Exhibit 1

2009 Integrated Resource Plan

For

Power Supply Resources
City of Pasadena Water and Power Department

Prepared by
Pace Global Energy Services, LLC

March 16, 2009

PACE

4401 Fair Lakes Court
Fairfax, VA 22033-3848 USA
Phone: 1.703.818.9100
Fax: 1.703.818.9108

2009 Integrated Resource Plan Report

Prepared for:

City of Pasadena Water and Power Department

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EXHIBITS

EXECUTIVE SUMMARY

In this 2009 Integrated Resource Plan (2009 IRP), Pasadena Water and Power ("PWP") identifies its Preferred Resource Plan for satisfying its electric power requirements, consisting of energy efficiency, demand side management resources, renewable resources and other supply side resources over the next twenty years. This Preferred Resource Plan best meets the multiple objectives of meeting PWP's long term electricity needs in a reliable, cost competitive, flexible, and environmentally conscious manner under a wide variety of market, regulatory, and economic conditions. The Preferred Resource Plan therefore improves PWP's ability to attain a position of environmental leadership, consistent with the City's broader environmental goals and commitments.

In preparing the 2009 IRP, PWP engaged public involvement in a participatory process over six months that included meetings of a Stakeholder Advisory Group representing the major constituencies in PWP's service territory, meetings with the Environmental Advisory Commission ("EAC") and the Municipal Services Committee ("MSC"), and several public meetings that were attended by a diverse group of stakeholders. The Stakeholder Advisory Group had monthly meetings, run through a facilitated process with PWP's participation, but organized by an independent consultant (Pace Global Energy Services or Pace) who was responsible for setting the agenda and facilitating the process. The Stakeholder Advisory Group reached unanimous consensus on the Preferred Resource Plan presented here.

The Preferred Resource Plan resulted from a structured, two-stage process. Phase I consisted of the screening of around 15 technology options and over 100 portfolios, representing combinations of these technology additions over different years. The number of uncertainties considered in the Phase II "risk" stage of the process is measured in the thousands, as uncertainty in load, gas prices, dispatch for technology choices, carbon prices, capital costs for technologies, market penetration of renewable and demand side options, and power prices for sales from the Intermountain Power Plant ("IPP") were quantified and considered. Regulatory uncertainty regarding both carbon legislation and renewable portfolio standards was also considered explicitly in the process. The Phase II "risk analysis" reveals the strengths and risks associated with each portfolio by exposing them to a wide range of conditions to see how portfolios compare on average and at extreme conditions. In this way, the stability of the portfolio was assessed for rate impacts, and the range of costs that might be required to achieve higher levels of environmental stewardship was evaluated.

PREFERRED RESOURCE PLAN

The Preferred Resource Plan represents a dramatic reconfiguration of PWP's existing electricity portfolio over the next 20 years, accompanied by significant reductions in the portfolio's greenhouse gas ("GHG") emissions, facilitated by the addition of substantial amounts of new, efficient and renewable resources to replace existing resources that have a much higher environmental impact. The Preferred Resource Plan consists of a diverse mix of resource additions to PWP's existing generation portfolio including a range of renewable resources such as wind, solar, geothermal, and landfill gas (LFG) resources, aggressive use of demand-side options including energy efficiency and load management programs, and a new local gas-fired combined cycle plant that will replace some inefficient existing local generating units located within Pasadena. The Preferred Resource Plan also includes a reduction in PWP's purchase of power from its entitlement to power from the coal-fired IPP facility, which is replaced by the resources listed above. The plan would help the City meet or exceed the United Nations Urban Environmental Accords for renewable energy, energy efficiency, and climate change. Key elements of the incremental changes to PWP's current portfolio in the Preferred Resource Plan include:

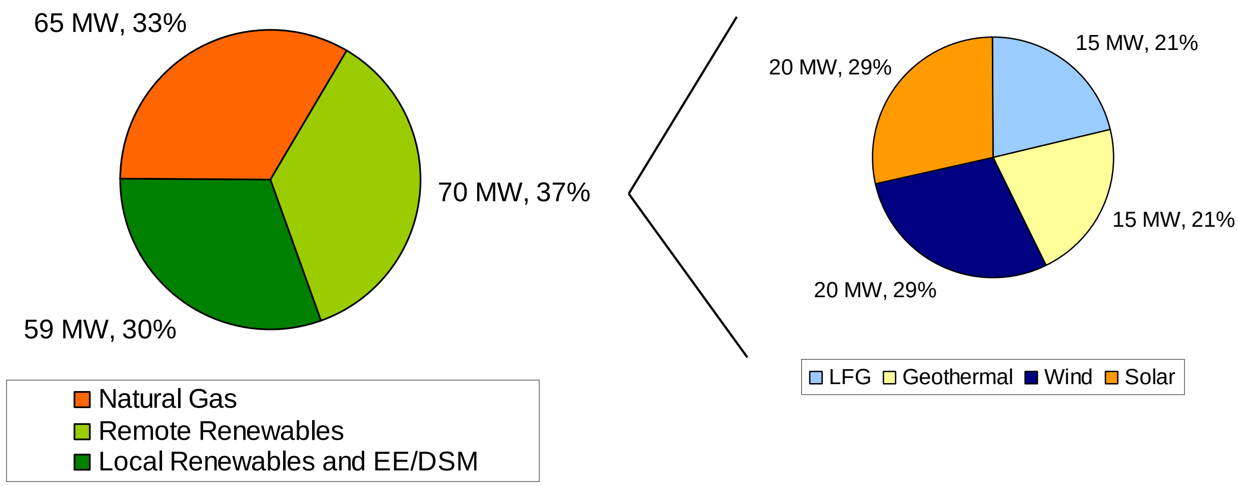
- **Diverse Renewable Energy Additions:** The Preferred Resource Plan adds 20 MW of solar thermal, 20 MW of wind, 15 MW of geothermal, 15 MW of landfill, 19 MW of local solar photovoltaic capacity, and a new feed-in tariff program for 10 MW of local renewables.
- **Partial Sale of Intermountain Power Project (IPP):** Approximately 35 MW of IPP capacity would be removed from the portfolio and sold to markets outside of California under the Preferred Resource Plan. This reflects the amount of IPP capacity that PWP believes may be feasible to sell under the existing contract arrangements. The 35 MW is comprised of one contract share that is currently recallable in Utah and a remaining share of capacity above and beyond PWP's minimum capacity factor requirements.
- **New Local Generation:** The Preferred Resource Plan adds a new 65 MW gas-fired combined cycle facility at the site of Broadway 3, which would be retired at the time the new facility achieves commercial operation. The addition of this new local generation, at an estimated capital cost of $107 million, is the most cost-effective means to ensure PWP's ongoing ability to satisfy reliability requirements.
- **Upgrades of Existing Generation:** A capital budget of $17 million has been assumed to maintain and upgrade the existing Glenarm 1 & 2 generating units in order to extend their operating lives. This is a minimum requirement for maintaining these older, local gas-fired generation options over the next twenty years.
- **Deferral of Transmission Investments:** While some capital expenditures are required to maintain the existing transmission system within the City and are included in all potential resource options, the Recommended Resource Plan is expected to defer the need for over $100 million in transmission upgrades that would be necessary to address transmission constraints and reliability concerns in the absence of adding the new local generation

Exhibit 1 provides a summary of the Preferred Resource Plan as it is expected to evolve over time, with unit additions and subtractions relative to the existing portfolio shown by installation date. The changes summarized in the table are incremental to the existing portfolio. A negative number refers to a resource retirement or removal from the portfolio. In the case of local, gas-fired resources, for example, the Preferred Resource Plan retires 65 MW of old capacity and replaces it with a new 65 MW combined cycle. The pie charts below the table illustrate the balance and diversity of the Preferred Resource Plan, as they display the mix of total incremental resource additions. It should be recognized that these resource strategy elements represent an overall vision for PWP's long-term electric resource portfolio, and developments over the next 20 years may result in changes to the Preferred Resource Plan during that period.

Exhibit 2 illustrates the historical resource generation mix for PWP in Fiscal Year 2008 and the expectations for 2020 under the Preferred Resource Plan. Generation shares are calculated against total retail sales rather than against total generation.

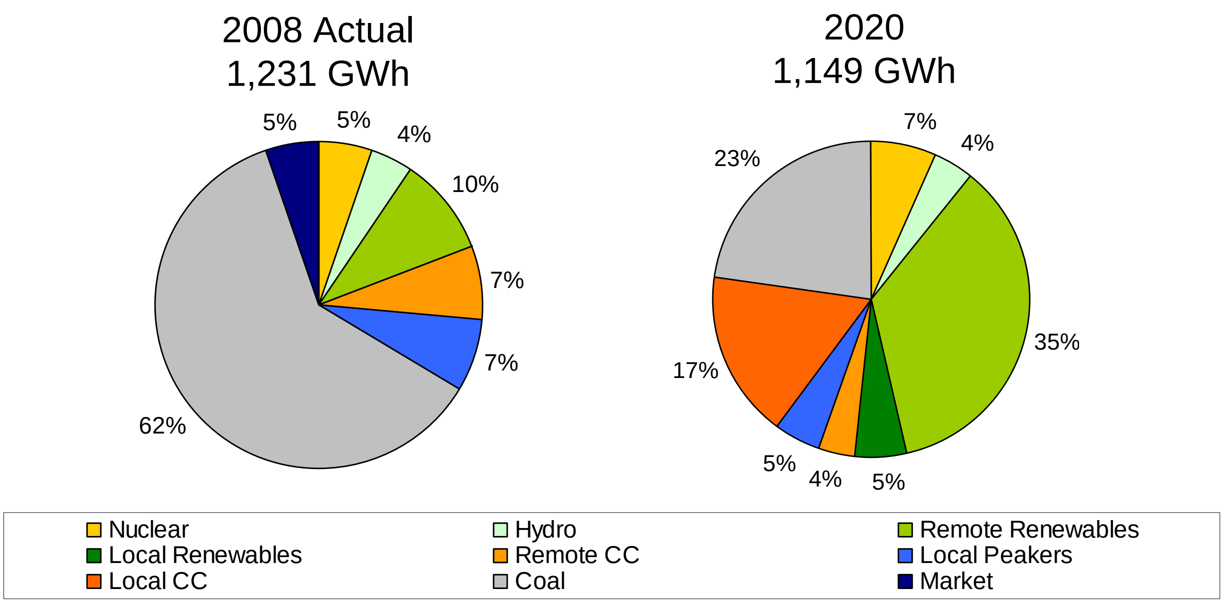
Exhibit 1: Summary of Preferred Resource Plan

Year	Remote Renewables (MW)				Local Renewables (MW)			Fossil (MW)		
	LFG	Geo	Wind	Solar Thermal	DR	Solar PV	Feed-in Tariff	CC	Gas Peaker	Coal
2008						0.9				
2009						1.0				
2010						1.1	0.7			
2011						1.1	0.7			
2012	5	5	5	5	5	1.2	0.7			
2013						1.4	0.7			
2014						1.5	0.7	65	-65	
2015						1.7	0.7			
2016	5	5	5	5		1.9	0.7			-35
2017	5	5				2.2	0.7			
2018						0.7	0.7			
2019						0.7	0.7			
2020			10	10		0.7	0.7			
2021						0.7	0.7			
2022						0.7	0.7			
2023						0.7	0.7			
2024						0.7				
2025										
Total	**15**	**15**	**20**	**20**	**5**	**19**	**10**	**65**	**-65**	**-35**



Source: Pace

Exhibit 2: Energy Mix of Current Portfolio and Preferred Resource Plan



*Note that the generation shares are calculated as the proportion of total retail sales, rather than total generation.
Source: PWP and Pace

IRP POLICIES AND ACTION PLAN

Development of the Preferred Resource Plan considered a wide range of potential options, and there were several criteria against which these options were evaluated. These criteria included:

- Environmental Stewardship (measured in carbon reductions and the proportion of the overall energy mix provided by renewable resources)
- Competitive Rates (measured in lowest present value of revenue requirements and levelized resource costs)
- Rate Stability (measured as deviation in the range of costs from expected levels)
- Reliability (evaluated based on reducing exposure to PWP's aging local generating units)
- Flexibility (evaluated based on the ability to respond to uncertain future developments)
- Financial responsibility (measured by the amount of capital expended)

The Preferred Resource Plan is not rated the highest in every single objective category but rather provides the best balance of all objectives over a wide range of outcomes. This portfolio:

- Rated near the top of all portfolios with regard to overall cost, renewable percentage, reliability, and diversity
- Rated in the middle for price risk (rate stability) and total carbon emission reductions, with the only potential weakness being exposure to spot market power price volatility, a risk that can be managed.

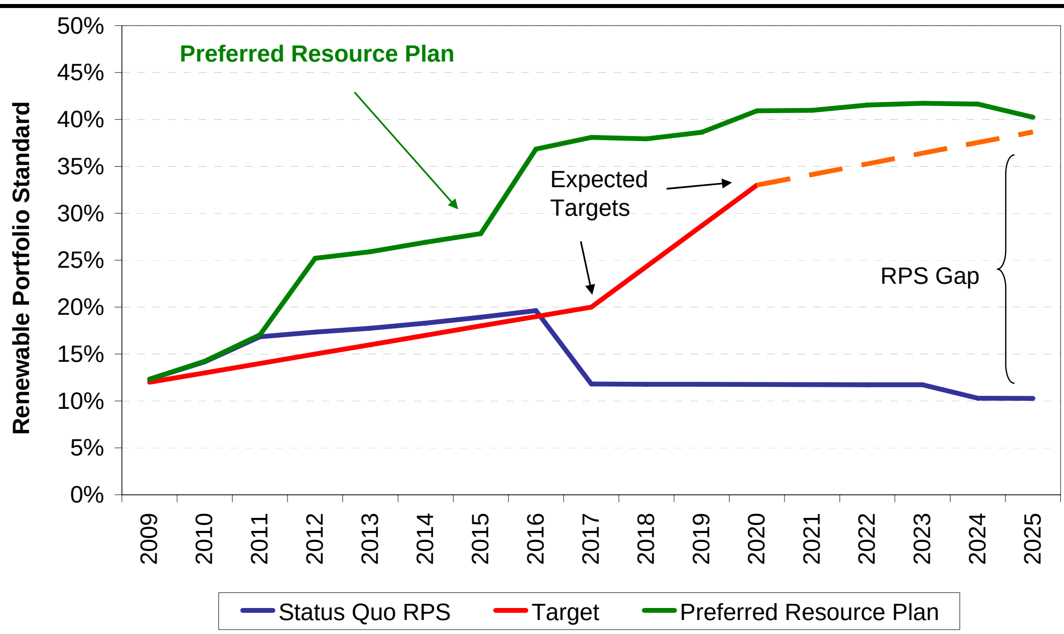
* Rated high in environmental stewardship in all of the carbon price scenarios and rated high in the efficiency of expenditures for environmental stewardship.

The Preferred Resource Plan calls for several action items to meet certain policy objectives and benchmarks established in the plan. These can be summarized as follows:

* **Coal Power Displacement:** By 2016, reduce purchases of power from the IPP coal plant by at least 35 MW
* **New Local Gas-Fired Generation:** By 2014, retire the existing 65 MW Broadway 3 power plant and replace it with a comparably sized new combined cycle plant at the same site
* **Energy Efficiency and Load Management:** Implement programs to achieve significant reductions in electricity consumption according to the following timeline:
    * **Energy Savings:** Reduce energy sales by 12.5% below expected levels by 2016
    * **Peak Load Savings:** Reduce peak load by 10% below expected levels by 2012
    * **Demand Response:** Reduce peak load by an additional 5 MW by 2012 through programs that provide customers with information and economic incentives to reduce their consumption during peak load periods
* **Renewable Energy:** By 2020, increase the proportion of PWP's energy mix provided by renewable energy sources to 40% according to the following general guidelines:
    * 15% by 2010
    * 33% by 2015
    * 40% by 2020

  Exhibit 3 displays the expected annual renewable generation share for the Preferred Resource Plan along with the "status quo" and expected targets.

Exhibit 3: Renewable Generation Share of Preferred Resource Plan



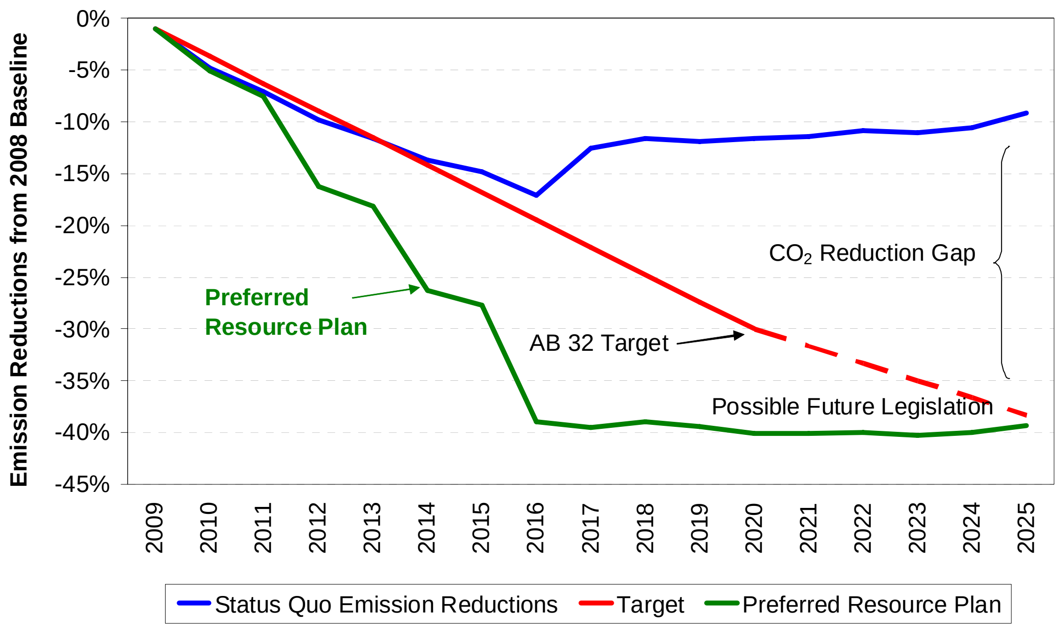
Source: Pace

- **Solar Photovoltaic:** By 2024, develop programs to add at least 19 MW of solar photovoltaic installations in Pasadena according to the following timeline:
  - 3 MW by 2010
  - 10 MW by 2015
  - 15 MW by 2020
  - 19 MW by 2024

  Analysis of the performance of different solar technologies indicates that a rebate of approximately $4/Watt would prove the incentive to make solar PV expansion cost-competitive.
- **Feed-In Tariff:** By 2020, establish a feed-in tariff program offering to purchase up to 10 MW of qualifying renewables of all technologies located inside Pasadena at an average price up to 15 cents/kWh
- **GHG Emissions Reductions:** By 2020, achieve CO_2 emission reductions of at least 40% according to the following timeline:
  - 5% by 2010
  - 25% by 2015
  - 40% by 2020

  Exhibit 4 displays the expected annual GHG reductions for the Preferred Resource Plan along with the "status quo" and the expected regulatory targets.

Exhibit 4: GHG Emission Reductions for Preferred Resource Plan



Source: Pace

Related elements of the recommended action plan to implement the Preferred Resource Plan over the next four years include:

- Complete the ongoing transmission system options study being conducted with RW Beck. This study is considering the evaluation of required investments to PWP's transmission infrastructure and how it will affect the reliability of its system over time.
- Conduct an assessment of the potential sale of IPP power. Determine the sale prices and quantities of PWP's IPP entitlement that can be achieved, and over what time frame. This will determine the potential for replacing this block of power with carbon-reducing technologies.
- Evaluate the potential load management impacts from the proposed aggressive demand side and energy efficiency programs.
- Continue to evaluate the potential from landfill, geothermal, wind, and solar technologies from remote sources and at what price.
- Continue to assess the potential from solar photovoltaic and rooftop solar programs. Determine the market potential from subsidy programs to determine how cost effective they are.

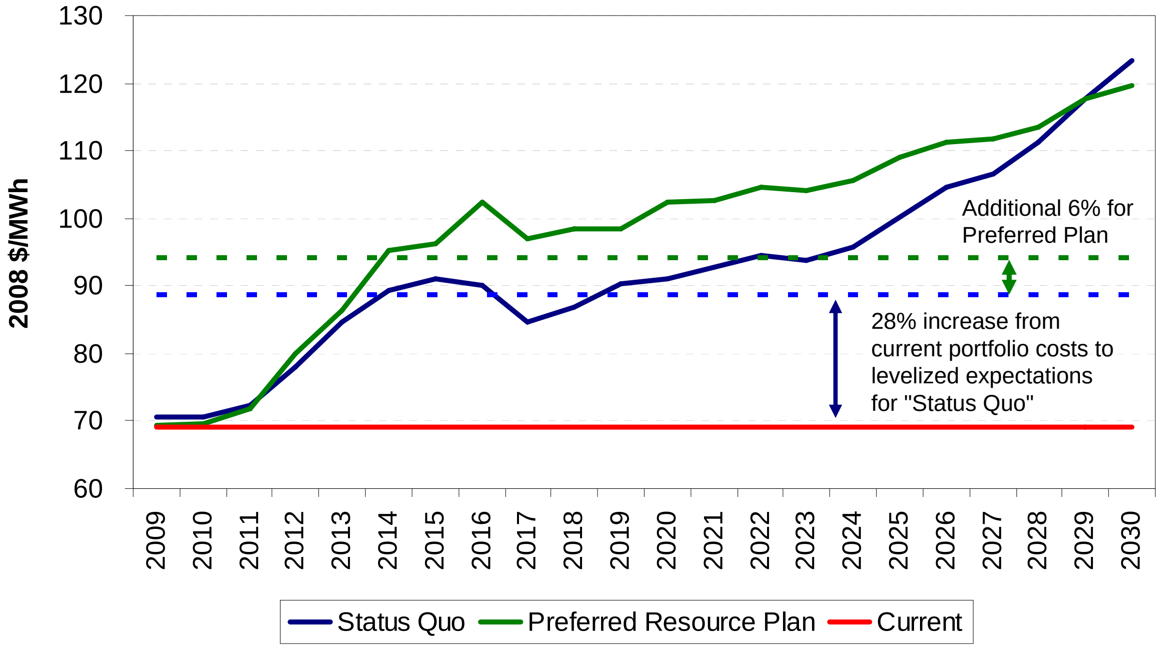
In addition, PWP should immediately commence with the following short-term implementation steps that are common among all of the long-term strategies:

- Continue securing contracts for power from a diverse mix of new renewable energy sources, balanced among landfill gas, geothermal, wind and solar projects
- Expand PWP's already aggressive energy efficiency programs
- Develop demand response programs and rates to provide customers with economic incentives to reduce their peak electricity consumption
- Develop a new feed-in tariff program in which PWP will offer to purchase power, at a fixed price, to any qualifying renewable energy project within the City in order to facilitate the development of local renewable energy sources
- Evaluate innovative new financing approaches and electric rate structures in order to spur more PWP customers to install solar photovoltaic projects inside Pasadena

RATE IMPACTS OF THE PREFERRED RESOURCE PLAN

Implementation of the Preferred Resource Plan, when measured over the entire 20 year planning horizon covered by the 2009 IRP, is projected to lead to a levelized increase in PWP's generation costs of approximately 36% over 2008 levels over a 20-year period. Such an increase may at first appear to be unreasonably large and beyond many customers' ability or willingness to pay for such increases. However, it is critical to recognize that PWP's costs are projected to increase by approximately 28% even if PWP made no incremental changes to its existing portfolio. Accordingly, the estimated cost impact of Preferred Resource Plan is actually projected to produce an increase of approximately 6% above "status quo" operations in the absence of the actions recommended in the Preferred Resource Plan. These projected cost increases for the Preferred Resource Plan and the Status Quo portfolio are expressed in real, 2008 dollars that are not adjusted for future inflation. Exhibit 5 displays the expected annual portfolio cost impacts under the Preferred Resource Plan and assuming the status quo.

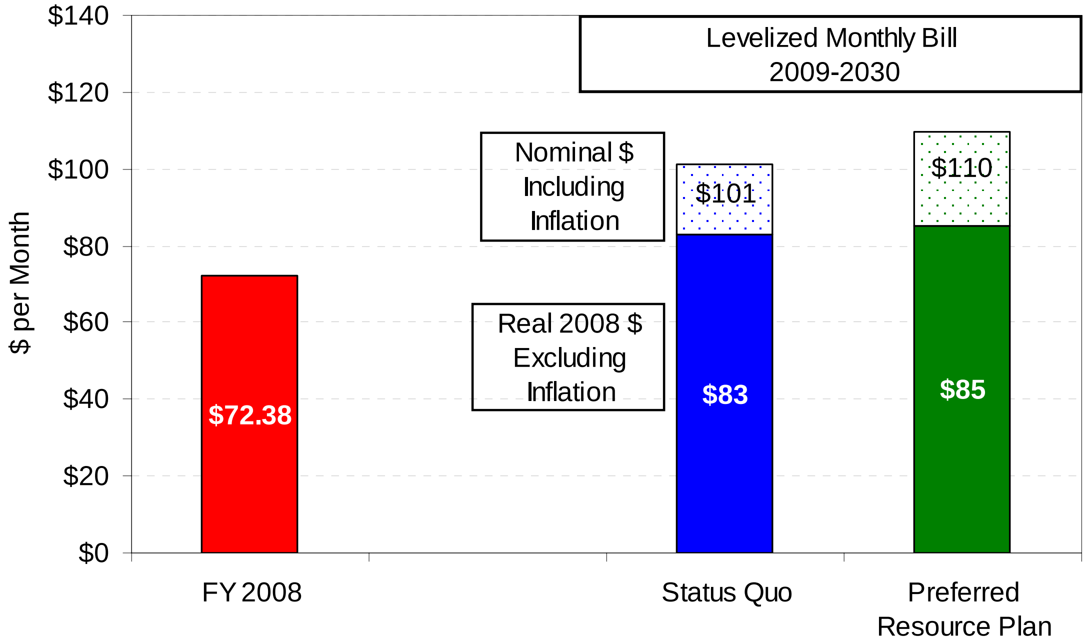
Exhibit 5: Expected Impacts on Portfolio Costs of Preferred Resource Plan



* Note that bill values are for power only and exclude water rates
Source: Pace

Exhibit 6 displays the expected PWP electricity bill impacts of the Preferred Resource Plan on a levelized basis over the entire planning horizon along with the current average residential electricity bill and the expectations under the "status quo." In addition to presenting the levelized values in real 2008 dollars, the expectations in nominal terms are also shown. After adjusting for inflation at an assumed rate of 2.5% per year, the Preferred Resource Plan is projected to lead to approximately a 9% increase in PWP's costs and rates over the status quo when measured over the 20 year planning horizon. While no rate increase is desirable, the Preferred Resource Plan is a cost-effective strategy for satisfying PWP's long-term electricity requirements, particularly given the significant benefits provided by the Preferred Resource Plan with regard to environmental stewardship, reliability and flexibility to respond to an uncertain future.

Exhibit 6: Expected Impacts on Residential Electricity Bill of Preferred Resource Plan



* Note that bill values are for power only and exclude water rates
Source: Pace

FUTURE IRP UPDATES

In order to ensure that Pasadena's resource strategy remains robust and responsive to evolving regulatory and market conditions, PWP should commit to the following schedule for IRP updates in the future:

- Conduct a comprehensive IRP evaluation every five years
- Update the most recent IRP every two years to account for new developments occurring during that period

This approach to updating the 2009 IRP is intended to allow PWP to adjust its resource strategy over time, as needed to account for new information and new developments as they occur.

PLANNING ENVIRONMENT AND KEY DRIVERS

PWP has provided reliable and economical electric service in the City for over one hundred years, but now faces critical new challenges as it makes plans to continue doing so well into the future:

- New and emerging laws will require PWP to reduce the greenhouse gas emissions associated with serving Pasadena's energy needs, although the exact reductions that ultimately will be required are still unknown.
- Pasadena aspires to a position of environmental leadership, which could drive PWP to reduce its GHG emissions even more than these new laws may require, through significantly expanded use of renewable energy and energy efficiency improvements.
- PWP relies on the coal-fired Intermountain Power Plant in Utah for a significant share of its current power supply, so achieving significant GHG emissions reductions depends in part on the feasibility of displacing power from Intermountain with cleaner sources, most of which will be more expensive than the costs that PWP incurred in the past.
- The natural gas-fired generating units located within the City are critical to ensuring the continuing reliability of PWP's service, but they are old and inefficient and PWP's ability to rely on these facilities in the future is increasingly uncertain, so there may be a need to invest in new local generation to resolve this critical exposure.
- The costs of serving Pasadena's electricity requirements will inevitably increase in the future because new energy resources are more expensive than the current supply mix.
- PWP must continue to invest in new infrastructure to maintain and improve its supply and delivery systems.

The manner in which PWP addresses each of these concerns could have a significant impact on the rates that PWP charges its customers and how well it achieves the City's environmental objectives. PWP has conducted a detailed assessment, known in the utility industry as an "Integrated Resource Plan ("IRP")," to identify a preferred approach for meeting all of these challenges. The IRP, which was guided by active participation among PWP, a Stakeholder Advisory Group, and the public, included the following key steps:

- Developing a set of realistic resource strategies, which call for GHG emissions reductions of at least 25% and perhaps as much as 80%, that could guide PWP's future power resource decisions;
- Evaluating a full range of energy efficiency, load management, and new supply options available to PWP to reconfigure its current portfolio of energy sources and identifying the best options for PWP to achieve its GHG emissions reduction strategy;
- Assessing the critical trade-offs between reliability, cost, environmental stewardship and risk that are inherent in each resource strategy in order to appropriately balance these conflicting objectives;
- Choosing a recommended long-term resource strategy as well as a short-term action plan focusing on immediate steps PWP should take over the next two years.

KEY DRIVERS AFFECTING PWP'S IRP OPTIONS

Integrated Resource Planning for electric utilities like PWP is an exceptionally complex undertaking accompanied by significant risk and uncertainty. Commitments made by utilities to specific resource options such as new power plants or power purchase agreements typically last 20 years or more. At the same time, legal, regulatory and market conditions that affect the apparent wisdom of those choices are changing constantly and require ongoing monitoring and adjustment. These considerations affect all electric utilities generally, but the key issues driving the choices that PWP must make in its 2009 IRP are as follows:

- Volatile fuel and capital costs
- Rising Renewable Portfolio Standards
- Carbon constraints weighing on fossil fueled generation sources
- Significant exposure to potential cost increases
- Evolving regulatory and environmental challenges
- Ongoing technology advances opening new opportunities
- Power supply reliability and local generation requirements

Each of these driving forces represents a key source of risk and uncertainty that must be considered in an IRP process. While these risk issues are discussed in greater detail in the body of this report, the following section highlights the evolving regulatory environment and environmental mandates that are driving PWP's resource planning needs.

REGULATORY ENVIRONMENT

There are a wide variety of regulatory policies and requirements, but the most significant regulatory policies affecting the 2009 IRP involve the mandates to reduce the environmental impact of providing electric service:

- **Renewable Portfolio Standards (RPS):** State law that requires electric utilities to obtain a minimum percentage of their electricity requirements from renewable resources that have a smaller environmental impact than most conventional resources.
- **Greenhouse Gas (GHG) Reductions:** State law that requires electric utilities to reduce the level of GHG emissions they produce through the provision of electric service.

Renewable Portfolio Standards

California is a world leader in the development and utilization of renewable energy supplies that reduce the State's dependence on fossil fuels and the environmental impacts of electricity consumption, and also support the development of indigenous resources within the State. California's current RPS policy intends to require all investor-owned electric utilities to obtain at least 33% of their electricity requirements from renewable resources by 2020, although this current law does not require PWP to achieve this RPS level. Moreover, a proposed new RPS mandate in AB 64, introduced in the California Assembly on December 9, 2008, would establish a new RPS requirement of 50% renewables by 2035. While PWP currently obtains approximately 10% of its electricity requirements from renewable resources and has announced a goal to achieve a 20% RPS level by 2017, those goals fall significantly short of the existing

33% RPS policy as well as the potential increase to 50%. The 2009 IRP needs to address this significant shortfall between PWP's existing RPS targets and potential RPS requirements that it may be obligated to meet in the future.

Greenhouse Gas Reductions

California's policy for addressing global warming risks through reductions in greenhouse gas emissions was established by Assembly Bill ("AB") 32, the California Global Warming Solutions Act of 2006. AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020, which is estimated to require a 30% reduction relative to the GHG emissions levels in 2020 that would be expected without any specific action to reduce emissions. Achieving GHG emissions reductions of 30% or more by 2020 will require PWP to make significant changes to its existing portfolio. Attaining a position of environmental leadership, through even larger GHG emission reductions, ultimately will require displacement of at least a portion of PWP's purchases of coal-fired power from IPP. Such significant changes to PWP's existing portfolio of electric resources will have dramatic, lasting changes on PWP's costs of service, and the 2009 IRP needs to clearly assess the trade-offs between cost and environmental stewardship associated with achieving higher levels of GHG emissions reductions.

REVIEW OF PREVIOUS IRP PROCESS

PWP prepared its 2007 Draft IRP beginning in late 2005 and throughout 2006, presenting its first draft to the public in November 2006. Subsequent to the initiation of this IRP, the City Council adopted United Nations Urban Environmental Accords of 2005 ("UEA"), and developed the Green City Action Plan. In late 2006, the California Legislature also adopted several electric generation and environmental initiatives such as AB32, AB2021, SB107, and SB1368. Pasadena's Renewable Portfolio Standard ("RPS"), which was adopted in 2003, was updated in light of the City's and the state's evolving environmental goals. On September 24, 2007, the City Council adopted Energy Efficiency ("EE") and Demand Reduction ("DR") Goals, and an SB-1 compliant Solar Photovoltaic ("PV") program and goals, along with a funding mechanism for these programs. These goals collectively require significant reductions in both peak and average load from energy efficiency and demand side reduction programs, reductions in greenhouse gas emissions, and increases in the mix of renewable energy in PWP's generation portfolio. They also establish greater priorities for cost effective, reliable and feasible load reduction and efficiency improvement measures.

The City Council instituted an Environmental Advisory Commission ("EAC") in early 2007 to oversee and advise the City Council on the City's environmental initiatives. The EAC concluded that the underlying policies that guided the 2007 Draft IRP may not fully reflect the City's updated broad environmental objectives. After their review, in mid 2007, PWP and the EAC decided that the 2007 IRP should be re-evaluated and revised as necessary prior to adopting a new IRP. It was recommended that an independent consultant review the energy and environmental policies, recommend potential policy changes, and identify additional opportunities to jointly meet the City's environmental goals and other key objectives. It was also recommended that the IRP development and review process include more thorough public and stakeholder participation. Exhibit 7 summarizes the key shortcomings in the 2007 Draft IRP identified by the EAC and how they have been addressed in this 2009 IRP.

Exhibit 7: Key Shortcomings in the 2007 Draft IRP

Shortcoming	Resolution in 2009 IRP
Inadequate weighing of environmental impacts	• GHG emissions costs incorporated into all price projections and cost metrics • Explicit consideration of the environmental and cost trade-offs across options
Opportunity costs of fossil fuel vs. local renewable investments; opportunities for fossil-fuel reductions	• Evaluation of local fossil-fuel and renewable options throughout portfolios • Evaluation of cost and environmental effects of reducing IPP generation as well as consideration of gas-fired vs. renewable-focused portfolios
Inadequate RPS goals and consideration of local renewable resources	• Evaluation of significant expansion of RPS and GHG policies beyond expected State requirements (including both RPS and GHG policies) • Specific evaluation of local renewable options vs. remote renewable options
Expanded energy efficiency efforts and balance between residential & commercial	• Evaluation of significantly expanded energy efficiency programs consistent with AB 2021 targets; evaluation of even more aggressive targets • Explicit selection of most cost-effective mix of commercial and residential options
Partnership opportunities to pursue green and clean power opportunities	• Discuss options for meaningful partnership opportunities with business and research organizations to pursue clean and green opportunities consistent with preferred portfolio options and recommendations

Source: EAC and Pace

PUBLIC OUTREACH AND STAKEHOLDER INPUT

In order to improve the IRP process and ensure that the resulting plan would reflect the needs of the Pasadena community and its various stakeholders, PWP engaged in a public participation process with active stakeholder involvement.

From the beginning of the planning process in July 2008, the 2009 IRP was developed with the intent to satisfy several key objectives:

- Ensure alignment with the City's aspirations to be an environmental advocate and leader
- Directly address several issues raised in the previous IRP
    - Quantification of environmental impacts (CO_2 costs)
    - Resources options considered (In-city generation, local renewable energy, energy efficiency, fossil-fueled generation)
    - Aggressiveness of policies (RPS)
    - Strategic partnerships with local entities
- Conduct a collaborative process for public and stakeholder involvement in the planning process

In order to facilitate a productive dialogue with a diverse and representative group of Pasadena stakeholders, PWP and Pace agreed to conduct the 2009 IRP process to provide several opportunities for stakeholders to provide input and direction to the plan. The two primary avenues of public/stakeholder participation were:

- **IRP Stakeholder Advisory Group:** A working group that attended monthly half-day sessions reviewing analysis and providing input and suggestions for the IRP analysis
- **Public meetings:** Presentations to the public at large to discuss findings and solicit feedback

PWP and Pace conducted a total of 15 separate meetings with the various stakeholder groups and the public, which provided immense value to the quality and completeness of the entire 2009 IRP process and recommendations. Many comments from the Stakeholder Advisory Group and various members of the public have been directly incorporated into the analysis. In response to the preliminary recommendations and the draft report, PWP and Pace received written comments from Dr. Carol Carmichael of the EAC, Caltech, and the Pasadena Group of Sierra Club. The comments from Caltech revolve primarily around implementation planning and will be addressed by PWP in a future implementation plan. The other written comments and responses are summarized in the appendix and can be found with other public comments and responses in the section on the Public Input Process.

PWP SITUATION ASSESSMENT

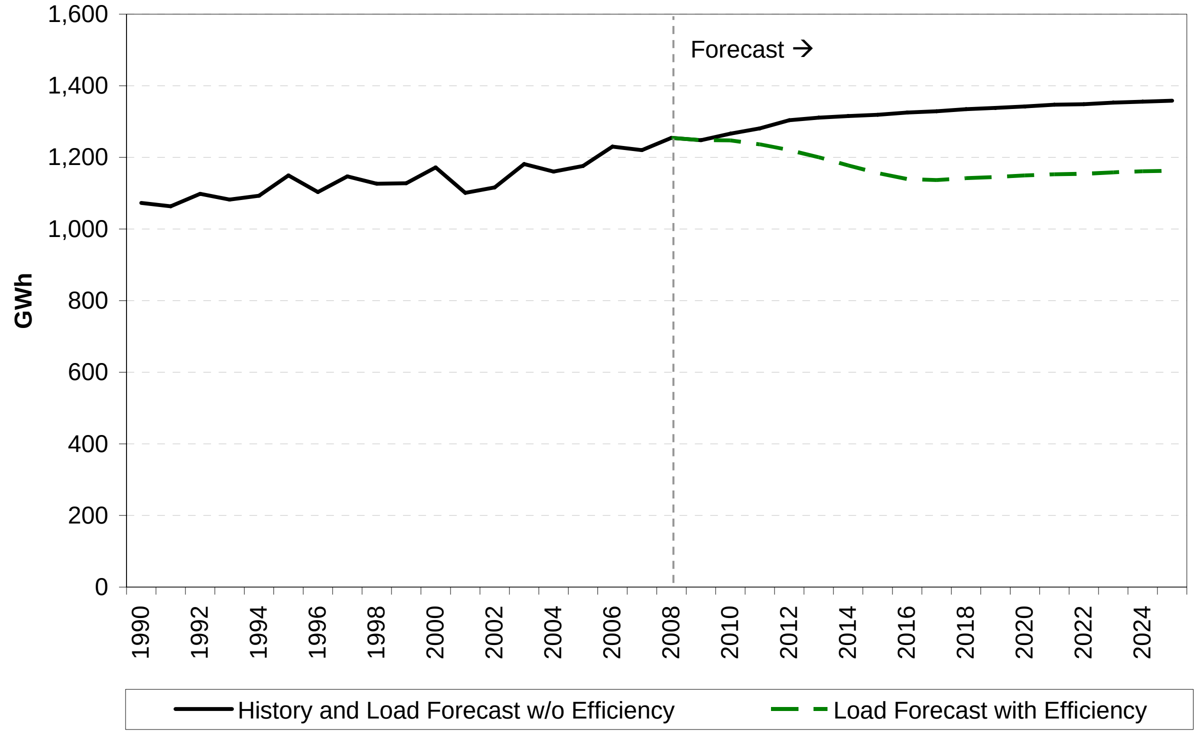
LOAD GROWTH AND EFFICIENCY GOALS

PWP is a municipal utility that manages a service territory of 58,000 customers with a peak load of slightly more than 300 MW. PWP's electricity sales growth has averaged less than one percent per year over the past two decades, due in large to limited opportunities for expansion of the residential and business customer base. Total sales grew from 1.07 TWh in 1990 to 1.22 TWh in 2007, for an average annual growth rate of 0.8%. As part of the 2009 IRP process, a long-term forecast of electricity sales for PWP was developed, based on forecasts of population growth, employment, commercial floor space, and retail electricity prices.

Without accounting for demand side management and energy efficiency programs, sales growth over the near term is estimated to average 1.2% per year, and long-term growth (through 2030) is estimated to average 0.5% per year. Peak load growth rates are expected to exceed sales growth rates due to relatively faster sales growth in summer months. Peak load is projected to grow at an average annual rate of 0.52% during the 2010-2030 period compared with sales growth of 0.38% during that period. Additional details on load forecast methodology and detailed results can be found in the appendix section on PWP Load Forecast.

The City of Pasadena's Green City Energy Action Plan calls for significant reductions in peak demand. PWP has a standing goal of reducing the City's peak load by 10% by 2012. PWP currently has several energy efficiency and demand response programs aimed at accomplishing this goal and aimed at reducing total energy sales by 12.5% below their expected levels by 2016. This target represents deployment of 100% of all economically feasible efficiency options and programs. As part of this plan, the load forecast analysis incorporated all economical energy efficiency programs, as per the Rocky Mountain Institute's energy efficiency model. Deployment of such programs serves to lower the long-term energy demand forecast considerably. Exhibit 8 presents the historical and forecasted net energy for load forecasts for PWP with and without energy efficiency improvements. Uncertainty in the success of these targets is dealt with in the Phase II risk analysis.

Exhibit 8: Historical and Forecast PWP Net Energy for Load



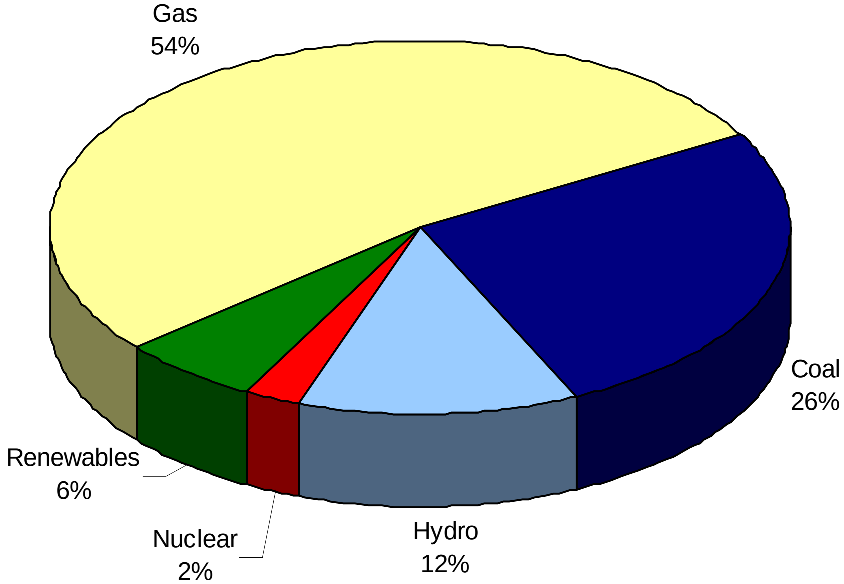
Source: PWP and Pace

EXISTING SUPPLY RESOURCES

The City of Pasadena owns over 200 MW of on-site, natural gas-fired local generation and is capable of importing up to 215 MW more through its interconnection with Southern California Edison. Pasadena also has ownership shares and long term contracts with a number of power generation facilities located throughout the west. The share of all Pasadena owned and contracted capacity by fuel type is displayed in Exhibit 9, and a more detailed summary of the existing portfolio is shown in Exhibit 11. Additional summary descriptions of the plants and contracts can be found in the appendix section on the Existing PWP Portfolio.

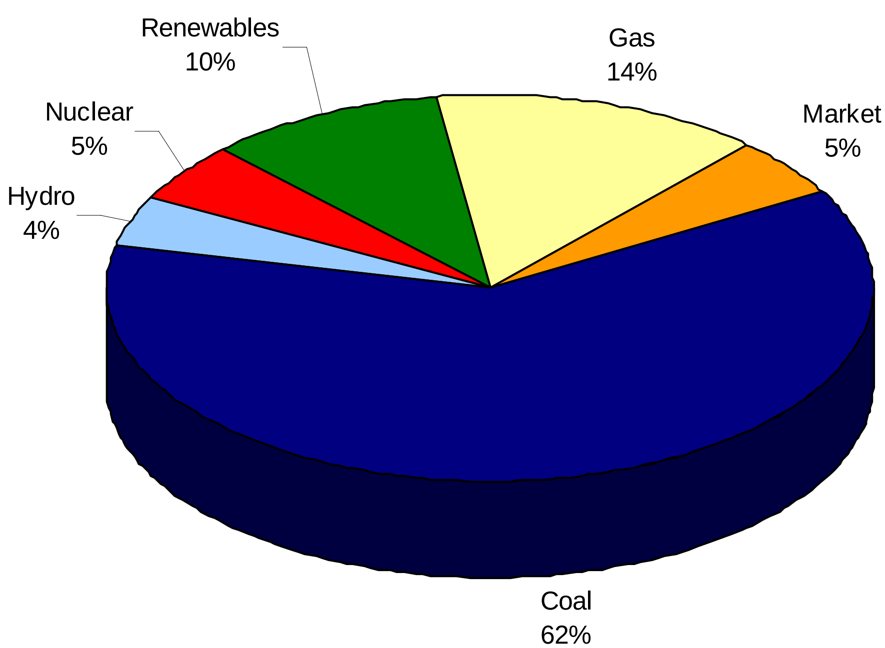
Although the majority of the portfolio's installed capacity is natural gas-fired, PWP relies on power generation from the coal-fired Intermountain Power Plant IPP for over 60% of its energy needs. This is because the coal plant has a lower variable cost of operation compared with the gas resources. As such a significant part of the overall portfolio, IPP costs heavily influence the overall costs of generation for PWP. Exhibit 10 displays the share of actual power generation by fuel type, indicating a significant difference with installed capacity.

Exhibit 9: Share of Capacity by Type



Source: PWP and Pace

Exhibit 10: Share of Generation by Type



Source: PWP and Pace

PWP is a participant in the California Independent System Operator ("CAISO"), which operates the high voltage electric transmission grid throughout most of California. The CAISO also facilitates the buying and selling of power in wholesale energy markets in California and the broader Western market in order to balance energy requirements. Such transactions expose the portfolio to fluctuations in market prices that prevail in the wider market area. Energy prices in the wider market area are governed primarily by fuel prices, demand for energy, and the mix of generating technologies producing power at any given time. Because PWP has a significant amount of gas-fired capacity, it is also exposed to natural gas price volatility if fuel purchases are un-hedged.

Exhibit 11: PWP Plant Details

Plant Name (Contractor)	Unit Type	Primary Fuel	Start	End	Capacity (MW)	% FY 2008 Energy*
Intermountain Power Project	Steam Turbine	Coal	1987	2027	108	62%
Hoover Power Plant	Hydro	Hydro	1941	2017	20	4%
Azusa	Hydro	Hydro	1933	-NA-	15	<1%
Palo Verde	Steam Turbine	Nuclear	1988	2030	9.9	5%
Broadway	Steam Turbine	Gas	1965	-NA-	65	3%
Glenarm	Combustion Turbine	Gas	1975	-NA-	22.3	4%
	Combustion Turbine	Gas	1975		22.3	
	Combustion Turbine	Gas	2004		42.4	
	Combustion Turbine	Gas	2004		44.8	
Magnolia Power Plant	Combined Cycle	Gas	2005	2033	19	7%
BPA Exchange	Contract	Contract	2008	2013	15	<1%
High Winds (Iberdrola)	Wind Turbine	Wind	2003	2023	2	2%
Milford (UPC/First Wind)	Wind Turbine	Wind	2009	2029	5	NA
Heber South (Ormat)	Steam Turbine	Geothermal	2007	2032	2.1	2%
Tulare & West Covina Landfill (Minnesota Methane)	Combustion Turbine	Landfill Gas	2007	2016	9.5	6%
Chiquita Canyon Landfill (Ameresco)	Combustion Turbine	Landfill Gas	2009	2029	6.7	NA
				Total Capacity:	**409**	

*Note that the total does not add to 100%, as market purchases made up the remaining balance.
Source: PWP and Pace

SYSTEM RELIABILITY

System reliability is a priority objective for the IRP planning process, and it depends critically on PWP's local generating units. One of the dominant factors affecting PWP's ability to maintain reliable electric service is that PWP has a single point of connection with the California power grid with Southern California Edison at the TM Goodrich substation on Pasadena's Eastern border. PWP's imports at Goodrich are limited to 215 MW, so local units must be used when customer demand exceeds this level, and when constraints on PWP's cross-town transmission lines limit PWP's ability to serve customers reliably through imports. Since PWP's peak load exceeds 300 MW, significant local, in-city capacity is currently required to be available in order to meet this requirement. Furthermore, recent history indicates that PWP operates the local units approximately 50% of the hours during the year to comply with various reliability criteria, including the 215 MW import limit and constraints on PWP's cross-town transmission system.

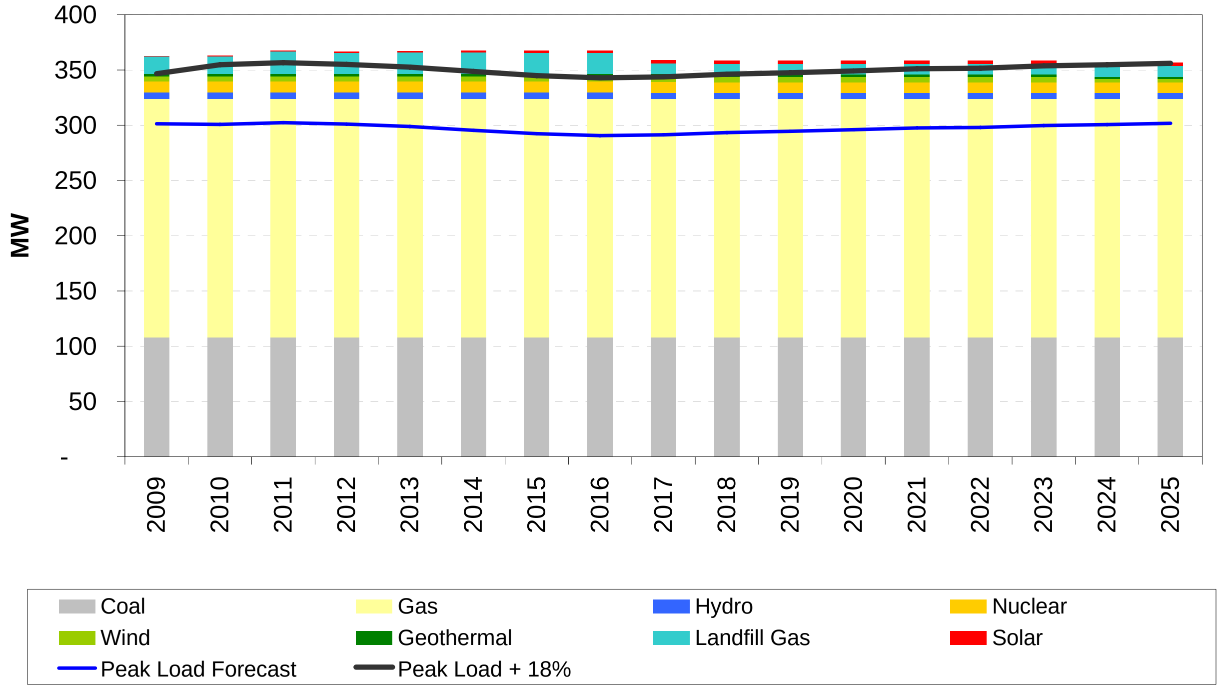
Three of the five local gas-fired units (Broadway 3 and Glenarm 1 & 2) are aging, inefficient, and increasingly difficult for PWP to keep operating. These units are all over 33 years old and comprise about 110 MW of PWP's portfolio. This is about 25% of PWP's total installed capacity and over 50% of the in-city capacity. Continued reliance on the Broadway 3 and Glenarm 1 & 2 units places PWP's service reliability at increasing risk in the future, given the ongoing need to maintain local generation in light of the Goodrich import limit and the cross-town transmission constraints.

