Chapter 3
Alternatives Analysis

CALIFORNIA
ENERGY
COMMISSION

DISTRIBUTED GENERATION AND COGENERATION POLICY ROADMAP FOR CALIFORNIA

STAFF REPORT

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

Mark Rawson and John Sugar
Co-Authors

John Sugar
Manager
PUBLIC PROGRAMS OFFICE

Valerie T. Hall
Deputy Director
EFFICIENCY, RENEWABLES & DEMAND ANALYSIS DIVISION

B.B. Blevins
Executive Director

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ABSTRACT

This report defines a year 2020 policy vision for distributed generation and cogeneration for California. It also defines megawatt penetration targets for different distributed generation technologies and cogeneration. Additionally, this report describes long-term strategies, pathways, and milestones to take California from today's situation to attain the 2020 vision and the distributed generation and cogeneration capacity targets.

KEYWORDS

Distributed generation, cogeneration, photovoltaics, wind, biomass, combined heat and power, roadmap

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EXECUTIVE SUMMARY

Distributed generation (DG) and cogeneration are seen by many as potentially attractive energy resource options for California, both in the near-term and long-term. They can provide added capacity to meet peak demand, provide additional energy supply, and can be integrated into the current electrical infrastructure to reduce congestion. However, DG and cogeneration are, in many regards, major departures from how energy is procured, generated, and delivered to end-use customers. Therefore, policy issues need to be considered in a comprehensive, integrated approach.

In this context, staff defines DG as electricity production that is on-site or close to a load center and is interconnected to the utility distribution system. In practical terms, this limits the definition of DG to less than 20 megawatts (MW) since systems larger than this would be interconnected at sub-transmission or transmission system voltages. This definition includes such technologies as photovoltaics; small wind; small biomass; small combined heat and power (CHP) or small cogeneration; small combined cooling, heat and power (CCHP); and small non-CHP systems.

Cogeneration is defined as electricity and heat production that is on-site or close to the load center that could be interconnected at distribution, sub-transmission, or transmission system voltages. Cogeneration in many instances can be systems from several kilowatts (kW) to hundreds of MW in size. For this roadmap, staff will define DG to mean systems less than 20 MW (including small cogeneration) and large cogeneration to mean systems greater than 20 MW.

Just as it is important to define what is considered DG and cogeneration, it is equally important to define what is not considered DG or cogeneration for the purposes of this roadmap. Hydroelectricity, geothermal, and non-CHP-related digester gas, landfill gas, and municipal solid waste are not considered DG as load is typically not close to generation and onsite load is negligible. Large (>20 MW) wind and large biomass projects are not considered DG as they are not likely to be interconnected at the distribution level.

The DG and Cogeneration Policy Roadmap (Roadmap) will provide a long-term perspective for DG and cogeneration policy. The Roadmap includes a 2020 DG and Cogeneration Vision and a Pathway with detailed actions and milestones for implementing policies. The Roadmap responds to current energy policy as directed by the *Integrated Energy Policy Report* (IEPR) and the *Energy Action Plan* (EAP).

The 2020 DG and Cogeneration Vision will require some new energy policy initiatives, which neither the EAP nor IEPR processes have addressed to date. The Roadmap presents potential policies to consider and the timing necessary to implement those policies for California to attain the 2020 DG and Cogeneration Vision. To continue pursuit of the Vision, the Roadmap will need periodic updates to adapt to and reflect changes in related policies and conditions. Implementing this

Roadmap will require the participation of agencies and stakeholders outside the Energy Commission.

The current regulatory framework encourages DG through subsidies, incentives, and recognition of DG in procurement and planning processes. Rules and regulations have been developed and put in place that encourage some forms of DG. The current rate structure in California is based on controlled averaged pricing. Externalities (for example, environmental impacts and locational value) are not incorporated into these rates. This approach assumes, from the customer's perspective, all electrons have the same value regardless of how, when, and where they were generated. Lack of a price signal that will change customer behavior undervalues the environmental, temporal, and locational aspects of many resources, including DG and cogeneration. In addition, the California Independent System Operator (California ISO) rules (for example, high DG aggregation requirement and metering requirements) highly discourage DG and cogeneration customers from participating in wholesale markets.

Large cogeneration is a major component of the generation fleet in California, serving about 15 percent of the peak demand in California. Most of these systems are long established and provide heat and electricity to industrial applications such as petroleum refining, paper, food processing and primary metals. Other significant cogeneration exists in the commercial sector for wastewater treatment facilities. Despite being a mature industry, the cogeneration industry struggles to sustain itself in California primarily due to market and some institutional barriers.

The DG industry is still a nascent industry that survives despite some difficult market conditions. There are numerous institutional, industry and market barriers that have impeded the growth and adoption of DG to date. Due to low penetration rates, DG installations do not have a large impact on, nor is it integrated with, the state's electric and natural gas infrastructures.

Although DG's potential is recognized, it is not currently a significant energy resource. The current DG penetration is 2.5 percent of total peak demand in California. As a result, many projects are highly customized and rely on incentives. The industry is fragmented with many small developers installing PV and natural gas engines provided by large equipment suppliers.

The Energy Commission staff developed a DG and Cogeneration Vision (Figure ES-1) based on current policy, future scenarios, and the market potential for DG and cogeneration:

California 2020 DG and Cogeneration Vision Statement
DG and cogeneration are significant components of California's electric system, meeting over 25% of the total peak demand. • Customers have multiple options, including DG and cogeneration, to consider as part of their energy sourcing strategy. • DG (customer and utility-owned) and cogeneration are integral to procurement, Transmission and Distribution planning and operations. • A robust DG industry fulfills consumer and utility needs for affordable clean DG. • Large cogeneration has maintained and increased its position as an important resource to California, and these facilities can readily participate in the wholesale power market. • Transparent, dynamic rates and market structures are in place that account for environmental attributes and incorporates locational and temporal power system needs. • The Renewables Portfolio Standard (RPS) mandates were satisfied, and there is no new RPS mandate. Regulated incentive programs have been phased out, and no new incentives are being put in place. • Other barriers to DG have been removed and all DG permitting is efficient and environmentally responsible.

Table ES 1: 2020 DG and Cogeneration Vision Statement

To achieve its Vision, California will implement a strategy with three key elements:

1. *Support Incentives in the Near-term* – Over the next 10 years, California should continue to provide incentives for DG and cogeneration. Many of these incentives are identified in the IEPR, or are implemented by the California Public Utilities Commission (CPUC). However, these incentives will be discontinued over time as DG and cogeneration gain access to other markets.

2. *Transition to New Market Mechanisms* – To remove incentives and still encourage vibrant growth of DG and cogeneration in California, incentives will have to be replaced with market mechanisms, including transparent dynamic rates, which encourage DG and cogeneration. The roadmap will transition to these market mechanisms through – portfolio standards; allowing DG and cogeneration to compete more directly with central plants and traditional T&D; and providing access to emissions markets.

3. *Reduce Remaining Institutional Barriers* – California has made tremendous strides in the past several years in removing barriers to DG and cogeneration. However, there is still work to be done. The last strategic thrust addresses remaining barriers.

CHAPTER 1: INTRODUCTION

Need for Policy Roadmap

Distributed generation (DG) and cogeneration are potentially attractive energy resource options for California, both in the near-term and long-term. The DG and cogeneration concepts are major departures from how energy is procured, generated, and delivered to end-use customers. This raises many regulatory issues that public policy makers need to address in an integrated manner. In 1999, California made a concerted effort to begin to address policy issues related to DG[1]. Since that time the *Integrated Energy Policy Report* (IEPR) and *Energy Action Plan* (EAP) process has become the main policy planning activity for energy in California. In the *2005 IEPR*, the Energy Commission addressed further policy issues for DG and expanded the discussion to cogeneration.[2] The IEPR/EAP process is the vehicle for state energy policy and drives all energy policy. While this process has provided a focal point for integrated policy discussions and has included many DG and cogeneration related issues, it is not a vehicle to provide implementation of DG and cogeneration specific policy.

DG and Cogeneration Definition

Defining what is and is not DG has continued to be an issue in California. In the last DG rulemaking at the CPUC, parties could not reach consensus on a definition. In the *2005 IEPR*, stakeholders had varying definitions for DG and cogeneration. For this report, staff defines DG as electricity production that is on-site or close to a load center and is interconnected to the utility distribution system. In practical terms, this limits the definition of DG to less than 20 megawatts (MW) since systems larger than this would typically be interconnected at sub-transmission, or transmission system voltages. This definition includes such technologies as photovoltaics; small wind; small biomass; small combined heat, and power (CHP) or small cogeneration; small combined cooling, heat, and power (CCHP); and small non-CHP systems.

Cogeneration is defined as electricity and heat production that is on-site or close to the load center that could be interconnected at distribution, sub-transmission, or transmission system voltages. Cogeneration in many instances can be systems from several of kilowatts (kW) to hundreds of MW in size. For the purposes of this roadmap, staff will use the DG definition to mean systems less than 20 MW (including small cogeneration) and large cogeneration to mean systems greater than 20 MW.

Just as it is important to define what is considered DG and cogeneration, it is equally important to define what is not considered DG or cogeneration for this roadmap.

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[1] California Energy Commission, *Distributed Generation Strategic Plan*, Publication # P700-02-002, June 2002

[2] California Energy Commission, *Integrated Energy Policy Report*, Publication #CEC-100-2005-007CMF, November 2005

Hydro, geothermal, digester gas, landfill gas, and municipal solid waste are not considered DG as load is typically not close to generation and onsite load is negligible. Large (>20 MW) wind and large biomass projects are not considered DG as they are not likely to be interconnected at the distribution level, nor located near load.

Purpose of Policy Roadmap

The cogeneration Policy Roadmap (Roadmap) will provide a long-term policy perspective for DG and cogeneration with detailed actions and milestones for implementing those policies. The Roadmap responds to energy policy as directed by the IEPR/EAP and will, in the future, inform the IEPR/EAP process. The detailed Roadmap will feed into the ongoing IEPR/EAP process and identify current and future policy issues for IEPR/EAP based on a Pathway to a 2020 DG and Cogeneration Vision. The Roadmap will also link existing and future DG and cogeneration policy initiatives with the correct policy implementation mechanisms.

Understanding the desired end-state for DG and cogeneration will provide context and a long-term perspective for policy makers, regulators, legislators, and industry stakeholders. Therefore, the Roadmap will look at policy initiatives aimed at achieving the 2020 Vision end-state. The robust adoption and integration of DG and cogeneration into the California energy enterprise is expected to take more time than the near-term planning horizon of the IEPR/EAP. For example, some policy initiatives may take longer and may be best supported by research and analysis that has yet to be completed. In addition, many DG technologies are still emerging, and the policy strategies for DG are likely to change as these technologies mature and California energy policy continues to evolve post-energy crisis. Therefore, the Roadmap will provide the Public Interest Energy Research program with a basis for future research and analysis to support these longer-term policy decisions.

Development of the Policy Roadmap

The Roadmap was developed by the Energy Commission DG Policy Team comprising Melissa Jones, Gary Klein, Tim Tutt, Lorraine White, Marwan Masri, Mike Smith, Scott Tomashefsky, Darci Houck, Art Soinski, John Beyer, John Sugar, and Mark Rawson. The development of the Roadmap relied on existing policy, both within and outside the DG area, and research performed under the PIER Distributed Energy Resources Integration Research Program. Additional market analysis and research was performed by the Policy Team to close knowledge gaps.

The Policy Roadmap has three major elements – the Current Situation in 2005, the Vision in 2020, and the Pathway to the Vision. The current market penetration for DG and cogeneration technologies (in MW) was determined to provide a baseline for the Current Situation in 2005. The Current Situation description was further augmented to include a characterization of the existing regulatory framework in 2005, as well as the key industry characteristics that define the health of the DG and cogeneration industry today.

The Vision in 2020 was developed by examining potential scenarios for California's energy future in 2020. The team used previous scenario planning efforts[3] to identify a detailed Vision for DG and cogeneration in California. This Visioning activity was informed by existing policy documents and PIER-Distributed Energy Resource Integration Program research[4] to be consistent with current policy and to leverage the latest industry and academic research.

A strategy was formed – based on the tools available to policy makers in the near- and long-term – that would allow California to reach its DG and Cogeneration Vision. This strategy provided a foundation for the Pathway including defining milestones from the 2005 Current Situation to the 2020 Vision. To ground the Vision – to ensure it has stretch but realistic goals and to determine the timing of milestones – market potential and penetration. Growth rates for technology penetration were determined and compared against historic penetration of similar technologies to make certain that the penetration growth rates are realistic.

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[3] California Energy Commission, *Identifying Distributed Energy Resources Research Priorities Through Emerging Value Networks,* Navigant Consulting (NCI), Publication #700-02-002, July 2002; *Energy and Environment Scenarios for California,* Global Business Network (GBN), 2002; California Energy Commission, *California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios,* (Electric Power Group) *(CERTS),* Publication #500-03-106, November 2003; California Energy Commission, *Final DG Scenario Development Report,* UC Irvine, Publication #500-00-033, September 2003; *Policy and Regulatory Roadmaps for Integration of Distributed Generation and the Development of Sustainable Electricity Networks,* European Commission, August 2004

[4] California Energy Commission, *2003 Integrated Energy Policy Report,* Publication #100-03-019, December 2003; California Energy Commission, *2005 Integrated Energy Policy Report*, Publication #100-2005-007-CMF, November 2005; California Energy Commission and California Public Utilities Commission, *Energy Action Plan II – Implementation Roadmap for Energy Policies*, September 21, 2005; California Energy Commission, *Recommended Changes to Interconnection Rules,* Publication #100-2005-003-CMF, February 2005; California Energy Commission, *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, Publication #500-2005-173, November 2005; California Energy Commission, *Distributed Generation Strategic Plan*, Publication # P700-02-002, June 2002; California Energy Commission Project, *Evaluation of Policy Impacts on the Economic Viability from a Project Owner's Perspective of California Based Distributed Generation/Combined Heat and Power, Competitive Energy Insight Inc.,* Contract # 500-04-015, Publication #CEC-500-2006-068; California Public Utilities Commission, *Distributed Generation Policy Proceeding (R.04-03-017),* http://www.cpuc.ca.gov/proceedings/R0403017.htm; California Energy Commission, *Distributed Generation OII (Order Instituting Investigation) Implementation and Distribution Planning (Docket #04-DIST-GEN-1, #03-IEP-1),* http://www.energy.ca.gov/distgen_oii/index.html; California Air Resources Board, *Distributed Generation Certification Program*, http://www.arb.ca.gov/energy/dg/dg.htm; California Energy Commission, *Rulemaking Pertaining to Data Collection for Qualified Departing Load CRS Exemptions, Docket #03-CRS-01*, http://www.energy.ca.gov/exit_fees/index.html

CHAPTER 2: CURRENT SITUATION

Current DG and Cogeneration Regulatory and Industry Framework

Developing a Vision and a Pathway to the Vision requires a clear understanding of the Current Situation for DG and cogeneration in California in terms of the regulatory framework (Table 1) and DG and cogeneration industry characteristics (Table 2). The current regulatory framework encourages DG through subsidies, incentives and recognition of DG in procurement and planning processes. Rules and regulations have been developed and put in place that encourage some forms of DG. In the case of large cogeneration, there are limited incentives and little consideration of cogeneration in procurement and planning processes. Static, controlled-average electric rate structures and pricing, which do not account for the full costs of electricity and do not send consumers the proper price signals are preventing the realization and compensation for some of the locational, temporal, and environmental benefits of DG and cogeneration.

Table 1: Summary of Current Regulatory Framework

Regulatory Characteristics	Current Situation
Planning and Procurement Policy	• State energy policy aims to incorporate DG into utility procurement and DG into distribution planning processes. • Cogeneration has little consideration in utility procurement and planning processes. • Renewables Portfolio Standard (RPS) exists.
Rate Structures	• Energy prices are not transparent; inhibits customer response to actual costs. • Current rate structure is based on controlled averaged pricing that does not include locational and environmental externalities. • It is difficult for DG to participate in wholesale power markets. • It is difficult for cogeneration to execute new contracts with utilities.
Incentives	• Incentives (subsidies, tax credits, low interest loans) are in place to promote clean DG. • Incentives are limited for cogeneration.
Rules and Regulations	• Rules and regulations (e.g. interconnection rules, net metering, and exemptions from standby charges) have been changed to benefit some or all DG.

Current state energy policy aims to incorporate DG and cogeneration into utility procurement and DG into distribution planning processes. The *2003 Energy Action Plan* identified a preferred loading order for California. DG is a preferred resource in the loading order, following energy efficiency, demand response, and renewables. In addition, the *2003 IEPR* aimed to create a transparent distribution planning process that addresses the benefits of DG and determines the extent to which DG can/should be incorporated into utility resource planning and procurement. There are other related policies aimed at environmental aspects that also impact DG. The *2005 IEPR* broadened the policy consideration for DG and addressed cogeneration for the utility system benefits, energy efficiency improvements, other critical infrastructure security and reliability support, and greenhouse gas benefits it affords California. California has an RPS requirement for utilities to increase use of energy from renewable resources annually until 2010, when the RPS would be at 20 percent. The CPUC requires utilities to use a “greenhouse adder” of $8 per ton in their long-term procurement plans.

