PROPOSED CRITERIA FOR EVALUATION OF TRANSMISSION AND ALTERNATIVE RESOURCES

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EXECUTIVE SUMMARY

Developing and maintaining a highly reliable electric transmission infrastructure that promotes a competitive and efficient electricity market is critical for the State of California. Although significant new generation has been built in California during the last 20 years, considerably less new transmission capacity has been added.

Historically, transmission additions have been justified on the basis of reliability, economics, or both. Most of the transmission additions in California during the last 20 years have been justified on the basis of reliability. Of the 17 transmission projects approved by the California Independent System Operator (CA ISO) since the beginning of 2000, only five have been justified on economic grounds.[1] The concept of reliability upgrades is well understood and standardized methods for assessing reliability needs and alternatives both exist and are well accepted.

Conversely, procedures for identifying and calculating the economic benefits of transmission additions are not similarly standardized, defined, or accepted. New or improved transmission can result in benefits that are actually broader than economic or least-cost criteria. They can include benefits outside the scope of the well-defined reliability needs established by regional and national reliability councils, such as reducing risk and minimizing environmental impact.

The purpose of this report is to recommend resource evaluation criteria that can be used to evaluate potential transmission expansions and other resource alternatives. This report was originally documented in draft form as Appendix A of the July 2005 California Energy Commission (Energy Commission) Transmission Staff Report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond* (Pub. no. CEC 700-2005-018.)[2] A summary of the report was presented at the Energy Commission July 28, 2005, "Integrated Energy Policy Report Committee Hearing on Strategic Transmission Planning Issues and Transmission Staff Report."[3] Parties were invited to file comments regarding this and other presentations provided on July 28, 2005, by August 4, 2005.[4]

No comments were received either verbally at the July 28, 2005 hearing, or in writing after the hearing, that addressed any of the conclusions or recommendations reached in either Appendix A of the Transmission Staff Report or in the contractor's presentation of that material. Therefore, with the exception of new material in the introductory section of Chapter 4, the content of this report is identical to that of Appendix A of the Transmission Staff Report. The addition in Chapter 4 is intended to more fully explain the absence of the environmental category of stakeholder-proposed criteria from the final set of recommended evaluation criteria, and to explain how the environmental criteria were treated (for example, subsumed within other related criteria, recommended for consideration only when substantial differences exist, or assumed to be minimum standards not subject to optimization).

Minimum Requirements

Important resource criteria have already been adopted as part of federal, state, and local laws and policies. For purposes of this report, these criteria are considered "minimum requirements" and include resource requirements including accepted reliability standards; minimum levels of energy efficiency and renewable energy; resource adequacy; and others. The concept of "environmental justice" is also considered a minimum requirement since it has been adopted at federal, state, and local levels. Resources additions included in portfolios to meet one or more of these minimum requirements are not considered to be optional and are, therefore, not modified as alternative resource portfolios are evaluated.

Stakeholder Criteria

Numerous parties are affected by the operation of the California electricity market. These parties have an interest in any decision that affects either the market structure or the composition of the underlying resource infrastructure. These parties are called stakeholders. In order to develop resource criteria that appropriately consider the priorities of these stakeholders, a diverse group of participants was surveyed. They included the following:

- Consumer groups
- California Public Utilities Commission (CPUC)
- CA ISO
- Environmental groups
- Independent energy producers
- Investor-owned and publicly owned utilities
- Renewable resource groups
- Transmission owners

In total, 22 different groups and approximately 30 individuals were interviewed for their perspectives on resource planning criteria. These groups are listed in Appendix A. The criteria they suggested fell into one of the following four general categories:

- Reliability
- Least-Cost
- Environmental
- Risk

Reliability

The stakeholder-suggested reliability criteria are focused on issues not already considered to be part of either a reliability justification study or a minimum requirement. These criteria include reducing the cost of energy-not-served in the market simulation study, reducing reliability-related payments to California generators, and increasing homeland security. The homeland security concern became much more significant after the September 11, 2001, New York terrorist attacks. It focuses on the question of whether transmission facilities can be sited in a way to reduce the likelihood and impact of a potential terrorist attack on the electric transmission grid.

Least-Cost

The least-cost criteria suggested by the various stakeholders are considerably more extensive than reliability criteria. Suggested criteria ranged from traditional least-cost integrated resource planning to alternative perspectives of least cost – for example, excluding generator profits from uncompetitive market conditions. The efficiency of the California electric market is considered an important criterion by some stakeholders. Market efficiency can be measured by either evaluating the overall market prices compared with the underlying marginal costs, or by comparing the total magnitude of imports and exports as a measure of achievement of the goal of seamless regional markets.

Other stakeholder-suggested criteria included in the least-cost category include consideration of the impact on the capital budget for the next two, five, or ten years, from a rate stabilization perspective. Several least-cost criteria, such as market valuation and portfolio fit, were also suggested in evaluating a single resource option, although they are less important when comparing extensive long-term resource portfolios.

Risk

The concept of measuring and comparing risk for resource alternatives or portfolios has been extensively explored in the past 10 to 15 years. The criteria suggested by the stakeholders under the general classification of risk include financial portfolio concepts such as value at risk, cash flow at risk, expiration value at risk, and others. More basic applications of portfolio risk include concepts including “risk of extreme outcome,” which is the difference between the expected and average of a set of pre-specified worst cases. Several stakeholders with strong renewable or environmental preferences suggested use of a simple “pie chart” illustrating fuel and resource types as valuable indicators of potential risk.

Other stakeholder-suggested risk criteria focused on risk caused by the potential occurrence of specific types of events including CO_2 regulation, the political feasibility of portfolio implementation, and the impact of market paradigm changes. Other suggested project feasibility criteria included credit, cost overruns, and scheduling risks.

Environmental

The stakeholder-suggested environmental criteria demonstrated priorities for cleaner air, greater amounts of renewable resources, less dependence on fossil fuels, more efficient use of limited clean water sources, and reduction of the environmental and visual impacts of new transmission lines. Some stakeholders also indicated a strong desire for federal and state government and local utilities to more fully comply with the provisions of "environmental justice laws" which protect minorities from a disproportionate amount of pollution from electric facilities.

The specific resource evaluation criteria suggested by the 22 stakeholder groups are contained in Appendix B.

Recommendations

There are six important evaluation criteria for resource evaluation. The six recommended criteria are:

- Least-Cost
- Risk
- Reliability
- Market Efficiency
- Fuel Diversity
- Resource Flexibility

Many resource planners contend that the overall goal should be to develop a least-cost resource portfolio, subject to tolerable risk levels. Simply put,, the two most important criteria are clearly least-cost and risk. Since many direct costs, including environmental impacts and reliability payments, can now be considered in a comprehensive least-cost framework, it is essential that least-cost and risk criteria be included in a rational manner when evaluating resource strategies or extensive portfolios.

The least-cost analytical approach can be best specified by the planner performing an actual case study instead of applying a one-size-fits-all prescriptive formula without regard to the specifics of an individual case. The least-cost framework should identify perspectives that will actually be considered (including societal, state, consumer, and generator) and be based upon the present-value cost and benefits calculation over the assumed economic life of the project or portfolio.

The measurement of risk is also best left to the person actually performing the evaluation. That way, the risk calculation could be either statistically sophisticated and computationally demanding or as simple as defining a standard risk index based upon an "average worst case." The risk assessment must quantitatively consider variables that can be defined and will have a substantial impact on the results. The risk assessment should also include a qualitative evaluation of risk factors that cannot be easily quantified, including the unknown impacts of a new market structure.

Beyond least-cost and risk criteria, other criteria should be considered. Since this inclusive approach would incorporate virtually all stakeholder-suggested resource evaluation criteria, a few comprehensive "standard" criteria are recommended for most evaluations. These include:

- Reliability – Identify any significant reliability impacts that are not specifically required by existing reliability standards or easily quantified. For example, suppose two alternatives for transmission to San Francisco were being considered. One used the existing peninsula corridor, and the other was a type of trans-bay cable. The second corridor may not be required to meet existing reliability standards nor may it be quantified in traditional economic benefits analysis. However, since the alternative paths may provide differing levels of reliability, the reliability benefit of each should be identified and qualitatively considered.
- Market Efficiency – Market power is a significant concern for the California consumer. The total benefit calculation of a proposed transmission or generation upgrade does not identify the "winners" and "losers." A proposed project that has high positive total benefits may not benefit the individual consumer in a manner desired by state policy makers. Therefore, a simple computation of market efficiency can be a valuable indicator of the relative advantage of one particular resource portfolio when compared to another.
- Fuel Diversity – In a perfect world where a rigorous risk assessment would include a comprehensive treatment of all fuels and related variables, a high-level summary of fuel diversity would not be necessary. However, since it is likely that this level of risk analysis is beyond the available capabilities and time of most entities engaged in resource planning, a simple, high-level summary comparison of fuels would be valuable for evaluating risk. Fuel diversity is an indicator of overall portfolio risk and can help identify future dependence on fossil fuels and amounts of airborne pollutants. For these reasons, it is recommended that a fuel diversity summary be prepared for each resource scenario.
- Resource Flexibility – As a resource evaluation parameter, resource flexibility does not equate to operational flexibility. It rather examines resource or portfolio flexibility in order to adjust timing and capital commitments. Assume, for example, that two transmission alternatives have identical benefits and costs. However, one requires a full commitment of capital funds at the beginning of the permitting phase while the other allows for some "stepping-off" milestones. The second alternative would be clearly preferred because of its timing and decision-making flexibility. This "resource flexibility" evaluation criterion is applied in this context in this report, and can be used to evaluate differences in the commitment of capital.