Significant capital investments are required to extend the units' operating lives. PWP estimates these costs at $20 million over the next 10 years and $65 million over the next 20 years. In addition, PWP may need to upgrade its transmission system, such as increasing the capability of the single Goodrich interconnection and its cross-town tie lines, in order to mitigate reliability risks relating to long-term reliance on the aging local units. The costs of such potential transmission upgrades, estimated at a minimum of $100 million pending the completion of a detailed evaluation of transmission upgrade alternatives, has been incorporated into the economic evaluation of resource options later in this report.

SUPPLY AND DEMAND BALANCE

Exhibit 12 presents the long term supply and demand balance for PWP, assuming all existing resources and contracts, as well as full deployment of energy efficiency and demand side measures to reduce peak load. The full capacity of all resources and contracts is assumed, unless the resource is intermittent. In those cases, average annual capacity factors were used to display firm capacity levels. All existing resources are assumed to remain in service in this display, and all contracts are assumed available until their expiration dates. The level of capacity required to achieve an 18% planning reserve margin is also displayed.

Exhibit 12: Business as Usual Long Term Supply and Demand Balance

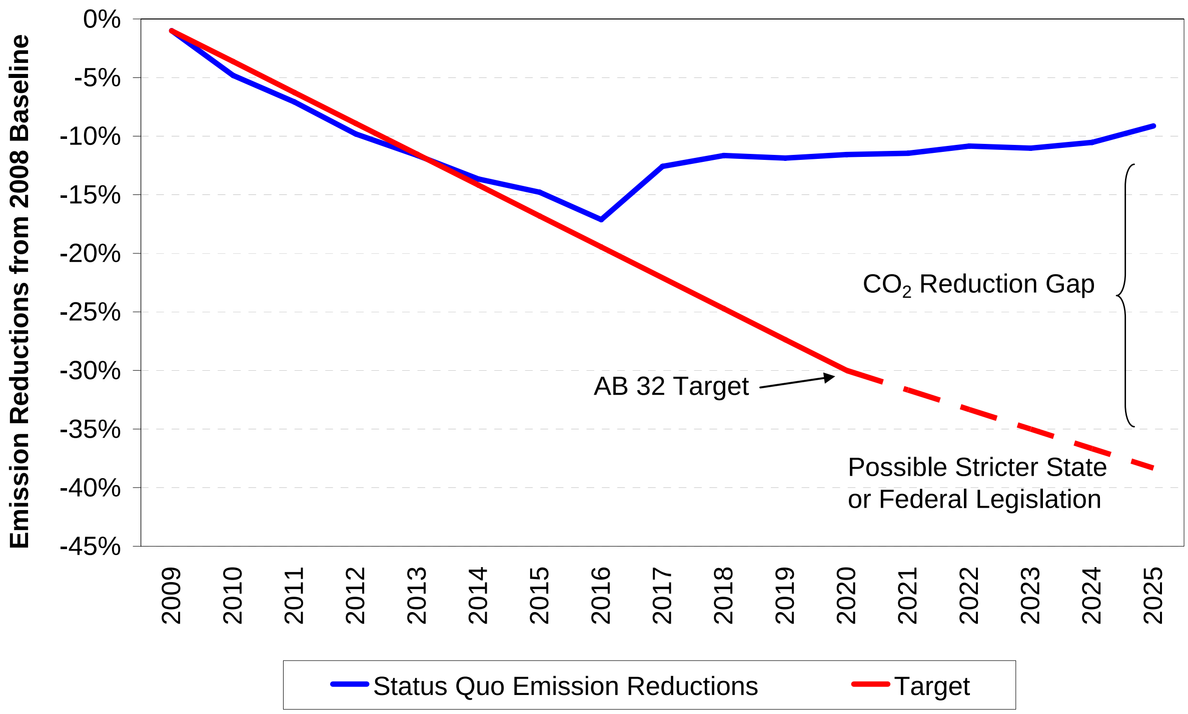


Source: PWP and Pace

CO_2 EMISSIONS

Reducing CO_2 emissions is a primary objective of the 2009 IRP planning process. As a member of the California Climate Action Registry, PWP reports its total CO_2 emissions from owned generation, purchased generation, and market power purchases. The last detailed accounting was performed in 2005, when PWP reported total emissions of 953,000 metric tonnes of CO_2. Of this total, over 600,000 metric tonnes were generated from PWP's fossil fueled power plants, with the majority coming from IPP. This illustrates the fact that significant carbon reductions are only possible with some displacement of power from generation of the coal-fired IPP unit. Compliance with California's AB 32 will require emissions to be reduced to 1990 levels by 2020, likely representing a reduction for PWP of about 30% from current emission levels. Exhibit 13 presents expected CO2 emission reductions for the status quo portfolio, assuming no additional resource additions or changes are made (aside from anticipated solar PV expansion and efficiency improvements), along with the projected target for emission reductions for current state law and potential future regulations. As is shown, a significant reduction gap is expected to develop.

Exhibit 13: Business as Usual CO_2 Emission Reduction Projections with Targets

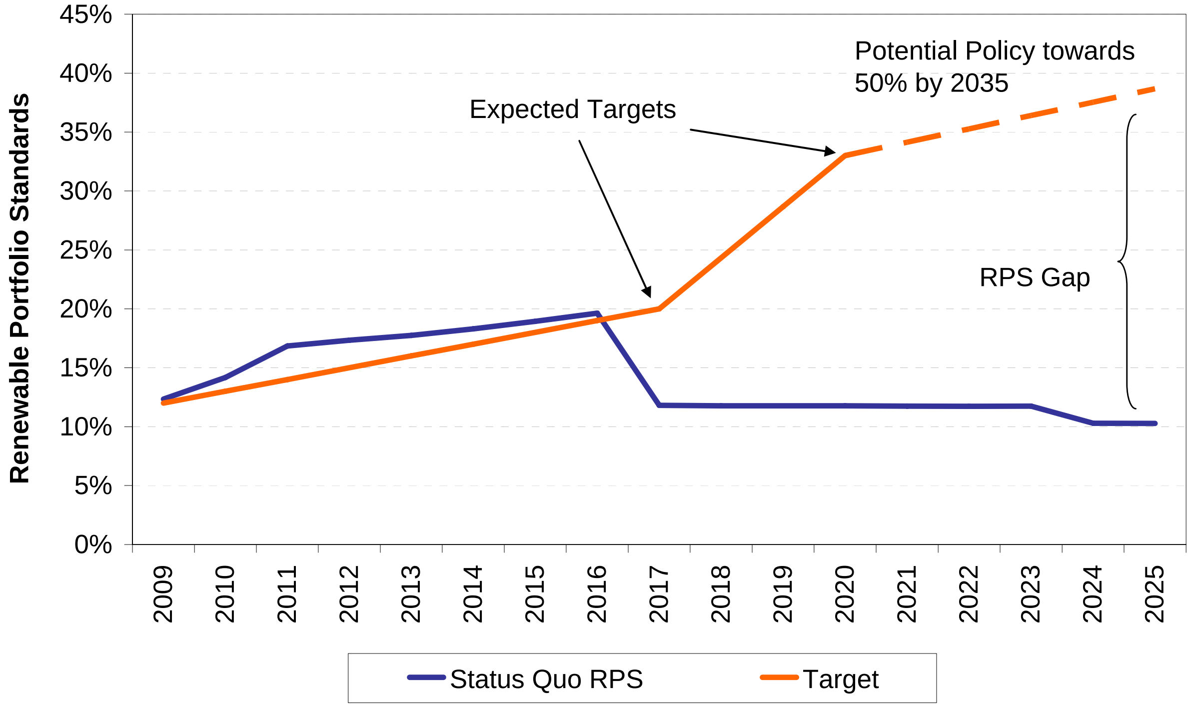


Source: Pace

RENEWABLE PORTFOLIO STANDARDS

PWP's existing renewable energy goals call for 10% of its electricity supply to be obtained from renewable sources by 2010 and 20% by 2017. California's current policy, as articulated recently by the AB 32 scoping plan issued in December 2008, is for all electric utilities like PWP to obtain at least 33% of their electricity supplies from renewable resources by 2020. Thus, PWP's existing renewable energy commitment falls short of existing statewide goals and indicates a clear need to reassess these commitments and adjust them upward, especially given the emerging need to reduce GHG emissions pursuant to AB 32. Exhibit 14 displays PWP's projected RPS percentage, assuming no resource additions other than committed contracts, solar PV expansion and efficiency goals, along with the expected targets.

Exhibit 14: Business as Usual RPS Projections with Targets



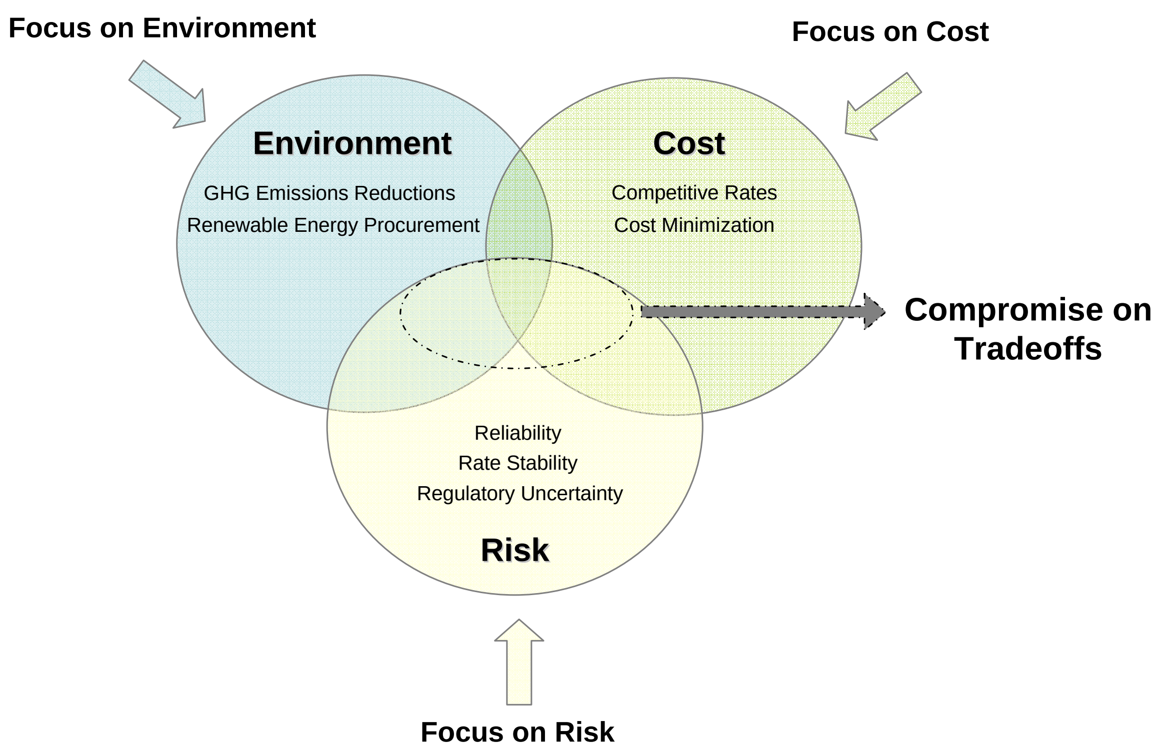
Source: Pace

PLANNING OBJECTIVES AND METRICS

To properly evaluate resource decisions, the planning objectives were identified very early in the resource planning process, through facilitated discussions with the Stakeholder Advisory Group. The Stakeholder Advisory Group was set up to guide the process from start to finish. The members of the Group represented a cross section of all of the customer classes in the City. The Group met every month from July 2008 through January 2009 to track progress, establish guidelines, reflect stakeholder positions, provide counsel and evaluate results. Ultimately, the Stakeholder Advisory Group developed a consensus around the Preferred Resource Plan by selecting the portfolio that best met the planning objectives over a wide range of regulatory and market outcomes. Metrics for each planning objective were created to form a basis for comparing different portfolios.

Even with the appropriate metrics identified for each planning objective, the tradeoffs associated with resource decisions represent the biggest challenge for resource planning. Exhibit 15 displays three competing objectives identified as priorities by the stakeholders and the public. As is shown, focus on any one objective can move the resource plan away from focus on the others. In the IRP process, a wide range of metrics were used to rank portfolios for each objective, helping the stakeholder group evaluate the tradeoffs associated with different portfolio options and ultimately arrive at a resource plan that balances many competing goals.

Exhibit 15: Competing Stakeholder Objectives



Source: Pace

The following section describes the list of planning objectives that were identified by the Stakeholder Advisory Group for the current IRP and defines the metrics used throughout the analysis to evaluate the performance of the different portfolio options.

PRIMARY PLANNING OBJECTIVES, CONSTRAINTS, AND METRICS

Environmental Leadership

Environmental stewardship is at or near the top of Pasadena's resource planning objectives. Although the current supply mix of Pasadena is extremely diverse and includes some renewable technologies, dependence on generation from the coal-fired IPP project has become an increasing concern due to new and pending CO_2 legislation. Significant CO_2 reductions and increased generation from clean resources have played a primary role in the evaluation of adequate portfolios for PWP.

Increased environmental stewardship is generally associated with higher costs. Increases in CO_2 reductions, for example, are generally associated with higher cost actions. The willingness of utilities to pay for improvements in desirable metrics such as environmental stewardship will depend on how much they value reductions in carbon. There is an obvious trade-off between cost minimization and environmental stewardship.

CO_2 Emission Reductions

An increasing concern regarding global climate change has put specific emphasis on the carbon intensity associated with different power generating resource options. Although coal-fired generation remains one of the most efficient sources of power generation, its potential environmental impacts pose a growing concern to the public and utility planners alike. Moreover, the potential advent of significant costs associated with CO_2 emissions constitutes a major risk for coal plant owners.

Different portfolio options were evaluated based on the achieved CO_2 reductions by 2020 from a 2008 baseline. Assuming all other metrics are the same, any portfolio that achieves a higher CO_2 emission reduction will be preferable under this metric.

Renewable Generation (RPS 2020)

Specific regulations concerning RPS standards for utilities in California will drive renewable resource additions. Increasing generation from renewable resources will also directly result in reduced CO_2 emissions for the portfolio. Due to the uncertainty surrounding future RPS regulations in California, assuming all other metrics are the same, the percentage of generation from renewable resources is the metric used to reflect greater renewable stewardship.

Annual RPS percentage was tracked, and different portfolio options were evaluated based on the percentage of the utility's net energy for load that is served by qualified renewable generation by 2020.

Preserve Competitive Rates (Cost)

Preserving competitive rates is a common objective for utilities. In the case of Pasadena, there is a concern about keeping its rates below that of the local Investor Owned Utilities, such as

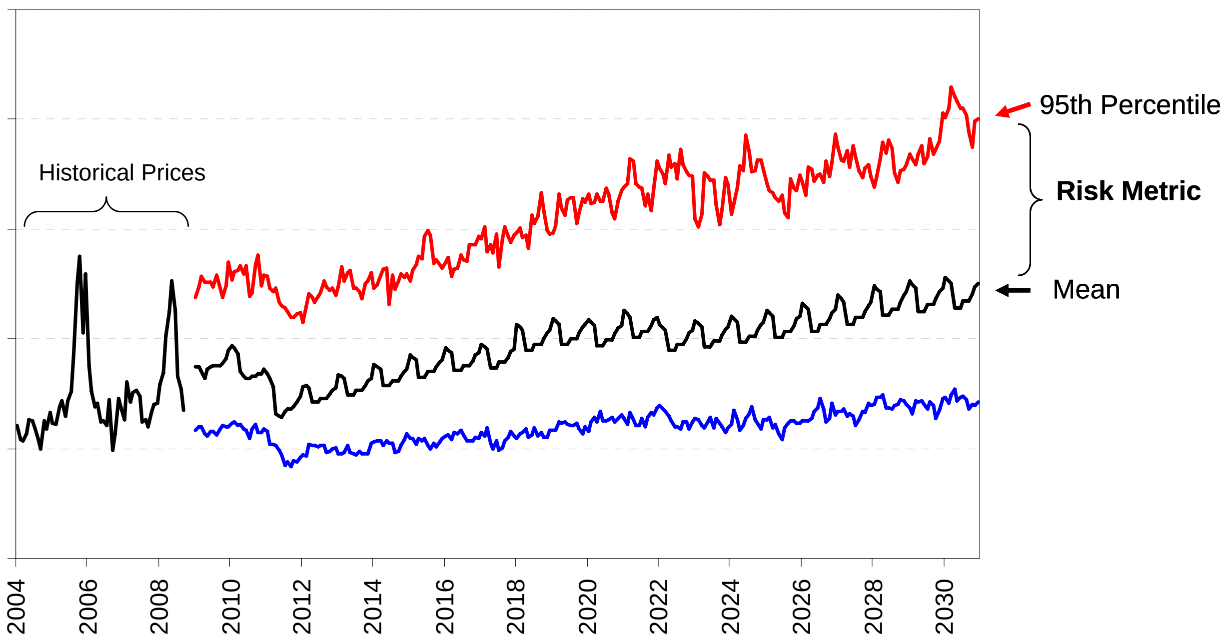
Southern California Edison. Since it is difficult, if not impossible, to estimate SCE's IRP long-term rate trends, we used cost minimization as a proxy for maintaining competitive rates. For comparison purposes, different portfolio options were evaluated based on the levelized net present value of all generation-related costs associated with serving the utility's load (2008$/MWh). Pace's cost metric includes the variable cost of generation, fixed costs, capital costs investments, and the cost of net market transactions (purchases minus sales).

Maintain Stable Rates (Price Risk)

Without proper hedging programs in place, fuel and power price volatility can result in significant changes in cost. Portfolios that can mitigate significant market swings can also achieve higher rate stability. Rate stability can be measured by different metrics like standard deviation or probability bands.

Portfolios were evaluated against statistically derived distributions on key market drivers, like natural gas prices, energy demand, power market prices, and capital costs. Rather than record portfolio costs under one set of assumptions, costs were measured under a distribution of the key assumptions drivers. In this context, portfolios were evaluated based on the difference between the mean of the distributions of total incremental generation costs and the 95% confidence band of the distribution of these costs. This represents a metric of how wide the distribution of costs can get for each portfolio. The lower the difference between the mean and the 95% confidence band, the less exposed the portfolio is to market volatility. Exhibit 16 presents an illustrative display of the quantification of this metric. As is shown, the mean and the statistically derived 95th and 5th percentiles are shown along with historical observations. The difference between the mean and the 95th percentile is used as the measure of price risk in this analysis.

Exhibit 16: Illustration of Risk Metric



Source: Pace

Provide Reliable Service (Reliability)

System reliability is a primary concern for any load-serving entity, and long-term utility planning is usually done using a capacity reserve margin criterion, such as the 18% planning reserve margin used by PWP. In this context, PWP would plan to have reliable resources in place to meet 118% of its customers' expected demand in order to ensure reliability even after the loss of one or more key resources, where the 18% reserve margin provides sufficient flexibility to adjust to such contingencies. However, reliability planning for PWP is complicated by the fact that PWP has only a single interconnection with the CAISO grid and the loss of that interconnection would have very serious reliability consequences. Due to Pasadena's dependence on a single 215 MW transmission line into the City, PWP historically has placed significant reliance on maintaining local generation inside the City to mitigate those reliability consequences, and any portfolio that includes additional local generation reduces Pasadena's reliance on that line to serve load. Moreover, about 70% of the capacity currently installed in-city is more than 30 years old. Even with reliable transmission, an unplanned outage of the in-city resources could lead to unserved load during high load months. Newer, more reliable in-city resources help mitigate the probability of unserved load by decreasing the probability of unplanned outages for the local resources.

Although the likelihood of rolling blackouts in Pasadena related to the loss of transmission and/or local generation resources is relatively small, such outages could have potentially catastrophic consequences for the safety and well-being of PWP's customers. For context, an industry-accepted standard reliability standard in the electric utility industry is to target outages that are no more frequent than 1 day in 10 years. PWP's ability to satisfy that standard is at significant risk given its reliance on a single interconnection point and aging local generation.

Given the complexity of the electric utility system and the interdependent nature of the various components of the system, modeling reliability and developing a quantitative assessment of the reliability, beyond reserve margin, of alternative resource portfolios generally is not attempted in a typical IRP evaluation. Instead, each portfolio was evaluated from a reliability perspective on a qualitative basis with regard the replacement of the aging local generation with new, modern and efficient in-city generation facilities. Additionally, Pace developed an economic comparison of portfolios that included development of new, in-city generation resources versus portfolios that emphasized transmission system upgrades to permit expanded use of imported resources.

Maintain Fiscal Health (Capital Charges)

The Portfolio Cost metric mentioned above illustrates the total portfolio cost for the utility on a net present value ("NPV") basis throughout the Study Period. This metric encompasses capital costs, fixed operating costs, variable costs of generation, and the costs of all net market transactions. The level of capital investments by themselves, however, constitutes another important metric. The financial stability of the utility can be greatly influenced by the size and timing of the investments it makes.

For comparison purposes, the levelized capital costs of all capacity additions in 2030 was evaluated for all portfolios. This metric illustrates the size of capital investments associated with the resource additions in each of the portfolios.

Manage Market Risks (Spot Market Dependence 2020)

Although the ability to sell and buy in the spot market represents a significant benefit to the utility by allowing it to optimize the use of its resources, significant reliance on the spot market can constitute a risk for the utility. The spot market is highly volatile and the utility's dependence on a large volume of market transactions increases the market uncertainty associated with each portfolio.

The annual volume of net market transactions was analyzed as a percentage of the utility's load in 2020. Portfolios with net market sales are recorded with positive percentages, while portfolios with net market purchases are recorded with a negative percentage. High exposure in either direction can pose significant market risks for overall portfolio costs.

Provide Diversity and Flexibility (Regulatory Risk)

A diverse portfolio is a means of achieving an objective of minimizing the risks of any concentrated portfolio. But it is also an objective consistent with an intention of having the flexibility to adapt to changing circumstances. A portfolio that commits to one technology or assumes that legal and regulatory conditions will remain constant through the planning horizon may be unable to adapt quickly to changing market conditions. Hence, flexibility and diversity are objectives that are on the list of key objectives from the perspective of the stakeholder group.

Exhibit 17 summarizes PWP's primary planning objectives for this study and the corresponding metrics evaluated throughout this analysis. The rankings placed on each of these metrics by members of the Stakeholder Advisory Group and the Pasadena community, as compiled through the Stakeholder Advisory Group meetings and public questionnaire results, are summarized as well. A lower number denotes a ranking with higher priority. As illustrated earlier in Exhibit 15, achieving ideal outcomes in all of the top three metrics is likely not feasible with a single resource plan. Instead, certain compromise actions may be necessary to strike a balance between the competing objectives and achieve positive outcomes on as many of the priority objectives as possible.

Exhibit 17: Summary of Primary Planning Objectives and Associated Metrics

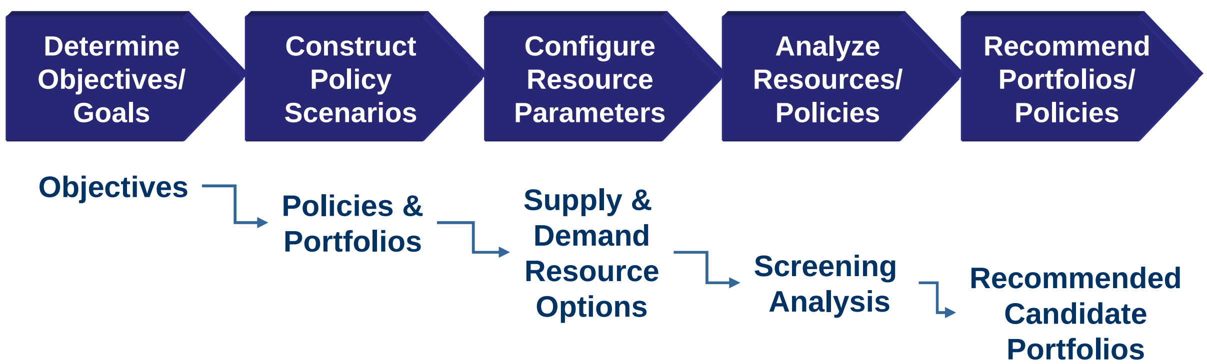
Objective	Metric	Unit	Advisory Group Ranking	Public Ranking #1	Public Ranking #2
Environmental Leadership	CO_2 Emission Reductions in 2020 from 2008 Baseline	%	2	2	1
	Renewable generation as a percentage of net energy for load	%			
Preserve Competitive Rates	Mean of the levelized NPV of Total Portfolio Costs	*2008* $/MWh	5	3	2
Maintain Stable Rates	Difference between the mean of the distributions and the 95% confidence band	*2008* $/MWh	3		3
Provide Reliable Service	Exposure to risk of loss of existing local, in-city resources	Qualitative	1	1	4
Maintain Fiscal Health	Levelized costs of all capacity additions in 2030	*2008* $000	7		7
Manage Market Risks	Annual volume of net market transactions as a percentage of load in 2020	%	6		5
Allow for Flexibility	Exposure to risk of emerging GHG regulations and market mechanisms	Qualitative	4		5

Source: Pace and PWP Public Questionnaire Results

ANALYSIS OF IRP STRATEGIES AND TRADEOFFS (PHASE I)

The resource planning approach taken in this 2009 IRP consists of two major phases. The first phase is designed to screen all the feasible resource options that meet the utility's timing and size requirements. The screening process includes a representation of all expected market conditions and planning constraints (RPS standards, emission reduction rules, and transmission limits). These options are evaluated based on the utility's objectives and different policy scenarios. A number of portfolios are then selected based on different planning objectives to be further evaluated during the "risk" phase of the analysis. Exhibit 18 summarizes the steps taken in the Phase I process.

Exhibit 18: Phase I Overview



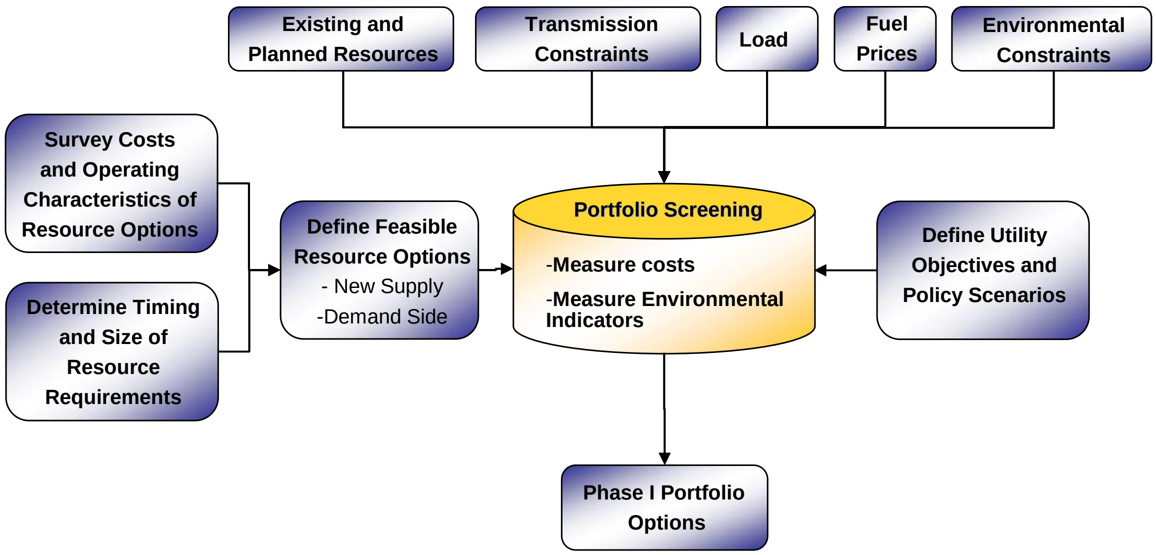
Source: Pace

SCREENING ANALYSIS

Once the goals have been established and the objectives and metrics formed, feasible resource plans need to be developed and configured. The existing resource mix, size and timing requirements, and the costs of new resource additions need to be evaluated against the utility's key planning objectives. This process is used to narrow all possible alternatives down to those options that are practical for the utility. Screening analyses were performed with a customized screening tool, which is able to rapidly evaluate key metrics for a variety of technology combinations within the framework of PWP operations. Screening analyses were performed in the context of different environmental goals in order to focus the exercise around the planning objectives and constraints that were established in the stakeholder process and outlined in the previous chapter.

The screening process was performed in accordance with Exhibit 19. As is noted, the screening analysis incorporated a detailed representation of portfolio resources, PWP demand, local transmission constraints, and all relevant costs such as fuel prices, power prices, environmental compliance costs, and fixed operating charges. The process involved a survey and review of resource options, an analysis of requirements to meet reserve margin and regulatory targets and an accounting of costs and environmental indicators in order to meet planning objectives and policy goals. The process was performed in two distinct steps: resource screening and more detailed portfolio screening.

Exhibit 19: Process Diagram for Screening Analysis



Source: Pace

Resource Screening

In order to analyze new resource options, an assessment of costs and operating characteristics was performed for a broad range of technologies. The following options were evaluated:

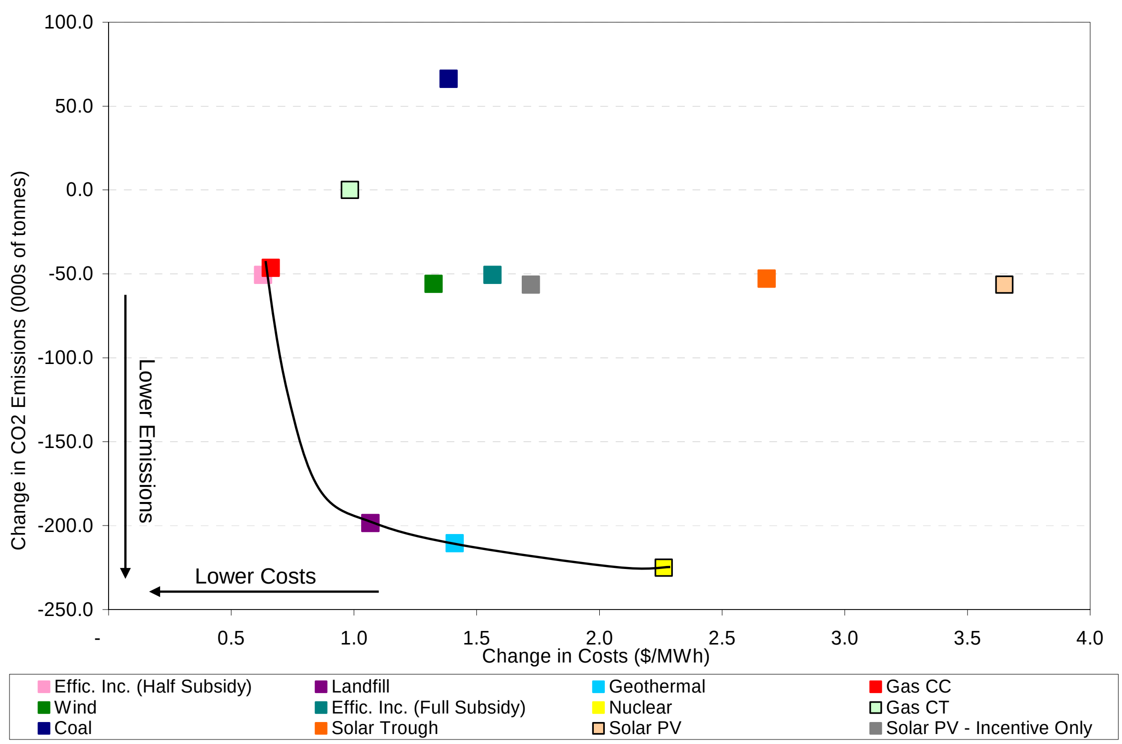
- Coal-fired steam turbine
- Coal-fired Integrated Gasification Combined Cycle ("IGCC") with and without sequestration
- Nuclear
- Natural gas-fired combined cycle turbine
- Combined heat and power
- Geothermal
- Landfill gas
- Biomass – combustion and anaerobic digester
- Wind
- Solar thermal – trough and tower technology
- Solar photovoltaic
- Hydroelectric
- Energy efficiency options

Capital cost estimates and operating profiles were developed for these resource options from a combination of information from project bids received by PWP, Pace technology assessments from consulting projects and public reports from California. These estimates were combined with financing assumptions and tax rules to develop appropriate cost comparisons. Operational parameters were applied and specified at the hourly level, where appropriate. Details on these cost assessments are summarized in the appendix section on Phase I Analysis of IRP Strategies and Tradeoffs.

Before developing complete portfolios, the screening analysis evaluated the impact of resource additions on portfolio costs and the performance of individual technology options in reducing CO_2 emissions. As is illustrated in Exhibit 20, the resource screening analysis targeted several technology options as preferred for further analysis in Phase II. Those technologies closer to the bottom left axis in Exhibit 20 perform best on reducing carbon emissions at the lowest incremental cost to the portfolio. All technologies that were above and to the right of the line had higher costs and lower emission reductions than those on the line. In order to rank resource options on a similar footing, costs per tonne of CO_2 reduced were calculated for each technology. Exhibit 21 summarizes the relative performance of each of the technologies on this metric.

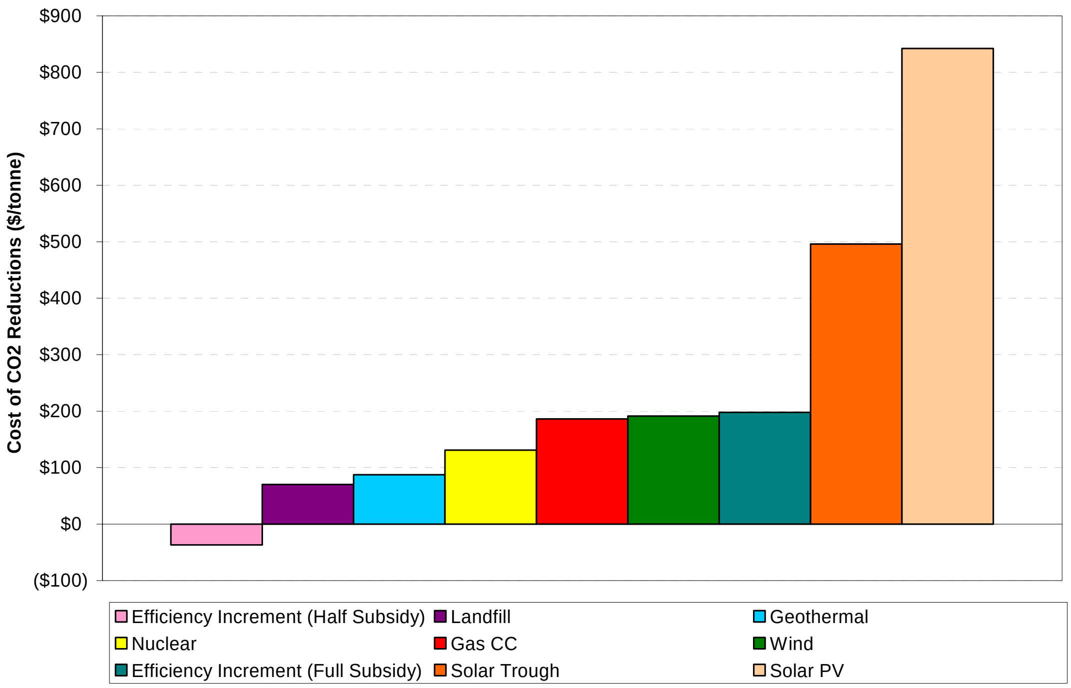
The analysis indicated that certain renewable resources (landfill gas and geothermal) and efficiency measures were preferable for future resource planning. Although nuclear proved best on CO_2 emission reductions, it was deemed an infeasible technology option for PWP on the grounds of capital requirements and general availability. Coal-fired and gas-fired combustion turbines were determined to be ineffective at reducing carbon emissions, and it was concluded that gas-fired combined cycle technology was the preferred local fossil resource.

Exhibit 20: Resource Screening Summary of Costs and Emission Reductions



Source: Pace

Exhibit 21: Resource Screening Costs per Tonne of CO_2 Summary



Source: Pace

The key conclusion of the initial resource screening was that numerous resource options are available to satisfy Pasadena's multiple objectives, but they each carry significant risks that must be considered:

- Landfill and geothermal are least-cost, but may have limited availability and may depend on new transmission to make them feasible in significant quantities.
- Wind and solar thermal are feasible, but at a higher cost. They might also increase PWP's exposure to reliability and commodity market risks because of their intermittent and unpredictable delivery patterns.
- Local non-traditional resource options are viable, but with significant risk that customers may not adopt their use as quickly or to the extent anticipated or desired. A feed-in tariff program can be a way to encourage such local renewable resource development by offering a fixed price for any qualifying resources that can come to market within the City of Pasadena. A price of $150/MWh was determined to be an appropriate level to evaluate such a program. The proposed price of $150/MWh is set at a premium above the market clearing price because it is designed to encourage the development of local resources and because the price incorporates the locational value associated with procuring resources that avoid transmission investment, line losses, and congestion. While the average price is $150/MWh, the program structure should include time-differentiation to provide a price signal that encourages delivery during on-peak time periods. On-peak prices should be $225/MWh (+150%) or higher, with off-peak prices adjusted accordingly.
- A solar rebate of approximately $4/Watt would make the PV technology cost-competitive with competing solar options on a $/ton basis.

Portfolio Screening

With the resource screening analysis conclusions guiding portfolio development, specific details regarding PWP's projected supply/demand balance and required reserve margins were analyzed in order to develop practical timing and size (capacity addition) parameters for resource additions. Within those parameters, portfolios were developed around specific planning objectives, based on environmental goals.

The environmental goals and strategies used to guide portfolio development were categorized generally as follows:

- Minimum: 20% carbon reduction by 2020 and 20% RPS by 2017
- Low: 30% carbon reduction by 2020 and 33% RPS by 2020
- Medium: 60% carbon reduction by 2020 and 50% RPS by 2020
- High: 80% carbon reduction by 2020 and 80-90% RPS by 2020

A strategy that pursued a 100% carbon reduction was also explored in the screening analysis. Costs escalated significantly in this portfolio, however, and the requirements of PWP to balance energy requirements with dispatchable gas-fired resources, as well as the need to maintain significant local capacity made achievement of such a reduction infeasible. Therefore, it was concluded that an 80% reduction would represent the high-end target.

In the course of portfolio development, a structured methodology was followed in order to build resource plans around different technologies and timing, using the results from the resource screening analysis. The following process was employed:

- Add resources when needed to either meet reserve requirements, the carbon reduction requirement, or the RPS requirement
  - Preferred resources from the resource screening phase were added first (landfill gas and geothermal before wind and solar resources, for instance)
  - Portfolios were constructed to recognize limitations of the preferred resources in a given year or over the entire planning period
- Change the timing of the portfolio additions to reflect feasibility concerns, impacts on total costs, and extrapolated annual environmental targets
- Consider more diverse portfolio options in response to stakeholder and public comments

PHASE I RESULTS

Portfolio options were narrowed down in accordance with each environmental strategy, in order to develop a set of options that performed adequately in each of the stated objectives. The screening tool allowed for analysis and measurement of all cost and environmental metrics to in the course of portfolio summary. In response to stakeholder and public comments, diverse portfolios were preserved. Several key conclusions were reached in the course of the Phase I analysis. They can be summarized as follows:

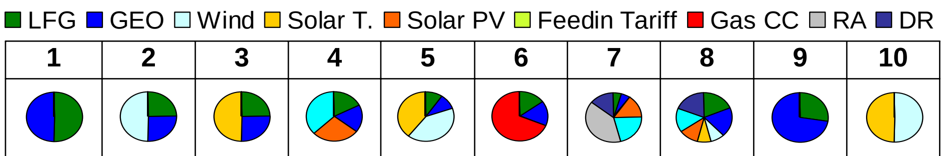
- Achievement of greater emission reductions is associated with higher portfolio costs over the planning horizon. The Phase I analysis indicated that for approximately every additional 10% increase in CO_2 emission reductions, costs would be expected to increase by 4%. Selection of a preferred Pasadena resource plan hinges primarily on customers' willingness to pay to reduce PWP's environmental impacts, while ensuring the reliable operation and financial integrity of the utility.

- Options premised on the displacement of IPP power carry significant risk related to (i) the feasibility of selling the power, (ii.) getting credit for reduced carbon emissions and (iii.) the price that can be realized in the market for the displaced power.
- Overall preferences for carbon reduction strategies can be refined as follows:
    - The minimum (20%) reduction strategy should be dropped, as it fails to achieve likely minimum renewable portfolio standards in emerging state policy and does not represent environmental leadership;
    - The low (30%) reduction strategy can be achieved with modest incremental cost impacts through reconfiguring the existing supply portfolio with renewables to achieve a 33% RPS target;
    - The medium (60%) and high (80%) carbon reduction strategies are feasible if IPP coal generation can be displaced, but they create potentially significant cost and risk exposures.
- Each carbon reduction strategy involves similar planning and procurement decisions over the next 3-5 years, so it may be possible to defer a final commitment to a specific carbon reduction strategy to develop further clarity regarding emerging carbon policies, IPP displacement options, and the cost/availability of alternative renewable resources.

The Phase I analysis resulted in the creation of ten distinct portfolios that met the three preferred carbon reduction goals with a variety of potential resource options. The ten selected portfolios are summarized in Exhibit 22 as incremental additions to the existing PWP portfolio. The total MW added, IPP displacement, and general portfolio resource mix for each portfolio is shown in the legend below the table. As the 14 MW solar PV expansion and energy efficiency targets are common to all portfolios, the legend below does not include them in the total MW added calculation.

Exhibit 22: Phase I Portfolio Details (Incremental Changes to the Existing Portfolio)

		Remote Renewables				Local Renewables/DSM					Fossil-fueled	
Carbon Reduction Target	Portfolio #	Landfill	Geo thermal	Wind	Solar Thermal	Solar PV (Existing)	Solar PV (Expand)	Feed-In Tariff	Energy Efficiency	DR & RA	Local Gas	Coal
Low	1: LFG/Geo	15	15			14			26			
	2: Wind	10	10	20		14			26			
	3: Solar	10	10		20	14			26			
	4: Local	10	10			14	15	21	34			
Med	5: Remote Renew	15	15	60	60	14			26			-47
	6: CC	15	15			14			26		65	-108
	7: Local	5	5			14	15	21	34	55		-108
High	8: Diverse	25	25	10	10	14	15	21	34	25		-108
	9: LFG/Geo	25	65			14			26			-108
	10: Wind/Solar			125	125	14			26			-108



	1	2	3	4	5	6	7	8	9	10
Total MW Added	30	40	40	56	150	95	101	131	90	250
IPP Replacement					47	108	108	108	108	108

Source: Pace

The details of each of the incremental portfolio options referenced in Exhibit 22 are outlined below. Once again, the common 14 MW of solar PV expansion and the reference case efficiency improvements are not explicitly mentioned in the summaries.

1. **Low LFG/Geo** – A total of 30 MW of landfill gas and geothermal capacity, added to the portfolio between 2012 and 2017.
2. **Low Wind** – 10 MW each of landfill gas and geothermal capacity, supplemented by 20 MW of wind.
3. **Low Solar** – 10 MW each of landfill gas and geothermal capacity, supplemented by 20 MW of solar thermal.
4. **Low Local** – A portfolio centered on an incremental 15 MW of solar PV and 21 MW of local renewables procured through a $150/MWh feed-in tariff offering. Capacity additions are supplemented by landfill gas and geothermal additions in order to meet CO_2 target.
5. **Med Remote Renewables** – Liquidation of the electricity from 47 MW of the IPP coal plant and replacement with a diverse (landfill gas, geothermal, wind, solar thermal) set of remote renewable options.
6. **Med Combined Cycle** – Liquidation of the electricity from all shares of the IPP coal plant and replacement with 15 MW each of landfill gas and geothermal and a 65 MW natural gas combined cycle unit.
7. **Med Local** – Liquidation of the electricity from all shares of the IPP coal plant and replacement with an emphasis on local efficiency programs, demand response, solar PV, and feed-in tariff procurement. Due to limitations on local resources, additional capacity requirements are procured through resource adequacy purchases.

8. **High Diverse** – Liquidation of the electricity from all shares of the IPP coal plant and an "all-of-the-above" strategy for meeting resulting energy needs, including expanded efficiency, demand response, local renewables, and remote renewables.
9. **High LFG/Geo** – Liquidation of the electricity from all shares of the IPP coal plant and replacement with 25 MW of landfill gas capacity and 65 MW of geothermal capacity by 2016.
10. **High Wind/Solar** – Liquidation of the electricity from all shares of the IPP coal plant and replacement with 125 MW each of wind and solar thermal capacity.

Outstanding Risks Factors for Further Consideration

The Phase I analysis highlighted several key risks that cannot be accounted for in a screening exercise reliant on single point estimates for key market drivers. As a result, further evaluation of the following key risks was determined to be required as part of the Phase II analysis:

- Evaluation of the exposure of all of the portfolio options to statistically quantifiable risk factors, such as:
    - Customer demand and regional load
    - Natural gas prices
    - Power market prices
    - Capital costs for resource additions

- Evaluation of certain portfolio options in the context of quantum events through scenario analysis that explore the:
    - Feasibility of liquidating IPP power and the price that can be realized for it
    - Availability of renewable resources to displace IPP
    - Uncertainty around the reliability of local generation
    - Emerging state/regional/federal carbon policy constraints and valuation

QUANTITATIVE AND RISK ASSESSMENT OF PROPOSED PORTFOLIOS (PHASE II)

RISK INTEGRATED RESOURCE PLANNING APPROACH

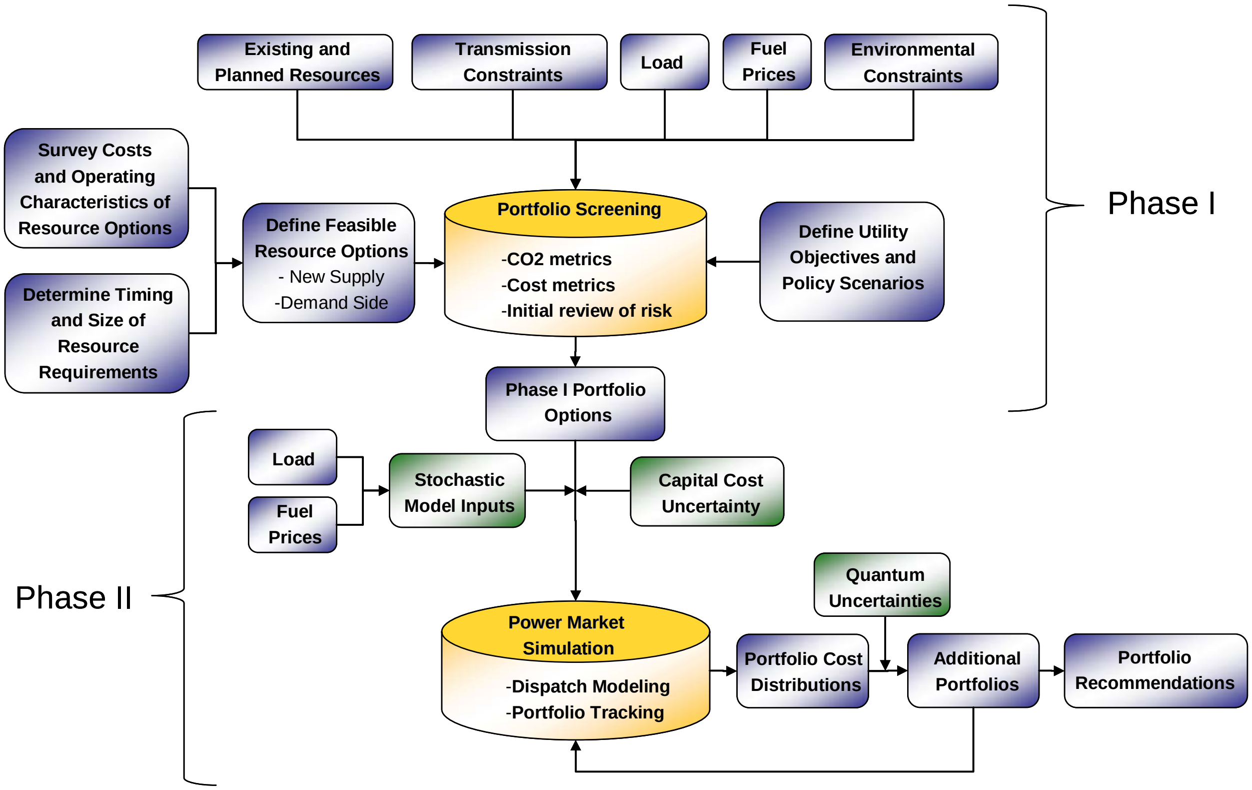
PWP, just like most electric utilities, has to make resource decisions under a great deal of uncertainty. A resource decision that meets all objectives when judged only under current or best guess forecasted conditions may prove to be a future financial burden on the utility over time if the forecasts are wrong. Fuel market volatility, capital cost uncertainty, load uncertainty, emission regulations, and regulatory changes will all affect how a resource portfolio performs throughout its operational life. Understanding the range of potential market volatility and the severity of impending regulatory changes on alternative generation portfolios is crucial to make the appropriate portfolio choices. The least expensive resource addition may not be the best if it also exposes PWP to severe market volatility or severe negative effects associated with an impending regulatory change. The tradeoffs between costs, risks, reliability, environmental stewardship, and other utility objectives need to be quantified for each portfolio and need to inform the selection of the portfolio that performs best according to those objectives the utility ranks as its highest priorities.

As introduced in the previous chapter, the 2009 IRP took a risk-based approach to resource planning.[1] The first phase screened all the feasible resource options through an analysis that included a representation of all expected market conditions and planning constraints (RPS standards, emission reduction rules, and transmission limits). These options were evaluated based on the utility's objectives and different policy scenarios. A number of portfolios were then selected based on different planning objectives to be further evaluated during the second phase of the analysis.

The portfolios in Phase I were constructed to capture a broad spectrum of resources, size, and timing possibilities in the context of its critical objectives. This allows PWP to evaluate all viable resource options and identify the resource characteristics and combinations that constitute a good portfolio. Phase II of the 2009 IRP process focuses on the quantification of risks and the impact of different uncertainties on the performance of all portfolios selected from the screening process. The Phase II process was designed to assess the impact of different uncertainties on each portfolio and allow the utility to rank the importance of all metrics based on their hierarchy of objectives. Exhibit 23 illustrates the details of the Phase I and Phase II components of the 2009 IRP process.

[1] Pace employed its Risk Integrated Resource Planning ("RIRP") approach in analyzing feasible portfolio options in the context of a variety of uncertainties in order to measure performance under multiple planning objectives.

Exhibit 23: Risk Integrated Resource Planning Process



Source: Pace

The Phase II process focuses on the quantification of uncertainty, which can be measured through different methodologies. Uncertainty was evaluated using two main methods: statistically-driven stochastic analyses and scenario analyses. Stochastic simulations are generally deemed appropriate for variables that have a wide and continuous range of potential outcomes that can be quantified based on historical relationships and volatilities. In this analysis, load, fuel, and capital cost uncertainty were evaluated using stochastic inputs. Discrete events that result in significant or quantum changes for portfolio performance or market outcomes were evaluated through scenario analyses.

Uncertainty is measured as a distribution of the aggregation of all potential costs (capital, O&M, fuel etc) of the incremental generation portfolio decisions over time. By quantifying the costs over a wide range of potential market and regulatory outcomes, we can get an accurate picture of the full range of risks associated with any portfolio over the entire planning horizon. Additional detail on the Phase II process and tools can be found in the appendix.

STOCHASTIC (QUANTIFIED RISK) PORTFOLIO ANALYSES

Stochastic inputs used in Phase II were based on a combination of historic volatility and expectations for future market trends. Pace's market insight is used to develop a view on future market trends; statistical and modeling tools are then employed to quantify the uncertainty around the expected trends and evaluate the performance of each portfolio under different uncertainties. Additional information about the development of stochastic inputs and stochastic simulations can be found in the appendix section on Phase II Risk Analysis.

As with any resource plan, the first step in the process was the development of a load forecast. The load forecast, developed by Pace, used an econometric analysis, supplemented by full inclusion of all economical energy efficiency measures. The forecast and supporting analyses are described in the appendix section on PWP Load Forecast. Then for each generating facility in the fleet and potential generation addition, operating characteristics, fuel cost projections and emission characteristics were developed. These are also described more fully in the appendix.

The Phase II analyses require that uncertainties in these forecasts are determined. The effects of fuel and load uncertainty on the portfolios are quantified by simulating the hourly operations of all portfolio resources over the study horizon under 500 different load and fuel combinations. As stated previously, these distributions were based upon historical statistical analyses of load and fuel prices. This simulation results in 500 different cost outcomes associated with fuel and load uncertainty for each portfolio, for each year in the Study Period. In other words, the stochastic simulation of load and fuel results in a distribution around portfolio costs for each year of the Study Period. Cost distributions represent the probability of occurrence over a range of outcomes.

Capital cost uncertainty is evaluated by defining stochastic bands around the capital costs of each resource addition in the portfolio for each year of the Study Period, based on historical commodity cost volatility and breakdowns of capital costs for different generating technologies. The capital cost distributions were added to the distribution of costs associated with fuel and load uncertainty in order to arrive at a Total Cost distribution for each portfolio.

