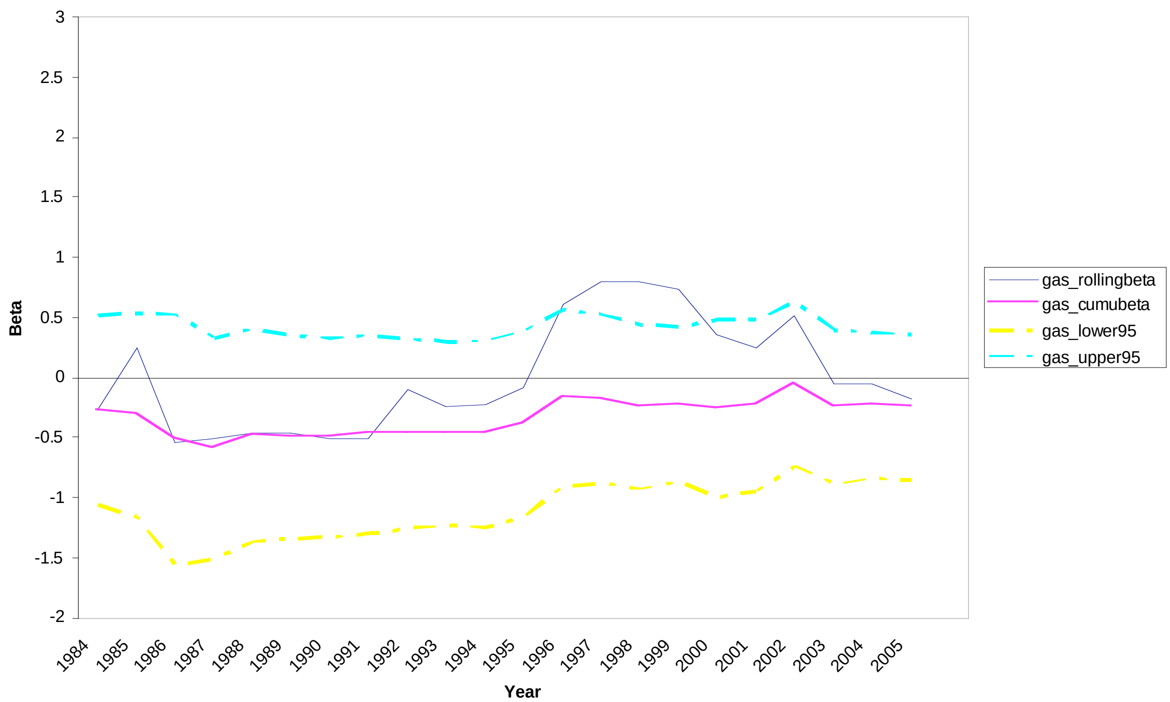
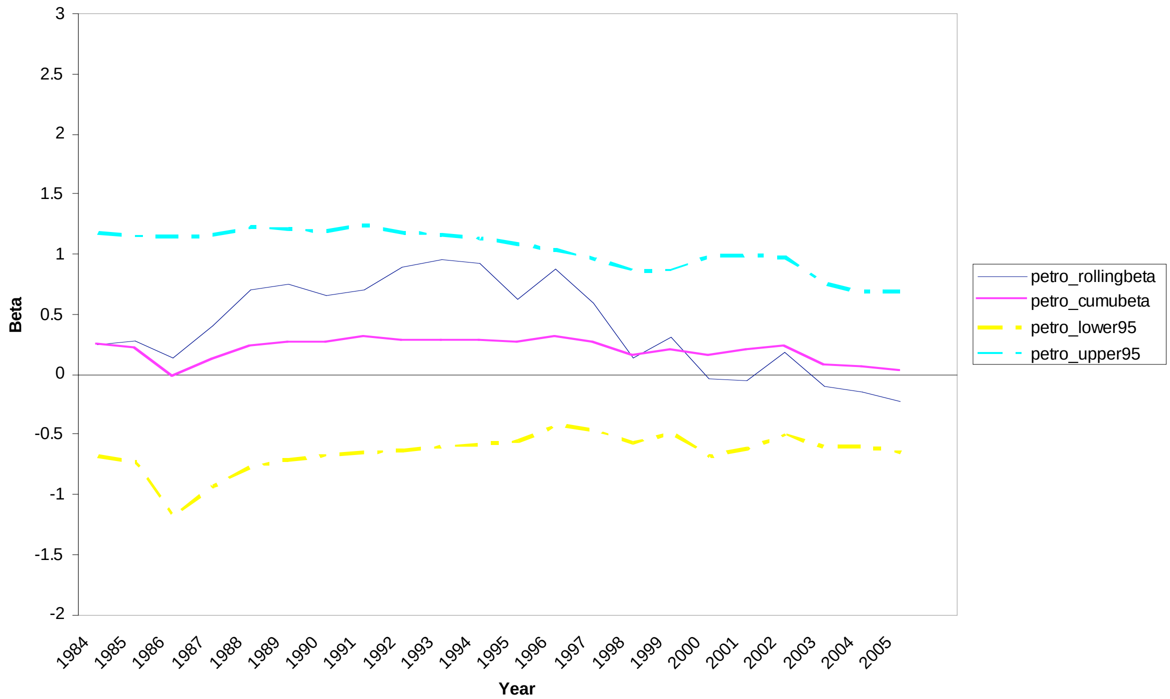


Figure 3 reports the cumulative beta, the 95 percent confidence interval of the cumulative beta, and the rolling beta for oil. Compared to coal, petroleum oil is also much more volatile. Both the cumulative beta and the rolling beta seem consistently positive for most of the time period except for the last three years, but are statistically insignificantly different from 0 due to the high volatility.

Figure 3: Historical Beta of Oil Delivered to Electric Generating Plants



The results of the analysis confirms the hypothesis that, because fossil fuel costs are inversely correlated with economic growth, and have betas that are zero or negative, returns to renewable resources will also have zero or negative betas. (Again, as fossil fuel costs increase, so do the returns to renewable resources, but the returns in the market decrease, implying renewable betas of zero or less.)

Because it could not be concluded that the cumulative betas were statistically different from zero, even though the betas averaged zero or below, the appropriate discount rates for renewables using beta values of zero in equation (2-3) were determined. With a beta value of zero, equation (2-3) implies that the appropriate discount rate with which to determine the MPR is the risk-free rate.

2.6 Summary of Results

MPR values were determined using a risk-free rate and compared those values to the CPUC's WACC-based MPR values. Table 2 below shows the CPUC's WACC-based 2006 MPR values.

Table 2: WACC-based 2006 MPR Values

WACC-based 2006 Market Price Referents (Nominal - dollars/kWh)			
Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08046	0.08176	0.08424
2008 Baseload MPR	0.07979	0.08195	0.08482
2009 Baseload MPR	0.07925	0.08223	0.08548
2010 Baseload MPR	0.07929	0.08295	0.08652
2011 Baseload MPR	0.07890	0.08307	0.08688
2012 Baseload MPR	0.07961	0.08420	0.08820
2013 Baseload MPR	0.08072	0.08566	0.08981
2014 Baseload MPR	0.08229	0.08746	0.09167
2015 Baseload MPR	0.08435	0.08964	0.09468

Table 3 below shows the CAPM-based 2006 MPR values.

Table 3: CAPM-based 2006 MPR Values

CAPM-based 2006 Market Price Referents (Nominal - dollars/kWh)			
Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.08371	0.08970	0.09610
2008 Baseload MPR	0.08299	0.09005	0.09584
2009 Baseload MPR	0.08241	0.08955	0.09687
2010 Baseload MPR	0.08244	0.09045	0.09828
2011 Baseload MPR	0.08192	0.09143	0.09977
2012 Baseload MPR	0.08260	0.09262	0.10335
2013 Baseload MPR	0.08370	0.09664	0.10510
2014 Baseload MPR	0.08699	0.09852	0.10707
2015 Baseload MPR	0.08928	0.10076	0.11143

Table 4 below shows the difference between CPUC's WACC-based 2006 MPR values and the CAPM-based 2006 MPR values. As Table 4 shows, the difference between the

MPR values increases for longer-duration resources. For example, in 2015, the difference is about ½ cent per kWh for a 10-year resource, but 1.7 cents per kWh for a 20 year resource.

Table 4: Difference between WACC-based and CAPM-based 2006 MPR Values

Difference between WACC-based and CAPM-based 2006 MPR values (Nominal - dollars/kWh)			
Resource Type	10-Year	15-Year	20-Year
2007 Baseload MPR	0.00325	0.00794	0.01186
2008 Baseload MPR	0.00320	0.00811	0.01102
2009 Baseload MPR	0.00316	0.00732	0.01139
2010 Baseload MPR	0.00315	0.00750	0.01176
2011 Baseload MPR	0.00303	0.00835	0.01289
2012 Baseload MPR	0.00299	0.00841	0.01515
2013 Baseload MPR	0.00298	0.01099	0.01529
2014 Baseload MPR	0.00470	0.01106	0.01540
2015 Baseload MPR	0.00493	0.01112	0.01675

CHAPTER 3: MARKET-BASED FEED-IN TARIFF DESIGN

3.1 Introduction

Policy approaches to promote renewable energy supplies have taken on increasing importance in many countries. Although the relative weight given to underlying reasons for accelerating renewable energy technology development may vary (e.g., reducing global climate change, a desire to reduce dependence on imported fossil fuels, portfolio diversity, economic development, etc.), policy instruments used to promote renewables must necessarily balance a number of competing economic and non-economic objectives. These include the following, among others:

(1) Specific positive environmental impacts, such as reduced emissions of air pollutants and greenhouse gases, versus perceived negative impacts on bird populations and landscape aesthetics (in the case of wind turbines, for example).

(2) Reduced dependence on fossil fuels, greater portfolio diversity, and lower exposure to fuel price volatility, versus adverse economic impacts of higher retail electric rates, including lessened economic competitiveness and lack of affordability.

Consideration of these trade-offs is unavoidable, and there are a number of multi-objective methodologies that can be employed to this end which are both efficient and consistent (Madlener and Stagl 2005).[6] Regardless of how such policymakers evaluate such trade-offs, however, the policies implemented to encourage accelerated renewables development should be as economically efficient as possible. In other words, while economic theory may not be able to fully answer whether accelerated renewables development or development of specific renewable technologies are themselves *Pareto-superior* policies,[7] economic theory can help determine the most efficient, "least-cost" approaches to achieve the chosen policy goals.

Increasingly, feed-in tariffs have been argued to be a superior policy approach for promoting renewable generation (Sijm, 2002;[8] Rowlands, 2005[9]), especially in their ability to reduce financial risks for developers (Mitchell, Bauknecht and Connor, 2006).[10] (Of course, feed-in tariffs and other policies to promote renewable energy, such as renewable portfolio standards, are not necessarily mutually exclusive.) Germany, for example, has been especially aggressive about feed-in tariff implementation. Germany's Ernueurbare Energien Gesetz (EEG) was implemented in 1991 and revised in 1998. By 2002, total generation using renewable energy technologies in Germany had increased to over twenty terawatt-hours (TWh) per year (Mitchell, Bauknecht and

Connor 2006).[11] The payment schemes vary by technology, plant vintage, and location. For example, under the German system, payments for solar photovoltaic plants are over seven times greater than payments for geothermal plants.

Yet, feed-in tariffs are not a panacea. In particular, one difficulty with the development of feed-in tariffs compared with renewable portfolio standards (RPS) and "renewables obligations" (RO), is that feed-in tariffs require policymakers to define <u>all</u> of the feed-in tariff attributes. These attributes include specific payment *levels* for individual technologies (wind, solar, geothermal, etc.), payment *structures* (e.g., fixed or declining over time), and payment *duration*. All three attributes can require significant "guesswork" on the part of policymakers as to future market conditions and rates of technological improvements. Essentially, traditional feed-in tariff designs require policymakers to substitute their judgment for that of markets in the selection of technological "winners and losers. "However, long-term forecasting is notoriously imprecise and inaccurate, given the multitude of uncertainties that affect the future. Moreover, once specific price paths (i.e., level, structure, and duration) are specified, changing those paths is both difficult and costly, as it creates excessive regulatory uncertainty that, in turn, increases investment costs.

Feed-in tariffs were first used in the guise of "avoided cost" payment schemes mandated as part of the United States Public Utility Regulatory Policies Act of 1978 (PURPA). Under PURPA, US electric utilities were required to purchase all of the output from so-called "qualifying facilities" (QFs) at prices that reflected the utilities' long-term avoided costs. Since there were no direct market prices that could be used, such as futures markets, avoided costs were administratively established and approved by state energy regulators, who typically relied on various forecast models to estimate future fossil fuel prices and electric prices. For example, in the 1980s, it was not uncommon to see predictions that crude oil prices would reach more than $100 per barrel by the year 2000; the actual price turned out to be less than $30 per barrel. Moreover, during the entire decade of the 1990s, crude oil prices were less than $25 per barrel.[12]

Qualifying facilities were either industrial plants using co-generation technologies or renewable resources, including hydroelectric facilities with less than 80MW capacity and wind power. As a result of overestimated avoided costs, electric utilities and their retail ratepayers were saddled with sometimes copious amounts of high-priced generation, and this led to the derisive description of many co-generation facilities as "PURPA machines" (Barclay, Gegax, and Tschirhart, 1989).[13] Moreover, several states, notably California, established a number of alternative "Standard-Offer" contracts for QFs, depending on the type and size of generator (Gipe 2007).[14] Some of these, especially the Standard Offer Four (SO4) contract provided for even higher payments and thus further distorted the electric markets.[15]

Like avoided cost rates set under PURPA, feed-in tariffs whose prices are set too high or that last too long will needlessly subsidize renewable energy technologies and create welfare losses for society. Not only do such subsidies distort electric markets and reward inefficient developers and operators; electricity consumers can be negatively impacted because subsidies are a tax that increases as the overall share of renewable energy increases. Even the highly successful German feed-in tariffs has been criticized for its adverse impact on electric rates,[16] and retail customers increasingly protest its implementation. The challenge, therefore, is to develop an economically efficient feed-in tariff mechanism that achieves the broader policy goals associated with accelerated renewable energy development.

The remainder of this chapter is organized as follows: Section 3.2 compares feed-in tariffs and other renewable energy technology support schemes, such as tradable renewable energy certificates (sometimes referred to as “green tags”), and renewable portfolio standards (RPS) designs. Section 3.3 provides a brief literature review on feed-in tariff design and experience in Europe, where feed-in tariffs are most common, including a discussion of the differences between feed-in tariffs and other common support schemes, including quotas and auctions. Section 3.4 discusses the key components of an economically efficient feed-in tariffs. Section 3.5 describes the forward capacity market auction approach that is the basis for the proposed two-part feed-in tariff design, which also incorporates incentive mechanisms to maximize renewable energy generation. The focus is on the auction-determined capacity payment, explaining the economic benefits of this approach compared to other feed-in tariff designs. Section 3.6 offers some policy guidelines and concluding thoughts.

3.2 Comparison of feed-in tariffs and other renewable energy development approaches

Various renewable generation support schemes share one feature: a demand is created for renewable generation by mandating either renewables capacity or output, which otherwise would not exist whatsoever or would not exist at desired levels under current market conditions. However, the various renewable generation support schemes that have been developed differ in the channels through which additional incentives for renewable generation operate. Better understanding the strengths and weaknesses associated with various renewable generation support approaches provides valuable lessons for improving those mechanisms.

The most common component of feed-in tariff design is a guarantee of a long-term minimum price for generated electricity. (The same thing existed under PURPA.) The advantage of feed-in tariffs is that individual renewable energy developers are provided with a sufficient degree of financial stability, and thus, a hedge against future market volatility. This encourages renewable capacity installation. However, this advantage of feed-in tariffs is also an Achilles' heel: a fixed, long-term price—or a price series with a built in technology adjustment factor—will almost certainly deviate from realized market prices by greater amounts over time. If the resulting feed-in tariff rates are too high, electricity prices will increase, reducing economic well-being. If the resulting feed-in tariff rates are too low, renewable generation will not be developed at the rates desired by policymakers, and the associated policy goals of renewable generation development will not be met.

Tradable renewable energy certificates use market mechanisms and competition to determine the certificate price. The certificates foster competition, favor more efficient renewable energy technologies over less efficient ones, and more efficient producers over less efficient ones. However, there are two potential problems with TGCs. First, uncertainty about the current and future price of tradable renewable energy certificates increases the financial risks faced by developers and reduces their incentives to invest in renewable generation. This issue can be ameliorated somewhat if utilities sign long-term purchase contracts with renewables developers. (Although such long-term contracts can also create their own set of issues, such as their treatment as "debt" on utilities' balance sheets).[17] Second, and more importantly, these certificates can affect competition between different renewable technologies that are at different stages of development. Thus, less mature but potentially promising renewable technologies, such as solar photovoltaics, may not receive a sufficient share of support and thus suffer adverse development impacts, which can lead to greater inefficiency and higher costs in the long term.

A third approach, best exemplified by Britain's Non-Fossil Fuel Obligation called for offers from renewable energy suppliers to fulfill a pre-specified quota on each renewable technology at intermittent intervals.[18] Providers of the lowest asking price were given the contracts. Similar to tradable renewable energy certificates, the competition in the tender process is designed to distinguish more efficient renewable generation producers from less efficient renewable energy producers, and since a separate quota is specified for each renewable technology, the Non-Fossil Fuel Obligation bypassed the second problem faced by tradable renewable energy certificates, namely, the fairness of competition among different renewable technologies. But the Non-Fossil Fuel Obligation also had several problems of its own. First, less than one-third of the winning bids for wind power were realized, so the actual installed capacity fell short of the pre-specified quota. The second problem had to do with the Non-Fossil Fuel Obligation procedure's intermittent nature. The lack of a set schedule for the Non-Fossil Fuel Obligation increased financial uncertainty and reduced the incentive to invest in renewable generation.

3.3 Efficacy of existing feed-in tariff designs

Current feed-in tariff policies share several characteristics. First, current feed-in tariff policies provide an above-market energy payment to generators. Thus, there is an incentive for generators to produce as much energy as possible. Second, current feed-in tariff policies are time limited, recognizing that offering payments forever is inefficient. Third, feed-in tariffs often include technology improvement factors designed to reduce payments over time. This is similar to performance-based regulation schemes that allow prices to increase at the rate of inflation less an allowance for improved productivity.[19] Fourth, feed-in tariffs are typically differentiated by technology: prices paid to wind power suppliers, for example, are not the same as those paid for solar power or biomass. Fifth, by setting feed-in tariff prices the overall impact of feed-in tariffs on retail electric rates is subject to increased uncertainty. Too high a feed-in tariff will stimulate over-investment, causing too rapid development of above-market cost renewable technologies and triggering adverse economic impacts owing to higher than expected electric rates, as well as customer backlash.

Other than as applied under the original “avoided cost” guidelines of PURPA, in the USA, feed-in tariffs have not been used to spur renewable generation development. Instead, many US regulators have adopted renewable portfolio standards (RPS). Typically, an RPS establishes a gradually increasing annual minimum supply percentage from renewable energy technologies for electric utilities, including traditional vertically integrated utilities, as well as distribution utilities that have standard offer service (SOS) obligations to serve a subset of retail (typically residential) customers. However, individual state RPS designs differ, often substantially. First, the types of generation that are deemed “renewable” can vary owing to political and economic considerations. In Vermont, for example, natural gas-fired distributed generation is considered renewable. In several other states, waste-to-energy plants (i.e., burning garbage) are considered renewable. In Pennsylvania, generators that burn waste coal are considered renewable—this leverages that state’s coal deposits and mining industry. Individual state RPS designs also typically segregate renewables into several categories and require different minimum percentages of each type. However, the categories are not generally defined by individual technology within a given resource, but by specific “classes” of renewables. Connecticut, for example, has three separate renewables classes, each with its own set of target saturations.

In states that have been restructured, and in which local electric utilities are no longer responsible for securing generation supplies, RPS obligations fall onto retail providers. Those providers must demonstrate that the mandated percentages of generation by different renewables have been secured, or that the providers have purchased equivalent quantities of green tags. Typically, states impose a significant financial penalty, often four cents per kWh or higher, on firms that have not obtained sufficient renewable generation. Green tags and other approaches that lump technologies together thus encourage development of the most economically efficient, least-cost renewable energy technologies. The largest flaw with a green tag program, however, is that it discourages development of higher-cost, less mature technologies. Thus, if policymakers wish to provide incentives to those technologies, other policy instruments must be used. This is where feed-in tariffs can provide a significant advantage. Owing to feed-in tariff prevalence in European Union, especially in Germany and Denmark, the feed-in tariff programs in those two countries are reviewed next.

Germany. Germany's feed-in tariffs was introduced in its Electricity Feed-in Law in 1991. Under this law, utilities are obligated to buy renewable energy (RE) at 90 percent of the retail rate of electricity. By creating the market for renewable energy and guaranteeing RE producers a high price to cover their long-term costs for the life of the plant, the German Feed-in Law had a significant, positive impact on the development of renewable electricity generation in Germany. The installed wind capacity was over 6,000 MW at the end of year 2000, up from less than 100 MW in 1990.