In summary, the criteria recommended in this report for the evaluation of transmission, generation, and demand-side resource alternatives are not presented as inflexible established fact. They are offered instead as a flexible, case-specific standard that can be tailored and modified according to the best judgment of the resource planner. The report presents a common starting point for all resource evaluation. Its suggested approach will surely evolve as superior methodologies emerge and become available. Meanwhile, it is hoped that application of this set of resource evaluation criteria will be used to better plan for the critical changes in the generation and transmission infrastructure that are urgently needed to ensure a robust and efficient California electricity market.

CHAPTER 1: INTRODUCTION

The purpose of this report is to recommend specific criteria to evaluate generation, transmission and demand-side resource alternatives. Planning for the optimum combination of resources to meet its customers' needs has traditionally fallen to the serving utility, with regulatory oversight by federal, state and local agencies. In many cases, all planning was performed by the same resource or power system planning department. The nature of this task changed significantly for many utilities when the Federal Energy Regulatory Commission (FERC) issued Order 888, requiring utilities to offer non-discriminatory transmission access. One practical result of FERC's open access Order is the requirement that utilities view themselves as separate generation and transmission companies. This Order was followed by additional load and generation disaggregation policies mandated by the state's deregulation statute, Assembly Bill 1890 (AB 1890). The California Independent System Operator (CA ISO), merchant generation, trading companies, and energy service providers were subsequently added to the planning mix.

Today there is a lack of consistent integrated transmission and resource planning in California. Each technical area has developed its own criteria, planning cycles, and processes. The purpose of this study is to identify basic criteria, acceptable to the full range of stakeholders, which can form core criteria upon which all resource options can be evaluated and compared.

The process for developing criteria to evaluate resource alternatives such as transmission, generation, and demand-side programs included:

- Identifying the diverse group of California stakeholders involved in or directly affected by the California electricity market.
- Surveying these stakeholders to identify their preferences for appropriate evaluation criteria.
- Determining what set of available criteria provide the best and most comprehensive information upon which to base resource decisions so that a set of specific criteria can be effectively applied to all future evaluations.

The goal of this process is twofold: to advance, improve and standardize the methodology for evaluating transmission and other resource alternatives, and to increase the transparency and understandability of evaluation findings for the general public.

The paper first reviews minimum requirements which must be fundamental to any California resource assessment. It then describes and assesses potential evaluation criteria, as suggested in interviews with stakeholders. Finally, it proposes broad-based criteria. More detail is provided in the appendices.

CHAPTER 2: CURRENT MINIMUM REQUIREMENTS

National, regional, state, and local authorities have made decisions and implemented policies establishing both a minimum level of reliability for electric systems and the preferred resource types and amounts of each to be used in meeting customer demand. The resource standards that these authorities generally consider to be "minimum requirements" can be categorized as follows:

- Reliability
- Energy Efficiency
- Demand Response
- Renewable Resources
- Distributed Generation
- Qualifying Facilities
- Resource Adequacy

When planning additions or enhancements to an electrical system, these minimum requirements must be met regardless of the resource strategy or project being evaluated. Any new resource mix must also meet all environmental, public health, and safety regulations and comply with applicable existing law. While these minimum requirements affect the evaluation, the planning process considers them givens rather than variables. The usual practice is to not reevaluate these prior policies and reliability decisions in the assessment. Reevaluating and recommending changes to existing policy is left to other forums.

A brief summary of these minimum requirements can help describe one of many sets of constraints affecting resource planners' choices.

> ***Reliability –*** The North American Electric Reliability Council (NERC) has the responsibility of ensuring that North America's bulk electric system is "reliable, adequate, and secure."[5] NERC is divided into 10 reliability regions. California is in the Western Electricity Coordinating Council (WECC), which covers all 14 of the western states, the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja, Mexico. Throughout the NERC, utilities and other entities voluntarily enter into contracts to abide by reliability criteria. Violations can result in monetary penalties. NERC and WECC establish "reliability requirements" for purposes of planning and operating the interconnected electric transmission system during both normal and defined-abnormal events.[6]
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> In California, the California Independent System Operator (CA ISO) is also responsible for ensuring the "reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria…"[7] The

CA ISO has established additional reliability criteria for the California market under its control, specifically for local area reliability and transmission congestion reduction.[8]

Investor-owned or municipal utilities can also adopt additional reliability criteria for their utility service area or a particular local area within their territory. As an example, the Los Angeles Department of Water and Power (LADWP) bases its long-term planning reserves requirements on the annual hourly peak with an 1-in-10-year expectation of occurrence, instead of the more common and less conservative 1-in-2-year expectation.[9]

NERC, WECC, CA ISO, and utility reliability standards are collectively considered to be "minimum requirements" for purposes of this report.

Energy Efficiency – For many years, one of California's top priorities has been to maximize consumer participation in economic energy efficiency programs. For the investor-owned utilities (IOUs), electric savings from energy efficiency programs are funded by ratepayers through both a public goods charge (PGC) and procurement rates. In a September 23, 2004, decision, the CPUC indicated that IOUs are expected to capture 70 percent of the energy efficiency "economic potential" for the years 2004-2013. Between 2004 and 2013, these efforts are expected to meet almost 60 percent of their incremental electric energy needs.[10] This policy is reinforced in Decision 04-12-048, which requires the IOUs to meet or exceed the Commission's energy efficiency goals over the next 10 years and specifically over the next energy efficiency program funding cycle (2006-2008). As the goals are updated, IOUs are required to incorporate the most recently adopted goals into their resource planning efforts. In a similar manner, aggressive energy efficiency goals have been established and are being implemented by California's publicly owned utilities (POUs).

Demand Response – Demand response is used to reduce demand when energy prices are high or supplies tight. The two general types of demand-response programs are "price-responsive" and "reliability-triggered" programs. In price-responsive programs, customers respond to the price of energy and implement load reductions when prices rise. In reliability-triggered programs, customers agree to reduce their load when directed by the IOU, their POU,, or by the CA ISO, in exchange for a price incentive. The CPUC initiated development of large-scale demand response programs in June 2003. For the IOUs, the 2005 goal was to meet 4 percent of the annual system peak load with demand-response programs in 2006, and 5 percent in 2007 and thereafter.[11] Deployment tests in 2004 indicate that new program designs will be needed to meet these goals. In Decision 05-01-056, released in January 2005, the CPUC revised its definition to allow megawatts (MWs) "from any program that provides a day-ahead demand reduction signal, whether it is based on a price, temperature, or reliability forecast, to count towards meeting the utilities' price responsive demand program goals adopted in D.03-06-032 and D.04-12-048."[12] This most recent definition distinguishes between day-of and day-ahead demand response. Its reasoning is that the purpose of day-of demand response is to support immediate system reliability. For procurement purposes, this demand response is accounted for separately.

Renewable Resources – Renewables Portfolio Standards (RPS) require that a specific percentage of the state's total generation mix come from resources defined as "renewable." This definition includes solar, wind, geothermal, biomass, and small hydro. California's RPS require that load serving entities (LSEs) increase their renewable energy amount by at least 1 percent per year, achieving 20 percent by 2017, at the latest.[13] California's IOUs have committed to meeting the state standard more rapidly by achieving 20 percent renewable by 2010. California's POUs have set similar targets.. For example, the Sacramento Municipal Utility District (SMUD) has set its goal of achieving the 20 percent target by 2011.

Distributed Generation – Distributed energy resources are small-scale power plants, usually in the 3 to 10,000 kilowatt (KW) range, that are located close to areas of electric demand.. Distributed generation can provide incremental capacity to the electric grid. In some instances, it can avoid or reduce the cost of transmission and distribution upgrades.[14] One of California's *2003 Energy Action Plan's* goals is to "promote customer and utility owned distributed generation."[15] At this point the plan contains no specific utility goals regarding the amount and timing of distributed generation. It is possible these goals could be established in the future.

Qualifying Facilities – Qualifying Facilities (QFs) are independent cogenerators or power producers that often generate from renewable or alternative resources. By federal law, QFs meet specific operating, efficiency, and fuel-use standards and have the right to sell the electricity they generate to the IOUs under long-term contracts at the utilities' avoided-cost.[16] The Energy Commission estimated QF dependable capacity at 5,567 MW in 2005.[17] A long-term policy for expiring QF contracts, including pricing terms, is currently under consideration at the CPUC, with a decision expected in late 2005.