The current rate structure in California is based on controlled averaged pricing. Externalities (for example, environmental impacts and locational value) are not incorporated into these rates. This approach assumes, from the customer’s perspective at the retail level, all electrons have the same value regardless of how, when, and where they were generated. Lack of a price signal that will change customer behavior undervalues the environmental, temporal and locational aspects of DG or cogeneration. In addition, California ISO rules (for example, high DG aggregation requirement and metering requirements) highly discourage DG and cogeneration customers from participating in wholesale power market.

Incentive programs are in place to promote clean DG. The Energy Commission administers the Emerging Renewables Program (ERP) that provides rebates for residential and small business customers. The CPUC administers the Self-Generation Incentive Program (SGIP), which provides rebates for certain DG technologies and unit sizes not covered by the ERP rebate. Low-interest loans are available from the Energy Commission for renewable DG projects at government facilities and institutions. State tax credits for PV and wind systems exist; however, there are no state tax credits for cogeneration.

While rules and regulations are in place that benefit DG in some instances, other rules and regulations hinder some forms of DG. Most renewable DG qualifies for net energy metering and is exempt from departing load[5] and standby charges. “Clean DG” is currently exempt from standby charges and partially exempt from departing load charges. Some interconnection requirements are standardized under Rule 21, reducing the time and costs for interconnecting DG. A new California Air Resources Board standard for 2007 may make it difficult for some DG technologies to be air-permitted without restrictive higher costs. Existing tariffs for natural gas require large DG facilities to purchase natural gas from a third-party supplier.

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[5] A customer with departing load generally refers to utility customers that leave the utility system in part or entirely to self-generate electricity.

Table 2: Summary of Current DG and Cogeneration Industry Characteristics

Industry Characteristics	Current Situation
Economics	• DG equipment costs typically too high (i.e., some DG technologies not economical without incentives); however, some CHP projects are economically attractive even without incentives. • Some cogeneration projects are cost-competitive without incentives. Large cogeneration projects have attractive economics, particularly those with large thermal loads and the ability to export.
Financing	• Capital is available for attractive projects.
Technology	• DG projects dominated by natural gas engine CHP or photovoltaics. • Large cogeneration projects dominated by combustion turbines and combined cycle systems.
Value Proposition to Customer	• Lower electricity costs – cogeneration. • Green power – photovoltaics.
Industry Participants	• For DG, “large” equipment suppliers and “small” DG developers. • For large cogeneration, “large” equipment suppliers, “large” developers, and sophisticated customers. • Many early DG entrants have been unsuccessful and exited the market.
Infrastructure	• With the current DG penetration, both the natural gas and electric distribution systems can accommodate DG. For large cogeneration, natural gas and transmission systems can accommodate these facilities. • Adequate communications, control, and net metering technology is available.

The current state of DG and cogeneration is shaped in large part by the current regulatory framework and by other industry characteristics (Table 2). The DG industry is still a nascent industry that survives despite difficult market conditions. Many projects are highly customized and rely on incentives. The industry is fragmented with many “small” developers installing PV and natural gas engines provided by large, well-established equipment suppliers. There is fragmentation by technology type and diverse business models. Many early market entrants were unsuccessful and have exited the market; however, new players continue to enter the market attracted by current conditions such as high energy prices and incentives.

Due to low penetration rates, DG installations do not have a large impact on, nor are they integrated with, the state's electric and natural gas infrastructures. Although DG's potential is recognized, it is not a significant energy resource in terms of capacity or energy. A perception exists that in the future the electric and natural gas infrastructures will not be able to accommodate a large penetration of DG. Adequate communication, control, and net metering technologies are available, although a robust communications and control infrastructure is not in place to facilitate a large penetration of DG. Due to its larger inventory, California is dependent upon large cogeneration, and these plants are integrated to a large extent into the operations of the state's electric and natural gas infrastructure.

Installed costs (equipment, engineering, and construction) for recent DG projects are typically too high and would not likely go forward without incentives. There are some DG CHP projects that are economically attractive even without incentives. Most large cogeneration projects are economic without incentives. High electric prices create opportunities for DG projects; however, increasing natural gas prices limit the opportunities for non-renewable projects. Capturing more of the benefits of these DG projects could improve the economics for DG. Large cogeneration projects at industrial facilities are designed to meet thermal needs with electricity as a byproduct. However, the inability to cost-effectively export excess electricity has limited the size of many of these plants. Simply being able to economically export would improve the investment outlook for these industrial and commercial sector end-users. Financing DG and cogeneration projects is typically not a barrier. There is a range of financing options (debt, project capital, third-party service providers, and so forth) for attractive projects. Low-cost loans are available for some DG projects.

The majority of DG installations are photovoltaic (by number of installations) and natural gas-fired CHP systems (by capacity). Most DG customers are installing these systems for green power or to reduce energy costs. However, many customers are placing value on other aspects of DG (for example, Carbon dioxide emissions and reliability). Large cogeneration systems are dominated by combustion turbines and combined-cycle power plants. To a lesser degree, boiler/steam turbine plants are also used.

With the current DG penetration, both the natural gas and electric distribution systems can accommodate DG.

Current DG and Cogeneration Market Penetration

The current DG penetration is 2.5 percent of total peak demand in California (Table 3). The majority of DG capacity is CHP units (reciprocating engines fueled with natural gas). The current penetration of large cogeneration is 14.5 percent.

Table 3: Current Situation – DG and Cogeneration Penetration[6]

Technology	2004 (MW)
DG Technologies	
Small Biomass	80
Small Wind	1.4
PV	93
Co-generation (CHP)	975
Non-cogeneration (Peaking / Primary)	234
Total DG Technologies	**1,383**
Total Large Cogeneration	**8,155**
DG Technologies + Large Cogeneration	**9,538**
Net Peak Demand	**56,435**
Penetration of DG	**2.5%**
Penetration of Large Cogeneration	**14.5%**
Penetration of DG + Large Cogeneration	**17.0%**

[6] Note: See *Appendix A: Current Situation DG and Cogeneration Penetration – Sources and Assumptions*

CHAPTER 3: DG AND COGENERATION POLICY VISION

DG and Cogeneration Scenarios

The team used the existing strategic planning frameworks and reports to construct four possible scenarios for DG and cogeneration in California[7] (Figure 1). In the "Market Competitive Energy" scenario, California's electricity needs are met by a large fleet of central power plants, supported by a robust transmission and distribution (T&D) system and a robust, wholesale competitive electricity market that encourages investment. This scenario is typified by few environmental constraints to building out the central generation and delivery system, and where regulations are structured to rely on market forces to dictate electricity system investment and energy consumption (for example, transparent and dynamic pricing exists).

The "Vertically Integrated Utility" scenario is similar to the "Market-Competitive Energy" scenario in terms of energy infrastructure but would rely on regulations to provide sufficient economic incentives for investment. This scenario is further typified by controlled-averaged pricing of electricity where there is little transparency to the price for electricity and its true cost at any given time throughout the day.

The "Not Your Traditional Utility" scenario also would depend heavily on regulations to encourage energy infrastructure investment; however these regulations would offer more incentives for alternatives (DG, demand response, energy efficiency) than for traditional central power plants. Controlled-averaged pricing of electricity would still exist; however, consideration of environmental and peak power system constraints and costs would be evaluated as part of the utilities' procurement and rate design processes.

The "Informed Energy" scenario would leverage market structures that would allow alternative resources to compete more readily with central power plants to meet California's energy needs. This scenario is further typified by existence of transparent and dynamic pricing where customers see the true costs of electricity throughout the day that reflect the higher economic and environmental cost of electricity when the power system is constrained during peak periods. The "Informed Energy" scenario was selected as the basis for the DG and Cogeneration Vision since it provides the best balance in achieving the IEPR's objectives of affordable energy, energy reliability, public health, economic well-being, and environmental quality. It also provides the best market opportunities for DG and cogeneration since many of the external costs of providing electricity during peak system demands are internalized and not lost to the effects of controlled-averaged pricing, thus resulting in more equal economic and environmental footing between central generation and DG and cogeneration.

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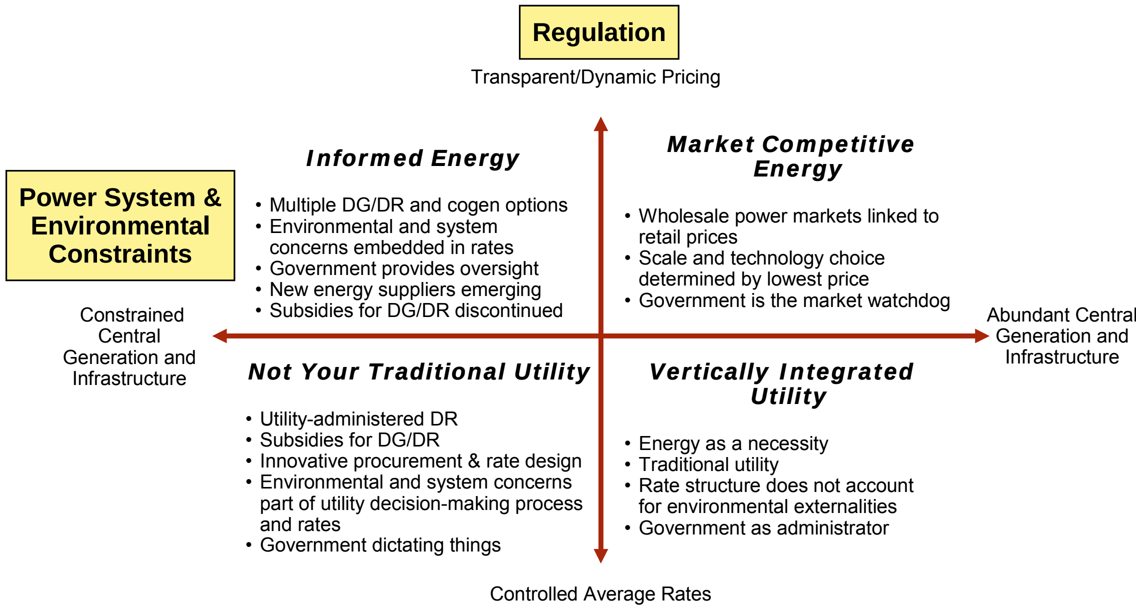
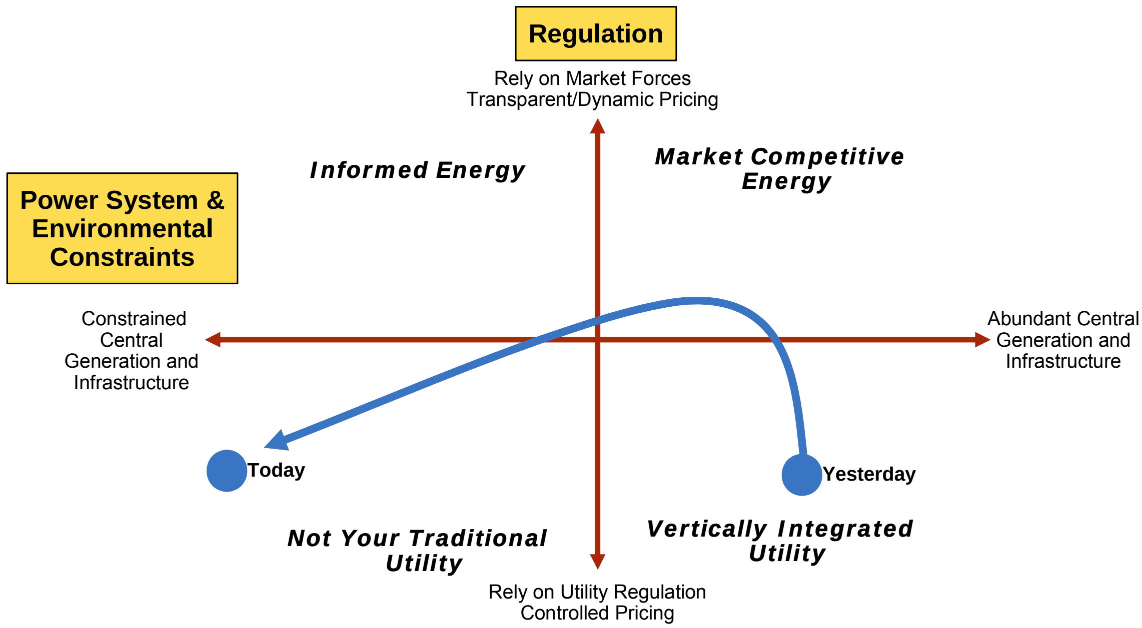
[7] See *Appendix B: DG Scenarios – Background* for a description of the key elements used to construct the scenarios and Table B-1 for more detailed description of scenarios.

Figure 1: DG and Cogeneration Scenarios



Three of the four scenarios are very similar to conditions that California has been in or aspired for in the last decade. Indeed, one could say that California followed a path through these scenarios over the last decade (Figure 2). Our failed attempt to get to the “Market Competitive Energy” scenario led us to a situation where the state had an underinvestment in central plants and the related T&D infrastructure to support them, and a heavier reliance on utility regulations and controlled pricing. Regulatory uncertainty and other financial and environmental constraints have limited the amount of new central station capacity. The 2020 DG and Cogeneration Vision would again move California to more transparent, dynamic pricing of electricity. However, it is unlikely, nor desirable, for California to rely solely on a strategy that included only central power plants – it is currently the last option in the state’s *Energy Action Plan* loading order. This would perpetuate the boom/bust or abundance/constraint cycle of central generation that California experienced in decades past. It would also not ensure that more environmentally friendly generation sources are developed. Finally, it would not address the reliability and security problems becoming more prevalent with today’s central generation system paradigm. Allowing all potential resources to compete equally for the same or greater value will reduce the risks and costs of providing electricity to California.

Figure 2: DG and Cogeneration Scenarios and the 2020 DG and Cogeneration Vision



DG and Cogeneration Policy Vision Statement

Consideration of the "Informed Energy" scenario leads to the following vision statement for DG and cogeneration:

California 2020 DG and Cogeneration Vision Statement
DG and cogeneration are significant components of California's electric system, meeting over 25% of the total peak demand. • Customers have multiple options, including DG and cogeneration, to consider as part of their energy sourcing strategy. • DG (customer and utility-owned) and cogeneration are integral to procurement, Transmission and Distribution planning, and operations. • A robust DG industry fulfills consumer and utility needs for affordable clean DG. • Large cogeneration has maintained and increased its position as an important resource to California, and these facilities can readily participate in the wholesale power market. • Transparent, dynamic rates and market structures are in place that account for environmental attributes and incorporate locational and temporal power system needs. • The Renewables Portfolio Standard (RPS) mandates were satisfied, and there is no new RPS mandate. Regulated incentive programs have been phased out, and no new incentives are being put in place. • Other barriers to DG have been removed, and all DG permitting is efficient and environmentally responsible.

Table 4: 2020 DG and Cogeneration Vision Statement

Regulatory and Industry Framework for Vision 2020

The 2020 DG and Cogeneration Vision can be further detailed by examining the regulatory framework (Table 5) and DG and cogeneration industry characteristics (Table 6) required to achieve this Vision.

In the 2020 Vision, there is a diversified portfolio mix, including central generation, demand response, energy efficiency, DG, and cogeneration. Market mechanisms are in place that allow DG and cogeneration to compete with central power plants equally. Transparent rate structures connect customers more closely to market forces. Externalities are internalized in rates, including environmental impacts and T&D constraints. DG and cogeneration customers are allowed to more easily participate in the wholesale power market. Aggregation tools, which are in place, allow DG customers to fully participate in wholesale power market.

In the 2020 Vision, regulated incentive programs have been phased out, and no new incentives are being put in place. The Energy Commission's ERP and California Public Utilities Commission's SGIP have ended. There are no utility incentives for promotion of DG, but utilities can own DG. State tax credits for cogeneration owners or suppliers have also ended.

Other rules have changed to allow DG and cogeneration to compete as an energy resource on a more level playing field. Net-metering for DG that provides net societal benefits is in place. Departing load charges have ended for all customers. DG customers pay for standby service at volumetric rates. All DG permitting is efficient and environmentally responsible.

Table 5: 2020 Vision Regulatory Framework

Characteristics	Situation in 2005	2020 Vision
Planning and Procurement Policy	• State energy policy aims to incorporate DG into utility procurement and DG into distribution planning processes. • Cogeneration has little consideration in utility procurement and planning processes. • Renewables Portfolio Standard (RPS) exists.	• Diversified portfolio mix, including central generation, demand response, energy efficiency, and DG, and cogeneration. • Market mechanisms are in place that allow DG and cogeneration to compete with central generation. • RPS has been satisfied, and mandate has ended.
Rate Structures	• Energy prices are not transparent; inhibits customer response to actual costs. • Current rate structure is based on controlled averaged pricing that does not include locational and environmental externalities. • It is difficult for DG to participate in wholesale power markets. • It is difficult for cogeneration to execute new contracts with utilities.	• Rate structures are transparent and connected to market forces. • Externalities are internalized in rates, including environmental impacts and Transmission and Distribution constraints. • DG customers and cogeneration are allowed to more easily participate in wholesale power market.
Incentives	• Incentives (subsidies, tax credits, low-interest loans) are in place to promote clean DG. • Incentives are limited for cogeneration.	• No regulated incentive programs are in place.
Rules and Regulations	• Rules and regulations (e.g. interconnection rules, net metering, exemptions from standby charges) have been changed to benefit some or all DG.	• DG and cogeneration compete on a level playing field.