However, the German Feed-in Law also created some problems. Electric utilities and their customers have opposed it because of the high costs both have had to bear to support the RE producers. In 2000, Germany passed the Renewable Energy Law, which set specific prices that independent renewable power producers could receive for each type of renewable energy source, but for a limited amount of time. For instance, in 2000, a new wind turbine project would be paid 0.178 DM per kWh (eleven cents per kWh) for the first five years, and then the rate would begin to fall. The buyback tariff rate for PV systems was € 0.51 per kWh (forty-five cents per kWh) and was set to decrease by 5 percent annually. This law also better targets each RET by specifying different buyback rates for different renewable energy technologies and taking their cost of generation into account.

Denmark. Denmark's feed-in tariffs started in 1992, when utilities became obligated to purchase renewable energy from private producers at a fixed price of between 70 percent and 85 percent of the retail price of electricity (a price higher than the price of privately generated fossil fuel-fired electricity). feed-in tariffs, together with other market support programs, led to a sharp increase in the installed wind capacity in Denmark, from 343 MW in 1991 to 2,300 MW by the end of year 2000. In 2000, Denmark abandoned guaranteed pricing and introduced tradable green certificates. The new goal is to create a market for green power via these certificates. The change in policy seems to have led to a collapse of the Danish wind energy market. Since 2004, almost no new wind capacity has been installed, although there are several ongoing programs to replace older, smaller wind turbines with newer and larger ones. Moreover, 200 MW of offshore turbines are expected to be on-line by 2009.

3.4 Components of an economically efficient feed-in tariff structure

It is not surprising that feed-in tariffs, like most policies, have both benefits and costs. While it may be difficult to judge whether the policy goals justify the costs, once such policy goals are established, it is relatively straightforward to compare alternative policy proposals on their economic merits, i.e., to determine which approach will best meet the specified policy goals – economic and non-economic – at the lowest cost. In this section there is a discussion on the essential components in an economically efficiency feed-in tariff structure, regardless of its specific form.

First, since the policy goals of feed-in tariffs are to encourage both new capacity installation of renewable energy technologies and renewable electricity generation, an efficient feed-in tariff structure should directly target these objectives. More specifically, the feed-in tariff level should not be set so low that it provides inadequate incentives for renewable energy producers to install new capacity and/or generate renewable energy. Nor should a feed-in tariff be set too high to "overcompensate" producers, since the "price tag" for feed-in tariffs and, hence, supporting renewable energy technology is eventually borne by retail customers. Too high a price tag is not only economically wasteful, but can also raise political opposition to a well-intended policy. Therefore, striking an appropriate balance for renewable energy technology development rates and costs is a challenging task faced by all policymakers.

Second, renewable capacity is of little value without corresponding electricity production. Thus, linking feed-in tariff payments, either directly or indirectly, to capacity installed and energy produced is appropriate. Although feed-in tariffs linked to generation alone can provide financial support necessary to enhance renewable energy technology development, the volatility of energy markets virtually assures that preset tariff structures will deviate by larger amounts from contemporaneous market prices as the tariff progresses over time. Of course, feed-in tariffs linked to installed capacity alone can lead to uneconomic installations of generating capacity that rarely operates and that provides few benefits to society at large.

Third, feed-in tariffs encompass both short-term and long-term policy goals. In the short-term, feed-in tariffs are designed to encourage penetration of currently available RETs, even though feed-in tariffs are not mature enough to be directly competitive against traditional fossil fuel-fired technologies (FFTs). Over the long term, feed-in tariffs are designed to promote the advancement of renewable energy technologies so that the renewable energies can compete directly with FFTs.

The difficulty confronting policymakers is that these short-term and long-term goals are unlikely to be perfectly aligned, since technological progress is endogenous. In other words, policies enacted today affect current and future R&D behavior, which in turn affects innovation rates and technological progress. Most importantly, these effects may be counterintuitive: increasing feed-in tariff rates may, in fact, reduce the rate of technological progress. Because the relative expected returns to renewable energy investment favor technologies that are more promising in the long term rather than in the short term, too great a feed-in tariff may encourage more rapid growth of near-term renewable technologies, thus diverting investment resources away from medium-term ones. Too great a feed-in tariff may also encourage investment in renewable energy technologies that are too speculative and far removed from practical application. If so, the probability of technological setbacks will increase, leading to increased perceived financial risk of investment in such technologies and reducing incentives for further investment. Thus, in setting traditional feed-in tariff values, policymakers must determine tariff levels that will maximize the rate of technological improvement for each technology covered.

In the face of uncertainty over market prices and technological progress, it is not clear how policymakers can meet these three objectives by using administratively determined feed-in tariffs. Not only do policymakers need accurate information about current and near-future markets, policymakers must also be able to accurately predict long-term market and technological trends. Thus, policymakers need accurate information about future market prices for electricity, as well as future capital and operating costs for both renewable energy technologies and FFTs. However, the prices and volatility of fossil fuels markets (which have proved difficult to forecast accurately over the long-term) and the costs of new FFTs will be driven by uncertainty over both future worldwide demand for electricity and future environmental regulations, such as carbon taxes and greenhouse gas emissions caps.

An efficient feed-in tariff will also attempt to minimize reliance on administrative information. Economic theory dictates, and policy experience has shown, that when asked directly, individuals may choose not reveal their information truthfully. All other things equal, renewables developers should prefer higher administratively set feed-in tariffs and lower technology advancement parameters, just as an electric utility operating under a performance-based regulation regime will want a higher inflation index and lower X factor. How to efficiently elicit truthful information from the industry without undue administrative burden is yet another important policy design challenge, because the right information set is fundamental to the effectiveness of a feed-in tariff structure.

3.5 Design of a two-part feed-in tariff

Rather than an administratively determined feed-in tariff price structure, the proposal instead is a two-part feed-in tariff that (1) uses proven market mechanisms to elicit truthful information, (2) ensures installation efficiency and generation efficiency both in the short term and in the long term, (3) guarantees timely achievement of policy goals, and (4) is easy to implement and monitor. The proposed two-part tariff consists of a capacity payment that is determined through an auction process, and an energy payment that is tied to the spot market price of electricity. Policymakers need only specify (as inputs) the individual types of renewable generation that policymakers wish to encourage and the quantity of renewable energy desired. Market mechanisms take care of the rest.

The design of the proposed two-part feed-in tariff is based on the design of forward capacity markets. As Crampton and Stoft (2006) discuss, the benefits of a forward capacity market include coordination of new capacity entry, lower risk premiums, and stable prices. The approach consists of an annual capacity auction for the specific renewable technologies for which policymakers wish to accelerate development. The auction is held several years in advance to allow winning bidders time to build their renewable capacity. The winning auction price is guaranteed for a predetermined number of years. In the case of the forward capacity market for ISO-NE, for example, the duration of the fixed auction price for new generating capacity is four years. For a feed-in tariff auction, of course, the auction price would likely be guaranteed for a longer period of time, although there is no uniquely “right” duration.

The forward capacity market also includes a “pay-for-performance” incentive. In the case of actual forward capacity markets, this incentive is based on generators’ availability when spot market energy prices are above a set amount (based on the estimated variable operating cost of a peaking generator).

3.5.1 Administrative inputs

The two-part feed-in tariff requires the following four administrative actions:

1. Identify the renewable technologies that will be eligible to receive feed-in tariff subsidies

2. Determine the desired capacity goals for each technology

3. Determine the overall time horizon over which the feed-in tariffs will be in place

4. Set the payment period for the winning auction prices

Establishing which renewable technologies will qualify for feed-in tariff subsidies will depend on the policymakers’ attitudes toward risk in pursuing technological progress. As a general guideline, it makes sense to focus on medium-term renewable technologies. Technologies that are competitive in the market today clearly do not require any subsidies, but renewable technologies that are close to market competitiveness will likely derive additional benefits from a feed-in tariff. feed-in tariffs that are theoretically promising, but that are unlikely to be competitive for many years, may best be addressed under other policies, such as publicly funded/sponsored R&D, etc. Otherwise, under the two-part tariff design, the prices paid to such technologies may be more likely to have adverse impacts on retail electric rates.

The second input, the time horizon of feed-in tariff, can either be a calendar date or depend on some “trigger condition” such as a specific renewable energy technology reaches a certain percentage of total power generation. The third input, the duration of the auction payments for each vintage, balances the trade-off between providing necessary financial stability to encourage renewable energy investment and not subsidize renewables excessively, especially when the renewable becomes technologically obsolete and economically inefficient. Finally, the fourth input gives policymakers both control and flexibility in achieving the overall policy goals: the annual incremental renewables capacity can be adjusted according to market conditions, expected and unexpected technology breakthroughs, political developments, and so forth.

To put the feed-in tariff into context, in California, the RPS establishes general guidelines for administrative inputs (specifically, the desirable level of RETs and the time horizon for achieving policy goals), and the feed-in tariff is one of several policy instruments, such as the market price referent (MPR) and supplemental energy payments (SEP), that can be used to achieve policy goals. The advantage of the proposed two-part feed-in tariff over MPR/SEP is that it takes most of the “guesswork” out of the policy design and achieves greater economic efficiency in both capacity installation and actual energy production of renewable technologies.

3.5.2 Capacity payment

Once the policy inputs from policymakers are in place, the rest of the two-part feed-in tariff is operated by market mechanisms. Starting with the annual target of incremental capacity for a qualified renewable energy technology, the capacity payment for this vintage is determined through an auction process. The auction for RET capacity is very similar to the forward capacity market approach, which has been recently introduced by several transmission system operators in the United States to ensure adequate supplies of electric generating capacity to meet reliability standards. The forward capacity market establishes annual auctions for capacity through descending clock auctions (described below), and the amount of capacity procured is the amount required to maintain the installed capacity requirement. A capacity supplier’s capacity payment depends on its availability during designated periods of system stress (i.e., shortage events) and the auctions are designed to curb incentives to manipulate the market and distort capacity prices.

Under the proposed two-part feed-in tariff capacity payment auction, potential renewables developers would submit their bids for capacity payments that would be sufficient to induce them to participate in the administratively established capacity investment. The design and format of the capacity auction could be based on a number of design formats. For example, the forward capacity market developed by ISO-NE (Independent System Operator-New England) uses a descending clock auction structure. The auction begins with ISO-NE announcing a set price. Suppliers then announce the quantity of capacity the suppliers are willing to offer at that price. If there is more supply than is needed, ISO-NE decreases the announced price. As it does, some suppliers will choose not to offer some of their capacity. This price lowering process continues until the remaining capacity offered exactly equals the quantity of capacity requested. The resulting price is then the clearing price, which all selected suppliers are paid.

Once the market price has been established through the desired auction mechanism, the price is guaranteed for a prespecified number of years. As with the forward capacity market auction, winning renewable technology bidders are then given several years to construct the generating capacity that the winning bidders have agreed to supply. Developers who fail to bring the capacity on-line as promised are required to pay a pre-established penalty. Like the incentives embedded in the forward capacity market design to reward capacity owners for availability during hours when market prices are highest, the proposed two-part feed-in tariff also includes a market incentive for renewable generation developers. Specifically, the renewable generation developer receives a performance-based capacity payment given by the following formula:

$$P_{V,N,T} = P_V * \frac{CF_{V,N,T}}{CF_{V,T}}$$

Where: P_V is the uniform cutoff level established through the auction process for the current renewable technology vintage V;

$CF_{V,N,T}$ is the capacity factor for a specific firm N of vintage V in year T; and

$CF_{V,T}$ is the average capacity factor for all the firms of vintage V in year T.

Thus, the better performance an individual developer has compared to its peers for the same type and vintage renewable technology, the higher the capacity payment it will receive. This form of capacity payment can be applied to both schedulable resources such as geothermal, as well as non-schedulable resources such as wind. For resources like wind, this payment structure would encourage siting in locations with the greatest wind resources. It could also encourage developers to bid in their own wind portfolios to take advantage of site diversity, thus reducing their overall financial risk.

A carefully constructed competitive bidding process can better allow the policymakers to (1) distinguish more efficient versions from less efficient versions of the given renewable technology, (2) distinguish more efficient renewables developers from less efficient ones, and (3) ensure that feed-in tariff subsidizes renewable energy producers at both the technology frontier and the operation frontier.

Since the overall capacity payment is linked to how an individual generating facility's capacity factor compares to the average capacity factor for other facilities of equivalent technology and vintage, it ensures efficient siting, which can be referred to as installation efficiency (e.g., windy locales for wind turbines and sunny ones for solar photovoltaics). It also encourages maximum energy production by winning bidders, which is called operating efficiency. This approach avoids the "PURPA machine" issue.

For a given vintage of renewable generating capacity, the capacity payment is fixed for a sufficient period to provide financial stability for developers and reduce financial risk. Like traditional feed-in tariff energy payment approaches, this can reduce financing costs. However, unlike traditional feed-in tariff energy payment approaches, capacity payments for each new vintage will automatically adjust to the technological progress rate, because bidders in the auction take the current technological status into account and compete with one another to win the feed-in tariff subsidy. This avoids the difficult problem of policymakers having to determine administratively a fixed technological progress rate and an associated declining payment structure.

Finally, even though different developers are likely to have different actual costs, all developers will receive the same capacity payments on average. As a result, the more cost-efficient developers will enjoy greater profits, and this provides the economic incentive for renewables developers to invest in R&D. In the long run, developers with the greatest technological advantage and lowest installation costs will benefit, expand their market share, and gradually weed out less cost-efficient developers. In this way, the capacity payment aligns short-term and long-term policy goals: developers optimally decide how much to invest in which renewable technologies, which solves the endogeneity problem associated with rates of technological progress present in administratively determined feed-in tariff payment streams. An advantage of this approach is that it automatically accounts for variability of equipment prices. For example, the prices of wind turbines can be quite volatile. Developers will account for that volatility in their capacity bid prices.

In California, to fulfill the RPS requirement, the large investor-owned utilities have adopted a competitive solicitation practice to solicit renewable energy from potential suppliers. This practice enables utilities to distinguish more efficient from less efficient renewables developers, and, in providing this advantage, it is very similar in nature to the proposed auction-based capacity payment. The major differences between competitive solicitation and the auction-based capacity payment are that competitive solicitation operates at the individual utility level without a uniform public policy guideline and that it is not as transparent or easily comparable across different utilities. If a uniformly designed auction procedure is used to determine the capacity payment for renewables, potential developers are not restricted by utility-by-utility solicitation procedures, and the potential developers can respond more efficiently across different utilities.

3.5.3 Energy Payment

The second part of the proposed two-part feed-in tariff is an energy payment tied directly to the market price for electricity. Rather than an administratively determined feed-in tariff energy price, under this approach renewables developers themselves decide how the developers prefer to sell the renewable energy that the developers' facilities generate. Thus, developers can sell their output directly in the spot market, under bilateral contracts to wholesale and retail suppliers, such as those offering "green-power," and so forth. Moreover, this approach can be used in conjunction with mandated RPS designs or tradable renewable energy certificate programs. The concept is straightforward: more renewable generation means higher energy payments, which translate into higher capacity factors and ensure generation efficiency. However, because the energy sold by renewables developers is priced at the market, it does not distort the overall wholesale energy market. Instead, it contributes to the competitiveness of wholesale energy markets by adding new supplies and new suppliers. Just as with the forward capacity market design, renewables developers can receive higher energy payments if more energy is proportionately generated when market prices are high.

The energy payment also has a positive impact on generation efficiency, even for renewable energy that is not dispatchable, such as wind. Of course, non-dispatchability per se implies that wind developers cannot choose to produce more wind power when the spot market price is high, i.e., during the peak periods; but it does allow wind producers to increase the overall capacity factor through better management and maintenance. Because all wind energy producers deal with the non-dispatchable nature of wind, the capacity factor in either the energy payment or the capacity payment does not distort the relative efficiency among the same cohort of RET developers; it only acts as extra incentive for them to compete with each other, because the technological constraint is a given.

3.6 Summary and conclusions

Under the proposed two-part feed-in tariff, since renewables developers receive market-based energy payments, the capacity payments function as the subsidy for renewable energy technologies. Given that energy prices will vary over time, it is the sum of the capacity and energy payments that investors will focus upon when determining the expected rate of return on their investment. Thus, the proposed two-part feed-in tariff is not risk free; there will be market risk when spot market price fluctuates. However, unlike existing feed-in tariffs with administratively determined energy payments, the two-part feed-in tariff allows developers themselves to allocate their necessary risk premium through the capacity market auction. The more concerned an individual renewables developer is about market-price volatility, the higher the capacity market price he will bid for a given quantity of capacity. Since those developers presumably are more knowledgeable about their proposed developments than policymakers, this market-based risk allocation mechanism will be more efficient than an administrative mechanism.

Of course, none of the existing feed-in tariff designs provide a guarantee of complete revenue certainty, nor should the feed-in tariff design. A guarantee of total revenue certainty eliminates the incentive for efficiency, which was one of the reasons that many PURPA-based generating resources were inefficient and costly. Moreover, even if a feed-in tariff is a fixed dollar number, there is still unavoidable market risk, such as inflation and interest rate risk. The proposed two-part feed-in tariff does not expose renewables developers to market risk that is any greater than other (existing) feed-in tariffs. However, it achieves greater economic efficiency through its unique approach of using the market to determine appropriate subsidies and its allocation of that market risk based on developers' own requirements and risk attitudes.

Given the technological progress in renewable energy and the increasingly stringent market conditions for traditional FFTs (such as increasing and volatile fuel costs, stricter emissions requirements, and so forth), renewables developers will bid more aggressively in the auction process for the capacity payment on their proposed capacity investments. This will tend to reduce capacity payments for subsequent renewables vintages. Thus, even if policymakers start out with "wrong" expectations of how renewable energy markets will evolve over time, the annual auction process automatically accounts for new market information and guarantees that annual renewable energy targets are met at the lowest possible cost. When renewable energy technologies can directly compete against traditional FFTs, the auction process ensures that the capacity payment will be driven down to zero, and policymakers need not worry about overcompensating specific renewable technologies for too long. In summary, the proposed two-part feed-in tariff uses all available information, leads to economically efficient outcomes, is easy to implement, and impose far less an administrative burden.

Under current market conditions, government support schemes are needed to encourage the penetration of renewable energy. The question to answer is: given a fixed set of policy objectives, what is an economically efficient policy design to achieve those policy goals? The proposed two-part feed-in tariff allows policy makers to focus on determining the desirable policy objectives, which are used as policy inputs; at the same time, the two-part feed-in tariff spares policymakers all the trouble of performing long-term market forecast, and it relies on proven market mechanism to elicit truthful information directly from market participants.

The two-part feed-in tariff introduces proper competition into the innate subsidy nature of a feed-in tariff, so it provides just the right level of long-term financial stability without overcompensating or undercompensating renewables developers. Although many European countries have been successful using feed-in tariffs to develop renewables, those designs may be inefficient. The European countries can needlessly pay too much for renewable energy, thus raising overall electric costs and reducing economic competitiveness. The danger is that, if feed-in tariffs are set too high, there is likely to be a political backlash that could abruptly halt the entire feed-in tariff approach. The proposed two-part feed-in tariff offers a solution to observed feed-in tariff problems, while avoiding the need for policymakers to set administratively prices and technology parameters that are likely to diverge substantially from the most well-intentioned estimates.

CHAPTER 4: PORTFOLIO-BASED APPROACH TO ELECTRICITY RESOURCE PLANNING

Background

The Energy Commission's 2005 Integrated Energy Policy Report (2005 IEPR),[20] and other state energy policy documents reinforce policies to ensure adequate energy resources, reduce energy demand, develop alternative energy sources, and improve the state's infrastructure. An essential component of California's energy policy is to reduce greenhouse gas emissions in part by increasing renewable generation to 33 percent of retail sales in 2020.

The use of renewable generating technologies is considered to be an effective means for climate change mitigation. Policy makers, consumers, and companies, however, are wary because of the widespread perception that these technologies cost more than conventional alternatives so that increasing their deployment will raise overall electricity generating costs. Moreover, some program designed to encourage renewable resource development, such as green tags and the renewable portfolio standards (RPS) program, may not adequately develop a variety of renewable resources, including those that may hold great long-term promise, but are more expensive today.

The 2006 Integrated Energy Policy Report Update (2006 IEPR Update)[21] shows that California does not appear to be on course to achieve the short-term goal of 20 percent renewable generation by 2010. The 2006 IEPR Update identifies five primary barriers to achieving this policy that include a common theme, risk and costs:

1. Inadequate transmission infrastructure to connect remotely located renewable resources.

2. Uncertainty regarding whether projects with supplemental energy payment awards will be able to obtain project financing.

3. Complexity and lack of transparency in the Renewable Portfolio Standard program implementation for investor owned utilities (IOUs).

4. Insufficient attention to the possibility for contract failure and delay.

5. Lack of progress in re-powering aging wind facilities.

From the utility's perspective, managing portfolio risk is of strategic importance. But when utilities pass-through fuel costs, there is a potential conflict between minimizing shareholder risk and minimizing ratepayer risk.

The role of renewable energy resources in utility portfolio risk reduction has been cited to support the claim that the fixed cost nature of renewable energy resources, as opposed to fuel or variable cost, should earn these projects a premium over traditional resources such as natural gas fired power plants. In order to install a renewable generation power plant, the power generator must outlay a significant capital expenditure in the short-term to launch the facility; the fixed costs are front-loaded and constitute a significant capital outlay in the current period.[22]

In the longer term, however, the cost to operate the facility is considerably less than that of a fossil fuel facility. The renewable power generator must only concern themselves with the operations and maintenance of the facility, because the fuel, for some renewable technologies such as solar and wind is "free."