SCENARIO ANALYSES

For any given portfolio, there are significant sources of uncertainty that cannot be quantified using stochastic simulations. Quantum cases developed around discrete assumptions changes have been analyzed through separate scenario analyses. In this study, the portfolio risks evaluated using scenario analyses included:

- Uncertainty around the sale price of IPP
- Availability of renewable generation
- Uncertainty around the reliability of local generation
- Regulatory risk: GHG emission accounting uncertainty
- Regulatory risk: CO_2 prices

Uncertainty around the Sale Price of Power from the Intermountain Power Plant (IPP)

Several (6 out of 10) of the portfolios analyzed were constructed around the replacement of part or all of the IPP generation. In order to significantly reduce CO_2 emissions, the generation from IPP has to be replaced by cleaner resources. Replacing IPP, however, involves significant costs and risks, by removing a significant source of supply and replacing it with new capacity. The ability of PWP to offset some of these costs will depend on the price that can be secured for the sale of the IPP generation. Under the current regulatory environment and the expectation for more stringent environmental regulations, there is significant uncertainty around the terms and conditions that can be negotiated for the sale of coal generation into a different market area. The larger the contemplated size of the displacement, the more the portfolio is exposed to risk around the price that can be achieved for the sale of IPP power.

In its reference case analysis, Pace assumed that IPP power would be sold at a slight discount to the market for power in the southwest. In our sensitivity analysis, Pace has analyzed the impact of a sale of IPP generation at a price of zero for all the portfolios. This means that PWP is still responsible for all fixed and variable costs associated with IPP operations, without receiving any benefit from the resulting power. Portfolios that replace more generation from IPP will be more exposed to the possibility of a zero price for its energy.

Availability of Renewable Generation

The limitations on the availability of certain renewable resources to generate electricity are an important factor to consider when evaluating renewable-intensive portfolios. Renewable resource options like geothermal, for example, are highly limited by geographic location and may face transmission obstacles in delivering power to Pasadena. Resource options like landfill gas, on the other hand, are limited by the general resource availability in the area. Pace's portfolio review incorporated the impact on total portfolio costs of less-than-anticipated availability of renewable resources. Pace evaluated the impact of this in portfolios where landfill gas and geothermal are the predominant resource options. If significant capacity of this type is unavailable, energy and capacity shortfalls would have to be replaced by market purchases with their associated carbon emissions. As a result, costs would be expected to increase and emission reductions decrease. In the reference case, portfolios were constructed as if the availability of landfill and geothermal was unlimited. In Portfolio 9 for example, it was assumed that 65 MW of geothermal and 25 MW of landfill gas capacity was available for development and delivery into PWP service territory. In the sensitivity case, we assumed that only 15 MW of this power combined was available and the rest of the required power had to be purchased in the market.

Uncertainty around the Reliability of Local Generation

About 70% of the capacity located within the City of Pasadena is more than 30 years old. Even with reliable transmission, an unplanned outage of the in-city resources could lead to unserved load during high load hours. In order to assess the potential reliability risks of continued reliance on the 110 MW of aging local generating units, Pace reviewed PWP operating criteria for the local, in-city units as well as projected load data. PWP studies indicate the need to initiate rolling blackouts when customer loads exceed 253 MW and the 110 MW of aging local units is unavailable.

- Pace's analysis indicates this has a 2.04% probability of occurring (179 hours/year)
- An accepted industry planning standard is 0.027% probability (1 day in 10 years)
- Achieving the industry standard requires at least a 76.2% probability that each of the three aging local units will be available when called to meet PWP customer's electricity requirements. The age of the existing units could put pressure on this requirement if upgrades or replacements are not made.

Previous analyses of PWP's transmission system upgrade options as an alternative to maintaining local generation capacity indicate that such options would be difficult and costly to achieve. A Black & Veatch study completed in April, 2003 evaluated transmission interconnection of Pasadena on its west side with City of Glendale and Southern California Edison (Eagle Rock substation) and recommended not to pursue such options further due to high environmental impact, cost, difficult terrain and congestion of transmission lines. PWP also has a 40 MW "emergency only" interconnection with Los Angeles Department of Water & Power ("LADWP") on the southwest side. Since this interconnection cannot be used simultaneously with the Goodrich interconnection due to phase differences between LADWP and Southern California Edison, and it does not have sufficient capacity to handle PWP's external resources, PWP would only use it when the Goodrich interconnection failed. Given the interconnection constraints and design of the sub-transmission system, PWP has historically pursued a balanced approach between local generation and transmission for import of energy.

As noted previously, reliability assessments in an IRP context do not lend themselves to precise modeling and quantitative comparisons, given the complexity of electric utility system operations and the interdependent nature of the various components of the system. Instead, each portfolio was evaluated from a reliability perspective on a qualitative basis with regard to the replacement of the aging local generation with new, modern and efficient in-city generation facilities. Additionally, Pace developed an economic comparison of portfolios that included development of new, in-city generation resources versus portfolios that emphasized transmission system upgrades to permit expanded use of imported resources.

Regulatory Risk: GHG Emission Accounting Uncertainty

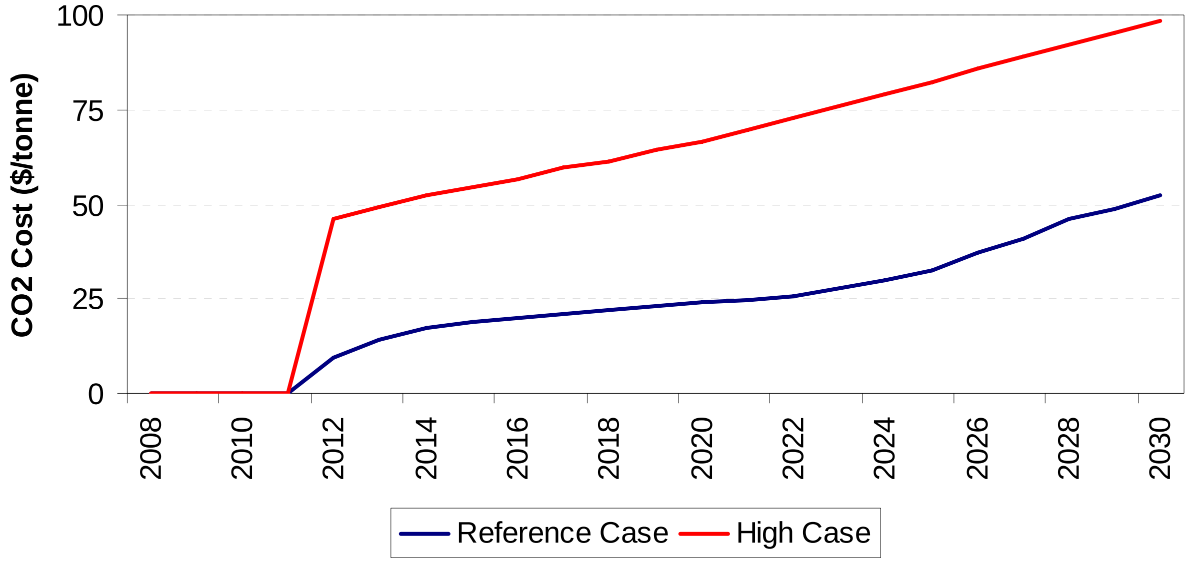
The emission reduction goal of this planning process is driven by both an environmental stewardship objective and by the need to comply with existing and potential greenhouse gas reduction regulations. The level of reductions above what is required by law will be, in part, determined by the customers' willingness to pay for additional emission reductions. The accounting norms for CO_2 emissions, however, will impact how the emissions associated with serving the utility's load are recorded. Determining the appropriate accounting rules will define which portfolio achieves the desirable emission reductions.

Pace analyzed the resulting CO_2 emission reductions around three possible accounting mechanisms. The reference case counts emission reductions for market sales at a portfolio average emission rate. An optimistic case assumes that the cleanest resources will serve native load first and that emissions from dirtier resources will only be counted if used to serve native load. A pessimistic case assumes that the emissions associated with all PWP power generation count towards their carbon footprint.

Regulatory Risk: CO_2 Prices

Significant CO_2 emission compliance costs are expected over the Study Period. The uncertainty surrounding the timing and pricing level of such costs represents a big risk for any CO_2-intensive portfolio. Pace's analysis included the evaluation of all portfolio costs under a high CO_2 case. Exhibit 24 displays the annual CO_2 compliance costs assumed in the reference case and the high CO_2 case. Portfolios with a larger share of IPP will suffer a relatively greater impact than those with less reliance on coal. Pace evaluated the relative impact of CO_2 on costs based on the NPV of portfolio costs under a high CO_2 scenario.

Exhibit 24: CO_2 Costs for Reference Case and High Case



Source: Pace

PORTFOLIO RISK ASSESSMENT RESULTS

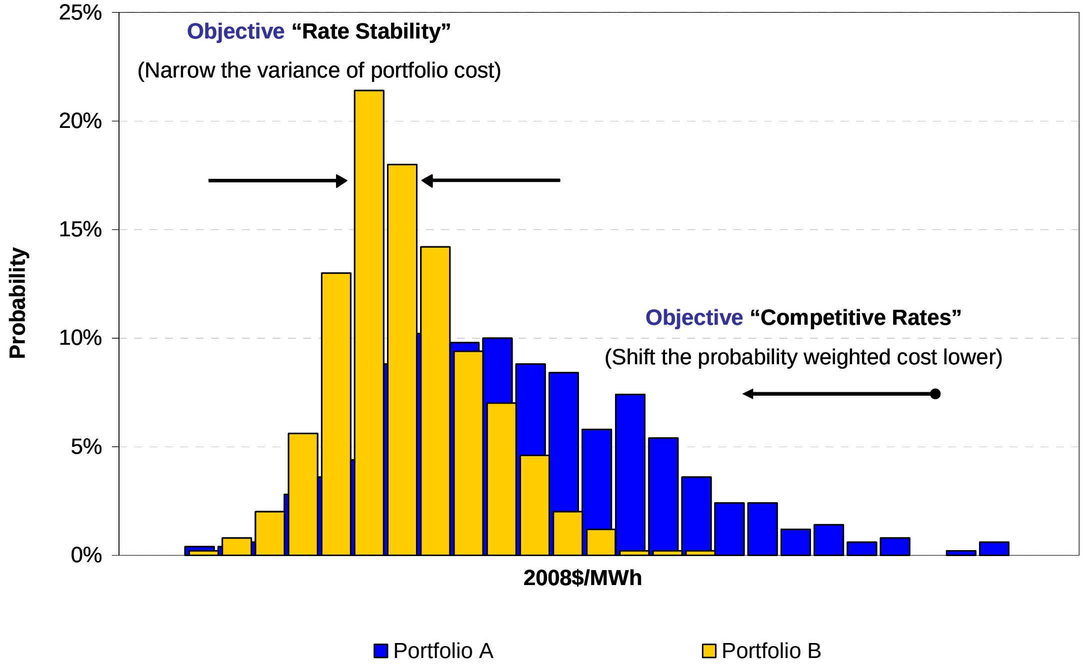
The quantification of risks within the Phase II analysis was performed first through stochastic analysis. This analysis quantified distributions around the total costs of each of the portfolios and calculated the associated emission reductions. Key result metrics included the net present value of portfolio costs (computed as a levelized annuity price per MWh), the width of the distribution (the difference between the mean and the 95th percentile outcome), and the percent reduction in CO_2 emissions by 2020. Additional scenario analyses were then performed to measure the exposure of each of the utilities to other risk factors, such as major regulatory changes or uncertainties around particular aspects or components of the portfolio. Where appropriate, the impact of these scenarios on the total portfolio costs was measured as an increment to the mean of the portfolio distributions.

Cost Distributions

Whereas traditional "base case" approaches quantify the effects of one set of fuel price, load, and capital cost assumptions, the stochastic simulation of these variables results in distributions around the "base case." Portfolio cost distributions convey information regarding the general cost level of different portfolios, but also provide valuable insight into the risks associated with each portfolio.

Exhibit 25 presents two illustrative portfolio distributions. In the example, Portfolio B's distribution is centered further to the left. This implies that the mean of the costs for Portfolio B are lower than the mean of the costs for Portfolio A. As shown, Portfolio B also has a tighter distribution than Portfolio A. This means that there is more risk associated with Portfolio A since the uncertainty around its costs is bigger.

Exhibit 25: Portfolio Cost Distributions



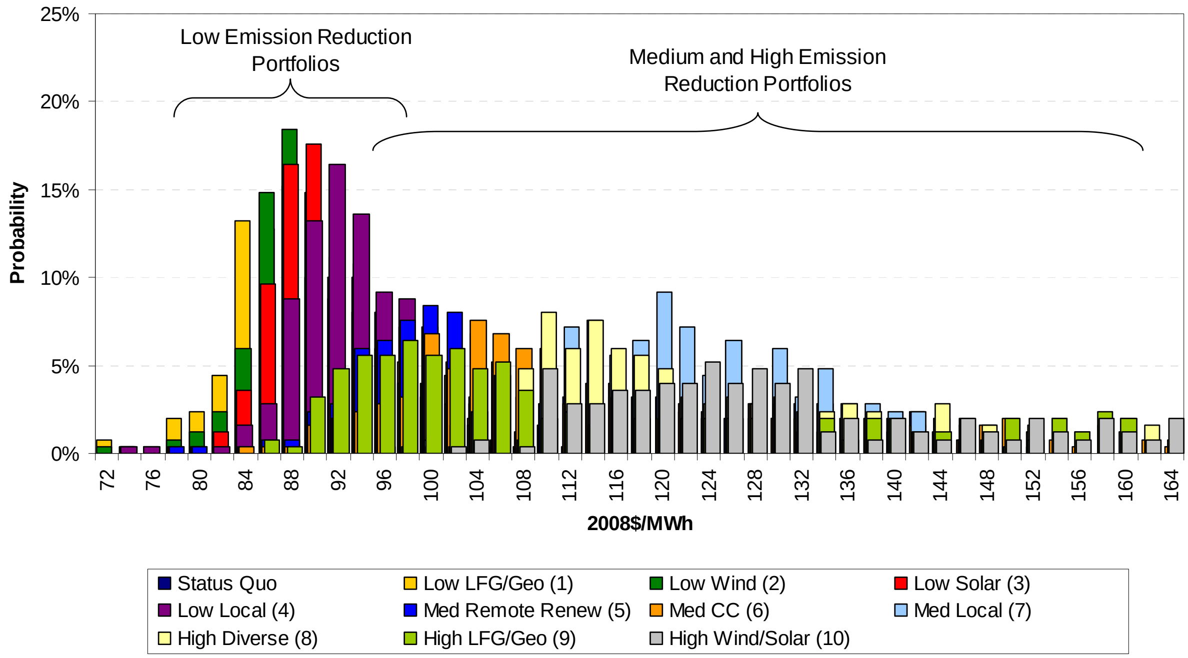
Source: Pace

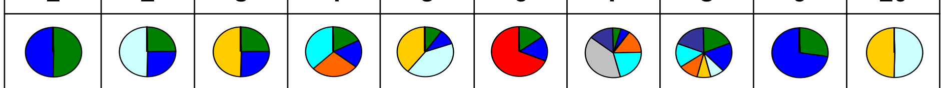
As the different portfolio distributions were evaluated throughout this analysis, portfolio costs were compared based on the mean of the distribution; the market risks associated with the portfolio were evaluated based on the width of the distribution. The status quo, represented as PWP's existing portfolio plus existing goals on efficiency and solar PV expansion, was evaluated with any future energy needs being met by market purchases. This "risk profile" was then compared against the other ten portfolios.

Stochastic Analyses Results

The status quo portfolio is analyzed in the stochastic analysis against each of the other resource plans in order to evaluate the costs and risk exposure of a suite of alternatives. Exhibit 26 presents a summary of cost distributions for each of the portfolios selected from Phase I. As an illustrative example, the year 2016 is displayed. This represents a year when many major portfolio decisions are already made. Although the shape and center of the distributions may change year by year, the relative portfolio costs and risks for 2016 are reflective of the relationships that exist over the entire Study Period. As can be seen, the low emission reduction portfolios are generally lower cost than the medium and high emission reduction portfolios. Furthermore, they have narrower distributions, meaning that the price risk associated with them is lower. For reference, the total MW added, IPP displacement, and general portfolio resource mix is shown below the graph.

Exhibit 26: Total Cost Distributions for Phase I Portfolios (2016)





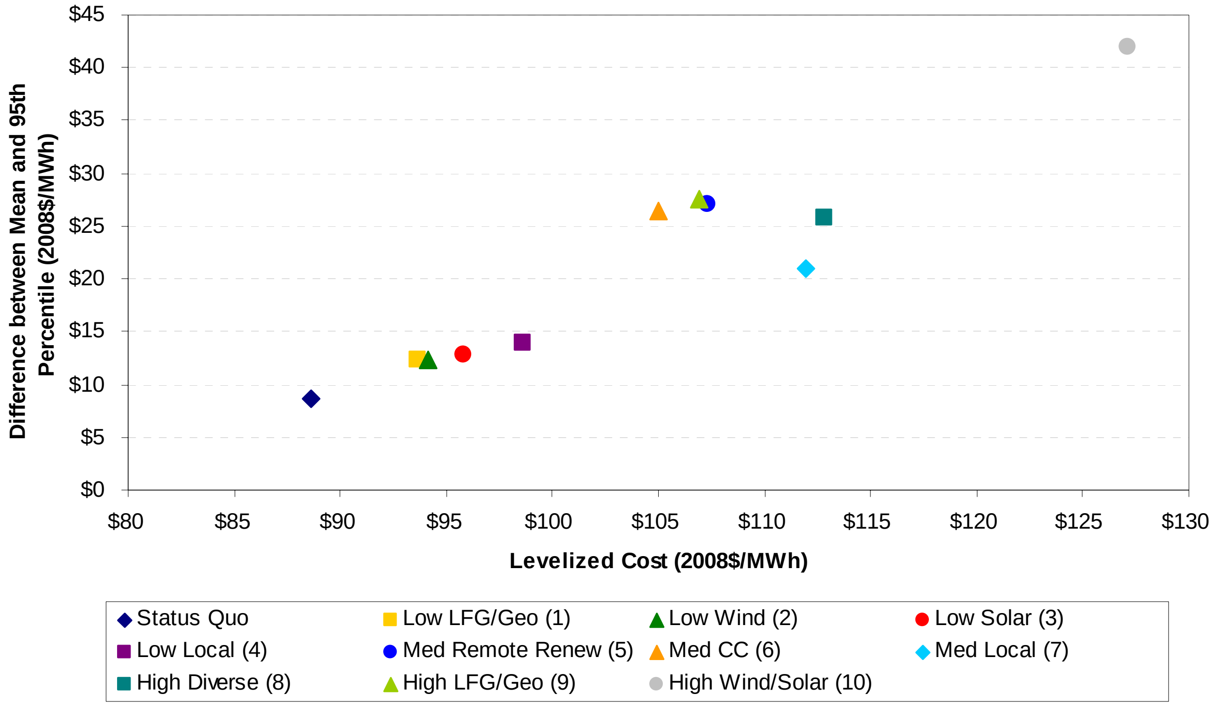
	1	2	3	4	5	6	7	8	9	10
Total MW Added	30	40	40	56	150	95	101	131	90	250
IPP Replacement					47	108	108	108	108	108

Source: Pace

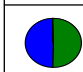
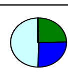
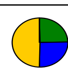
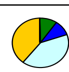
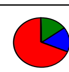
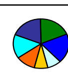
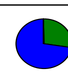
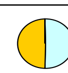
Costs and Market Risks

For portfolio comparison purposes, the yearly distributions of all portfolios were summarized into a levelized annuity, which is the Net Present Value ("NPV") of revenue requirements spread into an average $ per MWh over the planning horizon. Exhibit 27 presents the summary of the expected (probability weighted) annuity prices for each portfolio on the horizontal axis and the measure of risk (the difference between the mean and 95% outcome) on the vertical axis. As shown, portfolios with distributions centered closer to the y-axis in Exhibit 26 show a lower mean cost in Exhibit 27. Similarly, portfolios with wider cost distributions in Exhibit 26 show a higher difference between the mean and the 95th percentile in Exhibit 27. For reference, the total MW added, IPP displacement, and general portfolio resource mix is shown below the graphs.

Exhibit 27: Summary Cost and Risk Metrics for Phase I Portfolios



LFG GEO Wind Solar T. Solar PV Feedin Tariff Gas CC RA DR

	1	2	3	4	5	6	7	8	9	10
										
Total MW Added	30	40	40	56	150	95	101	131	90	250
IPP Replacement					47	108	108	108	108	108

Source: Pace

As shown in Exhibit 27, portfolios with higher levelized costs over the Study Period generally show a higher difference between the mean and the 95th percentile of their cost distribution. The portfolios in Phase I were created around different levels of IPP displacement, so those resource plans that displace IPP also remove a relatively stable cost component of the portfolio. Furthermore, the higher capital investments needed to replace more of IPP are generally also associated with higher capital cost risks.

Although the level of costs and risks associated with the portfolios will depend in part on the assumed capacity mix, in general, the tradeoffs between the costs and risks need to be evaluated in the context of achieved emission reductions. For most portfolios, the tradeoff between costs and risks is not sufficient to evaluate their performance in the context of the planning objectives.

Emission Reductions

As mentioned before, one of the primary objectives of the current resource plan is to identify the best alternatives to reduce the CO_2 emissions associated with serving the utility's load. In order to significantly reduce CO_2 emissions, the existing coal generation in the portfolio needs to be replaced with cleaner resources. In general, the more IPP capacity that a portfolio displaces, the more capacity that needs to be built to replace the coal generation. This results in higher costs for the portfolio and higher exposure to capital cost risks. The achieved emission reductions for the level of costs and risk incurred will define how portfolios are compared against each other.

For comparison purposes, portfolios were grouped based on the mean of the distribution of emission reductions:

- Low: Illustrates reductions on the low-end (<30%) of AB 32 scoping plan requirements and generally corresponds with a 33% RPS
    - Portfolios 1 to 4

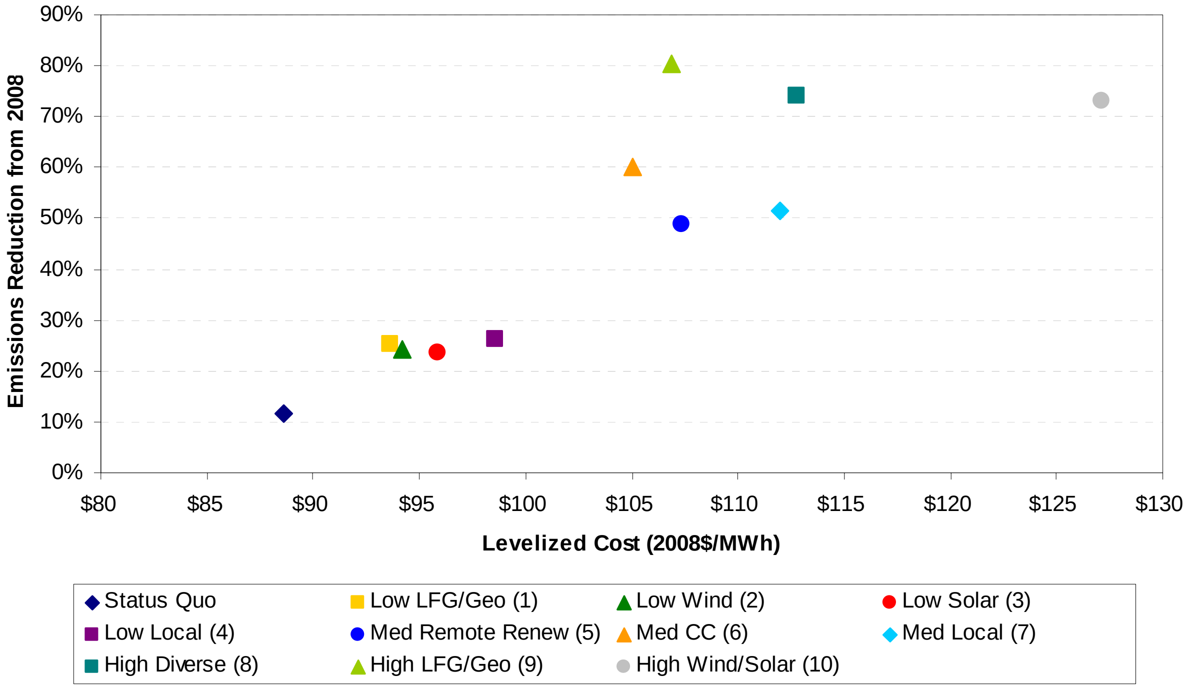
- Medium: Illustrates a range (35% - 60%) of reductions more in line with a scenario where AB 32 mandates are imposed disproportionately on a utility like PWP; higher reductions correspond with higher displacement of IPP
    - Portfolios 5 to 7

- High: Illustrates a high level of environmental leadership by achieving reductions approaching the state's long term goal (80% reduction by 2050) in an accelerated manner
    - Portfolios 8 to 10

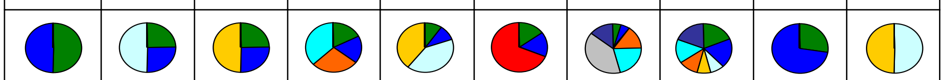
Exhibit 28 summarizes the mean of the Total Costs for each portfolio from Phase I and the mean of the achieved emission reductions. The actual year-to-year CO_2 reductions for any given portfolio will depend on a number of factors like load, fuel prices, market purchases, and market sales. As will be discussed later, there is also uncertainty surrounding the accounting methodologies employed to measure the CO_2 emissions associated of market transactions. For reference, the total MW added, IPP displacement, and general portfolio resource mix is shown in Exhibit 28.

As can be seen, portfolios that achieve greater emissions reductions are generally associated with higher costs due to additional expenses associated with new renewable resource additions and the removal of shares of the IPP coal facility. There are plans, however, that can achieve modest emission reductions without increasing costs above those expected under status quo conditions. This is due to the addition of a modest amount of low-cost renewable resources that insulate the portfolio from market power purchases, which are exposed to natural gas prices and CO_2 compliance costs.

Exhibit 28: Summary Cost and CO_2 Reduction Metrics for Phase I Portfolios



LFG GEO Wind Solar T. Solar PV Feedin Tariff Gas CC RA DR

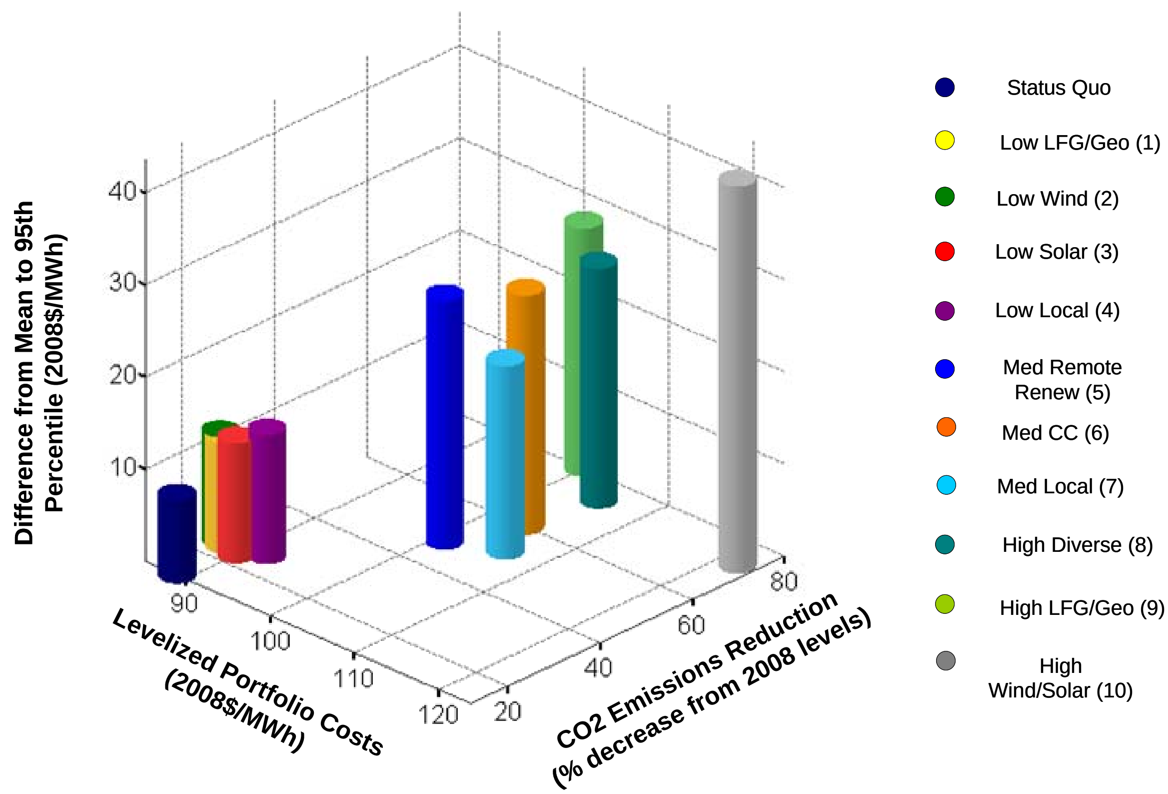
	1	2	3	4	5	6	7	8	9	10
										
Total MW Added	30	40	40	56	150	95	101	131	90	250
IPP Replacement					47	108	108	108	108	108

Source: Pace

Evaluation of Cost, Risk, and Emission Reduction Metrics

The required capital cost investment and associated risks for each portfolio need to be assessed within the context of emission reductions. This requires the simultaneous evaluation of costs, risks, and emission reductions. The tradeoff between these three metrics can be better visualized in three-dimensional space. Exhibit 29 illustrates the costs, risk, and emission reductions associated with the portfolios analyzed using a 3-D graph. As is shown, the portfolios with lowest emission reductions generally have lower costs (to the left on the cost axis) and lower price risk (shorter height on the risk axis). As higher and higher emission reductions are achieved, certain portfolios perform better on the cost metric, while others have lower risks. Exhibit 29 shows that some portfolios are candidates for elimination (Portfolio 10), but also illustrates that additional scenario analyses are needed to determine plan performance under a wider range of planning metrics.

Exhibit 29: Summary Cost, Risk, and CO_2 Reduction Metrics for Phase I Portfolios



Source: Pace

Scenario Analyses Results

As mentioned before, Pace evaluated the exposure of all portfolios to risks associated with several quantum scenarios. The results of these sensitivities can be summarized as follows:

Uncertainty around the Sale Price of IPP: Portfolios (e.g. Portfolios 5-10) that displace IPP will be exposed to significant uncertainty around the price at which the energy of IPP can be sold. The effects of this uncertainty on the total cost of the portfolio will depend on the quantity of IPP being sold. Portfolios that displace all of the IPP generation (e.g. Portfolios 6-10) would face an additional $24/MWh in levelized NPV costs if no revenue could be achieved from the sale of IPP power.

Availability of Renewable Generation: Portfolios (e.g. Portfolio 9) with a large amount of landfill and geothermal capacity will be exposed to the uncertainty surrounding the amount of these resources available to PWP. While these portfolios might perform well under other metrics, the feasibility of large landfill and geothermal capacity additions can be a significant limiting factor. Therefore, sole reliance on landfill and geothermal resources exposes portfolios to an unacceptable risk.

Uncertainty around the Reliability of Local Generation: Portfolios with a stronger focus on local capacity will increase the reliability of Pasadena's system by limiting its dependence on the single 215 MW intertie with the California power grid and adding back-up capacity for the aging in-city plants. Portfolios that add sufficient new gas-fired generation in-city to displace the need for Pasadena's older local generating units perform the best on reliability.

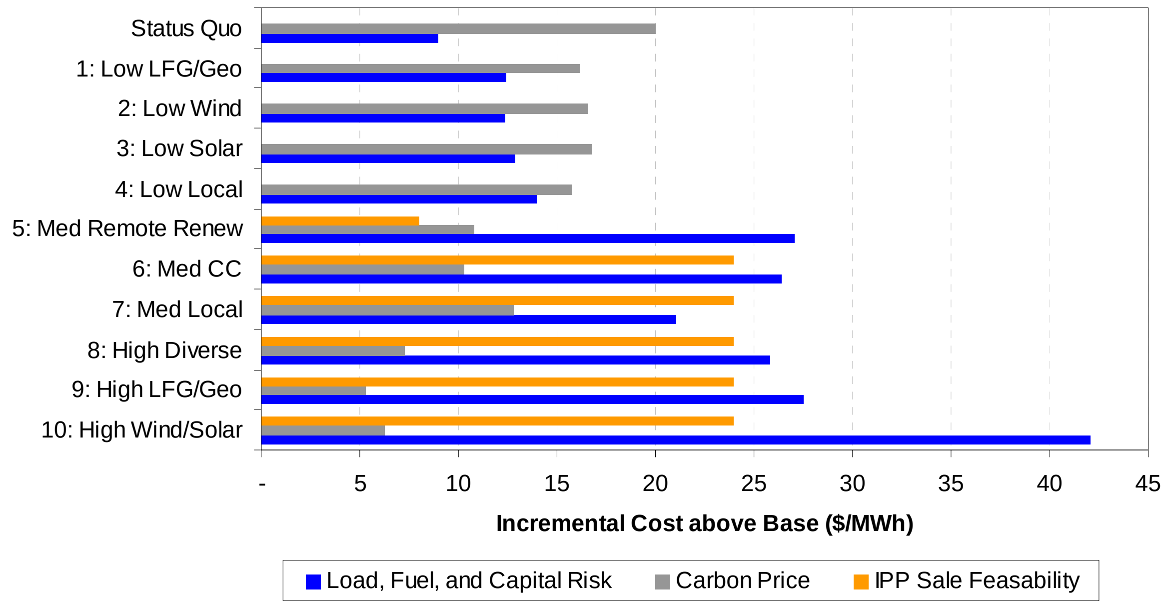
Expanding the transmission capacity into the City would be an alternative to local resource expansion that could improve system reliability. Portfolios that attempt to address existing reliability concerns through transmission upgrades would expect to require at least $100 million invested over the next 10 to 20 years to upgrade the existing single point of interconnection with SCE at Goodrich and PWP's in-city transmission system. These costs would not be incurred by portfolios adding new, natural gas-fired local generation within the City. As a result, summary cost metrics include this additional transmission costs.

Regulatory Risk: GHG Emission Accounting Uncertainty: The accounting rules for greenhouse gas emissions will impact how CO_2 emissions are counted for market sales. Because IPP is Pasadena's resource with the highest CO_2 intensity, this uncertainty will affect portfolios that keep all or part of IPP (e.g. Portfolios 1-5). The relative impact of these accounting rules, however, will also depend on the volume of market sales in a particular portfolio. Portfolios that keep a larger share of IPP but also have a lot of market sales will benefit more from a rule that counts the highest intensity resources towards market sales.

Regulatory Risk: CO_2 Prices: The risks associated with high CO_2 prices will be directly related to the amount of coal in the portfolio. Portfolios that displace a big part of IPP will significantly limit their exposure to high CO_2 prices, while portfolios that keep IPP face a significant cost risk if CO_2 prices are higher than anticipated. Portfolios that hold all of IPP (e.g. Portfolios 1-4) are exposed to an additional cost of $16-20/MWh on a levelized NPV basis in the event of a very high CO_2 price environment.

Exhibit 30 summarizes key price risks for each of the portfolios, as quantified through the scenario analyses. The expected portfolio cost increases associated with load, fuel, and capital risk (earlier referred to as "price risk"), sale price risk for IPP, and high carbon price risk are displayed together. As is shown, the risk associated with the IPP sale is as large as the combined risks associated with load, fuel prices, and capital at the 95th percentile for several portfolios that remove all of the IPP power. This indicates that such sale price risk needs to be considered in the selection process. In addition, for those portfolios that keep IPP, the carbon price risk is most significant. The portfolio that only removes a portion of the power from the coal-fired IPP facility (Portfolio 5) hedges against both of these risks.

Exhibit 30: Comparative Cost Risks for Each Portfolio



Source: Pace

Exhibit 31 summarizes the results of the stochastic and scenario analyses for the portfolios created in Phase I. The metrics presented for the planning objectives are consistent with those introduced in the Planning Objectives and Metrics chapter. The emission reductions, cost, and price risk metrics are summarized as discussed in detail above. The table displays projected RPS percentage in 2020 and denotes which portfolios withstand reliability concerns. Those portfolios that add some local generation above baseline solar PV additions are qualitatively deemed to be positive, while the portfolio with substantial gas-fired local generation (Portfolio 6) is deemed best, because it provides 65 MW of reliable, in-city capacity. The table also provides additional comparative metrics on total capital charges, the percent dependence on the spot market, the added costs of attaining zero price for IPP sale, and the impact of carbon price risk on portfolio costs. This summary is used to illustrate portfolio strengths and weaknesses and to narrow the list of potential resource plans.

Exhibit 31: Phase I Portfolios Summary Metrics

Portfolio	Emissions Reduction	Cost	Price Risk	RPS 2020	Reliability	Capital Charges	Spot Market Dependence 2020	IPP Sale Feasibility	Carbon Price Risk
	% Reduction from 2008	*Levelized $/MWh*	*Added cost for 95% $/MWh*	*% of NEL*		*Annual Levelized $MM in 2030*	*% of 2020 Load*	*Added Cost Levelized $/MWh*	*Added Cost Levelized $/MWh*
Status Quo	12%	89	9	12%		0	4%	0	20
1: Low LFG/Geo	25%	94	12	31%		21	22%	0	16
2: Low Wind	24%	94	12	29%		21	20%	0	17
3: Low Solar	23%	96	13	28%		24	19%	0	17
4: Low Local	26%	99	14	33%	✓	23	26%	0	16
5: Med Remote Renew	49%	107	27	58%		65	26%	8	11
6: Med CC	60%	105	26	33%	✓+	34	-2%	24	10
7: Med Local	52%	112	21	38%	✓	17	-40%	24	13
8: High Diverse	74%	113	26	74%	✓	49	-8%	24	7
9: High LFG/Geo	81%	107	27	72%		58	3%	24	5
10: High Wind/Solar	73%	127	42	66%		94	-4%	24	6

Source: Pace

Hybrid Portfolio Construction

The ability to identify and quantify the effects of different uncertainties on the specified metrics of each portfolio can be used to target particular portfolio characteristics that are desirable by the utility. This process can lead to the development of "hybrid" portfolios. For this analysis, hybrid portfolios were created based on the desirable characteristics of portfolios with similar metrics. This facilitates the comparison of portfolios and allows the insights obtained from the risk analyses to enhance the decision-making process. The hybrid portfolios created for this analysis are summarized below.

Hybrid Portfolio "1a"

Portfolio "1a" was created based on a combination of desirable characteristics in portfolios 1 to 4. These can be summarized as follows:

- Landfill and geothermal are the least costly renewable additions feasible for Pasadena. Subject to availability, capacity from these resources is desirable over other renewable options.
- Additional local renewables improve emission reductions and potentially reduce reliability risks.

Exhibit 32 presents the capacity mix assumed for Portfolio 1a in comparison with the resource additions in Portfolios 1 to 4.

Exhibit 32: Hybrid Portfolio 1a Characteristics

		Remote Renewables				Local Renewables/DSM					Fossil-fueled	
Carbon Reduction Target	Portfolio #	Landfill	Geo thermal	Wind	Solar Thermal	Solar PV (Existing)	Solar PV (Expand)	Feed-In Tariff	Energy Efficiency	DR & RA	Local Gas	Coal
Low	1	15	15			14			26			
	2	10	10	20		14			26			
	3	10	10		20	14			26			
	4	10	10			14	15	21	34			
	1a	15	15	10	10	14	5	5	26	5		

Source: Pace

Hybrid Portfolios “5a” and “5b”

Portfolios “5a” and “5b” were created based on the strengths of several other portfolios. These can be summarized as follows:

- Displacing only a portion of IPP reduces the risk associated with obtaining little or no revenue for its power. According to input from PWP, a displacement of 35 MW may be the most practical and feasible option for the utility at this time. This amount is based on the capacity currently deemed most feasible to sell. The 35 MW is comprised of one contract share that is currently recallable in Utah and a remaining share of capacity above and beyond minimum capacity factor requirements.
- Additional gas-fired, in-city generation addresses reliability concerns tied to the reliance of Pasadena on aging local generation.
- Greater diversification of renewable capacity additions with a greater emphasis on local generation improves emission reductions, increases RPS, decreases reliance on one technology type, and improves reliability.

Exhibit 33 presents the capacity mix assumed for portfolios 5a and 5b in comparison with the resource additions for the other medium and high emission reduction portfolios.

Exhibit 33: Hybrid Portfolios 5a and 5b

		Remote Renewables				Local Renewables/DSM					Fossil-fueled	
Carbon Reduction Target	Portfolio	Landfill	Geo thermal	Wind	Solar Thermal	Solar PV (Existing)	Solar PV (Expand)	Feed-In Tariff	Energy Efficiency	DR & RA	Local Gas	Coal
Med	5: Med Remote Renew	15	15	60	60	14			26			-47
	5a: Med Diverse Renew	15	15	20	20	14	5	10	26	5		-35
	5b: Med CC Renew	15	15	20	20	14	5	10	26	5	-65 + 65	-35
	6: Med CC	15	15			14			26		65	-108
	7: Med Local	5	5			14	15	21	34	55		-108
High	8: High Diverse	25	25	10	10	14	15	21	34	25		-108
	9: High LFG/Geo	25	65			14			26			-108
	10: High Wind/Solar			125	125	14			26			-108

Source: Pace

SUMMARY OF PLANNING OBJECTIVES AND PORTFOLIO METRICS

Exhibit 34 summarizes the results of the stochastic and scenarios analyses for all the portfolios created in Phase I and the hybrids developed during the Phase II analyses. As was shown above, in addition to the key results for emission reductions, cost, and price risk, all other metrics are quantified or summarized so all options can be compared across objectives. Additional detail on the summary metrics, the stochastic analyses, the sensitivity analysis, and the individual portfolio results can be found in the appendix section on Phase II Risk Analysis. This summary analysis formed the basis by which to compare portfolios and identify the preferred option, as outlined in the following chapter.

Exhibit 34: Phase I and Hybrid Portfolios Summary Metrics

Portfolio	Emissions Reduction	Cost	Price Risk	RPS 2020	Reliability	Capital Charges	Spot Market Dependence 2020	IPP Sale Feasibility	Carbon Price Risk
	% Reduction from 2008	*Levelized $/MWh*	*Added cost for 95% $/MWh*	*% of NEL*		*Annual Levelized $MM in 2030*	*% of 2020 Load*	*Added Cost Levelized $/MWh*	*Added Cost Levelized $/MWh*
Status Quo	12%	89	9	12%		0	4%	0	20
1: Low LFG/Geo	25%	94	12	31%		21	22%	0	16
2: Low Wind	24%	94	12	29%		21	20%	0	17
3: Low Solar	23%	96	13	28%		24	19%	0	17
4: Low Local	26%	99	14	33%	✓	23	26%	0	16
1a: Low Diverse	29%	96	16	40%	✓	31	29%	0	15
5: Med Remote Renew	49%	107	27	58%		65	26%	8	11
5a: Med Diverse Renew	38%	101	18	58%	✓	39	21%	5	13
5b: Med CC Renew	40%	94	23	41%	✓+	51	41%	5	12
6: Med CC	60%	105	26	33%	✓+	34	-2%	24	10
7: Med Local	52%	112	21	38%	✓	17	-40%	24	13
8: High Diverse	74%	113	26	74%	✓	49	-8%	24	7
9: High LFG/Geo	81%	107	27	72%		58	3%	24	5
10: High Wind/Solar	73%	127	42	66%		94	-4%	24	6

Source: Pace

SELECTION OF THE PREFERRED RESOURCE PLAN

The IRP process is designed to evaluate different resource options against the utility's planning objectives and required metrics. The tradeoffs between different resource options and planning strategies can be better compared when the risks associated with each alternative are methodically analyzed and understood. The planning process has been applied throughout PWP's 2009 IRP process, and is designed to quantify risk and identify the portfolio characteristics that help the utility achieve its desired metrics under different market and regulatory uncertainties.

Defining the utility's planning objectives is critical to the success of any IRP process. PWP and the Stakeholder Advisory Group defined the planning objectives of this study early in the process. A reminder of the primary planning objectives and associated metrics is presented in Exhibit 35.

Exhibit 35: Summary of Primary Planning Objectives and Associated Metrics

Objective	Metric	Unit
Environmental Leadership	CO_2 Emission Reductions in 2020 from 2008 Baseline	%
	Renewable generation as a percentage of net energy for load	%
Preserve Competitive Rates	Mean of the levelized NPV of Total Portfolio Costs	*2008* $/MWh
Maintain Stable Rates	Difference between the mean of the distributions and the 95% confidence band	*2008* $/MWh
Provide Reliable Service	Exposure to risk of loss of existing local, in-city resources	Qualitative
Maintain Fiscal Health	Levelized costs of all capacity additions in 2030	*2008* $000
Manage Market Risks	Annual volume of net market transactions as a percentage of load in 2020	%
Allow for Flexibility	Exposure to risk of emerging GHG regulations and market mechanisms	Qualitative

Source: Pace

The planning process quantifies the impact of different uncertainties and allows for the ranking of each portfolio based on each of the outlined metrics. The selection of the best portfolio, however, will depend on the importance the stakeholders place on each planning objective.

The following sections outline the portfolio selection process and define the ranking of a selection of options based on all planning metrics.

PORTFOLIO PERFORMANCE ASSESSMENT

Through this portfolio evaluation process, some portfolios were eliminated on the basis of costs and risks; others were eliminated because of feasibility concerns. The metrics of even those portfolios that were ultimately eliminated, however, were carefully analyzed. In some cases, the desirable characteristics of distinct portfolios were combined to create hybrids that would perform better under all uncertainties. A summary of the portfolio elimination and selection process is presented below. For reference, the summary metrics for all portfolios are shown in Exhibit 36.

Exhibit 36: Portfolios Summary Metrics

Portfolio	Emissions Reduction	Cost	Price Risk	RPS 2020	Reliability	Capital Charges	Spot Market Dependence 2020	IPP Sale Feasibility	Carbon Price Risk
	% Reduction from 2008	*Levelized $/MWh*	*Added cost for 95% $/MWh*	*% of NEL*		*Annual Levelized $MM in 2030*	*% of 2020 Load*	*Added Cost Levelized $/MWh*	*Added Cost Levelized $/MWh*
Status Quo	12%	89	9	12%		0	4%	0	20
1: Low LFG/Geo	25%	94	12	31%		21	22%	0	16
2: Low Wind	24%	94	12	29%		21	20%	0	17
3: Low Solar	23%	96	13	28%		24	19%	0	17
4: Low Local	26%	99	14	33%	✓	23	26%	0	16
1a: Low Diverse	29%	96	16	40%	✓	31	29%	0	15
5: Med Remote Renew	49%	107	27	58%		65	26%	8	11
5a: Med Diverse Renew	38%	101	18	58%	✓	39	21%	5	13
5b: Med CC Renew	40%	94	23	41%	✓+	51	41%	5	12
6: Med CC	60%	105	26	33%	✓+	34	-2%	24	10
7: Med Local	52%	112	21	38%	✓	17	-40%	24	13
8: High Diverse	74%	113	26	74%	✓	49	-8%	24	7
9: High LFG/Geo	81%	107	27	72%		58	3%	24	5
10: High Wind/Solar	73%	127	42	66%		94	-4%	24	6

Source: Pace

Initial Portfolio Evaluation and Elimination

- **Low Emission Reduction Concept:** Portfolios 1, 2, 3, and 4 perform very similarly on emission reductions, cost, and risk metrics.
    - To simplify the comparison of portfolios going forward, Pace analyzed the best performing aspects of these portfolios and combined them to create a “hybrid” portfolio.
        - Portfolio “1a” is created based on a combination of portfolios 1 to 4.
        - Portfolios 1 to 4 are eliminated

- **Medium Emission Reduction Concept:** Portfolios 5, 6, and 7 achieve similar emission reductions. The costs associated with portfolio 7, however, are significantly higher than the costs for 5 and 6.
    - Portfolio 7 is eliminated based on Total Cost
    - Portfolio 5 is not fully exposed to IPP sale risk and is low cost, but may not adequately address reliability concerns tied to reliance on aging local generation
    - Portfolio 6 addresses reliability concerns with new local gas-fired generation, but has higher costs and more exposure to market volatility and IPP sale price
        - The strengths of portfolios 5 and 6 were combined to create portfolios 5a and 5b

- **High Emission Reduction Concept:** Portfolios 8, 9, and 10 achieve similar emission reductions. The costs and risks associated with portfolio 10, however, are significantly higher than those for portfolios 8 and 9.
    - Portfolio 10 is eliminated based on Total Cost

- o In addition to the risk associated with the sale of IPP power, Portfolio 9 is heavily reliant on low-cost LFG and Geo, which have uncertainty associated with their general availability and with regard to transmission to PWP.
  - ▪ Portfolio 9 is eliminated, with the recognition that LFG and Geo procurement should still be pursued as much as possible.

Selected Portfolio Ranking

A summary of the metrics and ranking of the initial selection of portfolios discussed above is shown in Exhibit 37. For ease of comparison, red, yellow, and green rankings are provided for each category to highlight the relative performance of each of the portfolios across each objective. Some of the key points and conclusions include:

- Portfolio 1a has the lowest cost and price risk but, because it holds all of IPP, it achieves the smallest emission reductions and is significantly exposed to the impact of higher CO_2 pricing. Also, it may not adequately address reliability concerns.
- Portfolio 5 requires the most capital investment but achieves nearly 50% emission reductions; however, it may not adequately address reliability concerns.
- Portfolio 5a achieves moderate emission reductions, mitigates risk of IPP sale, and has low market risk; however, it may not adequately address reliability concerns.
- Portfolio 5b achieves moderate emission reductions at relatively low cost; however, it directly addresses reliability concerns due to the addition of new local gas-fired generation.
- Portfolio 6 achieves significant emission reductions but at a higher cost and with exposure to market and IPP sale uncertainty; however, it directly addresses reliability concerns.
- Portfolio 8 achieves the highest emission reduction, but at highest cost, exposure to IPP sale uncertainty; moreover, it may not adequately address reliability concerns.

Exhibit 37: Final Portfolio Ranking

	Primary Objectives					Secondary Objectives			
Portfolio	Emissions Reduction	Cost	Aggregate Price Risk	RPS 2020	Reliability	Capital Charges	Spot Market Dependence 2020	IPP Sale Feasibility	Carbon Price Risk
	% Reduction from 2008	*Levelized $/MWh*	*95% $/MWh*	*% of NEL*		*Annual Levelized $MM in 2030*	*% of 2020 Load*	*Added Cost Levelized $/MWh*	*Added Cost Levelized $/MWh*
Status Quo	12%	89	103	12%		0	4%	0	20
1a: Low Diverse	29%	96	110	40%		31	29%	0	15
5: Med Remote Renew	49%	107	133	58%		65	26%	8	11
5a: Med Diverse Renew	38%	101	118	58%		39	21%	5	13
5b: Med CC Renew	40%	94	115	41%		51	41%	5	12
6: Med CC	60%	105	135	33%		34	-2%	24	10
8: High Diverse	74%	113	136	74%		49	-8%	24	7

Source: Pace

As is shown in Exhibit 37, Portfolio 5b performs best in all of the primary objectives. It achieves the major environmental goals and performs best or second best on the cost, aggregate price risk (cost plus risk), and reliability metrics. The portfolio receives no red rankings and totals three out of five green rankings across the primary objectives. For each of the secondary objectives, Portfolio 5b achieves rankings in the middle of all of the candidate resource plans, indicating that there are no major weaknesses that should disqualify the option. For many of the secondary objectives, Portfolio 5b represents a compromise between more divergent plans.

RECOMMENDED IRP STRATEGY

The preferred portfolio options can be summarized according to different emission reduction options, as outlined below:

- **Reduce GHG emissions by about 30% (Portfolio 1a)** by 2020 through modest additions of renewable energy and other clean resources. This option seeks to minimize the upward pressure on PWP's costs, but may not address reliability concerns and PWP's ability to satisfy emerging environmental obligations.

- **Reduce GHG emissions by about 40% (Portfolio 5b)** by 2020 through a diverse mix of renewable energy, other clean resources, and efficient new natural gas-fired generation inside Pasadena. This option attempts to balance environmental, cost and reliability objectives without subjecting PWP to extreme risks.

- **Reduce GHG emissions by about 60% (Portfolio 6)** by 2020 through completely displacing existing coal resources and replacing them with efficient new natural gas-fired generation and modest additions of renewable energy and other clean resources. This option addresses reliability risks, but at higher cost and the risk that full coal displacement is infeasible.

- **Reduce GHG emissions by about 75% (Portfolio 8)** by 2020 through completely displacing existing coal resources and replacing them with a diverse mix of renewable energy and other clean resources. This option provides the highest GHG emissions reductions, but is the most expensive of the four options and may not adequately address reliability concerns associated with continued reliance on the aging local generating units.

A final selection among these alternatives required specific decisions in consultation with all stakeholders about the preferred balance between greater GHG emissions reductions, higher costs, and infrastructure improvements to reduce reliability risks.