In the 2020 Vision, the DG and cogeneration industry is strong, growing, and dynamic (Table 6). Technology advances and mass customization have reduced DG installation costs, whereas large cogeneration facilities continue to be cost-effective. DG and cogeneration are an economically attractive option for many customers. Investment and operating costs are predictable and favorable. DG and cogeneration benefits are captured by customers, rate structures, and other markets. Simple, low-cost financing is available for attractive DG and cogeneration projects. There are multiple DG technology and fuel options that compete with one another. Some DG technologies cannot compete, while others have been successful. This “survival of the fittest” environment has encouraged innovation and new products that meet customers’ needs for low-cost, green, and premium power. This situation attracts well capitalized companies to complete the DG value network: project developers, project financing, insurance, equipment suppliers, and so forth.

DG and cogeneration have reached a considerable penetration level and are seen as a significant resource. A communications and control backbone, which supports the “Informed Energy” scenario, allows suppliers and customers to be informed of energy demands and pricing on a near to real-time basis. This information technology infrastructure allows DG to be an integral part of the larger electricity infrastructure. Electric and natural gas distribution systems can accommodate the increasing penetration of DG, as can the transmission system for large cogeneration facilities.

Table 6: 2020 Vision DG and Cogeneration Industry Characteristics

Characteristics	Situation in 2005	2020 Vision
DG Economics	• Equipment costs typically too high (i.e., some DG technologies not economical without incentives); however, some CHP projects are economically attractive even without incentives. • Some cogeneration projects are cost competitive without incentives. Large cogeneration projects have attractive economics particularly those with large thermal loads and the ability to export.	• DG and cogeneration are economically attractive option for many customers without incentives.
Financing	• Capital is available for attractive projects.	• Simple, low-cost financing is available for DG and cogeneration projects.
DG Technology	• DG projects dominated by natural gas engine CHP or photovoltaics. • Large cogeneration projects dominated by combustion turbines and combined-cycle systems.	• Multiple technology options exist, "survival of the fittest."
Value Proposition to Customer	• Lower electricity costs – cogeneration. • Green power – Photovoltaics.	• Customer options include low cost, green, and premium power.
Industry Participants	• "Large" equipment suppliers and "small" DG developers. • For large cogeneration, "large" equipment suppliers, "large" developers, and sophisticated customers. • Many early DG entrants have been unsuccessful and exited the market.	• Environment attracts well capitalized world class companies: project developers, project financing, insurance, and equipment suppliers.
Infrastructure	• With the current DG penetration, both the natural gas and electric distribution systems can accommodate DG. For large cogeneration, natural gas and transmission systems can accommodate these facilities. • Adequate communication, control, and net metering technologies are available.	• Electric and natural gas distribution systems can accommodate the amount of DG, as can the transmission system for large cogeneration facilities. • Information technology and communication backbone that allows for "Informed Energy."

DG and Cogeneration Market Penetration in the Vision 2020

To achieve the Vision 2020 market penetration target of 26 percent of total peak demand being met by DG and large cogeneration, a mix of technologies and fuels will be required (Table 7). The basis of the 2020 targets for the various technologies are based on current policy (for example, Million Solar Roofs Initiative, extrapolation from Renewables Portfolio Standards) or market studies that include the market conditions described in the Vision (for example, California Energy Commission, *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, Publication #500-2005-173, November 2005).

Table 7: 2020 DG and Cogeneration Vision – DG and Cogeneration Penetration

Technology	2020 (MW)	2020 Projection Assumptions
DG Technologies		
Small Biomass	300	In 2004 electricity from all renewables generates 10.6% of CA's electricity. Assuming an RPS of 33% in 2020, 2020 renewable generation would be 3.8 times greater than 2004.
Small Wind	10	The share small wind DG composes of renewable generation will increase by a factor of 2 in 2020 compared to 2004. Therefore, 2020 small wind generation would be 7.6 times greater than 2004.
PV	3,000	Governor's Million Solar Roof Initiative 3,000 MW target is achieved in 2020.
Co-generation (CHP)	3,300	2005 EEA California CHP Study aggressive market scenario. Considered installations < 20 MW. Includes small biomass CHP projects.
Non-cogeneration (Peaking / Primary)	790	Same growth as CHP
Total DG Technologies	**7,400**	
Total Large Cogeneration	**11,200**	2005 EEA California CHP Study aggressive market scenario. Considered installations >20 MW.
Total DG + Large Cogeneration	**18,600**	
Net Peak Demand	**70,776**	California Energy Demand 2006 – 2016. The annual growth rate of 1.2% for the forecast period, 2008 – 2016, is used for 2016 – 2020.
Penetration of DG	**10.5%**	Total DG/Net Peak Demand
Penetration of Large Cogeneration	**15.8%**	Total Large Cogen/Net Peak Demand
Penetration of DG + Large Cogeneration	**26.3%**	

CHAPTER 4: DG AND COGENERATION POLICY PATHWAY TO ACHIEVE VISION 2020

Overall Strategy

To achieve its Vision, California will implement a strategy with three key thrusts[8]:

- Support Incentives in the Near-Term.
- Transition to New Market Mechanisms.
- Reduce Remaining Institutional Barriers.

Support Incentives in Near-Term

Over the next 10 years, California should continue to provide existing incentives and add new incentives for DG and cogeneration. Many of these incentives are identified in the IEPR. However, these incentives will be discontinued over time (Figure 3) as new market mechanisms are implemented.

There are four areas of incentives:

- Provide tax credits for the capital expense of renewable and clean DG systems in the near-term.
- Continue ERP and SGIP programs in the near-term.
- Support adoption of renewable and clean DG systems by providing low-interest loans in the near-term.
- Provide value for environmental attributes in the near-term through use of production tax credits (PCT) for criteria pollutants and CO_2 emission reductions.

[8] In addition to these three key thrusts, the Energy Commission will continue to engage in R&D activities that will reduce the cost of and improve the performance of DG technologies.

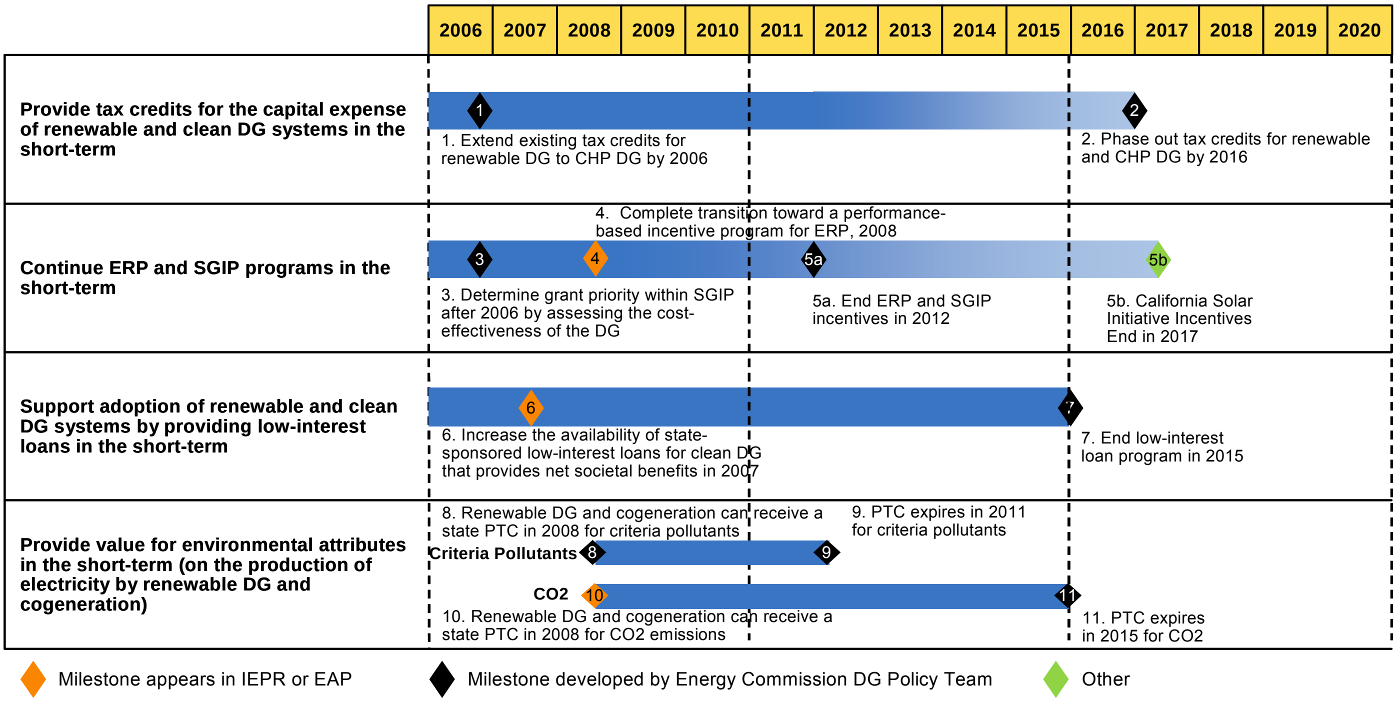


Figure 3: Strategic Thrust – Support Incentives in the Near-Term[9]

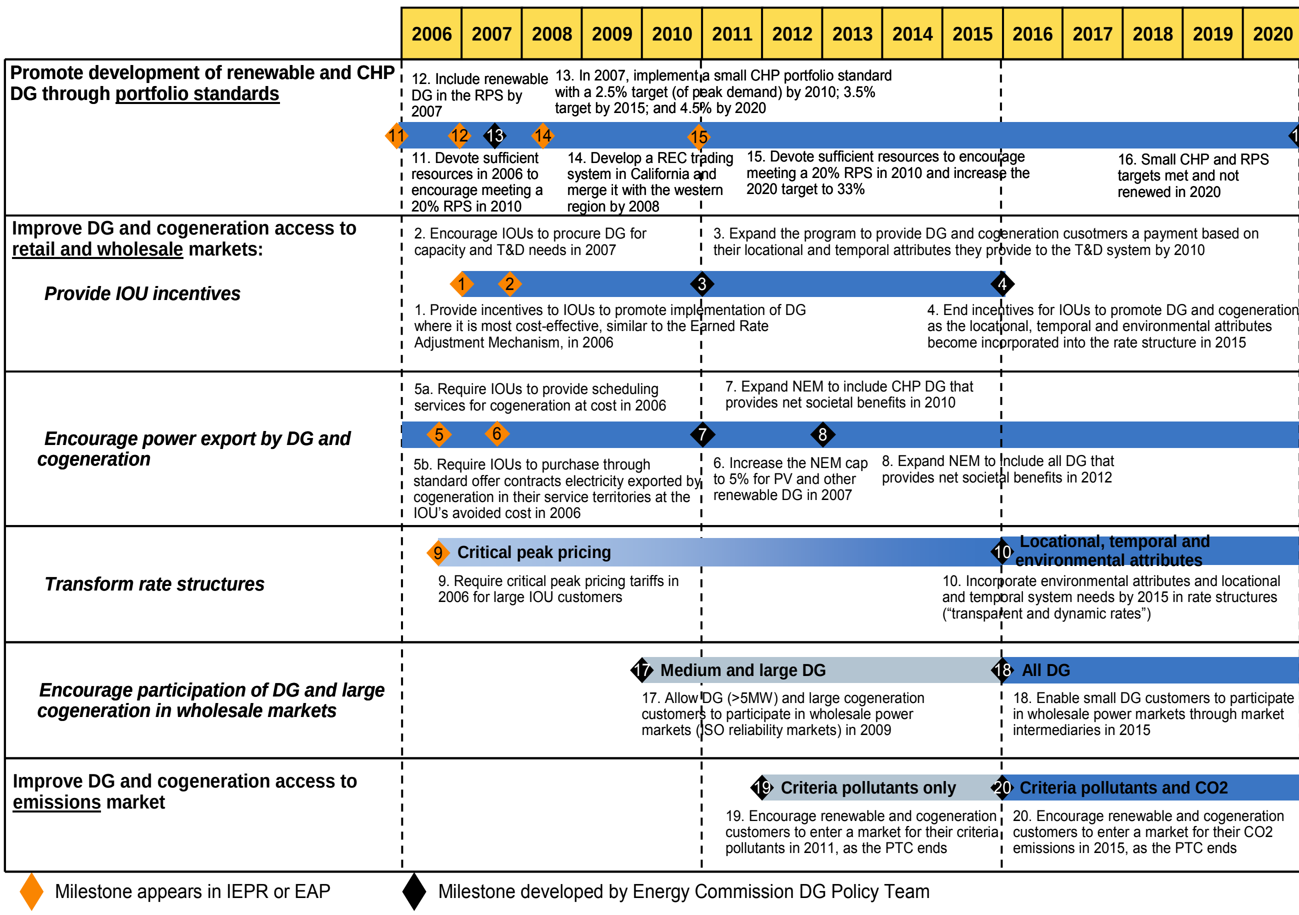
Transition to New Market Mechanisms

To remove incentives and still encourage vibrant growth of DG and cogeneration in California, incentives will have to be replaced with market mechanisms that encourage DG and cogeneration (Figure 4). Key transition activities on the roadmap will:

- Promote development of renewable and CHP DG through portfolio standards.
- Establish market mechanisms to allow DG to compete with central plants and traditional T&D:
  - Provide utility incentives to procure DG while remaining revenue neutral.
  - Encourage power export by cogeneration so that systems are optimized for onsite heat loads and installations are large enough to provide T&D capacity to utilities.
  - Transform rate structures to internalize location, temporal and environmental benefits.
  - Encourage participation of DG and cogeneration in wholesale markets.
- Create access to emissions markets:
  - Develop emissions markets that include and appropriately value DG and cogeneration.

[9] Note: For specific references to IEPR/EAP milestones, see *Appendix C: DG and Cogeneration Policy Pathway/IEPR and EAP Milestone Cross References*.

Figure 4: Strategic Thrust – Transition to New Market Mechanisms[10]



Reduce Remaining Institutional Barriers

California has made tremendous strides in the past several years in removing barriers to DG and cogeneration. However there is still work to be done. The last strategic thrust would address remaining barriers (Figure 5):

- Institute an analytical framework for DG and cogeneration for assessing costs and benefits.
- Enable DG and cogeneration to be effectively integrated into the electric power system by addressing rate design.
- Promote DG through rules and standards development.
- Institute a permitting process that is environmentally responsible.

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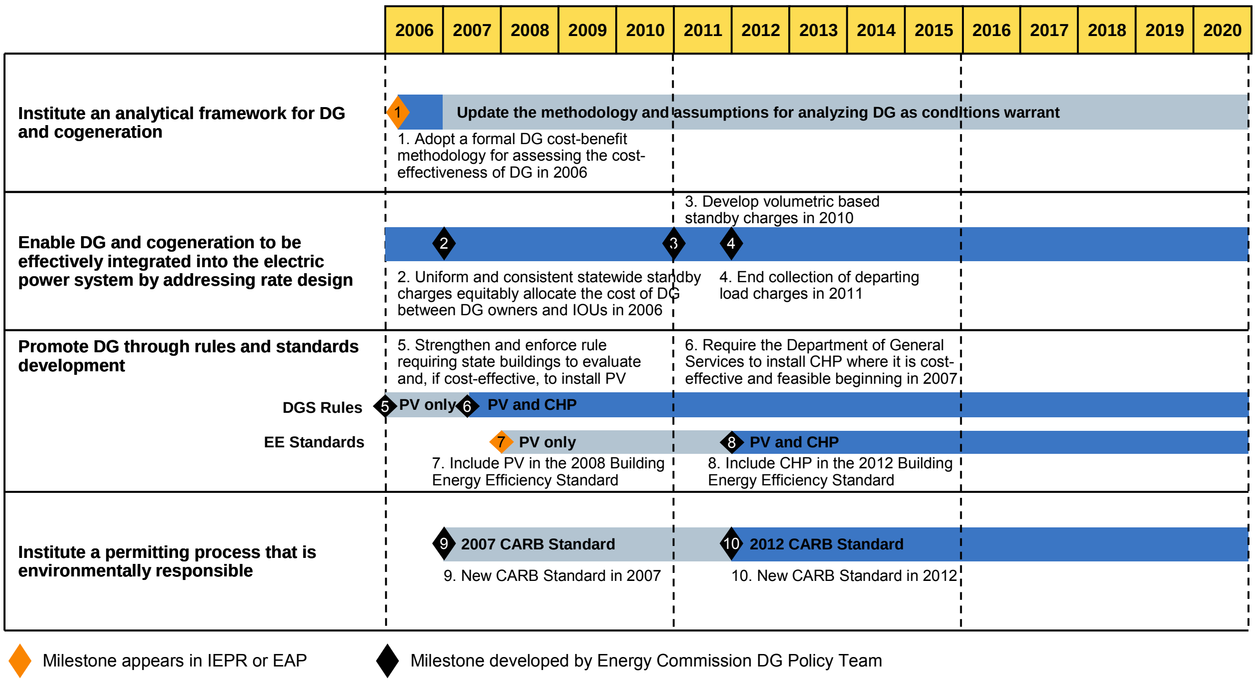
[10] Note: For specific references to IEPR/EAP milestones, see *Appendix C: DG and Cogeneration Policy Pathway/IEPR and EAP Milestone Cross References*