Although there has been a substantial amount of economic analyses on the cost side, little has been done to incorporate risk into analysis. California regulators and utilities, however, face numerous challenges to achieve renewable energy targets. Some of these issues include:

- Will renewable technologies continue to develop?
- How will politics, pressure from the insurance industry, and fuel prices affect climate change regulation? How will "early credit" programs be treated?
- Will consumer interest in "clean power" increase or wane?
- Will the United States continue to be bifurcated into regional markets and territorial markets?
- Will capacity expansion be driven regionally and, if so, by what mechanisms?
- Will renewable energy development satisfy state targets?
- Will fuel prices and environmental constraints strand some assets and speed development of new technologies?

This report builds on the previous and ongoing research by treating energy planning as an investment-decision problem. Investors commonly evaluate such problems using portfolio theory to manage risk and maximize portfolio performance under a variety of unpredictable economic outcomes. Treating energy planning as an investment-decision problem, this report uses mean-variance portfolio theory to examine the risk and cost effects of achieving the California's renewable energy goals as discussed in the 2005 IEPR and 2006 IEPR Update.

Use of portfolio theory involves quantifying risk. In this case, construction, investment, operations and maintenance, and fuel risks are quantified using data provided by the California Energy Commission, Energy Information Administration (EIA), Federal Energy Regulatory Commission (FERC), and if necessary, European data from

TECHPOLE, an energy database operated and maintained at LEPII, University of Grenoble.

This report applies portfolio-theory optimization to produce an expository evaluation of the 2020 projected California business as usual electricity generating mix (BAU mix) with the following objectives:

- Highlight the benefits of applying portfolio optimization to assessing the costs and risks of future generating portfolios by measuring the risk of achieving the penetration of preferred resources;
- Demonstrate a new rationale for renewable energy technologies that goes beyond the least-cost planning arguments that have dominated the debate on this subject to date; and
- Create a vehicle for constructive dialogue among the state's energy agencies and electric utilities.

In addition to the portfolio analysis, there are three other related studies that were conducted for 2007 Integrated Energy Policy Report ("2007 IEPR"): These are Portfolio Analysis and Its Potential Application to Utility Long-Term Planning ("Staff Portfolio Report")[23] and Scenario Analyses of California's Electricity System ("Scenario Analyses Report"),[24] and Intermittency Analysis Project ("IAP Study")[25] all undertaken by teams made up of CEC staff and contractors. The following three sections compare those studies with the portfolio analysis.

Relationship between The Portfolio Analysis and Staff's Portfolio Report

Staff's Portfolio Report explores the potential for Portfolio Analysis to be incorporated into electric utility resource planning for California's investor-owned utilities (IOUs) such as Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric Company (SDG&E). It provides an overview of planning activities in California and other selected areas and entities, describes long-term resource plans, discusses Portfolio Analysis and underlying Modern Portfolio Theory, and explores how current IOU planning requirements may incorporate such a method to long-term utility resource planning.

Overall, the report indicates that although electric utility resource long-term planning utilizes risk assessment and scenario analyses, gas-fired resources continue to be added at levels that do not meaningfully reduce California's reliance on natural gas, resulting in long-term price and carbon risk. The report also indicates that renewable resources represent relatively risk-free alternatives to gas-fired resources and the value of this risk reduction is not being properly considered in either the procurement or long-term planning processes. The report further describes planning and evaluation methods used by California's IOUs and other selected utilities outside California, and summarizes how risk and uncertainty are incorporated into the respective planning processes. The report concludes that total portfolio risk should be the primary measure of concern, so that some version of "portfolio analysis," based on Modern Portfolio Theory, may be the means by which such risk should be examined.

The report describes that portfolio analysis may enable a decision maker to assess potential changes to a portfolio's risks and costs brought about by adding generation assets having their own individual risk and cost profiles. The resultant portfolio risks and costs of various combinations of assets can be quantified, such that the most efficient portfolios can be recognized on a curve referred to as the "efficient frontier." That is, for any given level of risk, the least expensive portfolio can be determined. Conversely, for any given level of cost, there is an associated least-risk portfolio. Portfolio analysis allows for considering risk preferences in choosing among portfolios, as well as for examining different tradeoffs among various risks and costs.

With regard to the treatment of carbon risk, the report expresses concerns that, if low carbon portfolios are screened out too early in the analysis, the full range of options for mitigating exposure to carbon regulatory risk may not be properly considered. The report also discusses stochastic and scenario risk and the potential issues associated with the implementation of the portfolio theory in a utility's resource planning process.

The portfolio analysis serves as a first attempt to implement many of the concepts described in the Staff Portfolio Report in the California setting. The analysis uses mean-variance portfolio theory to examine the risk and cost effects of achieving the California's renewable energy goals. As described more fully below, perhaps the single most important lesson of the portfolio optimization analysis is that adding a non-fossil fuel, fixed-cost technologies (such as wind energy) to a risky generating portfolio lowers expected costs at any level of risk, even if the non-fossil technology costs more when assessed on a stand-alone basis. This underscores the importance of policy-making approaches grounded in portfolio concepts as opposed to stand-alone engineering concepts.

Relationship between The Portfolio Analysis and Staff's Scenario Analyses

The Scenario Analyses Report examines the implications of resource plans in California and the Western Electricity Coordinating Council (WECC) under the various scenario settings such as different levels of penetrations of energy efficiency measures and renewable generation. Scenario analyses are necessary to understand how selected performance measures such as reliability, cost, and environmental impacts may change across resource cases that use alternative combinations of preferred resources (i.e., energy efficiency measures, end-user roof top photovoltaic systems, and supply-side renewable generating technologies) supplemented by conventional resources to assure reliable system operation. The assessed resource cases cover a wide range of alternative resource mixes extending from a low penetration of preferred resources that might result from continuation of "status quo" to a high level of penetration beyond current expectations. High penetrations of these preferred resource types may be necessary to achieve the major GHG emission reductions established by the California Legislature such as Assembly Bill 32 adopted in 2006.

The report studied the following nine thematic scenarios using both the production cost modeling as well as sensitivity assessment such as sensitivity to high and low fuel price projections. Each has also been tested against simulated "shocks" to determine robustness of the underlying resource plan as well.

- Case 1 — Current conditions extended into the future.
- Case 1B — Compliance with current requirements.
- Case 2 — High sustained natural gas and coal prices.
- Case 3A — High energy efficiency in California only.
- Case 3B — High energy efficiency throughout the West.
- Case 4A — High renewables in California only.
- Case 4B — High renewables throughout the West.
- Case 5A — High energy efficiency and renewables in California only.
- Case 5B — High energy efficiency and renewables throughout the West.

The preliminary findings of the Staff's Scenario Analyses include the following:

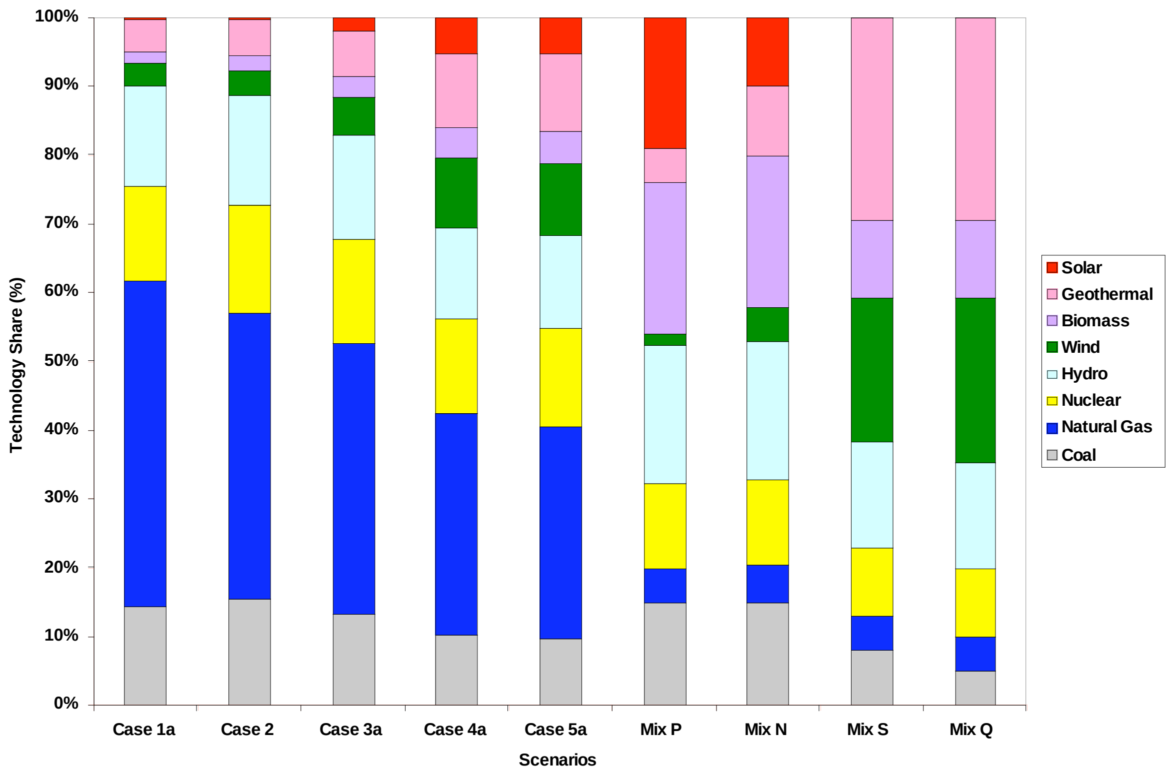
- Increased penetration of preferred resources reduces greenhouse gas emissions significantly, even when dispatchable resources to assure reliability are taken into account;
- Increased penetration of preferred resources outside California increases imports into California as surpluses of cheaper Rest‑of‑WECC power plants displace more expensive California power plants; and
- Assuming a fixed set of technology characteristics and costs, increased penetrations of energy efficiency and renewables may increase total system costs as the capital cost additions of these resource types outweigh the production costs savings.

The report also lists potential limitations of results with respect to data assumptions, modeling assumptions, and uncertainty characterization assumptions so that the results should be interpreted as "indicative" of the consequences of the scenario in question, but not definitive. There are numerous shortcuts in modeling technique that have been undertaken, and data limitations that have been encountered, in attempting to complete this project within available time and budget. The report also acknowledges the fact that the analyses that have been conducted are on a physical basis, while many of the forthcoming policies to achieve major GHG reductions will be designed for individual load serving entities (LSE) and generating companies. None of the analyses conducted in the report are specific enough to allow the impacts on an individual LSE to be evaluated.

The staff's Scenario Analyses and this Portfolio Analysis are mutually complementary. As described more fully later in the Future Improvements section of this report, scenario analysis can be incorporated into the framework of portfolio analysis since the former may be utilized as an overarching framework for the latter. In other words, one can study "Efficient Frontier" for each envisaged scenario and subsequently compare them together in order to arrive at the "optimal" portfolio that suits policy makers' preference and tolerance (i.e., trade-off) regarding expected portfolio cost and risk.

Figure 4 below compares the generation mixes reported in the Staff's Scenario Analyses and this Portfolio Analyses. Note that the Portfolio Analysis mixes are "short" on natural gas and "long" on renewables compared to Staff's Scenario Analysis results. The main reason is that this expository portfolio analysis did not address operational issues of integrating a high level of renewable resources such as wind into the existing transmission grid. There is further discussion on this issue in the Future Improvement section of this report.

Figure 4: Comparison of Technology Share between Staff's Scenario Analysis Results and The Portfolio Analysis Results.



Relationship between The Portfolio Analysis and IAP Study

The Intermittency Analysis Project (IAP) addresses multiple aspects of the potential impact of more intermittent renewables. It considers the impacts on the electricity grid of higher levels of intermittent renewables from a scenario basis. The report examines the state-wide impacts of more intermittent renewables on the California electricity and transmission infrastructure through transmission load flows, statistical analysis, and production cost modelling. These higher levels are in response to meeting the Renewables Portfolio Standard of 20 percent renewable energy by 2010 and the accelerated target of 33 percent renewable energy by 2020. It quantifies impacts on the grid as a result of increasing renewable penetration by analyzing transmission infrastructure needs as well as operational flexibility though a series of scenarios. Mitigation options as well as operational response strategies were demonstrated using production cost modelling and load-flow simulation tools. It provides a framework for system operators, utilities, and infrastructure planners to gauge transmission and future grid needs for their service areas and the region as more renewable energy generation is installed in California.

The report considered the following four scenarios:

- ***2006 Base*** - Baseline for the existing California grid.

- ***2010T*** - 2010 Tehachapi case with 20 percent renewables and 3,000 megawatts (MW) of new wind capacity at Tehachapi.

- ***2010X*** - 2010 accelerated case planning toward 33 percent renewables.

- ***2020*** - 2020 case with 33 percent renewables.

The report concludes that California can incorporate the amount of renewables based on the IAP scenarios, provided appropriate infrastructure, technology, and policies are in place. Specifically, this successful integration will require:

- Investment in transmission, generation, and operations infrastructure to support the renewable additions.

- Appropriate changes in operations practice, policy and market structure.

- Cooperation among all participants, for example, the California Independent System Operator, investor-owned utilities, renewable generation developers and owners, non-Federal Energy Regulatory Commission jurisdictional power suppliers, and regulatory bodies.

The IAP Study can be used with an expanded version of the Portfolio Analysis. This portfolio analysis uses mean-variance portfolio theory to examine the risk and cost effects of achieving the California's renewable energy goals as well as California's carbon reduction goals. Since the analysis is primarily focused on the high level implementation of the Modern Portfolio Theory, the detailed transmission and operational feasibility studies have been abstracted. A discussion on how to incorporate such a study will be included in the Future Improvement section of the report.

Least-Cost versus Portfolio Based Approaches

Financial investors commonly apply portfolio theory to manage risk and maximize portfolio performance under a variety of unpredictable economic outcomes. By contrast, traditional energy planning focuses on finding the least-cost generating alternative. This approach worked sufficiently well in a technological era marked by relative cost certainty, low rates of technological progress, and technologically homogenous generating alternatives and stable energy prices. However, today's electricity planner faces a diverse range of resource options and a dynamic, complex, and uncertain future. Attempting to identify least-cost alternatives in this uncertain environment is virtually impossible. As a result, more appropriate techniques are required to find strategies that remain economical under a variety of uncertain future outcomes.

Given this uncertain environment, it makes sense to shift electricity planning from its current emphasis on evaluating alternative technologies to evaluating alternative electricity generating portfolios and strategies. The techniques for doing this are rooted in modern finance theory – in particular mean-variance portfolio theory. Portfolio analysis is widely used by financial investors to create low risk, high return portfolios under various economic conditions. In essence, investors have learned that an efficient portfolio takes no unnecessary risk to its expected return. In short, these investors define efficient portfolios as those that maximise the expected return for any given level of risk, while minimizing risk for every level of expected return.

Portfolio theory is highly suited to the problem of planning and evaluating electricity portfolios and strategies because energy planning is not unlike investing in financial securities. Similarly, it is important to conceive of electricity generation not in terms of the cost of a particular technology today, but in terms of its expected portfolio cost. At any given time, some alternatives in the portfolio may have high costs while others have lower costs, yet over time, an astute combination of alternatives can serve to minimize overall generation cost relative to the risk. In sum, when portfolio theory is applied to electricity generation planning, conventional and renewable alternatives are not evaluated on the basis of their stand-alone cost, but on the basis of their contribution to overall portfolio generating cost relative to their contribution to overall portfolio risk. Portfolio-based electricity planning techniques thus suggest ways to develop diversified generating portfolios with known risk levels that are commensurate with their overall electricity generating costs. Simply put, these techniques help identify generating portfolios that can minimize California's energy price cost and risk.

This also has important implications for energy security. Although energy security considerations are generally focused on the threat of abrupt supply disruptions, a case can also be made for the inclusion of a second aspect: the risk of unexpected electricity cost increases. This is a subtler, but equally crucial, aspect of energy security. Energy security is reduced when ratepayers hold inefficient portfolios that are needlessly exposed to the volatile fossil fuel cost risk. Displacing California's coal and gas dependency by adding renewables technologies enhances California's energy security. The reason is that renewables costs are generally uncorrelated to fossil prices; this enables these technologies to diversify California's generating mix and enhance its cost-risk performance while simultaneously reducing CO_2 emissions.

Portfolio Optimization Basics

Portfolio theory was developed for financial analysis, where it locates portfolios with maximum expected return at every level of expected portfolio risk. In the case of electricity generating portfolios, it is more convenient to optimize portfolio generating *cost* as opposed to *return*. This choice does not affect results and conclusions presented in this report.

How Adding More Costly Renewable Resources Can Reduce Overall Cost

Efficient generating portfolios are defined by twin properties: the expected costs are minimized for any given level of risk, while minimizing expected risk at any level of expected cost. The idea that adding a more costly technology raises average generating cost seems obvious and compelling. Nonetheless, it is flawed. Estimating overall generating costs for a given mix involves assessments of long-term future cost *expectations* for highly uncertain fossil fuel and other outlays that have fluctuated significantly and unpredictably in the past. In other words, generating cost estimates reflect an assessment of how cost will behave in the distant future, 10 or 20 years from now. Highly uncertain long-term generation costs cannot be directly observed or calculated in a manner that – for example – fruit salad costs for dinner can be calculated at the market. Here the arithmetic is simple and intuitive: adding expensive strawberries to the mix, for example, raises the cost of making fruit salad.

The simple salad making cost formula does not work for fuel and operating outlays or any other uncertain future cost stream. Nonetheless, this is more or less how electricity planning models estimate costs for given generating mixes. According to traditional electricity planning models, when, for example if a 10¢/kWh wind energy is added to a 6¢/kWh fossil-fuel generating mix, the overall resource mix cost must increase. However, contrary to what these models say, adding an appropriate share of renewable-based electricity, even if it costs more on a stand-alone basis, does not necessarily raise expected generating costs. The key for understanding this counter-intuitive result is “portfolio risk” and developing optimal portfolios (See Box 1, below, for an introduction to portfolio optimization).

Box 1. Portfolio optimization basics

Portfolio theory was initially conceived in the context of financial portfolios, where it relates expected portfolio return to expected portfolio risk, defined as the year-to-year variation of portfolio returns. This box illustrates portfolio theory as it applies to a two-asset generating portfolio, where the generating cost is the relevant measure. Generating cost (cent/kWh) is the inverse of a return (kWh/cent), that is, a return in terms of physical output per unit of monetary input.

Expected portfolio cost

Expected portfolio cost is the weighted average of the individual expected generating costs for the two technologies:

(1) Expected Portfolio Cost = $X_1 E(C_1) + X_2 E(C_2)$,

Where X_1 and X_2 are the fractional shares of the two technologies in the mix, and $E(C_1)$ and $E(C_2)$ are their expected levelized generating costs per kWh.

Expected portfolio risk

Expected Portfolio risk, $E(\sigma_p)$, is the expected year-to-year variation in generating cost. It is also a weighted average of the individual technology cost variances, as tempered by their covariances:

(2) Expected Portfolio risk = E(σ_p) = $\sqrt{X_1{}^2\sigma_1{}^2 + X_2{}^2\sigma_2{}^2 + 2X_1X_2\rho_{12}\sigma_1\sigma_2}$,

Where: X_1 and X_2 are the fractional shares of the two technologies in the mix; σ_1 and σ_2 are the standard deviations of the holding period returns of the annual costs of technologies *1* and *2* as further discussed below; and ρ_{12} is their correlation coefficient.

Portfolio risk is always estimated as the standard deviation of the holding period returns (HPRs) of future generating cost streams. The HPR is defined as: *HPR = (EV–BV)/BV*, where *EV* is the ending value and *BV* the beginning value (see Brealey and Myers 2004 for a discussion on HPRs). For fuel and other cost streams with annual reported values, *EV* can be taken as the cost in year *t+1* and *BV* as the cost in year *t*. HPRs measure the rate of change in the cost stream from one year to the next. A detailed discussion of its relevance to portfolios is given in Awerbuch and Yang (2007).

Each individual technology actually consists of a portfolio of cost streams (capital, operating and maintenance, fuel, CO_2 costs, and so on). Total risk for an individual technology – that is, the portfolio risk for those cost streams – is σ_T. In this case, the weights, X_1, X_2, and so on, are the fractional share of total levelized cost represented by each individual cost stream. For example, total levelized generating costs for a coal plant might consist of ¼ capital, ¼ fuel, ¼ operating costs, and ¼ CO_2 costs, in which case each weight X_j = 0.25.