The assessment of the impact of different risks and uncertainties on all portfolios has provided valuable insights into the best alternatives for PWP to mitigate risks and achieve its planning objectives. Key items that were considered in the recommendation of a Preferred Resource Plan included:

- **Minimum Environmental Performance:** Portfolio options break down into low, medium, and high emission reduction targets

    - If the low reduction is considered a "non-starter" because it is deemed insufficient for likely carbon limits, then Portfolio 1a can be eliminated
- **IPP Sale Feasibility:** Uncertainties regarding the sale of IPP power may dictate how much is removed from the portfolio, and the level of emission reductions that is achievable
    - If no more than a 35 MW displacement is considered feasible at the present, then Portfolios 6 and 8 can be eliminated
- **Reliability:** What local infrastructure investments provide acceptable reliability?
    - If new local gas-fired generation is considered essential to providing an acceptable assurance of reliability (rather than extending the life of existing local units plus potential transmission system upgrades), then Portfolios 5, 5a, and 8 can be eliminated

After considering all metrics and these specific questions, the unanimous selection of the Stakeholder Advisory Group was Portfolio 5b. This portfolio consists of a diverse portfolio of 65 MW of new combined cycle capacity to replace old inefficient turbines and secure local generation options into the future, some remote renewable power from geothermal, landfill gas, solar, and wind, considerable energy efficiency, local solar PV and feed-in tariff options, and a significant reduction in coal-based IPP generation. This provides an intermediate reduction in carbon from current levels, meets expected RPS requirements through 2020, is the most reliable of the portfolio options as the result of preserving local generation and does so in a cost-effective manner. Of all the portfolios it has the highest ratio of positive (green light) rankings to negative (red light) of any of the portfolios and also is the most diverse.

For all of the above reasons, Pace recommends this portfolio as the Preferred Resource Plan, but also suggests that PWP keep its options open by evaluating its contractual obligations regarding IPP and re-evaluating as more information becomes available. The following section outlines a near term action plan that provides flexibility to adapt to changing conditions as more information becomes available, with the primary objective to follow a course consistent with Portfolio 5b.

ACTION PLAN

The Preferred Resource Plan includes the following key elements, which will require PWP to take specific actions to begin reconfiguring its existing portfolio over the next several years:

- **Coal Power Displacement:** By 2016, reduce purchases of power from the IPP coal plant of at least 35 MW
- **New Local Gas-Fired Generation:** By 2014, retire the existing 65 MW Broadway 3 power plant and replace it with a comparably sized new combined cycle plant at the same site
- **Energy Efficiency and Load Management:** Implement programs to achieve significant reductions in electricity consumption according to the following timeline:
    - **Energy Savings:** Reduce energy sales by 12.5% below expected levels by 2016
    - **Peak Load Savings:** Reduce peak load by 10% below expected levels by 2012
    - **Demand Response:** Reduce peak load by an additional 5 MW by 2012 through programs that provide customers with information and economic incentives to reduce their consumption during peak load periods
- **Renewable Energy:** By 2020, increase the proportion of PWP's energy mix provided by renewable energy sources to 40% according to the following general guidelines:
    - 15% by 2010
    - 33% by 2015
    - 40% by 2020
- **Solar Photovoltaic:** By 2020, develop programs to add at least 15 MW of solar photovoltaic installations in Pasadena according to the following timeline:
    - 3 MW by 2010
    - 10 MW by 2015
    - 15 MW by 2020
    - 19 MW by 2024
- **Feed-In Tariff:** By 2020, establish a feed-in tariff program offering to purchase up to 10 MW of qualifying renewables of all technologies located inside Pasadena at a price up to 15 cents/kWh
- **GHG Emissions Reductions:** By 2020, achieve CO2 emissions reductions of at least 40% according to the following timeline:
    - 5% by 2010
    - 25% by 2015
    - 40% by 2020

This Preferred Resource Plan aligns with Portfolio 5b described above, but maintains a significant measure of flexibility to adapt to options regarding IPP and future regulations, and is a course that addresses all of the concerns associated with the previous IRP and the recommendations of the Environmental Advisory Commission.

- The approach fully considered all relevant technologies
- Both current and potential future environmental regulations were fully evaluated
- Competing objectives of cost competitiveness, risk and environmental stewardship were considered

- Reliability was considered in the context of both local generation and transmission options
- The potential of energy efficiency and load management was considered
- The risks and opportunities for reducing reliance on conventional coal fired generation were evaluated.

Every attempt was made to provide PWP and the Stakeholder Advisory Group a fair assessment of the trade-offs associated with a range of portfolio options and both market and regulatory outcomes over time. Fortunately, after full consideration of these options, a consensus solution was reached by PWP, the Stakeholder Advisory Group and the Consultant, on the best Portfolio and Actions that will provide guidance going forward considering the flexibility needed to adapt to changes over time.

In order to implement the Preferred Resource Plan, PWP should perform a series of ongoing evaluations to ensure that the plan can be adapted to changing circumstances, including:

- An evaluation of PWP customers' appetite for paying premiums for environmental stewardship
- An evaluation of the potential sales, GHG accounting treatment, and price for power sales from IPP
- An evaluation of whether new local gas-fired generation or transmission system enhancements (or both) is the preferred approach for ensuring reliability
- An evaluation of the availability of low cost geothermal and landfill gas renewable energy projects to achieve potential cost reductions

Regardless of the outcome of these evaluations, PWP should immediately commence with the following short-term implementation steps that are common among all of the long-term strategies:

- Continue securing contracts for power from a diverse mix of new renewable energy sources, balanced among landfill gas, geothermal, wind and solar projects
- Expand PWP's already aggressive energy efficiency programs
- Develop demand response programs and rates to provide customers with economic incentives to reduce their peak electricity consumption
- Develop a new "feed-in tariff" program in which PWP will offer to purchase power, at a fixed price, to any qualifying renewable energy project within the City in order to facilitate the development of local renewable energy sources
- Evaluate innovative new financing approaches and electric rate structures in order to spur more PWP customers to install solar photovoltaic projects inside Pasadena

The details for introducing and carrying out successful programs and initiatives in these areas should be outlined by PWP in a long-term implementation plan to be completed in the near future.

PACE

4401 Fair Lakes Court
Fairfax, VA 22033-3848 USA
Phone: 1.703.818.9100
Fax: 1.703.818.9108

2009 Integrated Resource Plan Appendices

Prepared for:

City of Pasadena Water and Power Department

February 13, 2008

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EXHIBITS

PUBLIC INPUT

PROCESS AND CONSIDERATION OF PUBLIC COMMENTS

The City Council instituted an Environmental Advisory Commission ("EAC") in early 2007 to oversee and advise the City Council on the City's environmental initiatives. The EAC concluded that the underlying policies that guided PWP's 2007 Draft IRP may not fully reflect the City's updated broad environmental objectives. After their review, in mid 2007, PWP and the EAC decided that the 2007 IRP be re-evaluated and revised as necessary prior to adopting a new 2009 IRP. It was recommended that an independent consultant review the energy and environmental policies, recommend potential policy changes, and identify additional opportunities to jointly meet the City's environmental goals and other key objectives. It was also recommended that the IRP development and review process include more thorough public and stakeholder participation. Exhibit 1 summarizes the key shortcomings in the 2007 Draft IRP identified by the EAC.

Exhibit 1: Key Shortcomings in the 2007 Draft IRP

Shortcoming	Resolution in 2009 IRP
Inadequate weighing of environmental impacts	• GHG emissions costs incorporated into all price projections and cost metrics • Explicit consideration of the environmental and cost trade-offs across options
Opportunity costs of fossil fuel vs. local renewable investments; opportunities for fossil-fuel reductions	• Evaluation of local fossil-fuel and renewable options throughout portfolios • Evaluation of cost and environmental effects of reducing IPP generation as well as consideration of gas-fired vs. renewable-focused portfolios
Inadequate RPS goals and consideration of local renewable resources	• Evaluation of significant expansion of RPS and GHG policies beyond expected State requirements (including both RPS and GHG policies) • Specific evaluation of local renewable options vs. remote renewable options
Expanded energy efficiency efforts and balance between residential & commercial	• Evaluation of significantly expanded energy efficiency programs consistent with AB 2021 targets; evaluation of even more aggressive targets • Explicit selection of most cost-effective mix of commercial and residential options
Partnership opportunities to pursue green and clean power opportunities	• Discuss options for meaningful partnership opportunities with business and research organizations to pursue clean and green opportunities consistent with preferred portfolio options and recommendations

Source: EAC and Pace

In order to improve the IRP process and ensure that the resulting plan would reflect the needs of the Pasadena community and its various stakeholders, PWP engaged in a public participation process with active stakeholder involvement. PWP and Pace conducted a total of 15 separate meetings with the various stakeholder groups and the public, which has provided immense value to the quality and completeness of the entire 2009 IRP process and recommendations.

From the beginning of the planning process in July 2008, the 2009 IRP was developed with the intent to satisfy several key objectives:

- Ensure alignment with the City's aspirations to be an environmental advocate and leader
- Directly address several issues raised in the previous IRP
    - Quantification of environmental impacts (CO2 costs)
    - Resources options considered (In-city generation, local renewable energy, energy efficiency, fossil-fueled generation)
    - Aggressiveness of policies (RPS)
    - Strategic partnerships with local entities
- Conduct a collaborative process for public and stakeholder involvement in the planning process

In order to facilitate a productive dialogue with a diverse and representative group of Pasadena stakeholders, PWP and Pace agreed to conduct the 2009 IRP process to provide several opportunities for stakeholders to provide input and direction to the plan. Two primary avenues of public/stakeholder participation were:

- **IRP Stakeholder Advisory Group:** A working group that attended monthly half-day sessions reviewing analysis and providing input and suggestions for the IRP analysis, and
- **Public meetings:** Presentations to the public at large to discuss the goals of the IRP, analytical approach and findings, and to solicit feedback

In preparing the 2009 IRP, PWP engaged public involvement in a participatory process over six months that included monthly meetings of the Stakeholder Advisory Group representing every major constituency in PWP's service territory, meetings with the EAC and the Municipal Services Committee ("MSC"), and several public meetings that were attended by a diverse group of stakeholders. The Stakeholder Advisory Group held monthly meetings, run through a facilitated process with PWP's participation, but organized by an independent consultant (Pace Global Energy Services or Pace) who was responsible for setting the agenda and facilitating the process. The Stakeholder Advisory Group reached unanimous consensus on the recommended resource plan presented here.

PWP and Pace conducted four separate public meetings throughout the development of the 2009 IRP in order to provide a broader forum to discuss the results of the IRP analysis at various stages, solicit input and advice on the analytical approach and assumptions used in the IRP analysis, and address specific comments and questions from participants in the public meetings. In the course of those public meetings, PWP and Pace responded to every comment or question submitted in writing, as well as every question or comment offered orally during the meetings. Almost all of the comments and questions, and responses to them, were provided orally during the public meetings.

Without attempting to catalogue each and every oral comment, the following table provides a summary of the topics addressed in the comments and questions offered during the public meetings, as well as the response and/or resolution of the comment.

Exhibit 2: Summary of Public Comments and Responses

Comment	Response
Clarify the terms “local” solar and “remote solar” in the 9/17/2009 IRP workshop presentation on pages 32-38.	Local solar means solar systems installed within the City of Pasadena. Generally speaking these would be photovoltaic systems. Remote solar represents solar systems located outside the City of Pasadena and would require transmission system to import energy to Pasadena's load. Such systems are generally large commercial scale thermal solar type systems.
The IRP analysis should include consideration of energy conservation and the behavioral aspects of reducing energy use through economic signals, rather than just considering energy efficiency through changes to energy-consuming equipment.	The 2009 IRP recommends implementation of a demand response / load management program to evaluate PWP customers’ interest in adjusting their electricity consumption based on price signals.
The IRP analysis should incorporate a peak-hour analysis of resource options in order to account for the contribution of resources (such as solar) whose generation is weighted more heavily to high price, on-peak periods.	Both the Phase 1 and Phase 2 analysis consisted of a detailed, quantitative accounting of the hourly costs and benefits of potential resource options on PWP’s portfolio, which are incorporated in the relevant cost metrics. We believe this captures the referenced peak-hour benefits of resource options like solar and therefore that our analysis adequately addresses this concern. Nevertheless, Pace provided, on the IRP website, a calculation of the hourly benefits of various resource options based on both CAISO hourly prices for 2007 and for projected 2020 prices to permit members of the public to evaluate the peak-hour impacts themselves.
The IRP analysis should place a greater emphasis on rates and total bills for residential customers as a basis for evaluating IRP options.	The 2009 IRP analysis uses the average, levelized cost of PWP’s resource portfolio ($ per MWh) as the primary metric for evaluating the costs of alternative options. However, throughout the process, the impact of various portfolio choices on typical monthly bills of PWP’s residential customers ($ per month) has been used as a critical benchmark for evaluating the feasibility and attractiveness of those portfolio options.
The IRP analysis should evaluate options for PWP to achieve more aggressive levels of energy efficiency than is possible through existing rebates, such as	The 2009 IRP action plan recommends continuation and expansion of PWP’s already aggressive energy efficiency and load management programs, to include the suggested improvements. It also recommends that

innovative financing, expanded education programs and improved customer service approaches.	PWP consider alternative financing arrangements for financing solar energy projects inside the City, such as a special assessment district that would facilitate customers' adoption and implementation of solar projects.
The IRP analysis should consider the flexibility and cost of displacing IPP generation, the "full cost" of coal, and the risk exposure to PWP of potential carbon values given its current high dependence on coal power.	The 2009 IRP analysis evaluated several portfolio options that included full or partial displacement of PWP's purchases from the IPP coal plant, as well as the risk exposure to varying levels of carbon values for the portion of IPP that is not displaced but remains part of PWP's portfolio. The Preferred Resource Plan includes a partial IPP displacement at a level (35 MW) that PWP believes may be feasible. The economic comparison of these coal displacement options included a specific evaluation of the incremental costs of liquidating the IPP power and the risk to PWP of failing to find a buyer for the power at any positive price.
The IRP analysis should take account of the fact that the availability of landfill gas and geothermal resources may be limited.	It is acknowledged that landfill gas resource availability is likely to be constrained, given the limited number of landfill sites in California and the modest number of new or expanded landfills that may be developed. Likewise, new geothermal developments are likely to be resource constrained and transmission limited, given their remote geographic locations. In order to account for these limitations, the 2009 IRP analysis incorporated a "supply curve" approach wherein prices for geothermal and landfill gas resources are assumed to increase for incremental additions beyond 10 MW for each technology. PWP's recent experience in competitive solicitations of renewable resources supports the change to incorporate a higher cost for incremental geothermal and landfill gas resources, as recent offers in response to those solicitations have included prices consistent with the higher price levels that were used.
The IRP analysis should take account of the fact that the cost of solar resources should trend downward over time as the technology is commercialized	It is acknowledged that solar (and possibly wind) resources are unlikely to have the same availability limitations as landfill gas and geothermal resources. However, there is no conclusive evidence that such downward cost trends have occurred to this point, nor that they clearly will occur in the foreseeable future. Moreover, evidence from the marketplace in the recent past indicates that, as the demand for solar energy projects is rising, their costs have been rising. Our conclusion is that there is no clear evidence to support the assumption that solar costs will trend downward over time, and we have therefore declined to adjust our solar cost assumptions used in the 2009 IRP.

Source: Pace summary notes from public meetings

Dr. Carol Carmichael of the EAC and Stakeholder Advisory Group and Mr. David Czamanske of the Pasadena Group of Sierra Club submitted questions that were addressed by Pace and PWP in writing. The questions and associated answers are summarized below. In addition, the comments of Caltech on the PWP 2009 IRP focus on implementation of the IRP and will be address separately by PWP.

Response to Dr. Carol Carmichael's questions by Pasadena Water and Power

Dated January 5, 2009

1. *You mention a standard of a 76.2% probability that the aging units will be available when called to meet the city's requirements, and your slide #32 seems to indicate that this cannot be achieved but does not provide the current risk assessment for the three local units. Can you provide the data for the assessment of this probability? What is the probability that all three units will not be available and the load exceeds 253 (or 215) MW?*

Response: The 76.2% probability represents the minimum probability for the availability of each of the 3 aging local units that is required in order for PWP to satisfy the industry-accepted reliability standard of 1 day in 10 years loss of load expectation (LOLE). PWP provided Pace with its estimate that there is a 75% probability that the 3 aging local units will be available when called, but we are unaware of any historical data to support that estimate. Accordingly, the probability that all three aging local units will be unavailable and load exceeds 253 MW (or 215 MW) is relatively small. This comparison was not intended to provide a precise quantitative risk assessment but instead was intended to indicate what PWP considers to be an unacceptable reliability risk given the dependence on the ongoing availability of the aging local units, and that risks to reliability are increasing with the passage of time and in the absence of specific actions to add new local generation.

2. *What has changed since the January 2007 Draft IRP, which recommended repowering 110 MW (GT-1, GT-2 and B3), to the current scenario 5b, recommending replacing only 65 MW (B3)?*

Response: Pace concluded in the 2009 IRP that the 65 MW combined-cycle addition included in Portfolios 5b and 6 represents a better fit with PWP's overall portfolio requirements than the 110 MW repowering project recommended in the January 2007 Draft IRP. This conclusion was influenced by the following key considerations and changes since the 2007 Draft IRP was prepared:

- **A significant increase in PWP's energy efficiency and load management targets** (ranging from a minimum of 26 MW to a maximum of 59 MW in the 2009 IRP) that was not explicitly included in the 2007 Draft IRP. While this 26+ MW of demand-side resources are not firm, dispatchable capacity that can be counted on to meet PWP's reliability requirements, directionally they reduce the need for and benefit of higher levels of local gas-fired generation.
- **A significant increase in PWP's local renewable energy targets** (ranging from a minimum of 14 MW to a maximum of 50 MW in the 2009 IRP) that was not explicitly included in the 2007 Draft IRP. While this 14+ MW of local renewable resources are not firm, dispatchable capacity that can be counted on to meet PWP's reliability requirements, directionally they reduce the need for and benefit of higher levels of local gas-fired generation.
- **A significant increase in PWP's overall RPS targets** (ranging from a minimum of 33% to a maximum of 74% in the 2009 IRP) compared to maximum of 20% in the 2007 Draft IRP. While a portion of these renewable resources are intermittent and therefore are not firm, dispatchable capacity that can be counted on to meet PWP's reliability requirements, directionally they reduce the need for and benefit of higher levels of local gas-fired generation.
- **New Generation Sized to displace the 65 MW Broadway Unit 3.** After reviewing the historic and projected operation of the existing local generation, Pace's concluded that the majority of the benefits from adding new local generation would result from displacing the 65 MW Broadway 3 because it represents the majority of the hours of operation and energy from the aging local

generation. Therefore, Pace included the 65 MW combined-cycle addition in Portfolios 5b and 6 specifically because it represents a direct displacement of the same amount of capacity currently provided by Broadway Unit 3.

- **Life Extension of GT 1 and GT 2 Explicitly Assumed.** Pace recommends in the 2009 IRP that PWP should make the necessary investments in GT1 and GT2 to extend their lives over the 20+ year planning horizon so they can be used for during extreme peak demand periods in order to ensure reliability. Conversely, the 2007 Draft IRP assumed that GT1 and GT 2 must be retired by 2012 to facilitate redevelopment of the Glenarm site. Pace believes that the costs of life extension (estimated by PWP at approximately $8.7 million each, spread over 20 years) for GT1 & GT2 represents a low-cost approach to holding these units in reserve for use only during stress conditions. The 45 MW represented by GT1 & GT2, plus the new 65 MW combined cycle facility included in Portfolios 5b and 6, totals the same 110 MW represented by the repowering project recommended in the January 2007 Draft IRP.

I understand Pace's conclusion that replacing the aging units is essential if we assume that local generation will be maintained indefinitely, and our transmission plans are not sufficient to address the overall reliability issue. Ms. Currie mentioned the R.W. Beck study that recommended strategies for improving reliability (transmission and local generation). She also indicated that the study assumes local generation will be maintained indefinitely (as you did on slide #32). Marc Baum told me that in the advisory group meeting he attended on my behalf, the Pace consultants gave the impression that system reliability could be attained through outside power resources and grid interconnection. This was in response to discussion about the relatively poor performance of the combined cycle scenario in the original set of 10 scenarios examined.

3. *From an economic perspective, how does a scenario for achieving reliability based on expanded transmission interconnection compare to the approach currently proposed in scenario 5b (in combination with the current transmission options under consideration)? Will the current transmission study provide information to examine that alternative?*

Response: Ms. Currie's comment was related to a study performed by RW Beck in 2001 to indentify and evaluate options for the Power Systems Strategic Resource Plan. That study recommended the continued maintenance of a target of 200 MW local generation, with a minimum of 150 MW of local generation in order to ensure reliable operations in the absence of significant investments in new transmission infrastructure.

Pace's comment in October 17th IRP Advisory Group meeting that Mr. Baum mentioned was in reference to that alternative of high/total reliance on imported energy through upgrading import interconnection(s) and City's internal distribution system e.g. cross-town tie should be looked at vis-à-vis local generation. As additional information, a Black & Veatch study completed in April, 2003 evaluated transmission interconnection of Pasadena on its west side with City of Glendale and Southern California Edison (Eagle Rock substation) and recommended not to pursue such options further due to high environmental impact, cost, difficult terrain and congestion of transmission lines. PWP also has a 40 MW "emergency only" interconnection with Los Angeles Department of Water & Power (LADWP) on the southwest side. Since this interconnection cannot be used simultaneously with the Goodrich interconnection due to phase differences between LADWP and Sothern California Edison, and it does not have sufficient capacity to handle PWP's external resources, PWP would only use it when the Goodrich interconnection failed. Given the interconnection constraints and design of sub-transmission system PWP has historically pursued a balanced approach between local generation and transmission for import of energy.

RW Beck is currently evaluating alternatives to upgrade PWP's transmission and Distribution system with the assumption that existing local generation capacity remains in place, reliably and indefinitely.

Based on information provided by PWP and its own research, Pace developed cost estimates for investments to upgrade the transmission system that could be required, absent the addition of new, gas-fired local generation, in lieu of any definitive information from RW Beck. Pace concluded that portfolios that attempt to address existing reliability concerns through transmission upgrades (Portfolios 5a and 8) need to include the following additional costs that are not included in portfolios that address reliability concerns through the addition of new, gas-fired local generation:

- Approximately **$65 million** invested over the next 20 years to extend the lives of the 110 MW of aging local generation represented by Broadway Unit 3 and Glenarm Units 1 & 2. For comparison, the January 2007 Draft IRP assumed costs of $59.9 million, primarily associated with capital improvements to extend the lives of the existing local generation, **plus**
- At least **$100 million** invested over the next 10 to 20 years to upgrade the existing single point of interconnection with SCE at Goodrich and PWP's in-city transmission system. Although Pace has not performed a detailed assessment of the range of potential transmission system upgrades (which is within the scope of RW Beck's work), its cost estimate is based on the following:
    - An additional 230/69 kV transformer bank at Goodrich, at an estimated cost of $10 million. This estimate is consistent with SDG&E's estimated costs for the addition of similar equipment as part of the proposed Sunrise Powerlink, plus:
    - A new underground 69 kV cross-town transmission line within the City to replace the existing 34 kV system at an estimated cost of $100 million. This estimate is also based on SDG&E's estimated costs for similar facilities as part of the Sunrise Powerlink, and assumes the need to add approximately 10 miles of new 69 kV underground lines at a cost of $10 million per mile (which still may understate the actual costs of new 69 kV underground lines inside Pasadena.
    - Pace believes that the $100 million cost estimate for transmission system upgrades most likely represents the lower end of the plausible range of transmission upgrade costs that PWP would incur in the absence of adding new, gas-fired local generation. Pace expects that the RW Beck study, once completed, will add more precision to this estimate, but that the $100 million transmission upgrade cost estimate is sufficient for evaluating the portfolio options currently being compared in the 2009 IRP.
    - Note also that this $100 million cost can be benchmarked against a cost of approximately $97.5 million for transmission upgrades (65 MW times $1.5 million per MW for a second interconnection with Glendale) that were evaluated in a 2003 Black & Veatch report on behalf of Burbank, Glendale and Pasadena to assess options for increasing reliability through transmission upgrades.
- Using these assumptions, Pace showed (see p. 38 of the presentation prepared for the December 17, 2008 Advisory Group meeting) an economic comparison of portfolios that add new local gas-fired generation (5b and 6) against portfolios that add new transmission upgrades (5a and 8). From that comparison and its judgment, Pace draws the following conclusions:
    - The inclusion of approximately $65 million in generation life extension costs and $100 million in transmission upgrade costs to Portfolios 5a and 8 adds approximately $8/MWh to their levelized costs.
    - Portfolio 5b is clearly superior to Portfolio 5a from an economic perspective: the levelized cost of Portfolio is $92/MWh, compared to approximately $100/MWh for Portfolio 5a after the costs of generation life extension and transmission upgrades are included.
- Pace concluded qualitatively that portfolios that add new, gas-fired local generation (Portfolios 5b and 6) are superior from a reliability perspective because they directly address PWP's reliability concerns by reducing its dependence on the aging units. Without any insight from the RW Beck study as to the reliability impacts of the illustrative $100 million transmission upgrade described above, it is unclear if Portfolios 5a and 8 adequately address PWP's reliability concerns.
- Pace also concluded that, contrary to the views of some participants in the December 17, 2008 public meeting, the new 65 MW combined-cycle unit included in Portfolios 5b and 6 could actually be added faster than the $100 million transmission system upgrades, which PWP believes could

take 10 years or more to complete. Even if these transmission upgrades can be added more quickly than this, Pace believes that the new combined cycle unit can be added earlier (by 2014) than the new transmission system upgrades.

- Accordingly, Pace believes that Portfolio 5b is superior, from both reliability and economic perspectives, to Portfolio 5a.

4. *Is it possible that the energy market, and expectations for additional sources to it, has changed sufficiently since the Beck study to change the underlying assumptions about local generation and transmission?*

Response: As noted above, the 2001 RW Beck study concluded that maintaining a balance of 200 MW of local generation with the capability to import 200 MW at Goodrich is desirable for reliable operation of PWP's system, and that maintaining 150 MW of local generation between 3 generating units is considered a minimum level of local generation for reliable operations. The 2001 RW Beck study did not identify or evaluate any specific transmission upgrade projects that would change those conclusions, and we are unaware of specific changes in energy market conditions and/or expectations that would change those underlying assumptions.

The most significant change is that, while previous resource plan analyses including the 2001 RW Beck study did not specifically compare the economic and reliability impacts of transmission and local generation options, Pace's analysis in the 2009 IRP (summarized in response to Question 3 above) provides such a comparison.

We believe that economic, reliability and risk considerations establish Portfolio 5b as superior to transmission alternatives as well as other portfolios that incorporated combined cycle generation in addition to the existing five units.

Here's one thought I bring to the technology options based on my experience in systemic evolution of engineering designs, especially of complex systems. If the future conditions or technology options for the system are uncertain, then at each stage of the system evolution (from and opportunity/risk perspective), you should consider those options that provide as much flexibility for change in the future. It seems to me that we have transmission issues not only with respect to reliability but also with respect to importing additional sources of renewables, landfill gas, etc.

5. *Wouldn't a reliability strategy focused on transmission interconnections/capacity provide opportunities for improving our options for importing sources of power from outside the city?*

Response: A reliability strategy focused on transmission upgrades most likely would increase options for importing power from outside the City. However, the benefit of such optionality needs to be balanced against the cost and reliability impacts of transmission upgrades vs. local generation, which can be summarized as follows:

- The current transmission interconnection facilities (including the 215 MW import limit at Goodrich) already permit PWP to meet approximately 90% of its annual energy requirements from remote resources.
- Pace's analysis of expanding the Goodrich import limit (e.g., to 300 MW or 400 MW) concluded that there were minimal projected economic benefits associated with relaxing the import limit as a means to access lower-cost energy. This suggests that the existing interconnection facilities permit PWP to extract most, if not all, of the benefits that can be achieved by importing power from outside the City.
- Pace concluded that the Portfolio 5b, which adds new, gas-fired local generation instead of transmission upgrades, is superior from the perspectives of economics, reliability, and operational flexibility (ability to economically dispatch to match changing loads and access the most cost-

effective resources – see #6) to Portfolio 5a, which relies on new transmission upgrades and increased power imports from outside the City.

6. *Does the long-term financial commitment to replacing the Broadway unit lock us into a power source in the same sense that we are constrained by IPP? Given our experience with the latter, does this seem wise?*

Response: A long-term commitment to replace Broadway 3 with a 65 MW combined cycle facility does not lock PWP into a power source in the same sense as IPP. The key reason is that PWP is contractually obligated to accept and pay for a minimum amount of power from IPP (approximately 88% of its maximum output), which limits PWP's flexibility to displace IPP with other sources that may have superior cost or environmental characteristics. In contrast, the gas-fired combined cycle can be operated flexibly in response to energy market conditions and environmental considerations and, subject to reliability constraints, can be dispatched down to 0% of output or up to 100% of output, at PWP's discretion. Accordingly, the combined-cycle commitment is clearly distinguishable from the IPP commitment because it is inherently a more flexible resource that increases PWP's flexibility to respond to evolving conditions.

That said, the new combined cycle unit does carry an incremental fixed cost burden for PWP, which has been incorporated into the "Capital Charges" metric used to rank all portfolios. However, Portfolio 5b, which includes the new, 65 MW gas-fired combined cycle facility, performs comparably under this metric relative to the other portfolios and has a lower expected levelized cost.

Finally, on slide #33, Pace indicates that they are "unable to offer a definitive recommendation on the best option for ensuring reliability." Aldyn said last night that this was, in part, because it was not within the scope of the study. Given the questions about the underlying assumptions regarding the city's options for ensuring reliability, and their implications for the decision to replace aging unit B3 and options for increasing our capacity to import electricity from external sources, I believe that clarification of these issues is important.

PWP has engaged RW Beck to evaluate long-term options to upgrade PWP's transmission system, and this study is expected to provide more definitive conclusions when it is completed over the next several months. However, as stated earlier the RW Beck study is based on the assumption that existing local generation capacity would remain in operation. Pending the completion of that study, Pace's analysis concludes the following with respect to the recommended portfolios under consideration in the 2009 IRP:

- The replacement of PWP's 43 year-old steam unit with a new 65 MW combined cycle unit, or the addition of 65 MW of new, gas-fired local generation is superior from a reliability (and economic) perspective to options that rely on life extension of the existing local generation . The new local generation directly addresses PWP's reliability concerns by reducing PWP's reliance on the aging local units, which does not appear to be possible under portfolios that rely on hypothetical transmission upgrades in the event that new local generation is not added.
- Portfolio 5b is superior to Portfolio 5a from both reliability and economic perspectives, as describe above.

Response to Dr. Carol Carmichael's questions by Pasadena Water and Power

Dated January 21, 2009

1. *The transmission studies referenced in your responses were conducted in 2001 (RW Beck) and 2003 (Black & Veatch). I imagine that the playing field has changed significantly in the past 5-7 years, especially with respect to the increased recognition of the need to address transmission issues not only for reliability purposes but also for improving our ability to incorporate additional sources of renewable energy into the grid.*

   (a) How do the transmission opportunities/issues in the City of Pasadena play into the larger discussion on transmission needs at the regional/state/national levels?

   (b) I wonder: Are we making a near-term economic decision to invest in local, fossil-fueled generation capacity rather than invest in infrastructure that may contribute to a longer-term solution to our energy needs?

Response: PWP believes that it is important to distinguish between: a) the transmission constraints on PWP's system that impact the reliability of PWP's service and its ongoing need for local generation to ensure reliable service, and b) transmission constraints on the broader California and Western power grid that impact the ability to access and integrate additional sources of renewable energy for all market participants. The selection of the Preferred Resource Plan, including the addition of new local generation, is specifically related to the first consideration regarding reliability, and not the second consideration regarding renewable resource access. However, PWP is concurrently expanding its reach in the broader California and Western power grid. The Southern Transmission System (STS) upgrade under construction would provide and additional 28 MW of capacity to Utah, the proposed Green Path would provide 15 MW of capacity to the Imperial Valley, and the recently approved Sunrise Powerlink transmission system when built would allow PWP to access renewable resources in Imperial and San Diego Counties as a CAISO participating transmission owner.

There is nothing in the 2009 IRP analysis or from PWP's experience in planning and operating its system to suggest that the constraints on PWP's local transmission system place a limit on the amount of renewable energy that PWP can access. In fact, the 2009 IRP analysis explicitly evaluated the potential impact, from the perspective of improving access to additional sources of renewable or lower-cost energy, which could be realized by relaxing the existing constraints on PWP's local transmission system. That analysis found that there are essentially no benefits, from the perspective of lower cost or increased ability to import renewable energy, which could be realized by relaxing the constraints on PWP's local transmission system. Thus, the 2009 IRP analysis of the merits of investing in local generation vs. transmission upgrades on PWP's system is strictly related to their relative benefits in satisfying PWP's reliability requirements.

(a) The reliability considerations on PWP's system that affect the choice of local generation vs. transmission upgrades is readily distinguishable from the broader regional/national considerations associated with the need for transmission to access greater levels of renewable energy sources. Upstream investments in transmission will be needed to access renewable energy sources, but the IRP analysis focuses on the local investments needed to ensure ongoing reliability of service:

i. Since the city has only one viable location for power imports (the TM Goodrich substation or "TMG"), it is an unacceptable risk to overly/totally depend on one source of power. Local generation provides the necessary risk mitigation associated with the single point of interconnection. The City has pursued this strategy for over last 100 years successfully.

ii. Periodically, PWP reviews how the City's aging sub-transmission (distribution) system can be modified to provide higher capacity and reliability. Currently, RW Beck is analyzing various options to overcome bottlenecks in the distribution system. Sub-transmission system upgrades to alleviate B3 replacement are expected to cost a minimum of $100 million, take 15+ years to build, and actually increase the risk of greater dependence on single point of import.

iii. The 40+ year old B3 would cost considerable to maintain with no assurance that it will generate power when needed. If local generation is to be maintained, the old units eventually will have to be replaced by new ones.

(b) PWP believes that the decision to invest in new local gas-fired generation inside Pasadena, as embodied in the Preferred Resource Plan, is the appropriate choice given current and expected future options for ensuring reliability given the constraints on the existing system. PWP will continue to evaluate long-term solutions to both reliability and resource access needs, but at present there are no readily apparent long-term solutions, other than the proposed addition of local generation specified in the Preferred Resource Plan, that can satisfy PWP's immediate needs to ensure reliability of service within the context of the existing system. Thus, the Preferred Resource Plan represents a bridge to potential long-term solutions that may be developed in the future.

2. *In the preferred portfolio, we are choosing local generation which is to be used to meet peak demand and reliability requirements. When local generation is used to displace coal as a source of power, then the carbon intensity of our electricity is reduced. But what incentives do we have to do this? As you indicate, one benefit of local generation is that it is flexible or not on a take-or-pay basis. So, it doesn't have the same status in the portfolio as renewable energy procured on a take-or-pay basis (which gives it a priority in the dispatching algorithm). This is clear when one compares the energy portfolio to the energy content label for any given year. While around 50% of our portfolio is natural gas, only 15% of the electricity sold was actually derived from natural gas (according to the third quarter 2008 label). For coal/IPP, the amount in the portfolio is about 25%, but the contribution to the electricity sold is about 62%.*
   (c) So, as long as the IPP power is available and cheaper, why would PWP choose to displace the coal during times when its electricity needs can be met using it?
   (d) If we choose to voluntary release/sell some of our IPP entitlement, how are the sales of this power arranged and reflected in the dispatching algorithm?
   (e) What other policy mechanisms ensure that the plan for the addition of renewable energy sources (local and remote) is achieved?

Response: The Preferred Resource Plan specifies a 35 MW displacement of coal-fired generation from IPP with cleaner resources having lower GHG emissions, and concludes that the increased costs of doing so is justified by the significant GHG emissions reductions attributed to this action. Therefore, the incentive for PWP to displace coal-fired generation with cleaner and more-efficient natural gas-fired generation is specifically to comply with the policies and directives of the resource plan, assuming it is ultimately approved and adopted. PWP would consider the elements of the Preferred Resource Plan to be obligations and directives that cannot be altered at PWP's discretion or otherwise changed in the exercise of its incentives.

(a) The Preferred Resource Plan would require PWP to permanently remove 35 MW of IPP capacity from its resource portfolio and replace it with alternative resources, including renewable energy, DSM and natural gas-fired sources as detailed by the new resource additions outlined in the plan. PWP believes that any deviation from this approach would require formal approval of a future revision to the long-term resource plan, and that PWP otherwise would not have any discretion to use the 35 MW of displaced IPP capacity in its short-term dispatching decisions, regardless of the incentives that might suggest an alternative outcome.

It should not be assumed that coal generation would be always cheaper than natural gas generation. The level of fuel prices, carbon values and determination of the party responsible for controlling GHG emissions are major future uncertainties. Most experts agree that the carbon price would be integrated in the energy price that would impact dispatching decisions and serve to make coal generation less attractive relative to other sources

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(b) The IRP analysis assumes that PWP liquidates the 35 MW of IPP power, but remains obligated under its existing contracts to meet its financial responsibilities to cover the costs of the facility. The analysis further assumes that the price PWP receives for this liquidated IPP power represents a $5 per MWh discount to PWP's costs under the IPP contracts, such that there is a net loss of $5 per MWh on the displaced 35 MW of IPP power and it is no longer available to serve PWP's load. Recognizing that the price received for liquidated IPP power in the future is uncertain, the IRP analysis also evaluated the implications of receiving a price as low as zero (see p. 28 of the January 24 Public Meeting presentation).

(c) As with the IPP displacement element of the Preferred Resource Plan, PWP considers each of the other key elements of the plan (RPS %, Emissions reductions, renewable resource additions, etc.) to be obligations upon PWP in support of implementing the Preferred Resource Plan.

3. *One concern I have about the replacement of local generation is that, if it is used to generate electricity in excess of the needs for the city's customers, it will compete with the introduction into the market of renewable energy sources. By law we're not adding coal-fired power plants in the state of California, so this excess capacity in natural gas power generation at the local level competes with renewable sources that could be added into the grid. Based on the 2008 PWP financial report, sales to other utilities has increased dramatically (from ~$5million in 2007 to ~$14million in 2008). It seems that we have the ability to generate more electricity than we need. It was stated in the draft 2007 IRP report that one of the benefits of local generation is the ability to sell electricity (and generate revenue) to other utilities.*
   (a) How are the GHG emissions from sales to other utilities accounted for in the IRP analysis?
   (b) How are the sales to other utilities accounted for in the financial analysis of the IRP study?

Response: We believe that the risk is very small (or even non-existent) that renewable resources will be displaced by natural gas-fired generation from facilities like the proposed 65 MW combined cycle unit. On the contrary, quick start and efficient combustion turbines, such as proposed in the Preferred Resource Plan, would enable integration of more intermittent renewable resources like wind and solar in meeting state and region wide GHG reduction initiatives. PWP treats its renewable energy supplies as "must-take" resources that cannot be displaced by other sources such natural gas-fired generation, and this approach was used in the modeling done for the IRP. We believe that this is consistent with the approach used by other utilities and regulatory agencies in California, and we are unaware of any evidence to contradict this belief. In fact, because most utilities are finding renewable energy resources to be in very high demand and difficult to secure, their incentive is to do just the opposite and maximize renewable energy sources in order to maximize their ability to increase renewable energy as a share of their portfolios in an attempt to comply with RPS requirements. Assuming that RPS requirements will continue to increase in the future (i.e., from 20% to 33% and possibly higher), that incentive is likely to persist for the foreseeable future.

Moreover, because many renewable energy sources are "intermittent" resources whose energy delivery patterns typically cannot be predicted accurately, we believe it is more appropriate to consider natural gas-fired generation as a back-up or supplemental energy source to renewable energy sources, not a replacement. In fact, states with aggressive RPS are increasingly seeking load-following type natural gas fired simple cycle and combined cycle combustion turbines to stabilize transmission grids to accommodate intermittent renewables like wind and solar. As a recent example, on Feb. 26, 2008 in West Texas wind production suddenly dropped by 80% to 300 megawatts from about 1,700. Shortages degraded reliability and pushed up prices. Wholesale power prices surged to $1,055 per MWh in West Texas on Feb. 26 versus $299 elsewhere in the state. Subsequently, Texas raised its price ceiling to $2,250 per MWh from $1,500. Two days later, it hit the ceiling for the first time as wind production again trailed off.

Following are responses to the specific questions on how emissions and revenues associated with wholesale sales were treated in the IRP analysis:

- **GHG emissions associated with wholesale sales.** Based on our review of the current AB 32 reporting protocols, our expectation is that the regulations will require load-serving entities (LSEs) like PWP to "net-out" emissions associated with generation that is not used to serve native load and only report emissions associated with the LSE's retail load serving obligations. Therefore, the IRP analysis netted-out the emissions associated with wholesale sales using the resource portfolio's average emission rate (i.e., the weighted average emission rate for all of PWP's resources, including coal, natural gas, nuclear, hydro and renewables). Although we believe that this is a reasonable assumption to use given the uncertainty of AB 32's final implementation details, we recognize that there is some uncertainty about how this netting process ultimately will be implemented. The IRP analysis considered the impacts of alternative netting approaches in its assessment of regulatory risk (see p. 29 of the January 24 Public Meeting presentation).
- **Financial analysis of wholesale sales.** The revenues associated with sales of energy to the wholesale market are incorporated into the IRP analysis by netting wholesale sales revenue out of the projected costs of PWP's overall resource portfolio. The result is to reduce the total portfolio costs by the amount of the wholesale sales revenue, thereby reducing the cost and rate impacts of the Preferred Resource Plan relative to what would occur if these wholesale sales were not made.

4. *Our sales of electricity to other utilities, while profitable, add to the carbon footprint of the electricity we need to meet our needs in the city.*
   1. What is the minimum revenue needed to service the debt (or to pay) for the replacement of the Broadway unit?
   2. Given historical experience, how much electricity must be generated and sold to PWP customers to meet the minimum revenue requirements for the Broadway unit?
   3. How does the estimated amount of electricity from the Broadway unit (based on the minimum revenue required to service the debt to pay for it) compare to the requirements for meeting peak and other reliability load requirements?
   4. If we have excess capacity for generating electricity (from our take-or-pay contracts and obligations to IPP), under what conditions would we use the local generation to sell electricity to other utilities/cities (meaning: outside the PWP service area)?
   5. Is there an upper bound to the amount of electricity we will generate and sell to other utilities?
   6. Do we have an upper bound on the additional greenhouse gas emissions per unit of electricity used in the City we are willing to emit for these additional revenues?

<u>Response:</u>
(a) The annual debt service on the new local combined-cycle power plant is estimated at <u>$6.25 million per year</u>, based on the following assumptions

i. $86.1 million capital cost (65 MW capacity, $1,324/kW installed cost)
ii. 30-year debt
iii. 6% interest rate on debt

In comparison, the annual debt service for the life extension of B3 is estimated at <u>$4.15 million per year</u>, based on the following assumptions

i. $44.6 million capital cost
ii. 20-year debt
iii. 6% interest rate on debt

(b) Using FY 2008 average retail rates of 13.9 cents/kWh, PWP would need to sell 44,980 MWh to its retail customers (approximately <u>3.65%</u> of PWP's FY 2008 total retail sales) to generate revenue sufficient for the projected annual debt service of $6.25 million for the new combined-cycle unit.

(c) For the 12 month period of December 2007 through November 2008 (the most recent 12 month period for which data is available), PWP's local units generated a total of 124,062 MWh, so the retail sales volume required to service the debt for the new combined-cycle unit represents approximately 36.3% of the total generation from the local units required for to satisfy peak load and reliability requirements.

(d) The IRP analysis assumes that PWP offers its local generating units into the CAISO's energy and ancillary services markets with bid prices reflecting the units' costs, consistent with the primary criteria that the units remain available to serve PWP's native load requirements before making any wholesale sales. The IRP dispatch analysis further assumes that the CAISO markets accept those bids when they can economically displace other, higher-cost alternatives, and estimates the resulting generation and wholesale sales from PWP to the CAISO market that results from that economic dispatch modeling algorithm.

(e) Generally, the air quality permits for the plant will impose the upper bounds for emissions and operating conditions. As a CAISO participant, PWP takes advantage of the CAISO's statewide transmission system, maintenance of voltage/ frequency stability, and the availability of energy at market prices when short; it also has legal obligations in consideration for these benefits. As a CAISO participant, PWP is required to make its units available at reasonable cost. CAISO, based on its needs, calls for energy from generating units throughout the system based on least-cost dispatch principles. Generally, PWP operates its local units to either meet its own load or provide energy in the CAISO market. Currently, PWP does not have any bilateral contracts for its local units (other than CAISO).

(f) The amount of additional GHG emissions due to the sale of electricity by the local plant would be affected by numerous factors (many beyond control of PWP) such as unit or utility specific environmental regulatory limits, GHG accounting rules, RPS, CASIO/CEC/FERC requirements, market conditions or disruptions (e.g., California electricity deregulation of 2000, the recent Sylmar fires, Northridge earthquake, transmission disruptions leading to northeast blackout of 2003, Texas nodal market failure in 2008). We think when all utilities follow state and federal GHG legislations, region/statewide wide goals would be met, achieving the similar overall environmental benefits as if each utility had set an upper bound. By setting GHG reduction goal higher than the expected regulatory mandate, PWP is indicating its commitment to go above and beyond the minimum requirements.

5. *The business model underpinning the local generation results in emission of additional greenhouse gases---beyond those emissions resulting from power generation required to meet the city's customers' needs. This is a philosophical issue that should be addressed explicitly in the City's policies and statements about the environment and PWP.*

Response: The 2009 IRP process has focused throughout on the need to choose a long-term resource strategy that balances competing objectives, particularly the three Primary Objectives of: a) reliability, b) environmental leadership, and c) cost stability and minimization. The Preferred Resource Plan, including the projected 40% reduction in GHG emissions by 2020, was recommended based on the conclusion, following detailed analysis and discussion, that it is the best option for PWP that balances among the three Primary Objectives. While the IRP analysis considered other options that would have produced greater levels of GHG emissions reductions, those options were determined to be inferior to the Preferred Resource Plan in balancing among the three Primary Objectives. PWP agrees that it would be appropriate for the City to articulate, in its policies and statements about the environment and PWP, that it has selected a long-term resource strategy that produces a balance among the Primary Objectives in a manner that best meets the needs of the community.

6. *I'm not saying the City Council and other city leaders can not choose to proceed in this manner, I'm only asking that we do so with full recognition and disclosure of the climate change implications of our choice.*

(a) Are the goods and services supported by the revenues from the sales to other utilities worth the additional climate change impacts?
(b) Is there another way such goods and services could be obtained without contributing additional greenhouse gases to the atmosphere?
(c) In the long run, what do such choices say about the values and attitudes of the community? Will future generations feel we made the right choice?

Response: PWP fully agrees that issues affecting climate change and choices made based on the best available current information and Pace's assumption should be made known to public and discussed thoroughly. PWP website provides extensive information on these matters. The issues of local generation vs. transmission options; higher levels of expected operation of the new proposed combined cycle unit and resulting emissions locally and portfolio wide; and sale of 35 MW from IPP resulting in continued emissions were discussed at length in the last Advisory Group and Public Meetings. It is important to recognize that the IRP process offers flexibility to periodically (every 3 or 5 years, or more often if necessary) review and appropriately change objectives and the plan. However, keeping realities in mind, certain commitments need to be made now such as replacing the local 40+ year old generation, accelerated addition of renewable energy sources in the next few years, and efforts to reduce dependence on IPP. Many milestones for later years would be revisited periodically and goals readjusted based on the current circumstances. The adoption of the Preferred Resource Plan should only be made with full recognition of the trade-offs inherent in the decision, and suggests that the following concepts should be articulated in that context:

(a) The selection of the Preferred Resource Plan reflects the conclusion that it provides the best balance for Pasadena in terms of satisfying the 2009 IRP's Primary Objectives of reliability, environment and cost, and therefore that the reliability and cost benefits of adding new local gas-fired generation to PWP's portfolio justify the GHG emissions associated with that plant within the larger context of a projected 40% reduction in PWP's aggregate GHG emissions.

(b) The 2009 IRP analysis evaluated options that would have produced greater GHG emissions reductions than the Preferred Resource Plan is projected to produce, but concluded that the 40% reduction in aggregate GHG emissions, when considered alongside the superior reliability and cost performance of the Preferred Resource Plan compared to those options, represented the best choice for Pasadena at this time.

(c) The selection of the Preferred Resource Plan suggests that the Pasadena community prefers a long-term resource strategy that achieves a balance of reliability, environmental and cost objectives in preference to alternatives that may achieve higher levels of GHG emissions reductions. It also acknowledges the need to continually revisit the Preferred Resource Plan at regular intervals in the future to consider changes in the planning environment that may change the community's preferred balance among these core objectives. PWP believes that future generations will judge not only the choices that are made in the 2009 IRP, but also in future updates and revisions to its long-term plans that are made in response to evolving conditions and priorities.

Response to Sierra Club comments and questions by Pasadena Water and Power

Dated February 13, 2009

1. It is unclear why Pasadena needs to maintain the amount of local power generation it currently has, by replacing the aging Broadway steam generating plant, capable of producing over 65 MW of power, with a combined cycle unit of the same capacity.

According to PWP, Pasadena customers' average peak daily usage is about 200 MW; on July 24, the day of highest use in 2006, customers usage peaked at a rate of 316 MW.

Currently, base load sources are capable of producing up to 159 MW of power as follows: IPP: 108 MW, Hoover Hydro: 20 MW; Palo Verde Nuclear: 9.9 MW; Magnolia Combined Cycle: 19 MW; Ormat Geothermal: 2.1 MW. (Exhibit 7, page 15)

As Exhibit 7 also illustrates, Pasadena has more than 200 MW of local generating capacity, yet these local plants produced only 6% of the power consumed in FY 2007. The Broadway steam plant produced 3% of this 6%. Given the fact that Broadway is considered to be less efficient in terms of heat produced per BTU of fuel burned, and it takes much longer to fire up than Glenarm 1, 2, 3, and 4 units (which have a combined capability of 135 MW), it is unclear why Broadway was utilized to the extent it was; however the fact remains that not only Broadway but the four gas turbine units stand idle most of the time.

It is therefore questionable whether it would be a wise to replace the Broadway plant with a new combined cycle plant; other power sources having a less costly and more flexible investment profile should also be considered as replacement for the Broadway plant. Taking into account that peak consumption occurs during hot days in summer months when solar power is highly reliable, and that local generation is desirable, alternatives might include (a) development of one or more thermal solar units at the Broadway site or at other locations in Pasadena, (b) development of one or more photovoltaic solar farms at the Broadway site or at other locations in Pasadena, and (c) strong encouragement of development of solar power by owners of private or institutional properties in Pasadena.

Response: Pace's analysis concludes that the replacement of PWP's 43 year-old steam unit with a new 65 MW combined cycle unit, or the addition of 65 MW of new, gas-fired local generation is superior from a reliability (and economic) perspective to options that rely on life extension of the existing local generation or other sources of local generation, including solar power. The new local generation directly addresses PWP's reliability concerns by reducing PWP's reliance on the aging local units, which does not appear to be possible under portfolios that rely on hypothetical transmission upgrades in the event that new local generation is not added. As a prudent practice, given the fact that the existing old sub transmission system is experiencing greater unplanned outages, reliable local generation must be dependable. Additionally, approximately 200 MW of local capacity is necessary to meet the California Independent System Operator's (CAISO) local capacity requirement which is approximately 50% of the 1 in 10-year summer peak forecast for local areas, and the City's (and State) requirements for Resource Adequacy capacity requirements of 118% of annual highest projected peak load. Accordingly, the Recommended Resource Plan is superior to Portfolio 5a from both reliability and economic perspectives.

PWP believes that replacing the aging local units with a new gas-fired generating unit is the only prudent source of locally generated power that is capable of, and necessary for, providing balancing energy into California and regional transmission grid in real time to compensate for the fluctuating and/or intermittent nature of renewable energy resources such as wind and solar generation. PWP further believes that that overdependence on a single point of energy import into the City, and/or reliance on intermittent resources like solar energy to meet peak demand, jeopardizes the reliability of electricity in the City. Therefore, the current arrangement of local power plant capacity of about 200 MW and an import capability provides an acceptable balance of reliability.

After reviewing the historic and projected operation of the existing local generation, Pace's concluded that the majority of the benefits from adding new local generation would result from displacing the 65 MW Broadway 3 because it represents the majority of the hours of operation and energy from the aging local generation. Therefore, Pace included the 65 MW combined-cycle addition in Portfolios 5b and 6 specifically because it represents a direct displacement of the same amount of capacity currently provided by Broadway Unit 3.

Alternatives of renewable energy resources at the existing power plant location or within the City in lieu of B3, which can reliably generate power 24 hours a day as and when needed, are not feasible in the foreseeable future.

2. This leads to another question: Does the Preferred Resource Plan assume that a significant portion of the reduction of coal power from IPP (at least 35 MW) will be replaced by increased use of local generation by running the natural gas turbines, both the four existing units and the proposed combined cycle unit, at a higher frequency, thereby producing more air pollution and greenhouse gases locally? This would seem a high probability, since the resource profile of the Preferred Resource Plan presented in Exhibit 29 (page 49) calls for 59 MW of capacity to be supplied by wind and solar power, non-load sources which may require substitution during times of low power production.