Figure 5: Strategic Thrust – Reduce Remaining Institutional Barriers[11]

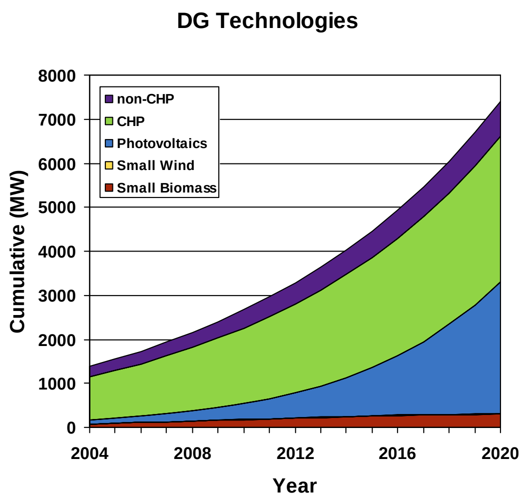


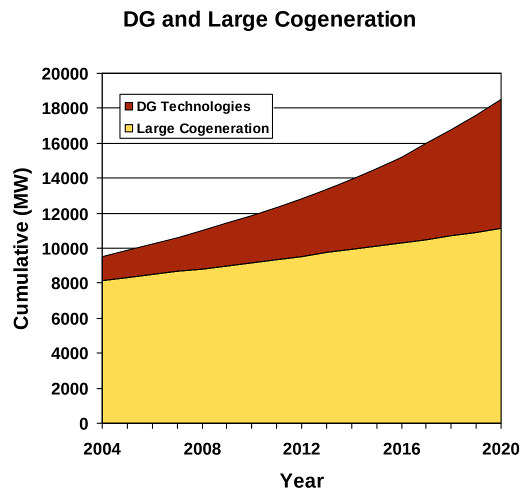
DG and Cogeneration Market Penetration Curves

It will require a mix of DG technologies and cogeneration (as in Table 7) to reach the Vision's penetration target of 26 percent by 2020 (Figure 6). Technologies penetrate the market at different rates depending on the maturity of the technology and the market. Large cogeneration, which uses mature technology and has relatively high market saturation, will grow at a slower rate as compared to some of the DG technologies. For example, photovoltaics is still a growing technology and is not likely to reach its maximum penetration rate until after 2020. Small CHP, which uses mature reciprocating engine and gas turbine technology and still has a large technical market, will reach its maximum penetration rate (in terms of annual MWs added per year) before 2020. This will cause, in the future, for photovoltaic technology to make up a greater percentage of DG. While CHP will still be an important component of the DG portfolio, decades of incentives, pent-up technical market potential and improved technology performance will lead to a greater penetration of PV capacity.

[11] Note: For specific references to IEPR/EAP milestones, see *Appendix C: DG and Cogeneration Policy Pathway/IEPR and EAP Milestone Cross References*.

Figure 6: DG and Cogeneration Penetration Curves[12]





[12] These penetration patterns were determined based on the projected installations in 2020 and the pattern of similar technologies using a Fischer-Pry analysis (see Appendix D: DG Penetration Curves).

CHAPTER 5: RECOMMENDATIONS FOR ADOPTION AND IMPLEMENTATION

IEPR/EAP Interaction

The DG and Cogeneration Vision requires some new energy policy initiatives that have not been addressed nor discussed in the IEPR/EAP process yet. The Roadmap will now provide a prospective view to the IEPR committee on potential policies to consider and the timing necessary to implement those policies for California to attain the 2020 DG and Cogeneration Vision. It is also expected that other policy initiatives not in the Roadmap will be identified by the IEPR/EAP process, or greater emphasis will be placed on some policy initiatives. Therefore, the Roadmap will need periodic updates to reflect these changes.

Roadmap Implementation

Implementing this Roadmap will require the participation of agencies and stakeholders outside the Energy Commission. This Roadmap will need to be reviewed with those stakeholders, and an implementation plan will need to be developed to begin to implement the Roadmap. There is a need to assign responsibility either within or outside the Energy Commission for the adoption and implementation of the Roadmap since some policy activities on the Pathway fall under the regulatory or legislative authority of other parts of state government.

APPENDIX A: CURRENT SITUATION DG AND COGENERATION PENETRATION – KEY SOURCES AND ASSUMPTIONS

Key Sources

1) CA Power Plants > 0.1 MW (Accessed 02/18/2005): http://www.energy.ca.gov/database/POWER_PLANTS.XLS
   a) DG is considered any generation < 20 MW (except geothermal and hydro, which are not DG).
   b) Any renewable DG that is also used for cogeneration is counted under "Cogeneration/CHP."
   c) Considers only CA generation operational before 2004.

2) Rule 21 Interconnection Authorizations > 10 kW (Accessed 02/18/2005): http://www.energy.ca.gov/distgen/interconnection/rule21_stats.html
   a) DG is considered any generation < 20 MW (except hydro, which is not DG).
   b) DG is not used for standby or backup electricity.
   c) Any renewable DG that is also used for cogeneration is counted under "Cogeneration/CHP."
   d) The wide majority of DG < 10 kW approved in Rule 21 is assumed to be PV.
   e) Data for PGE&E, SCE, and SDG&E.

3) Energy Commission Emerging Renewables Program (ERP) (Accessed 02/18/2005): http://www.energy.ca.gov/renewables/emerging_renewables/2005-01-13_ERP_Cmptd_Apprvd.XLS
   a) Only considered DG with status of "Payment Claim Processed."
   b) Calendar year based on the date in the "Completed" column.
   c) Includes < 10 kW wind installations not listed in the Rule 21 authorizations.
   d) Data for mainly for PG&E, SCE, and SDG&E. Some cells are blank or for POUE and BVE.

4) Grid-connected PV in CA (Accessed 02/18/2005): http://www.energy.ca.gov/renewables/emerging_renewables/2005-01-18_GRID_PV.XLS
   a) Data for all grid connected PV in CA.

5) CPUC Self-Generation Incentive Program (SGIP) (Accessed 02/23/05): http://www.sdenergy.org/uploads/SelfGen_Statewide%20Data_Jan05.xls

a) There may be overlap with DG installations in the Rule 21 Authorizations and CA Power Plants databases
b) Only considered DG with status “Completed”.

6) California Energy Commission, *Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration*, Publication #500-2005-173, November 2005:
   a) Appendix A provides complete data on installed cogeneration capacity in California in 2004.

Key Assumptions

Small Biomass – Energy Commission CA Power Plants database. Considered biomass projects under 20 MW. Excludes Small Biomass CHP estimated at 126 MW

PV – Energy Commission report of grid-connected PV from 1991 to present.

Small Wind – Energy Commission Emerging Renewables Program. Includes net-metered wind projects.

Cogeneration (CHP) – EEA CHP Study. Considers all cogeneration installations in California. Includes small biomass CHP projects. Breakdown included in Appendix.

Non-cogeneration (peaking and primary) – Energy Commission CA Power Plants database. Considered installations < 20 MW

Peak Demand – Forecast of California Energy Demand 2006 – 2016

APPENDIX B: DEVELOPING DG AND COGENERATION SCENARIOS

DG Scenario Drivers

Future scenarios for electricity, cogeneration and DG in California are strongly influenced by six key drivers:

- Power System and Environmental Constraints – Ability to add new central generation capacity and new transmission and distribution infrastructure to meet load growth. Based on environmental and power system (or, electric generation, transmission and distribution) constraints.

- Regulation – Whether regulatory policy shifts toward allowing market determination of prices or toward stronger regulatory control of prices.

- Load growth – The increased demand for electricity based on the estimated rates of economic and population growth and the rate at which electricity is consumed.

- Spark Spread – The difference between natural gas and electricity prices.

- Environmental Push – Degree of consumer and government support for environmentally friendly energy solutions.

- Transportation Tech Transfer – Degree to which the transportation industry develops technologies that can be transferred to the DG industry (for example, fuel cell, battery or power electronics technology).

These drivers vary in importance to future scenarios based upon the impact they will have on the future of DG and cogeneration in California and level of uncertainty associated with the respective drivers. “Regulation” and “Power System and Environmental Constraints” are the two drivers that will shape and bound the scenarios for electricity, cogeneration and DG in California because they are likely to have the greatest effect on adoption of DG and cogeneration and tend to have higher uncertainties than the other drivers (Figure B-1). Therefore, these two drivers were selected to build the scenarios around.

Figure B-1: DG and Cogeneration Scenario Drivers

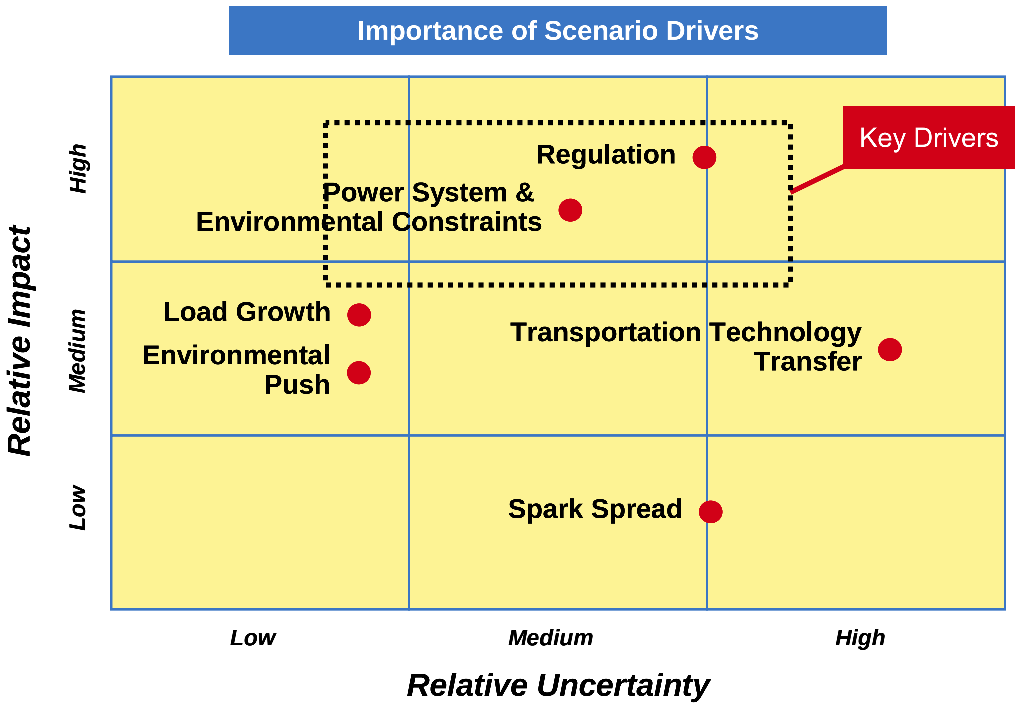


Table B-1: Detailed Description of Scenarios

	Informed Energy	Market Competitive Energy	Not Your Traditional Utility	Vertically Integrated Utility
Power System/ Environmental Constraints	• Limited new central generation and Transmission and Distribution capacity due primarily to environmental concerns and years of regulatory uncertainty.	• Adequate generation and robust transmission infrastructure. • Environmental objectives are easily met.	• Limited generation and Transmission and Distribution capacity due primarily to environmental concerns and ongoing regulatory uncertainty.	• Adequate generation and robust transmission infrastructure. • Environmental objectives are easily met.
Regulation	• Limited, relying on market forces.	• Limited, relying on market forces.	• Highly regulated utilities and energy markets; formula not clear; trial and error approach.	• Highly regulated utilities and energy markets.
Character Of Rate Structure	• Transparent, dynamic pricing structure with embedded environmental externalities and system needs (locational and temporal).	• Transparent, dynamic pricing structure. • Wholesale power markets. • Competition at retail level.	• Controlled pricing, with environmental and system concerns embedded in rates with no customer choice.	• Controlled averaged pricing. • Utility offers single power option to all retail customers.
Government Role	• Oversight, supports development of free markets, ensures rules are followed.	• Arm's length watchdog.	• Heavily dictating things, achieves policy objectives through regulation.	• Administration and oversight.
Energy Supply	• Large penetration of central power, with multiple energy options driven by customer demand (e.g., green, nuke, gas, hydro, DG). • New business models and market entrants in industry.	• Central fossil fuel-based power plants dominate. • Boom and bust cycles are mitigated by long-term contracts.	• Regulated mix that will achieve policy objectives.	• Vertically integrated utilities. • Increased reliance on fossil fuels.
Dg Ownership	• Customer, third party and utility owned. PV and CHP are primary technologies.	• Customer, third party and utility owned, mostly CHP and microgrids.	• Utility-owned DG to meet Renewable and CHP portfolio mandates, and Transmission and Distribution constraints.	• Limited, end-user owned.
Demand Response Role	• Market driven. Customers will be exposed to transparent, dynamic price signals for capacity and system constraints.	• DR available, but normally plays a limited role; will play a larger role during capacity "bust" cycles. • Market driven, based on wholesale capacity markets.	• Utility administered programs.	• Limited
Energy Efficiency Role	• Market driven. Customers will be exposed to transparent, dynamic price signals for capacity and system constraints.	• Market driven, but low energy cost make it difficult for EE to compete.	• Utility administered programs.	• Strong continuing thrust but entering area of diminishing returns due to success in programs in 2000- 2015.
Customer	• Well informed; choose energy on environmental impact, cost, and quality.	• Buying decisions based on cost.	• Little choice and high prices.	• No choices.
Price Volatility	• Highest	• Medium high, as a function of infrastructure building cycles.	• Medium low.	• Lowest.

APPENDIX C: DG AND COGENERATION POLICY PATHWAY/IEPR AND EAP MILESTONE CROSS REFERENCES

Support Incentives in the Near-term

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
4. Complete transition toward a performance-based incentive program for ERP, 2008.	2004 IEPR Update, pg 45. "The Energy Commission supports performance-based incentive programs for PV." 2005 Draft IEPR, pg 124: "A truly sustainable solar program will pay for kWhs produced rather than for system installation with no measure of performance to ensure that systems are appropriately installed and functioning correctly."
6. Increase the availability of state-sponsored low-interest loans for clean DG that provides net societal benefits in 2007	2005 EAP II, pg 4. "10. Increase the availability of State-sponsored low-interest loans for energy efficiency and clean distributed generation projects."
10. Renewable and CHP DG can receive a state PTC in 2008 for CO2 emissions	2005 Draft IEPR, pg 79. "California should explore establishing production credits for CO2 reductions from CHP."
Milestones 11-15	2005 EAP II, pg 7. "Implement a cost-effective program to achieve the 3,000 MW goal of the Governor's "Million Solar Roofs" initiative."

Transition to New Market Mechanisms

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
1. Provide incentives to IOUs to promote implementation of DG where it is most cost-effective, similar to the Earned Rate Adjustment Mechanism, in 2006.	2005 Draft IEPR, pg 78. "The CPUC should immediately develop a method to provide DG and CHP incentives to utilities and implement them by the end of 2006." 2005 Draft IEPR, pg 79. "By the end of 2006, the CPUC should direct utilities to make transmission and distribution capacity payments to CHP projects."
2. Encourage IOUs to procure DG for capacity and T&D needs in 2007.	2005 Draft IEPR, pg E-4. "The CPUC and the Energy Commission should establish annual utility procurement targets by the end of 2006." 2005 Draft IEPR, pg 79. "The CPUC should require utilities to implement comparable planning models to determine where DG and CHP is most beneficial from system transmission and distribution perspectives."
5a. Require IOUs to provide scheduling services for CHP customers at cost in 2006.	2005 Draft IEPR pg 77. Utilities should be required to offer CA ISO scheduling services at cost to their CHP customers.
5b. Require IOUs to purchase through standard offer contracts electricity exported by CHP plants in their service territories at the IOU's avoided cost in 2006.	2005 Draft IEPR pg 77. "By the end of 2006, the CPUC should require IOUs to buy, through standardized contracts, all electricity from CHP plants in their service territories at their avoided cost, as defined by the CPUC in R.04-04-025.118"
6. Increase the NEM cap to 5% for PV and other renewable DG in 2007.	2004 IEPR Update, pg 48. "The Energy Commission believes that a higher net metering cap is necessary to facilitate the orderly development of PV markets and other renewable DG."
9. Require critical peak pricing tariffs in 2006 for large IOU customers.	2005 EAP II, pg 5. "2. Expedite decisions on dynamic pricing tariffs to allow increased participation for summer 2006 for customers with installed advanced metering systems and encourage load shifting that does not result in increases in overall consumption." 2005 Draft IEPR, pg 72. "In 2005, IOUs filed applications to implement default critical peak pricing tariffs for large customers, beginning in summer 2006. The CPUC expects to issue a decision on these tariffs in early 2006."
Milestones 5, 6, and 9	2005 EAP II, pg 8. "9. Develop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects."