Correlation, diversity, and risk

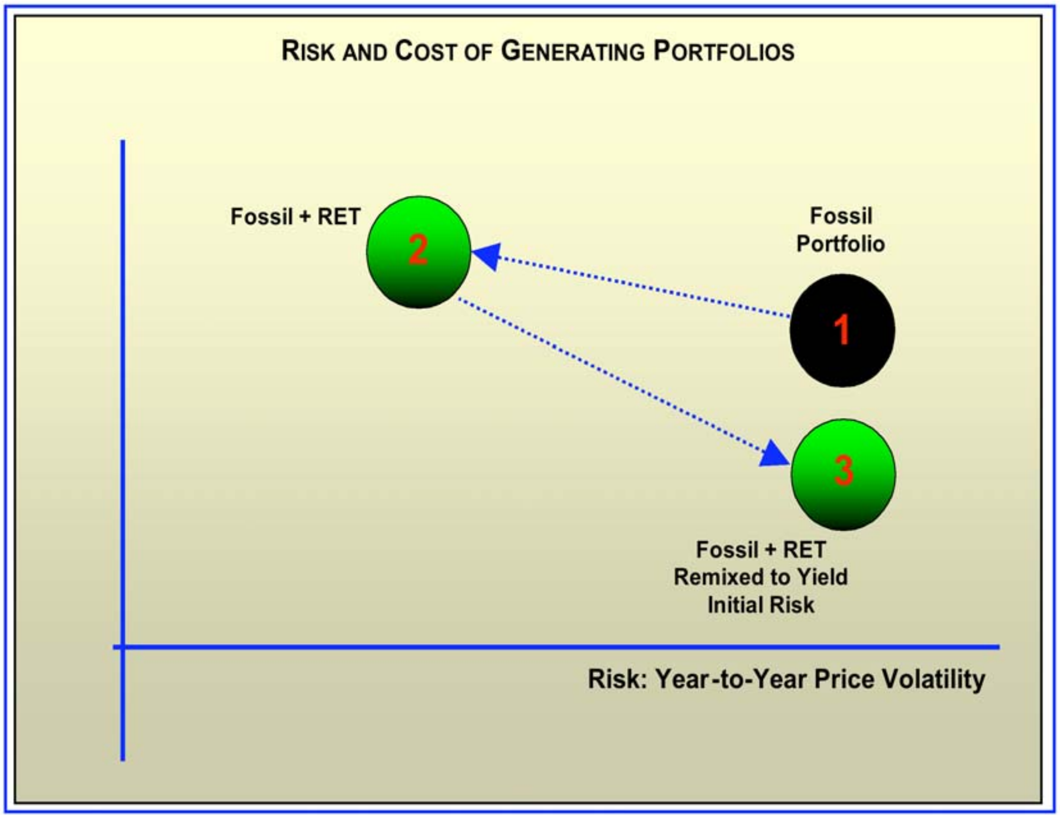
The correlation coefficient, *ρ,* is a measure of diversity. Lower ρ among portfolio components creates greater diversity, which reduces portfolio risk σ_p. More generally, portfolio risk falls with increasing diversity, as measured by an absence of correlation between portfolio components. Adding renewables to a risky fossil fuel generating mix lowers expected portfolio cost at any level of risk, even if the renewable technologies have higher direct costs. A pure fuel-less, fixed-cost technology, has $\sigma_i = 0$ or nearly so. This lowers, σ_p, since two of the three terms in equation (2) reduce to zero. This, in turn, allows higher-risk/lower-cost technologies into the optimal mix. Finally, it is easy to see that σ_p declines as $\rho_{i,j}$ falls below 1.0. In the case of fuel-less renewable technologies, fuel risk is zero and its correlation with fossil fuel costs is zero. too.

When the element of risk is included, the portfolio equation produces important results that are part of the so-called *portfolio effect* discussed in any finance textbook. The portfolio effect of adding a fixed-cost asset, such as wind, to the risky fossil generation mix is powerful and counterintuitive. Modern finance theory tells us that a fixed-cost asset can have the remarkable effect of *lowering* expected portfolio cost, adjusted for risk, even if its stand-alone cost is *higher* than the remaining portfolio components. For example, adding riskless government bonds yielding 5 percent to an existing stock portfolio producing 10 percent raises (not reduces) the expected return of the resulting portfolio that contains both risky stocks and riskless government bonds. This outcome is based on statistics: by definition, a fixed-cost asset is uncorrelated with the costs of all of the other assets. Statistical correlation affects the degree of diversification and hence overall portfolio risk.

This idea applies directly to generating portfolios. Passive, capital-intensive, and fuel-less renewables technologies such as wind and solar photovoltaic (PV) have cost structures that are nearly fixed or riskless over time, once construction is complete. Viewed over a sufficiently diversified geographic area, for example, the “production” costs of a generating portfolio with 20 percent wind varies less than one without wind.

Figure 5 illustrates how adding a more costly renewable generating resource reduces overall portfolio costs. Beginning with a 100 percent fossil portfolio (circle 1), when wind generation is added, portfolio costs increase, but portfolio risk decreases. This is shown as a move up and to the left to circle 2. Next, suppose that after adding wind generation, the overall resource portfolio is adjusted, so that the portfolio risk is increased back to the initial level before the wind generation was added. If this is done, it will be found that the wind generation lowers the *expected* or average cost of the portfolio at the original level of risk (circle 3). (In other words, the portfolio moved from an *inefficient*, 100 percent fossil portfolio, to an *efficient* portfolio that includes renewable generation.) This is how portfolio optimization minimizes portfolio costs and risk when higher cost, but less risky, renewable resources are added to a lower cost, but higher risk, portfolio of fossil-fuel resources. Without considering “risk” this counterintuitive result is not possible. Thus, traditional generation planning efforts that fail to incorporate portfolio risk are incomplete: the focus is on overall cost and useful information about risk is ignored.

Figure 5: How adding a more costly renewable resource can reduce overall expected cost



Risk from a Portfolio Perspective

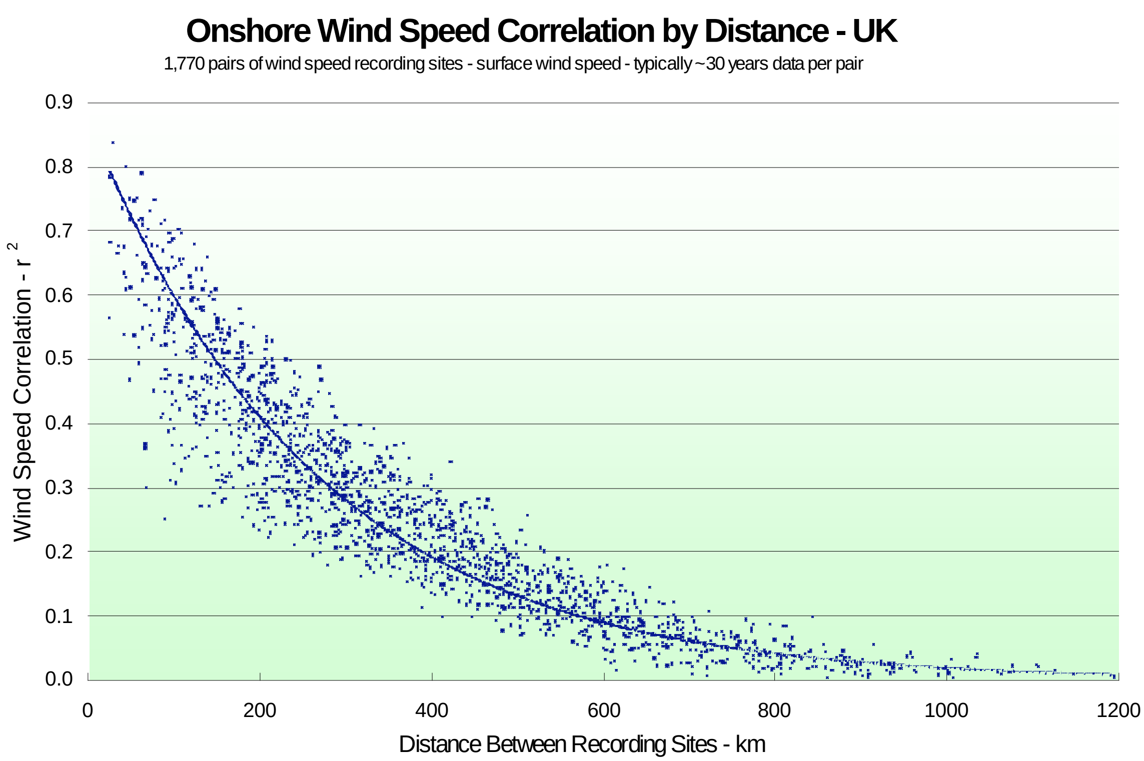
Having outlined the portfolio approach to electricity generation planning, it is useful to comment on the distinction between unsystematic (i.e., firm-specific) risk, systematic (i.e., market) risk, and risks usually considered in engineering approaches to analysing the pros and cons of alternative generation technologies.

Finance theory divides total risk into two components: unsystematic risk that affects primarily the prices of an asset (these risks can be reduced through diversification) and systematic risk that affects the prices of all assets. Systematic risk refers to the risk common to all securities and cannot be diversified away (within one market). Within an efficient portfolio, unsystematic risk will be diversified away to the extent possible. Systematic risk is therefore equated with the risk (standard deviation) of the market portfolio.

In the case of generating technologies and other real assets, diversification and portfolio risk are frequently misunderstood. Some analysts adopt an engineering approach that strives to enumerate all conceivable risks, include those risks that do not affect overall portfolio risk by virtue of diversification. Ignoring diversification effects in this manner, however, yields a portfolio risk estimate that is systematically biased upwards.

For example, year-to-year fluctuations in electric output from a wind farm is an unsystematic risk that is likely irrelevant for portfolio purposes. The reason is that wind output is uncorrelated to the risk of other portfolio cost streams. For example, the output of a wind farm is uncorrelated with the price of coal. Of course, this unsystematic risk can be a financial risk to the owner of the wind farm and lead to increased system integration costs. However, in the case of a large, geographically dispersed mix, year-to-year wind resource variability can be considered random and uncorrelated to fossil fuel prices or other generating cost components. While it is possible to measure the standard deviation of the yearly wind resource at a given location, its correlation to the output of other distant wind farms, or to many other generating cost components, is arguably zero (that is, $\rho_{12} = 0$ in equation (2) of Box 1). Thus, wind variability at a particular location does not contribute significantly to portfolio risk. Figure 6 shows how wind speed correlations rapidly decrease as distance between wind farms increase.

Figure 6: Onshore wind speed correlation by distance – United Kingdom



From a portfolio perspective, there is another important point to consider. Operating costs for wind, solar, and other passive, capital-intensive renewables are essentially fixed, or riskless, over time.[26] More importantly, these costs are uncorrelated to fossil fuel prices. This enables these technologies to diversify the generating mix and enhance its cost-risk performance. Given sufficient geographic dispersion in the wind resources, the operating cost of a generating system with 20 percent wind will fluctuate less from year-to-year than a system with no wind.

The idea that all conceivable unsystematic risks must be enumerated is misleading for purposes of a generating portfolio stud. The same can be said for other unsystematic risks, such as annual variations in attained fuel conversion efficiency for a particular gas plant. Whereas some analysts might choose to include this risk and, although such yearly efficiency fluctuations might change the accountant's estimate of kWh generating costs at a given site,[27] it is reasonable to assume that risk is uncorrelated, making only small contributions to overall portfolio risk.

Summary: How Portfolio Theory Improves Decision-making

As noted above, current least-cost approaches for evaluating and planning electricity generating mixes can understate the value of wind, PV, geothermal, and similar fuel-less fixed-cost, low-risk, passive, capital-intensive technologies. The evidence indicates that such renewables technologies offer a unique cost-risk menu along with other valuable attributes that traditional least-cost utility resource planning models cannot "see." For example, Bolinger, Wiser, and Golove (2004)[28] show that compared to standard financial hedging mechanisms, accelerating and promoting wind technology cost-effectively hedges fossil price risk.

By contrast, portfolio optimization exploits the interrelationships (i.e. correlations) among the various technology generating cost components. For example, because fossil prices are correlated with each other, a fossil-dominated portfolio is undiversified and exposed to fuel price risk. Conversely, renewables such as wind and geothermal, along with other non-fossil options, diversify the generation portfolio and reduce its risk because their costs are not correlated with fossil prices.[29] This portfolio effect is illustrated in Figure 7, which shows the costs and risks for various possible two-technology portfolios. Technology A is representative of a generating alternative with higher cost and lower risk such as geothermal. It has an expected (illustrative) cost around $0.10 per kWh with an expected year-to-year risk of approximately 8 percent. Technology B is a lower-cost/higher-risk alternative such as gas-fired generation. Its expected cost is about $0.08 per kWh with an expected risk of 12 percent. The correlation factor between the total cost streams of the two technologies is assumed to be zero. This is a simplification since in reality the capital and operating cost risks of geothermal will exhibit some non-zero correlation with the capital and operating costs of gas-fired generation.

Box 2: Risk Measurement

There are many ways to measure risk besides variance. All of them rely on the existence of probability distributions that are used to develop analytical estimates of risk. Thus, how such probability distributions are estimated is crucial. Some of the more common measures include:

1. Coefficient of Variation (CV). This measure is the ratio of the distribution's standard deviation to its mean. It is one way to measure risk relative to return, or in this case, variation in price relative to mean price, measured over a defined period. Tolerance bands can be established around CV.

2. Beta. Beta is a measure of the systematic risk of a single instrument or an entire portfolio and describes the sensitivity of an instrument or portfolio to broad market movements. A portfolio with a large beta will tend to benefit or suffer from broad market moves more strongly than the market overall, while one with a small beta will swing less violently than the broad market. It is defined as the ratio of the portfolio's covariance with the market divided by the market's variance or Covariance (portfolio, market) / Variance (market). Beta is used to measure volatility of stock returns relative to an index like S&P 500 returns, and one could consider measuring volatility of a resource portfolio's cost relative to volatility of spot market prices. However, it must be remembered that beta does not capture specific risk (the riskiness of the portfolio itself, irrespective of market risk). A portfolio can have a low beta but still be very volatile if its variations are simply not correlated with those of the market.[30]

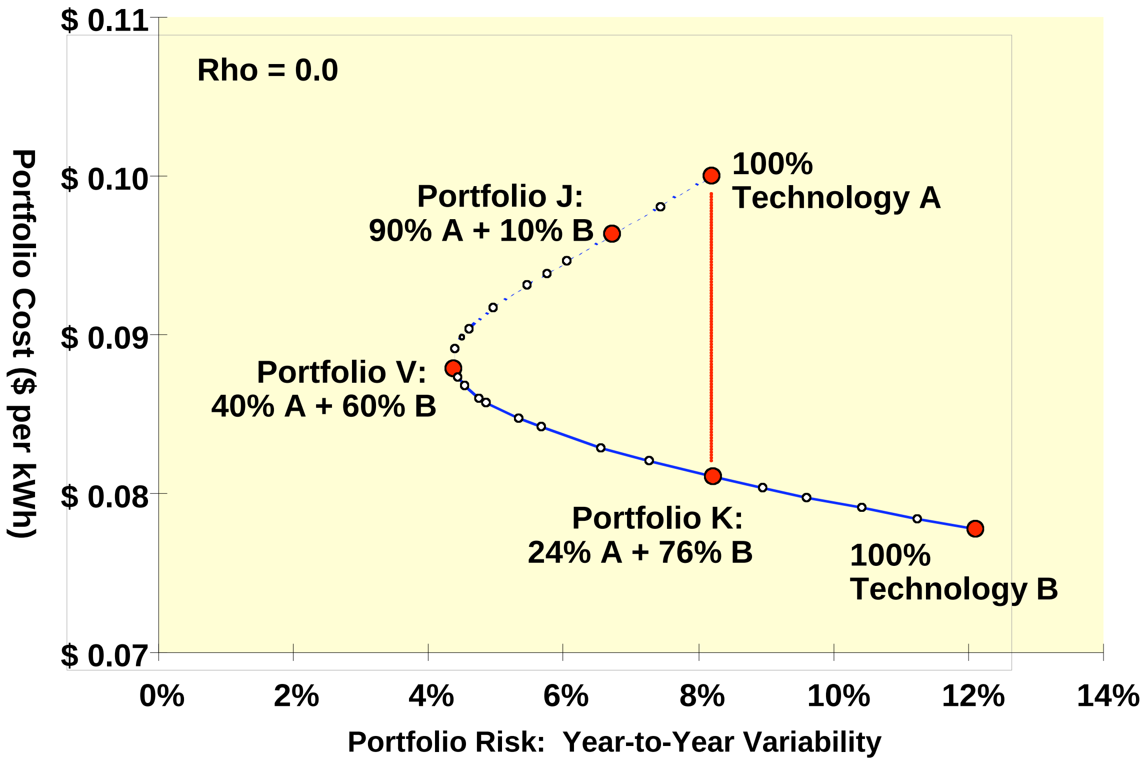
3. Extreme Value Measures - This term is used as a catch-all for a variety of conceptually straightforward measures of portfolio riskiness. In general, this type of measure is the difference in cost between a portfolio's expected cost and some estimate of

4. Value-at-Risk (VaR) - A traditional approach for quantifying risk of investment portfolios.101 VaR measures the downside risk of a portfolio. It is always calculated in the context of a risk level and a planning horizon. In the case of an electricity resource portfolio, VaR would be a measure of the dollar cost increase that has a certain probability (the selected risk level) of occurring over a certain time period (the selected planning horizon). For example, a regulator might be interested in the VaR of a proposed resource portfolio over a one year planning horizon at the 99 percent risk level. That VaR would tell us the amount of extra cost that would have a 1 percent chance of occurring over the next year. Or, a VaR at the 90 percent risk level for a ten year planning horizon would tell us the amount of extra cost that portfolio has a 10 percent chance of incurring over the next ten years.

5. Cash-flow-at-Risk (CFaR), Earnings-at-Risk (EaR). CFaR and EaR are similar to VaR, except "value" is defined in specific terms.

The benefits and drawbacks of using specific risk measurements are application-specific. For example, where risks are asymmetric, especially downside risks, variance alone will not provide an accurate risk measure. Detailed estimates of CFaR or EaR, on the other hand, may be especially sensitive to changes in underlying assumptions.

Figure 7: Portfolio effect for illustrative two-technology portfolio



As a consequence of the portfolio effect, total portfolio risk decreases when the riskier Technology B is added to a portfolio consisting of 100 percent A. For example, Portfolio J, which comprises 90 percent of Technology A plus 10 percent B, exhibits a lower expected risk than a portfolio comprising 100 percent A. This is counter-intuitive since Technology B is riskier than A. Portfolio V, the minimum variance portfolio, has a risk of 4 percent, which is one-half the risk of A and one-third the risk of B. This illustrates the concept of portfolio diversification.

Investors would not hold any mix above Portfolio V, since mixes exhibiting the equivalent risk can be obtained at lower cost on the solid portion of the line, below portfolio V. Portfolio K is therefore superior to 100 percent A. It has the same risk, but lower expected cost. Investors would not hold a portfolio consisting only of Technology A, but rather would hold the mix represented by K. Taken on a stand-alone basis, technology A is more costly, yet properly combined with B, as in Portfolio K, it has attractive cost and risk properties. Not only is Mix K superior to 100 percent A, most investors would also consider it superior to 100 percent Technology B. Compared to B, Mix K reduces risk by one-third while increasing cost by approximately 10 percent, which gives it a favorable Sharpe ratio.[31]

To summarize, Mix K illustrates that astute portfolio combinations of diversified alternatives produce efficient results, which cannot be measured using stand-alone cost concepts: portfolio optimization locates minimum-cost generating portfolios at every level of portfolio risk, represented by the solid part of the line in Figure 7, that is, the stretch between V and B.

CHAPTER 5: CALIFORNIA PORTFOLIO COST, RISK, AND CORRELATIONS

Applying portfolio optimization to the CA generating mix requires the following inputs:

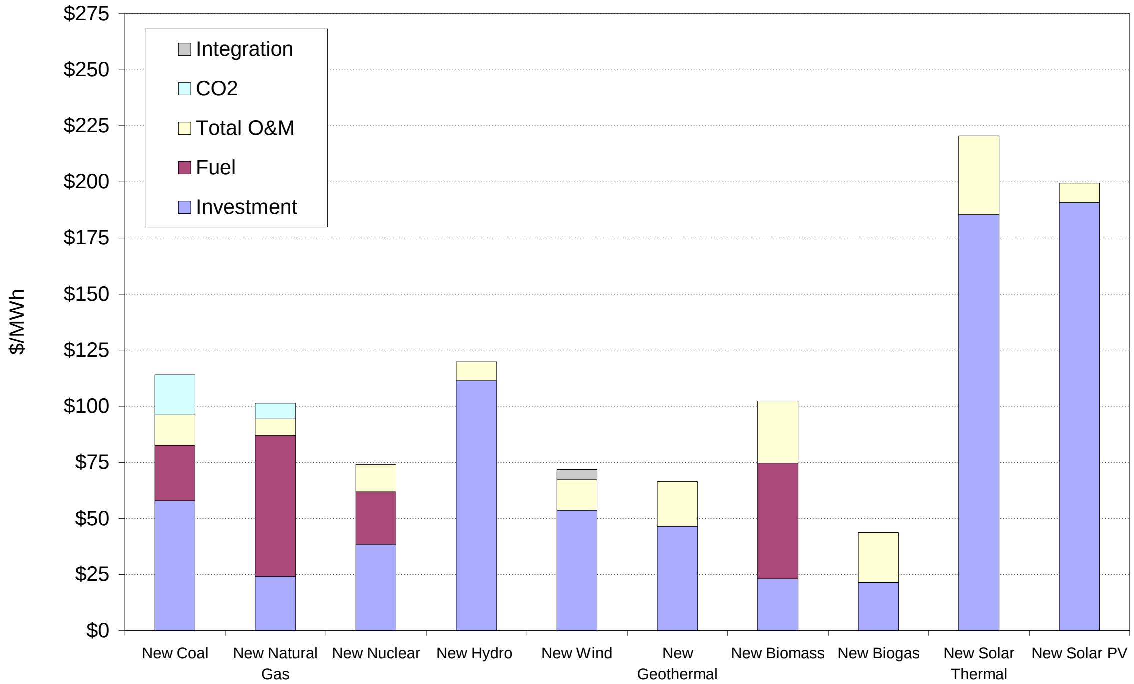
- Capital, fuel, operating, and CO_2 costs per unit of output for each technology;
- The risk (standard deviation) of each cost component; and
- The correlation factors between all cost components.