Response: It is true that Pace's analysis indicates that the new local gas-fired generating unit is expected to operate more hours, generating fewer emissions on a per MWh basis but more emissions in aggregate than the status quo. However, the Preferred Resource Plan specifies adding 30 MW of landfill gas and geothermal baseload resources in addition to 69 MW to solar, wind and other in-city renewables. Thus, 35 MW of coal-fired generation from IPP is displaced with a variety of cleaner resources having lower GHG emissions, including but not limited to local natural gas fired generating units. The new unit would provide power within minutes when needed with lower emissions. This approach results in an overall reduction of Pasadena's GHG emissions and improved reliability.

3. The alternative of investment in upgrading transmission lines, both external and internal to the city, is not fully analyzed in the IRP Report itself. Several times in the text of the report, and in discussions at the Stakeholders Advisory Committee and in public meetings, reference has been made to the assertion that such investment would cost over $100 million and take 15 to 20 years, but there is little discussion of the specific details of this alternative, which reportedly was the subject of a 2001 report by consultant R.W. Beck currently being updated. (I am aware *there have been email exchanges between PWP staff and interested members of the Stakeholders Advisory Committee on this topic, but these exchanges are not thorough and are not available to the general public.)*

Response: Economic analysis by Pace, based on certain well-researched industry assumptions, indicate that adding new local gas-fired generation under the Preferred Resource Plan is the lower cost option compared to portfolios that consider new transmission upgrades. The annualized cost of installing a new generating unit is only marginally higher than maintaining the existing 43 year old B3 unit for 20 more years, if possible. Additionally, Pace concluded qualitatively that portfolios that add new gas-fired local generation were superior from a reliability perspective because they directly addressed PWP's reliability concerns by reducing its dependence on the aging units as well as a single point of entry for importing energy into Pasadena. According to Pace, the current transmission interconnection facilities with their 215 MW import limits at Goodrich permit PWP to meet approximately 90% of its annual energy requirements from remote resources including renewable resources. Therefore, the Preferred Resource Plan is superior from reliability, economic, and risk management perspectives. PWP believes that overdependence on a single point of energy import into the City jeopardizes the reliability of electricity in the City. Therefore, the current arrangement of local power plant capacity of about 200 MW and an import capability provides an acceptable balance of reliability.

Periodically, PWP reviews how the City's aging sub-transmission (distribution) system can be modified to provide higher capacity and reliability. RW Beck is currently evaluating alternatives to upgrade PWP's transmission and Distribution system with the assumption that existing local generation capacity remains in place, reliably and indefinitely.

Based on information provided by PWP and its own research, Pace developed cost estimates for investments to upgrade the transmission system that could be required, absent the addition of new, gas-fired local generation, in lieu of any definitive information from RW Beck. Pace concluded that portfolios that attempt to address existing reliability concerns through transmission upgrades (Portfolios 5a and 8) need to include the following additional costs that are not included in portfolios that address reliability concerns through the addition of new, gas-fired local generation:

- Approximately **$65 million** invested over the next 20 years to extend the lives of the 110 MW of aging local generation represented by Broadway Unit 3 and Glenarm Units 1 & 2. For comparison, the January 2007 Draft IRP assumed costs of $59.9 million, primarily associated with capital improvements to extend the lives of the existing local generation, **plus**
- At least **$100 million** invested over the next 15 to 20 years to upgrade the existing single point of interconnection with SCE at Goodrich and PWP's in-city transmission system. Although Pace has not performed a detailed assessment of the range of potential transmission system upgrades (which is within the scope of RW Beck's work), its cost estimate is based on the following:
    - An additional 230/69 kV transformer bank at Goodrich, at an estimated minimum cost of $10 million. This estimate is consistent with SDG&E's estimated costs for the addition of similar equipment as part of the proposed Sunrise Powerlink, plus:
    - A new underground 69 kV cross-town transmission line within the City to replace the existing 34 kV system at an estimated cost of $100 million. This estimate is

also based on SDG&E's estimated costs for similar facilities as part of the Sunrise Powerlink, and assumes the need to add approximately 10 miles of new 69 kV underground lines at a cost of $10 million per mile (which still may understate the actual costs of new 69 kV underground lines inside Pasadena.

- Pace believes that the $100 million cost estimate for transmission system upgrades most likely represents the lower end of the plausible range of transmission upgrade costs that PWP would incur in the absence of adding new, gas-fired local generation. Pace expects that the RW Beck study, once completed, will add more precision to this estimate, but that the $100 million transmission upgrade cost estimate is sufficient for evaluating the portfolio options currently being compared in the 2009 IRP.
- Note also that this $100 million cost can be benchmarked against a cost of approximately $97.5 million for transmission upgrades (65 MW times $1.5 million per MW for a second interconnection with Glendale) that were evaluated in a 2003 Black & Veatch report on behalf of Burbank, Glendale and Pasadena to assess options for increasing reliability through transmission upgrades.

- Using these assumptions, Pace showed (see p. 38 of the presentation prepared for the December 17, 2008 Advisory Group meeting) an economic comparison of portfolios that add new local gas-fired generation (5b and 6) against portfolios that add new transmission upgrades (5a and 8). From that comparison and its judgment, Pace draws the following conclusions:
  - The inclusion of approximately $65 million in generation life extension costs and $100 million in transmission upgrade costs to Portfolios 5a and 8 adds approximately $8/MWh to their levelized costs.
  - Portfolio 5b is clearly superior to Portfolio 5a from an economic perspective: the levelized cost of Portfolio is $94/MWh, compared to approximately $101/MWh for Portfolio 5a after the costs of generation life extension and transmission upgrades are included.
- Pace concluded qualitatively that portfolios that add new, gas-fired local generation (Portfolios 5b and 6) are superior from a reliability perspective because they directly address PWP's reliability concerns by reducing its dependence on the aging units. Without any insight from the RW Beck study as to the reliability impacts of the illustrative $100 million transmission upgrade described above, it is unclear if Portfolios 5a and 8 adequately address PWP's reliability concerns.
- Pace also concluded that, contrary to the views of some participants in the December 17, 2008 public meeting, the new 65 MW combined-cycle unit included in Portfolios 5b and 6 could actually be added faster than the $100 million transmission system upgrades, which PWP believes could take 15 years or more to complete. Even if these transmission upgrades can be added in less than this, Pace believes that the new combined cycle unit can be added earlier (by 2014) than the new transmission system upgrades.
- Installing local generation by 2014 is cost effective solution for the near term and maintains system reliability.
- Accordingly, Pace believes that Portfolio 5b is superior, from both reliability and economic perspectives, to Portfolio 5a.

4. A major objective of the Sierra Club and many, many community residents is to end the use of coal burning as a fuel source for generating power for the City of Pasadena. It is common *knowledge that the contract for purchasing power from IPP ends in either 2024 or 2027. The IRP Report appears to conclude that it is too expensive to terminate all but 35 MW of the contract earlier if the Preferred Resource Plan is adopted and implemented, yet fails to address the all-important issue of how the city can, as it must, wean itself off IPP once the contract term expires.*

On this topic the report makes a worse-case assumption that the market value of power generated by IPP may be zero on the open market. This seems highly unlikely, in that 50% of electric power in the United States is generated by burning coal, and communities in the state of Utah are, unfortunately, increasing their demand for coal-generated power, their cheapest power source by far, since the state contains abundant coal reserves.

We submit that the issue of eliminating the use of coal as a power source must be addressed in this report if long range plans are to be made to meet this objective.

<u>Response: </u>The Preferred Resource Plan specifies a 35 MW displacement of coal-fired generation from IPP with cleaner resources having lower GHG emissions, and concludes that the increased costs of doing so is justified by the significant GHG emissions reductions attributed to this action. Given the fact that nearly 50% of electricity in the country is generated by coal, there is a strong possibility that commercially viable carbon capture and sequestration type GHG reduction technology will be developed in the next 8 to 12 years. The IPP plant retrofitted with such GHG reducing technology would become a valuable low cost clean energy asset for PWP once the debt is retired. Many alternatives are being studied at IPP to evaluate GHG reduction measures. IPP is owned by numerous utilities from Sothern California and Utah. It is extremely difficult, logistically and legally, to modify the long term contracts to relieve PWP of its interest in the plant. Further, even if PWP were to successfully sell its interest in the plant, it is almost assured that the buyer would continue to draw its portion of energy. Thus, the sale of the IPP contract would not result in reduced emissions. By committing to sell energy equivalent to 35 MW of PWP share and not use that energy to serve City's load, the same objective is achieved.

Regarding the price at which power generated by IPP may be sold, the IRP analysis assumes that PWP liquidates the 35 MW of IPP power, but remains obligated under its existing contracts to meet its financial responsibilities to cover the costs of the facility. The analysis further assumes that the price PWP receives for this liquidated IPP power represents a $5 per MWh discount to PWP's costs under the IPP contracts, such that there is a net loss of $5 per MWh on the displaced 35 MW of IPP power and it is no longer available to serve PWP's load. Recognizing that the price received for liquidated IPP power in the future is uncertain, the IRP analysis also evaluated the implications of receiving a price as low as zero (see p. 28 of the January 24 Public Meeting presentation).

Caltech comments regarding the PWP 2009 IRP

February 9, 2009

Mr. Gurcharan Bawa
Power Supply Director
Pasadena Water & Power
150 S. Los Robles Ave
Pasadena, CA 91101

RE: 2009 Draft Integrated Resource Plan Comments

Dear Mr. Bawa:

The California Institute of Technology hereby respectfully submits the following comments regarding Pasadena Water & Power's 2009 Draft Integrated Resource Plan.

Pace Global Energy Services, LLC should be commended for conducting an extensive analysis that recommended a Preferred Resource Plan that if successfully implemented will exceed current RPS and GHG reduction goals. The Preferred Resource Plan identified nine critical action items that PWP must implement to achieve these goals.

Toward that end, we believe it is critical for PWP to develop an Execution Plan that details the steps to be taken to implement each one of the action items identified in the Preferred Resource Plan. The Execution Plan should be developed with public participation to ensure transparency and accountability. In general, the plan should outline specific actions, milestones to complete those actions, projected costs and funding sources and mitigation of fiscal and environmental impacts. The plan should also ensure flexibility as technology will change and future IRP reports will recommend new actions.

Without a concerted effort to ensure implementation, the Preferred Resource Plan will not become a reality. To assist in the development of the Execution Plan, we have provided our suggestions based on some of the action items identified by Pace in the Draft Integrated Resource Plan Report dated January 13, 2009 and the Public Meeting #4 Presentation dated January 24, 2009:

Energy Efficiency
While energy efficiency education is important, genuine progress will only be achieved through the use of incentive programs that create strong price signals. Southern California Edison is aggressively setting the pace in the marketplace by pursuing energy efficiency strategies such as smart metering, demand response programs and load control platforms. PWP must increase investment in these technologies and programs. Delaying this investment will increase the costs and regulatory risks.

Rate structures must be changed from the aging ratcheted system that hinders energy efficiency to a competitive time-of-use demand system that stimulates efficiency through strong price signals. Online metering options should be provided to give customers the information to proactively manage demand. Utility bills should be redesigned to show more trended consumption data so customers can identify monthly savings and compare their consumption to city-wide averages (suggested metric: kWh per square foot for both residential and commercial customers).

Load Management

Pasadena's largest customers can arguably be Pasadena's largest contributors to successfully managing peak loads. If programs, rates, and initiatives were available to incentivize large customers to conserve, then the large users can take advantage of the incentives in the most efficient and cost effective way. Therefore the overall cost to the City is limited to fewer accounts, and reliability is increased for all customers. To accomplish this, rate structures must be changed from the aging ratcheted system to a competitive time-of-use demand system.

The importance of this is illustrated by the fact that normal monthly service shut-downs of our co-gen facility can be performed at a time of our choosing. Currently, they are preformed during the day, which burdens the grid by taking down 12 MW during the daytime peak periods. If there were time-of-use demand pricing incentives in place, it would be more economical for us to perform these shut-downs at night and the resulting stain on the grid and PWP will be reduced.

Local Renewable Energy

A "feed-in tariff" program may be a valuable tool to increase local renewable energy production, but such a program must be developed with consideration of existing renewable energy incentives and financing structures. Would this program be optional? How would this program work for clients who have already entered into Power Purchaser Agreements?

Solar PV

Developing rate structures and incentives to spur PV installation is a worthwhile goal, but attention must be given to the financing of these incentives and rebates. The demand for rebates will be high so PWP must find a way of sustainably funding these programs to ensure all customers willing to install PV have access to the rebates.

Based on a recent brief to the Municipal Services Committee, the revenue generated by the Public Benefits Charge is not sufficient to meet the demand for rebates and solar incentives. In the short-term, consideration should be given to borrowing money to fund the rebate programs as the return-on-investment from installing solar will service the debt.

The ultimate long-term solution is to restructure current programs and operations so that generation and procurement costs are reduced, efficiency is increased and the resulting savings can be reinvested into solar incentives, rebates and modernization of the grid. The energy efficiency and load management programs recommended by the IRP can accomplish these goals.

New Local Generation & Existing Generation Upgrades

Investing in local fossil fuel generation today will determine Pasadena's ability to meet Federal and State carbon emission regulations in 2050. Therefore, care should be taken to select and design the most efficient generation facility possible given current technology. Flexibility and design-for-the-future should be integrated into any new generation facility and existing facility upgrade. By doing so, facilities will be able to accommodate new technologies and alternative generation sources (such as fuel cells) with minimal cost.

Transmission Evaluation

Transmission capacity and reliability are absolutely critical to meeting future demand and supplying decentralized power from renewable sources. When will this report be completed? Will the report be available to the public?

Thank you for the opportunity to comment. We look forward to working in partnership with PWP to ensure the Integrated Resource Plan is successfully implemented.

Sincerely,

John Onderdonk – Manager for Sustainability Programs
Matthew Berbee – Energy Manager

EVALUATING IRP PRIORITIES THROUGH SURVEYS

Recognizing the importance of gathering public opinion and input to the IRP planning process in order to improve the quality and responsiveness of the decision making, PWP and Pace considered several sources of survey data during the development of IRP alternatives and the Preferred Resource Plan. The survey results and key conclusions are summarized below.

PWP Surveys

PWP conducted informal surveys to develop insight into the most important objectives and concerns of stakeholders that should guide the IRP planning and decision-making process for Pasadena. This consisted of three separate surveys, as described below:

- **IRP Advisory Group.** During the initial meeting of the IRP Advisory Group, Pace asked the Advisory Group participants individually to develop a list of IRP objectives, and then rank the group's list of objectives from highest to lowest in priority. Exhibit 3 shows the seven priorities identified by the Advisory Group, and the order or priority assigned to them.
- **Public Questionnaire 1.** PWP developed a questionnaire to provide customers an opportunity rank the same set of IRP planning objectives on a scale. Exhibit 3 also shows the results of this questionnaire.
- **Public Questionnaire 2.** PWP also asked survey participants to rank, in order of importance, a longer list of the 14 IRP objectives, many of which overlap with the list of seven priorities identified and ranked by the IRP Advisory Group. Exhibit 3 shows the results of this second questionnaire.

This process collectively indicates a broad consensus around the three primary objectives that were used to guide the evaluation of IRP alternatives and select the Preferred Resource Plan:

1. **Provide Reliable Service**
2. **Strive for Environmental Leadership**
3. **Maintain competitive/stable rates**

Exhibit 3: Summary of Survey Results for IRP Objectives

	IRP Advisory Group Rankings	Public Questionnaire 1 Rankings	Public Questionnaire 2 Rankings
Provide Reliable Service	1	1	4
Strive for Environmental Leadership	2	2	1 **
Maintain Stable Rates	3	3	3
Preserve Competitive Rates	5		2
Allow for Flexibility	4		5
Manage Market Risks	6		5
Maintain Fiscal Health	7		7

** High rankings for "Energy Efficiency and Conservation", Environmental Protection" and "Building a Renewable Energy Portfolio" also incorporated from Public Questionnaire responses

Source: PWP and Pace

RKS Research Survey

In cooperation with the Southern California Public Power Authority ("SCPPA"), PWP also participated in a formal survey conducted by RKS Research to help understand its customers' views on key issues in the 2009 IRP and their preferences regarding environmental and cost trade-offs. The results of the survey are summarized below.

First, customers were asked about their awareness of and concern about the global warming/climate change mitigation issue. The results of this question are summarized in Exhibit 4, and commentary offered by RKS on the implications of these responses is detailed below.

Exhibit 4: RKS Research Survey Results – Awareness about Climate Change

	PWP Residential Customers		PWP Business Customers	
1. Customers were asked about their awareness of and concern about the global warming/climate change	Participants %	Non-Participants %	Participants %	Non-Participants %
Very familiar*	59	57	33	56
Very concerned^	67	55	33	55

Source: RKS Research Survey

- **Residential Customers**
  - **Awareness.** Nearly three out of five in both cases – of participants and non-participants – respond that they are very familiar with global warming and climate change
  - **Concern.** Two-thirds of participants and just over half of non-participants express concern.

- **Business Customers**
    - **Awareness and concern.** Among both participants and non-participants – appear in synch

Second, customers were asked a series of questions testing the amount of electricity rate increase that they would consider "reasonable" to fund solutions to global warming and climate change. All customers were asked:

> "As you know, California state mandates require all customers in the state to pay for solutions to global warming and climate change through their electric bills. If your organization's rate for electricity increased by 20%, do you think that is a reasonable or not reasonable amount to help fund solutions to global warming and climate change?"

Customers that responded "reasonable" at the 20% level were not asked further questions in this series. Those that responded "not reasonable" at the 20% increase level were asked the same question at steadily reduced amounts – increased by 15%, increased by 10%, increased by 5% and increased by 3%. Due to the small number of PWP participants, we show only non-participant responses. Exhibit 5 Exhibit 6 provide a summary of the survey responses to this series of questions.

For PWP residential customers, at a rate increase level of 10%, about half of PWP participants sign off, calling this level "reasonable." Non-participants respond similarly:

Exhibit 5: RKS Research Survey Results – Residential Customer Bill Increase

PWP Residential Customers Amount of Electricity Rate Increase that is Reasonable to Fund Global Warming (Percent Saying "Reasonable")				
	PWP Residential Customers Participants %	PWP Residential Customers Participants Cumulative %	PWP Residential Customers Non-Participants %	PWP Residential Customers Non-Participants Cumulative %
20% increase	**30**		**18**	
15% increase	**6**	**36**	**4**	**22**
10% increase	**15**	**51**	**24**	**46**
5% increase	**28**	**79**	**16**	**62**
3% increase	**6**	**85**	**8**	**70**

Source: RKS Research Survey

For PWP business customers, the 5% level is where about half of the non-participants call this level of rate increase reasonable.

Exhibit 6: RKS Research Survey Results – Commercial Customer Bill Increase

PWP BUSINESS CUSTOMERS AMOUNT OF ELECTRICITY RATE INCREASE THAT IS REASONABLE TO FUND GLOBAL WARMING CLEANUP (PERCENT SAYING "REASONABLE")		
	PWP Business Customers Non-Participants %	Cumulative %
20% increase	**9**	**9**
15% increase	**6**	**15**
10% increase	**19**	**34**
5% increase	**22**	**56**
3% increase	**23**	**79**

Source: RKS Research Survey

RKS Survey Methodology

Following are pertinent details underlying the RKS survey methodology.

1. **Number of respondents interviewed**
   - Residential = 105 (54 who had participated in PWP programs, 51 who had no prior participation)
   - Business = 101 (15 who had participated in PWP programs, 86 who had no prior participation)
2. **Sample size**
   - PWP provided RKS with four separate lists of residential and nonresidential customers, including those who had participated in PWP programs between FY2005 and FY2008 and all active residential and business accounts that have not participated in EE programs.
3. **Sampling method**
   - A "simple random sampling" (SRS) within each of the 4 subgroups (residential customers who had participated in PWP programs between FY2005 and FY2008, active residential accounts, business customers who had participated in PWP programs between FY2005 and FY2008; and active business accounts. That is, in conducting the interviews each contact in the sample had and equal probability of being selected to participate in the survey.

4. **Sampling error and confidence intervals at the 95% confidence Interval**
   - +/- 13.6 - for the 54 completed of 4,906 residential customers who had participated in PWP programs between FY2005 and FY2008;
   - +/- 13.7 - for the 51 completed among the 48,053 active residential accounts
   - +/- 23.6 - for the 108 completed business customers who had participated in PWP programs between FY2005 and FY2008; and
   - +/- 10.5 - for the 86 completed among the 8,209 active business accounts
5. **Survey method**
   - Telephone interviews among
     a. residential customers conducted between September 9-28, 2008 and
     b. energy decision-makers at business customer organizations conducted between September 15 and October 16, 2008.
6. **Validity of the survey instrument**
   - The instrument was designed with feedback from clients, and used standard questionnaire construction procedures, as well as industry recognized response options to all questions. The only necessary validation from the customer standpoint is that the survey was pretested for readability and completeness prior to fielding the interview. In addition, since this was sponsored by four SCPPA utilities, and results generated differed from one utility to another (in other words, the survey "discriminated" among respondents) all measures point to a valid instrument.
7. **Known types of potential response bias**
   - There is no know response bias since the questionnaire was designed using industry standard questions (0 – 10 scales, open-ends – if used) and respondents were given a full range of options within each question, and indeed chose their level of feedback for each question.

STRATEGIC PARTNERSHIPS

One of the recommendations made by the EAC regarding the 2007 Draft IRP was to evaluate the potential for PWP to enter into strategic partnerships to advance the goals of introducing clean and renewable resources into PWP's resource mix. The recommendation followed a consistent theme, although it was expressed in slightly different terms:

- "Explore the development of strategic partnerships with technological leaders, including those available in Pasadena, in order to take advantage of innovative green and clean power solutions."
- "Form meaningful partnerships with JPL, Caltech and other technological leaders to take advantage of innovative green and clean power solutions."

In certain critical respects, PWP has already entered into strategic partnerships in furtherance of the goal of increasing PWP's use of clean and renewable resources:

- PWP has worked in partnership with Pace to conduct the 2009 IRP process, which clearly has been focused on the potential to increase the use of clean and renewable energy resources in PWP's portfolio in the interest of achieving environmental leadership. The outcome of this engagement, as described in the Preferred Resource Plan, will be a dramatic and fundamental increase in PWP's use of clean and renewable resources on a long-term basis.

- PWP works in partnership with literally dozens of renewable resource developers through at least six competitive solicitations, on its own or in collaboration with the Southern California Public Power Authority, of renewable energy projects and/or power purchase agreements that can cost-effectively increase PWP's use of clean and renewable energy resources. These solicitations, which represent a central component of PWP's ongoing power resource procurement activities, permit PWP to work in partnership with a wide variety of technological leaders in the renewable energy industry and permit PWP to take advantage of innovative clean and renewable power solutions.
- PWP has worked with Caltech to implement a solar photovoltaic project at the Caltech campus, which represents the largest and most recent innovative clean and renewable power solution deployed within the Pasadena community to date.
- Organizations like JPL and Caltech are important strategic partners not only because of their status as key customers of PWP, but because they potentially provide access to state-of-the-art technological expertise that PWP can use to evaluate and commercialize emerging clean and renewable energy solutions in the future.

In addition, there are a number of small and emerging clean and renewable energy manufacturers and marketing firms located in Pasadena and Southern California that provide innovative technologies and business models that PWP can leverage to increase the size of the technological prowess of its resource portfolio. Such firms are logical candidates to form strategic partnerships with PWP to facilitate the deployment of innovative technologies and solutions. They can assist PWP in such areas as educating customers about the benefits of their technology solutions, providing financing solutions to facilitate customer commitments to those solutions, and managing the construction and implementation of those solutions. Following are just a few examples of potential strategic partners in this regard:

- ESolar (Pasadena): Utility-scale solar generating systems
- Solar Integrated (Los Angeles): Building-integrated PV roofing systems
- Open Energy (Solana Beach): PV and CSP commercialization
- EnerNOC (La Verne): demand response provider and auditor

Finally, PWP should consider establishing strategic partnerships with environmental groups and technology associations with whom PWP could conduct a broader range of activities around clean and renewable energy resources beyond the evaluation, procurement and deployment of advanced energy efficiency and supply technologies. For example, organizations like the California Clean Energy Fund (CalCEF) accelerate investment in California's clean energy economy . To the extent that exploiting innovative technologies may require PWP to evaluate other options, organizations such as West Start CALSTART represent opportunities to deploy advanced transportation technologies to clean the air, improve energy efficiency and create high quality jobs in and around Pasadena.

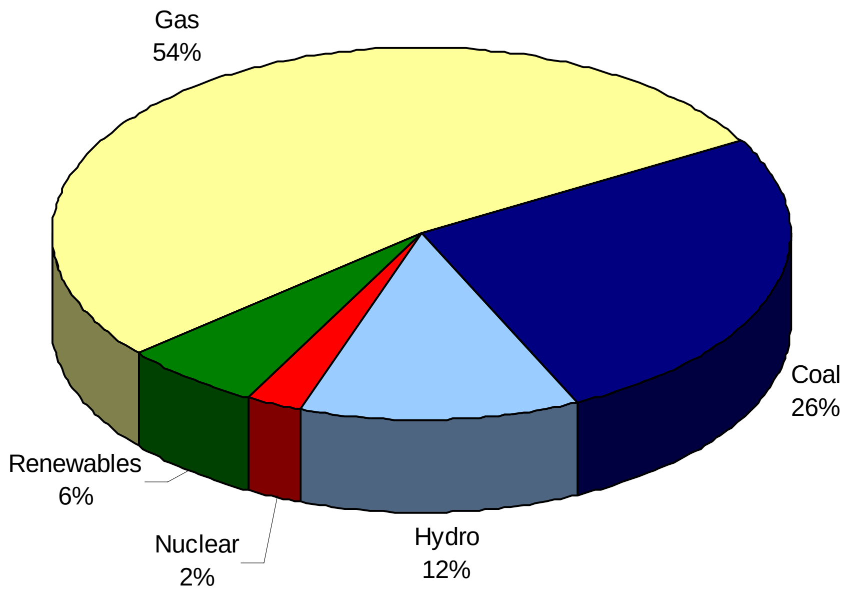
EXISTING PWP PORTFOLIO

COMPANY PROFILE

PWP is a municipal utility that manages a service territory of 58,000 customers with a peak load of slightly more than 300 MW. The City of Pasadena (the "City" or "Pasadena") owns 200 MW of on-site, natural gas-fired local generation and is capable of importing up to 200 MW of power through its Sylmar-Goodrich tie line. Pasadena also has ownership shares and long term contracts with a number of power generation facilities located throughout the west. In addition, Pasadena partially owns and has long term contracts on various transmission lines. Pasadena also partly owns natural gas wells and transportation pipelines; and supplements its natural gas needs for power generation through long and short term contracts. PWP is a Scheduling Coordinator ("SC") and Participating Transmission Owner ("PTO") in the California Independent System Operator ("CAISO").

Combining local capacity with partial ownership of capacity outside the service territory's boundaries, PWP has a current capacity profile of 410 MW. Exhibit 1 displays the composition of this capacity by fuel type, and Exhibit 2 further details PWP's plant portfolio.

Exhibit 7: PWP's 2007 Capacity by Fuel Type (%)



Source: PWP and Pace

Exhibit 8: PWP's Existing Portfolio

Plant Name (Contractor)	Unit Type	Primary Fuel	Start	End	Capacity (MW)	% FY 2008 Energy
Intermountain Power Project	Steam Turbine	Coal	1987	2027	108	62%
Hoover Power Plant	Hydro	Hydro	1941	2017	20	4%
Azusa	Hydro	Hydro	1933	-NA-	15	<1%
Palo Verde	Steam Turbine	Nuclear	1988	2030	9.9	5%
Broadway	Steam Turbine	Gas	1965	-NA-	65	3%
Glenarm	Combustion Turbine	Gas	1975	-NA-	22.3	4%
	Combustion Turbine	Gas	1975		22.3	
	Combustion Turbine	Gas	2004		42.4	
	Combustion Turbine	Gas	2004		44.8	
Magnolia Power Plant	Combined Cycle	Gas	2005	2033	19	7%
BPA Exchange	Contract	Contract	2008	2013	15	<1%
High Winds (Iberdrola)	Wind Turbine	Wind	2003	2023	2	2%
Milford (UPC/First Wind)	Wind Turbine	Wind	2009	2029	5	NA
Heber South (Ormat)	Steam Turbine	Geothermal	2007	2032	2.1	2%
Tulare & West Covina Landfill (Minnesota Methane)	Combustion Turbine	Landfill Gas	2007	2016	9.5	6%
Chiquita Canyon Landfill (Ameresco)	Combustion Turbine	Landfill Gas	2009	2029	6.7	NA
				Total Capacity:	**409**	

Source: PWP and Pace.

Significant capital investments are required to extend the operating lives of the Broadway and Glenarm gas-fired units. PWP estimates these costs at $20 million over the next 10 years and $65 million over the next 20 years. In its analysis, Pace has included these costs on a levelized basis as part of the annual portfolio costs for every option that maintains the existing in-city units. In return for these capital upgrades, the fixed costs of the older, in-city units are assumed to decline by 20%.

CONTRACT SUMMARY

The following summarizes PWP's contract rights to their diverse mix of generating resources:

- Intermountain Power Project ("IPP") – PWP owns three shares of IPP for a total of 108 MW. The original entitlement is for 61 MW. The next share is for 18 MW and was procured through a layoff contract. The final share is for 29 MW and is part of an excess sales contract, which may be recalled at any time. In recent history, 5-10 MW have been recalled during the winter and 19 MW in the summer.

- Hoover Hydroelectric - PWP is entitled to approximately 4,500 MWh each month at 14-20 MW per peak hour depending on reservoir availability. History suggests that 17 MW is a representative average for modeling purposes.
- Azusa run-of-river hydro - PWP's contract with SCE allows them to bank all MWh generated each year and schedule those MWh in 15 MW blocks throughout the year. This resource is typically used for Super Peak hours from July-September.
- Magnolia - PWP's contract is for a 14 MW portion of the combined cycle, 3 MW of duct-firing and 2 MW for steam injection. Magnolia currently has a minimum operating capacity assumed to be 12 MW.
- Palo Verde - A contract provides PWP with 9.9 MW of nuclear capacity.
- High Winds – PWP's contract specifies 6 MW of capacity. However, the contract was negotiated such that PWP receives 2 MW around the clock firm capacity (6MW with assumed 33% capacity factor). The contract is trued-up in February.
- Ormat Geothermal - This is a contract for 2.1 MW of renewable energy with SCPPA
- Tulare City Landfill / BKK Landfill (Minnesota Methane) – PWP has a contract for landfill gas from these two sources totaling around 9.5 MW
- Chiquita Canyon Landfill - PWP has a contract for landfill gas approximating 6.67 MW. The plant is expected to come online in 2009.
- Milford Wind Corridor – This wind farm is currently in the planning phase, and Pace anticipates its online date to be around June 2009. PWP has 5MW of contracted wind capacity from this source. Available capacity will vary depending on the actual wind conditions.
- BPA Swap
    - For May and June, PWP can take 15 MW during all peak hours. PWP must replace their consumed energy during this time (a minimum of 3,260 MWh) in the off season (considered September to mid-March) during the off-peak hours.
    - From July to September, PWP must replace all on-peak consumption during the off-peak hours.
    - A "capacity payment" totaling 16,500 MWh must be supplied to BPA from September to mid-March.

For intermittent resources, actual hourly capacity factor profiles were used in all operational analysis where applicable.

LOCAL PASADENA TRANSMISSION PROFILE

PWP relies on importing its energy from resources around WECC and has worked to build stable transmission capability that allows for system reliability. Sylmar-SP15 is the primary transmission line into Pasadena, as almost all other transmission lines flow through Sylmar. PWP holds a contract for 215 MW on this line. This crucial tie allows PWP to have access to major power market hubs. Pace has taken this import constraint into consideration and has conducted reliability analysis that recognizes this constraint.

PWP LOAD FORECAST

Pace has designed and estimated an econometric model of Pasadena Water & Power's electricity sales to retail customers, and has developed a long-term forecast of sales based on forecasts of population growth, employment, commercial floor space, and retail electricity prices. Descriptions of the model equations and definitions of the variables are presented below, as well as forecast assumptions and forecast results.

Pasadena's electricity sales growth has averaged less than one percent per year over the past two decades, due in large to limited opportunities for expansion of the residential and business customer base. Total sales grew from 1.07 TWh in 1990 to 1.22 TWh in 2007, for an average annual growth rate of 0.8%. Residential sales have been stronger than sales to the commercial and industrial (C&I) sectors, averaging 1.3% since 190 and 2.0% since 2000, while C&I sales averaged 0.6% per year since 1990 and less than 0.1% since 2000.

Exhibit 9: Average Annual Percentage Growth of Electricity Sales

	Total	Residential	C&I
1990-2000	0.89	0.77	0.93
2000-2007	0.58	1.98	0.06
1990-2007	0.76	1.27	0.57

Source: PWP, Pace

The increase in residential sales growth coincides with estimated growth of Pasadena's population, which grew at an average rate of 0.2% during the 1990s and is estimated to have grown by 1.3% per year since 2000. C&I sales, on the other hand, are not wholly consistent with available measures of economic activity. Labor data indicates that employment in Pasadena grew at an average annual rate of 2.1% between 1994 and 2006, although the growth was slower (1.9%) since 2000.

FORECAST SUMMARY

Sales growth over the near term is estimated to average 1.2% per year, and long-term growth (through 2030) is estimated to average 0.5% per year. This projection is lower than the 1% growth rate adopted by PWP's 2007 Integrated Resource Plan, and is due in large to expectations of restrictive land use policies in PWP's service territory.

This growth is subject to the Smart Growth planning principles adopted by the City in its General Plan and is largely occurring as in-fill projects in designated planning zones. Once housing and commercial space have reached density levels specified in the Plan, Pace expects that new business and electric sales growth will taper off. To the extent that the City revises its planning limits in the future (for example, by letting the community to "grow taller" with high-rise condominium and office towers), then sales growth would be much faster.

Also, this forecast is a reference case that does not include the impact of state or local demand side management and conservation programs. Natural consumer responses to rising prices are incorporated in the modeling and reference forecast, but unique mandated or incentive programs that are anticipated are not reflected in the initial forecast analysis.

The near term growth is being driven by a mini construction boom, with expansion of the housing and commercial sectors following guidelines set by the City's General Plan. Over the longer term, Pace expects that allowed density limits will be reached and that sales growth will slow significantly. Under that plan, over 5,000 new housing units are expected to be permitted. In addition, over two million square feet of new commercial floor space is completed or in the planning phase, including large construction projects at the California Institute of Technology and Huntington Memorial Hospital.

Exhibit 10: Projected Sales Growth Rates by Customer Class

	Residential	C&I	Street Lighting	Total
2007-2010	0.97%	1.36%	-0.06%	1.24%
2010-2030	0.63%	0.29%	0.00%	0.38%
2007-2030	0.68%	0.43%	-0.01%	0.49%

Source: Pace

Residential electricity sales grew at an average annual rate of about 2% since 2000, as nearly 3,000 new housing units were added. Expectations for near-term growth have slowed slightly due to the foreclosure of the 820-unit Ambassador College development in June, 2008 and a general slowdown in regional housing markets, but Pace expects that the remainder of the 5,095 units allowed under the Plan will be permitted and completed within the next few years. Commercial electricity sales growth during this period was much slower, barely registering a gain since 2000. However, with over a half-million square feet of new space at Caltech and Huntington Memorial either complete or underway, and proposals for close to another 1.5 million square feet of office and retail space in Pasadena, commercial sector sales are poised for a sudden growth spurt.

Peak load growth rates are expected to exceed sales growth rates due to relatively faster sales growth in summer months. Peak load is projected to grow at an average annual rate of 0.52% during the 2010-2030 period compared with sales growth of 0.38% during that period. Peak is expected to drop during the next few years on weather-normalized basis.

METHODOLOGY

Pace's model of electricity sales in Pasadena is predicated on the assumption that sales take the following general functional form.

Sales = f(season, degree days, economic/demographic activity, electric price)

- Sales and the other variables in the model are defined and measured on a seasonal basis, as demand for electricity is observed to follow a seasonal pattern. Load is highest during summer months due primarily to air-conditioning requirements. Load is also fairly high during winter months due to greater need for lighting and for heating (primarily to provide power to pumps and fans for heating and ventilation.) Sales are generally at their lowest during the “shoulder” months of spring and fall when demand for heating or cooling is minimal.

- Degree days are measured as the arithmetic difference between the daily average temperature and a specified reference point. Colder-than-normal weather in the winter or hotter-than-normal weather in the summer increases the number of heating degree days (HDD) or Cooling degree Days (CDD), respectively, and vice versa. As HDD or CDD increase, electric load is expected to increase because of increased demand use of heat pumps and air handling equipment during the winter and increased demand for air conditioning during the summer. Given the different requirements for power during different seasons, it is not expected that the load response will be the same for identical percentage changes in HDD and CDD.
- Economic and demographic growth has a direct impact on demand for electricity. Increases in the number of households, income level, commercial floor space, and manufacturing activity all require increasing amounts of electricity, all else unchanged.
- Prices are expected to elicit an inverse response in demand. As the price of a product increases, consumers will reduce purchases of that product. If there are few substitutes or if the product is a necessity, then the demand response to an increase in price is expected to be small. Numerous economic studies conducted over the past four decades have shown that electricity demand is relatively inelastic - a one percent increase in price produces less than a one percent decrease in demand. There is also extensive empirical evidence that the long-run response to price is typically greater than the short-run response, as consumers are largely limited to behavioral changes in the short run, but can replace older equipment (appliances, light fixtures, motors and drives) with new more efficient equipment in the longer run.

DATA SOURCES

Data series for this analysis were compiled from several data sources, as shown below.

Electric Sales
- Pasadena Water and Power
- California Energy Commission
- U.S. Energy Information Administration

Weather variables
- Western Regional Climate Center, Desert Research Center

Economic, demographic, and customer variables
- U.S. Department of Commerce, Census Bureau
- U.S. Energy Information Administration
- California Energy Commission
- California Department of Finance
- City of Pasadena, Department of Planning and Development, Planning Division

Electric Prices
- Pasadena Water and Power
- California Energy Commission
- U.S. Energy Information Administration
- U.S. Department of Commerce, Bureau of Labor Statistics

DATA DEFINITIONS

Sales

Sales data for the PWP service territory were collected from three sources: PWP, the California Energy Commission ("CEC"), and the US Energy Information Agency. PWP provided monthly sales data by rate class from 1998 through mid-2008. The CEC was able to provide monthly data by residential and NAICS business grouping, as well as street and highway lighting, for 1980-2007. The EIA data sets included annual sales from 1990-2006 for broadly defined residential, commercial, industrial and other customer classes. While data was available for some categories as far back as 1980 in the CEC data sets, the completeness, quality and reliability of the older data was inconsistent. Usable monthly data sets were developed for residential sales for 1983-2008, for combined commercial and industrial sales for 1990-2008, and for street and highway lighting for 1998-2008. These monthly data were consolidated to quarterly data for use in the model.

Weather

Daily HDD are defined as the larger of zero or 60° minus the daily average temperature and daily CDD are defined as the larger of zero or the daily average temperature minus 70°. Pace has adopted HDD on a 60°F basis and CDD on a 70°F basis, rather than using a standard 65°F reference point for both, under the expectation that consumers in Pasadena are less likely to turn on their heat until average temperatures drop to 60°F and less likely to turn on their air-conditioning until temperatures rise up to average daily levels of 70°F. Daily degree day data ware aggregated to monthly levels and then transformed to rolling bi-monthly averages. This reflects the fact that sales data generally follows 30-day billing cycles and that approximately half of the sales billed in a current month were consumed in the prior month. These billing period-adjusted degree days were then converted to quarterly degree day data series.

In the model, there are separate degree day variables for each quarter. The first quarter variable, for example, is set equal to the sum of HDD and CDD for the first quarter and zero for the other three quarters. The other three quarters' variables are compiled in the same manner. This method allows the model estimator to more accurately estimate the demand response in different seasons. The degree day variables were compiled for the period 1980-2008.

Economic and Demographic

The range of potentially viable economic and demographic variables for this analysis is limited by the small size of the service territory. Variables that are commonly used, such as personal income, value added, or gross regional product, are available for larger geographic areas such as counties, metropolitan areas, or states. These levels of aggregation are not suitable for this model because Pasadena comprises a very small share of the population and economic base of Los Angeles County.

Two alternative variables were used to represent economic activity in PWP's territory: the number of residential customers and total employment. Residential customer accounts were compiled from CEC and EIA data and used in the residential model. Total employment data was extracted from County Business Patterns files on the U.S. Census Bureau site and used for the commercial and industrial sales model. In addition, a regional index of air conditioning penetration was used in the residential model.

Residential customer data was available on a monthly basis in the CEC data and on an annual basis in the EIA data. The CEC data shows a large downward revision of about 50% from 2001 to 2002, apparently reflecting a change in reporting or accounting methods at PWP. The EIA annual data does not show a downward revision. The customer accounts variable was constructed by adopting the CEC data from 2002 forward "as is" and adjusting the CEC monthly data for 2001 and earlier years downward based on the ratio of CEC 2002 data to EIA 2002 data.

Growth in residential sales per customer during the summer months has outpaced growth in other seasons for several years, indicating fast growth in cooling load. To account for this trend, an index of air-conditioning was developed from 1990 Census data and from U.S. EIA Residential Energy Consumption Survey data and other EIA sources for California and the West for 1987, 1990, 1993, 1997, 2001, and 2005. This index shows that the percentage of households in California, and by assumption Pasadena, has steadily increased since the mid-1980s.

Local employment data for Pasadena for 1994-2006 was extracted from County Business Patterns files at the Census Bureau, and approximately 85% of employment rolls in Pasadena were concentrated in four zip codes: 91101, 91103, 91105, and 91107. 1994 was the first year for which data were made available at the zip code level, and the last data reported in the County Business Patterns system is 2006. The data is also limited in that it does not provide data in sufficient detail to discern between industrial and non-industrial sector employment.

Prices

Average quarterly prices were calculated for all periods as the ratio of revenue to kWh sales and then converted to real 2007$ using a GDP price deflator. Four-quarter moving averages of these quarterly prices were then constructed and lagged by three quarters. This price variable measures persistent changes in prices, with a sufficiently long lag to allow measurement of demand response to changes in price.

ECONOMETRIC RESULTS

The final forms of the residential and commercial equations are presented below, with estimated coefficients and relevant statistical results. In both cases, Pace adopted a standard "double-log" format. In this approach, the dependent variable (sales) and the independent variables (prices, employment, and so forth) are converted to their natural log value before statistically fitting the variables to a linear form. Mathematically, this allows the estimated coefficients for variables to be interpreted as an elasticity measure. For example, the coefficient on prices in the residential equation, -0.155, is interpreted as meaning that a 10% increase in the real price of electricity will result in a 1.55% decrease in demand for electricity.

The R-square statistics measure the amount of variation from the average level of sales over the estimation period that is "explained" by the regression equation. In both regressions, approximately 85% of the variation in sales can be explained by movements of the variables tested in the equations. These are shown in Exhibit 11.

Exhibit 11: Summary Regression Statistics

Sector	Period	Obs.	F-Statistic	R Square	Adj. R Square
Residential	1989:I – 2008:II	78	51.855	0.838	0.822
Commercial & Industrial	1998:I – 2006:IV	36	50.910	0.895	0.877

Source: Pace

The statistical results of the regression equations are displayed in Exhibit 12 and Exhibit 15. The residential equation results were well behaved and consistent with expected values. Changes in degree days have the largest impact during summer months, when air conditioning load increases. Changes in the size of the customer base translate directly to increased sales. The coefficient 0.838 indicates that average use per customer has been increasing over time, consistent with consumer patterns of increased numbers of home electronics and a tendency toward larger and more wired homes. Residential customers demonstrate some responsiveness to electricity prices, but, as most studies have demonstrated over the past several decades, their demand elasticity is low. The air-conditioning index also has a statistically significant result in the model.

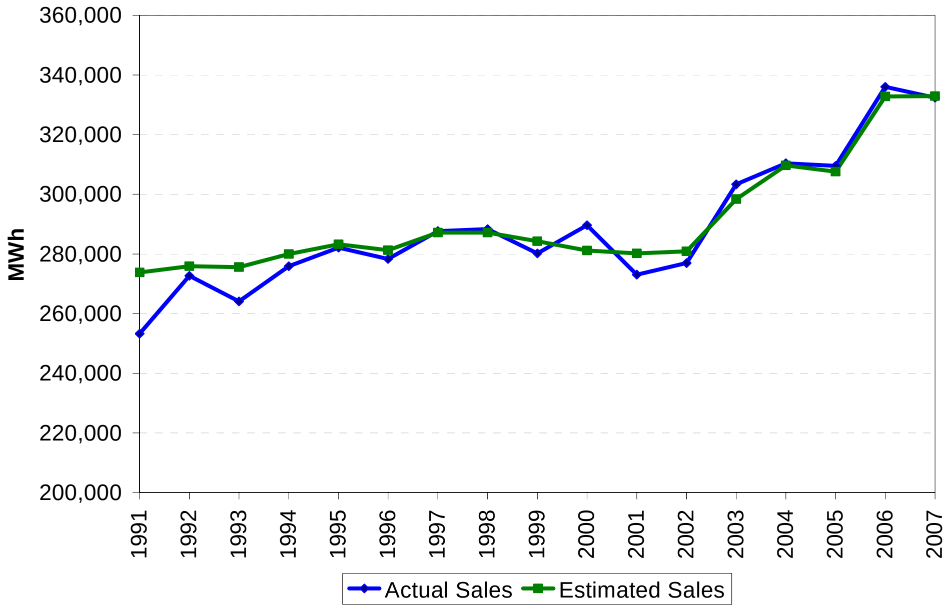
Exhibit 12: Residential Regression Results

Independent Variable	Description	Coefficient	t-statistic
(Constant)		2.778	2.402
LQTR1DDa	ln(HDD) in QTR1, 0 elsewhere	0.098	3.952
LQTR2DDa	ln(HDD+CDD) in QTR2, 0 elsewhere	0.090	3.146
LQTR3DDa	ln(CDD) in QTR3, 0 elsewhere	0.161	6.713
LQTR4DDa	ln(HDD+CDD) in QTR4, 0 elsewhere	0.097	3.760
LACIndex	ln(air conditioning penetration index)	0.449	4.629
LResCust	ln(number of residential customers)	0.838	7.859
LResPriceMALag3	ln(real price of electricity, lagged)	-0.155	-2.391

Source: Pace

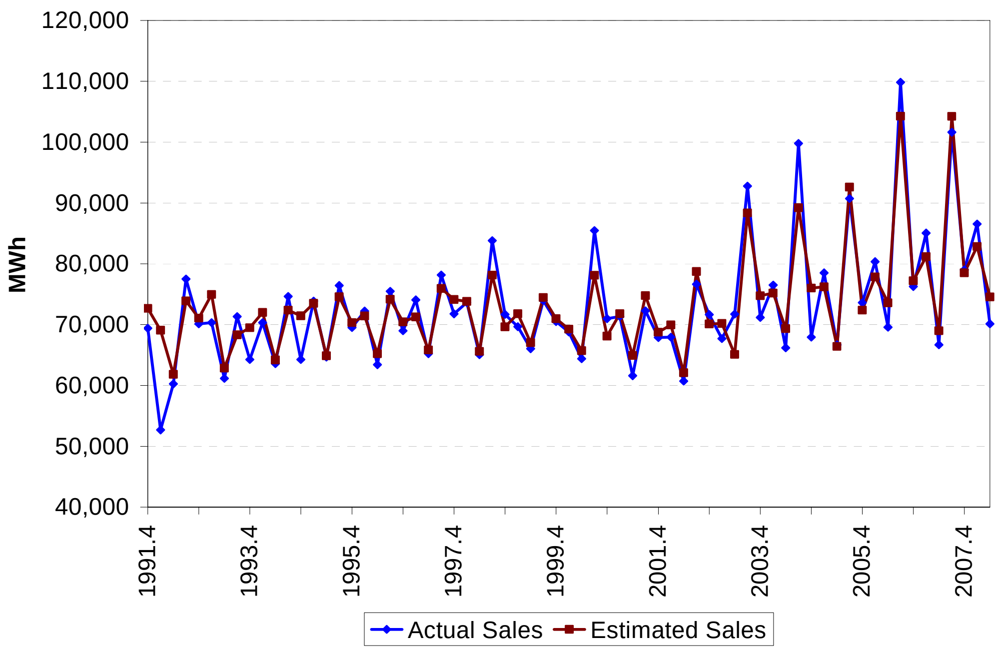
Comparisons of actual and estimated residential sales are shown in Exhibit 13 and Exhibit 14. The residential equation provides a good fit to actual sales, particularly in the period 2001-2008. There is a tendency in the quarterly data for the model to miss some of the variation between the 4th and 1st quarters, but the 2nd and 3rd quarter data provide a better fit. Relative variations between summer and winter sales have been widening in recent years and this pattern is continued forward in the forecast.

Exhibit 13: Annual Residential Sales - Actual vs. Estimated



Source: Pace

Exhibit 14: Quarterly Residential Sales - Actual vs. Estimated



Source: Pace

The commercial and industrial sector equation was estimated for the period 1998 to 2006, although data for sales and all of the selected explanatory variables were available back to

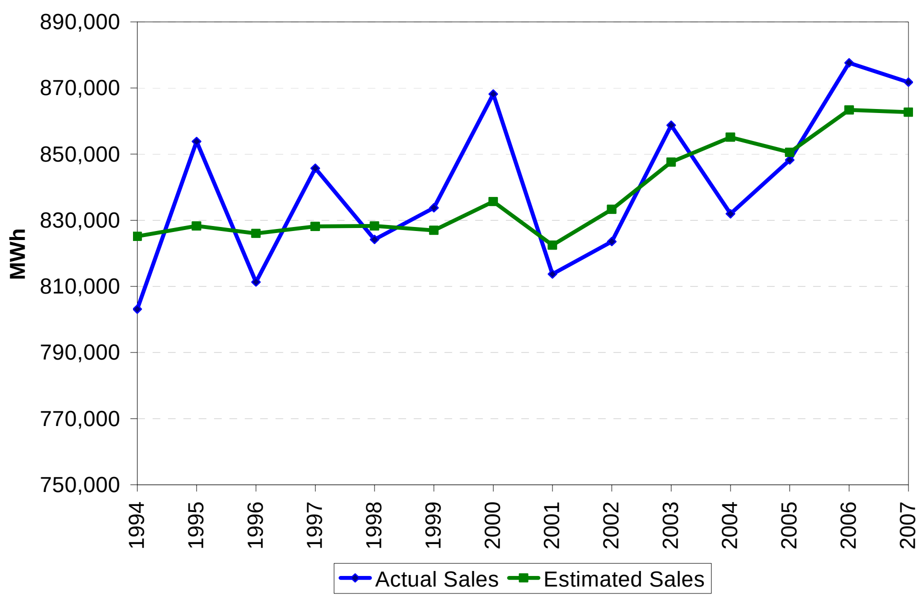
1994. Wide quarterly swings in sales data were evident during 1994-1997 but were greatly compressed after that. This is due possibly to changes in the composition of the combined commercial and industrial sector or merging different data sets from PWP and CEC. Regardless of the root cause, the quarterly swings in data wide swings in quarterly data in those years disrupted the estimated relationships between sales and employment and between sales and prices and were therefore dropped from the data set. The data set was truncated at the latter end, 2006, due to lack of employment data estimates for 2007. The equation structure provides a good fit of the quarterly variations in C&I sales. Seasonal variations are still strong, although only the summer sales (Q3) were found to be sensitive to weather conditions. The model also presents an acceptable description of long term trends although year-to-year changes are not well explained. Comparisons of actual and estimated C&I sales are shown in Exhibit 16 and Exhibit 17. These include data prior to 1998 for illustration purposes.