Transition to New Market Mechanism (Continued)

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
11. Devote sufficient resources in 2006 to encourage meeting a 20% RPS in 2010.	2003 EAP, pg 5-6. "*Accelerate the State's Goal for Renewable Generation*" 2004 IEPR Update, pg 35. "As originally specified in SB 1078, the RPS requires all IOUs to increase their portfolio of renewable resources by at least one percent of sales every year to reach the target of 20 percent renewable resources by 2017. The Energy Action Plan accelerated the 20 percent target to 2010." 2004 IEPR Update pg 37-38. "*Develop Ambitious RPS Goals*" 2005 EAP II, pg. 6 "5. Evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities."
12. Include renewable DG in the RPS by 2007.	2003 EAP, pg 8. "4. Develop standards so that renewable distributed generation may participate in the Renewable Portfolio Standard program." 2005 Draft IEPR, pg A7. "Status: Achieved. The CPUC determined that the owner of renewable DG facilities owns the renewable energy credits associated with the generation of electricity from those facilities and is eligible to participate in the RPS program."
14. Develop a REC trading system in California and merge it with the western region by 2008.	2004 IEPR Update, pg 40-41. "*Unbundled Renewable Energy Certificates*" 2005 Draft IEPR, pg 114. "In the longer-term, however, California should move toward full REC trading in the state and western region once WREGIS is operational," 2005 EAP II, pg 6. "11. Complete the Western Renewable Generation Information System to accurately account for renewable generation through an electronic certificate tracking system. 2005 EAP II, pg 6. "12. Implement a renewable energy certificates trading system for meeting RPS goals."
15. Devote sufficient resources to encourage meeting a 20% RPS in 2010 and increase the 2020 target to 33%.	2005 EAP II, pg. 6 "Evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33 percent renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities."
17. Allow medium and large DG customers to participate in wholesale power markets (ISO reliability markets) in 2009.	2005 Draft IEPR, pg 76. By the end of 2006, the CA ISO should modify its CHP tariffs in recognition of the unique operational requirements of CHP and allow CHP owners to sell their power to the state's electric grid at reasonable prices"
Milestones 1 and 2	2005 Draft IEPR, pg. 79. "The state should require utilities to design and build distribution systems that are more DG and CHP compatible."
Milestones 1 and 2	2003 IEPR, pg 16. "Create a transparent electricity distribution system planning process that addresses the benefits of distributed generation."

Reduce Remaining Institutional Barriers

California Energy Commission DG Policy Pathway Milestone	Milestone Identified in IEPR and EAP Process
1. Adopt a formal DG cost-benefit methodology for assessing the cost-effectiveness of DG in 2006	2003 EAP, pg 8. "3. Determine system benefits of distributed generation and related costs."
7. Include PV in the 2008 Building Energy Efficiency Standard	2003 EAP, pg 5. "8. Incorporate, as appropriate per Public Resources Code section 25402, distributed generation or renewable technologies into energy efficiency standards for new building construction." 2005 Draft IEPR, pg 124 "… leveraging energy efficiency improvements should be a key consideration in deploying PV, new homes should be required to exceed current building efficiency standards, while existing buildings should be required to improve their efficiency by a fixed percentage." 2005 EAP II, pg 4. "9. Adopt new building standards for implementation in 2008 that include, among other measures, cost effective demand response technologies and integrated photovoltaic systems."

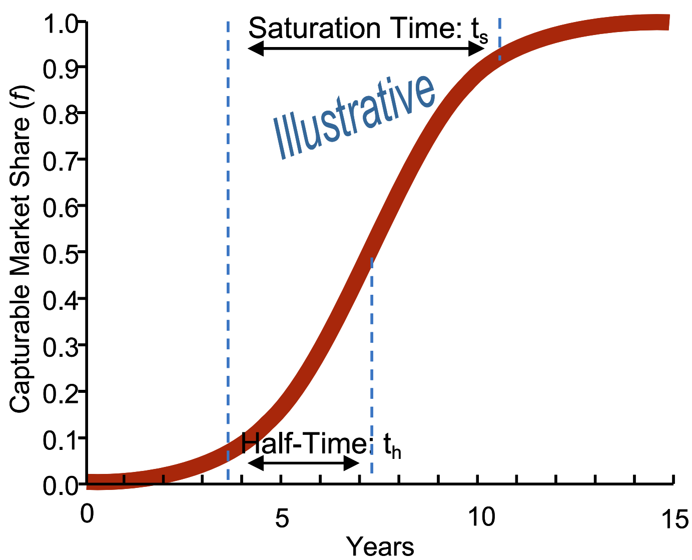
APPENDIX D: DG AND COGENERATION PENETRATION CURVES

Fisher-Pry Technology Substitution Methodology

The Fisher-Pry technology substitution model is used to estimate the rate at which the marketplace will adopt a new technology. In 1971, Fisher and Pry published a paper describing a model of technological change, which is extremely effective in modeling the competitive substituting of one technology by another. In addition to the 17 substitutions listed in Fisher and Pry's original work, at least 200 other examples are in the public record and support the Fisher-Pry approach. The Fisher-Pry technology substitution model predicts market adoption rate for an existing market of known size. The fraction of market adoption, f, by technology substitution for an existing segment is represented as:

$$f = \frac{1}{1+e^{-\alpha(t-t_h)}}$$

- α is an empirical constant
- The half time t_h is the time at which f = 0.5.
- The takeover time t_s is the time between f = 0.1 and f = 0.9.



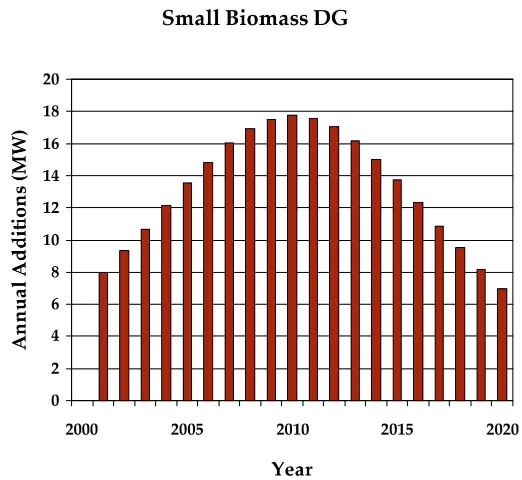
To predict the annual penetration of each DG technology the following steps were performed:

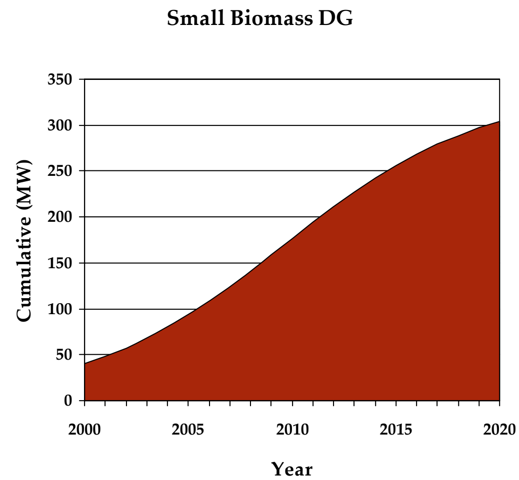
Step 1 – Estimate the current installed capacity (Table 3) and 2020 target (Table 6).
Step 2 – Estimate the total market that is addressable using existing data.
Step 3 – Fit a Fisher-Pry curve to obtain key parameters.
Step 4 – Calculate the annual cumulative installations and the annual additions.

Specific DG Technology Penetration Curves

Small Biomass DG

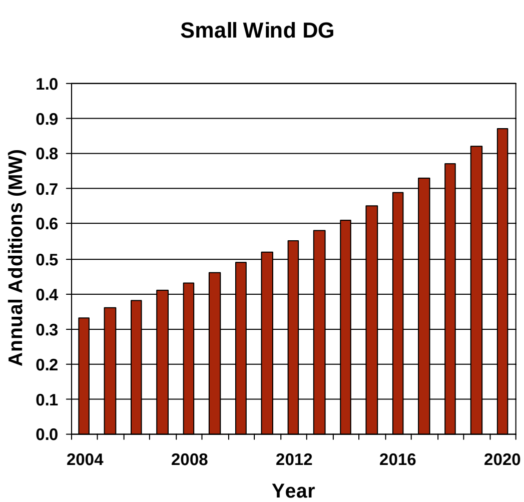
The cumulative small biomass installations increase toward a total of 304 MW in 2020 with annual installations peaking in 2010. The cumulative small biomass installations in 2020 are assumed to be 90 percent of the total market that is addressable, 338 MW. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity, 2020 target, and the total addressable market. The time to saturation time is 20.9 years, and the midpoint occurs in 2010.

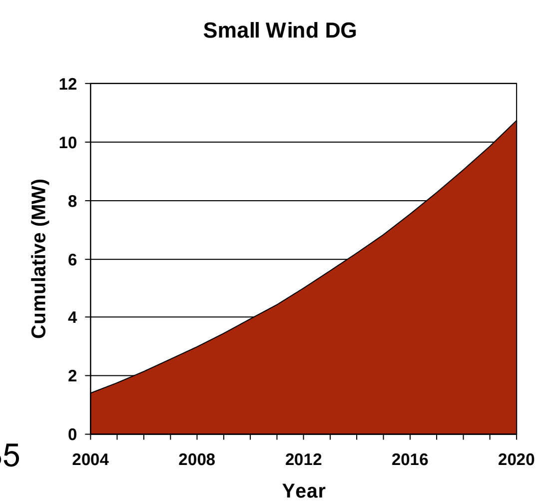




Small Wind

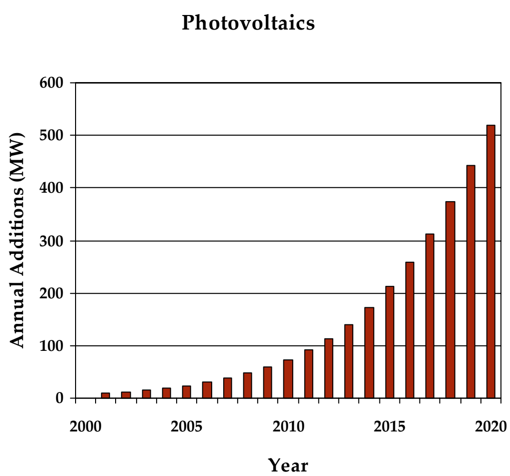
The cumulative small wind installations increase throughout the period toward a total of 10.7 MW in 2020. The technology is assumed to still be in the early stages of adoption curve (<10 percent penetration). The annual additions in 2005 are 6 percent greater than the average annual additions for the prior three years. Between 2005 and 2020 the annual additions of small wind DG grow 6 percent annually.

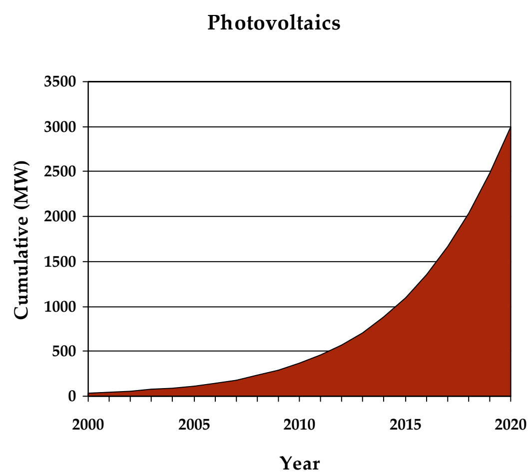




Photovoltaics

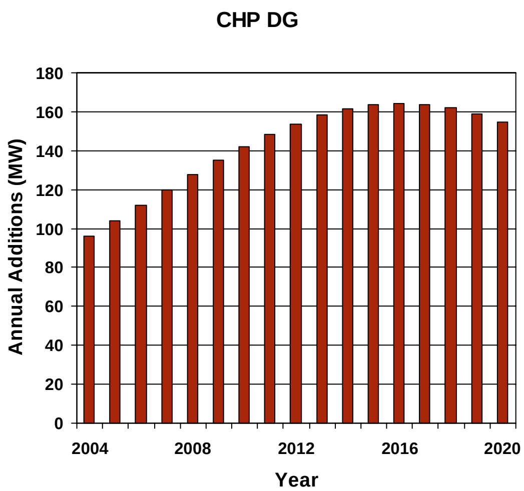
The cumulative photovoltaic installations increase toward a total of 3000 MW in 2020 with annual installations peaking after 2020. The total photovoltaic technical potential in California is 85,000 MW, which is the sum of the residential and commercial technical potential from "California Solar Resources," Energy Commission Draft Staff Report, April 2005, CEC-500-2005-072-D. Navigant Consulting estimates that the PV installations will have an installed cost average $4 per watt throughout the period as a result of incentive programs and cost reductions. This corresponds to a payback period estimate of six years, which is derived from the Energy Foundation/Navigant Consulting report *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, March 2005. The total addressable market is 18.5 percent of the technical potential. This was determined by analyzing the average payback vs. cumulative market penetration curve provided in the Energy Foundation/Navigant Consulting's, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, March 2005. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity, 2020 target, and the total addressable market. The time to saturation time is 17.6 years and the midpoint occurs in 2026.

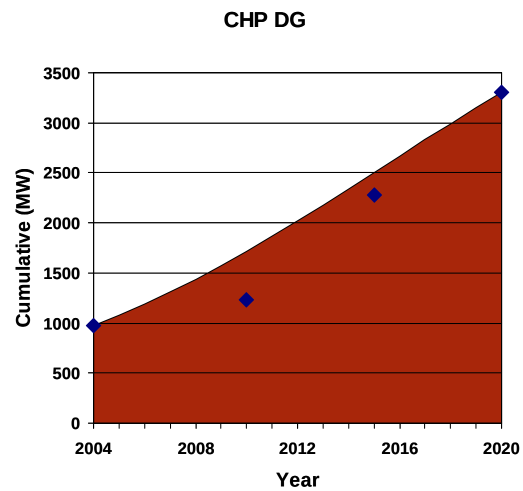




Combined Heat and Power DG

The cumulative CHP DG installations increase toward a total of 3,305 MW in 2020 with annual installations peaking in 2016. The total addressable market is 5,205 MW. This is obtained from the EEA 2005 CHP Study's "High Deployment Scenario" and excludes installations ≥ 20 MW. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity and the EEA 2005 CHP Study aggressive market scenario for 2020, and the size of the total addressable market. The time to saturation time is 34.8 years and the midpoint occurs in 2016.

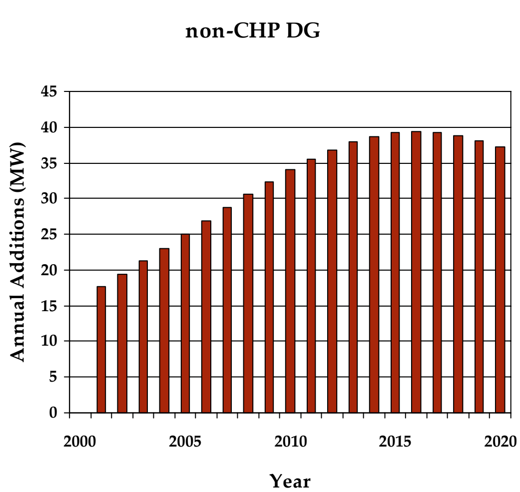


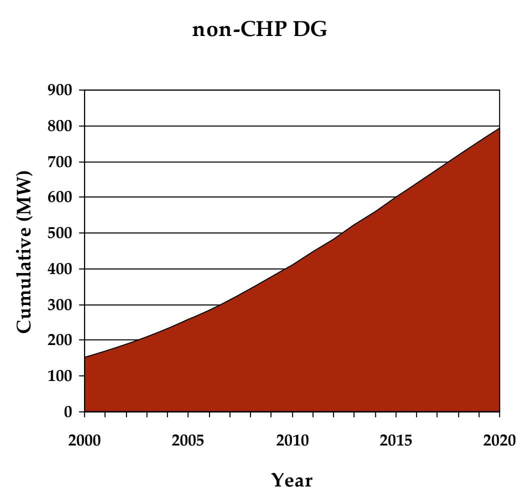


The blue diamonds represent the values from the EEA 2005 CHP Study.

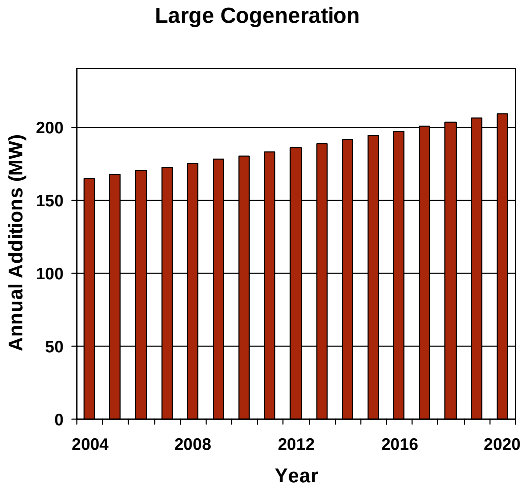
Non-Combined Heat and Power DG

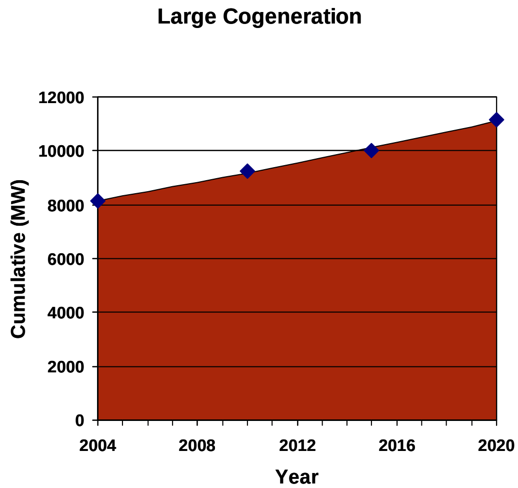
The cumulative non-CHP installations increase toward a total of 790 MW in 2020 with annual installations peaking in 2016. The addressable market for cumulative non-CHP DG is estimated to parallel the market for CHP DG. The share of the current installed non-CHP DG capacity is expected to be the same share initially of CHP DG compared to the total addressable market. The fit for the S-curve was obtained by Fisher-Pry analysis of the 2004 cumulative capacity, 2020 target and the total addressable market. The time to saturation time is 24.0 years, and the midpoint occurs in 2008.