The following sections address each input and how the inputs are used to determine optimal portfolios.

Technology Generating Cost

Figure 8 shows the levelized 2020 generating cost for various technologies based on the Energy Commission staff's Cost of Generation (COG) Report.[32] All costs are taken on a post-tax/credit basis. Existing coal and nuclear technology costs are estimated using the TECHPOLE database,[33] because the COG report did not estimate them. New coal and nuclear technology costs are assumed to be equal to the COG estimation of IGCC and advanced nuclear costs, respectively. New solar PV technology costs are assumed to decrease by 50 percent by 2020. The 50 percent decrease for solar PV technology is based on expectations of the California Solar Initiative.[34] The rest of the technology costs are assumed to be the same as the corresponding levelized 2006 generating costs.[35]

Figure 8: CA 2020 Generating Costs for Various Technologies (CO_2 = $20/tonne)



Under the European Union Emissions Trading Scheme, the most mature of the carbon trading systems to date, emissions allowances for December 2008 deliveries have been trading in the range of €22 per metric tonne in mid-October 2007.[36] (This is equivalent to a price of about $28 per short ton, based on the current Euro exchange rate of €1 = $1.40.) For comparison, the CPUC incorporated a GHG adder into the calculation of the 2007 MPR. The adder is based on an assumption of CO2 adder of $8 per ton in 2004, growing to $26.52 per ton in 2030. [37]

As for the cost of CO_2, a value of $20 metric tonne was used. This can be interpreted as an expected market price of CO_2, assuming that economic policies aimed at internalising the economic cost of CO_2 emissions are based on a market price of CO_2. California's Market Advisory Committee to the Air Resources Board has issued a set of recommendations for developing a cap-and-trade program.[38] However, the Market Advisory Committee explained that renewable energy for electricity should not create GHG emissions offsets for a cap-and-trade system because RPS requirements simply reduce the demand for allowances from regulated sources and do not provide additional reductions in emissions. For example, a recent Synapse study estimates the future cost of CO_2 in 2020 to be between $10/ton and $33/ton and EIA analysis of proposed CO_2 legislation assumes a CO_2 cost of between $14/ton and $36/ ton in 2020.[39]

System integration is a complex issue. As renewable resources continue to increase, it is anticipated that there may be additional integration costs to accommodate renewables, specifically intermittent resources like wind. Typically, an integration cost is added to wind generation to compensate for additional regulation or load following needed to “firm up” wind resources. On top of these costs, the existing electricity network organization and protocols require capacity reserves to ensure system reliability, such as spinning and non-spinning reserves.

The portfolio analysis uses the results of the California Intermittency Analysis Report (IAP), which estimates the aggregate intermittency costs in the range of $0.69 per MWh for a 33 percent percent total renewable penetration rate.[40] Accounting for these costs, an average system operating cost of $4.50/MWh is applied for the portfolio analysis. However, possible associated systematic risks that may become more significant for wind penetrations in excess of 20-30 percent or any transmission infrastructure costs were not included.[41]

Technology Risk Estimates

One of the major benefits of renewables technologies over traditional fossil-fuel technologies is that the renewable technologies are relatively unaffected by upheavals in fossil-fuel prices. However, renewables technologies are not risk-free. There are a number of market and non-market risks that can affect the value of renewables as part of an overall portfolio of resources to meet electricity demand in California. Thus, in determining future generation portfolios having the lowest expected costs, it is crucial to incorporate the key risks that affect those costs and to understand the unique risks associated with for both renewables and fossil-fuel technologies. The following sub-sections will address each risk components.

Investment Cost Risk

Investment cost risks vary by technology types and are generally related to the complexity and length of the construction period. A World Bank analysis covering a large number of projects estimates the standard deviation of construction period outlays for thermal plants and for large hydro plants (Bacon *et al.* 1996).[42] Investment cost risk estimates for wind, gas, geothermal, and solar risk were determined from developer interviews as reported in Awerbuch *et al*. (Sandia Report). Investment cost risks of existing technologies were assumed to be zero percent. This means that ‘new’ assets are riskier than old ones – for example, the investment cost risks for a new, not yet constructed coal plant are greater than those for an existing coal plant.

Fuel Cost Risk

Fuel cost risks have been estimated on the basis of historical (1980-2005) California (biomass and natural gas), NUEXCO (uranium), and EIA (coal) prices. Annual price observations were used because seasonal variations are eliminated that could potentially bias the results. Since renewable technologies require no fuel costs and thus there is no fuel cost risk, with the exception of biomass.

O&M Cost Risk

The EIA (Energy Information Agency) and FERC (Federal Energy Regulatory Commission) databases maintain O&M costs of units operated by regulated utilities. This data was used to estimate the holding-period-return (HPR) standard deviations (SD) for O&M costs (along with the correlations between these costs discussed in the next subsection).[43]

CO_2 Risk

The last risk cost category is the cost of CO_2 emissions. The future cost of CO_2 emissions is relevant for fossil fuel technologies. The HPR standard deviation for CO_2 has been estimated at 0.26. This estimation was obtained using two principal methodologies – an analytical approach and a Monte Carlo simulation. Various sensitivity analyses were performed to test the reasonableness and robustness of the estimated CO_2 HPR standard deviation value of 0.26.

Summary of Risk Estimates

Table 5 summarizes the technology risk estimates. Investment cost risks of new technologies range from 0.10 for new solar technologies to 0.40 for new nuclear technology. Fuel cost risks for both existing and new technologies range from 0.05 for coal to 0.35 for nuclear. Natural gas fuel cost risk is estimated to be 0.30. For O&M risks, different technologies show different year-to-year fluctuations – ranging from 0.034 percent for solar photovoltaic to 0.153 for hydro technology.[44] This takes us to the risk associated with last cost category, that is, the cost of CO_2 emissions, which is relevant for fossil fuel technologies. As Table 5 indicates, the HPR standard deviation for CO_2 has been estimated at 0.26. The approach that underlies this estimate will be presented next in the context of discussing the correlation between fossil fuel costs, O&M costs for different technologies, and CO_2 costs.

Table 5: Technology Risk Estimates

Generating Resource	Investment	Fuel	Total O&M	CO_2
Coal	0.35	0.049	0.054	0.260
Biomass	0.20	0.133	0.108	-
Natural Gas	0.20	0.291	0.105	0.260
Nuclear	0.40	0.346	0.055	-
Hydro - Large	0.35	0.000	0.153	-
Hydro - Small	0.20	0.000	0.153	-
Wind	0.20	0.000	0.080	-
Solar Thermal	0.10	0.000	0.080	-
Biogas	0.20	0.133	0.108	-
Solar PV	0.10	0.000	0.034	-
Geothermal	0.20	0.000	0.153	-

Correlation Coefficients

The correlation coefficient, *ρ,* is a measure of diversity. Low (or negative) correlation among portfolio components creates greater resource diversity, which serves to reduce overall portfolio risk. More generally, portfolio risk *falls* with increasing diversity, as measured by an absence of correlation (covariance) between portfolio components. Adding a fixed-cost technology to a risky generating mix serves to *lower* expected portfolio cost at any level of risk, even if the fixed-cost technology costs more. A pure fixed-cost technology has a cost variance (σ_i) of 0.0. This lowers portfolio risk (since two of the terms in Equation (2) of Box 1 reduce to zero), which in turn allows other higher-risk/lower-cost technologies into the optimal mix.[45] In the case of fuel-less renewable technologies, fuel risk is zero, and its correlation with fossil fuel costs is also taken as zero.

In the context of an electric generating portfolio, the expected risk of future CO_2 cost is further affected by the correlation (covariance) of CO_2 prices against future fossil fuel costs and other important generating cost streams. The estimates of the standard deviations and correlations of CO_2 prices are derived using both analytic techniques and Monte Carlo simulation. The analytical approach to estimating CO_2 risk and correlation follows the spirit of Green (2006),[46] who expresses CO_2 price in terms of gas and coal prices. This relationship is used to derive the HPR standard deviation of CO_2 as well as its correlation with fossil fuels. The Monte Carlo approach uses a series of simulations that provide a second set of CO_2 risk and fossil fuel correlation estimates. In the Monte Carlo analyses, the volatility and other trends were used from 18 months of actual European Union Emissions Trading Scheme (EU-ETS)[47] historical data to simulate 20 years of trading. It should be noted that historical data from the EU-ETS reflects start-up problems and may not accurately simulate future volatility. However, because carbon trading is a recent development, this and its correlation to coal and gas, provide an estimate of annual risk factors for CO_2.

The two methods provide a range of estimates of CO_2 risk and correlations. The analytical and Monte Carlo results were compared and also performed various sensitivity analyses to test the reasonableness and robustness of these estimates. The HPR standard deviation for CO_2 that was used in the portfolio optimization model (0.26) is shown in the last column of Table 5 above. The CO_2 cost/fuel cost correlation coefficient used in the portfolio optimization is shown in the last column (or row) of Table 6 below.

Table 6: Fuel and CO_2 HPR Correlation Factors

Generating Resource	Coal	Biomass	Natural Gas	Uranium	CO_2
Coal	**1.00**	0.39	0.53	-0.25	-0.49
Biomass	0.39	**1.00**	0.30	-0.27	0.00
Natural Gas	0.53	0.30	**1.00**	-0.16	0.68
Uranium	-0.25	-0.27	-0.16	**1.00**	0.00
CO_2	-0.49	0.00	0.68	0.00	**1.00**

As can be seen from these correlation coefficients, there is a negative correlation between CO_2 and coal prices and a positive correlation between CO_2 and gas. This is the expected result. Intuitively, as gas becomes more expensive, electricity generation shifts to coal, putting upward pressure on CO2 prices – whether market determined or shadow prices. Conversely, rising coal prices shift generation to gas, which emits about half as much CO2. As a result, the price of CO_2 falls with rising coal prices.

Table 6 above also shows the correlation coefficients among the various fuels. In most cases, there is positive correlation between fuels – reflecting the fact that most fuels are substitutes for one another – with the notable exception of nuclear. A number of researchers (e.g., Awerbuch and Berger 2003; Roques, et al. 2006)[48] have found a negative correlation between nuclear and fossil fuels. This suggests a greater diversification potential of nuclear technologies depending on the level of risks for nuclear technologies. The impact of potential nuclear acceleration and promotion policies for California is described in Section 5 of the report.[49]

In addition, O&M correlation coefficients were estimated based upon the historical maintenance costs reported in the EIA and the FERC databases. These are shown in Table 7.

Table 7: O&M Correlation Coefficients

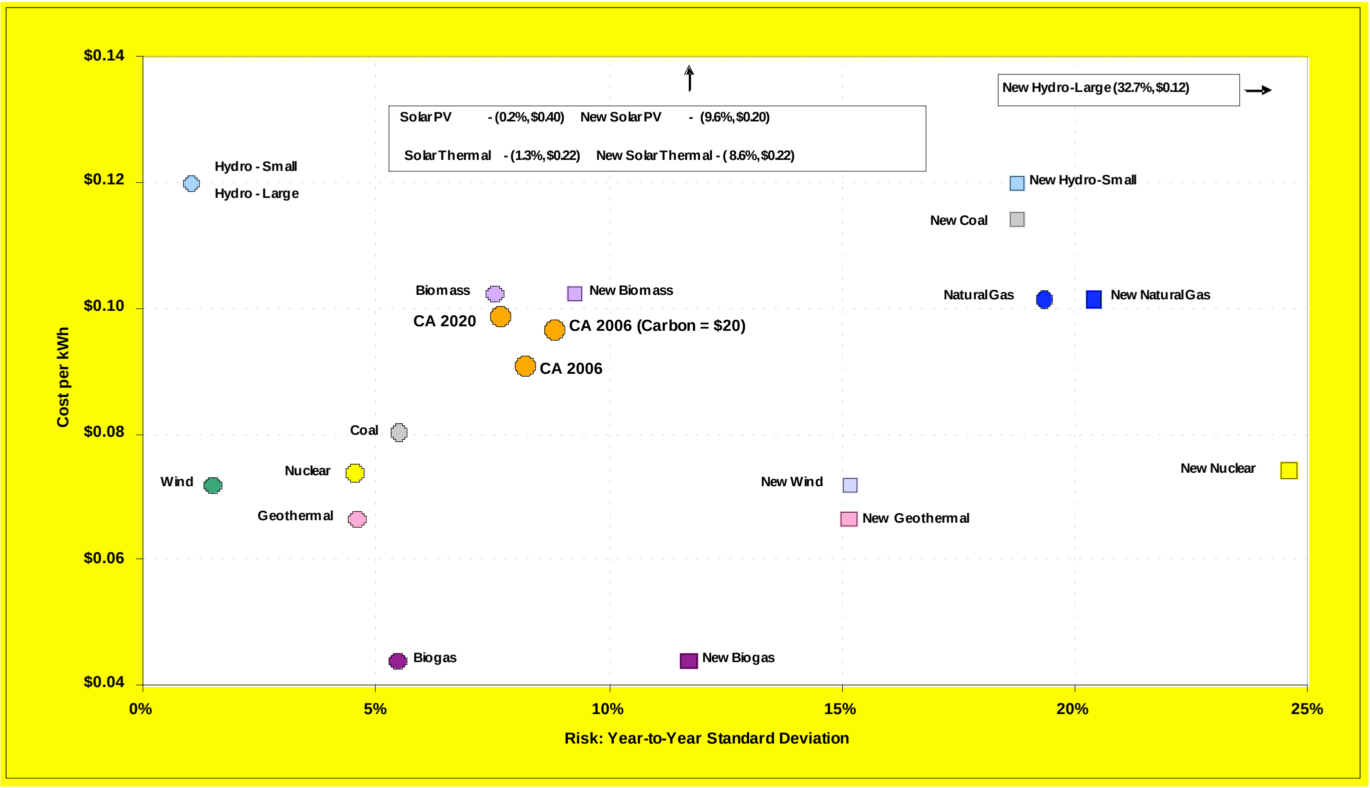
Generating Resource	Coal	Gas	Nuclear	Hydro	Wind	Geo	Solar	Bio
Coal	1.00	0.25	0.00	0.03	-0.22	0.14	-0.39	0.18
Gas	0.25	1.00	0.24	-0.04	0.00	-0.18	0.05	0.32
Nuclear	0.00	0.24	1.00	-0.41	-0.07	0.12	0.35	0.65
Hydro	0.03	-0.04	-0.41	1.00	0.29	-0.08	0.30	-0.18
Wind	-0.22	0.00	-0.07	0.29	1.00	-0.28	0.05	-0.18
Geo	0.14	-0.18	0.12	-0.08	-0.28	1.00	-0.48	-0.70
Solar	-0.39	0.05	0.35	0.30	0.05	-0.48	1.00	0.25
Bio	0.18	0.32	0.65	-0.18	-0.18	-0.70	0.25	1.00

Total Portfolio Cost and Risk

The previous subsections described the cost and risk inputs for the various generating technologies. These are combined using equation (2) in Box 1 to produce a total HPR standard deviation for each technology, where the weights (X_1, X_2, … etc.) are given by the proportional values of the levelized cost components, that is, capital, fuel, O&M, and CO_2 costs.

Figure 9 shows the costs per kWh for each of the generating technologies in 2020 along with its risk, with the added assumption that CO_2 costs $20 per tonne. For comparison, Figure 9 also shows the cost-risk combination of the projected CA 2020 BAU mix and historical CA 2006 mix.[50] The analysis indicates that there exist optimal and efficient portfolios that are less risky, less expensive, and that substantially reduce California's CO_2 emissions and energy import dependency. This optimal generating portfolio mixes include greater shares of renewables technologies: the optimal 2020 generating portfolios not only achieve California's 33 percent RPS goal, but also reduce overall electricity generating costs and market risks as well as CO_2 emissions relative to the projected 2020 CA-BAU mix.

Figure 9: Cost and Risk of Existing and New Generating Alternatives in 2020



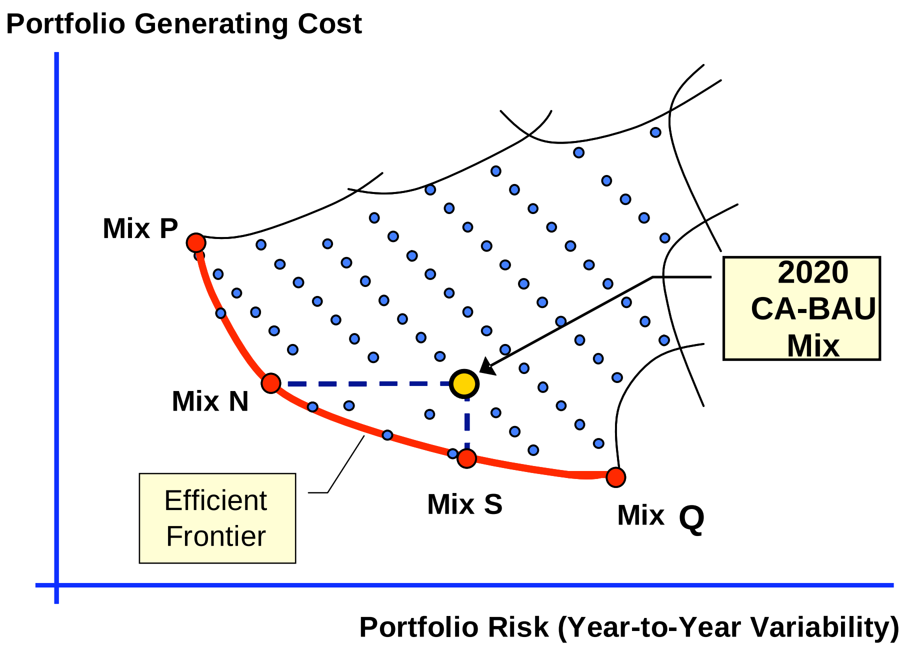
CHAPTER 6: PORTFOLIO OPTIMIZATION OF THE CALIFORNIA GENERATING MIX

Portfolio Optimization and the Efficient Frontier: an Illustration

As previously stated, the aim in this study is to evaluate whether there exists feasible 2020 generating mixes that are ‘superior’ to the 2020 CA-BAU mix by virtue of reducing risk or CO_2 emissions or by producing lower-cost electricity. To interpret the results of the portfolio optimization results, it is useful to offer a general illustration of possible results.

Figure 10 illustrates an infinite number of different generating mixes that could meet the 2020 electricity needs with a unique mix of the various technology options. The different portfolios all have different cost-risk as represented by the blue dots. Interestingly, technology shares do not change monotonically in any direction in Figure 10 so that two mixes with virtually identical cost-risk (i.e. two mixes located close to each other in cost-risk space) can have radically different technology generating shares (Awerbuch-Yang 2007). Likewise, radically different mixes can have nearly identical cost-risk, i.e. a particular mix could be virtually co-located in risk-cost space. The intuition for this is straightforward: there are many ways to combine ingredients in order to produce a given quantity of salad at a given price.

Figure 10: Feasible region and efficient frontier for multi-technology electricity portfolios



The red curve (PNSQ) is the efficient frontier (EF), the locus of all optimal mixes. There are no feasible mixes below the EF, and along the EF, only accepting greater risk can reduce cost. The Blue-dot mixes in Figure 10 are sub-optimal or *inefficient* because it is still possible to reduce both cost and risk by finding mixes on the EF by moving below or to the left. As shown below, the 2020 CA-BAU mix lies above the efficient frontier.

Although an infinite number of possible generating portfolios lie along the EF, the focus is on four 'typical' optimal mixes P, N, S, Q. Taking the 2020 CA-BAU mix as the benchmark, the four 'typical' optimal mixes are defined as follows:

- Mix P is a high-cost/low-risk portfolio. It is usually the most diverse mix.
- Mix N is an equal-cost/low-risk portfolio, that is, it is the mix with the lowest risk for costs equal to that of the 2020 CA-BAU mix.
- Mix S is an equal-risk/low-cost portfolio, that is, it is the mix with the lowest costs for a risk equal to that of the 2020 CA-BAU mix.
- Mix Q is a low-cost/high-risk portfolio. It is usually the least diverse portfolio.