Exhibit 15: Commercial and Industrial Regression Results

Independent Variable	Description	Coefficient	t-statistic
(Constant)		10.778	11.242
DumQTR2	1 in QTR2, 0 elsewhere	0.051	3.406
LQTR3DDa	ln(CDD) in QTR3, 0 elsewhere	0.035	14.794
DumQTR4	1 in QTR4, 0 elsewhere	0.064	4.298
LLabor	ln(employment)	0.145	1.895
LCIPriceMALag3	ln(real price of electricity, lagged)	-0.054	-1.422

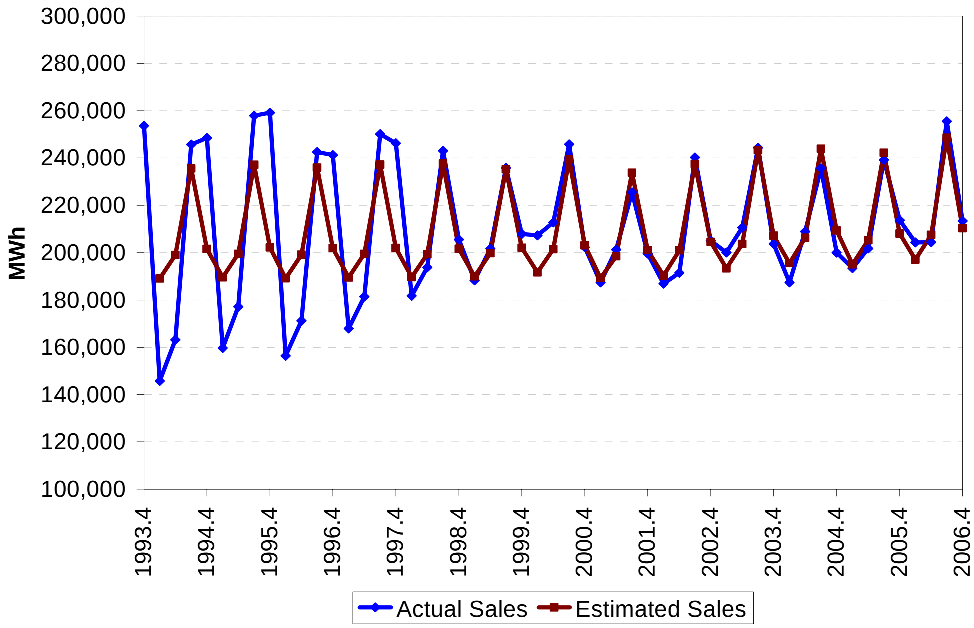
Source: Pace

Exhibit 16: Annual Commercial and Industrial Sales - Actual vs. Estimated



Source: Pace

Exhibit 17: Quarterly Commercial and Industrial Sales - Actual vs. Estimated



Source: Pace

FORECAST ASSUMPTIONS

Degree Days

For the forecast period, heating and cooling degree days are set equal to their 30-year average value. It has been accepted practice in utility forecasting to use a 30-year average for degree days under the assumption that this length of time is adequate to cover mini-cycles in climate patterns. It should be noted that the first 10-year block of that 30-year period was cooler, and that averages of HDD and CDD over the past 20 years and 10 years are warmer than the 30-year averages. While Pace is not recommending that shorter climate periods be adopted, our forecast models show that sales could be expected to increase only slightly relative to the base case if climate and weather conditions during the forecast period were at the 10-year average.

Exhibit 18: Normal Heating and Cooling Degree Days - 30 Year Average

Monthly Totals	HDD (60°)	CDD (70°)
January	141	0
February	119	1
March	77	3
April	46	11
May	18	23
June	4	55
July	0	131
August	0	197
September	0	189
October	1	113
November	26	31
December	96	3
Quarterly totals		
QTR1 – adjusted for billing cycles	337	4
QTR2 – adjusted for billing cycles	67	89
QTR3 – adjusted for billing cycles	0	517
QTR4 – adjusted for billing cycles	122	146

Source: Pace

Residential Customers

The forecast of the number of residential customers is estimated based on the historical relationship between customers and population, and near-term adjustments for known expansion of housing stock in Pasadena. Over the period 1987-2007, the rate of growth of residential customers exceeded the rate of growth of Pasadena's population, with the customer base growing slightly faster than 1% per year while the population grew at about 0.64% per year. This pattern is especially pronounced in the period 2000-2007 when customer growth was at about 2.35% per year, a full percentage point ahead of estimated population growth.

Pasadena's growth in the 1990s was significantly lower than the surrounding areas and the state, largely as a result of land restrictions on growth. Under Smart Growth plans developed and approved by the City in the 1990s, up to 5,095 permits for new housing are anticipated with most of that growth concentrated in "in-fill" projects in a handful of planning zones. From 2000-2007, it appears that about 3,000 new housing units have been completed or are under construction, leaving about 2,000 units to be completed. A large project on the Ambassador College site was slated to have 820 units but that project faced financial problems and has been stopped. This will delay the housing expansion but not eliminate it. Pace assumes for this forecast that the residential build-out will be complete by 2011 and that residential growth will then return to a slow growth period.

Exhibit 19: Projected Pasadena Residential Customer and Population Growth

Year	Customers	Population
1990	26,849	131,586
2000	27,620	133,936
2007	32,506	146,452
2011	35,060	153,609
2020	37,976	163,097
2030	40,055	169,740
Growth Rates		
1990-2000	0.28%	0.18%
2000-2007	2.35%	1.28%
2007-2011	1.91%	1.20%
2011-2020	0.89%	0.67%
2020-2030	0.53%	0.40%

Source: Pace

Air Conditioning Index

EIA's Residential Energy Consumption Surveys since 1993 have shown that penetration of air conditioning in the residential sector has risen steadily in the Western states during the past decade and a half, as shown in Exhibit 12. Pace used the California index as a proxy for Pasadena because the EIA does yet report 2005 penetration levels for southern California. The rates of growth of these indices are consistent with an underlying pattern where 100% of all new housing units have air conditioning and 1%-3% of pre-existing homes without air conditioning convert. Pace applied that pattern to the residential customer base throughout the forecast period, results in a steady increase in the air conditioning index to 0.64 by 2010 and 0.85 by 2030.

Exhibit 20: Projected Air Conditioning Index (Proportion of Homes with Air Conditioning)

Year	West	Pacific	California
1993	0.384	0.370	0.441
1997	0.409	0.380	0.414
2001	0.457	0.440	0.483
2005	0.574	0.560	0.595
2010			0.677
2015			0.735
2020			0.786
2030			0.872

Source: Pace

Employment and Floor Space

Employment

Long-term employment growth of 1.2% is adopted for this forecast. The CEC June 2005 energy demand forecast assumed 1.5% growth in nonfarm jobs in the LA Basin area, based on long term real personal income growth of 2.2% and population growth of 1%. In the 2007 forecast for the LADWD planning area, the CEC did not provide a projection of employment growth but did slightly increase its projections for income and population growth to 2.3% and 0.2%, respectively. The combination of these two, higher income and slower growth in the labor force, implies a slower level of employment growth.

Floor Space Additions

Employment growth rates in Pasadena have exceeded growth rates in the broader region since 2000, in part due to commercial floor space expansion allowed under the City's development plans. While Pace assumes that employment growth will track that of the surrounding region in the long run, there are several large commercial construction projects currently underway that will provide a boost to commercial electricity sales. Pace's sales forecast assumes that approximately 1.5 to 2.0 million square feet of new floor space will be added in the next three years, adding an additional 26 GWh of annual sales when the construction phase is over. This includes approximately 200 thousand square feet in three projects at the California Institute of Technology (Cal Tech), 600 thousand square feet in four separate projects at Huntington Memorial Hospital, and over 1 million square feet at a half dozen other announced office and commercial building projects. In addition, anticipated growth at Cal Tech is assumed to add another million square feet and 15 GWh in the middle years of the next decade.

Prices

Retail prices are comprised of energy, delivery, and customer service charges. In general, delivery and customer service prices are assessed based on the cost of service. PWP's tariffs for these two components of service are specified in terms of fixed monthly charges, charges per kWh, and/or charges per kW of maximum metered demand. PWP's tariffs for the energy component specify a set, or base, price power kWh but also include a mechanism for automatic adjustments to the energy charge based on fluctuations in the wholesale cost of fuel and purchased power. Pace's analysis of these tariffs indicates that roughly half of the base charges are for delivery and customer service and the rest for energy. The price projections used in this forecast assume that delivery and customer service charges will increase at an average annual rate of 1%, in real terms. Escalation of energy costs are based on Pace's 2008 second quarter assessment of the Southern California wholesale markets. In Pace's reference case, wholesale power prices in Southern California are projected to increase nearly 30% by 2010 over 2007 average levels, and to escalate at an average annual rate of 1.87% through the end of the forecast period. Residential retail prices are projected to increase at a rate of 1.55% over the long-term and C&I prices are projected to increase at 1.65% per year.

Exhibit 21: Real Price Growth (Average Annual Percentage Growth)

	Residential	Commercial and Industrial
2007-2010	4.08	4.28
2010-2030	1.55	1.65

Source: Pace

Street and Highway Lighting

Lighting sales generally are stable for long periods of time in electric utility territories. Monthly sales by PWP saw a large one-time increase 1,162 MWh to 1,498 MWh in August of 2002 and then backed off to about 1,370 MWh/month in October 2005. Sales have stayed at or about this level since then. These changes are likely the result of one-time changes in customer classifications or physical infrastructure. Given that the city has a geographic territory that is already built out and cannot expand (at least not without a merger of land and electric systems with neighboring municipalities), it is unlikely that there will be major changes in this sales category. Development of the Ambassador College site, when it resumes, will cause an upward bump in lighting demand, but introduction of more efficient lighting technology (including solar methods) will have a tendency to reduce ST&HL demand. For this forecast, Pace assumes that demand stays constant at current levels.

FORECAST RESULTS

Sales growth in Pasadena is projected to slow considerably from historic levels. Despite the relatively high growth that has been evident during the past few years, development limits imposed y the City's General Plan will be reached within a few years and the City's housing and building based will have little room to grow. In addition, increasing prices are expected to trigger a consumer response to reduce power consumption.

While annual sales growth is expected to slow considerably, peak load growth will grow at a faster rate because of the continuing pattern of faster load growth during the summer months, which is the season when PWP's demand reached it annual peaks. Peak load is based on an assumption of normal weather conditions. Given that the 2006 and 2007 summers were notably hotter than the normal level, the weather normalized peaks during the first years of the forecast period are lower than recently experienced. Forecasts are shown below in Exhibit **22**.

Exhibit 22: Summary Sales and Peak Forecast

	Sales (MWh)				Peak Load
	Residential	C&I	Lighting	Total	MW
1990	268,346	791,453	13,133	1,072,932	
1991	253,263	796,828	13,230	1,063,321	
1992	272,676	812,102	13,292	1,098,070	
1993	264,063	804,287	13,501	1,081,851	
1994	275,898	803,127	13,746	1,092,771	
1995	282,130	853,833	13,786	1,149,749	
1996	278,275	811,312	13,789	1,103,376	270
1997	287,663	845,715	13,816	1,147,194	284
1998	288,349	824,213	13,879	1,126,441	295
1999	280,183	833,775	13,912	1,127,870	285
2000	289,652	868,182	13,928	1,171,762	275
2001	273,045	813,737	13,938	1,100,720	245
2002	276,961	823,564	15,631	1,116,155	270
2003	303,348	858,735	19,274	1,181,357	281
2004	310,392	831,982	17,741	1,160,115	277
2005	309,502	848,236	17,887	1,175,625	292
2006	335,998	877,620	16,345	1,229,962	316
2007	332,375	871,773	16,269	1,220,417	313
2008	340,563	887,988	16,274	1,244,824	304
2009	339,418	881,266	16,240	1,236,923	304
2010	342,135	894,467	16,240	1,252,842	305
2011	350,312	898,085	16,240	1,264,637	309
2012	354,640	900,866	16,240	1,271,746	311
2013	357,248	901,736	16,240	1,275,224	313
2014	358,460	901,137	16,240	1,275,837	313
2015	359,369	900,181	16,240	1,275,791	314
2016	361,597	900,662	16,240	1,278,500	315
2017	364,126	901,483	16,240	1,281,849	316
2018	367,873	903,553	16,240	1,287,666	318
2019	370,590	904,597	16,240	1,291,427	320
2020	373,465	905,755	16,240	1,295,460	321
2021	376,018	907,749	16,240	1,300,008	323
2022	377,036	908,241	16,240	1,301,517	323
2023	379,567	910,224	16,240	1,306,031	325
2024	381,287	911,427	16,240	1,308,954	326
2025	382,816	912,456	16,240	1,311,512	327
2026	383,186	912,296	16,240	1,311,722	327
2027	384,183	912,823	16,240	1,313,246	328
2028	385,739	913,934	16,240	1,315,913	329
2029	387,037	914,772	16,240	1,318,049	330
2030	388,245	915,518	16,240	1,320,003	331
1990-2000	0.8%	0.9%	0.6%	0.9%	
2000-2007	2.0%	0.1%	2.2%	0.6%	1.9%
2007-2010	0.97%	0.86%	-0.06%	0.88%	-0.88%
2010-2030	0.63%	0.12%	0.00%	0.26%	0.41%
2007-2030	0.68%	0.21%	-0.01%	0.34%	0.24%

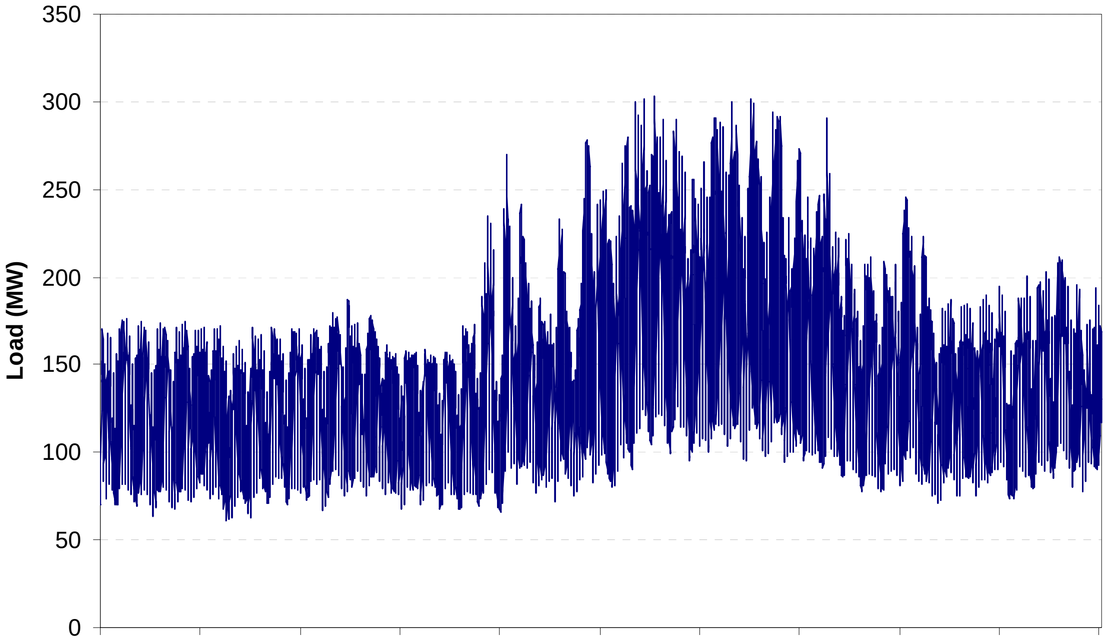
Source: Pace

HOURLY LOAD PROJECTIONS

Pace has recorded monthly average and peak demand for PWP from 1993-2006 to develop monthly load shapes. This process creates and applies a monthly shape factor to the annual forecasts in order to replicate representative seasonal load patterns. To arrive at more granular hourly load projections, Pace's methodology applies growth factors derived from the PWP peak demand and energy forecasts to the actual 8,760 hours of load occurring in a utility system. In this way, our market modeling system contains the highest level of detail to reflect not only the cost to serve certain levels of load but also how hourly changes impact the use of different types of generation units. Pace uses an Hourly Load Module, based on a historical year of actual reported hourly load within PWP (2003 for this simulation), to translate annual peak demand and energy growth factors into future hourly demand for a given Study Period.

The result of this process is an hourly demand shape that replicates actual market fluctuations and allows for representative dispatch patterns of the generating resources in the market. Exhibit 23 displays the hourly load profile for 2003, a relatively normal year for the entire WECC region. The PWP system is strongly summer peaking, with highest loads expected during the July-August time period.

Exhibit 23: Hourly Load Profile for PWP



Source: PWP and Pace

DEMAND SIDE MANAGEMENT

Municipal utilities in California are legislatively bound to evaluate demand-side management ("DSM") in their long-term resource planning prior to securing new generating supply. Assembly Bill ("AB") 2021 (Levine) was signed into law in 2006, which expanded upon the energy efficiency ("EE") policy established in Senate Bill 1037. These laws created a regulatory framework that makes utility DSM programs a priority and imposes specific compliance and reporting requirements. SB 1037 requires that publicly-owned utilities ("POU") acquire all cost effective, reliable, and feasible EE and demand response ("DR") measures prior to other resources and report their investment in EE and DR programs annually to both their customers and the CEC. The intent of AB 2021 is to enable the state to meet its goal of reducing total forecasted electrical consumption by ten percent in ten years. POUs must identify all achievable, cost-effective EE savings and establish annual targets on a ten year planning horizon every three years. The rule requires annual reporting on the investment in EE and DR programs as well as an independent evaluation that verifies the EE savings and demand reduction achieved. The law also requires POUs to "treat investments made to achieve energy efficiency and demand reduction targets as procurement investments."

In 1996, PWP adopted the City's Urban Environmental Accords ("UEA"). The goal of these policies is to provide leadership in the development of sustainable urban centers and promote a clean, healthy and safe environment for all. Specifically, the UEA targets a reduction of GHG emissions of 25 percent by 2030, a decrease in the city's peak electric load of 10 percent by 2012, and an increase in the use of renewable energy to meet 10 percent of the city's peak load by 2012. This initiative combined with California legislation creates a need for PWP to actively and aggressively pursue EE and DR measures.

ENERGY EFFICIENCY

EE measures are a key element in any utility-run DSM program. These programs induce customers to upgrade equipment or structures through a combination of marketing and direct subsidies.[1] Many EE measures are economic when compared to the cost of power generation coupled with avoided transmission costs since EE occurs at the point of sale. Once installed, EE measures provide passive reductions in demand which may vary by season, day type, and time of day for each measure considered in the resource plan. The range of EE program options varies between residential and commercial customers.

PWP has invested significant resources into investigating EE options and has consistently refined their DSM goals and programs. In order to properly meet their goals and their legislative mandates, PWP partnered with 33 other members of the California Municipal Utilities Association ("CMUA") to have the Rocky Mountain Institute ("RMI") evaluate EE potential as a basis for setting program goals. RMI developed an Excel-based model customized for each POU that also provided a framework that would satisfy CEC reporting requirements. The model was based upon the California Energy Efficiency Potential Study and California Commercial

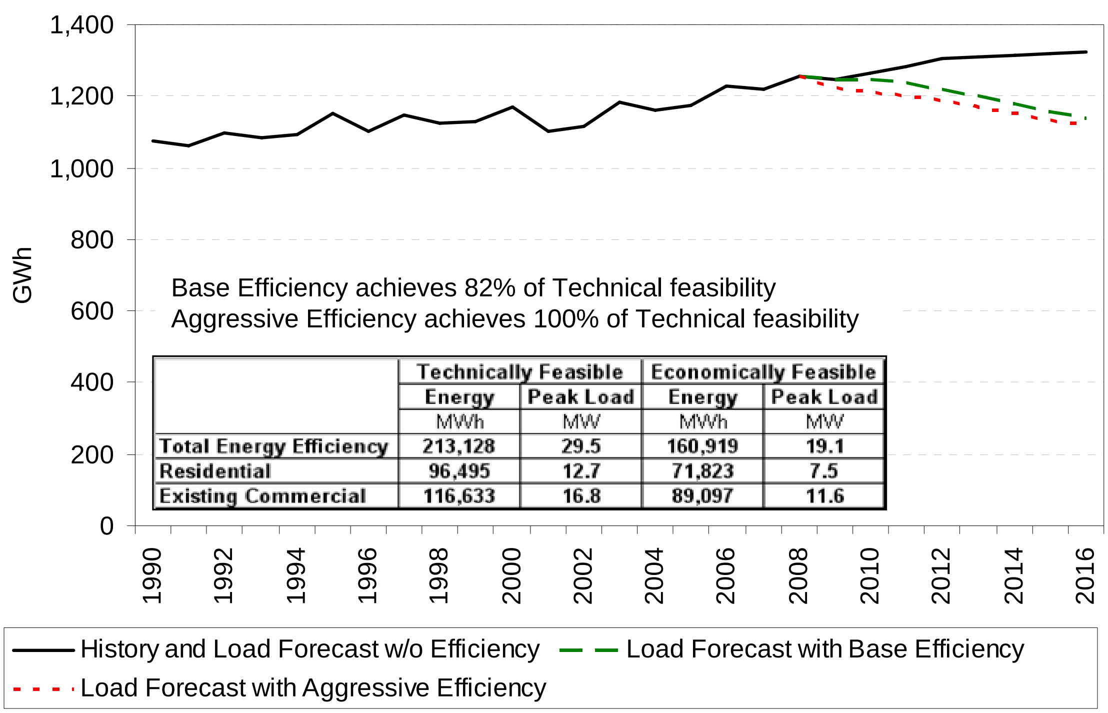
[1] The assumption is made that customers would not have made these investments in the absence of the DSM program, although utilities do adjust claimed reductions for customers who would have made the upgrades in any event, or "free riders"

End-Use Survey prepared by Itron in 2006 for California's three large IOU's. It also used the California Statewide Residential Appliance Saturation Study prepared in 2004 and the California Statewide Residential Sector Energy Efficiency Potential Study prepared in 2003 both by Kema-Xenergy. The cost test methodology used to calculate cost-effective efficiency potential is adapted from the form created by Energy and Environmental Economics, Inc. ("E3").

Pace used the RMI tool as the basis for evaluating EE measures. In Pace's Phase I analysis, the RMI model parameters were used in determining the measures selected and their associated costs. Pace developed adoption curves for the different efficiency programs to properly measure market saturation potential and diminishing rates of program participation at higher rates of participation. These curves allow for more realistic rates of market penetration, with higher rates of technology adoption in the near term that diminish as each program approaches market saturation.

Pace's analysis in both Phase I and Phase II incorporated all economical energy efficiency programs for every portfolio. Certain portfolios that targeted aggressive efficiency goals included an additional increment of efficiency expansion, which was representative of all technically feasible efficiency in the RMI calculator. Exhibit 24 displays PWP historical load, Pace's Reference Case energy demand forecast, and the impacts of energy efficiency expansion on projected demand levels. The base efficiency was the minimum efficiency deployment assumed in all portfolio analysis.

Exhibit 24: Impact of Efficiency Programs on PWP Energy Demand Projections



	Technically Feasible		Economically Feasible	
	Energy	Peak Load	Energy	Peak Load
	MWh	MW	MWh	MW
Total Energy Efficiency	213,128	29.5	160,919	19.1
Residential	96,495	12.7	71,823	7.5
Existing Commercial	116,633	16.8	89,097	11.6

Source: Pace

DEMAND RESPONSE

Demand response ("DR") options are deployed by utilities to induce customers to reduce peak load requirements or shift load to off-peak periods to avoid expensive peaking capacity investments and spot market exposures. DR programs are often linked to time of use ("TOU") price signals to incent customers to curtail consumption. In the absence of TOU signals, programs incent customers to participate through fixed monthly or capacity-based payments, where reductions are required when called for and either subject to verification or controlled directly by the utility as in direct load control programs. Some DR programs focus on educating the customer and recommend or subsidize measures to reduce peak demand or improve efficiency.

The added customer participation and potential penalties for non-compliance required by non-passive DR measures may lead to lower rates of customer participation and limit participation mainly to larger customers. Many DR measures will require the installation of devices to directly control load or provide the necessary metering accuracy to ensure proper billing and verification requiring an initial capital investment by the utility. TOU signals need to be substantial enough to induce the desired behavior which may also limit program effectiveness or penetration rates.

As mentioned previously, California has pushed for increased DR programs in addition to EE programs in pursuit of promoting long-term energy savings and maximizing grid reliability. The legislation governing DR programs requires reporting similar to EE measures and verification that DR measures undertaken are economically viable. DR programs are provided funding in three-year cycles, and in order to secure funding, utilities must prove that they are economically viable and cost effective.

Due to PWP's relatively smaller amount of commercial and industrial users, certain programs that are applied in other areas of California are not applicable to PWP. The following section describes a subset of these programs that are currently being used in California by SDG&E, PG&E, or SCE that can be adapted to PWP's customer base. Pace researched the public filings available for each of these DR programs in California. The data was compiled and analyzed to provide a rough estimate of the costs associated with each of the selected programs. The capacity and number of customers enrolled was evaluated against program cost data to determine the program cost on a dollar per kW installed basis. This cost was used in both the Phase I and Phase II analysis. The trigger for DR measures based on the market heat rate was assumed to be 15,000 Btu/kWh.

Programs

Capacity Bidding Program ("CBP")

CBP pays customers with a monthly capacity payment for their previously-specified load reduction and additional payments based on kWh reduction for events. Programs can vary in notice and hours of participation. Typical options are day-ahead or day-of with four hour blocks available. These programs are generally triggered with a market heat rate signal. For instance, when the forecast heat rate is 15,000 Btu/kWh on a day-of or day-ahead basis, the program may be put into force. Typical programs run Monday through Friday, 12 p.m. to 8 p.m., and customer performance is often insured by penalties for noncompliance.

Critical Peak Pricing (“CPP”)

This program uses price signals in the market place to change behavior. It requires 15 minute usage interval data to allow for accurate billing. Under CPP, the utility will inform the customer of peak times in order to provide them with the opportunity to reduce their demand during critical hours. Generally, customers will face very high rates during super-peak times, with discounted rates during off-peak periods. For those customers who are concerned with the volatility that market pricing may bring, programs have offered a Capacity Reserve Charge (“CRC”) in which customers may hedge against the peak rate, but will still pay a higher price for peak energy use.

Air Conditioner Cycling Program (“ACCP”)

This type of program allows the utility to turn-off or cycle-off customers’ air conditioner compressors during peak demand times and system emergencies. In return, the customers typically receive a predetermined monthly credit on their bill. Customers may or may not be limited in the number of times their air conditioner can be cycled, although this is program is naturally limited to the summer season.

Technical Assistance / Technology Incentives (“TA/TI”)

These programs are seen as necessary in order to continue to expand customer participation and awareness in demand response. TA informs customers of potential load reduction that could be achieved, provides strategies and technologies to achieve that reduction, and advises customers on energy efficiency and demand response programs available to them. TI programs provide financial incentives for customers to adopt and install demand response enabling technologies.

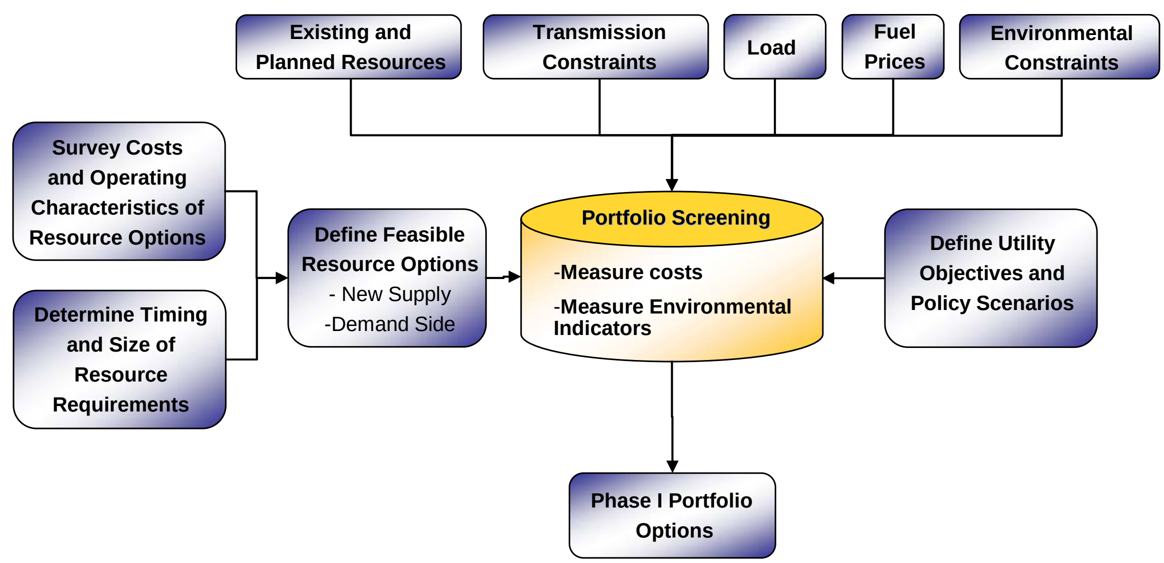
PHASE I ANALYSIS OF IRP STRATEGIES AND TRADEOFFS

SCREENING PROCESS AND INPUTS

The screening process employed the use of a proprietary Excel-based screening tool in modeling PWP's portfolio in the context of a set of assumptions regarding market price inputs and resource options. The screening process is outlined in Exhibit 25. The screening tool contains hourly-level detail on existing and planned resources in PWP's portfolio, while representing market sales and purchases with Pace's published long-term power price forecast for the California South region.

Key inputs for resource characteristics, transmission constraints, load, fuel prices, and environmental costs are outlined in other appendices. In addition to the plant capacities and online dates detailed above, the screening modeling explicitly accounts for a number of other operational parameters, including: plant heat rates, forced outage rates, maintenance schedules, fixed and variable operating and maintenance costs, emission rates, annual contract costs and escalation rates, and hourly generation profiles for intermittent resources. As detailed earlier, all efficiency program characteristics are modeled in accordance with the E3 tool, adjusted for Pace's adoption curves.

Exhibit 25: Process Diagram for Pace Screening Analysis



Source: Pace

RESOURCE COST AND OPERATING CHARACTERSITIC ASSESSMENT

For all new resource options, Pace performed an assessment of the capital costs and operating characteristics of a broad range of technology choices. Pace's internal engineering review was supplemented by public data from the recent Navigant/California Energy Commission study and the E3 calculator.

Capital Cost Drivers

After a period of recession in the US around the year 2000, worldwide prices for basic commodities such as aluminum, copper, lead, nickel and steel began a rapid rise around 2004. Prices for most commodities rose through much of 2008, but have since fallen over the last few months.

Furthermore, the power equipment industry and Engineering, Procurement, and Construction ("EPC") contractors seem to have learned some lessons from past boom and bust cycles and are now more inclined to improve margins than to rapidly increase capacity. Equipment manufacturing has consolidated over the past 10 years, with the international leaders being GE, Siemens, and Alstom. Other manufacturers in Japan and Italy also serve worldwide demand. China and India are producing many parts for international manufacturers, but much of their domestic manufacturing of complete boilers and turbine generators is going into domestic projects. Russia is restructuring its power industry and planning major capacity additions after a decade of little growth. This strategy will absorb its domestic manufacturing capability and lead to some international purchasing, as well.

The US energy industry is also experiencing labor shortages that are driving up labor costs. We have seen estimates of expected labor cost escalation as high as 6 percent per year, which would have a significant impact on labor-intensive power plant construction. Although labor costs are not expected to decrease in real terms, Pace believes that the labor market will react and adjust to these increased wages of skilled engineers and construction personnel over the long-term.

As a result of commodity price increases and labor shortages, installed costs for power plants in the US and worldwide have increased significantly in the last several years. The drivers for these cost increases are demand for equipment; commodities and labor resulting from consistent, strong growth in China, India and the developed countries; and a recent rise in oil and gas prices that has prompted a high level of investment in hydrocarbon exploration, production and processing. The discussions below describe the experienced changes in the main drivers of capital cost escalation in the last few years.

Scope, Scale, and Escalation

To fully understand costs for any project or a group of projects requires attention to basic details about scale, scope, and schedule assumptions.

- **Scale factor** – Power plants typically have lower unit costs with increasing unit size. Scale factors applied to the ratio of unit sizes for capital cost estimation range from an exponent of 0.7-0.8. Thus, an 800 MW unit may have a cost/kW 15-25 percent lower than a 400 MW unit assuming all other conditions are the same.

- **Fuels** – For coal plants, particularly, the expected quality of the fuel can greatly influence the necessary technology investments for the plant. Coals vary widely in characteristics such as heating value and ash and moisture content, which affect boiler size, coal and ash handling systems and ash disposal requirements. Pace expects coal-fired plants that burn PRB coal to cost from 7 to 12 percent more than plants burning bituminous coal, due to the technology differences necessary to deal with the high moisture content of PRB coal. Fuel delivery by rail, barge or both affects scope and cost.

- **Scope** – Power plants vary widely in technology, emission controls and site-specific requirements. Differences include boiler types (PC vs. CFB), cycle/efficiency (supercritical vs. subcritical), emission controls (FGD, SCR, mercury and particulate removal, etc.) and site preparation and offsite costs (water lines, rail spurs, transmission lines and substations, etc.)

- **Siting** – Developing a project on a new (greenfield) site typically is more expensive than using a brownfield site where some usable infrastructure is already there for existing units. Savings for the latter may be up to 15 percent. Also, site location affects whether the project can be built with union or non-union labor and determines local wage and benefit rates and craft productivity.

- **Multiple units** – Typically a duplicate unit may save 10-15 percent in cost compared to the first unit constructed on the same site.

- **Owner's costs** – Besides the cost of the EPC contractor(s), Owner's costs include project development, early engineering, land acquisition, project management, Operation & Maintenance mobilization and training and startup fuel. Financial costs may include Allowance for Funds Used During Construction ("AFUDC") for regulated Owners or Interest During Construction ("IDC") for IPPs, plus additional costs such as working capital and financing fees and costs. Owner's costs may equal 20-40 percent of EPC costs and typically are on the higher side for projects structured as single purpose entities with non-recourse financing.

- **Execution approach** – For the wave of about 200,000 MW of gas fired combined cycle plants built in the 1990s the predominant contracting method was a fixed price EPC Turnkey contract with schedule and performance guarantees. Because coal plants have higher costs, longer schedules and higher construction man-hours, only a few contractors are able to perform projects on a Turnkey basis and have a balance sheet capable of standing behind the financial guarantees. Thus, many projects instead will utilize alternate contracting methods such as an engineering contractor developing construction packages in which the Owner will be exposed to the cost and schedule risks that in a turnkey contract would have been allocated to the EPC contractor. This approach affects the cost certainty at the time of project approval and the final cost results. Limited competition among EPC contractors combined with greater risk aversion have led to increased contractor margins and risk premiums.

- **Schedule** – Most projects will try to adopt a reasonably optimum schedule for EPC. Accordingly, accelerating schedules to meet an early need date tends to increase execution costs, whereas delaying the project unnecessarily will increase AFUDC/IDC and contractor and Owner management and other fixed costs. Establishing the project start and completion dates affects the amount of escalation estimated and incurred.

Capital Cost Assumptions

In evaluating potential generation technologies for meeting future demand requirements, Pace assessed several generation technologies' maturity levels, operating histories, and operating regimes. Based on Pace's review of available generation technologies, reviews of other public sources for capital cost estimates, and consultation with equipment manufacturers, estimates for new technology costs were developed. The characteristics of these technologies are detailed in Exhibit 26. Pace's estimates have explicitly accounted for recent trends in commodity price inputs, and Pace has adjusted all cost assumptions to approximate best estimates for the present time, given recent contract bids or other market signals observed by Pace and PWP.

Furthermore, in an environment of cost volatility, establishing accurate estimates is challenging. Single-point cost estimates do not reflect the variance in costs that may be observed over the course of a long planning horizon. As a consequence Pace has preformed additional analysis around the uncertainty of capital costs. These uncertainty measures have been applied to each portfolio in Phase II to provide further insight into the effects capital cost volatility. This analysis is addressed in more detail in the section on the Phase II analysis.

Exhibit 26: New Resource Technology Parameters (2008$)

Unit	Total Capital	FOM	VOM
	$/kW	*$/kW-yr*	*$/MWh*
Combined Cycle Turbine	1,324	10.15	3.05
Simple Cycle Turbine	1,249	14.30	2.20
IGCC	3,921	41.95	4.12
IGCC with CCS	6,985	41.95	4.12
Nuclear	4,612	55.00	1.20
Biomass - AD	10,400	51.81	15.77
Biomass - Combustion	5,090	51.81	15.77
Landfill Gas	4,042	13.80	6.99
Geothermal	5,373	78.00	5.00
Hydro - In Conduit	2,716	13.47	3.11
CSP - Trough	5,400	--	30.00
CSP - Tower	8,370	--	30.00
Wind	2,903	40.00	--
CHP < 5 MW	1,753	10.15	3.05
CHP > 5 MW	1,203	10.15	3.05
Coal	3,189	29.67	3.98
Solar-PV	7,425	18.00	5.00

Source: Pace, CEC

Resource Availability Assumptions

New resource additions were assumed to be available in accordance with historical maintenance, forced outage, and availability data. Combined cycle units were assumed to have 91% availability as dispatchable units in the market, landfill gas technologies were assumed to have 87% availability, and geothermal units were assumed to be available 96% of the time. Intermittent resources were modeled in accordance with hourly capacity factor shapes, consistent with local availability profiles. Wind units were assumed to have a capacity factor of 34%, solar thermal units were assumed to have a capacity factor of 27%, and solar PV units a capacity factor of 22%.

Supply Option Financing Assumptions

In assessing the costs of such resources in the context of PWP's wider portfolio, several financing assumptions have been made. Pace's financial analysis uses the capital and fixed operating cost estimates to arrive at a set of levelized cost payments to be allocated across multiple years. The following assumptions have been used:

- Merchant development and contract procurement assumed
- Tax incentives available for certain renewable technologies
- 50:50 Debt/Equity Ratio
- 15% Required Return on Equity, 8.25% Interest Rate on Debt

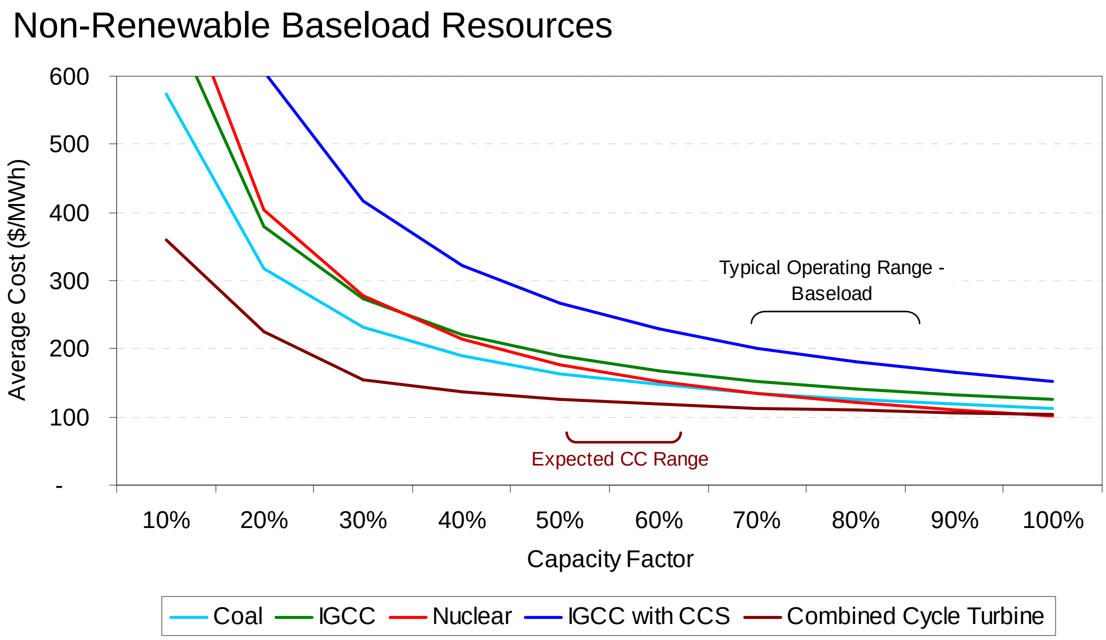
RESOURCE SCREENING

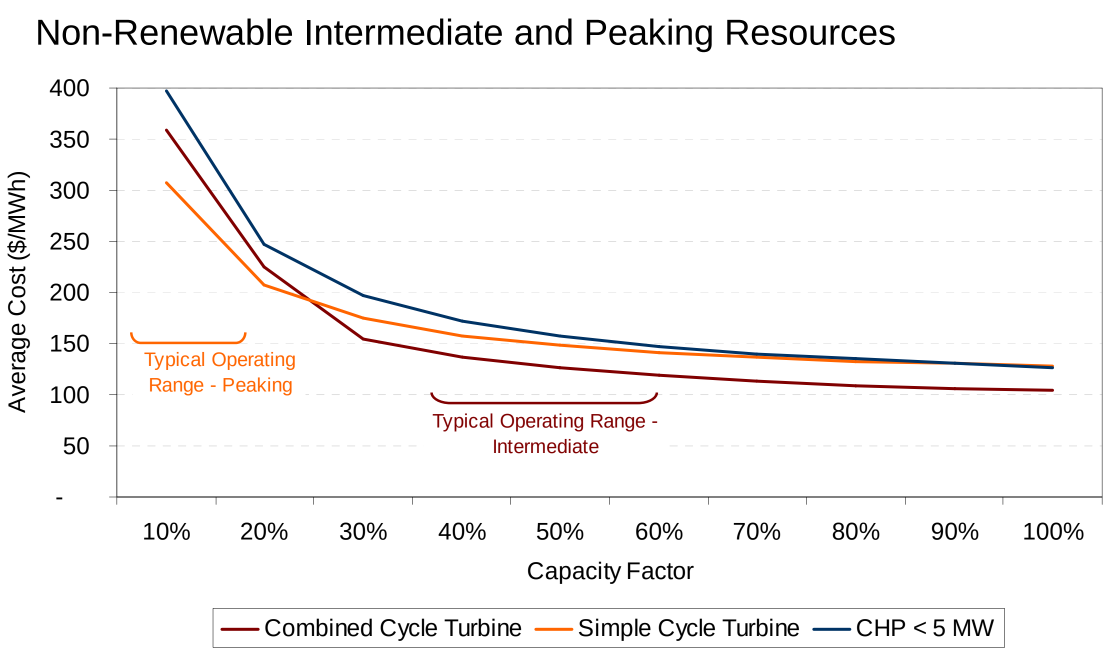
Pace's resource screening analysis employed a two-step approach. First, resource screening curves were developed to analyze the costs of a wide set of resource options across a range of potential capacity factors, using reference case financing assumptions and average fuel and variable costs, where appropriate. This screening was intended to pare down the list of potential options for more detailed assessment. Next, a smaller set of technology options was analyzed in greater detail in Pace's screening tool, in order to rank technologies according to cost and emission reduction metrics. This analysis introduced a hypothetical 5 MW addition to the existing portfolio, in order to measure performance in the context of the detailed operational characteristics of PWP's portfolio.

Screening Curves

The screening curve analysis was performed by converting all capital, fixed, variable, fuel, and emission costs into levelized average $/MWh values for each technology across a range of capacity factors. The process was used to screen out the most costly options in several categories, including IGCC, hydro, and biomass options. Exhibit 27 displays screening curve summaries for non-renewable technologies, while Exhibit 28 summarizes the screening curves for the renewable options.

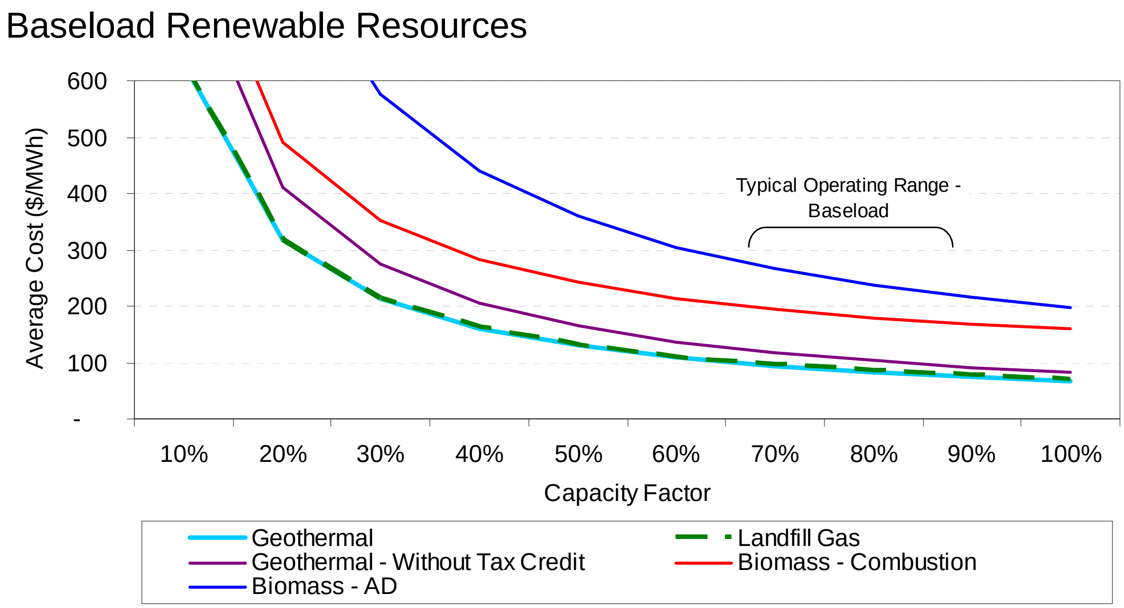
Exhibit 27: Non-Renewable Technology Screening Curves

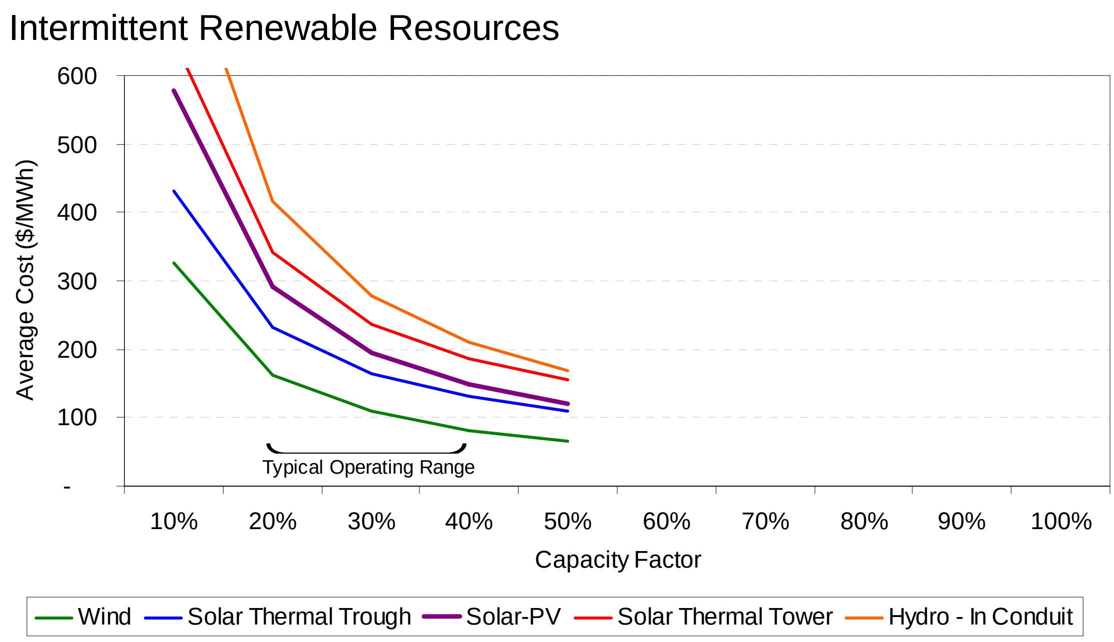




Source: Pace

Exhibit 28: Renewable Technology Screening Curves





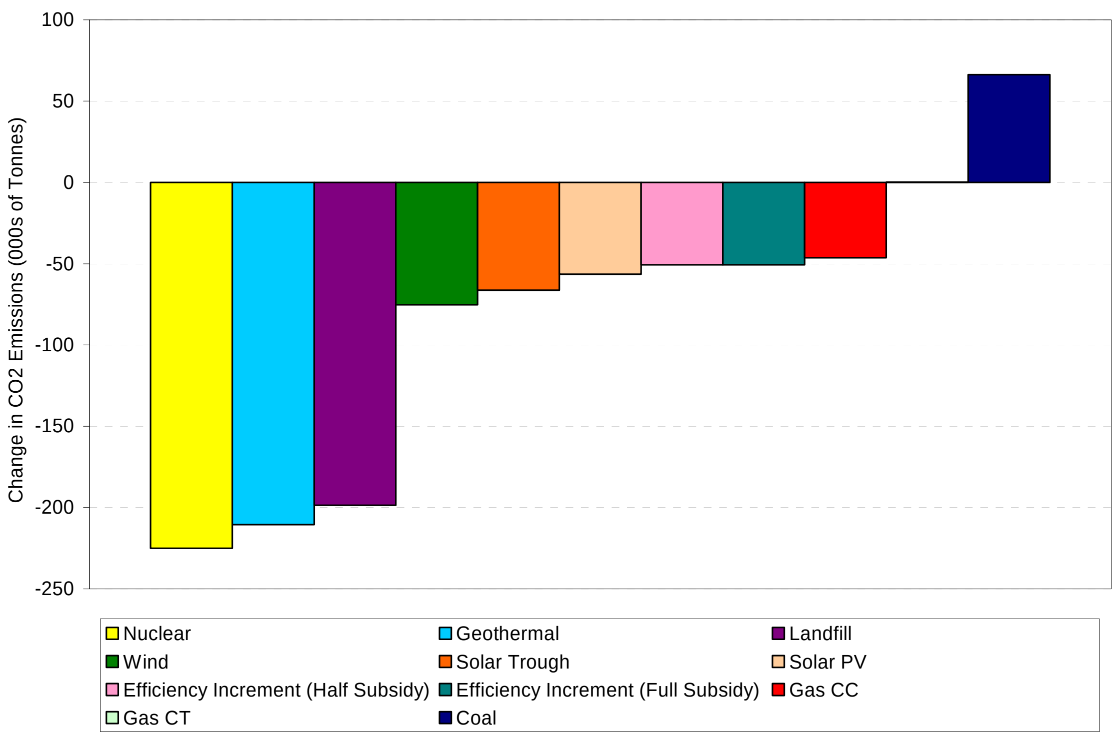
Source: Pace

Resource Screening in PWP Portfolio Context

Pace's portfolio screening analysis was performed by assessing the impact of a hypothetical addition of 5 MW of several resource technology types into PWP's existing portfolio mix. In this assessment, Pace's screening tool was used in order to capture expected dispatch of the options at an hourly level of detail. Key metrics like CO_2 emissions and portfolio costs were recorded and summarized in order to guide eventual portfolio development. Exhibit 29 summarizes the relative CO_2 emission reduction impacts of a variety of resource options, while Exhibit 30 summarizes the relative impact on portfolio costs.

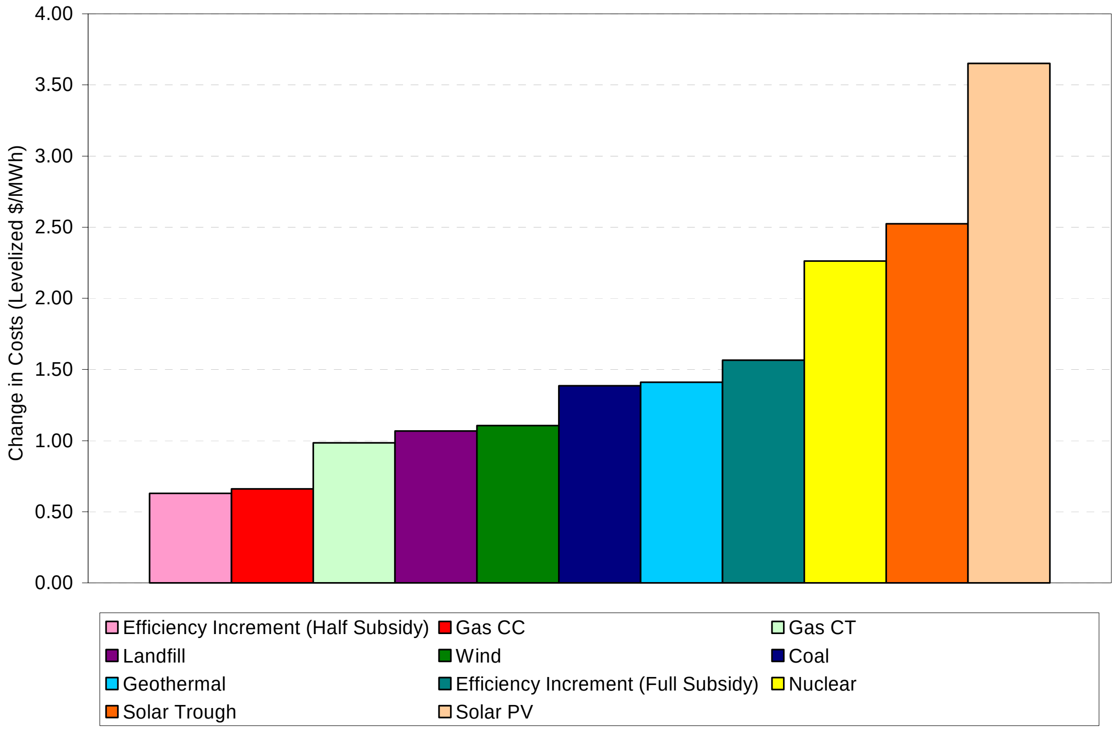
Geothermal and landfill gas capacity additions were determined to be the most effective resource additions for reducing carbon emissions at lowest cost. Incremental efficiency program expansion was also deemed a cost-effective resource option to pursue further. Additional renewable resources like wind and solar technologies were deemed plausible for further study, but at a higher cost and lower environmental benefit than the more preferred renewable options. Although nuclear proved best on CO2 emission reductions, it was deemed an infeasible technology option for PWP on the grounds of capital requirements and general availability. Coal-fired and gas-fired combustion turbines were determined to be ineffective at reducing carbon emissions, and it was concluded that gas-fired combined cycle technology was the preferred local fossil resource.