Large Cogeneration





The blue diamonds represent the values from the EEA 2005 CHP Study.

Table 1
Alternative 2
Construction Emissions Summary
Total Daily Criteria Pollutant Emissions by Component

Phase	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.19	1.85	0.19	0.00	1.08	0.10
Grading	11.63	52.09	117.60	0.16	33.18	9.46
Fencing	0.65	4.53	3.55	0.01	2.86	0.48
Civil	3.78	26.62	32.41	0.05	5.50	2.00
Substation MEER	0.26	2.30	0.71	0.00	2.10	0.21
Electrical	0.96	41.64	3.94	0.01	1.87	0.37
Wiring	0.27	11.14	0.48	0.00	0.29	0.04
Transformers	0.99	14.35	6.32	0.01	2.64	0.50
Maintenance Crew Equipment Check	0.12	1.14	0.12	0.00	0.86	0.08
Testing	0.11	1.03	0.10	0.00	0.39	0.03
Asphalting	4.82	16.58	28.54	0.04	4.80	1.68
Landscaping	1.96	9.05	15.14	0.02	3.02	0.87
Irrigation	2.15	8.53	5.09	0.01	1.10	0.46
Distribution Construction						
Civil	4.27	16.34	41.78	0.06	2.26	1.47
Electrical	3.43	14.15	26.75	0.04	1.53	0.97
Subtransmission Source Line Construction						
Survey	0.22	2.11	0.21	0.00	1.98	0.19
Marshalling Yard	0.99	5.42	7.15	0.01	0.58	0.32
Right-of-Way Clearing	3.10	14.05	24.96	0.03	40.02	6.94
Roads and Landing Work	12.57	51.16	138.21	0.18	280.90	37.02
Guard Structure Installation	2.73	12.13	24.57	0.04	19.60	2.73
Existing Wood Poles Removal	2.16	9.30	17.11	0.02	13.92	1.98
Tubular Steel Pole Foundations Installation	4.83	21.86	50.14	0.07	75.38	9.25
Wood Pole Haul	1.30	5.90	10.81	0.02	6.07	0.93
Wood Pole Assembly	2.43	11.50	17.64	0.03	11.96	1.85
Wood Pole Installation	3.43	16.31	31.82	0.05	18.12	2.80
Steel Pole Haul	1.30	5.90	10.81	0.02	6.07	0.93
Steel Pole Assembly	2.43	11.50	17.64	0.03	11.96	1.85
Steel Pole Erection	2.25	10.84	16.57	0.02	11.86	1.76
Conductor Installation	10.12	44.18	107.25	0.15	57.24	8.56
Guard Structure Removal	2.35	10.57	20.52	0.03	15.76	2.24
Restoration	2.29	10.81	17.17	0.03	22.83	3.89
Telecommunications Construction						
Control Building Communications Room	0.24	2.27	0.45	0.00	0.26	0.02
Roads and Landing Work	3.64	15.28	28.58	0.04	69.80	10.20
Overhead Cable Installation	2.74	12.72	29.52	0.04	66.39	7.38
Underground Facility Installation	1.14	6.33	5.54	0.01	0.80	0.42
Underground Cable Installation	2.95	12.25	28.20	0.05	1.28	0.90
Optical Systems Installation at Other Locations	0.57	5.51	0.56	0.01	0.64	0.04
Nuevo Substation Demolition						
Civil	1.47	8.17	10.40	0.02	0.99	0.67
Electrical	0.80	30.96	4.29	0.01	0.56	0.27
Maintenance Crew Equipment Check	0.11	1.01	0.10	0.00	0.12	0.01
Testing	0.11	1.01	0.10	0.00	0.38	0.03
Model P.T. Substation Demolition						
Civil	1.04	6.00	6.46	0.01	0.73	0.43
Electrical	3.47	14.63	30.57	0.04	1.53	1.42

Notes:
VOC = volatile organic compounds
CO = carbon monoxide
NOX = nitrogen oxides
SOX = sulfur oxides
PM10 = suspended particulate matter measuring less than 10 microns
PM2.5 = suspended particulate matter measuring less than 2.5 micron
lb/day = pounds per day
MEER = mechanical and electrical equipment room

Table 2
Alternative 2
Construction Emissions Summary
Total Daily Criteria Pollutant Emissions for Overlapping Construction Phases

Group[a]	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.19	1.85	0.19	0.00	1.08	0.10
Grading	11.63	52.09	117.60	0.16	33.18	9.46
Civil, Fencing	4.43	31.15	35.96	0.06	8.36	2.48
MEER, Electrical, Wiring, Transformers, Equipment Check, Testing, Asphalting, Landscaping, Irrigation	11.63	105.76	60.43	0.10	17.06	4.26
Maximum	**11.63**	**105.76**	**117.60**	**0.16**	**33.18**	**9.46**
Distribution Construction						
All	7.70	30.49	68.54	0.11	3.79	2.45
Maximum	**7.70**	**30.49**	**68.54**	**0.11**	**3.79**	**2.45**
Subtransmission Source Line Construction						
Marshalling Yard, Survey	1.21	7.53	7.37	0.01	2.56	0.51
Marshalling Yard, Right-of-Way Clearing, Roads and Landing Work	16.66	70.63	170.32	0.23	321.50	44.28
Marshalling Yard, Tubular Steel Pole Foundations Installation	5.82	27.28	57.30	0.09	75.96	9.57
Marshalling Yard, Steel Pole Haul	2.29	11.32	17.96	0.03	6.65	1.25
Marshalling Yard, Steel Pole Assembly	3.42	16.91	24.79	0.04	12.54	2.16
Marshalling Yard, Steel Pole Erection	3.24	16.26	23.72	0.04	12.44	2.07
Marshalling Yard, Wood Pole Haul	2.29	11.32	17.96	0.03	6.65	1.25
Marshalling Yard, Wood Pole Assembly	3.42	16.91	24.79	0.04	12.54	2.16
Marshalling Yard, Wood Pole Installation	4.42	21.73	38.98	0.06	18.70	3.12
Marshalling Yard, Existing Wood Poles Removal, Guard Structure Installation	5.88	26.84	48.83	0.07	34.09	5.03
Marshalling Yard, Conductor Installation	11.11	49.60	114.40	0.17	57.82	8.87
Marshalling Yard, Guard Structure Removal	3.34	15.99	27.67	0.04	16.34	2.56
Marshalling Yard, Restoration	3.28	16.23	24.32	0.04	23.40	4.21
Maximum	**16.66**	**70.63**	**170.32**	**0.23**	**321.50**	**44.28**
Telecommunications Construction						
Roads and Landing Work	3.64	15.28	28.58	0.04	69.80	10.20
Control Building Communications Room, Overhead Cable Installation, Underground Facility Installation, Underground Cable Installation, Optical Systems Installation at Other Locations	7.64	39.08	64.27	0.11	69.37	8.76
Maximum	**7.64**	**39.08**	**64.27**	**0.11**	**69.80**	**10.20**
CONSTRUCTION MAXIMUM DAILY[b]	**43.63**	**245.97**	**420.73**	**0.60**	**428.28**	**66.39**
Nuevo Substation Demolition						
Civil	1.47	8.17	10.40	0.02	0.99	0.67
Electrical	0.80	30.96	4.29	0.01	0.56	0.27
Maintenance Crew Equipment Check	0.11	1.01	0.10	0.00	0.12	0.01
Testing	0.11	1.01	0.10	0.00	0.38	0.03
Maximum	**1.47**	**30.96**	**10.40**	**0.02**	**0.99**	**0.67**
Model P.T. Substation Demolition						
Civil	1.04	6.00	6.46	0.01	0.73	0.43
Electrical	3.47	14.63	30.57	0.04	1.53	1.42
Maximum	**3.47**	**14.63**	**30.57**	**0.04**	**1.53**	**1.42**
DEMOLITION MAXIMUM DAILY[c]	**3.47**	**30.96**	**30.57**	**0.04**	**1.53**	**1.42**
PEAK DAILY[d]	**43.63**	**245.97**	**420.73**	**0.60**	**428.28**	**66.39**
SCAQMD Significance Threshold	**75**	**555**	**100**	**150**	**150**	**55**

[a] The construction phases within a group could all occur at the same time.

[b] Construction maximum daily emissions are the sum of the maximum daily emissions during construction of the substation, the distribution facilities, the subtransmission source lines and the telecommunications facilities, since construction of all of these components could occur at the same time.

[c] Demolition maximum daily emissions are the maximum daily emissions during demolition of the Nuevo Substation or the Model P.T. Substation.

[d] Peak daily emissions are the greater of the maximum daily emissions during construction and during demolition, since demolition would occur after construction is completed.

Table 1
Alternative 2 with Road Dust Mitigation
Construction Emissions Summary
Total Daily Criteria Pollutant Emissions by Component

Phase	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.19	1.85	0.19	0.00	0.62	0.05
Grading	11.63	52.09	117.60	0.16	29.51	9.10
Fencing	0.65	4.53	3.55	0.01	1.59	0.35
Civil	3.78	26.62	32.41	0.05	3.84	1.83
Substation MEER	0.26	2.30	0.71	0.00	1.11	0.12
Electrical	0.96	41.64	3.94	0.01	1.31	0.32
Wiring	0.27	11.14	0.48	0.00	0.29	0.04
Transformers	0.99	14.35	6.32	0.01	1.58	0.40
Maintenance Crew Equipment Check	0.12	1.14	0.12	0.00	0.47	0.04
Testing	0.11	1.03	0.10	0.00	0.24	0.02
Asphalting	4.82	16.58	28.54	0.04	3.53	1.56
Landscaping	1.96	9.05	15.14	0.02	2.18	0.79
Irrigation	2.15	8.53	5.09	0.01	0.95	0.45
Distribution Construction						
Civil	4.27	16.34	41.78	0.06	2.26	1.47
Electrical	3.43	14.15	26.75	0.04	1.53	0.97
Subtransmission Source Line Construction						
Survey	0.22	2.11	0.21	0.00	1.05	0.10
Marshalling Yard	0.99	5.42	7.15	0.01	0.58	0.32
Right-of-Way Clearing	3.10	14.05	24.96	0.03	29.23	5.86
Roads and Landing Work	12.57	51.16	138.21	0.18	155.66	24.50
Guard Structure Installation	2.73	12.13	24.57	0.04	9.84	1.76
Existing Wood Poles Removal	2.16	9.30	17.11	0.02	7.07	1.30
Tubular Steel Pole Foundations Installation	4.83	21.86	50.14	0.07	36.96	5.41
Wood Pole Haul	1.30	5.90	10.81	0.02	3.17	0.64
Wood Pole Assembly	2.43	11.50	17.64	0.03	6.26	1.28
Wood Pole Installation	3.43	16.31	31.82	0.05	9.30	1.92
Steel Pole Haul	1.30	5.90	10.81	0.02	3.17	0.64
Steel Pole Assembly	2.43	11.50	17.64	0.03	6.26	1.28
Steel Pole Erection	2.25	10.84	16.57	0.02	6.16	1.19
Conductor Installation	10.12	44.18	107.25	0.15	29.21	5.75
Guard Structure Removal	2.35	10.57	20.52	0.03	7.98	1.46
Restoration	2.29	10.81	17.17	0.03	16.03	3.22
Telecommunications Construction						
Control Building Communications Room	0.24	2.27	0.45	0.00	0.26	0.02
Roads and Landing Work	3.64	15.28	28.58	0.04	43.70	7.59
Overhead Cable Installation	2.74	12.72	29.52	0.04	31.54	3.89
Underground Facility Installation	1.14	6.33	5.54	0.01	0.80	0.42
Underground Cable Installation	2.95	12.25	28.20	0.05	1.28	0.90
Optical Systems Installation at Other Locations	0.57	5.51	0.56	0.01	0.64	0.04
Nuevo Substation Demolition						
Civil	1.47	8.17	10.40	0.02	0.99	0.67
Electrical	0.80	30.96	4.29	0.01	0.56	0.27
Maintenance Crew Equipment Check	0.11	1.01	0.10	0.00	0.12	0.01
Testing	0.11	1.01	0.10	0.00	0.24	0.02
Model P.T. Substation Demolition						
Civil	1.04	6.00	6.46	0.01	0.73	0.43
Electrical	3.47	14.63	30.57	0.04	1.53	1.42

Notes:
VOC = volatile organic compounds
CO = carbon monoxide
NOX = nitrogen oxides
SOX = sulfur oxides
PM10 = suspended particulate matter measuring less than 10 microns
PM2.5 = suspended particulate matter measuring less than 2.5 micron
lb/day = pounds per day
MEER = mechanical and electrical equipment room

Table 2
Alternative 2 with Road Dust Mitigation
Construction Emissions Summary
Total Daily Criteria Pollutant Emissions for Overlapping Construction Phases

Group[a]	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Substation Construction						
Survey	0.19	1.85	0.19	0.00	0.62	0.05
Grading	11.63	52.09	117.60	0.16	29.51	9.10
Civil, Fencing	4.43	31.15	35.96	0.06	5.43	2.18
MEER, Electrical, Wiring, Transformers, Equipment Check, Testing, Asphalting, Landscaping, Irrigation	11.63	105.76	60.43	0.10	11.66	3.72
Maximum	**11.63**	**105.76**	**117.60**	**0.16**	**29.51**	**9.10**
Distribution Construction						
All	7.70	30.49	68.54	0.11	3.79	2.45
Maximum	**7.70**	**30.49**	**68.54**	**0.11**	**3.79**	**2.45**
Subtransmission Source Line Construction						
Marshalling Yard, Survey	1.21	7.53	7.37	0.01	1.63	0.41
Marshalling Yard, Right-of-Way Clearing, Roads and Landing Work	16.66	70.63	170.32	0.23	185.46	30.68
Marshalling Yard, Tubular Steel Pole Foundations Installation	5.82	27.28	57.30	0.09	37.53	5.72
Marshalling Yard, Steel Pole Haul	2.29	11.32	17.96	0.03	3.75	0.95
Marshalling Yard, Steel Pole Assembly	3.42	16.91	24.79	0.04	6.84	1.59
Marshalling Yard, Steel Pole Erection	3.24	16.26	23.72	0.04	6.74	1.50
Marshalling Yard, Wood Pole Haul	2.29	11.32	17.96	0.03	3.75	0.95
Marshalling Yard, Wood Pole Assembly	3.42	16.91	24.79	0.04	6.84	1.59
Marshalling Yard, Wood Pole Installation	4.42	21.73	38.98	0.06	9.88	2.24
Marshalling Yard, Existing Wood Poles Removal, Guard Structure Installation	5.88	26.84	48.83	0.07	17.49	3.37
Marshalling Yard, Conductor Installation	11.11	49.60	114.40	0.17	29.79	6.07
Marshalling Yard, Guard Structure Removal	3.34	15.99	27.67	0.04	8.56	1.78
Marshalling Yard, Restoration	3.28	16.23	24.32	0.04	16.61	3.53
Maximum	**16.66**	**70.63**	**170.32**	**0.23**	**185.46**	**30.68**
Telecommunications Construction						
Roads and Landing Work	3.64	15.28	28.58	0.04	43.70	7.59
Control Building Communications Room, Overhead Cable Installation, Underground Facility Installation, Underground Cable Installation, Optical Systems Installation at Other Locations	7.64	39.08	64.27	0.11	34.52	5.27
Maximum	**7.64**	**39.08**	**64.27**	**0.11**	**43.70**	**7.59**
CONSTRUCTION MAXIMUM DAILY[b]	**43.63**	**245.97**	**420.73**	**0.60**	**262.47**	**49.81**
Nuevo Substation Demolition						
Civil	1.47	8.17	10.40	0.02	0.99	0.67
Electrical	0.80	30.96	4.29	0.01	0.56	0.27
Maintenance Crew Equipment Check	0.11	1.01	0.10	0.00	0.12	0.01
Testing	0.11	1.01	0.10	0.00	0.24	0.02
Maximum	**1.47**	**30.96**	**10.40**	**0.02**	**0.99**	**0.67**
Model P.T. Substation Demolition						
Civil	1.04	6.00	6.46	0.01	0.73	0.43
Electrical	3.47	14.63	30.57	0.04	1.53	1.42
Maximum	**3.47**	**14.63**	**30.57**	**0.04**	**1.53**	**1.42**
DEMOLITION MAXIMUM DAILY[c]	**3.47**	**30.96**	**30.57**	**0.04**	**1.53**	**1.42**
PEAK DAILY[d]	**43.63**	**245.97**	**420.73**	**0.60**	**262.47**	**49.81**
SCAQMD Significance Threshold	**75**	**555**	**100**	**150**	**150**	**55**

[a] The construction phases within a group could all occur at the same time.