The portfolio analysis does not advocate for any particular generating mix. Rather, it displays the risk-cost trade-offs across many different portfolios, with a focus on mixes that lie along the efficient frontier (EF). All solutions along the EF are conceded efficient. Although it may turn out that solutions in the region of the 2020 CA-BAU mix, e.g. solutions between portfolios *N* and *S*, may be the most practical, there is no claim that that optimization results provide a roadmap or set of 2020 technology targets. Such results would require considerably more detailed models. The results presented here are largely *expositional*. The results demonstrate the value of portfolio optimization approaches and suggest quite clearly that capacity planning made on the basis of *stand-alone* technology costs likely leads to highly inefficient mixes (from California customer's perspective). *Stand-alone* cost approaches ignore important portfolio risk and cost interactions (correlations) among various technologies.

Efficient Electricity Portfolios for 2020 Generation Mix

This portfolio optimization study evaluates the efficiency of the 2020 CA-BAU mix within a range of realizable constraints. This is shown in Figure 11. The purpose is to explore practical policy limits and identify policies that may be worth pursuing. For each set of constraints, efficient electricity generation mixes are computed and then the level of CO_2 emissions associated with them is analyzed. The following assumptions were used to develop the expository realizable case lower and upper bounds shown in Table 8:[51]

- The assumption is that there will be no *new* investment in coal, nuclear, and large hydro technologies.[52]
- The constraints on new resources are not based on detailed engineering studies of feasible penetration rates. The assumption is, a 10 percent upper bound for new biomass, biogas, small hydro, solar thermal and solar PV technologies. A 25 percent upper bound is assumed for new geothermal technology as well as a 30 percent upper bound for new wind and natural gas technologies.
- The assumption is that the minimum share percentages of new technologies are zero.
- The assumption is that the upper bound share percentages for existing technologies will be capped by their CA-BAU generation shares.
- The assumption is that the lower bound percentages for existing technologies of 50 percent of the CA-BAU generation share, with the following exceptions:
    - Lower bounds for Coal and Gas technologies are 5 percent.
    - Lower bounds for Nuclear and Large Hydro technologies are 80 percent of the CA-BAU generation share.

Figure 11: CA 2006 and 2020 CA-BAU Generation Mix (in TWh)

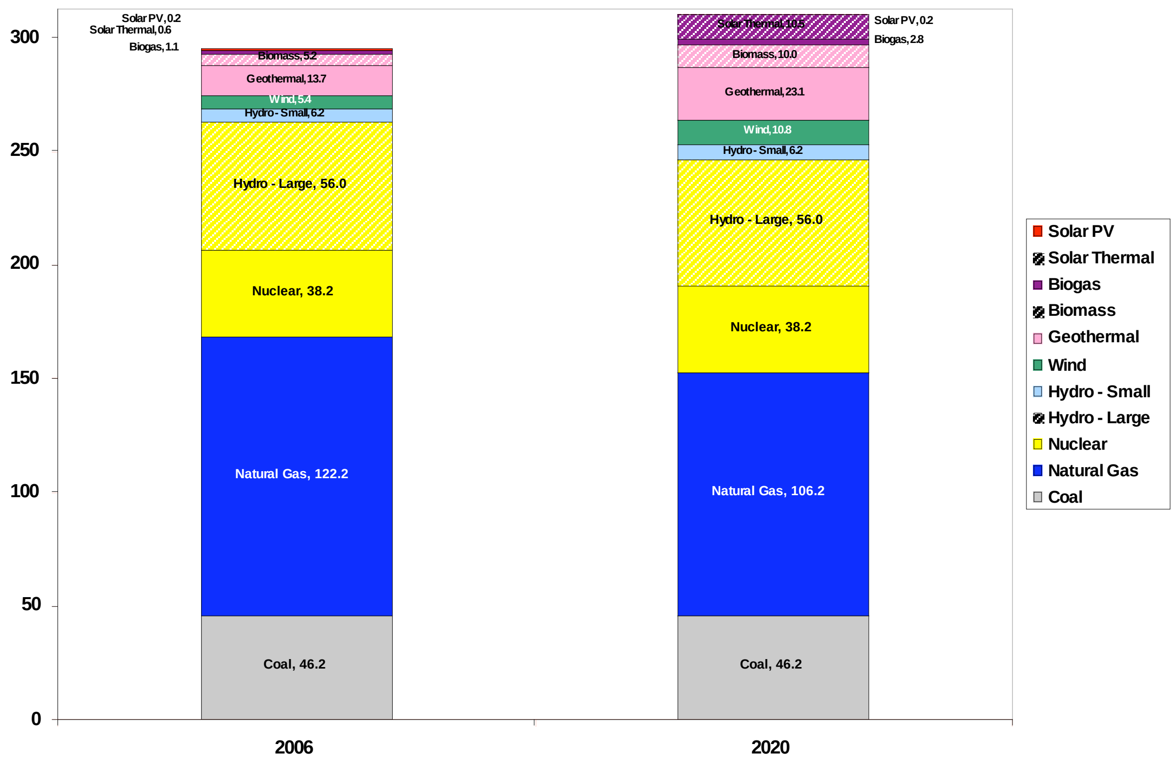


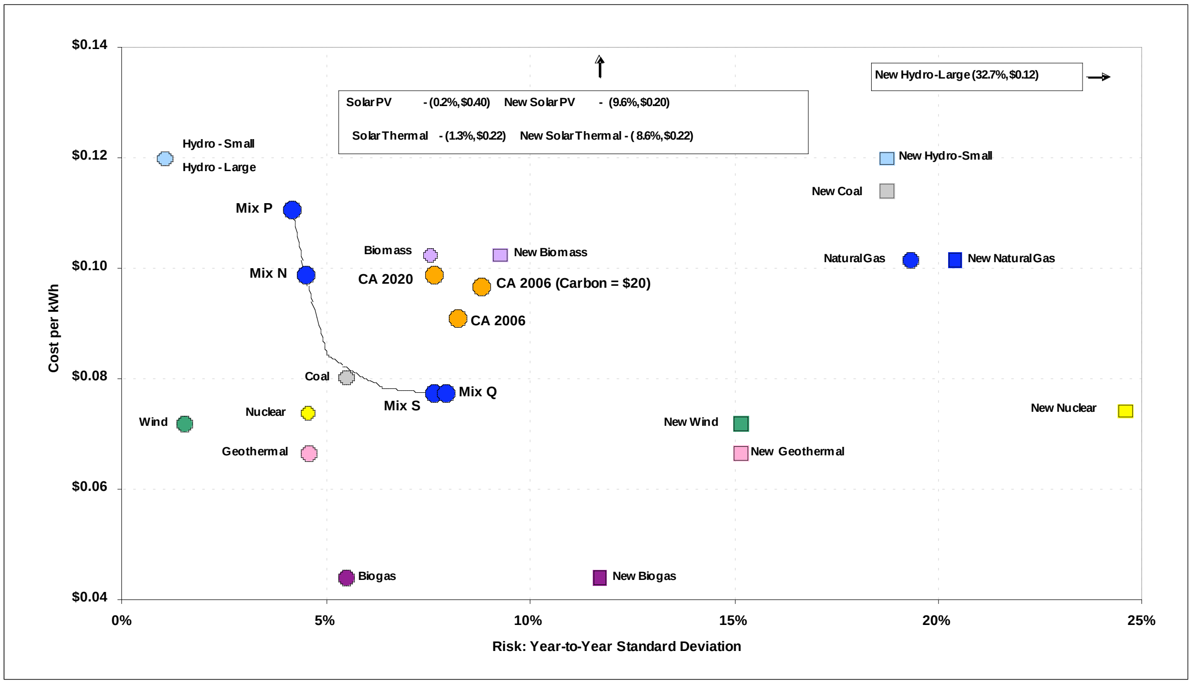
Table 8: Expository realizable case lower and upper limits

	Realizable	
Technology	**Lower bound**	**Upper bound**
Coal	**5.0%**	14.9%
Biomass	0.8%	1.7%
Natural Gas	**5.0%**	34.2%
Nuclear	**9.8%**	12.3%
Hydro - Large	**14.5%**	18.1%
Hydro - Small	1.0%	2.0%
Wind	0.9%	1.7%
Geothermal	2.2%	4.4%
Solar Thermal	0.1%	0.2%
Biogas	0.2%	0.4%
Solar PV	0.0%	0.1%
New Coal	0.0%	**0.0%**
New Biomass	0.0%	10.0%
New Natural Gas	0.0%	30.0%
New Nuclear	0.0%	**0.0%**
New Hydro-Large	0.0%	**0.0%**
New Hydro-Small	0.0%	10.0%
New Wind	0.0%	30.0%
New Solar Thermal	0.0%	10.0%
New Biogas	0.0%	10.0%
New Solar PV	0.0%	10.0%
New Geothermal	0.0%	25.0%

Efficient Portfolios: Results

This section discusses the 2020 expository realizable case optimization results and compares their risk-return characteristics and CO_2 emissions to those of the projected 2020 CA-BAU mix. The results indicate that the optimal realizable portfolios minimize cost and risk and reduce CO_2 emissions. This is shown in Figure 12, which illustrates the risk and return for the projected 2020 CA-BAU and for several optimized mixes under the realizable case. The efficient frontier PNSQ illustrates the location of all optimal portfolios. In other words, the efficient frontier represents portfolios with optimized combinations of risk and cost.

Figure 12: Efficient Frontier for 2020 Electricity Generation Mix – Realizable Case



As Figure 12 shows, the 2020 CA-BAU portfolio lies above and to the right of the efficient frontier, meaning that alternative portfolios can be selected that have both lower expected costs and less risk. The CA-BAU portfolio has an overall generating cost of 9.9 cents per kWh and a risk of 7.7 percent. By comparison, mix *N*, the equal-cost/low-risk portfolio, reduces risk nearly in 42 percent, to 4.5 percent. Alternatively, mix *S,* has the same risk as the 2020 CA-BAU but reduces generating costs by 2.2 cents per kWh, which equates to an CA-wide reduction in annual electricity costs of approximately $6.8 billion.[53]

Mix *P*, is the minimum-risk portfolio, reduces risk slightly relative to mix *N*, but comes with a significant increase in cost: this indicates an unattractive cost-risk trade-off over mix *N*. Similarly, mix *Q*, the minimum-cost portfolio, virtually did not reduce cost relative to mix *S*, but comes with a noticeable increase in risk. Thus, it appears that in cost-risk terms, the practical range of policy interest may be in the range between mix *N* and mix *S*.

Table 9 summarizes the generation components of portfolios P, N, S, Q, with respect to CA-BAU portfolio.

Table 9: Portfolio Mix Details – Realizable Case

	CA-2020 BAU	Portfolio P	Portfolio N	Portfolio S	Portfolio Q
RISK	7.7%	4.2%	4.5%	7.7%	8.0%
COST: cents/KWh	9.9	11.1	9.9	7.7	7.7
CO2: Mil-tonnes/Yr	78	47	47	19	19
Generating Resource			Generating Shares		
Coal	15%	15%	15%	5%	5%
Natural Gas	34%	5%	5%	5%	5%
Nuclear	12%	12%	12%	12%	11%
Hydro	20%	20%	20%	15%	15%
Wind	4%	2%	5%	22%	23%
Geothermal	7%	5%	11%	29%	29%
Biomass	3%	12%	12%	1%	1%
Biogas	1%	10%	10%	10%	10%
Solar Thermal	3%	10%	6%	0%	0%
Solar PV	0%	8%	4%	0%	0%
Renewables Share	20%	41%	45%	64%	64%

One finding of the analysis is that the share of renewables could be increased from 20 percent to 45 percent without an increase in expected portfolio costs (i.e., transition from the CA-BAU portfolio to portfolio N). In addition, Mix N reduces CO2 emissions by 31 million tonnes per year relative to projected 2020 BAU portfolio without increasing expected costs.

More importantly, the analysis shows that the share of renewables theoretically could be increased from 20 percent to 64 percent with a decrease in expected portfolio costs of 2.2 cents per kWh (i.e., transitioning from the CA-BAU portfolio to portfolio S). In addition, Mix S reduces CO2 emissions by 59 million tonnes per year relative to projected 2020 BAU portfolio without increasing expected portfolio risks. The expository portfolio results also show that, in addition to reducing cost and/or risk relative to the CA-BAU portfolio, the portfolios identified along the efficient frontier can reduce CO_2 emissions relative to the CA-BAU portfolio.[54] This is shown in Figure 13.

Figure 13: Technology Shares and CO_2 emissions – Realizable Case

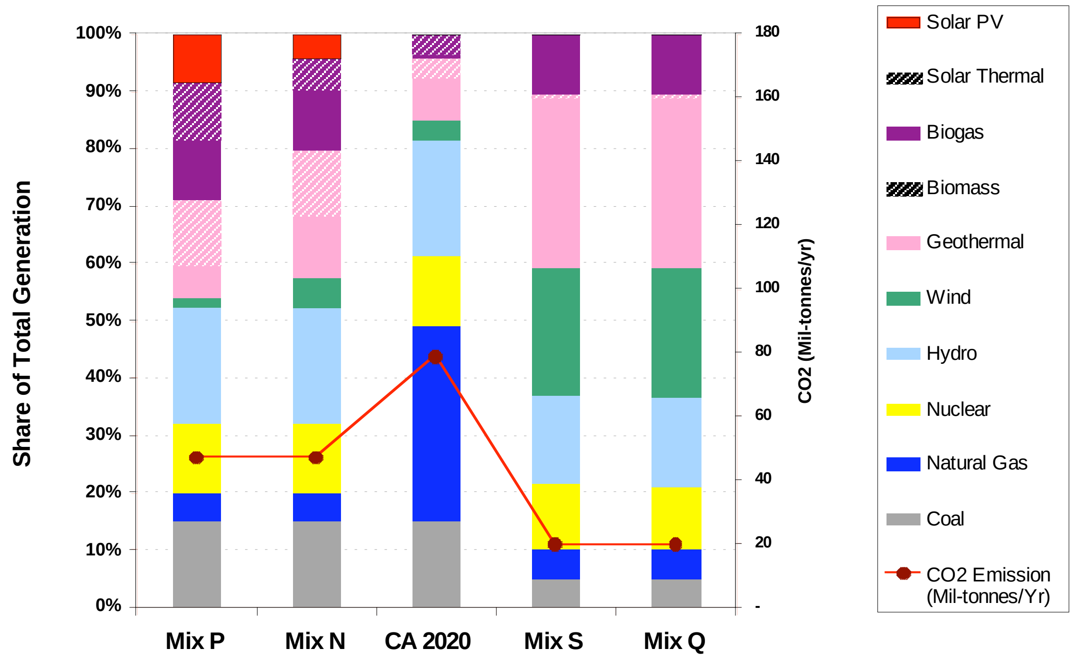
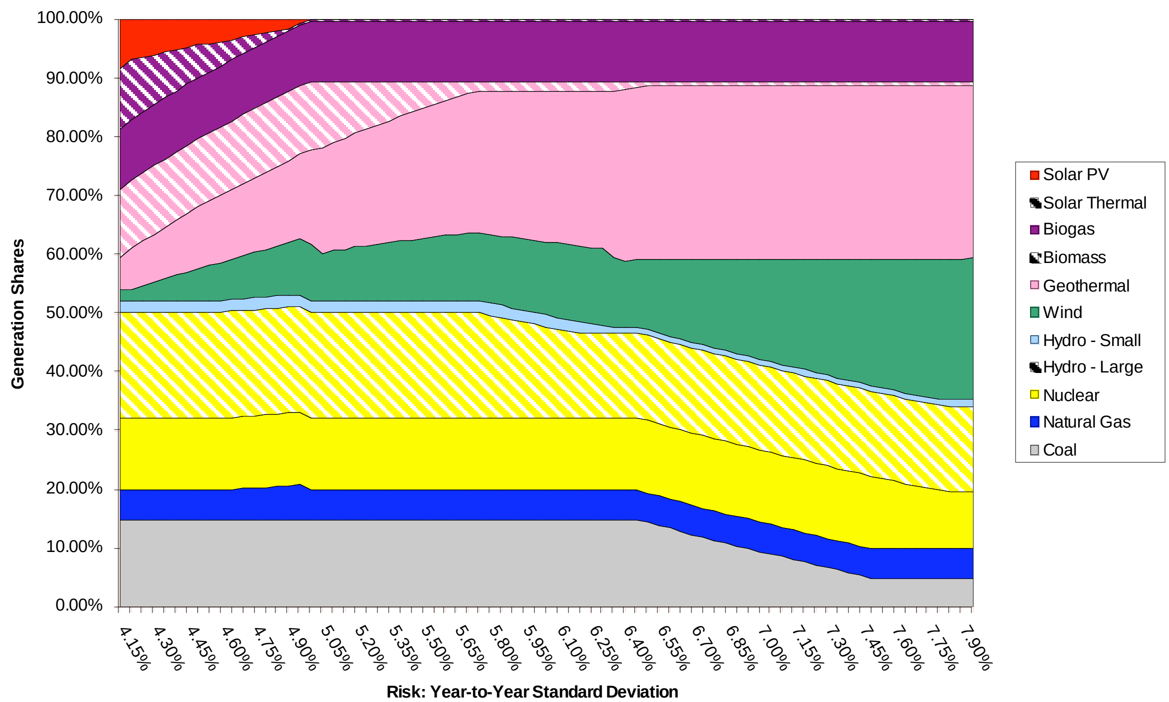


Figure 13 above shows technology shares on the left vertical axis, and CO_2 emissions on the right axis. The lower-risk and more diversified portfolios, P and N, reduce annual CO_2 to approximately 47 million tonnes, which is about 40 percent lower than emissions in the CA-BAU portfolio (78 million tonnes of CO_2). The lower-risk and more diversified portfolios accomplish this primarily by displacing natural gas-fired generation with renewables, including wind, biomass, and solar. Portfolio P, which is the most diverse resource portfolio, includes about 8 percent of solar PV.[55] The portfolios S and Q, the higher-risk and less diversified portfolios further reduce CO_2 emissions to 19 million tonnes, because smaller shares of coals are incorporated compared to CA-BAU mix. Figure 14 shows how shares of optimal generation mix changes as portfolio risk increases. As noted above, mixes are less diversified as portfolio risk increases.

Figure 14: Efficient Frontier Generation Mix Vs. Portfolio Risk: Realizable Case



To summarize, the preliminary results suggest that larger shares of renewables above the level in the BAU mix can reduce <u>both</u> the expected cost and risk of the CA generating portfolio, as well as CO_2 emissions. Against this background, a 33 percent RPS policy that accelerates the deployment of renewables technologies may be highly cost-effective. Perhaps the single most important lesson of the portfolio optimization analysis is that combining renewables having no fuel risk, with fossil-fuel generating technologies (such as gas and coal) may reduce expected portfolio costs for any level of risk, even if the renewables cost more when assessed on a stand-alone, levelized cost basis. In addition, the analysis also indicates that adding "too much" renewables would increase the resulting portfolio risk (see Mixes S and Q).

Specifically, the principal conclusions of the analysis are:

1. Generating-technology costs provide highly misleading signals when taken on a stand-alone basis, especially without reference to their overall market risks. The correlation of costs and risks among technologies yields portfolio outcomes that are generally not easy to predict.

2. Compared to the projected 2020 CA-BAU portfolio, and given a CO_2 price of $20 per tonne, there exist efficient generating portfolios that can reduce generating cost by as much as 22 percent without increasing risk (CA-BAU to Mix S transition). These cost improvements represent approximately $6.8 billion annual electricity cost savings.

3. Policies designed to accelerate the deployment of renewables technologies appear to be cost-effective, subject to the reliability issues mentioned previously. As a matter of policy, current investments to achieve California's 33 percent RPS goal, cost, risk and benefits are best estimated using portfolio-based approaches, rather than stand-alone methods.

4. Adding "too much" renewable generation increases (not decreases) resulting portfolio risk.

5. The imposition of CO2 taxes raises both the cost and the risks of the optimal 2020 generating portfolios.

6. High CO_2 prices increase the cost of fossil-fuel generating resources, although their effects on risk are more complex. High CO_2 prices substantially increase the market risk of existing fossil assets, whose risk is dominated by fossil-fuel volatility and other operating risks. Chapter 5 provides more detailed analysis of the effect of CO_2 prices on California optimal generating portfolios.

7. Except in the general terms presented, the precise relationship between technology shares, CO2 emissions, and cost-risk is complex and non-linear.

8. The single-most overriding lesson of the portfolio optimization analysis is that stand-alone technology costs and other characteristics interact within portfolios of generating resources in ways that are not always easily predictable. This underscores the importance of policy-based approaches grounded in portfolio concepts as opposed to stand-alone engineering concepts.