Resource Adequacy – Resource adequacy is often considered to be a part of the planning reliability requirements briefly described on the previous page. The purpose of resource adequacy is to ensure that sufficient resources exist to meet defined contingencies such as generator or transmission outages or load forecast uncertainty. The CPUC has adopted a planning reserve margin of 15 to 17 percent of load for the state's IOUs. The CPUC is in the process of developing the implementation rules. The planning reserve margin is expected to be fully implemented by 2006. Of this capacity reserve total, 90 percent must be acquired one year in advance.[18]

There are other resource standards or “minimum requirements” that are not summarized above. There will undoubtedly be additional minimum requirements established in the future. The purpose of this section of the report is not to provide a comprehensive list of all current and future resource standards, but to illustrate the concept of “minimum requirements” and provide examples of criteria that fit into that category. For purposes of future strategic resource planning, these resource standards are considered to be well established. All resource strategies proposed will be structured to meet these minimum requirements.

CHAPTER 3: STAKEHOLDER-SUGGESTED CRITERIA

Many parties are affected by the operation of California's electricity market. These parties have an interest in any decision that affects either how the market is structured or its underlying resource infrastructure. These parties are referred to as stakeholders. In order to develop resource criteria that appropriately consider the priorities of these stakeholders, we surveyed a diverse group of participants, including the following:

- Investor-owned utilities (IOUs) and publicly owned utilities (POUs)
- The California Public Utilities Commission (CPUC) and the California Independent System Operator (CA ISO)
- Environmental groups
- Renewable groups
- Independent energy producers
- Transmission owners
- Consumer groups

Appendix A contains a list of these participants. In total, 22 groups or organizations were interviewed and asked about criteria they considered to be appropriate. The stakeholders suggested criteria that ranged from traditional least-cost to more recent concepts like portfolio fit. We classified stakeholder-suggested resource evaluation criteria into the following four general categories:

- Reliability
- Least-Cost
- Environmental
- Risk

There are two requirements for a resource evaluation criterion. First, the criterion needs to be applicable to statewide resource planning. Although all of the information received from the stakeholders was interesting, not all of the feedback pertained specifically to criteria suitable for statewide resource evaluation. That information was recorded but not included in this report.

Second, the criterion is most valuable if it can be used to either measure or assess the impact of a resource decision in a consistent and standard manner. These measurements can be quantitative, using a specific mathematical methodology. They may also be qualitative if quantitative measurements are either not applicable or sufficiently developed, such as perceived public acceptance of a particular resource strategy. In some cases, a stakeholder suggested a criterion that, when applied, would provide valuable information. However, because it could not be used to evaluate all alternative resource plans in a standard, objective manner, the criterion was not valuable for the current purpose and was therefore not included on the list.

This chapter summarizes and reviews the suggested evaluation criteria, based upon the four categories listed above. Chapter 4 makes recommendations regarding the evaluation criteria.

Reliability

Reliability is a critical consideration for any resource strategy. Electric system reliability can be measured in a variety of ways.

Un-served Energy

In a chronological market simulation model, one measurement of reliability is the amount of energy that cannot be delivered to the customer because of generation or transmission limitations or outages. This energy is referred to as “un-served energy.”

One way to compare the overall reliability of alternative resource portfolios is to compute and compare un-served energy for each scenario. This criterion is a traditional measurement of reliability that was suggested by several stakeholders. Another stakeholder suggested that the persistence of un-served energy within a zone or location could also be a valuable indicator of reliability.

There are several arguments, however, against using un-served energy as a reliability criterion. First, some contend that if an appropriately high unit cost for un-served energy is used in the market simulation, (dollars per megawatt-hour ($/MWh)), the total cost of un-served energy is really part of the direct cost of energy already calculated by the simulation model. Computing a separate cost of un-served energy in the simulation and deeming it a reliability criterion would, essentially, double-count its impact.

In most simulations, if the resources and load are in approximate balance, there is little or no un-served energy calculated. In the CA ISO market simulations demonstrating its Transmission Economic Assessment Methodology (TEAM), the model calculated no un-served energy except for two areas in Canada where hydro generation had not been completely optimized. The same phenomenon occurred in the CA ISO’s Palo Verde-Devers No. 2 feasibility study. There was no un-served energy except in Canada. Therefore, if the criterion is conceptually valuable but the simulations do not produce results allowing significant differentiation among alternative resource plans, some stakeholders suggest that that criterion is not valuable for comparative evaluation.

Consumers’ experience, however, has been that un-served energy actually does occur and ultimately results in higher costs for them. One might therefore surmise that the measurement of un-served energy is not truly reflective of outages that the consumer could experience. This seems to be an accurate assessment, and there are several reasons for it.. First, the calculation of un-served energy often does not take into account distribution outages, the most frequent cause of consumer outages. A market simulation model includes specific logic dealing with generation and transmission operation. It does not specifically model the distribution system because of the overwhelming complexity of detail this model would require. Second, many simulation models do not include transmission outages due to either the lack of available input data or simply the program's inability to model such outages. Third, the critical interrelationship between multiple transmission and generation outages has not been explicitly solved. Finally,, most models assume "perfect foresight" with respect to future loads. This sometimes overstates a system's actual ability to respond to both weather and load fluctuations.

Reduction in Reliability Payments

The CA ISO makes significant operational payments to ensure an acceptable level of reliability. These reliability payments include the following:

- Minimum Load Cost Compensation (MLCC) – Payments to generators that are kept at their minimum capacity in order to protect against major generation and transmission outages. In 2004, MLCC payments totaled $290 million.[19]
- Reliability Must Run (RMR) – Payments to generators to ensure their availability for reliability purposes when the CA ISO dispatches them. Total 2004 RMR payments were $650 million.[20]

Although the above costs are significant, a goal or criterion of minimizing these and other reliability payments by themselves would not be appropriate since they are only a portion of total system costs. These and other relevant reliability costs should be included in an overall objective to minimize total system costs. This is true whether the reliability costs are either directly computed in the simulation or derived separately and included as a post-processing operation.

Minimize Potential Terrorist Consequences

Since the New York terrorist attacks on September 11, 2001, minimizing the likelihood and consequences of terrorist attacks on the national electric grid has been a high national priority. The North American Electric Reliability Council (NERC) has been tasked by the federal government to coordinate critical infrastructure protection from physical and cyber attacks. The NERC has the responsibility to "develop a plan to reduce electric system vulnerabilities."[21]

NERC has developed security guidelines to help each utility develop a comprehensive "vulnerability and risk assessment." The guidelines are contained in a document providing a structured risk assessment methodology prepared by subject matter experts. The methodology includes:[22]

- Identification of assets and loss impacts.

- Identification and analysis of vulnerabilities.
- Assessment of risk and the determination of priorities for the protection of critical assets.
- Identification of countermeasures, their costs, and trade-offs.

A similar type of vulnerability and risk assessment could theoretically be developed at the state or regional levels to subjectively evaluate alternative resources or portfolios. The criterion of minimizing potential terrorist consequences could then be measured by using an appropriate risk assessment methodology.

Qualitative assessments of differences in reliability levels can currently be made for reliability impacts that are not mandated by reliability criteria or included as a portion of un-served energy costs. Further research is needed for modeling transmission and generation outages in a statistically relevant manner.

Least Cost

A traditional methodology for evaluating resource alternatives or portfolios is to compare resource options, based on direct costs. Direct costs can be defined in a number of ways: total system cost, revenue requirements, average consumer bills, or average system rates. These “least-cost” definitions can be used to evaluate transmission, energy efficiency, demand-response programs, renewable resources, distributed generation, and central station thermal generation alternatives.

Calculated direct costs must be comprehensive enough to include all cost components that could change between resource scenarios. These “least-cost” definitions are traditional measurements that have been well established in industry literature and regulatory proceedings. Since the traditional least-cost evaluation criteria are so well known and accepted, this report does not define the criteria in greater detail. For further information, refer to the CPUC definitions of cost components.

In addition to the many ways that least cost can be defined, there are also different perspectives on how to interpret it. These perspectives address the question of “least cost to whom?” Traditional perspectives include those based on geography (societal, sub-region, state, local area, or utility); or type of market participant (generator, transmission owner, and consumer, or a combination). Thus, when a least-cost methodology is used as a criterion to evaluate a resource portfolio, three parameters should be used to establish its application: least-cost definition, geography, and market participant.

There have been several enhancements to the traditional least-cost methodology over the years. One enhancement is including bidding strategies instead of simply using marginal costs to forecast energy prices. Another is the computation of an expected value, based upon many alternative cases instead of upon a single one.

Several additional enhancements to the least-cost methodology or criteria were suggested by various stakeholders during the survey portion of this report. They are summarized below.

"Modified" Tests – The CA ISO evaluates the economic feasibility of potential transmission upgrades by computing the benefits of the upgrade from three perspectives: the Western Electricity Coordinating Council (WECC), the CA ISO ratepayer, and the CA ISO participant. All three of these perspectives are "modified," in the sense that generator benefits derived from monopoly profits (non-competitive prices) are excluded from the benefits calculation. This methodology appears to be unique to the CA ISO, since other stakeholders surveyed do not exclude generator profits from project benefits.[23]

From the CA ISO's perspective, if consumer and producer benefits are equally weighted, the transfer of monopoly profits from the generator to the consumer nets to zero since total benefits remain the same. According to the CA ISO:[24]

> "To the extent that policy makers believe there is value in transferring supplier monopoly profits to consumer surplus, the modified societal perspective will be a more appropriate measure of a transmission upgrade than the pure societal test."