Exhibit 29: Relative CO2 Emission Reductions for Resource Additions



Source: Pace

Exhibit 30: Relative Impact on Portfolio Costs for Resource Additions



Source: Pace

PORTFOLIO SCREENING

Using the results from the resource screening process, Pace developed several portfolio options around a set of concepts and objectives. The environmental goals and strategies used to guide portfolio development were categorized generally as follows:

- Minimum: 20% carbon reduction by 2020 and 20% RPS by 2017
- Low: 30% carbon reduction by 2020 and 33% RPS by 2020
- Medium: 60% carbon reduction by 2020 and 50% RPS by 2020
- High: 80% carbon reduction by 2020 and 80-90% RPS by 2020

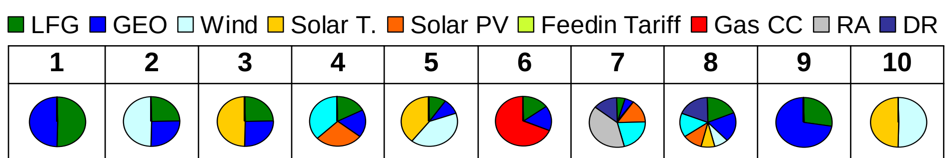
The plan concepts that focused resource choice and portfolio construction were categorized generally as follows:

- Existing portfolio with minimal remote renewable additions
- Local fossil generation options
- Coal displacement options
- Aggressive efficiency and technology

Portfolios were constructed around these objectives and concepts, using the preferred technologies and by tracking key annual metrics like reserve margins, CO_2 emissions, RPS percentage and total NPV costs. Based on public comments and stakeholder input, several diverse portfolios were created, incorporating a variety of renewable technologies and efficiency targets. Pace structured its analysis according to the emission reduction goals, eliminating portfolio combinations that did not meet identified constraints around emissions or reliability metrics as well as those that were highest cost. The iterative screening process resulted in the creation of ten distinct portfolios, around three carbon reduction targets. These portfolios are summarized in Exhibit 31. Each portfolio includes 14 MW of local solar PV as part of PWP's Solar Initiative program, as well as all economical energy efficiency programs as part of the demand reduction goals. The resource screening process also resulted in the creation of a feed-in tariff concept, whereby PWP would offer $150/MWh for all local renewable resources that were willing to supply at that price. This concept was employed in three portfolios. The annual timing of all unique portfolio additions (not including the solar PV and efficiency components common to all) is displayed in Exhibit 32, Exhibit 33, and Exhibit 34.

Exhibit 31: Phase I Portfolio Details

		Remote Renewables				Local Renewables/DSM					Fossil-fueled	
Carbon Reduction Target	Portfolio #	Landfill	Geo thermal	Wind	Solar Thermal	Solar PV (Existing)	Solar PV (Expand)	Feed-In Tariff	Energy Efficiency	DR & RA	Local Gas	Coal
Low	1: LFG/Geo	15	15			14			26			
	2: Wind	10	10	20		14			26			
	3: Solar	10	10		20	14			26			
	4: Local	10	10			14	15	21	34			
Med	5: Remote Renew	15	15	60	60	14			26			-47
	6: CC	15	15			14			26		65	-108
	7: Local	5	5			14	15	21	34	55		-108
High	8: Diverse	25	25	10	10	14	15	21	34	25		-108
	9: LFG/Geo	25	65			14			26			-108
	10: Wind/Solar			125	125	14			26			-108



	1	2	3	4	5	6	7	8	9	10
Total MW Added	30	40	40	56	150	95	101	131	90	250
IPP Replacement					47	108	108	108	108	108

Source: Pace

PACE

Exhibit 32: Annual Additions for Low Portfolios

	Low LFG/Geo		Low Wind			Low Solar			Low Local			
Year	LFG	Geo	LFG	Geo	Wind	LFG	Geo	Solar	LFG	Geo	Solar PV	Feedin Tariff
2008												
2009												
2010												1.5
2011												1.5
2012	5	5	5	5	5	5	5	5	5	5		1.5
2013												1.5
2014											2.15	1.5
2015											2.15	1.5
2016	5	5			5			5			2.15	1.5
2017	5	5	5	5	10	5	5	10	5	5	2.15	1.5
2018											2.15	1.5
2019											2.15	1.5
2020											2.15	1.5
2021												1.5
2022												1.5
2023												1.5
2024												
2025												
2026												
2027												
2028												
Total	15	15	10	10	20	10	10	20	10	10	15	21

Source: Pace

Exhibit 33: Annual Additions for Medium Portfolios

	Med Remote Renew				Med CC			Med Local					
Year	LFG	Geo	Wind	Solar	LFG	Geo	CC	LFG	Geo	RA	DR	Solar PV	Feedin Tariff
2008													
2009													
2010													1.5
2011													1.5
2012	5	5	20	20	5	5		5	5		15		1.5
2013													1.5
2014													1.5
2015													1.5
2016	5	5	20	20	5	5	65			40			1.5
2017	5	5			5	5							1.5
2018												2.15	1.5
2019												2.15	1.5
2020			20	20								2.15	1.5
2021												2.15	1.5
2022												2.15	1.5
2023												2.15	1.5
2024												2.15	
2025													
2026													
2027													
2028													
Total	15	15	60	60	15	15	65	5	5	40	15	15	21

Source: Pace

Exhibit 34: Annual Additions for High Portfolios

	High Diverse							High LFG/Geo		High Wind/Solar	
Year	LFG	Geo	Wind	Solar Trough	DR	Solar PV	Feedin Tariff	LFG	Geo	Wind	Solar Trough
2008											
2009											
2010							1.5				
2011							1.5				
2012	10	10	5	5	15		1.5	15	15	60	60
2013							1.5				
2014							1.5				
2015							1.5				
2016	15	15	5	5	10		1.5	10	50	65	65
2017							1.5				
2018						2.15	1.5				
2019						2.15	1.5				
2020						2.15	1.5				
2021						2.15	1.5				
2022						2.15	1.5				
2023						2.15	1.5				
2024						2.15					
2025											
2026											
2027											
2028											
Total	25	25	10	10	25	15	21	25	65	125	125

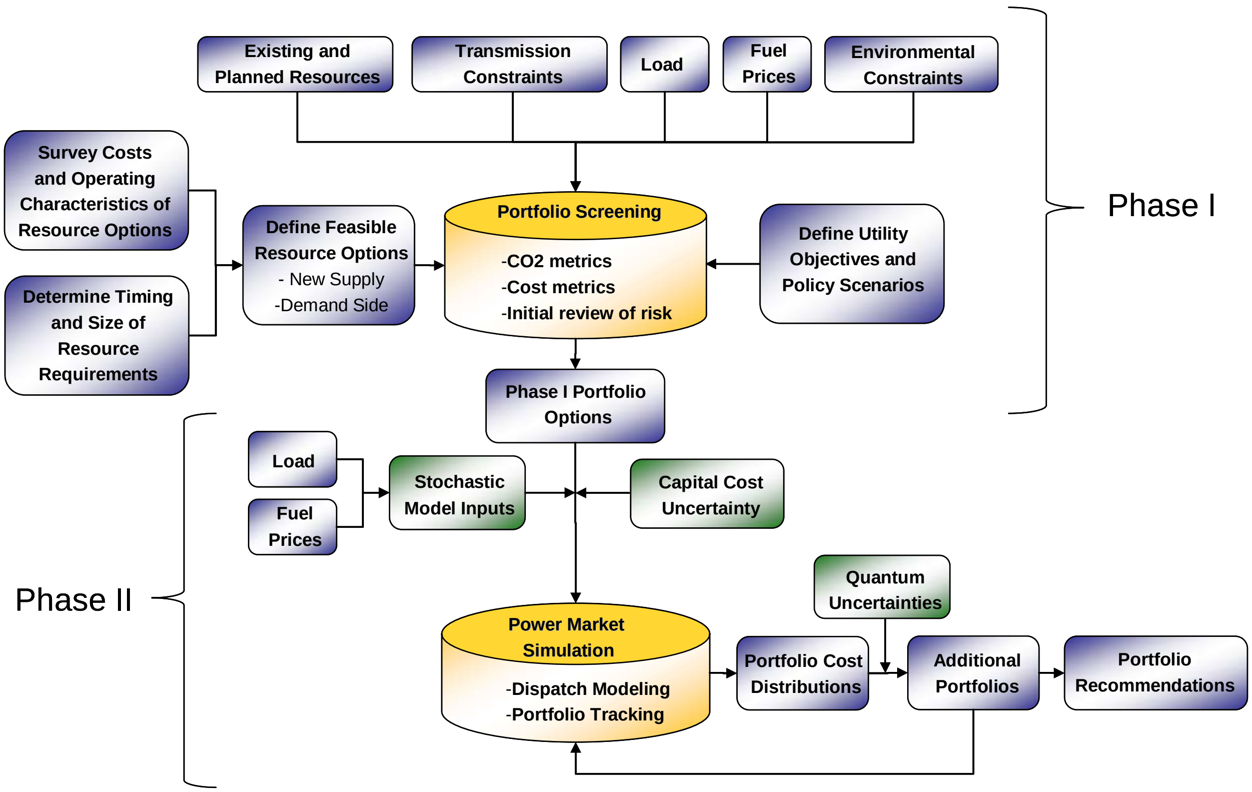
Source: Pace

PHASE II RISK ANALYSIS

RISK INTEGRATED RESOURCE PLANNING APPROACH

The Risk Integrated Resource Planning ("RIRP") approach analyzes key areas of uncertainty for the portfolios that were developed in the Phase I screening analysis. The process was designed to assess the impact of a wide range of risk factors through statistical and scenario-based analyses. Both phases of the approach are outlined in Exhibit 35. As is shown, the portfolios developed in Phase I are evaluated through a rigorous power market simulation that captures the uncertainty associated with several key market drivers, as well as the effects of discrete events that may result in significant or quantum changes for portfolio performance. The Phase II analysis employs an hourly dispatch modeling system, with full representation of PWP's portfolio and the wider market area. The risk analysis can be categorized into two major areas: stochastic uncertainty analysis and scenario analysis. These analyses and their related techniques are described below.

Exhibit 35: Risk Integrated Resource Planning Process



Source: Pace

STOCHASTIC UNCERTAINTY ANALYSES

Stochastic simulations are generally deemed appropriate for variables that have a wide and continuous range of potential outcomes that can be quantified based on historical relationships and volatilities. Pace has performed such analyses around load, fuel prices, and capital costs. Pace's analysis of load and natural gas prices involved the development of 500 propagated paths for each input, created from Pace's fundamental forecasts and statistical quantification of the underlying drivers. These paths were each independently analyzed in the context of Pace's power market simulation, resulting in 500 power market price outcomes, as well as 500 portfolio cost outcomes for each of the identified PWP portfolio options. Capital cost uncertainty was analyzed in a similar manner, and the resulting cost distributions were added to the distributions developed in the market simulation to arrive at a total cost assessment.

Load Uncertainty

As part of its Phase II uncertainty analysis, Pace developed average and peak demand distributions based on the influence of economic drivers, weather, and other short-term drivers. Uncertainty around both long-term and short-term factors was analyzed for modeling regional demand projections. For PWP load, Pace's analysis focused on short-term variability in order to investigate the impacts of weather-driven uncertainty on portfolio cost and performance. The core of Pace's statistical approach is described below and illustrated in Exhibit 36.

- Step 1: Develop a temperature-load relationship based on twenty years of historical daily load, daily temperature, and daily humidity data in Southern California and other relevant regions.

$$LOAD = \beta_0 + \beta_1 \times \mathrm{T} + \beta_2 \times \mathrm{T}^2 + \varepsilon$$

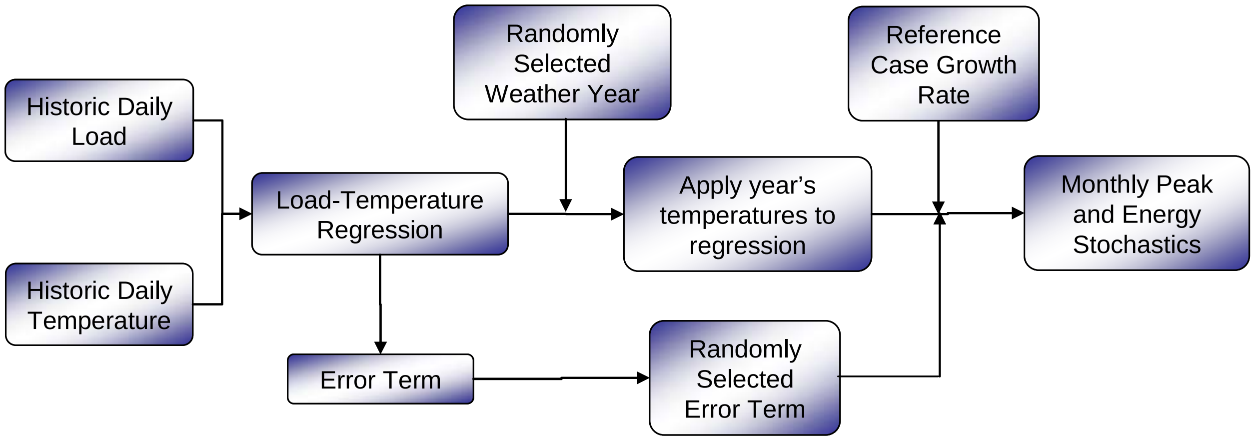
- Step 2: For each year in the Study Period, randomly select a historic weather year and apply the daily temperatures from that weather year to the load-temperature relationship plus the reference case load growth factor.

- Step 3: Add/subtract a random component to the daily load, based on the distribution of the error term from Step 1.

This approach:

- Captures the relationship between load and temperature, the primary driver of uncertainty in demand in a given year, and
- Reflects observed weather patterns across a range of hot, mild and normal years.

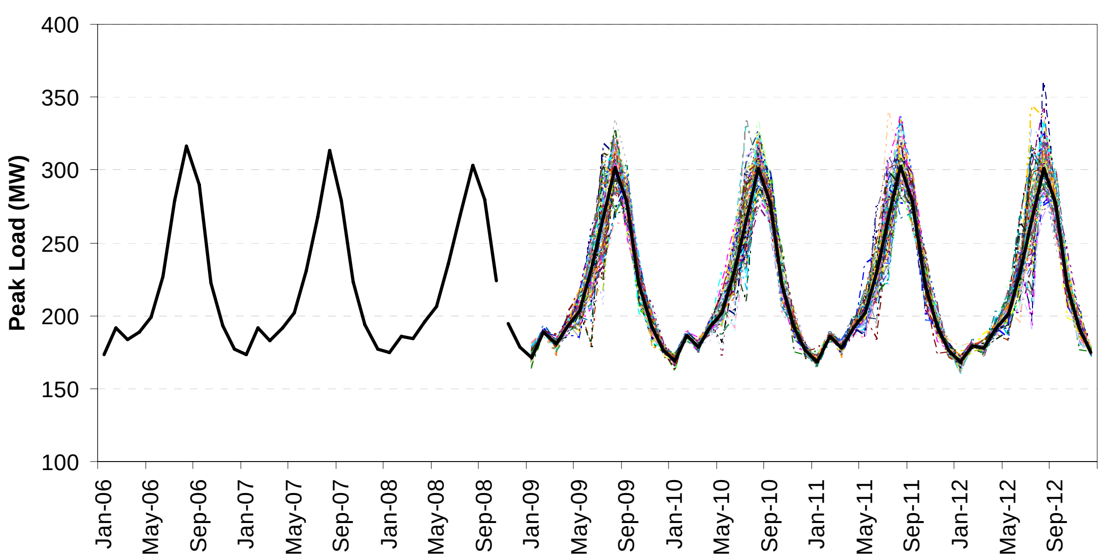
Exhibit 36: Load Stochastics Methodology



Source: Pace

Exhibit 37 illustrates a selection of the propagated load paths for PWP that were derived from Pace's statistical analysis. Each line in the graphic represents an independent load projection that was used in the Phase II analysis. Note that the impact of energy efficiency program expansion is included in these projections.

Exhibit 37: Uncertainty around Monthly PWP Peak Load Levels



Source: Pace

Natural Gas Price Uncertainty

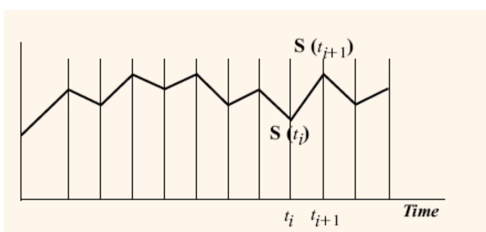
Volatility in the price of natural gas over the past twelve months illustrates the importance of capturing the tremendous uncertainty in this important market driver. Rather than perform its analysis with one or a few natural gas price projections, Pace models a statistically meaningful range of potential price outcomes. To project price paths for fuel prices such as natural gas, Pace uses a mean-reverting process, outlined by the stochastic equation in Exhibit 38. Key elements of this process include:

- Volatility and mean reversion rates based on daily historical price data;
- A mean reversion rate decay factor based on empirical data and market knowledge and judgment;
- A long run equilibrium price level equal to the reference case price forecast;
- Monte Carlo simulations of daily price, with monthly spot prices being the average of all daily prices for each simulation.

Exhibit 38: Fuel Price Stochastic Simulation Methodology

Price Evolution From t_i to t_{i+1}

$$\underbrace{S(t_{i+1})}_{\text{Price at } t_{i+1}} = \underbrace{S(t_i)}_{\text{Price at } t_i} \exp \underbrace{a[\theta_t - \log S_t]\,(t_{i+1} - t_i)}_{\text{Drift Component}} + \underbrace{\sigma\, \varepsilon_{i+1} \sqrt{(t_{i+1} - t_i)}}_{\text{Random Component}}$$

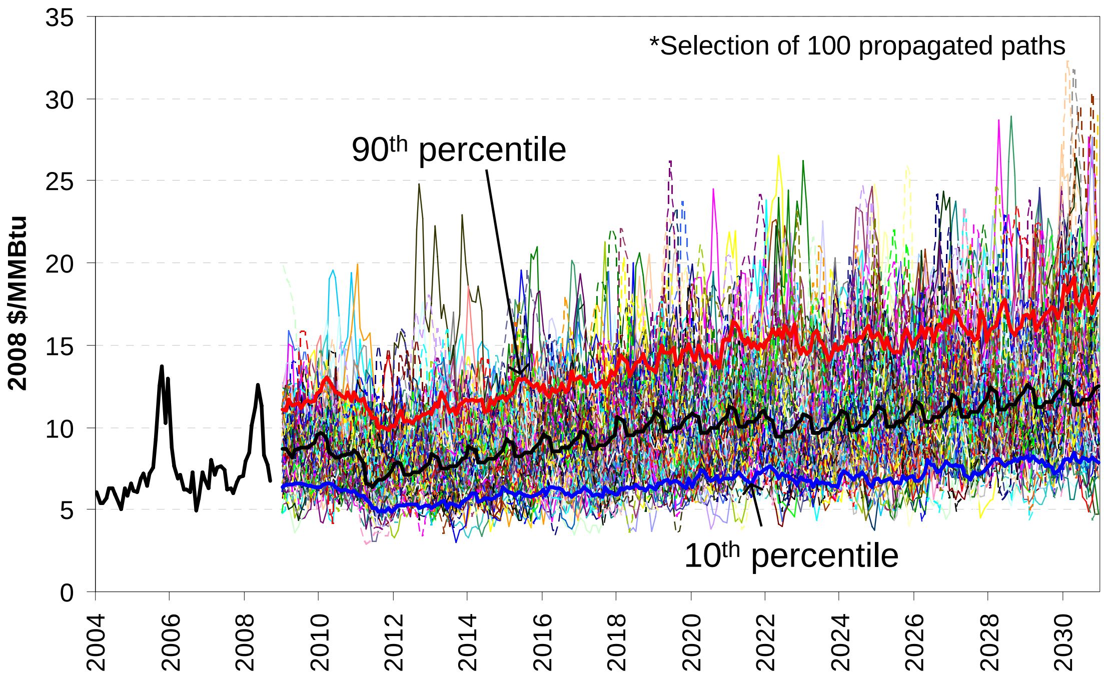


S_t is the 'spot' price of the commodity at time t,
a is a constant mean reversion rate (speed)
θ_t is expected value of S_t
σ is Annualised standard deviation of returns
$(t_{i+1} - t_i)$ Time step in years
ε_{i+1} is the random shock to price from t to $t+1$
exp the base of the natural logarithm

Source: Pace

Pace developed 500 price paths for its power market simulations. Exhibit 39 displays a sampling of 100 of these paths, along with constructed confidence bands and the price history for natural gas at the Henry Hub.

Exhibit 39: Monthly Henry Hub Natural Gas Propagations



Source: Pace analysis; Historical data: Platts

Capital Cost Uncertainty

Pace developed statistical distributions around the capital costs of various generation technologies, using the same mean-reverting process described above, according to the following methodology:

- Developed distributions for various component inputs based on historical volatility of underlying commodity prices;
- Developed estimates of representative capital and labor components for different technology types;
- Created capital cost distributions for each technology type;
- Applied technology cost distributions by year to portfolios based on the assumed online dates of each resource;
- Developed capital cost distributions for each portfolio.

STOCHASTIC DISTRIBUTIONS AND SUMMARY RESULTS

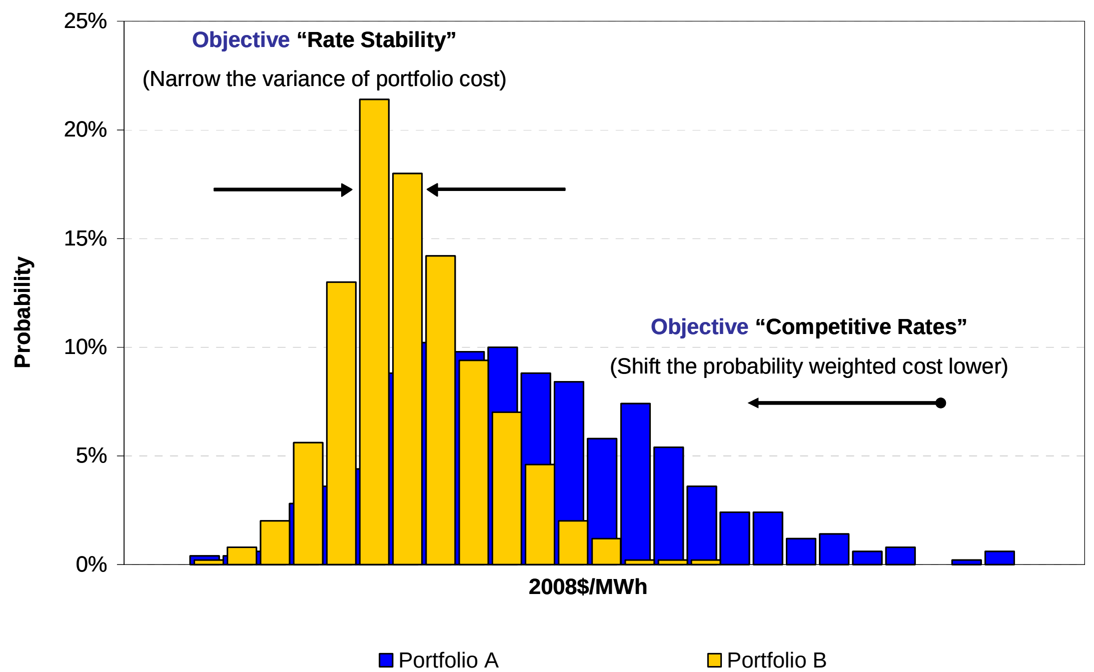
As discussed earlier, the stochastic inputs developed around load and natural gas prices were analyzed through 500 independent power market simulations to arrive at distributions of market power prices and portfolio costs for PWP for each year in the Study Period. These distributions were then added to the capital cost distributions to develop annual Total Cost distributions for each portfolio. Rather than present one single outcome, cost distributions represent the probability of occurrence over a range of outcomes.

Understanding Cost Distributions

Whereas traditional "base case" approaches quantify the effects of one set of fuel price, load, and capital cost assumptions, the stochastic simulation of these variables results in distributions around the "base case." Portfolio cost distributions convey information regarding the general cost level of different portfolios, but also provide valuable insight into the risks associated with each portfolio.

Exhibit 40 presents two illustrative portfolio distributions. In the example, Portfolio B's distribution is centered further to the left. This implies that the mean of the costs for Portfolio B are lower than the mean of the costs for Portfolio A. As shown, Portfolio B also has a tighter distribution than Portfolio A. This means that there is more risk associated with Portfolio A since the uncertainty around its costs is bigger.

Exhibit 40: Portfolio Cost Distributions



Source: Pace

As the different portfolio distributions were evaluated throughout this analysis, portfolio costs were compared based on the mean of the distribution; the market risks associated with the portfolio were evaluated based on the width of the distribution. Risk can be measured by different metrics like standard deviation or probability bands. For this study, Pace used the difference between the mean of the distributions and the 95% confidence band as the risk metric.

Cost Distribution Drivers

The costs and risks associated with a particular portfolio will depend on a number of factors. Capital cost investments and variable generation cost will impact the general level of costs for each portfolio. In general, portfolios with more capacity additions will show higher costs due to the increased capital cost investments required to build new capacity. The costs of building one additional MW of generation will vary considerably according to the type of resource added. On the other hand, portfolios with more renewable resources will generally show lower variable costs of generation. The relative impact of these factors will depend on the on the general mix of the portfolio and the size of the capital investments.

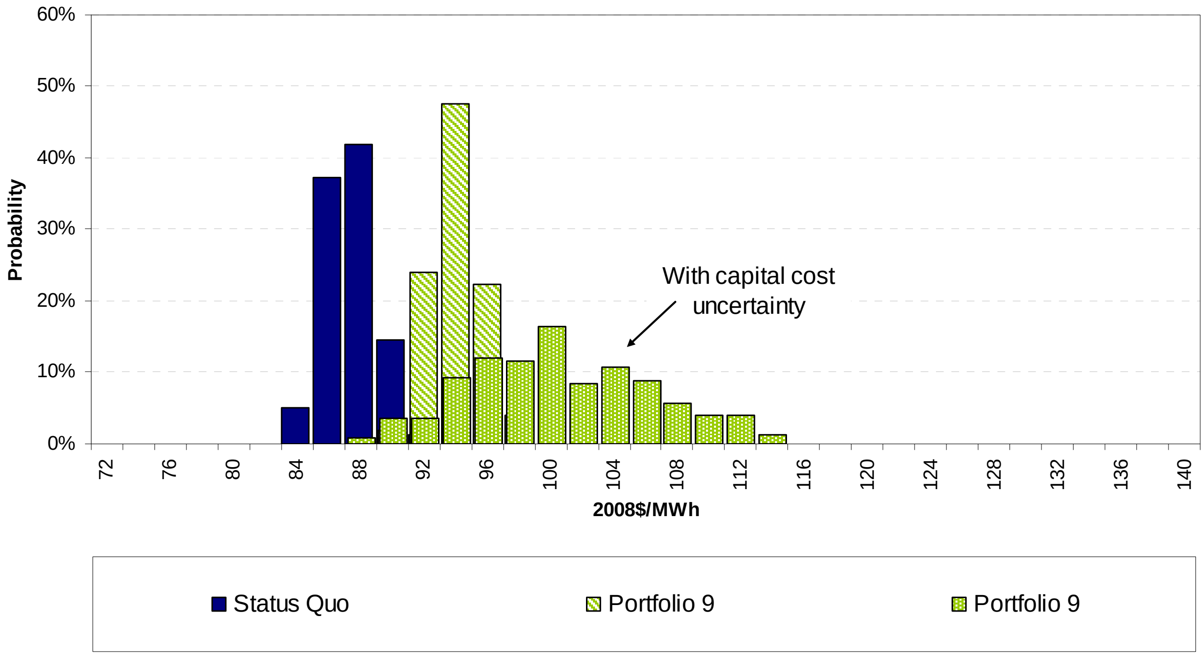
The risks associated with each portfolio will also depend on the resource mix of the portfolio and the size of required capital investments. The risk of significant capital cost increases will have a bigger impact on portfolios that depend on a larger capital investment. As further explained in the appendix, the relative mix of labor and materials in the capital cost component of the total cost will also create some differences in the way capital cost uncertainty affects each portfolio. The capacity mix of the portfolio will further impact its exposure to risk. Portfolios with a large renewable component will be largely shielded from the effects of fuel price volatility. On the other hand, portfolios with a large component of gas generation, for example, will be more exposed to fuel volatility. Portfolios with a significant volume of market sales or purchases will also be exposed to the effects of fuel and load uncertainty on the spot market's power price.

There are generally significant tradeoffs between the costs and risks associated with a particular portfolio. Assuming the same MW of capacity are added, portfolios that add solar, for example, will cost more than portfolios that add landfill and geothermal; similarly, portfolios that add landfill and geothermal capacity will cost more than portfolios that add gas capacity. The risk exposure of the gas portfolio to natural gas price and power market volatility, however, will be significantly greater than that of the renewables portfolio.

Portfolio Cost Distribution Results

For each portfolio, Pace summarized the distribution of annual outcomes for portfolio costs around load, fuel price, and power price uncertainty and then with the addition of capital cost uncertainty. This exercise is summarized in an illustrative manner in Exhibit 41 for Portfolio 9. As can be seen, the introduction of capital uncertainty for this portfolio with heavy reliance on substantial amounts of new landfill gas and geothermal capacity widens the distribution considerably.

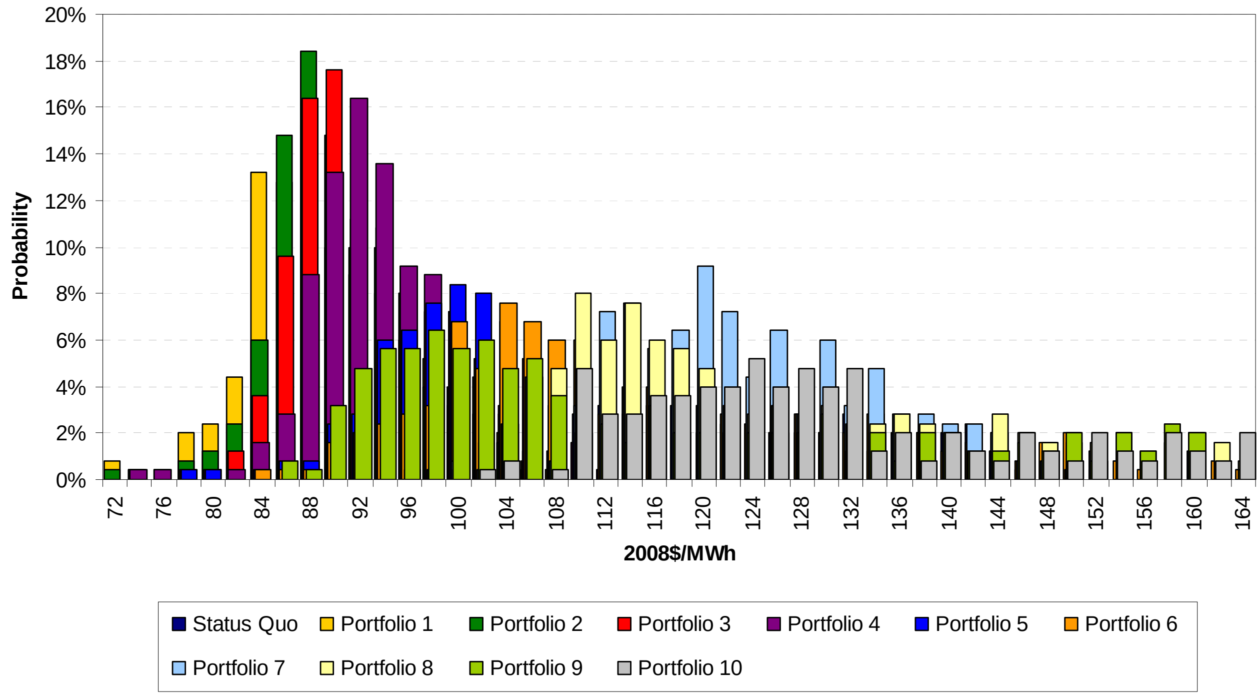
Exhibit 41: Portfolio Cost Distributions with and without Capital Cost Uncertainty

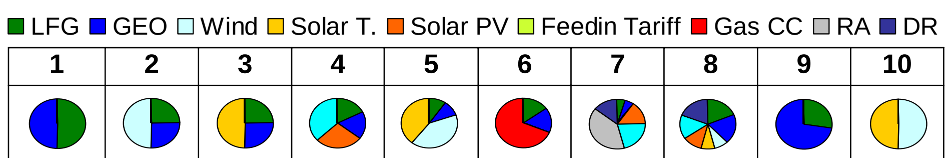


Source: Pace

Pace then summarized these Total Cost distributions for each portfolio. As an illustrative example, the year 2016 is displayed in Exhibit 42. This represents a year when many major portfolio decisions are already made. Although the shape and center of the distributions may change year by year, the relative portfolio costs and risks for 2016 are reflective of the relationships that exist over the entire Study Period.

Exhibit 42: Total Cost Distributions for Phase I Portfolios (2016)





	1	2	3	4	5	6	7	8	9	10
Total MW Added	30	40	40	56	150	95	101	131	90	250
IPP Replacement					47	108	108	108	108	108

Source: Pace

The annual distributions formed the basis for the summary cost and risk metrics that were used to measure portfolio performance against the defined objectives. For the cost metric, Pace calculated the mean of each distribution for each year and calculated a levelized NPV over the Study Period. A real discount rate of 5.4% was used. In order to quantify the risk for each portfolio, Pace calculated the levelized NPV of the 95th percentile of each portfolio for each year. The year-by-year mean portfolio costs for each portfolio are shown in Exhibit 43, while Exhibit 44 summarizes the levelized NPV of the mean portfolio costs as well as the difference from the mean to the 95th percentile cost outcome.

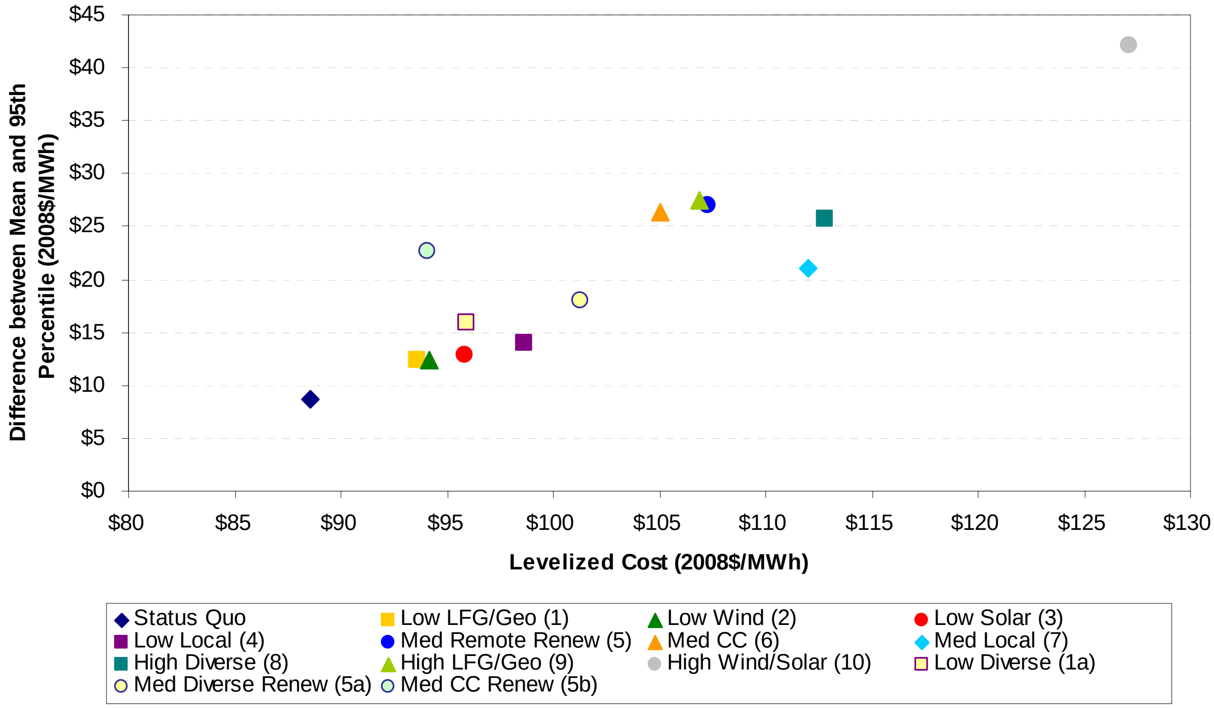
Exhibit 43: Annual Mean Portfolio Costs for Each Portfolio (2008 $/MWh)

Portfolio	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	70.47	70.61	72.39	79.45	85.83	90.44	91.89	91.88	86.22	87.56	90.01
2	70.47	70.61	72.39	80.01	86.29	90.88	92.27	91.67	86.03	87.61	90.26
3	70.47	70.61	72.39	80.66	86.99	91.64	93.01	93.19	87.54	89.36	91.79
4	70.47	71.04	73.27	80.76	87.33	93.26	95.72	95.95	91.75	94.21	97.79
5	70.47	70.61	72.39	86.48	92.29	96.99	97.88	111.86	105.97	108.02	109.43
6	70.47	70.61	72.39	79.45	85.83	98.66	99.83	117.49	111.54	115.67	120.12
7	70.43	71.50	77.34	86.59	97.50	107.52	107.55	124.45	104.95	109.42	115.32
8	70.43	71.50	77.34	90.09	100.37	110.25	109.82	129.89	110.20	113.08	117.14
9	70.47	70.61	72.39	82.94	88.36	92.63	93.45	118.49	112.11	113.97	116.73
10	70.47	70.61	72.39	98.79	103.96	108.97	109.08	147.38	140.97	145.43	145.37
1a	70.47	70.71	72.61	79.78	86.20	90.91	92.39	94.15	88.57	90.17	92.66
5a	70.47	70.81	72.83	81.86	88.17	92.99	94.37	101.49	95.93	98.11	100.95
5b	69.36	69.69	71.72	80.00	86.31	95.24	96.24	102.48	96.98	98.39	98.35
Status Quo	70.58	70.70	72.35	77.90	84.53	89.26	91.13	90.14	84.65	86.99	90.25

Portfolio	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	91.55	92.45	94.54	93.82	95.29	99.34	102.59	103.76	106.90	112.28	116.08
2	92.64	93.60	95.65	94.91	96.42	100.50	103.87	105.13	108.38	113.87	117.76
3	95.84	96.84	98.95	97.99	99.96	103.97	107.08	108.45	111.79	117.82	121.05
4	100.31	101.36	103.89	103.23	104.77	108.71	111.50	112.57	115.43	120.56	123.83
5	117.64	117.95	120.05	118.32	120.64	123.18	124.52	124.98	126.55	132.16	132.40
6	121.19	123.50	123.97	121.15	122.76	127.38	130.36	131.67	135.90	143.38	147.74
7	116.29	120.29	121.65	120.21	122.86	127.55	130.75	132.35	137.30	145.52	150.91
8	118.11	120.68	122.65	121.36	123.68	127.01	128.52	128.82	131.21	137.26	139.90
9	116.84	117.78	118.70	116.66	117.38	120.33	121.90	121.71	123.50	128.70	131.62
10	146.49	147.56	148.78	145.40	149.03	150.95	151.29	151.96	153.98	162.17	160.69
1a	96.15	97.09	99.74	99.28	101.21	104.89	107.58	108.50	111.02	116.08	118.83
5a	106.05	107.22	109.67	108.78	110.84	114.30	116.59	117.38	119.81	125.21	127.53
5b	102.33	102.71	104.64	104.16	105.68	109.02	111.37	111.67	113.41	117.74	119.67
Status Quo	91.15	92.84	94.45	93.81	95.64	100.13	104.66	106.67	111.30	117.76	123.34

Source: Pace

Exhibit 44: Summary Cost and Risk Metrics for All Portfolios



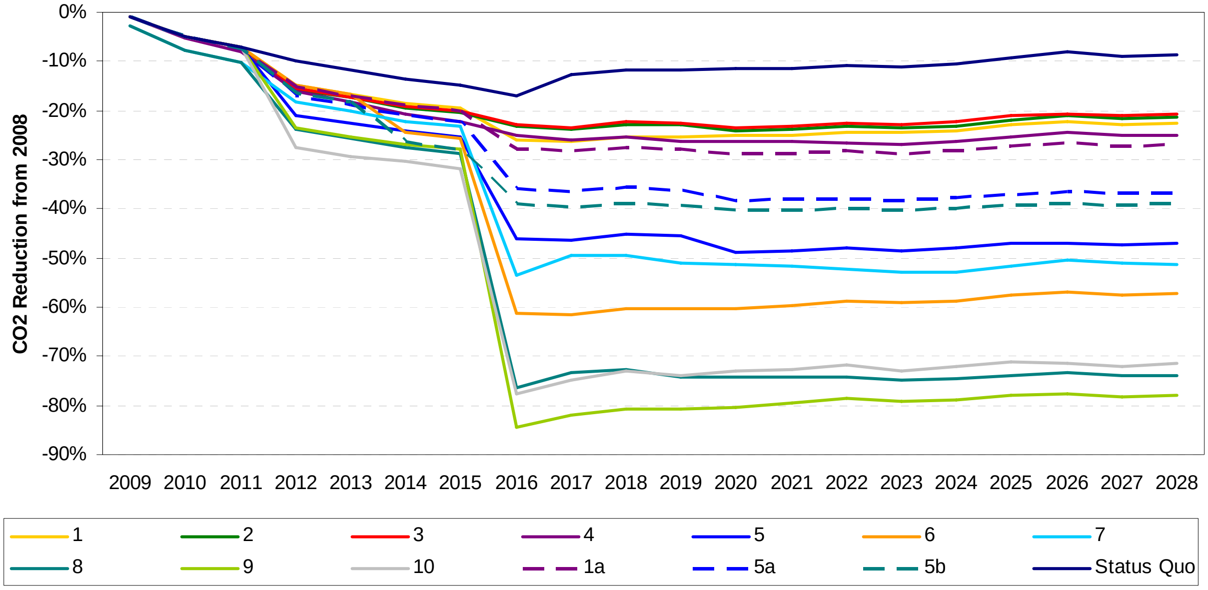
Source: Pace

Emission Reduction and RPS Performance Results

Pace's analysis also calculated the mean of the expected emission reductions for each portfolio in each year in order to measure performance against the planning objectives. While the actual year-to-year CO_2 reductions for any given portfolio will depend on a number of factors like load, fuel prices, market purchases, and market sales, Exhibit 45 displays the mean reduction levels for each portfolio, and Exhibit 46 compares the emission reduction levels in 2020 with the levelized NPV of costs for each portfolio. As can be seen, higher and higher emission reduction targets are generally associated with higher cost portfolios.

In addition to emission reduction performance, Pace calculated the percent of load being met by renewable resources for each of the portfolios for each year. The annual values for each portfolio are summarized in Exhibit 47.

Exhibit 45: Annual Emission Reduction Percentages by Portfolio

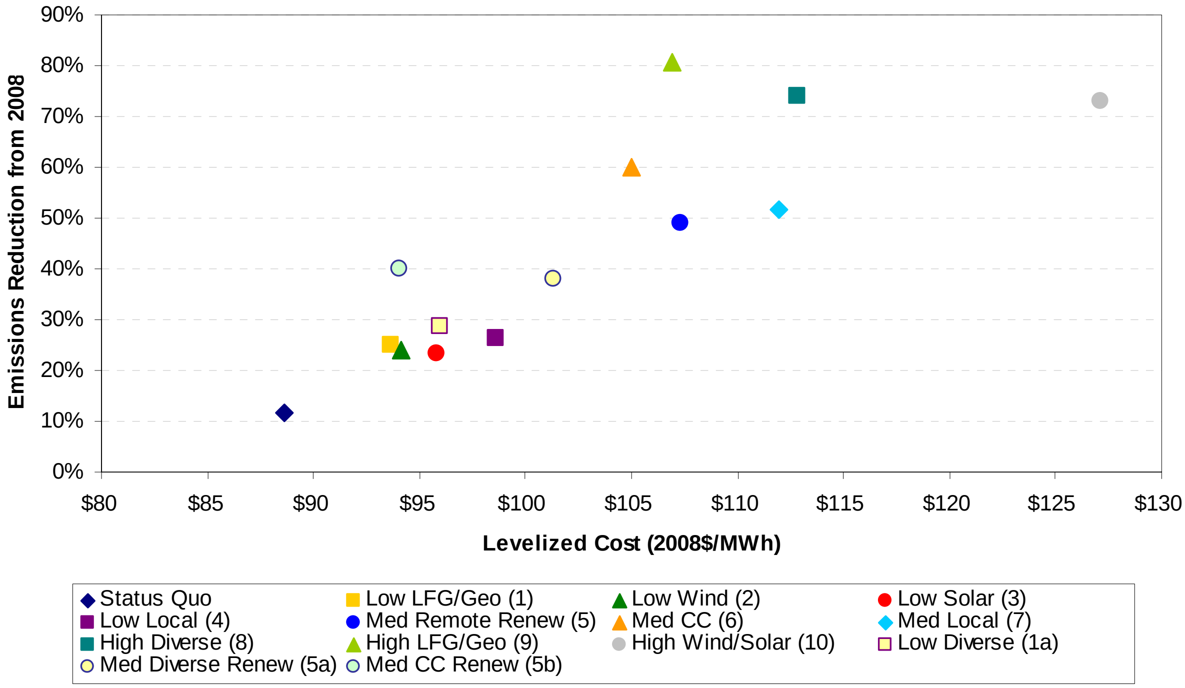


Portfolio	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	-1%	-5%	-7%	-15%	-17%	-18%	-20%	-26%	-26%	-25%
2	-1%	-5%	-7%	-16%	-17%	-19%	-20%	-23%	-24%	-23%
3	-1%	-5%	-7%	-16%	-17%	-19%	-20%	-23%	-23%	-22%
4	-1%	-5%	-8%	-16%	-18%	-21%	-22%	-25%	-26%	-25%
5	-1%	-5%	-7%	-21%	-23%	-24%	-25%	-46%	-46%	-45%
6	-1%	-5%	-7%	-15%	-17%	-24%	-26%	-61%	-62%	-60%
7	-3%	-8%	-10%	-18%	-20%	-22%	-23%	-54%	-50%	-49%
8	-3%	-8%	-10%	-24%	-26%	-28%	-29%	-76%	-73%	-73%
9	-1%	-5%	-7%	-24%	-25%	-27%	-28%	-84%	-82%	-81%
10	-1%	-5%	-7%	-28%	-29%	-30%	-32%	-78%	-75%	-73%
1a	-1%	-5%	-7%	-15%	-17%	-19%	-20%	-28%	-28%	-27%
5a	-1%	-5%	-8%	-17%	-19%	-21%	-22%	-36%	-37%	-36%
5b	-1%	-5%	-8%	-16%	-18%	-26%	-28%	-39%	-40%	-39%
Status Quo	-1%	-5%	-7%	-10%	-12%	-14%	-15%	-17%	-13%	-12%

Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	-26%	-25%	-25%	-24%	-25%	-24%	-23%	-22%	-23%	-23%
2	-23%	-24%	-24%	-23%	-24%	-23%	-22%	-21%	-22%	-21%
3	-23%	-23%	-23%	-23%	-23%	-22%	-21%	-21%	-21%	-21%
4	-26%	-26%	-26%	-26%	-27%	-26%	-26%	-25%	-25%	-25%
5	-46%	-49%	-49%	-48%	-49%	-48%	-47%	-47%	-47%	-47%
6	-60%	-60%	-60%	-59%	-59%	-59%	-58%	-57%	-57%	-57%
7	-51%	-51%	-52%	-52%	-53%	-53%	-52%	-50%	-51%	-51%
8	-74%	-74%	-74%	-74%	-75%	-75%	-74%	-73%	-74%	-74%
9	-81%	-81%	-80%	-79%	-79%	-79%	-78%	-78%	-78%	-78%
10	-74%	-73%	-73%	-72%	-73%	-72%	-71%	-72%	-72%	-71%
1a	-28%	-29%	-29%	-28%	-29%	-28%	-27%	-27%	-27%	-27%
5a	-36%	-38%	-38%	-38%	-38%	-38%	-37%	-37%	-37%	-37%
5b	-39%	-40%	-40%	-40%	-40%	-40%	-39%	-39%	-39%	-39%
Status Quo	-12%	-12%	-11%	-11%	-11%	-11%	-9%	-8%	-9%	-9%

Source: Pace

Exhibit 46: Summary Cost and CO_2 Reduction Metrics for All Portfolios



Source: Pace

Exhibit 47: Annual RPS Percentage for Each Portfolio

Portfolio	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	12%	14%	17%	24%	24%	25%	26%	33%	33%	33%
2	12%	14%	17%	25%	25%	26%	27%	29%	29%	29%
3	12%	14%	17%	25%	25%	26%	27%	28%	28%	28%
4	12%	15%	18%	25%	26%	28%	30%	32%	32%	32%
5	12%	14%	17%	32%	33%	34%	35%	52%	52%	54%
6	12%	14%	17%	24%	24%	25%	26%	33%	33%	33%
7	13%	15%	19%	31%	33%	35%	38%	42%	41%	40%
8	12%	15%	19%	40%	42%	45%	48%	79%	78%	77%
9	12%	14%	17%	36%	37%	38%	39%	78%	76%	75%
10	12%	14%	17%	43%	44%	45%	46%	72%	70%	68%
1a	12%	15%	18%	26%	27%	28%	30%	40%	40%	40%
5a	12%	15%	18%	34%	35%	37%	38%	56%	56%	56%
5b	12%	14%	17%	25%	26%	27%	28%	37%	38%	38%
Status Quo	12%	14%	17%	17%	18%	18%	19%	20%	12%	12%

Portfolio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1	32%	31%	31%	31%	31%	29%	29%	31%	31%	31%
2	29%	29%	29%	29%	29%	28%	28%	30%	30%	30%
3	28%	28%	28%	28%	28%	27%	26%	29%	29%	29%
4	33%	33%	33%	34%	34%	33%	33%	35%	35%	35%
5	56%	58%	58%	58%	58%	56%	56%	58%	58%	58%
6	33%	33%	33%	33%	33%	31%	31%	31%	31%	31%
7	39%	38%	39%	39%	40%	38%	38%	38%	38%	38%
8	76%	74%	75%	75%	76%	74%	74%	74%	74%	74%
9	74%	72%	72%	72%	71%	70%	70%	70%	70%	70%
10	67%	66%	66%	66%	66%	65%	65%	65%	65%	65%
1a	40%	40%	40%	40%	40%	39%	38%	41%	41%	41%
5a	57%	58%	58%	58%	58%	56%	56%	58%	58%	58%
5b	39%	41%	41%	42%	42%	42%	40%	40%	40%	40%
Status Quo	12%	12%	12%	12%	12%	10%	10%	12%	12%	12%

Source: Pace

SCENARIO ANALYSES

For any given portfolio, there are significant sources of uncertainty that cannot be quantified using stochastic simulations. Quantum cases developed around discrete assumptions changes have been analyzed through separate scenario analyses. In this study, the portfolio risks evaluated using scenario analyses included:

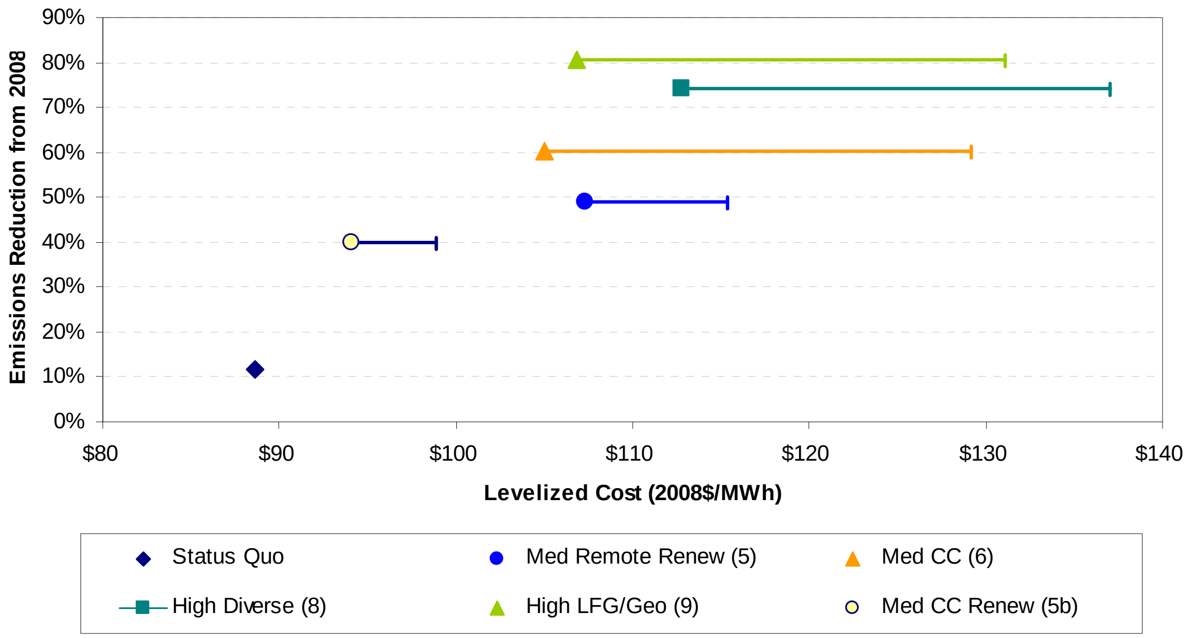
- Uncertainty around the sale price of IPP
- Availability of renewable generation
- Uncertainty around the reliability of local generation
- Regulatory risk: GHG emission accounting uncertainty
- Regulatory risk: CO_2 prices

Uncertainty around the Sale Price of IPP

About two thirds of the portfolios analyzed were constructed around the replacement of part or all of the IPP generation. In order to significantly reduce CO_2 emissions, the generation from IPP has to be replaced by cleaner resources. Replacing IPP, however, involves significant costs and risks, by removing a significant source of supply and replacing it with new capacity. The ability of PWP to offset some of these costs will depend on the price that can be secured for the sale of the IPP generation. Under the current regulatory environment and the expectation for more stringent environmental regulations, there is significant uncertainty around the terms and conditions that can be negotiated for the sale of coal generation into a different market area. The larger the contemplated size of the displacement, the more the portfolio is exposed to risk around the price that can be achieved for the sale of IPP power.