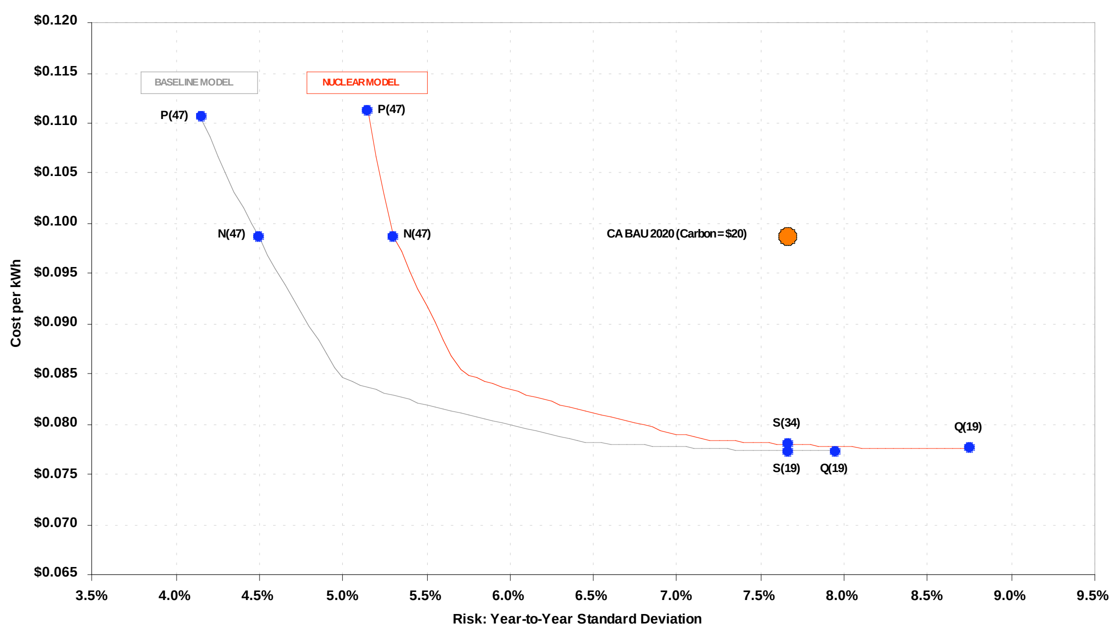
CHAPTER 7: NUCLEAR POLICY AND CO2 PRICE IMPACTS ON THE EFFICIENT FRONTIER

The Effects of a Nuclear Acceleration and Promotion Policy

The nuclear cost estimates used for identifying efficient electricity portfolios do not account for the costs and risks of storing nuclear waste. CORWM (2006) recommends a lengthy, potentially decades-long process, involving interim waste storage in preparation for ultimate geological disposal.[56] For example, Germany will not consider new nuclear capacity to meet future electric demand. California has had a similar policy since 1976.[57] Against this background, a policy of a nuclear acceleration and promotion was tested– that is, a generating portfolio that contains 10 percent new nuclear by 2020 – to evaluate its effects on cost and risk of generating resource portfolios.

Figure 15 compares the nuclear promotion policy to the baseline realizable scenario at the CO_2 price of $20 per tonne. (The parenthetical numbers next to the typical portfolios represent annual CO_2 emission levels.)

Figure 15: Comparison of realizable and nuclear promotion policy



As Figure 15 shows, the nuclear promotion scenario shifts California's optimal efficient frontier to the right (i.e., higher risk) without commensurate cost reductions. In addition, a nuclear promotion policy does not reduce the CO_2 emission levels in a material way compared to the no nuclear promotion policy. In fact, it increases the CO_2 emission levels in Mix S. Therefore, the analysis indicates that nuclear promotion policy for California is not an efficient move. Specifically, for portfolio N, cost stays the same, but risk significantly increases, that is from 4.5 percent to 5.3 percent. For portfolio S, risk stays the same, but cost slightly increases, i.e., from 7.7 cents/kWh to 7.8 cents/kWh.

Table 10 summarizes the details of portfolios P, N, S, Q, with respect to CA-BAU portfolio.

Table 10: Portfolio Mix Details – Nuclear Promotion Policy Case

	CA-2020 BAU	Portfolio P	Portfolio N	Portfolio S	Portfolio Q
RISK	7.7%	5.1%	5.3%	7.7%	8.8%
COST: $-cents/KWh	9.9	11.1	9.9	7.8	7.8
CO2: Mil-tonnes/Yr	78	47	47	34	19
Generating Resource			Generating Shares		
Coal	15%	15%	15%	10%	5%
Natural Gas	34%	5%	5%	5%	5%
Nuclear	12%	22%	22%	22%	20%
Hydro	20%	20%	20%	15%	15%
Wind	4%	2%	2%	6%	16%
Geothermal	7%	4%	4%	29%	28%
Biomass	3%	12%	12%	1%	1%
Biogas	1%	3%	10%	10%	10%
Solar Thermal	3%	10%	9%	0%	0%
Solar PV	0%	7%	1%	0%	0%
Renewable Share	20%	33%	39%	48%	56%

Compared to the expository realizable case, the nuclear case is characterized by significantly lower shares of wind and geothermal in portfolio N. This is primarily driven by the requirement to build 10 percent new nuclear by 2020.

Figure 16 shows technology shares on the left vertical axis, and the CO_2 emissions on the right axis for the nuclear case.

Figure 16: Technology Shares and CO_2 Emissions – Nuclear Case

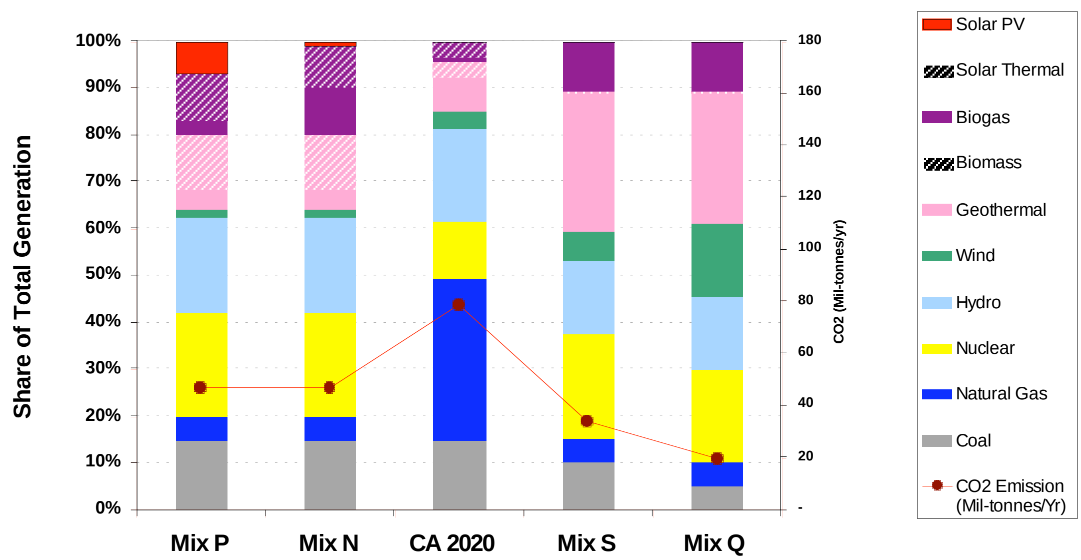
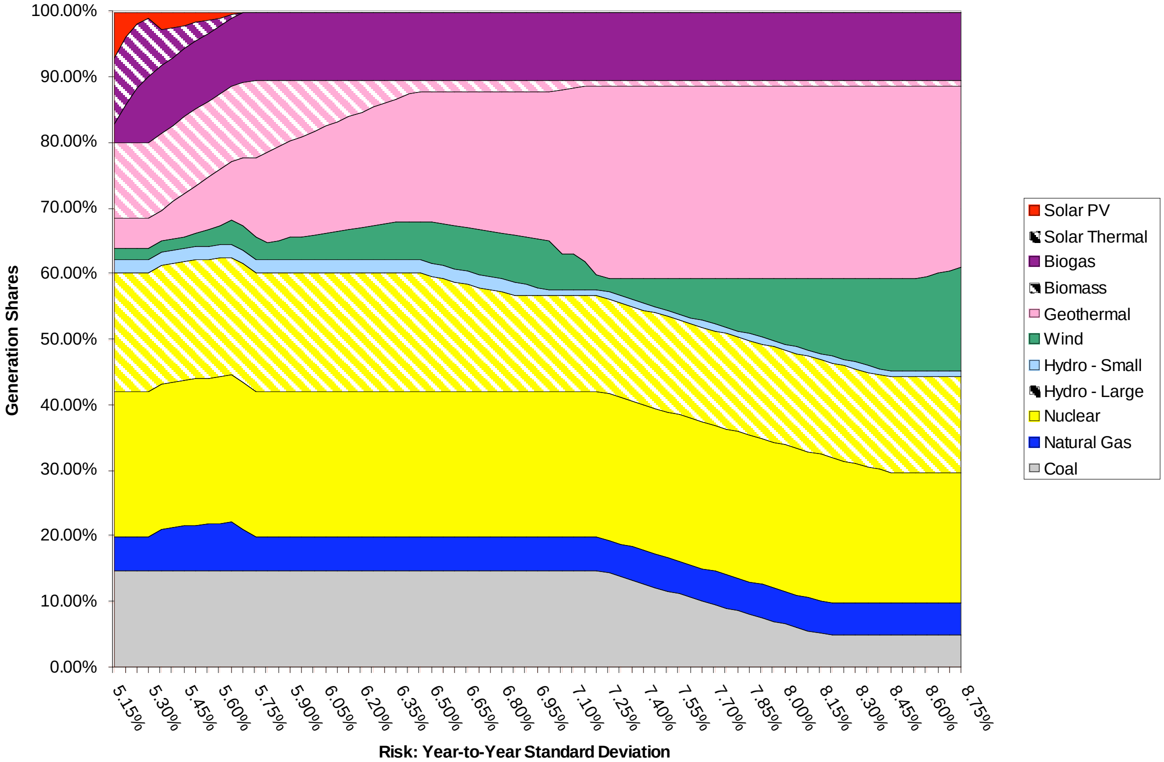


Figure 17 shows how shares of optimal generation portfolio changes as risk increases for the nuclear case. Similar to expository realizable case, the portfolios in the nuclear case are less diversified as portfolio risk increases. Also, adding “too much” renewable generation counter-intuitively increases (not decreases) resulting portfolio risk because (a) it reduces portfolio diversification; and (b) it replaces less risky existing technology with more risky new technology.

Figure 17: Efficient Frontier Generation Mix Vs. Portfolio Risk – Nuclear Case

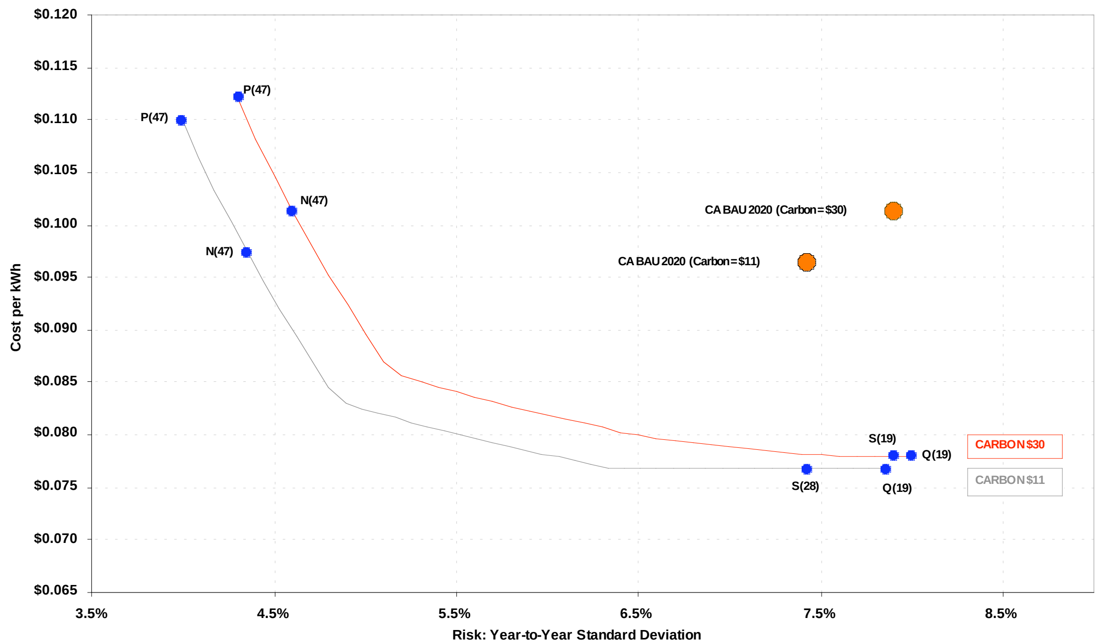


The Effect of CO_2 Pricing

So far, the analysis assumed a charge of $20 per tonne of CO_2 emitted, which was interpreted as either a market price or a marginal abatement cost for carbon emissions. The effect of pricing CO_2 emissions on the cost-risk characteristics of the 2020 CA-BAU mix and of efficient generating portfolios is now investigated.

As Figure 18 illustrates for the realizable case, portfolio risks and costs increase with increasing CO_2 prices. This is true for the BAU portfolio and the efficient electricity generating portfolios. The parenthetical numbers next to the typical mixes represent annual CO_2 emission levels.

Figure 18: Efficient Frontier as a Function of CO_2 price – Realizable Case



As an illustration, the expected cost of the BAU portfolio increases by nine percent or 0.5 cents per kWh (from 9.6 cents to 10.1 cents per kWh) as the CO_2 price increase from $11 to $20 per tonne. The risk of that portfolio correspondingly increases from 7.4 percent to 7.9 percent, illustrating its sensitivity to changing CO_2 prices. By definition, the share of each technology in the BAU portfolio and, thus, CO_2 emissions, do not change with a rise in CO_2 prices. Clearly, it makes little sense to keep technology shares constant when CO_2 prices rise.

By contrast, with rising CO_2 prices it is optimal to reduce the share of fossil fuels in electricity generation – as indicated by the amount of CO_2 emissions. (These are shown in parenthetical values next to the portfolios in Figure 18. For example, at CO_2 price of $11 per tonne, the portfolio *S* emits 28 million tonnes of CO_2 per year. As the CO_2 price increases, optimal portfolios are re-shuffled to minimize portfolios costs and risks. For a carbon price of $30/tonne CO_2, emissions fall by almost 32 percent to 19 million tonnes per year.

Figures 19 and 20 shows technology shares on the left vertical axis, and the CO2 emissions on the right axis for an $11/tonne and a $30/tonne CO_2 price case, respectively.

Figure 19: Technology Shares and CO_2 Emissions – CO_2 = $11/tonne case

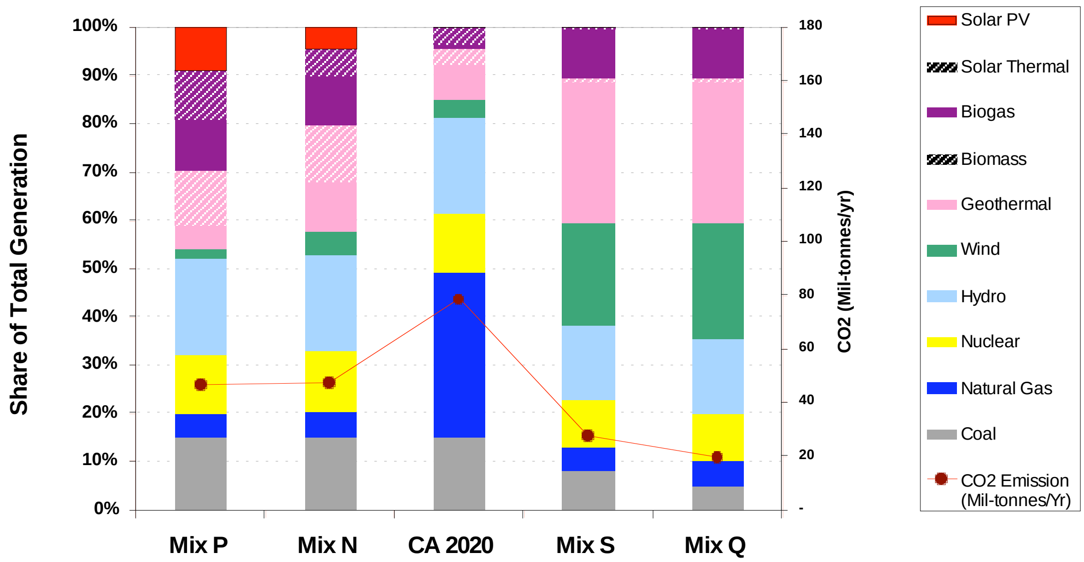
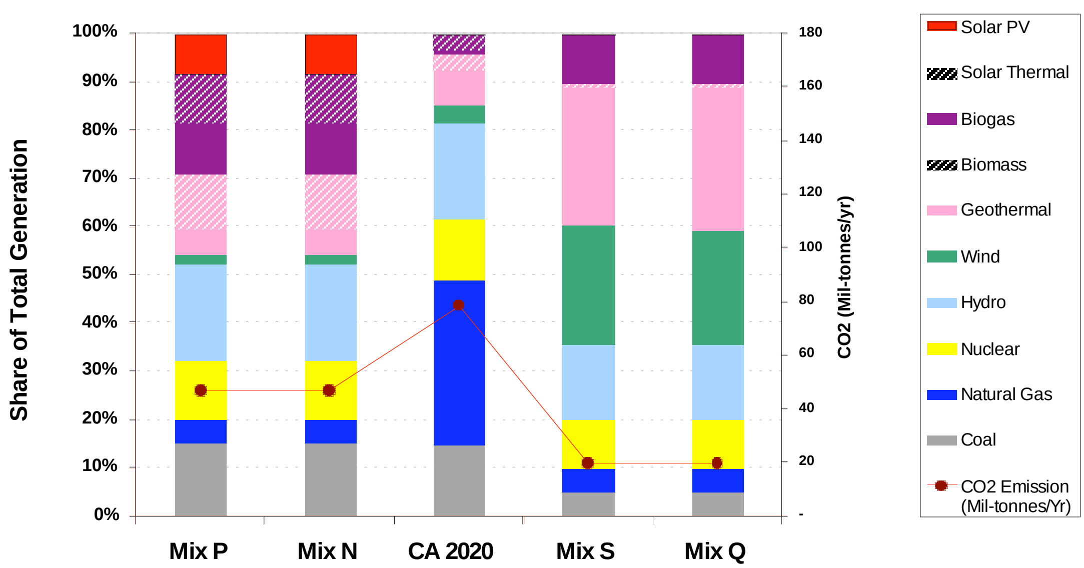


Figure 20: Technology Shares and CO_2 Emissions – CO_2 = $30/tonne case



CHAPTER 8: SUMMARY, CONCLUSIONS, AND FUTURE IMPROVEMENTS

This report has presented a mean-variance portfolio optimization analysis that develops and evaluates efficient CA electricity generating mixes for 2020. The results suggest that greater shares of non-fossil technologies can help reduce the cost and risk of the CA generating portfolio as well as its CO_2 emissions. To illustrate, an efficient generating mix considered to be achievable by 2020 is estimated to cut annual CA electricity generating cost by $6.8 billion and achieves 33 percent RPS requirements. This portfolio thus produces perpetual annual benefits sufficient to justify current investments in renewable technologies. Against this background, policies designed to accelerate the deployment of key non-fossil technologies appear to be cost-effective.

The analysis also indicates that nuclear acceleration and promotion policies may not be efficient. First, adding more nuclear capacity appears to increase overall portfolio risk relative to the case where it is not added. Second, although imposing higher CO_2 taxes results in optimized portfolios with less fossil-fuel capacity than if there are no CO_2 taxes, replacing fossil fuel capacity with additional nuclear capacity still results in higher overall levels of portfolio risk compared with replacing fossil fuel capacity with additional renewable generation.

Perhaps the single most important lesson of the portfolio optimization analysis is that adding a non-fossil fuel, fixed-cost technology (such as wind energy) to a risky generating portfolio can reduce expected costs at any level of risk, even if the non-fossil technology costs more when assessed on a stand-alone basis. This underscores the importance of policy-making approaches grounded in portfolio concepts as opposed to stand-alone engineering concepts. Of course, this does not mean that one can always increase the amount of renewable generation in a portfolio and continue to reduce portfolio risk. Portfolio risk depends critically on the overall mix of resources. Too much of any one resource, renewable or not, will tend to increase overall portfolio risk, because the portfolio becomes less diversified, just as the expression, “too many eggs in one basket,” implies. As any generation portfolio becomes less diversified, overall risk tends to increase.

Today’s dynamic and uncertain energy environment requires portfolio-based planning procedures that reflect market risk and de-emphasize stand-alone generating costs. Portfolio theory is well tested and ideally suited to evaluating electricity expansion strategies.[58] It identifies solutions that enhance energy diversity and security and are therefore considerably more robust than arbitrarily mixing technology alternatives. Portfolio analysis reflects the cost-risk relationship (covariances) among generating alternatives. Though crucial for correctly estimating overall cost, electricity-planning models universally ignore this fundamental statistical relationship and instead resort to sensitivity analysis and other ill-suited techniques to deal with risk. Sensitivity analysis cannot replicate the important cost inter-relationships that dramatically affect estimated portfolio costs and risks, and it is no substitute for portfolio-based approaches. The mean-variance portfolio framework offers solutions that enhance energy diversity and security and are therefore considerably more robust than arbitrarily mixing technology alternatives.

That said, it is important to recognize that the mean-variance portfolio approach has several important limitations with respect to generation planning. The portfolio optimization presented in this paper does not define any specific capacity-expansion plan. Such a plan would require far more detailed modelling and analysis. The results presented in this report are intended to be expositional. The results are designed to demonstrate the value of portfolio optimization approaches and suggest that capacity planning made on the basis of stand-alone technology costs will likely lead to economically inefficient outcomes.