[b] Construction maximum daily emissions are the sum of the maximum daily emissions during construction of the substation, the distribution facilities, the subtransmission source lines and the telecommunications facilities, since construction of all of these components could occur at the same time.

[c] Demolition maximum daily emissions are the maximum daily emissions during demolition of the Nuevo Substation or the Model P.T. Substation.

[d] Peak daily emissions are the greater of the maximum daily emissions during construction and during demolition, since demolition would occur after construction is completed.

SOUTHERN CALIFORNIA
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MEMORANDUM

DATE: September 2, 2011
TO: Michael Rosauer, Project Manager, CPUC Energy Division
FROM: Rosalie Barcinas, Project Manager, SCE

SUBJECT: Lakeview Substation Project – Evaluation of CPUC alternatives

The purpose of this memorandum is to address the potential alternatives proposed by the CPUC to SCE on June 8, 2011. SCE appreciates the opportunity to review these alternatives, and in doing so, took careful consideration to determine whether each alternative would avoid or substantially reduce significant environmental impacts, while at the same time meet the basic objectives of the Lakeview Substation Project (hereinafter referred to as the "Project").

In making these determinations, SCE evaluated whether the proposed alternatives were reasonable in accordance with CEQA Guidelines, § 15126.6 (a). In summary, SCE has determined that each of the alternatives proposed by the CPUC should not be considered further because 1) Alternatives 1 and 4 do not meet the basic objectives of the Project and are beyond the range of reasonableness under CEQA and 2) Alternatives 2 and 3 do not avoid or substantially lessen environmental impacts to a less than significant level.

SCE's analysis of each proposed alternative is discussed in detail below. As a preliminary matter, however, SCE notes that Project Alternative 1: "Phased Construction" involves only mitigation and does not constitute an alternative to the Project pursuant to CEQA. Alternatives included in an Environmental Impact Report ("EIR") need only relate to the proposed project *as a whole*, not to its various parts. [*See e.g., Big Rock Mesas Property Owners Association v. Board of Supervisors*, 73 Cal. App. 3d 218 (1977) (where the court held an EIR prepared for a tentative subdivision map was not required to analyze alternatives to the proposed grading plans and the location of an access road since those elements did not constitute the project "whole".).] Here, the proposed phasing affects only how the project components are sequenced during construction and does not relate to the project as a whole.

In addition, CEQA requires an analysis of "a range of *reasonable alternatives to the project*, or to the *location of the project*, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project…." (CEQA Guidelines § 15126.6) (emphasis added). Project alternatives typically fall into one of two categories: on-site alternatives, which generally consist of different uses of the land under consideration; and off-site alternatives, which usually involve similar uses at different locations."

(*Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal. 3d 553, 566.) In this case, phasing of construction does not change the use of the land (the land will still be used for the same project components) nor does it propose a similar use at a different location.

The below discussion explains why phasing construction in an attempt to mitigate air quality impacts to a less than significant level is neither feasible nor reasonable under CEQA.

<u>Alternative 1 - Phased Construction</u>

As detailed on page 1 of the CPUC's proposed alternatives table, Alternative 1 would involve altering the construction schedule to allow for phased construction. In particular, the CPUC proposes phasing construction activities in order to bring two criteria pollutants (specifically, NOx and PM10) to a less than significant level for purposes of calculating air quality impacts.

In determining whether each of the four alternatives proposed by the CPUC is appropriate, the CPUC has asked SCE to focus on two factors: 1) whether the alternative (or with respect to Alternative 1, the mitigation) would be feasible; and 2) whether it would be reasonable.

A. A phased project would not be feasible because it is not capable of being accomplished in a reasonable period of time.

With respect to the CPUC's request for information regarding the feasibility of phased construction, the CEQA Guidelines define "feasible" as: "capable of being accomplished in a successful manner within a reasonable period of time." (14 CCR § 15364.) In this case, the timing of the Project is critical because it implicates the primary objective of the Project. In particular, SCE's "Proponent's Environmental Assessment" ("PEA") identifies as a key project objective "to serve existing and long-term projected electrical demand requirements in the Electrical Needs Area beginning in mid-2013". Phasing construction would not meet this objective because it would delay construction, at a minimum, by 12 months and likely longer.

The CPUC's phasing proposal assumes the construction of the Project would extend from SCEs proposed 12 months (as described in the PEA) to 21.8 months in order to reduce the amount of overlapping construction activities. SCE reviewed the CPUC's proposal and it was determined that construction would actually be extended to 23.6 months based on the assumptions provided. Further, the extension of the construction period would have the potential to prolong the duration of temporary impacts to noise, traffic and aesthetics. While it is assumed that these impacts would remain less than significant, phasing construction would still not meet SCE's primary objective of serving existing and long-term demand by mid-2013. As a result, phased construction would clearly be infeasible as defined by CEQA Guidelines § 15126.6 (a), (f) since the necessary infrastructure would not be available until at least mid-2014, and likely after this date as discussed further below. On this basis alone, phasing construction should be rejected from further analysis.

B. Phasing construction is not reasonable due to technical, practical, and economic constraints.

1. <u>Technical Constraints</u>

Please find below the updated Substation Capacity and Peak Demand table (Table 1-1 from the PEA) for the Lakeview Substation Project. This table reflects SCE published projections for the years 2011-2020.

The Electrical Needs Area for the Lakeview Substation Project is currently served by the capacity of Nuevo Substation (16.1 MVA) and temporary capacity provided by Model Substation (10 MVA) which was installed in 2009 as overload mitigation while developing and licensing the Lakeview Substation Project. The total capacity is 26.1 MVA.

In 2013, the 1-in-10 year heat storm electrical demand is projected to be 26.5 MVA which would exceed the capacity of the Electrical Needs Area and each year after, the deficit in capacity increases.

If the Lakeview Substation Project operating date of 2013 is not met, additional mitigation would be required to serve the projected electrical demand and to prevent electrical service interruptions. Currently there are two feasible mitigation plans that could provide additional capacity to the Electrical Needs Area. Both are expected to require a minimum of 18-24 months to plan, engineer, and construct and would need to be in service by mid-2013. Additional time may also be needed if property and/or land rights are required.

The first would be to construct approximately 2-3 miles of new 12 kV distribution circuitry from an adjacent substation located approximately 5 miles due west from Nuevo Substation. This additional circuitry would allow for up to 6 MVA of electrical demand to be transferred from Nuevo Substation and provide enough capacity for the Electrical Needs Area through 2015. However, it would result in a distribution circuit that would serve electrical demand nearly 7 miles from its source substation and may require additional measures to meet voltage requirements. Detailed planning activities would be required to develop a complete scope of work.

The second mitigation would be to construct an additional temporary 33/12 kV 10 MVA distribution substation similar to the Model Substation. This would consist of acquiring property, fencing, grading, transformer installation, conduit and substructure installation, installation of poles, switches, circuit breakers, etc., as needed. Depending on where the substation property would be located, there would be an unquantified amount of construction activities required to bring in the 33 kV source line as well as to construct an outgoing 12 kV distribution line to serve the electrical demand. This temporary capacity addition is estimated to provide enough capacity for the Electrical Needs Area through 2016. Like the first mitigation option, this is only a high-level scope and detailed planning activities would be required to develop a complete scope of work. Upon completion of the Lakeview Substation Project, the temporary 33/12 kV substation installed as mitigation would be removed in a manner similar to the Model 33/12 kV Substation.

Neither option serves the long-term needs of the Electrical Needs Area and would only be constructed as temporary mitigation for a delay in the operating date and at best could provide three years of additional capacity. Moreover, each of these mitigation measures would require construction that would likely result in additional air emissions (over and beyond those emissions of the Lakeview Substation Project), which would defeat the purpose of phasing in the first place.

Table 1-1: Electrical Needs Area: Substation Capacity and Peak Demand					
Historical Capacity and Peak Demand	**2006**	**2007**	**2008**	**2009***	**2010**
Planned Maximum Operating Limit (MVA)	16.1	16.1	16.1	16.1	16.1
Peak Demand (MVA)	9.8	13.4	15.1	15.6	16.0
Planned Capacity and Peak Demand	**2011**	**2012**	**2013**	**2014**	**2015**
Planned Maximum Operating Limit (MVA)	16.1	16.1	16.1	16.1	16.1
Projected Peak Demand Normal Weather (MVA)	19.6	22.8	24.2	26.0	29.3
Projected Peak Demand 1-in-10 Year Heat Storm (MVA)	21.5	25.0	26.5	28.5	32.1
Reserve (MVA)	(5.4)	(8.9)	(10.4)	(12.4)	(16.0)
Planned Capacity and Peak Demand	**2016**	**2017**	**2018**	**2019**	**2020**
Planned Maximum Operating Limit (MVA)	16.1	16.1	16.1	16.1	16.1
Projected Peak Demand Normal Weather (MVA)	32.6	35.9	39.2	42.5	45.8
Projected Peak Demand 1-in-10 Year Heat Storm (MVA)	35.7	39.3	43.0	46.6	50.2
Reserve (MVA)	(19.6)	(23.2)	(26.9)	(30.5)	(34.1)

*In 2009, SCE added 10 MVA of substation capacity (for a total of 26.1 MVA) to the Electrical Needs Area by constructing the temporary Model 33/12 kV Substation. Electrical demand in excess of the capacity of Nuevo Substation will be temporarily served by Model Substation.

Revised-August 2011

2. Practical Constraints

Implementing a phased construction schedule is also unreasonable due to various practical considerations that are still unknown at the time the PEA is filed. The scheduling of construction activities for the Lakeview Substation, distribution getaways, subtransmission source lines, and telecommunications components is based on many factors, including, but not limited to the following:

- Final Engineering
- Permit Acquisition
- Land Rights Acquisition
- Contractor/Crew Availability
- Procurement of Materials
- Field Conditions

Because these factors are still in flux at the time SCE files a PEA for a project, SCE develops project construction schedules based on certain assumptions. Among these assumptions is the idea that engineering, once finalized, will be primarily consistent with the engineering provided in the PEA. SCE also assumes that land rights will be secured in a timely manner; that permits will be secured at various stages of the construction process; that contractors and materials will be available when needed; and that field conditions will be suitable for construction. However, by implementing a phased construction schedule, SCE will lose the flexibility it needs to account for these unknowns that are yet to be established.

For example, a certain amount of lead time is needed in order to secure permits and land rights for the project. During typical (non-phased) construction, if any one of these activities is delayed for some reason, SCE has the flexibility to move forward with construction on a different component of the project. However, by implementing a phased construction schedule, SCE loses this flexibility. This inflexibility would lead to yet further delay, and prolong SCE's ability to meet its project objective related to servicing existing and long-term demand by mid-2013.

Another practical consideration is contractor availability. Using a non-phased construction schedule, SCE has a high degree of certainty in knowing what contractors will be available and how those contractor's crews may be optimized. By contrast, a phased construction schedule without scheduling flexibility causes significant complications in terms of contractor and crew availability. As a general rule, contractors need a certain amount of flexibility and comfort in knowing how long the project construction will last so that they can plan their crews accordingly. Because the phased construction will not provide contractors with this level of comfort, contractor bids will likely be much more costly and may also be more difficult to obtain since phased construction could limit their ability to optimize their crews and other work. If there are multiple contractors on a project where phasing is enforced, one construction delay can cause a ripple effect that will impact other contractor contracts. Purchase Change Order or amendments to contracts would then be necessary, which could significantly escalate project costs. For any construction work that is dependent on another contractor's work to be completed, any delays would result in delays throughout the entire construction schedule. In this event, SCE would incur substantial unforeseen costs for crew idle time.

Because of the concerns raised above, the phased construction schedule as proposed by the CPUC may need to be pushed out even further should SCE be unable to secure the necessary contractors to construct the project.

Phased construction is also impractical and unreasonable because it does not provide SCE with the flexibility it needs to adjust the schedule in order to respond to changing conditions in the field. Those field conditions could include, among other considerations, weather challenges, environmental challenges (e.g. nesting birds and other species or unanticipated discovery of cultural resources), or construction related challenges (e.g., SCE encounters bedrock that requires different equipment for excavation than was previously anticipated). Because all of these activities are interdependent on each other, SCE must have flexibility during the construction of projects in order to get the projects constructed and meet the necessary operating dates.

3. Economic Constraints

Managing costs is always a factor and considered when planning and executing construction activities. Phasing construction activities or sequencing activities so that there is no overlap is not a cost effective way of doing business.

In summary, phasing construction is both infeasible and unreasonable because there are too many unknowns based on the dependencies discussed above.

C. CPUC Proposed Mitigation Measures for Air Quality Impacts

SCE has reviewed the proposed air quality mitigation measures provided by the CPUC for consideration with the phased project construction.

As SCE understands it, the concept for Mitigation Measure 1 would be to develop a plan to demonstrate that on- road and off- road NOx and PM10 exhaust emissions would be reduced by 20% and 45%, respectively, compared to the statewide fleet average. For both examples of language provided by the CPUC, the local Air Quality Management District was the approval agency with oversight of the plan. The San Joaquin Valley Air Pollution Control District (SJVAPCD) allows for off- site reduction fees to be paid to make up for any shortcomings in achieving the 20% and 45% reduction rates. However, the Proposed Project is under the jurisdiction of the South Coast Air Quality Management District (SCAQMD) which has no such NOx and PM10 reduction plan mechanism as compared to the SJVAPCD. Furthermore, at this time, SCE cannot confirm its ability to reduce on-road and off-road NOx and PM10 exhaust emissions by 20% and 45%, respectively, as equipment type, year, etc. is not known. At this time without knowing the details about the construction equipment that will be used for the Proposed Project, as well as not having a fee mechanism or guidance from SCAQMD to cover any shortcomings in the reduction rates, it is not clear to SCE that Mitigation Measure 1 is achievable for the Proposed Project.

The PM10 mitigation measure example explains SCE would apply water to subtransmission line access roads for the Proposed Project twice daily in order to reduce PM10 emissions. SCE agrees that this mitigation measure can be achieved and implemented during construction of the Lakeview Substation Project. In SCE's air quality emissions analysis for the Lakeview Substation Project it was assumed that vehicle speeds on unpaved roads would be limited to 15 mph. SCE agrees that a reduction in vehicle speeds on unpaved roads to 15 mph, can be achieved and implemented during construction of the Lakeview Substation Project.

As noted above, SCE reemphasizes that Project Alternative 1: "Phased Construction" involves only mitigation and does not constitute an alternative to the Project pursuant to CEQA.

Alternative 2 - Relocated Project

As detailed on page 5 of the CPUC's proposed alternatives table, Alternative 2 would involve relocating certain Project components in order to reduce subtransmisison line routes, access road requirements, and raw material requirements (such as poles, cement, etc.) that would be required to construct and operate the Project. According to the CPUC's analysis, this relocation will bring NOx and PM10 to a less than significant level for purposes of calculating air quality impacts.

> **Alternative 2 should not be considered for further analysis because it does not mitigate impacts to a less than significant level nor significantly lessen impacts compared to the proposed project.**

As provided in CEQA Guidelines § 15126.6 (b), "the discussion of alternatives shall focus on alternatives to the project or its location *which are capable of avoiding or substantially lessening any significant effects of the project*." SCE prepared a modified construction table for Alternative 2 and according to SCE's calculations, even with implementation of the mitigation measures provided by the CPUC, it has been determined that this alternative would not bring the potential impacts below the significance thresholds nor would the impacts be significantly lessened from those of the proposed project. Please see the attached air quality emissions analysis for Alternative 2.

Because Alternative 2 would not mitigate air quality impacts to a less than significant level or significantly lessen impacts compared to the proposed project, this Alternative should be dismissed for further analysis.

In addition, this proposal has the potential to create greater impacts to another property owner.

Alternative 3 - Partial Underground Subtransmission Line Route

As detailed on page 7 of the CPUC's proposed alternative table, Alternative 3 would involve installing the portion of the proposed subtransmission line route between 10th and 11th streets underground rather than overhead. This alternative is being proposed in order to address input received during the scoping period and according to the CPUC, would further reduce a less-than-significant impact on aesthetic and visual resources.

> **Alternative 3 should not be considered for further analysis because no mitigation is required for a less than significant impact.**

As stated in SCE's response to the CPUC, dated May 11, 2011, this alternative is technically feasible; however, it would not result in any changes to the significance conclusions made in the PEA. Moreover, while this alternative could potentially result in a slight decrease in impacts to prime farmland, it would still not significantly lessen or reduce that impact below the significant level. This alternative would also likely result in an increase to air quality impacts.

Because Alternative 3 would 1) not significantly lessen or reduce impacts below the significance level, or 2) would simply further reduce a less than significant impact, this Alternative should be dismissed from further analysis.

Alternative 4 - No project

As detailed on page 8 of the CPUC's proposed alternative table, Alternative 4 proposed no new 115/12 kilovolt (kV) substation in the proposed location; neither of the two new 115 kV subtransmission line segments; neither of the two new underground 12 kV distribution getaways; none of the new facilities to connect the substation to SCE's existing telecommunications system; no upgrades to existing fiber-optic equipment at the specified existing substations; and the Nuevo Substation and Model Pole Top Substation would remain in operation.