The CA ISO concludes that not all economists agree with this approach. However, the CA ISO provides both unmodified and modified tests so that policy makers can choose the most appropriate methodology on a case-by-case basis.[25]

Market Valuation – A common approach to measure economic viability is determining the value of a resource by comparing its benefits (determined by market prices) against its projected costs. Market value is based on valuing the resource's energy, capacity, and ancillary service capabilities against either a forward market curve or a forecast of market prices. The market price forecast needs to extend throughout the assumed economic life of the resource. This could be 20 years or more. Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) rely upon market valuation as one of their primary evaluation criterion in their "long-term request for offers," released earlier this year.[26]

One potential limitation of the market valuation approach is that it is more suited to a single resource or small resource portfolio than to a major generation station or transmission line. The larger the size of the project or portfolio of projects, the more likely it will impact market prices, limiting the validity of a static market price forecast calculated independently of the proposed resource additions.

***Portfolio Fit* –** The value of a resource is affected by its ability to complement or fit into an existing resource portfolio. If a particular resource portfolio is already surplus with must-run resources or must-take contracts, the value of additional energy is less than it would be to a portfolio where resource constraints have created an energy-deficit period. The concept of portfolio fit is expected to be used in both SCE's and PG&E's current long-term power procurements. Portfolio fit applies to energy, capacity, and ancillary services and has both temporal (time) and locational aspects. According to PG&E's Request For Offer (RFO):[27]

> "Portfolio fit thereby weighs a (resource's) costs and benefits in the context of (the system's) portfolio needs. In contrast, the market valuation component considers a (resource's) costs and benefits without taking into account (the system's) portfolio needs."

Portfolio fit is a valuable tool for company-specific, short- and mid-term resource evaluations. At the statewide level and for evaluation of 20-plus year resources, the portfolio fit measurement may have some limitations. For example, from a statewide perspective, long-term portfolios may require significant new resources. There is therefore much greater freedom to acquire and fit new preferred resources into the long-run, and at a state level, than there may be in the short- to mid-term at the company level.

Infrastructure Investments – Some energy resources may be economically attractive but have high initial capital costs such as a central-station base-load generation station or a major transmission line. These capital-intensive projects, with front-loaded cash requirements, can result in higher rates for the first few years compared with other alternatives. For most utilities, and particularly for many of the state's POUs, rate increases can be highly undesirable. Thus, load serving entities (LSEs) may have restrictions on the amount of capital they are willing to invest in infrastructure over a period of one, five, or 10 years. They evaluate alternative resource plans based on several factors, including capital requirements. A resource plan with a relatively high capital budget may be viewed as less desirable than one with equivalent lifecycle costs and risk but lower initial capital requirements.

***Market Competition* –** Part of the mission of the CA ISO is to ensure a competitive market for electricity in California.[28] It is important to the CA ISO and other stakeholders that resource futures be evaluated with respect to their anticipated potential for market power - when a market participant has the ability to raise prices significantly higher than the competitive energy market price.

One way to understand market power potential is to compare forecast market prices with underlying marginal costs. This approach is only valid if market prices provide a reasonable picture of the bid strategies potentially employed by generators to maximize their profits. The bid strategies in the market simulation model must be designed so they are generator owner-specific and dynamic (in other words, when bid strategies can change hourly depending upon system conditions and perceived market power.)

A major transmission upgrade can be very beneficial in this regard. A transmission expansion can allow a host of new, potential suppliers to compete for additional sales. On the other hand, a major generation project may not add significant new competition if the project is owned by one of the largest existing suppliers. And although market prices do not generally have a significant impact on societal benefits, the prices can have a major impact on benefits and costs to market participants, including California consumers.[29]

Seamless Markets – The creation of an electricity market that has seamless trading and operating practices within the WECC is an important goal for the region. As a result of utility interest, the Seams Steering Group – Western Interconnection (SSG-WI) was founded for the purpose of "facilitating the creation of a seamless western market and proposing resolutions for issues associated with differences in RTO (Regional Transmission Organization) practices and procedures."[30] For the CA ISO and other stakeholders, achieving a more seamless market is important to sustain a competitive and efficient California electric market.

Environmental

Generation and transmission resources can have significant environmental impacts. These impacts have been recognized for many years. In response to these environmental and other concerns, the state has developed policies for energy efficiency, renewable resources, and best-available control technologies. The current issue is not whether environmental impacts should factor prominently in the development of future resource plans but rather which impacts can be quantitatively or qualitatively compared and which ones are of greatest concern to Californians.

This section presents and discusses stakeholder-suggested environmental evaluation criteria. Many of these criteria cross over into other evaluation criteria categories such as least cost and risk. They are discussed here since their primary impacts are environmental.

Airborne Pollutants

Many stakeholders would likely agree with the Natural Resources Defense Council (NRDC) position on clean air and energy: "No element of the natural world is more essential to life than air, and no environmental task more critical than keeping it clean." According to the NRDC, electric generating plants are a major "source of air pollution and its myriad effects from lung damage to acid rain to global warming."[31]

In California, airborne emissions from generation plants of concern include:

- Carbon dioxide (CO_2)
- Carbon monoxide (CO)
- Nitrogen oxides (NO_x)
- Sulfur dioxide (SO_2)
- Particulates (PM_x)

These airborne emissions can be directly modeled in a detailed market simulation analysis, providing that reasonable data are available. The data required include emission rates for individual generation units (or composite rates for stations), and a cost (or range of costs) for each emission (generally specified in terms such as dollars per ton of emission emitted). The challenge is finding and acquiring the appropriate data. This is particularly true for CO_2 and other emissions which are of regional concern; for these emissions, the cumulative output of all generation sources in the WECC should be considered.

Aside from the difficulties inherent in modeling emissions and costs, some stakeholders suggested that emissions by themselves do not represent evaluation criteria. Rather, emissions have a cost associated with them that should be considered directly in the least-cost and risk criteria. Minimizing emissions beyond the point of recognizing their true societal costs, according to these stakeholders, is a form of double-counting and neither necessary nor appropriate.

Water Cooling

According to the Energy Commission, water use for power plant cooling can cause significant impacts on local water supplies. Since 1996, an increasing number of new power plants have been sited in areas with limited fresh water supplies. Use of fresh water for power plant cooling is increasing. Fresh water use can be reduced by using recycled or degraded groundwater, alternative cooling technologies, and closed cooling systems. These alternatives to fresh, high-quality water for once-through cooling are considered to be both technically feasible and practical.[32]

Therefore, comparing the amount of fresh water required for plant cooling could be an important criterion for alternative statewide resource strategies. This calculation would likely be a post-processing method where fresh water use per plant was estimated and summed with all other plants by region and state.

Transmission Impact

Some of the most heated siting discussions in the past 10 years have concerned new transmission rights-of-way. As a result of public sensitivities, one large POU has formally adopted a policy stating that it will maximize the use of existing rights-of-way before seeking to obtain new ones.[33] In addition to public concerns about transmission line visual impacts, there are environmental concerns such as migrating birds colliding with towers and their supporting wires.[34] Therefore, according to several stakeholders, the impact of a resource scenario involving new transmission lines should be evaluated and compared with alternative scenarios.

Amount of Renewable Resources

Most California utilities have already adopted specific renewables portfolio standards (see Chapter 2, "Current Minimum Requirements.") However, the fact that a particular statewide resource plan includes a greater level of renewable resources by a certain date could be an important distinguishing factor, according to several stakeholders. For example, the Energy Commission has asked the utilities, as part of the *2005 Integrated Energy Policy Report* process, to provide an "accelerated renewable scenario" with a longer-term goal of 33 percent renewable energy sources in 2020.[35] Some of the benefits of an increased level of renewable resources will be directly reflected in the least-cost and risk criteria, including reductions in emission costs and greater fuel diversity. However, not all benefits are captured in the modeling of direct costs, specifically the use of greater level of sustainable fuels. If studies were completed to demonstrate the net costs and benefits of various fuel types, subsequent resource plans might be able to use the resulting recommended percent of energy over the current renewable target as an important factor.

Fossil Fuel Dependency

The California League of Women Voters and other stakeholders have voiced a concern about reliance on fossil fuels, particularly oil and gas.[36] Their concern is that a continued dependence on fossil fuels increases airborne emissions, global warming, and rapid depletion of irreplaceable natural resources, among other reasons. The NRDC recommends that a simple pie chart showing California's annual energy requirement by production fuel type would be a valuable indicator of fossil fuel dependency and fuel diversity.[37]

Environmental Justice

The concept of environmental justice is that "all people – regardless of color, income, national origin or race are able to enjoy an equal amount of environmental protection."[38] The United States instituted a federal environmental justice program in 1994.[39] California adopted a similar environmental justice policy in 1999.[40]

The Bayview Hunters Point neighborhood in San Francisco is an example of some of the issues regarding environmental justice. There are approximately 1,100 households living within one mile of PG&E's Hunters Point Power Plant.. Two-thirds of this population lives in low-income public housing. Of the 1,100 households, approximately 70 percent are African American, 15 percent Asian (primarily Chinese and South Pacific Islanders), and the remainder Hispanic or Caucasian.[41]

Since Hunters Point is expected to be completely retired by March 2006, the remaining units have not been retrofitted with the most effective airborne emission abatement equipment and are currently out of compliance for NOx.[42] In 2003, the average NOx emission rate was .0394 pounds per million Btu (lbs/mmbtu), about 10-20 times higher than in plants using best-available control technologies. The total NOx emissions in 2003 were about 60 tons.[43]

According to residents of Bayview Hunters Point, “this low-income community of color” shoulders the burden of most of San Francisco’s pollution. Over the years the health of local residents “has been heavily and disproportionately impacted by the cumulative impact of pollution from PG&E’s Hunters Point Power Plant” and other facilities. The residents conclude that this “small community has suffered more than 50 years of apathy, neglect, and environmental racism.”[44] Thus, an evaluation criterion for alternative resource plans that measures, either qualitatively or quantitatively, how well the policy of environmental justice is being achieved is an important consideration.