Moreover, in deregulated markets, individual power producers evaluate only their own direct costs and risks when making investment decisions. These decisions do not reflect the effects the producers' technologies may have on overall generating portfolio performance. Wind investors, for example, cannot capture the risk-mitigation benefits the wind investors produce for the overall portfolio, which leads to under-investment in wind relative to levels that are optimal from society's perspective. Similarly, some investors may prefer the risk menu offered by fuel-intensive technologies such as combined-cycle gas turbines, which have low initial costs. Through existing regulatory mechanisms and strong correlation between electricity market price and gas price, gas generators may be able to transfer fuel risks onto customers. In effect, these investors may not bear the full risk effects imposed by the investors onto the generating mix, which may lead to over-investment in gas relative to what is optimal from a total portfolio perspective. All this suggests a rationale for economic policies in favor of technologies that capture diversification benefits.

Lastly, there are many assumptions and limitations affecting the application of mean-variance portfolio analysis techniques to generating assets. For instance, this analysis used exogenously prescribed fossil and nuclear fuel prices that do not vary with demand. As a result, generating mixes containing 35 percent gas-fired generation use the same natural gas price as mixes with 5 percent gas share. In reality, it is likely that gas prices across California would decline with reduced gas demand. For example, Sieminski (2007)[59] estimates that the current 10 percent warmer US winter is causing a 17 percent drop in natural gas prices and a 21 percent drop in oil prices. If such feedback between price and demand were included in the analysis, it might make gas more attractive as the portfolio share moves toward its lower limits, and less attractive as the portfolio share moves towards its upper bounds. In addition, assuming normal distribution of holding period returns and using past volatility as a guide to the future need to be refined and tested. Future improvement of the portfolio analysis will address such issues to provide better decision-making tools for California's energy planners. The next section describes further improvements of the portfolio analysis.

Future Improvements

The value of incorporating Modern Portfolio Theory into California's long-term resource planning is clear: the use of portfolio analysis approach in evaluating California's generation mix indicates that – contrary to the general belief – adding non-fossil fuel, fixed-cost technologies (such as wind energy) to a risky conventional fossil fuel portfolios lowers – rather than increases – expected generating portfolio costs while simultaneously reducing expected generating portfolio risks and CO_2 emissions, even if the non-fossil fuel technology costs are higher than the conventional technology ones when evaluated on a stand-alone basis. Because of the limited time and budget, an expository portfolio analysis was conducted for purposes of demonstrating the essential value of incorporating the portfolio analysis in California IOUs' long-term resource planning. Going forward, to provide more actionable insights to policy makers, the following work streams need to be conducted in the future portfolio analysis:

- **The CPUC and California IOUs can benefit from incorporating portfolio analysis as a basic framework in evaluating the long-term resource planning**. Of course, the value of portfolio analysis will be only as good as the quality of the input data. The portfolio analysis provides a basic framework for state utilities to properly incorporate the concept of portfolio risks into their resource planning. Utilities can use their own data inputs and the relationship between data inputs and modeling assumptions to create more realizable and realistic portfolio analysis outcomes. Utilities' resource planning process is far more complex and involved than the expository and illustrative analysis outcome that has been presented in this report. However, this should not hinder the implementation of portfolio analysis in the long-term resource planning process because its value in systematically incorporating risks is sufficiently demonstrated here. The challenge is to properly define and apply multiple and complex constraints and operating realities of, for example, incorporating higher levels of wind generation in the California's existing grid on the portfolio framework than those illustrated in this report.

- **Scenario analysis and portfolio analysis need to be integrated**. It is important to note that a scenario analysis can be formulated as a starting point for a more realistic portfolio analysis. "Efficient Frontiers" can be constructed for each plausible scenario that incorporates risks and uncertainties of various policy/regulatory and economic/forecasting parameters. The challenge is to assign a proper probability to each scenario envisaged because many uncertainties are not characterized well through probabilities. In an extreme, some scholars argue that mean-variance portfolio theory is not appropriate for dealing with uncertainties that cannot be quantified through probabilities. Some scholars further state that diversification is a response to "ignorance" rather than quantifiable risk and suggests diversity should be quantified using a Shannon-Wiener index instead of mean-variance portfolio.[60] Lastly, the integration task also requires close collaboration among the Energy Commission, CPUC, and the state utilities in terms of creating the proper scenarios so that portfolio analysis can be performed based on more realistic constraints and operational feasibilities.

- **The IAP study results and portfolio analysis need to be integrated**. The IAP study reiterated the importance of transmission infrastructure in order to meet 33 percent renewables goal in 2020. Portfolio-based electricity planning techniques incorporate both cost and risk on an equal footing so that the energy planners can systematically study the cost-risk tradeoff shown on the efficient frontier constructed by the portfolio analysis. The challenge is not only incorporating the need for transmission infrastructure but also considering operational and reliability consequences of adding significant amount of "must-take" surplus energy, especially during off-peak periods. The California Independent System Operator (CAISO) is in the process of finalizing a report that expands on IAP study results with a finer level of detail but limited to planning for wind from the Tehachapi resources area.[61] To properly integrate the portfolio analysis with system operation needs requires close collaboration among the Energy Commission, CAISO, CPUC, and the state's utilities.

- **The impact of energy efficiency needs to be quantified in the future portfolio analysis**. The use of portfolio analysis approach in evaluating California's generating mix is very important in properly understanding the crucial role of energy efficiency and renewable energy in reducing total portfolio cost-risk, and CO_2 emissions. In this report, the impact of renewable energy on California's energy mix has only been quantified. However, energy efficiency investments in California's generating portfolio mix have been incorporated. Energy efficiency investments can play a similar role as renewable energy because the fixed cost nature of efficiency investments can also act as a hedge against volatile fuel price risk, but at a cheaper cost. In fact, California's AB 2021 requires the Energy Commission to estimate the potential for energy efficiency by California's utilities and set efficiency targets to realize that potential. The future improvement on the portfolio analysis with respect to energy efficiency may support the Energy Commission's goal to implement California's AB 2021.

- **Improved modeling assumptions and input parameters (such as improved risk measure) are necessary in the future portfolio analysis**. Please note that the portfolio analysis is based on a set of assumptions that generally hold in highly efficient financial markets, but which may not be strictly analogous in the case of a portfolio of generating or other real assets. Some of these assumptions may not be crucial, while the importance of others still needs to be determined in the sense of how outcomes change when the assumptions are transferred from the purely financial setting to electricity generating context. In finance, the standard assumptions require that there exist perfect markets for trading assets, which generally implies low transaction costs, perfect information about all assets, and returns that are normally distributed. However, the electricity market for the generating assets, e.g. turbines, coal plants, etc., may be relatively imperfect as compared to capital markets, which suggests that, unlike financial securities, which can be readily sold, investments in generating assets are less easily liquidated. In addition, financial securities are almost infinitely divisible, so that a portfolio can contain between 0 percent and 100 percent of a given security. By contrast, generating assets are “lumpy” by comparison, which can cause discontinuities.

However, for large service territories, or for the analysis of state-wide generating portfolios, the lumpiness of individual capacity additions becomes considerably less significant. Given these caveats, the conclusion is that in spite of the limitations, portfolio theory is commonly applied to the valuation of tangible, non-financial assets. In future analysis, using semi-variance and other risk measures may be appropriate to cases where asset returns may not be normally distributed and higher moments of distribution becomes more pronounced in the distributional details (such as fat tails and skewness).

- **Future portfolio analysis would benefit from including “real-option” valuation techniques**. The current portfolio analysis framework cannot deal with “optionality.” Specifically, the portfolio analysis does not reflect valuable managerial options that may present themselves to project owners over time. The presence of such options in today’s competitive energy markets affects the value of renewable energy technologies as well as conventional technologies. For example, when spot gas prices rise, the owners of independent gas-fired generating plants may be able to reduce electricity production and profitably sell their contract gas supplies to others. Similarly, if peak electricity system demand and resulting high electric prices are linked to periods of high solar intensity (or reliable winds), then solar PV or wind energy converters may create valuable options to exploit such markets. Such possibilities widely referred to as real options in financial literature, can be accommodated in a current portfolio analysis approach.

- **Other approaches to quantify uncertainty and portfolio diversification needs to be explored**. Portfolio theory generally uses past volatility as a guide to the future, although nothing prevents analysts from estimating expected future volatility in some other manner. For example, the analysis estimates the variability of fuel price holding period returns (HPRs) using annual data time series in order to exclude seasonal fluctuations. However, other scholars argue that risk, properly defined, is a measure that applies only where a probability density function may meaningfully be defined for a range of possible outcomes. The focus therefore is on probabilistic risk, which will not reflect possible future “surprise.” This, therefore, suggests that there may still lurk surprises out there that cannot and have not been captured in the portfolio analysis. This reiterates the importance of properly integrating the portfolio analysis and scenario analysis.

ENDNOTES

[1] Assembly Bill 32, (Nuñez), Chapter 488, Statutes of 2006.

[2] For purposes of this report, “business-as-usual” includes 20 percent renewable energy (the 2010 goal) and predicted results from all funded energy efficiency.

[3] It is interesting to note that In California, over 90% of the RPS contracted energy so far is below MPR (market price reference).

[4] Prior to passage of Senate Bill 1036, Statutes of 2007, the Energy Commission administered funds from the New Renewable Resources Account to provide Supplemental Energy Payments (SEPs) to cover above-market costs of qualified applicants. In the future, these above-market costs will be recovered in rates if the above-market costs are approved by the CPUC in its contract approval process. However, the overall cost limitation will still be set as the sum of the amounts paid into the New Renewable Resources Account through December 31, 2007, plus the amount that would have been paid in from January 2008 to December 31 2011 under pre-existing law.

[5] Bolinger, M., Wiser, R., and Golove, G., “Accounting for Fuel Price Risk When Comparing Renewable to Gas-Fired Generation: The Role of Forward Natural Gas Prices,” Lawrence Berkeley National Laboratory, 2004.

[6] For a rigorous development of multi-attribute methods, *see* Keeney and Raiffa (1976).

[7] A Pareto-superior policy is one that achieves greater benefit at the same cost, or equivalently, the same benefit at lower cost.

[8] Sijm, J.P.M., The performance of feed-in tariffs to promote renewable electricity in European countries. ECN-C-02-083. (2002).

[9] Rowlands, I., “Envisaging feed-in tariffs for solar photovoltaic electricity: European lessons for Canada,” *Renewable and Sustainable Energy Review* 9 (2005), 51–68.

[10] Mitchell, C., Baucknecht, D., Connor, P.M., “Effectiveness through risk reduction: A comparison of the renewable obligation in England and Wales and the feed-in system in Germany,” *Energy Policy* 34 (2006), 297–305.

[11] Ibid.

[12] US Energy Information Administration, Refiner acquisition cost of crude, available at: http://tonto.eia.doe.gov/dnav/pet/hist/r0000____3a.htm, accessed 28 May 2007.

[13] The Energy Policy Act of 2005 (EPAct 2005) made significant changes to PURPA, modifying co-generation rules to prevent “PURPA machines” and altering the requirements for electric utilities to purchase the output from QFs.

[14] Gipe, P., “Renewable tariffs and standard offer contracts in the USA,” 2007. Available at: http://www.wind-works.org/FeedLaws/USA/USAList.html.

[15] *See* Gregory Morris, Biomass Energy Production in California: The Case for a Biomass Policy Initiative Final Report, National Renewable Energy Laboratory, (2000), 8–10.

[16] *See* Butler and Neuhoff, Comparison of Feed in Tariff, Quota and Auction Mechanisms to Support Wind Power Development, Cambridge Working Papers in Economics CWPE 0503, (2005) 8–9.

[17] This issue is known as “debt equivalency.” Financial rating agencies treat long-term contract obligations as the equivalent of debt. Thus, a utility signing a long-term contract with a renewable energy developer may have its credit rating reduced, increasing its overall cost of capital and raising

customer rates. As a result, the apparent cost of renewable energy purchased by the utility will be more expensive.

[18] In Britain, offers are called "tenders."

[19] This is typically referred to as "RPI – X" regulation, where "RPI" represents the forecast rate of inflation and "X" represents an allowance for improved productivity. For more information, see, e.g., J. Lesser and L. Giacchino, Fundamentals of Energy Regulation (Vienna, VA: Public Utilities Reports, Inc. 2007), Chapter 3, 69-70, 182-92.

[20] 2005 Integrated Energy Policy Report. Publication # CEC-100-2005-007-CMF.

[21] 2006 Integrated Energy Policy Report Update. Publication # CEC-100-2006-001-CMF.

[22] The one renewable generation exception is biomass, whose cost structure is similar to gas-fired generation.

[23] Portfolio Analysis and Its Potential Application to Utility Long-Term Planning, Final Staff Report, CEC-200-2007-012-SF.

[24] Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report, Staff Draft Report, CEC-200-2007-010-SD.

[25] Intermittency Analysis Report: Final Report, PIER Project Final Report, CEC-500-2007-081.

[26] Strictly speaking, in the case of capital costs, this statement holds only *ex post,* although, given the short lead times of renewables projects and the large proportion of manufactured components, construction-period risks for these technologies is low even *ex ante*. O&M costs for renewables arguably have the same portfolio risks as O&M costs of conventional technologies. However, because the O&M costs represent a small share of total cost of renewable generation, their risk contribution is also small.

[27] On an accounting basis, kWh generating cost is calculated by dividing annual capital charges plus operating costs by the year's kWh output. Given a fixed capital charge and relatively fixed maintenance costs, therefore, annual wind output variability would cause year-to-year kWh costs to vary. Sunk capital costs are irrelevant in an economic sense, but fluctuations in periodic wind output might change the economic kWh cost estimate on the basis of avoided costs: i.e. to the extent that periodic wind shortfalls will require replacement purchases from alternative sources which may have to be kept in reserve for such purposes.

[28] Bolinger, M., R. Wiser, and W. Golove, (2006) "Accounting for Fuel Price Risk When Comparing Renewable to Gas-Fired Generation: The Role of Forward Natural Gas Prices," *Energy Policy* 34(6), pp. 706-720.

[29] One notable exception is biomass fuel costs. Biomass fuel costs are correlated to diesel oil and thus to other fuels, because biomass fuel costs are highly dependent on transportation.

[30] There are also different "flavors" of betas, based on a firm's leverage.

[31] Developed by Nobel Laureate William F. Sharpe, this ratio relates changes in risk to changes in reward.

[32] Comparative Costs of California Central Station Electricity Generation Technologies. Draft Staff Report. June 2007. CEC-200-2007-011-SD.

[33] TECHPOLE database, LEPII, University of Grenoble, CNRS.

[34] This assumption is also consistent with Energy Commission's Scenario Analysis Project (CEC-200-2007-010-SD-AP).

[35] The same levelized cost is assumed for both large and small hydro. In California, only small hydro less than 30MW is eligible for the RPS.

[36] Source: Point Carbon, http://www.pointcarbon.com/Home/Market%20prices/Methodology/category745.html

[37] CPUC, Resolution E-4118, October 4, 2007 Available at: http://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/73594.PDF The 2020 value is calculated by escalating the 2004 value at five percent per year through 2023, and then increasing the value by $0.90 per year through 2030,following the methodology described in the Resolution. The resulting value of the GHG adder to the MPR ranges from $0.0027 per kilowatt hour to $0.00972 per kilowatt hour as the contract term increases from 10 to 20 years and the project on-line date changes from 2008 to 2020.

[38] "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California: Recommendations of the Market Advisory Committee to the California Air Resources Board," June 30, 2007. Available at: http://www.climatechange.ca.gov/documents/2007-06-29_MAC_FINAL_REPORT.PDF

[39] Synapse Energy Economics, Inc, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," prepared by Lucy Johnston, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Rocshelle, and David White, June 8, 2006. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.0.Climate-Change-and-Power.A0009.pdf.

[40] The IAP developed a component of the costs that can be attributed to wind by netting out imbalance costs, specifically those costs for regulation and load following. In the IAP study, based on an extreme penetration scenario aimed at 33%, these costs were estimated at $0.21/MWh for regulation and $0.07/MWh to $0.48/MWh for load following resulting in a $0.69/MWh cost for integrating the wind resource. This is consistent with a previous study called the Cost of Integrating Renewables (available at: http://www.abcsolar.com/pdf/500-04-054.pdf), which clearly defines the total costs and the costs associated with "integrating" a generator per market participation rules.

[41] The analysis also excludes the impacts of local interconnection costs and resource saturation. Specifically, only so much wind resource capacity can be interconnected to the transmission system grid at the local level. This issue can be addressed by creating multiple wind resources, each reflecting a specific local area, and performing the portfolio analysis with additional constraints.

[42] Awerbuch, S, J. Jansen, L. Buerskens, and T. Drennen, "The Cost of Geothermal Energy in the Western US Region: A Portfolio-Based Approach," Sandia National Laboratories, March 2005.

[43] HPR is defined as: HPR = $(P_2 – P_1) / P_1$ where P_t is the price/cost at time *t.* All the SD and correlation estimates refer to the HPRs, not the actual price/cost levels themselves.

[44] In principle, the O&M cost category should include outlays for property taxes, insurance, and other non-maintenance categories. These would most likely exhibit lower risk and potentially dampen the results of Table 1.

[45] Note that for a fixed-cost technology $\sigma_j = 0$ or nearly so. This reduces σ_p, since two of the three terms in Equation 2 are reduced to zero. It is also easy to see that σ_p declines as $\rho_{i,j}$ falls below 1.0.

[46] Green, R. (2006). "Carbon tax or carbon permits: the impact on generators' risks," Institute for Energy Research and Policy, University of Birmingham, September. Available at: http://ideas.repec.org/p/bir/birmec/07-02.html

[47] EU-ETS is the Carbon Trading Scheme within the European Union. The first compliance phase is from 2005 to 2007, while the second compliance phase continues from 2008 to 2012.

[48] Awerbuch, S., and M. Berger, "Energy Security and Diversity in the EU: A Mean-Variance Portfolio Approach," IEA Report Number EET/2003/03, Paris: February. Available at: http://library.iea.org/dbtw-wpd/textbase/papers/2003/port.pdf; Roques, F., W. Nuttall, D. Newberry, R. de Neuville, and S. Connors, 2006. "Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices?" *The Energy Journal* 27 (4), pp. 1-24.

[49] Current California policy, as described in the 2005 IEPR, has prohibited development of new nuclear facilities since 1976 because of a continuing lack of a permanent waste-storage facility. See 2005 IEPR, p. 84.

[50] The 2006 CA electricity generation shares that were published in the California Energy Commission's 2006 Net System Power Report is used, CEC-300-1007-007, April 2007. Available at: http://www.energy.ca.gov/2007publications/CEC-300-2007-007/CEC-300-2007-007.PDF. These values were then used as the basis to develop the projected 2020 business as usual (BAU) electricity generation shares. Specifically, the generation growth was held constant for Coal, Nuclear, Hydro (Large and Small), and Solar PV technologies, and the CA-BAU assumes that renewable energy account for 20 percent of the total generation in 2020.

[51] These expository bounds will be refined in the final report.

[52] For nuclear, the 2005 IEPR reaffirmed California's policy that suspended construction of new nuclear power plants beginning in 1976. No growth in new coal technology due to Senate Bill 1368 which limits GHG emissions to below CCGT emissions and also because the assumption is that carbon sequestration will not be sufficiently mature to play a part in California generation mix through 2020. No growth in new large hydro is assumed although small increases in small hydro or increased efficiency in large hydro are possible. The variability of hydro output is left for future consideration in the final report.

[53] This estimate is based on an annual electric consumption in 2020 of 310.2 TWh ($\$0.022/\text{kWh} \times 310.2 \times 10^9\text{kWh} = \$6.8$ billion).

[54] This is true only to the extent that the underlying generating costs shown in the Figure reflect all economic cost. However, since the costs shown in the Figure do not fully incorporate some economic costs such as investment grants that benefited some of these technologies (e.g., wind and nuclear), the resulting climate change mitigation may cost more than what in the Figure suggests.

[55] Renewables share does not include solar PV.

[56] CORWM, Committee On Radioactive Waste Management. (2006). "Managing our Radioactive Waste Safely." Available at: http://www.corwm.org.uk/pdf/Chapter09.pdf.

[57] See 2005 IEPR, p 84.

[58] Other techniques have also been applied. For instance, Stirling (1996, 1994) develops maximum-diversity portfolios based on a considerably broader uncertainty spectrum. Though radically different in its approach, his diversity model yields qualitatively similar results. See, Stirling, A. 1994 "Diversity and ignorance in electricity supply – Addressing the solution rather than the problem". *Energy Policy* (22:3), pp. 195-216; Stirling, A. 1996 *On the Economics and Analysis of Diversity,* Paper No. 28 Science Policy Research Unit (SPRU) University of Sussex, Available at: http://www.sussex.ac.uk/spru.

[59] Sieminski, A., "Varying Views on the Future of the Natural Gas Market Secrets of Energy Price Forecasting, 2007 EIA Energy Outlook, Modeling, and Data Conference Washington DC, March 28, 2007. Available at: http://www.eia.doe.gov/oiaf/aeo/conf/sieminski/sieminski.ppt.

[60] See, for example, A. Sterling, "Diversity and ignorance in electricity supply investment," Energy Policy, vol 22, pp. 195-216, Mar. 1994.

[61] CAISO, Draft Integration of Renewable Resources Report, September 2007, at http://www.caiso.com/1c60/1c609a081e8a0.pdf