> **Alternative 4 should be dismissed from further analysis because it does not meet the basic project objectives.**

Alternative 4 does not meet most of the basic objectives of the Project because the energy demand of the growing communities in the Lakeview and Nuevo areas of Riverside County is expected to exceed the combined energy capacity of the existing two substations in the 2013-2014 timeframe. As explained in the PEA, “The amount of electrical power that can be delivered to the Electrical Needs Area is limited to the maximum amount of electrical demand that Nuevo Substation can serve before the maximum operating limits are exceeded. Currently, the capacity of Nuevo Substation is limited to 16.1 MVA under normal operating conditions. In 2007, SCE projected that the peak electrical demand during 1-in-10-year heat storm conditions would exceed the planned Maximum Operating Limit by 2.0 MVA in 2009. Consequently, SCE planned the construction of a temporary solution to the projected shortfall in transformer capacity. Model Substation was constructed as an interim measure to meet the immediate capacity need in the Electrical Needs Area. The temporary Model Substation was constructed adjacent to Nuevo Substation and currently provides an additional 10 MVA of capacity and one 12 kV distribution circuit to the Electrical Needs Area.”

Thus, while Alternative 4 is economically, environmentally, legally, and technologically feasible, it should be dismissed from further analysis in accordance with CEQA Guidelines § 15126.6 (a) (“[a]n EIR shall describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project…”) because it does not meet the Project objectives.

DISCUSSION DRAFT: POTENTIAL ALTERNATIVES

SOUTHERN CALIFORNIA EDISON'S PROPOSED LAKEVIEW SUBSTATION PROJECT

(as of June 6, 2011)

<table>
<tr>
<td>Alternative 1 Phased Construction</td>
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Overview:

The Draft EIR identifies a significant and unavoidable impact associated with construction-related NOx and PM10 emissions. The other criteria pollutant emissions (e.g., CO, PM2.5, etc.) are not projected to exceed significance thresholds. Maximum proposed Project-related daily NOx and PM10 construction emission estimates for the Project would exceed South Coast Air Quality Management District (SCAQMD)'s significance thresholds. As analyzed in Section 4.3, Air Resources, Implementation of feasible mitigation measures would reduce maximum daily construction-related emissions of NOx and PM10 by approximately 20 percent and at least 30 percent, respectively; however, even as mitigated, maximum daily NOx and PM10 emissions would exceed SCAQMD's thresholds. See Table XX-1, below. [FN: The analysis assumes that demolition of the Nuevo Substation and Model Pole Top Substation would not overlap with other construction activities because these components of the existing power supply infrastructure would remain online until the Project was operational and cut-over could occur without causing a power outage in the area. Consequently, NOx and PM10 emissions associated with demolition are not included in the daily totals.] Consequently, the Project would cause a significant unavoidable impact related to daily emissions of NOx and PM10.
The purpose of Alternative 1, Phased Construction, is to reduce daily emissions of these criteria pollutants so as to avoid or reduce this significant environmental impact.
Significant environmental impact(s) avoided or substantially lessened: construction -related air emissions
Determination and rationale related to whether the alternative meets most of the basic project objectives: XX
Feasibility: XX
Reasonableness: XX

Main Distinction(s): Under this alternative, all aspects of the Project would remain as described in Chapter 2, Project Description, except for the construction schedule, which would be extended by approximately 10 months.
Details: As identified in the Proponent's Environmental Assessment (PEA), SCE anticipates that construction of four Project components (i.e., the Lakeview Substation, distribution, subtransmission lines, and telecommunication facilities) would overlap. Therefore, the maximum daily construction emissions would include the sum of emissions associated with each of the four components. However, with the exception of the subtransmission lie component, on an individual basis the maximum daily construction emissions for each the Project components would not exceed the thresholds. To ensure that emissions that would be associated with the subtansmission line component also would not exceed SCAQMD thresholds (and therefore be individually less than significant), activities related to subtransmission line ROW clearing and road development would not be able to overlap with each other or with the other activities that would be associated with the subtransmission line component. In other words, to address the subtransmission line emissions, Alternative 1 would require phased construction to ensure that the daily emissions would be below the threshold.
Using information obtained from PEA Appendix C, Table C-4, Possible Overlapping Construction Phases, the duration of each of the construction components for Alternative 1 were estimated (see Table XX-2, Estimated Duration of Alternative 1 Construction Activities). As noted in Table XX-2, implementation of Alternative 1 would result in a construction period of approximately 22 months, compared to the approximately 12-month construction period that would be associated with the Project's proposed overlapping of construction activities for the various components.
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Alternative 1 (continued)

TABLE XX-1

Project Component	**NOx (lbs/day)**		**PM10 (lbs/day)**	
	SCE Estimates	Mitigated (20%)	SCE Estimates	Mitigated (30%)
Lakeview Substation	*118*	94.4	33	23.1
Distribution	*69*	55.2	4	2.8
Subtransmission Lines	*159*	127.2	219	153.3
Telecommunications (fiber-optic)	*64*	51.2	69	48.3
Maximum Daily	***409***	**327.2**	**324.6**	**227.22**
SCAQMD Threshold	*100*	100	150	150
Nuevo Sub Demolition	10	8	1	1
Model Pole Top Sub Demolition	31	24	2	2

TABLE XX-2 ESTIMATED DURATION OF ALTERNATIVE 1 CONSTRUCTION ACTIVITIES

Project Component	**Days (months)**
Lakeview Substation[1]	220 days (11.0 months)
Distribution[2]	52days (2.6 months)
Subtransmission Lines[3]	77 days (3.9 months)
Telecommunication Facilities[4]	60 days (3.0 months)
Model Pole Top and Nuevo Substation Demo[5]	26 days (1.3 months)
Total	**21.8 months**

Notes:
1 Assumed grading, civil, and electrical work would occur sequentially with no overlap, all other activities would overlap.
2 Assumes two weeks civil work would occur prior to the electrical work and all other activities would overlap, all other activities would overlap.
3 Assumes road work, ROW clearing, installation of TSP foundations, and conductor installation would occur sequentially with no overlap, all other activities would overlap.
4 Assumes overhead cable installation and road and landing work would occur sequentially with no overlap, all other activities would overlap.
5 Note that the PEA indicates that the substation demolition components would not overlap with any of the other four Proposed Project components. Demolition construction duration assumes that activities associated with Model Pole Top Substation and Nuevo Substation would overlap; therefore days represent demolition of Model Pole.

Alternative 2 Relocated Project	**Overview**: • Relocating certain Project components would reduce subtransmisison line routes, access road requirements, and raw material requirements (such as poles, cement, etc.) that would be required to construct and operate the Project. The purpose of Alternative 2, *Relocated Project*, is to avoid or reduce significant environmental impacts of the Project by providing a "reduced," or less resource intensive, alternative. • Significant environmental impact(s) avoided or substantially lessened: construction -related NOx and PM10 air emissions, XX • Determination and rationale related to whether the alternative meets most of the basic project objectives: XX • Feasibility: XX • Reasonableness: XX **Main Distinction(s)**: Main distinctions between this alternative and the Project are as follows: • The Lakeview Substation would be constructed on the parcel located adjacent to and immediately northwest of the proposed site, at the corner of the continuation of 10th Street and future Avenue "A" (Figure XX, *Alternative 2*). • Subtransmission line segment XX would proceed up 10th Street as proposed for the Project, but would be approximately XX feet shorter than for the Project. Approximately 3-5 fewer wood poles would be required for this segment than for the proposed Project. • Subtransmission line segment XX would proceed southwesterly along Avenue "A" to its juncture with 11th Street. This segment would parallel, and be the same approximate distance as, the segment proposed for the Project. Approximately 7-8 wood poles would be installed along Avenue A, as well as two TSPs (one each at the north and northwest corners of APN 426-180-004, instead of the 9-10 wood poles proposed for the Project. • Access roads: This alternative would require XX fewer miles of road rehabilitation work along 11th Street (and XX fewer road miles overall relative to the proposed layout), no road construction or rehabilitation along the extension of Reservoir Avenue, a new access road from 10th Street at the existing corner of Reservoir, and XX miles of new/upgraded road work along "Avenue A." **Details**: Ybarrola Living Trust: • Owns approximately 100 acres (nine parcels) between 10th and 11th streets that would be bisected by the proposed Subtransmission line route • Requests that the line be located such that it is aligned with existing property lines and/or existing streets SCE's position (statements made in context of underground alt seem equally relevant here): • Needs two diverse paths for the subtransmission source lines that feed into the substation. • Opposed to multiple turns to follow property boundaries not located on planned streets

Alternative 2 (continued)	Comparison of the proposed Lakeview Substation location and the alternative substation site:
	• The alternative substation site would be adjacent to the proposed site on the proposed sites northwestern side.
	• Like the proposed site, the alternative substation site would be adjacent to the planned extension of 10th Street along the existing parcel boundary.
	• The alternative substation site also would be adjacent to planned "Avenue A" shown on the Assessor's parcel map and delineated between fields on Project figures.
	• SCE does not own, control access to, or have an existing right to construct and operate a substation on the alternative substation site. Rights would have to be obtained.
	
	Comparison of the proposed subtrasmission line route and the alternative alignment:
	• Proposed alignment would run southwest-southeast down 10th and 11th streets
	    o ALT ALIGNMENT WOULD NOT CHANGE THE LOCATION OF THE RUN;
	    o ALT ALIGNMENT WOULD REDUCE THE DISTANCE OF THE RUN
	• Proposed alignment follows established property lines
	    o ALT ALIGNMENT (NO CHANGE)
	• Proposed alignment does not follow existing streets
	    o ALT ALIGNMENT (NO CHANGE)
	• Proposed alignment would bisect private property held under one ownership (separating 4 parcels from 4 parcels)
	    o ALT ALIGNMENT WOULD MAINTAIN CONTIGUITY OF OWNERSHIP BLOCK (separating 1 parcel from 7 parcels)
	• Proposed alignment would install 3-5 TSPs at the substation site running southwest-southeast
	    o ALT ALIGNMENT WOULD NOT REQUIRE THESE POLES
	• Proposed alignment would install 9-10 wood poles along the segment of Reservoir Ave shown in the 2003 General Plan as a continuation of Reservoir Avenue, which is designated as an "urban arterial highway."
	    o ALT ALIGNMENT WOULD REQUIRE SAME NUMBER OF POLES, BUT WOULD INITIATE THE RUN AT THE NORTHWEST CORNER OF THE PROPOSED SUBSTATION SITE RATHER THAN THE SOUTHERN CORNER
	• Proposed alignment would install 25-27 wood poles along 11th Street between Reservoir Ave and the existing Valley-Moval 115 kV substransmission line
	    o 3-5 FEWER WOOD POLES COULD BE REQUIRED FOR ALT ALIGNMENT
	• The alternative subtransmission line route would require new ROW along "Avenue A" between 10th and 11th streets
	• The alternative subtransmission line route would be installed above ground

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<td>Alternative 3
Partial Underground Subtransmission Line Route</td>
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Overview:

Installing the portion of the proposed subtransmisison line route between 10th and 11th streets underground rather than overhead would address input received during the scoping period and would further reduce a less-than-significant impact on aesthetic/visual resources. The purpose of Alternative 3, Partial Underground Subtranmission Line Route, is to address input received and further reduce environmental impacts of the Project.
Significant environmental impact(s) avoided or substantially lessened: XX
Determination and rationale related to whether the alternative meets most of the basic project objectives: XX
Feasibility: XX
Reasonableness: XX

Main Distinction(s): Main distinctions between this alternative and the Project are as follows:

The portion of the subtransmission line route between 10th and 11th street, which was proposed along the future extension of reservoir avenue, would be installed underground rather than overhead. Other Project components would remain the same.

Details:

Ybarrola Living Trust:

Owns approximately 100 acres (nine parcels) between 10th and 11th streets that would be bisected by the proposed overhead subtransmission line route
Requests that the line be located underground to reduce aesthetic impacts

SCE's position:

Typically, electric lines with voltages greater than 50 kV are constructed overhead.
Overhead lines usually create less construction and long-term environmental impacts
Overhead lines usually are easier to maintain
Overhead lines usually cost substantially less than lines constructed underground.
There are no technical advantages to constructing the proposed 115 kV subtransmission lines underground.

Comparison of the Proposed Subtrasmission Line Route and the Partial Underground Route Alternative:

Would install 9-10 wood poles along the segment of Reservoir Ave shown in the 2003 General Plan as a continuation of Reservoir Avenue, which is designated as an "urban arterial highway."
ALT WOULD INSTALL ROUTE UNDERGROUND ALONG THE FUTURE EXTENSION OF RESERVOIR AVENUE TO 11TH STREET
Would bisect private property held under one ownership (separating 4 parcels from 4 parcels)
PARTIAL UNDERGROUND ALT: BISECTION WOULD OCCUR BELOW-GRADE

CEQA Considerations (per SCE)

Technically feasible. Based on a conceptual review, underground construction is technically feasible for this portion of the proposed subtransmission line. It would require an approximate 30-foot right of way with limited secondary land uses. For example, any land use or activities that would result in a change in grade that would not provide a minimum of 36" of cover over SCE's underground facilities would be restricted within the underground easement portion of SCE's right of way in order to protect the underground facilities over the long term. The

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Alternative 3 (continued)	County of Riverside's General Plan designates the extension of Reservoir Avenue to be used as an Urban Arterial with an approximate right of way of 152 feet. If construction of Reservoir Avenue, as identified in the General Plan, results in substantial grade changes, a potential rebuild/relocation could be necessary in order to maintain required underground clearances. Underground construction for this portion of the project would also cost more than the proposed overhead construction. • Aesthetics: The undergrounding of the subtransmission line in this location would have the potential to reduce, but not eliminate, the project's visibility to the public. There is still potential for some aboveground facilities (e.g., riser poles and protective bollards) to be visible in this location. Therefore, the impact would remain less than significant, as determined for the Proposed Project in the PEA. • Agriculture and Forest Resources: The PEA concluded that for the Proposed Project, 13.50 acres of farmland would be permanently impacted. This section of underground subtransmission line, combined with other project components, would result in approximately 13.23 acres of farmland permanently impacted. In addition to the 13.23 acres, approximately 0.10 acres would be restricted from the use of heavy equipment and deep-rooted plants, which have the potential to interfere with the underground system. The Proposed Project assumed a conversion of land would occur for set clearances around the proposed overhead facilities and for the access road. The underground subtransmission line assumes a conversion of land would occur for set clearances around the riser poles and vaults, an access road, and potentially for restricted uses above the underground trench. • Air Quality and Greenhouse Gas Emissions: The undergrounding of the subtransmission line in this location would not result in any changes to the significance conclusions made in the PEA. However, underground construction of the subtransmission line would result in slightly increased VOC (+3.9 lbs/day), CO (+27 lbs/day), and NOx (+14.8 lbs/day) peak daily emissions, as well as slight increases to CO (+3 lbs/day) and NOx (+11 lbs/day) on-site emissions during construction. Total greenhouse gas emissions would increase 57 metric tons. The sum total of greenhouse gas emissions during construction amortized over 30 years and annual operation greenhouse gas emissions would increase by approximately 2 metric tons/year. • The following resources are also not likely to result in any changes to the conclusions made for the Proposed Project in the PEA: Biological Resources; Cultural Resources; Geology, Soils and Seismicity; Hazards and Hazardous Materials; Hydrology and Water Quality; Land Use and Planning; Mineral Resources; Noise; Population and Housing; Public Services; Recreation; Transportation and Traffic; and Utilities and Service Systems.

Alternative 4 **No Project**	**Overview**: • No new 115/12 kilovolt (kV) substation in the proposed location; neither of the two new 115 kV subtransmission line segments; neither of the two new underground 12 kV distribution getaways; none of the new facilities to connect the substation to SCE's existing telecommunications system; no upgrades to existing fiber-optic equipment at the specified existing substations; and the The Nuevo Substation and Model Pole Top Substation would remain in operation. • Significant environmental impact(s) avoided or substantially lessened: [Any and all] • Determination and rationale related to whether the alternative meets most of the basic project objectives: Alternative 4 does not meet most of the basic objectives of the Project because the energy demand of the growing communities in the Lakeview and Nuevo areas of Riverside County is expected to exceed the combined energy capacity of the existing two substations in the 2013-2014 timeframe. As explained in the PEA, "The amount of electrical power that can be delivered to the Electrical Needs Area is limited to the maximum amount of electrical demand that Nuevo Substation can serve before the maximum operating limits are exceeded. Currently, the capacity of Nuevo Substation is limited to 16.1 MVA under normal operating conditions. In 2007, SCE projected that the peak electrical demand during 1-in-10-year heat storm conditions would exceed the planned Maximum Operating Limit by 2.0 MVA in 2009. Consequently, SCE planned the construction of a temporary solution to the projected shortfall in transformer capacity. Model P.T. was constructed as an interim measure to meet the immediate capacity need in the Electrical Needs Area. The temporary Model P.T. Substation was constructed adjacent to Nuevo Substation and currently provides an additional 10 MVA of capacity and one 12 kV distribution circuit to the Electrical Needs Area." • Feasibility: Alternative 4 is economically, environmentally, legally, and technologically feasible. However…. • Reasonableness: Alternative 4 is unreasonable because it "would create a high risk for the potential inability to serve electrical demand in the Electrical Needs Area."

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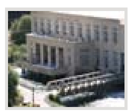

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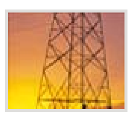

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