Risk

Perhaps the one area of resource planning that has evolved the most in the last 10 to 15 years is assessing the risk associated with alternative resource portfolios. In the early 1990s, a risk assessment typically consisted of a few discrete scenarios illustrating the impact of adverse outcomes - like high load growth, high gas prices, low hydro, or individual segments of transmission lines out of service for extended periods of time. In the early to mid-1990s, as utilities started to turn to the evolving wholesale energy market for their resource needs, more sophisticated and rigorous portfolio assessments (which had been used for years by commodity trading institutions) were implemented, with various degrees of success.

Both traditional and more recently developed ways of evaluating risk criteria were provided by the stakeholders interviewed for this report. These resource evaluation criteria and methodologies are summarized and described below.

Quantitative Portfolio Analysis

Portfolio analysis is generally used by financial traders to create robust portfolios that are efficient – that is, they maximize the expected return for any given level of risk. With respect to resource evaluation, portfolio-based techniques can be used to help compare and evaluate the relative cost and risk of alternative resource plans.[45]

In the mid 1990s, energy companies began to measure their risk by computing various risk measurements such as “Value at Risk” or VaR. Value at Risk is based on the probability distribution for a portfolio’s market value. It indicates the maximum probable loss, given a specified confidence factor. For example, if a portfolio has a one-year 90 percent value at risk of $260 million, it can expect to lose less than $260 million 90 percent of the time.[46]

However, VaR is oriented toward active trading operations and values the portfolio at current market prices, without regard to long-term price or operational risks. For longer-term resource portfolios that cannot be instantly liquidated, other risk management approaches such as “Cash Flow at Risk” (CFaR) or “Profit at Risk” (PaR) are often considered to be better tools for measuring long-term risks. CFaR and PaR have an advantage over VaR since they incorporate energy price volatility and volume risks, including the amount of retail sales 10 years in the future.[47]

The CPUC has recommended that California utilities use “TeVaR (To Expiration Value at Risk), a type of value at risk model, to measure and report risk ... “[48] Specifically, it recommends using TeVaR measured on a 12-month rolling basis, at a 99 percent confidence level, and states that the “risk reporting could cover a longer period if the if the utility entered (into) longer-term transactions within the quarter.”[49]

These risk management techniques have significant value because they systematically capture and measure many of the risk elements for a resource portfolio. These approaches, however, also have the limitation that they can be difficult to compute, are data intensive, and do not represent all the risks that affect the value of a portfolio, such as changes in a wholesale market structure. For a more complete discussion of the application of portfolio theory to energy portfolios, refer to Appendix C.

Several stakeholders suggested that a portfolio analysis based upon these models would be the best way to evaluate the risk component of an energy portfolio. Others suggested that the computational and data requirements for such an intensive approach would be infeasible for most planning organizations and suggested a simpler approach.

This simpler approach treats selected variables stochastically and derives a distribution of system costs, and profits.. It then averages the lower 10 percent of the cases to derive an “average worse value” and computes the difference between the expected value or mean and the average worse value. The greater this difference, the greater the risk. Alternative resource portfolios can be measured and compared on this basis. If hydroelectric energy is the largest variable, a company can simulate 100 years of hydrologic conditions, average the worst 10 cases, then subtract that value from the mean. This technique is popular in the Pacific Northwest where hydro energy is such a large part of the energy mix. If a gas price uncertainty statistic is available, then both hydro and gas prices are treated stochastically with the appropriate correlation indices. For this second group of stakeholders, this approach is easier to compute and explain to their customers and regulators.

Qualitative Portfolio Risk Evaluation

The stakeholders also suggested a number of methods to evaluate the risk of resource portfolio from a qualitative perspective. These suggestions included:

- Resource diversity

- Energy autonomy
- Portfolio or project flexibility
- Market risks
- Political feasibility

Resource diversity is similar to fuel diversity – it helps decision makers quickly recognize the level of generation diversity in the resource mix. It can also indicate overall dependency on fossil fuels and relative increases or decreases in airborne emissions. A resource diversity summary table is also a valuable tool for helping the public understand significant differences between alternative resource portfolios or strategies.

Energy autonomy is another risk assessment that can be provided in a summary table or pie chart for various alternative portfolios. Based on the input from one stakeholder, energy autonomy is an important consideration since it demonstrates California's ability to meet its energy needs with its own resources. This criterion is opposite to another suggested criterion – facilitating seamless markets in which the magnitude of imports and exports are considered.

Portfolio or project flexibility refers to the ability of a resource to be modified to respond to unexpected events. For example, a transmission upgrade may have several "stepping-off" points where changes to the project, like modification or cancellation, could be made without the full commitment of capital funds. For instance, the full commitment to capital funds for a transmission project could be withheld until all permitting and rights-of-way are secured. Flexibility is a valuable consideration for decision makers and yet is frequently not considered in an economic evaluation.

Several stakeholders also proposed review of the feasibility of a proposed resource portfolio that considers potential market risk. If the economic viability of a proposed transmission upgrade is dependent upon the assumption that the entire WECC will be operating under a locational marginal rice market, it may be prudent to at least qualitatively consider the economic impact on the project if part of the WECC remains with a contract-path market. These considerations are generally too difficult to consider in a quantitative fashion, but should at least be thought through and qualitatively assessed.

One stakeholder thought that political risk should be considered. In other words, what is the likelihood that a resource portfolio will receive full approval and funding? If a proposed resource portfolio involves significant infrastructure investment, can this plan receive required approvals, or will political considerations cause the plan to be compromised to the point that it no longer provides a significant portion of the benefits of the original resource portfolio?

Other areas of stakeholder-suggested risk assessments included CO_2 regulatory risk and project viability. The CPUC found that the IOUs should use a greenhouse gas adder when evaluating new resources (CPUC D.04-12-048). The range of reasonable adders is considered to be $8 to $25 per ton.[50] Translated into $/MWh, the adders range from 4 to 15 $/MWh.[51] From this perspective, the risk associated with the unknown cost of CO_2 emissions can be considered to be major.

Project viability risk concepts have been reasonably well defined in recent request for offers released by the state's three IOUs. These risk assessments include project credit, viability, transmission impact, debt equivalence, and qualifications.[52] These concepts are valuable for the evaluation of individual transmission or generation projects but are less informative when applied to a diverse, long-term resource portfolios or strategies.

CHAPTER 4: RECOMMENDED CRITERIA

The first step in integrating transmission, generation, and demand-side alternatives in resource planning is to agree on evaluation criteria that are objective, transparent, and properly reflective of the long-term priorities of California's energy market participants.

This chapter presents recommended criteria. These recommendations are not conclusive and do not represent the final word on which evaluation criteria should be used for California transmission and resource planning across the board. Rather, the recommendations are intended to provide food for thought. The hope is that this report will help demonstrate the need for clear, comprehensive, and understandable evaluation criteria that can be used to better understand the benefits of transmission and other resources.

There are six evaluation criteria that are important for resource evaluation. While other stakeholder-suggested criteria are valuable, they were not selected because they were either more difficult to measure, less comprehensive in scope, or should be included in minimum requirements set by state policy.

The six recommended criteria are:

- Least Cost
- Reliability
- Risk
- Market Efficiency
- Fuel Diversity
- Resource Flexibility

Of the original four categories of stakeholder-suggested criteria in Chapter 3 (reliability, least-cost, environmental, and risk), only the environmental category is not explicitly represented in the final list of recommended criteria. The six stakeholder-suggested environmental criteria (amount of airborne pollutants, amount of renewable energy beyond RPS requirements, transmission impact, environmental justice, fossil fuel dependency, and once-through water cooling impacts and thermal pollution) were described in Chapter 3 and are also contained in Appendix B, along with possible measurements. A brief explanation of the consideration of each of these six environmental criteria is contained below. A more detailed discussion of these criteria can be found in the remainder of this chapter, as well as in Chapter 5.

Airborne Pollutants - - It is recommended that the cost of airborne pollutants be included in the analysis of least cost, as described in the section below entitled "Least Cost."

Amount of Renewable Energy Beyond RPS Requirements - - This criterion is captured in the fuel diversity recommended criterion. See section below entitled “Fuel Diversity.”

Transmission Impact - - The cost of environmental, cultural, and social mitigation of alternative resources is recommended to be included in the analysis of least cost, to the extent that these costs are quantifiable; this is described below in the section entitled “Least Cost.”

Environmental Justice - - This criterion is seen as a minimum requirement rather than a parameter that should be optimized since it is mandated by federal and state law. See the section below entitled “Criteria Not Selected.”

Fossil Fuel Dependency - - This criterion is captured in the fuel diversity recommended criterion. See section below entitled “Fuel Diversity.”

Once-Through Water Cooling Impacts and Thermal Pollution- - As discussed in the section below entitled “Criteria Not Selected,” this criterion is an example of an item that can be used for comparison if there are significant and relevant differences in annual water requirements and thermal impacts between resource alternatives. To the extent that these differences can be quantified and assigned costs, these costs would be included in the analysis of least cost.

Least Cost

Least cost can be interpreted from different perspectives and calculated in many different ways. It is inappropriate to dictate which specific formula should be used. Rather, it is left to the evaluator to determine the appropriate least-cost methodology, depending upon the purpose of the study. However, some consistent type of least-cost methodology needs to be established. The least-cost methodology should be comprehensive enough to calculate all quantifiable direct and indirect costs. These costs should include:

- Un-served energy
- Fixed payments to reliability units and those dispatched out-of-order
- Airborne pollutants
- Environmental, cultural, and social mitigation

Some of these costs can be incorporated into the market simulation, like cost of airborne emissions, and others may need to be computed separately, like mitigation costs.

Reliability

For the most part, reliability requirements are already incorporated into examinations of alternative resource portfolios. The sophisticated modeling tools used to produce case results take into account NERC, WECC, CA ISO, and utility criteria in their simulations. They are therefore considered to be minimum requirements and do not change between scenarios. The market simulation values differences in un-served energy between the alternative scenarios, and includes them in total system cost comparisons. Therefore, it does not need to be a specifically evaluated criterion. As noted earlier, the amount of un-served energy calculated in a market simulation is usually so small that it is considered to be an insignificant part of the total costs.

The reliability criterion that can change from one portfolio to another, and thus be considered a legitimate evaluation criterion, is the qualitative consideration of extreme reliability events that would be better mitigated by one resource portfolio versus another. For example, assume one of the options for San Francisco is to increase the capacity of an existing transmission line bringing power north from the Peninsula. Assume that another option is to build a trans-bay cable. If both alternatives met the same NERC, WECC, and CA ISO reliability criteria, and the un-served energy for each is directly calculated in the market simulation, no additional reliability benefits would be noted in the analysis. However, in the extreme event of a fire, earthquake, or terrorist act eliminating the Peninsula's transmission capability, the trans-bay cable option would have the additional advantage of providing another corridor of power. Thus, the differential reliability benefits not mandated or captured in the market simulation should be qualitatively described, evaluated, and considered.

Risk

There are several comprehensive risk computational methods based on portfolio theory. These calculations are often too data and computationally intensive to be routinely used in most planning departments.

On the other hand, risk is much too important to ignore simply because of its potential complexity. After least-cost, many consider risk to be the second most important evaluation criterion. It is therefore essential that risk be considered in a way that can be calculated on a routine basis and used for comparative purposes.

Since understanding risk is very important in analyzing alternative resource strategies, a reasonable alternative would be to consider it in some type of standard way. This would be superior to either ignoring it or adopting a rigorous, inflexible definition of portfolio risk that is beyond the scope and capability of many planning groups. Besides, since the calculation of portfolio risk is both rigorous and complex, it often creates a false sense of confidence in the exact boundaries of uncertainty in any given portfolio. This sense of having established risk boundaries can be deceptive when the greatest risk factors cannot be readily considered in a quantitative manner.

Many entities derive a distribution of potential costs, compute the expected cost, and then calculate an average worst case. This can be a single case, or it can be the average of the worst 5 to 10 percent of cases. The difference between the expected cost and the average worst case is then computed and used as a measurement of risk. Therefore, either a formal calculation of a risk index ,such as cash flow at risk (see Appendix C), or a less rigorous calculation of the difference between expected and average worst case, could be an acceptable way of assessing risk. If any of these calculations are established as evaluation criteria, they can be helpful provided they are used consistently in routine decision making.

Market Efficiency

If the energy market is efficient, competitive prices exist and adequate generation resources are built and funded through revenues from energy, capacity, and ancillary services. If the market simulation model employs bidding strategies that are dynamic, the resulting simulated market-clearing prices can be compared with underlying competitive prices like the marginal cost of resources used in the simulation. A market efficiency index can then be developed. If a marginal cost market is modeled, or if static bid strategies are used (when bids are static or unchanged for a period of time independent of system and market conditions), the market efficiency calculation will have little or no value. However, currently computed, the market efficiency evaluation criterion can be a valuable indicator of how well markets are operating and providing energy to consumers at competitive prices.

Fuel Diversity

Fuel diversity is partially considered in the least-cost and risk criteria. If there is a significant amount of fuel diversity from renewables, then airborne emission costs are reduced and the reduction is reflected in the least-cost comparison. Fuel diversity is also apparent in the risk criterion since fuel diversity reduces risk and helps mitigate the effects of adverse outcomes.

Another way to approach risk is to use a method suggested by the NRDC. This method suggests that a simple pie chart of fuels, used for a given resource strategy, is an effective way to understand fuel diversity. Because there are a number of identified benefits associated with fuel diversity that are not necessarily captured by the least-cost and risk criteria, fuel diversity is recommended as a preferred evaluation criteria. For example, reducing fossil fuel dependence is an important goal of many California market participants. Additionally, not all airborne emissions can be quantified in the least-cost evaluation and not all risk impacts from choice of a fuel mix can be fully recognized in a standard risk analysis.

Resource Flexibility

Resource alternatives and plans that have both flexible timing and commitments of capital funds and the ability to respond to changes in expected conditions are more valuable than those with no flexibility and requirements for substantial expenditures early in their project lifecycles.

Unfortunately, inherent flexibility is sometimes traded away in contract negotiations. For example, merchant transmission projects may have significant advantages in keeping capital and operating costs down and reducing the risk of completion. However, if a contractual commitment for use of the transmission line is required before the permitting and licensing activities are initiated, some resource flexibility is lost. Typically, one can complete the permitting and licensing of a transmission project while spending less than 10 percent of total capital costs. For a decision maker, this spending schedule is valuable in that the decision to commit significant amounts of capital funds can be delayed for two to three years when more information is available and rights-of-way and environmental risks are more fully understood.

Therefore, it is important to at least qualitatively consider the comparative benefits of resource flexibility when evaluating alternatives.

Criteria Not Selected

Chapter 5 notes that many suggested criteria were not selected as recommended evaluation criteria. In some cases, the criteria were judged to be more appropriate for single resource or small portfolio comparisons than for evaluating alternative resource plans and strategies at the statewide level. These criteria included market valuation and portfolio fit.

In other cases, the criteria were determined to be minimum requirements rather than parameters to be optimized. One example is environmental justice. Treating people fairly is a basic mandate and should be a given for all resource alternatives, not a variable to be fine-tuned or tweaked until the appropriate result is achieved.

Finally, some criteria were thought best left to the judgment of the group performing the evaluation, to be included in something like an “other” category. Evaluation criteria such as once-through water requirements, cultural and visual issues, project viability, political feasibility, and third-party credit worthiness are examples of issues that could be used for comparison if there are significant and relevant differences in those categories. Otherwise, if the differences in these areas are not particularly significant, these criteria would not be added to the standard evaluation list.

CHAPTER 5: SUMMARY

All of the stakeholder-provided resource evaluation criteria are important. However, not all of the criteria can be included if the goal is to is formulate a standard set of criteria than can be used by planning departments without an unfeasible level of staffing, software models, and data collection. The six criteria selected were identified as providing the best balance between the need for pertinent and comprehensive evaluation criteria and an organization's ability to perform this work in a timely manner.

Table 1 summarizes the recommended criteria.

Table 1

Recommended Evaluation Criteria

Evaluation Criterion	Measurement Description	Criterion Derivation
Least-Cost	Compute present value of costs for appropriate perspective	Computed
Reliability	Summarize reliability improvements not required or quantified	Subjective
Risk	Determine difference between expected and average worse case	Computed
Market Efficiency	Compare market prices to competitive costs	Computed
Fuel Diversity	Summarize energy consumed by originating fuel source	Subjective
Resource Flexibility	Describe capital fund flexibility for resource commitments	Subjective

To evaluate the least cost among alternatives, an entity should perform one or more of the least-cost calculations. Least cost can be viewed from the perspective of relevancy to the planning group (societal, California, CA ISO, utility, consumer, generator, transmission owner) and defined in a way that is most meaningful to the evaluating group.

An evaluation of reliability should consider only those factors that are <u>not</u> considered to be requirements or that are already included as un-served energy costs.

Risk can be computed in a number of acceptable ways. Some indication of the maximum credible risk should be developed for variables that are quantifiable. A qualitative assessment should be provided for critical variables that cannot be quantified or measured.

Market efficiency should be considered providing that the underlying market simulation allows for reasonable modeling of changing bid strategies and examination of any resulting market power. The market efficiency index should <u>not</u> be calculated using more basic market simulation models where conclusions regarding market efficiency could be misleading.

Fuel diversity can be effectively represented by a simple pie chart showing the fuels used to produce energy consumed.

Resource flexibility is a qualitative measurement that can be used when there are significant advantages or disadvantages for the commitment and use of capital funds.

In summary, two of the suggested criteria are mandatory in all cases: least-cost and reliability. Both are computed from underlying data in a quantitative manner. The remaining indices should be used as appropriate – when there are large differences between alternative resource strategies and when these differences can be recognized. Three of the remaining suggested criteria – reliability, fuel diversity, and resource flexibility – need to be qualitatively evaluated and compared. The fourth remaining criterion - market efficiency – can be directly calculated as appropriate.

APPENDIX A: ORGANIZATIONS PARTICIPATING IN THE STAKEHOLDER SURVEY

1. California ISO (CA ISO)
2. California Public Utilities Commission (CPUC)
3. California Utilities Employees
4. California Wind Energy Association (CWEA)
5. Center for Energy Efficiency and Renewable Technologies (CEERT)
6. Constellation NewEnergy
7. Environmental Law and Justice Clinic, Golden Gate University
8. FPL Energy
9. Independent Energy Producers Association (IEPA)
10. League of California Cities
11. Los Angeles Department of Water and Power (LADWP)
12. Mirant California LLC
13. Natural Resources Defense Council (NRDC)
14. Northern California Power Agency (NCPA)
15. Pacific Gas and Electric Company (PG&E)
16. Pasadena Water and Power
17. Sacramento Municipal Utility District (SMUD)
18. San Diego Gas and Electric (SDG&E)
19. Southern California Edison (SCE)
20. The Utility Reform Network (TURN)
21. Trans-Elect, Inc.
22. Utility Consumers' Action Network (UCAN)

APPENDIX B: SUMMARY OF STAKEHOLDER-SUGGESTED CRITERIA

Category	Minimum Requirements	Proposed Criterion	Possible Measurement	Suggested by Stakeholder(s)
Reliability	NERC, WECC, and CAISO	Un-served energy	reflected in direct cost by using an appropriate value for un-served energy	many
		reduction in reliability-must-run (RMR) contracts and minimum load cost compensation (MLCC) costs	goal is to properly include RMR and MLCC costs in market simulation by modeling generation commitment accurately	CA ISO, generators
		minimize likelihood and consequences of terrorist attacks to power system	NERC-defined "Vulnerability and Risk Assessment"	many
Least-Cost	none specified	ratepayer total cost	present value (PV) of CA cost-to-load (CTL), net of utility-owned generation and transmission net revenue	many
		ratepayer rate	estimate rate impact due to increase in CTL	municipals, others
		societal cost	PV of WECC total production and fixed costs	many
		modified ratepayer cost	PV of CA modified CTL (excludes gen. profit from uncompetitive conditions), net of utility generation and transmission net revenue	CAISO
		modified participants cost	PV of CA modified CTL (excludes gen. profit from uncompetitive conditions), net of CA market generation and transmission net revenue	CAISO
		market valuation	NPV of project benefits compared to costs	utilities
		portfolio fit	reflected in ratepayer, participant, or societal cost (or market valuation)	utilities
		market competitiveness	CA weighted avg. price / cost mark-up	CAISO
		Seamless markets	average annual volume of imports and exports	CAISO
		Infrastructure investments	total capital requirements for next 5 and 10 years	utilities

Category	Minimum Requirements	Proposed Criterion	Possible Measurement	Suggested by Stakeholder(s)
Risk	none specified	CO_2 regulatory risk	include CO_2 cost in market simulation, consider as uncertain variable	many
		resource diversity	energy % from different resource categories in CA (DSM, DG, solar, natural gas, etc.)	NRDC, others
		project viability	qualitative evaluation regarding whether project will be built and perform according to expectations	utilities
		risk of extreme outcome	compute difference between expected cost, and average of worse 10 percent of cases	many
		insurance value	impact of extreme cases on overall expected value is already considered, risk premium could be quantified by estimating cost of obtaining equivalent coverage through other market instruments	CPUC, others
		payoff tables	information could be summarized into tables that indicate when decision is beneficial (or not); possible simplification is histogram	CPUC
		political feasibility	qualitative evaluation regarding risk relative to public and political support for project or resource scenario	CPUC
		cost overruns	qualitative assessment of ratepayer risk of incurring additional costs in the future due to cost overruns	IEPA
		project flexibility	qualitative assessment of how flexible resource decision and capital fund commitment is to changes in external factors	CPUC
		no additional infrastructure	risk should be measured against a base case of "doing nothing"	IEPA
		market changes	qualitative assessment of sensitivity of resource decisions to changes in market rules in CA and elsewhere	generators, CPUC
		counter-party, credit, debt equivalence	currently undefined	munis
		energy autonomy	amount of out-of-state annual imports	consumer groups

Category	Minimum Requirements	Proposed Criterion	Possible Measurement	Suggested by Stakeholder(s)
Environmental	CPUC RPS, DSM, DG goals	amount of airborne pollutants	include CO_2, NOx, SO_2, and particulate costs in market simulation	many
		amount of renewable energy beyond RPS requirements	percent of energy met by renewables in excess of RPS goal for that year	CEERT, others
		transmission impact	number of miles of new right-of-way, visual and environmental impact	utilities
		environmental justice	compare MWs of new projects built in low- versus higher-income zip codes; also consider population	consultant, others
		fossil fuel dependency	percent of energy needs met by fossil fuel	NRDC
		once-through water cooling impacts and thermal pollution	annual water requirements, thermal impact	CEERT, CEC

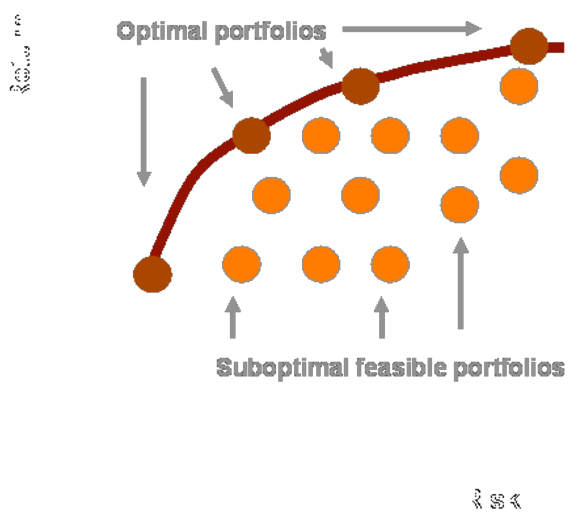
APPENDIX C: RISK, PORTFOLIO THEORY, AND TRANSMISSION PLANNING

Modern finance theory is well developed, with its tools increasingly being used in the electric power industry. In electricity planning exercises, it is commonly appreciated that risk is an important consideration.[53] A natural question that arises is, how well can the risk management methods of finance be applied to transmission planning?

Portfolio theory generally refers to the collection of financial models that describe how an investor might balance risk and reward in constructing portfolios. It answers the question: Among the feasible portfolios, how do I identify the best ones?[54] Classical portfolio selection consists of identifying the portfolios that maximize return for a given level of risk or, equivalently, that minimize risk for each given return.[55] The set of optimal portfolios form the widely recognized *efficient frontier*. When plotted with risk on one axis and return on the other, the efficient frontier identifies the optimal portfolios.

Figure 1

Portfolio Efficient Frontier



In Figure 1, the feasible portfolios are indicated with solid dark circles. The thick convex line indicates the efficient frontier, along which fall the set of optimal portfolios. In order to increase the return of a portfolio on the efficient frontier, one would have to increase risk. This is in contrast to the suboptimal portfolios which lie to the right and below the efficient frontier: in these, portfolio expected return can be increased by rearranging the asset mix without increasing portfolio risk.

A key insight of portfolio theory is called the portfolio effect: the addition of a low-risk, low-return asset to the portfolio that is not highly correlated to the existing assets in the portfolio will produce higher risk reduction relative to the return reduction from adding the asset to the portfolio. In other words, portfolio diversification lowers risk and/or increases returns.

Beyond providing important insights, portfolio theory is widely used in finance and other fields for a practical reason: computational ease. Its computational ease, however, derives from several key assumptions, one of which is that the standard deviation (the measure of spread in a distribution) represents risk.

There are several concerns with the use of standard deviation as a measure of risk. One is simply that two very different distributions can have the same mean and standard deviation. Yet the use of standard deviation as risk measure is unable to tell us anything about those differences. It ignores potentially valuable information about risk.

As a result of the shortcomings of the use of the standard deviation as risk measure, alternative measures have been developed, the most common of which are the “at risk” variety, such as Value at Risk (VaR) and the closely-related Cash Flow at Risk (CFaR).

VaR measures the possible change in value of a portfolio over a specified period, with a certain level of probability, caused by changes in quantifiable market risk factors. It answers the question: what is the maximum portfolio loss (or other performance measure) at a specified confidence level? The appeal of the VaR – and the “at risk” family of measures in general – is that risk is boiled down to one number (i.e., summary statistic) that is conceptually easy to understand and to compare to alternative portfolios.[56]

A variation on VaR is CFaR, which better deals with assets that cannot be marked to market or whose position cannot be closed at any time (e.g., on the forward market.)[57] Fixed assets or illiquid forward markets generally suggest the use of CFaR rather than VaR.

The academic literature has recently turned its attention to the development of additional measures of risk. The fruit of this effort is a measure of risk called Conditional Value at Risk (CVaR), also known as Expected Tail Loss or Expected Shortfall.[58] CVaR is surprisingly easy to understand: it is simply the average (expected value) of the tail, i.e., the distribution beyond VaR.

The CPUC has recommended that California utilities use "TeVaR (To Expiration Value at Risk), a type of VaR model, to measure and report risk ..."[59] Specifically, it recommends using TeVaR measured on a 12-month rolling basis, at a 99 percent confidence level, and state that the "risk reporting could cover a longer period if the utility entered (into) longer term transactions within the quarter."[60]

We briefly return to the portfolio selection problem. Once defined, the VaR (CFaR) or CVaR (ECFaR) can be defined as a constraint in the portfolio optimization problem, thereby forcing the feasible set of portfolios to respect the defined risk measure.

The use of portfolio theory for electricity planning and policy analysis is rapidly gaining favor. Work by the Northwest Power and Conservation Council (NPCC) provides an illustrative large-scale resource planning applications.

The Northwest Power and Conservation Council's 5th Power Plan is an impressive application of portfolio theory and risk measures. Its "risk-constrained least-cost planning approach" considers a multitude of possible futures ("combinations of sources of uncertainty, usually specified over the entire … study") for each plan ("actions and policies over which the decision maker has control that will affect the outcome of decisions.") In total, the analysis considers 750 futures over some 1000 alternative plans. The performance measure is the net present value of total system cost associated with each plan.

Replacing portfolio return with total system costs, and portfolio with resource plan, one can quickly see this analysis as an application of portfolio theory. It should come as no surprise, then, that an efficient frontier can be obtained describing the optimal (i.e., least cost) plans for different levels of risk. Risk, as defined in this study, is defined as the average of the total system cost outcomes above the 90 percent threshold (90th percentile) or, equivalently, the 10 percent worse outcomes in each plan.

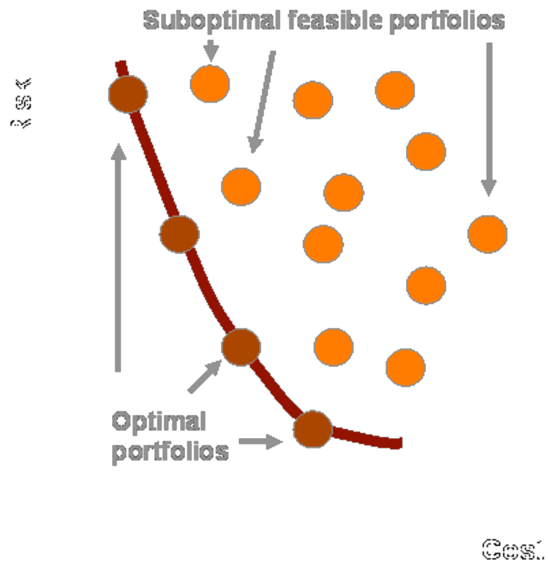
In order to prevent the problem from exploding (due to dimensionality), however, various simplifying assumptions were made, including:

- aggregation of similar generating units
- inter-temporal aggregation of generation capacity factors and costs over one or more months
- quarterly hydro generation profiles (on and off peak)
- no inter- or intra-transmission constraint modeling (although regional imports and exports limited to 6,000 MW.)

Figure 2 represents the efficient frontier in the context of total system cost, where now system cost is being traded off with risk.

Figure 2

The “Plan” Efficient Frontier



In a footnote of its Power Plan, the NPCC cites a simulation time estimate had they used Aurora, a production cost simulation model: 85 years. That estimate would likely assume the simplest modelling of transmission (i.e., in transport mode.) For utility or regional resource planning, it may be reasonable to abstract from detailed modeling (or any modeling, for that matter) of transmission. But, transmission planning without modeling some spatial element appears to be a contradiction in terms.

Considering spatial elements, however, increases the breadth of the problem. How much spatial or network detail is required to identify the “need” for a transmission upgrade? The answer to this question will probably speak to the plausibility of using portfolio theory for the purposes of transmission planning.

ENDNOTES

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[4] See the Energy Commission website at http://www.energy.ca.gov/2005_energypolicy/notices/2005-07-28_hearing_notice.html.

[5] See NERC's website at http://www.nerc.com/ .

[6] Ibid.

[7] California Public Utilities Commission (CPUC) Decision 04-07-028, "Interim Opinion Regarding Electric Reliability Issues," July 8, 2004, p. 3.

[8] CPUC Decision 04-07-028, p. 5.

[9] Discussion with Mohammed Beshir, Manager of Resource Planning and Development, LADWP, April 14, 2005.

[10] CPUC Decision 04-09-60, "Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond," September 23, 2004, pp. 2-3.

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[20] Ibid, p. 6-11.

[21] "Security Guidelines for the Electricity Sector," Critical Infrastructure Protection Committee, North American Electricity Reliability Council, p. 1, http://www.nerc.com/~filez/cip.html.

[22] NERC Security Guidelines, p. 3 of 5.

[23] CA ISO Transmission Economic Assessment Methodology Report, pp. ES-6 and ES-20.

[24] Ibid, p. 2-18.

[25] Ibid, p. 2-18.

[26] For example, see PG&E's "2004 Long Term Request For Offers Power Purchase," March 18, 2005. p. 8 (see website: http://www.pge.com/suppliers_purchasing/wholesale_electric_supplier_solicitation/ltpp_rfo2004.html).

[27] PG&E Request For Offers, p. 8.

[28] CA ISO Mission Statement (see website: http://www.caiso.com/surveillance/overview/Mission.html).

[29] By definition, the societal benefit of any resource addition is the difference in production and capital costs for two cases -- one "with" the project, and one "without." This production and capital cost difference is often only slightly impacted by market prices, since the market prices can cause a distortion to the least-cost generation commitment and dispatch.

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[31] "Clean Air and Energy," Natural Resources Defense Council (NRDC), (see website: http://www.nrdc.org/air/default.asp).

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[34] Interview with Dr. Richard Ferguson, Director of Research, Center for Energy Efficiency and Renewable Technologies (CEERT), May 4, 2005.

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[40] Senate Bill 115 (Chapter 690, Statutes of 1999) authored by Senate Member Hilda Solis (D El Monte), see website: http://www.calepa.ca.gov/EnvJustice/Legislation/#Senate).

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[42] "Update on Action Plan for San Francisco," California Independent System Operator, memo from Gary DeShazo and Julie Gill to the ISO Operations Committee, June 8, 2005, p. 1.

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[45] "Applying Portfolio Theory to EU Electricity Planning and Policy-Making," International Energy Agency, Report Number EET/2003/03, Shimon Awerbuch and Martin Berger, Paris, February, 2003, p. 4.

[46] Riskglossary.com (see website: http://www.riskglossary.com/link/riskmetrics.htm).

[47] "US Merchant Energy Sector Adds Tool to Weigh Risk," The Power Report, The Power Marketing Association, Sept. 12, 2003 (see website: http://powermarketers.netcontentinc.net/newsreader.asp?ppa=8knsoZZfhpsswrTThe'%40%3E+bfeiZv).

[48] "Walwyn Agenda Dec. on Electric Procurement Planning," CPUC, December 12, 2003 (see website: http://search.cpuc.ca.gov/query_portal.html?col=adocs&col=agda&col=cdecs&col=cpuc&col=cres&col=dcals&col=fdocs&col=gos&col=ora&col=pres&col=proc&col=rep&col=rul&ht=0&qp=&qt=TeVAR&qs=&qc=&pw=100%25&ws=0&qm=0&st=1&nh=10&lk=1&rf=0&rq=0&si=1 .

[49] Ibid.

[50] "PG&E Electric Resource Supply and Transmission Plan," April 1, 2005, p. 19 (CPUC D.04-12-048).

[51] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, p. 26.

[52] "2004 Long-Term Request For Offers, Power Purchase," Pacific Gas and Electric Company, p. 12.

[53] For the purposes of this discussion, the formal economic definition of risk is the condition under which it is possible both to define a broad set of possible outcomes and to be able to assign

probabilities to those outcomes. This narrower definition of the term is used in order to guide the discussion and frame our conclusions.

[54] Best here refers to the normative criterion used in economics, namely Pareto optimality. An allocation of resources is Pareto optimal if it is impossible to change the allocation in a way that would make someone better off without at the same time making someone else worse off.

[55] More specifically, the optimization seeks to identify the vectors of asset shares that satisfy constraints, and providing minimum total variance and total maximum return.

[56] This attribute is particularly important for senior managers.

[57] Earnings at Risk are sometimes identified separate from CFaR in the financial industry. We abstract from any difference between these measures for the purposes of this discussion.

[58] Analogously, Extreme Cash Flow at Risk measures have been developed to resolve the same issues with CFaR.

[59] "Walwyn Agenda Dec. on Electric Procurement Planning," CPUC, December 12, 2003 (see website: http://search.cpuc.ca.gov/query_portal.html?col=adocs&col=agda&col=cdecs&col=cpuc&col=cres&col=dcals&col=fdocs&col=gos&col=ora&col=pres&col=proc&col=rep&col=rul&ht=0&qp=&qt=TeVAR&qs=&qc=&pw=100%25&ws=0&qm=0&st=1&nh=10&lk=1&rf=0&rq=0&si=1 .

[60] Ibid.