In its analysis, Pace has analyzed the impact of a sale of IPP generation at a price of 0 for all the portfolios. This means that PWP is still responsible for all fixed and variable costs associated with IPP operations, without receiving any benefit from the resulting power. Portfolios that replace more generation from IPP will be more exposed to the possibility of a zero price for its energy. This is illustrated in Exhibit 48.

Exhibit 48: Impact of Zero IPP Sale on Portfolio Costs



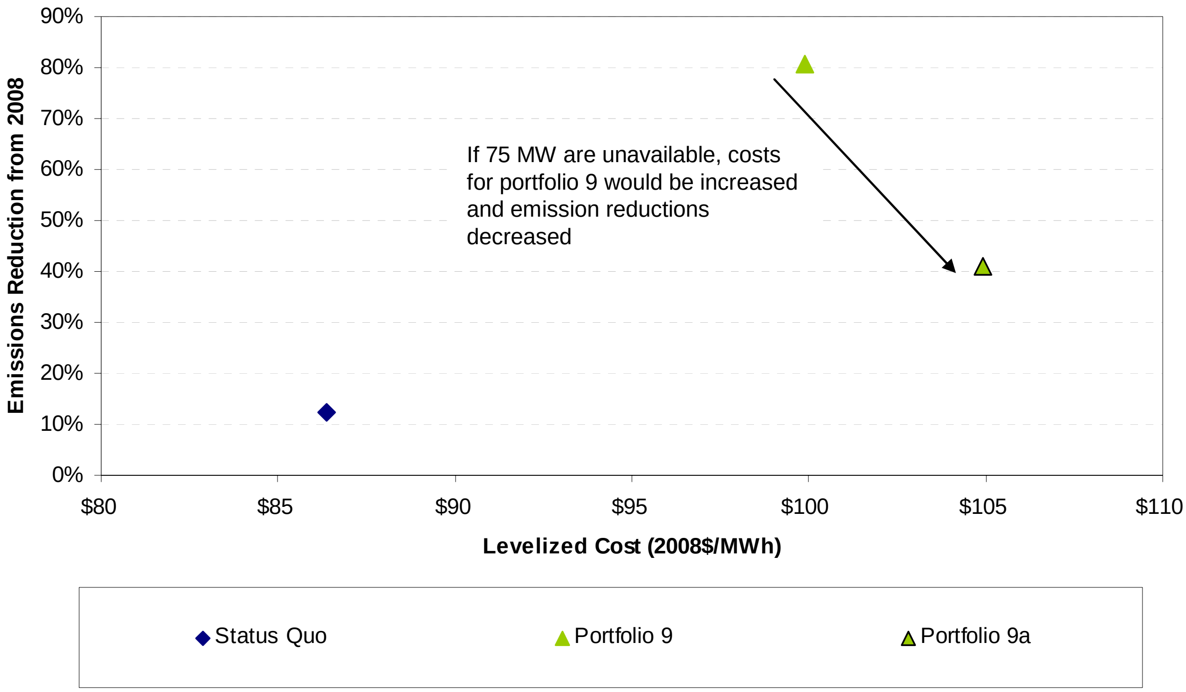
Source: Pace

Availability of Renewable Generation

The limitations on the availability of certain renewable resources to generate electricity are an important factor to consider when evaluating renewable-intensive portfolios. Renewable resource options like geothermal, for example, are highly limited by geographic location and may face transmission obstacles in delivering power to Pasadena. Resource options like landfill gas, on the other hand, are limited by the general resource availability in the area. Pace's portfolio review incorporated the impact on total portfolio costs of less-than-anticipated availability of renewable resources. Pace evaluated the impact of this in portfolios where landfill gas and geothermal are the predominant resource options.

Pace performed its availability analysis under the assumption that in a situation where the resources of the portfolio are not available, they would be replaced by purchases from the market. Increasing purchases from the market expose the portfolio to increased price volatility due to uncertainty around key drivers like fuel prices and demand. When the price of market purchases is greater than the cost of renewable generation, overall costs increase. Furthermore, market purchases have an associated emission rate, meaning that overall emissions for the portfolio increase when renewable options are unavailable. Exhibit 49 illustrates the cost and emission impacts for Portfolio 9 when 75 MW of geothermal and landfill gas capacity is unavailable and forced to be met by market purchases.

Exhibit 49: Impact of Availability Restrictions on Portfolio Costs and Emissions



Source: Pace

Uncertainty around the Reliability of Local Generation

About 70% of the capacity located within the city of Pasadena is more than 30 years old. Even with reliable transmission, an unplanned outage of the in-city resources could lead to unserved load during high load hours. In order to assess the potential reliability risks of continued reliance on the 110 MW of aging local generating units, Pace reviewed PWP operating criteria for the local, in-city units as well as projected load data. PWP studies indicate the need to initiate rolling blackouts when customer loads exceed 253 MW and the 110 MW of aging local units is unavailable.

- Pace's analysis indicates this has a 2.04% probability of occurring (179 hours/year)
- An accepted industry planning standard is 0.027% probability (1 day in 10 years)

- Achieving the industry standard requires at least a 76.2% probability that each of the three aging local units will be available when called to meet PWP customer's electricity requirements. The age of the existing units could put pressure on this requirement if upgrades or replacements are not made.

Expanding the transmission capacity into the city would be an alternative to local resource expansion that could improve system reliability. Based on information provided by PWP and its own research, Pace developed cost estimates for investments to upgrade the transmission system that could be required, absent the addition of new, gas-fired local generation. (A separate study evaluating alternatives to upgrade PWP's system is currently underway.) Pace concluded that portfolios that attempt to address existing reliability concerns through transmission upgrades need to include the following additional costs that are not included in portfolios that address reliability concerns through the addition of new, gas-fired local generation:

- Approximately $65 million invested over the next 20 years to extend the lives of the 110 MW of aging local generation represented by Broadway Unit 3 and Glenarm Units 1 & 2. For comparison, the January 2007 Draft IRP assumed costs of $59.9 million, primarily associated with capital improvements to extend the lives of the existing local generation, *plus*,
- At least $100 million invested over the next 10 to 20 years to upgrade the existing single point of interconnection with SCE at Goodrich and PWP's in-city transmission system. Although Pace has not performed a detailed assessment of the range of potential transmission system upgrades, its cost estimate is based on the following:
    - An additional 230/69 kV transformer bank at Goodrich, at an estimated cost of $10 million. This estimate is consistent with SDG&E's estimated costs for the addition of similar equipment as part of the proposed Sunrise Powerlink, plus,
    - A new underground 69 kV cross-town transmission line within the City to replace the existing 34 kV system at an estimated cost of $100 million. This estimate is also based on SDG&E's estimated costs for similar facilities as part of the Sunrise Powerlink, and assumes the need to add 20 miles of new 69 kV underground lines at a cost of $5 million per mile (which may substantially understate the actual costs of new 69 kV underground lines inside Pasadena).

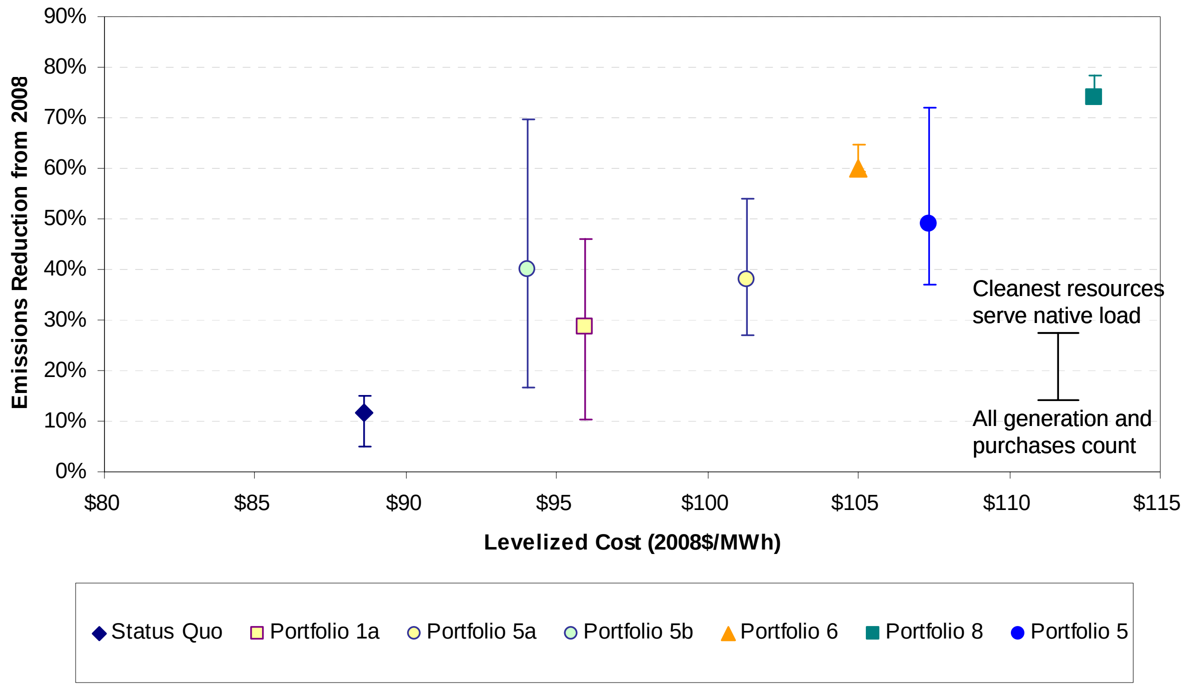
Pace believes that the $100 million cost estimate for transmission system upgrades most likely represents the lower end of the plausible range of transmission upgrade costs that PWP would incur in the absence of adding new, gas-fired local generation. Although the additional study on the costs of such transmission upgrades is still underway, the $100 million transmission upgrade cost estimate is sufficient for evaluating the portfolio options currently being compared.

Regulatory Risk: GHG Emission Accounting Uncertainty

The emission reduction goal of this planning process is driven by both an environmental stewardship objective and by the need to comply with existing and potential greenhouse gas reduction regulations. The level of reductions above what is required by law will be, in part, determined by the customers' willingness to pay for additional emission reductions. The accounting norms for CO_2 emissions, however, will impact how the emissions associated with serving the utility's load are recorded. Determining the appropriate accounting rules will define which portfolio achieves the desirable emission reductions.

Pace analyzed the resulting CO2 emission reductions around three possible accounting mechanisms. The reference case counts emission reductions for market sales at a portfolio average emission rate. An optimistic case assumes that the cleanest resources will serve native load first and that emissions from dirtier resources will only be counted if used to serve native load. A pessimistic case assumes that the emissions associated with all PWP power generation count towards their carbon footprint. The results of this analysis for a selection of portfolios are displayed in Exhibit 50.

Exhibit 50: Uncertainty around GHG Emission Accounting



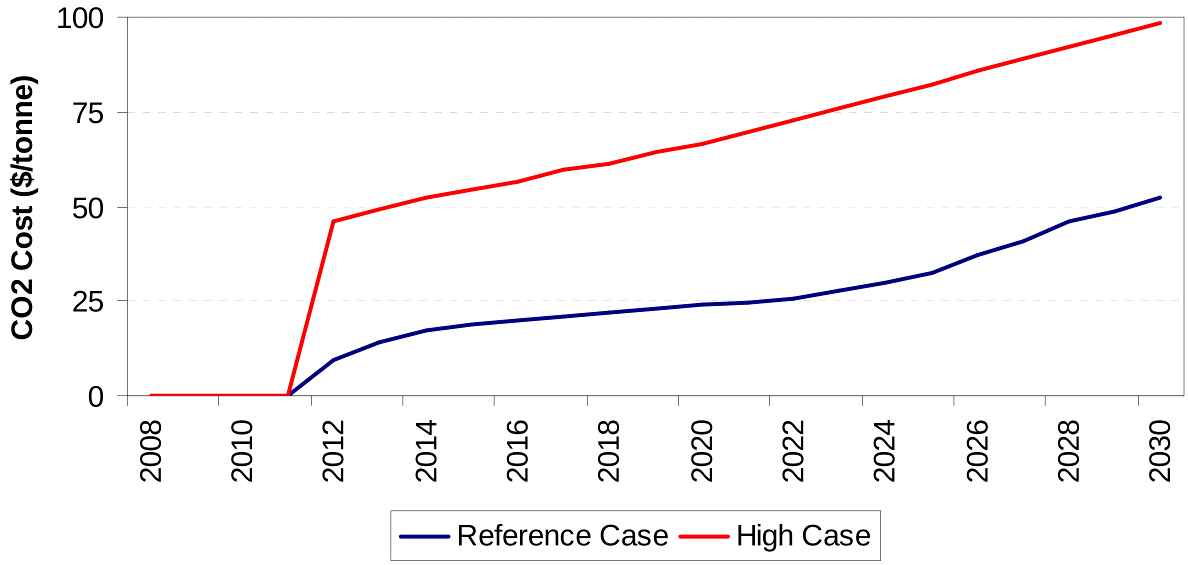
Source: Pace

Regulatory Risk: CO_2 Prices

Significant CO_2 emission compliance costs are expected over the Study Period. The uncertainty surrounding the timing and pricing level of such costs represents a big risk for any CO_2-intensive portfolio. Pace's analysis included the evaluation of all portfolio costs under a high CO_2 case. Portfolios with a larger share of IPP will suffer a relatively greater impact than those with less reliance on coal. Pace evaluated the relative impact of CO_2 on costs based on the NPV of portfolio costs under a high CO_2 scenario.

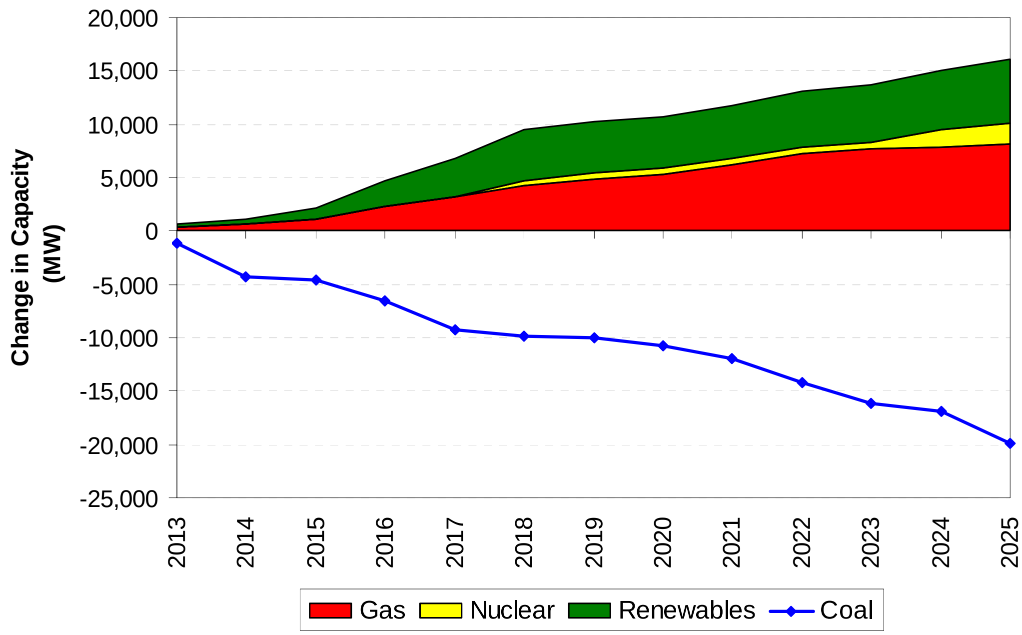
Pace's high CO_2 scenario envisions a stricter CO_2 policy calling for 60% to 80% emission reductions below 2005 levels by 2050. Such a policy is expected to lead to significantly higher CO_2 costs, as displayed in Exhibit 51. Furthermore, the introduction of such a policy is expected to lead to significant coal retirements and expansion of renewable and natural gas-fired capacity in the wider market area. Increased demand for natural gas is likely to put upward pressure on prices. The expected impacts on the WECC-wide expansion plan are summarized in Exhibit 52, and the expected impacts on the price of natural gas are illustrated in Exhibit 53.

Exhibit 51: CO_2 Costs for High Case



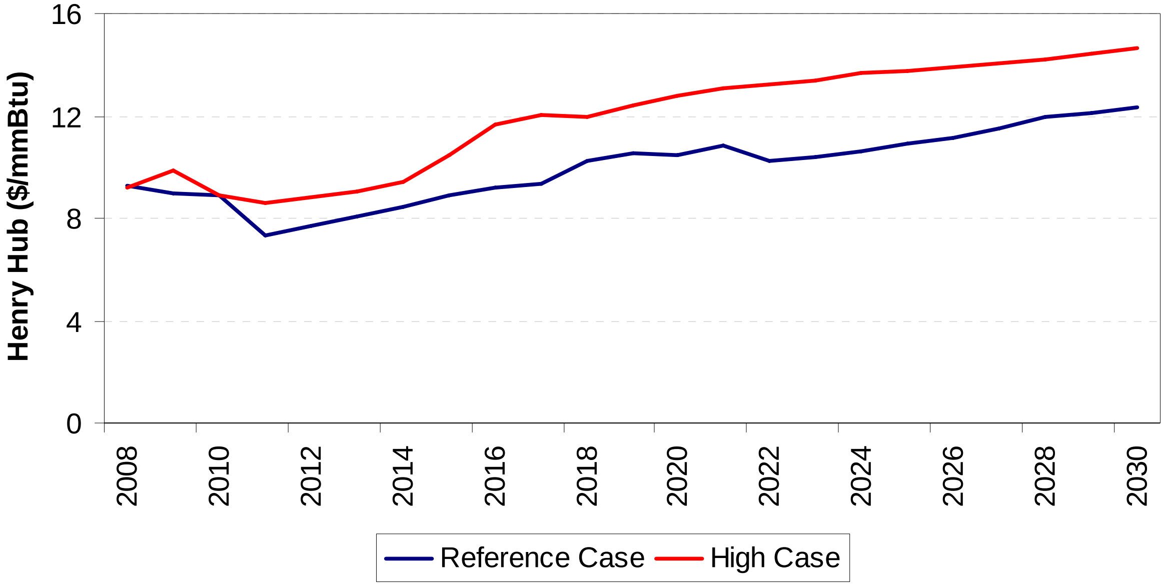
Source: Pace

Exhibit 52: Changes in WECC Expansion Plan for High CO2 Case



Source: Pace

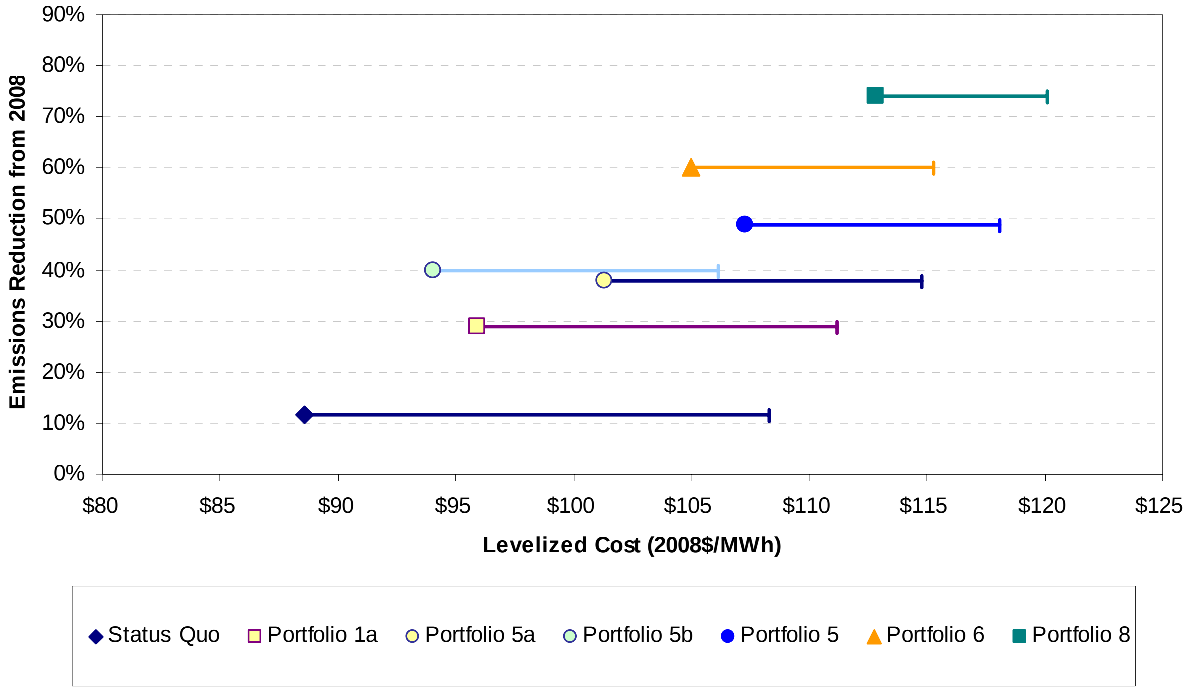
Exhibit 53: Changes in Natural Gas Price for High CO2 Case



Source: Pace

Under these assumptions, costs are expected to increase across all portfolios, but most especially for those that preserve a significant portion of IPP and hence have to absorb a significant carbon cost for power generation. This is illustrated in Exhibit 54 for a selection of portfolios. As can be seen, the projected costs for each of the portfolios is greater in the high CO_2 case, but portfolios that contain more coal or natural gas-fired capacity are more exposed to the potential upside impacts on cost.

Exhibit 54: Impact of High CO2 Case on Portfolio Costs



Source: Pace

SUMMARY OF PORTFOLIO METRICS AND RANKINGS

Pace's stochastic and scenario analyses resulted in several summary outcomes for each of the metrics identified as important for portfolio decision-making. These values are summarized for each portfolio in order to compare the performance of the various long term options. The relative performance of the various portfolios against planning goals and objectives was used to eliminate options and narrow the list of potential choices. Exhibit 55 summarizes the performance of 14 portfolios against 9 key metrics. The costs in this summary table also include transmission costs associated with the reliability upgrades required for those portfolios that do not include significant local expansion.

Exhibit 55: Portfolio Summary Metrics

Portfolio	Emissions Reduction	Cost	Price Risk	RPS 2020	Reliability	Capital Charges	Spot Market Dependence 2020	IPP Sale Feasibility	Carbon Price Risk
	% Reduction from 2008	*Levelized $/MWh*	*Added cost for 95% $/MWh*	*% of NEL*		*Annual Levelized $MM in 2030*	*% of 2020 Load*	*Added Cost Levelized $/MWh*	*Added Cost Levelized $/MWh*
Status Quo	12%	88	9	12%		0	4%	0	20
1: Low LFG/Geo	25%	94	12	31%		21	22%	0	16
2: Low Wind	24%	94	12	29%		21	20%	0	17
3: Low Solar	23%	96	13	28%		24	19%	0	17
4: Low Local	26%	99	14	33%	✓	23	26%	0	16
1a: Low Diverse	29%	96	16	40%	✓	31	29%	0	15
5: Med Remote Renew	49%	107	27	58%		65	26%	8	11
5a: Med Diverse Renew	38%	101	18	58%	✓	39	21%	5	13
5b: Med CC Renew	40%	94	23	50%	✓+	51	41%	5	12
6: Med CC	60%	105	26	33%	✓+	34	-2%	24	10
7: Med Local	52%	112	21	38%	✓	17	-40%	24	13
8: High Diverse	74%	113	26	74%	✓	49	-8%	24	7
9: High LFG/Geo	81%	107	27	72%		58	3%	24	5
10: High Wind/Solar	73%	127	42	66%		94	-4%	24	6

Source: Pace

KEY ENVIRONMENTAL LEGISLATIVE AND REGULATORY ISSUES AND POLICIES

RENEWABLE PORTFOLIO STANDARD

Renewable Portfolio Standards ("RPS") are regulated programs that set minimum requirements for renewable energy generation. No comprehensive national RPS exists in the U.S. at this time. At present, a total of 26 states and the District of Columbia have enacted state-level RPS requirements; numerous smaller city and regional level RPS programs also exist. Pace explicitly models all enacted state-level RPS requirements in its power price simulations.

Pace models expansion plans to meet the renewable energy requirements specific to each state's RPS including annual renewable energy production requirements, implementation timelines, accepted renewable technology types, and geographic sourcing requirements.

Western Region Electricity Generation Information System

Although RPS requirements are generally specified at a state level, we anticipate the ongoing development of West-wide mechanisms to assist utilities in complying with those requirements, further justifying an aggregate assessment of renewable energy market fundamentals for the entire WECC. The Western Region Electricity Generation Information System ("WREGIS") began tracking renewable resources for the WECC interconnect in June 2007. WREGIS is a voluntary tracking system that maintains a registry of renewable generation and issues renewable energy certificates for compliance verification. The WREGIS registry separates the renewable credit from the actual generation and issues one credit for every MWh of electricity produced. The WREGIS system was designed to make monitoring of RPS compliance easier and to assist in interstate Renewable Energy Certificate ("REC") transactions.

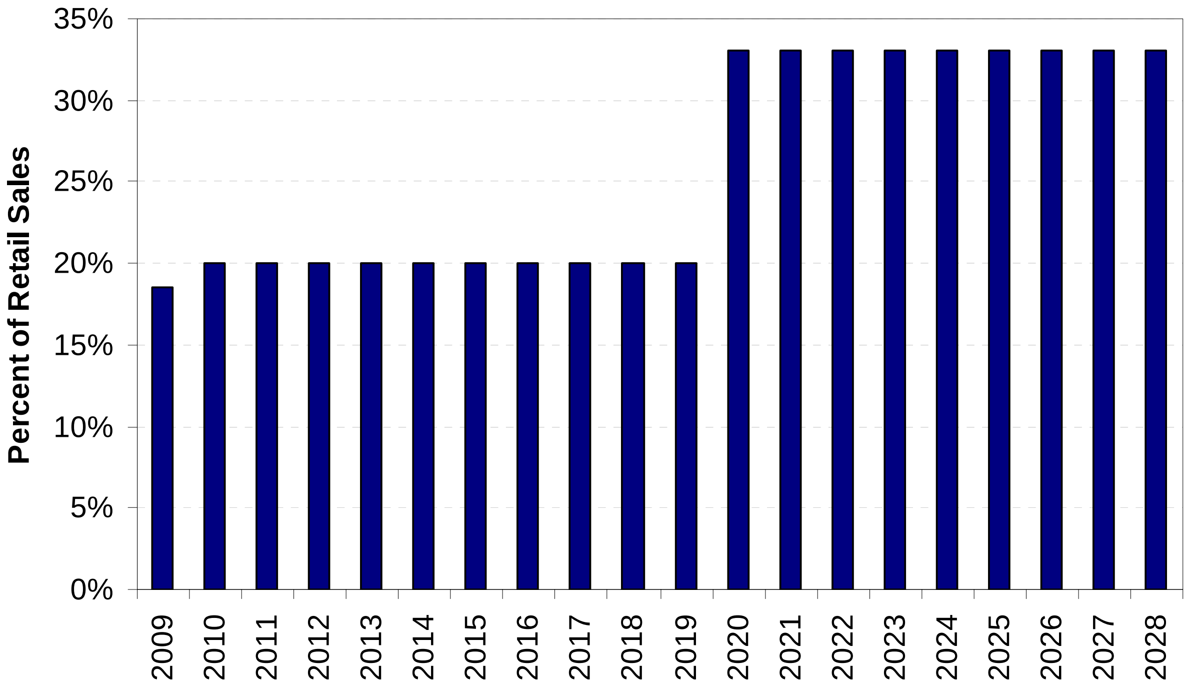
California RPS

California enacted its RPS in 2002 due to concern regarding high levels of emissions from California's power plants. Initially, the RPS mandate required regulated electric utilities and suppliers to purchase 20% of their electricity from green technology sources by 2017. This requirement was revised in 2006 under Senate Bill ("SB") 17 to require utilities and LSEs to purchase 20% of their electricity by 2010 from alternative sources. On November 17, 2008 Governor Schwarzenegger signed executive order S-14-08, which set a target to satisfy 33% of the state's generation from renewable sources by 2020. This target was initially only a goal set by the governor and was assumed in the original AB 32 scoping plan. There was a ballot initiative on the November ballot to increase the RPS standard to 50%, but this measure failed by almost a 30% margin.

The 33% target by 2020 is the most aggressive RPS standard to date in the United States. California recognizes that there are significant challenges to reaching the target. Among them are concerns about transmission expansion, new construction, the costs associated with both, as well as the impact intermittent renewables could have on system reliability.

Exhibit 56 shows California's RPS requirements and goals by year through the end of 2027, recognizing that there is likely to be new legislation to phase-in the new 33% RPS requirement between 2009 and 2020.

Exhibit 56: California's Renewable Portfolio Standard



Source: Pace

Investor Owned Utilities ("IOUs"), electric service providers, retail sellers, and community choice aggregators are required to increase the percentage of renewable-energy eligible resources by 1% per year to meet the state-wide mandate by 2010. Public utilities are not covered under law, but are expected to develop their own targets towards meeting state-wide renewable capacity goals.

For the purposes of satisfying RPS requirements, eligible technologies include wind, solar, biomass, geothermal, photovoltaic, fuel cells from renewable sources, hydropower online after January 1, 2006 and less than 30 MW, landfill gas, ocean wave, ocean thermal, tidal current, digester gas and some municipal waste.

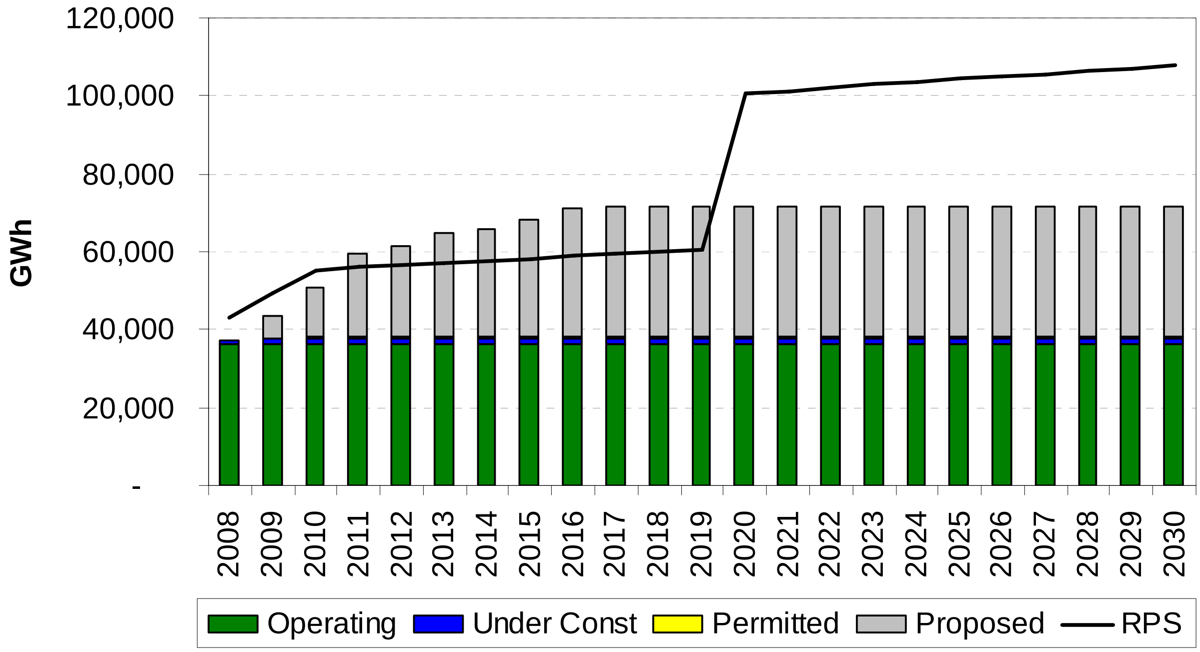
Each load serving entity ("LSE") must meet an Annual Procurement Target ("APT"), which is a sum of the baseline existing eligible renewable generation in the LSE's profile and it's Incremental Procurement Target ("IPT"), or the amount of eligible generation added to its profile over that year. LSEs that do not meet annual RPS requirements are subject to penalties of $.05/KWh, with a cap of $25 million per utility. LSEs can bank surplus incremental procurement indefinitely for future annual compliance. Deficits less than or equal to 25% of that year's target also can be carried forward for up to three years.

The California Energy Commission also allocates supplemental energy payments ("SEPs") through the New Renewable Facilities Program ("NRFP") to certain qualifying facilities. The SEP program was designed to cover above market costs directly associated with procuring renewable energy. Qualifying renewable resources that came online or were re-powered after January 1, 2005 and have been selected by a retail electricity provider through a competitive solicitation process are eligible for SEPs. If the final negotiated price for any new procurement bid involving a qualifying facility is above the market price referent ("MPR") as determined by the California Public Utility Commission, the facility may be eligible for a SEP. MPRs measure the long-run avoided cost of procuring non-renewable energy generation. By creating a ceiling of cost responsibility, the SEP program addresses IOU concerns over procuring renewable energy.

Out-of-state renewable resources can qualify for California's RPS and SEPs if they are connected to the WECC transmission system, begin operating on or after January 1, 2005, deliver generation into California markets, and participate in a RPS tracking system approved by the California Energy Commission. Facilities beginning operation before January 1, 2005 may qualify for the RPS program if they are a part of an expansion project or if they are a part of a baseline procurement portfolio.

In addition to RPS assessment for the PWP portfolio, Pace has implemented the RPS for California in its simulation model by building renewable capacity to eventually meet the mandate. In light of recent trends that suggest the standard will not be met on time with in-state resources, Pace expects some renewable builds in neighboring states to be contracted into California in order for California to meet their RPS obligation. Over the longer-term, Pace expects California's in-state renewable builds to increase and satisfy the 20% RPS mandate. Exhibit 57 illustrates the current amount of RPS eligible generating capacity installed in California and the current total capacity of resources that are either permitted, proposed or under construction.

Exhibit 57: California's Renewable Portfolio Standard vs. Capacity



Source: Pace and Energy Velocity©

California Solar Initiative

Created by the California Public Utilities Commission with the hope of creating a self-sustaining photovoltaic solar market, the California Solar Initiative ("CSI") will provide $2.2 billion worth of incentives to use solar energy over the next ten years to residential homes, industrial, commercial and agricultural properties. In January 2008, Senate Bill 1 initiated its Publicly Owned Utilities ("POU") element, requiring each municipal utility to offer a solar incentive program to its customers. The bill states a goal of 660 MW of sold solar energy, with utilities spending approximately $784 million dollars over the next decade.

Incentives for this renewable energy source will begin at $2.50 per watt for systems up to one megawatt in size and will be increased for low income housing installations. Additionally, a performance based incentive structure was implemented in 2007. For projects with capacity greater than 100 kilowatts, incentives will be rewarded on a monthly basis for the amount of energy produced over a five year span. For systems with a capacity of less than 100 kilowatts, incentives will be rewarded in a one-time upfront payment based on expected performance of the system. Beginning in 2010, systems with capacity greater than 30 kilowatts will be paid based on the actual amount of energy produced. Furthermore, Governor Arnold Schwarzenegger's Million Solar Roofs Initiative includes a goal of installing 3,000 MW of new solar electric systems by 2017. These programs are expected to lead to significant number of distributed solar PV installations in California. All of the PWP portfolios contain 14 MW of solar PV expansion within the city.

Other WECC State RPS Requirements

Arizona

The Arizona Corporation Commission established its RPS in 2006. As a result, 15% of all retail sales from IOUs must come from renewable generation by 2025, 60% of which must come from solar electric power. Of the 15% requirement, 30% (or 4.5% of total retail sales) must be met through distributed generation by 2012. Arizona is not poised to meet their RPS requirements with instate capacity in the near term.

Eligible resources must have come online after January 1, 1997 and include solar, wind, landfill gas, biomass, hydroelectric power coming online after January 1, 2006 with a maximum capacity of 10 MW, geothermal, CHP and cogeneration, anaerobic digestion, and fuel cells using renewable fuels. Bundled RECs from any year may be used to meet annual requirements. Out-of-state generation is eligible if delivered into the state.

New Mexico

The state of New Mexico's Renewable Portfolio Standard, through Senate Bill 418, mandates that IOUs procure 20% energy for retail sales from renewable generation resources by 2020, 10% must come by 2011, and 15% by 1015. The law also requires rural cooperatives to procure 10% of retail sales from renewable sources by 2020. Municipalities are exempt from the requirement. Pace believes that New Mexico will meet and exceed their RPS requirement.

Wind, solar, biomass, geothermal, landfill gas, fuel cells using renewable fuels, and hydroelectric facilities that come online after January 1, 2007 qualify as eligible resources. Renewable energy credit trading counts solar as 300% of one credit, wind and hydro as 100%, and all other qualifying resources as 200%. Preference is given to in-state resources; however, any qualifying resource that delivers into New Mexico qualifies for RECs.

Nevada

The Public Service Commission of Nevada established a Renewable Portfolio Standard in 1997 that requires IOUs operating in the state to procure 20% of their retail sales from renewable generation by 2015. Of this 20%, 5% must come from solar technology. Starting in 2007 the requirement is 9% and increases by 3% every other year until 2015. Nevada has fairly aggressive goals, which are compounded by some of the highest demand growth rates in WECC. There is more than enough proposed capacity at this point in time to have Nevada meet their standard with in state capacity. If however, one of the large wind farms proposed or some of the larger geothermal plants do not get built Nevada may fall short of their RPS goals.

Eligible resources include wind, solar, hydroelectric facilities under 30 MW, geothermal, biomass, and municipal solid waste. The law applies to all utilities excluding municipal utilities and cooperatives. Renewable energy credits can be banked for up to four years. Customer-sited solar PV receives a multiplier of 240%. All other customer-sited renewable energy credits count as 105% of one credit.

Oregon

The state of Oregon, through Senate Bill 838, enacted its Renewable Portfolio Standard in 2007. The law separates IOUs into three groups based on the percentage of Oregon's load that they serve. The largest three utilities must procure 15% of retail sales from renewable resources by 2015, 20% by 2020 and 25% by 2025. The second class must procure 10% of retail sales from renewable resources by 2025, and the smallest class must procure 5% by 2025. Oregon currently exceeds their RPS requirement with instate capacity and will most likely continue to do so.

For all three classes of utilities, eligible resources that began operation after January 1, 1995 include solar, wind, landfill gas, biomass, geothermal, hydrogen, tidal energy, wave energy, and ocean thermal. Each utility may also receive credits for up to 50 MW of hydroelectric generation per compliance year. Any generation delivered into Oregon from a facility located within the US portion of WECC qualifies for a REC. RECs can be banked and carried forward indefinitely.

Washington

The state of Washington established its Renewable Portfolio Standard through ballot Initiative 937 in 2006. All utilities, including municipalities and cooperatives must procure 3% of retail sales from renewable generation resources by 2008, 9% by 2016, and 15% by 2020. Washington, like Oregon, easily meets and exceeds their state RPS standard with installed capacity and the excess will likely be contracted to other states in the WECC region such as California.

Eligible resources include wind, solar, biomass, landfill gas, geothermal, fuel cells using renewable fuels, tidal energy, wave energy, and incremental hydroelectric generation that comes online after March 31, 1999. To be eligible for a REC, electricity must be delivered into Washington State. Credits can be banked forward for three years. However, incremental hydro facilities are not eligible for trading RECs. Credits for customer-sited generation are worth 200%.

Montana

The state of Montana, through Senate Bill 415, passed a Renewable Portfolio Standard in 2005. It requires public utilities to obtain a certain percentage of their retail electricity sales from renewable resources. By 2008, 5% of electricity sales must be generated by renewable resources; this percentage increases to 10% in 2010 and 15% in 2015. Montana does not currently meet their standards with in state capacity, but Pace believes that in the near term they will meet and exceed their goals allowing for Montana's renewable capacity to be contracted by other states in WECC to meet RPS requirements.

Eligible renewable resources in Montana must start after January 1, 2005 and include wind, solar, geothermal, hydroelectric projects with a capacity less than 10 MW, landfill or farm-based methane gas, and fuel cells where hydrogen is produced with acceptable renewable fuels. Renewable credits can be banked for up to three years.

The state allows for RECs to be traded, as long as they are properly certified. If the utility fails to satisfy the RPS, a $10/MWh penalty is assessed for the shortfall, effectively placing a cap on the value of the REC price in the state.

British Columbia

British Columbia currently has a nonbinding plan for promoting clean energy within the state. There are no binding targets or REC generating provisions. The region is, however, rich in renewable resources, which can be transmitted into the WECC regional trading system.

Alberta

Alberta also has a nonbinding renewable promotion policy. The "Albertans and Climate Change" report issued by the Alberta Ministry of the Environment established a goal of a 3.5% increase in renewable generation. While this goal has no legal enforcement mechanism, Albertan renewable generation can be transmitted into WECC.

Utah

In March of 2008, the Utah legislator enacted *The Energy Resource and Carbon Emission Reduction Initiative (SB 202).* This Renewable Portfolio Standard requires 20% of retail sales must come from renewable sources by 2025. Utah should be able to continue to meet their new requirements with instate capacity.

Renewable Resources that are eligible must have a start date after January 1, 1995. Eligible unit types include solar, wind, biomass, hydroelectric, wave, tidal or ocean thermal energy, geothermal, waste gas and waste heat. Solar resources count for 240%, and the amount of generation produced by nuclear plants can be subtracted from the retail sales before the RPS is applied.

Colorado

Colorado established its Renewable Portfolio Standard through ballot Initiative 37 in 2004. It has since been expanded to mandate that 10% of retail sales from IOUs must come from renewable generation sources by 2011, 15% by 2015, and 20% by 2020. Electric cooperatives must procure 10% of their retail sales from renewable generation, and municipal cooperatives serving more than 40,000 customers must procure 10% of their retail sales from renewable resources by 2020. Colorado currently exceeds their RPS with internal capacity and will in all likelihood continue to do so. This surplus should be contracted by California LSE's to serve towards meeting California's aggressive standards.

To qualify, resources must have come online on or after January 1, 2005. Eligible resources include solar, wind, landfill gas, biomass, hydroelectric that does not exceed 30MW, geothermal, fuel cells, anaerobic digestion, and "recycled energy". IOUs have a technology minimum for solar energy of 0.8% of total retail sales by 2020. Colorado does not require that RECs remain bundled to generation. Utilities that fail to meet the requirement are subject to a $.55/kWh fine. However, credits can be banked for up to five years and borrowed forward for up to two years. In-state generation qualifies for 1.25% of credits, and municipal and cooperative solar generation qualifies for 300% of credits.

DEMAND SIDE MANAGEMENT AND ENERGY EFFICIENCY

California has developed significant regulation setting requirements on energy efficiency for both IOU's and public utilities.

Under SB 1037 (2005), the CPUC established electricity efficiency savings targets based on an evaluation of all plausible cost-effective savings and required electric utilities to use all available energy efficiency and demand resources that are reliable and cost-effective when implementing their procurement plan.

AB 2021 (2006) built on SB 1037, requiring IOU's and public utilities to acquire all energy efficiency and demand resources that are cost-effective, reliable and feasible. The ultimate goal of this legislation is to meet the state goal of reducing forecasted electricity consumption 10 percent by 2010. Requirements for public utilities under AB 2021 are as follows:

- Public utilities must identify and report cost-effective efficiency opportunities every three years and create annual targets over a ten year period.
- Public utilities must also annually report on their sources of funding, cost-effectiveness, verified efficiency and independently verified demand reduction results.

In its assessment of PWP, Pace has analyzed energy efficiency programs and includes all cost-effective efficiency measures in each of the portfolio analyses that were performed. The treatment of efficiency programs is detailed in the appendix on efficiency programs.

GREENHOUSE GAS EMISSIONS

To date, the U.S. has declined to implement regulated carbon constraints either at the national level or through binding international climate change agreements. A number of states, however, are going forward and undertaking binding carbon emission reduction initiatives both in the form of state regulation and regional reduction agreements. Among the most advanced of these state initiatives is California's AB 32. State-led activity to reduce carbon emissions is sending a strong message to Congress to enact carbon legislation at the federal level.

Western Climate Initiative (WCI)

Seven western states and two Canadian provinces joined to form the Western Climate Initiative ("WCI") in 2007 to provide a net reduction in GHG emissions of 15 percent below 2005 levels by 2020 under an economy-wide cap. Quebec joined the WCI in April 2008 after having been an observer of both WCI and the Northeast's Regional Greenhouse Gas Initiative ("RGGI"). The WCI is binding for the states and provinces entering at the Partner level, while participants entering as Observers are not bound by the 2020 emissions reduction target. The current Partners and Observers are as follows:

- **Partners**: Arizona, British Columbia, California, Manitoba, Montana, New Mexico, Ontario, Oregon, Quebec, Utah, and Washington.
- **Observers**: Alaska, Colorado, Idaho, Kansas, Nevada, Wyoming, Saskatchewan, Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, Tamaulipas.

WCI calls for economy-wide activities to reduce greenhouse gas ("GHG") emissions. The initiative covers all major emitting sectors including stationary sources, energy supply, residential, commercial, industrial, transportation, waste management, agriculture, and forestry. GHG emissions are defined as all six Kyoto GHGs, versus only covering carbon dioxide as is called for under the RGGI program in the eastern U.S. The specific rules and framework of WCI are under development by signatory states and the Western Governor's Association.

Reporting requirements under the WCI's regional goal requires that each partner update its peers on its climate action plan and GHG emissions inventories progress every two years to help ensure the 2020 goal is achieved. WCI's objectives may be exceeded by state or provincial goals set by Partner states:

- **Arizona**: 2000 levels by 2020, 50 percent below 2000 by 2040;
- **British Columbia**: 10 percent below 1990 levels by 2020;
- **California**: 2000 levels by 2010, 1990 levels by 2020, 80 percent below 1990 by 2050, major industries – 1990 levels by 2020 (AB 32);
- **Manitoba**: 32 percent below 2004 levels by 2020, 80 percent below 2004 by 2050;
- **Montana**: no state goal;
- **New Mexico**: 2000 levels by 2012, 10 percent below 2000 by 2020, 75 percent below 2000 by 2050;
- **Oregon**: stabilize by 2010, 10 percent below 1990 by 2020, 75 percent below 1990 by 2050;
- **Quebec**: 1990 levels by 2010, 10 percent below 1990 levels by 2020, 75 to 85 percent below 1990 levels by 2050;
- **Utah**: 7 percent below 1990 levels by 2012; and
- **Washington**: 1990 levels by 2020, 25 percent below 1990 by 2035, 50 percent below 1990 by 2050.

CA State Level Carbon Legislation

AB 32

California's carbon reduction bill, AB 32, calls for California to reduce its carbon emissions to 1990 levels by 2020 (10% reduction below current levels) by capping emissions from the power, industrial and transportation sectors. AB 32 is slated to be implemented in 2012, and it appears likely that the reductions will be carried out through a market based emissions cap and trade scheme. The California Air Resources Board ("CARB") is the leading agency in implementing the AB 32 initiative. The electric power sector, which is responsible for 23% or 109 million metric tons (tonnes) of carbon equivalent ("CO2e") emissions, will be greatly affected by AB 32. In the current draft scoping plan, this sector is expected to reduce its emissions to 94 million tonnes of CO_2e by 2020.

The AB 32 scoping plan, the blueprint for how the reductions will be carried out, is still in draft format, but includes a myriad of tactics for reducing carbon emissions in California. These include:

- The development of a statewide cap-and-trade program that includes flexibility to link with a potential regional market created by the Western Climate Initiative ("WCI");
- Expansion of the state RPS to a required level of 33 percent;

- Expansion of logical and concrete energy efficiency programs and the implementing of additional environmental standards and laws into the initiative such as the Low Carbon Fuel Standard;
- Targeted fee structure to fund the State's long-term commitment to AB 32 to incentivize investment in renewable energy sources and help pay for reductions and other goals within the program, (i.e. taxing imported electricity from outside California).

Other key aspects of this legislation include mandatory reporting requirements for large emitting facilities, encompassing 94% of the state's emissions. Emissions tracking will begin in 2008 with reporting to be conducted in 2009. While 2008 data can be can be categorized as "best available data," 2010 emissions reports will likely be subject to more rigorous review and third party verification. Finally, it is important to note that other key provisions are being considered for inclusion in the regulation, including early action credit, offset credit, and banking of credits for future use.

Pace models a cost of carbon compliance in 2012 and beyond based on the expected timing of compliance requirements for carbon legislation ultimately implemented. Despite the forward progression of the implementation of AB32, Pace expects that federal carbon legislation will be enacted in the near term and will impart carbon compliance requirements nationwide and pre-empt state and regional initiatives currently in development. These carbon costs are presented below.

SB 1368

California also established carbon performance standards for electricity imported into the California grid through SB 1368, passed in September of 2006. The goal of this law is to limit the development of carbon-intensive energy sources, particularly coal, without having a negative impact on the reliability of energy services ratepayers receive. Utilities are prohibited from making new, long-term commitments to baseload generation sources whose CO_2 emissions exceed 1,100 lbs per MWh, allowing new capital investment in power plants for baseload generation only if the carbon emissions are as low, or lower, than the emissions from new, combined cycle power plants. More specifically, the following energy investments fall under SB 1368:

- Construction or purchase of a new power plant intended for baseload generation
- Purchase of existing power plants intended for baseload generation
- Capital investment in utility owned power plants intended for baseload generation (exceptions to this include power plant investments intended to increase rated capacity, convert from non-baseload to baseload, or for CC natural gas power plants permitted before June 20, 2007)

U.S. Federal Legislation

To date, the U.S. has declined to implement regulated carbon constraints either at the national level or through binding international climate change agreements. Carbon regulatory bills have been proposed sporadically in Congress since the mid to late 1990's. However, their sponsors have recently become more determined towards enacting mandatory, economy-wide, market-based caps on carbon emissions. This drive to pass federal legislation is borne from increasing pressure stemming from numerous constituencies both domestically and internationally.

At this time, federal carbon regulation in the U.S. appears imminent. Pace expects the passage of federal carbon legislation following the 2008 presidential election cycle sometime between 2009 and 2011, with compliance requirements likely to become effective in 2012 or 2013. Prominent policy mechanisms and how they work in the framework of carbon regulation are presented below.

Pace's forecast (see Exhibit 59) reflects carbon market pricing consistent with recently proposed bill design, geopolitical trends, control technology elasticity points, and domestic political palatability. In the absence of any finalized carbon mandates, many uncertainties encumber the ability to definitively predict the market cost of compliance instruments. Pace's carbon market price projections assume policy will include the following characteristics:

- **Carbon reduction targets** – Pace anticipates that U.S. carbon legislation will require significant carbon reduction caps over a long-term reduction timeframe. The Intergovernmental Panel on Climate Change ("IPCC") has spoken as the authoritative source on the science behind climate change and has said that countries should set goals to reduce national emissions to levels where atmospheric stabilization levels of 450 to 500 parts per million are possible. The latest IPCC report states that this level would entail reducing greenhouse gas emissions 50 to 85% below 1990 emission levels by 2050.
- **Cap & trade** – Virtually all U.S. carbon bills introduced to date call for a cap & trade system as opposed to a straight carbon tax. Pace anticipates that any passed legislation will impart carbon reductions via a market-based cap & trade scheme.
- **Supply flexibility mechanisms** – Pace assumes that the U.S. carbon policy will include a number of different options for procuring supply of compliance instruments. These policy mechanisms are likely to include direct allowance allocation, allowance auctions, banking of unused allowances for use in future years, borrowing forward year allowances, and tapping into international trading schemes. Most importantly, Pace expects a healthy offset market with 20% - 40% of covered entities' compliance positions allowed to be covered with offsets.
- **Allowance price controls** – Pace expects the carbon market design to include provisions intended to mitigate against undue market price spikes. This may come in the form of a set cap on the price of allowances, or more likely in the form of market control authority to inject more supply into the market or other market based approaches to ward off undue price levels of compliance instruments.

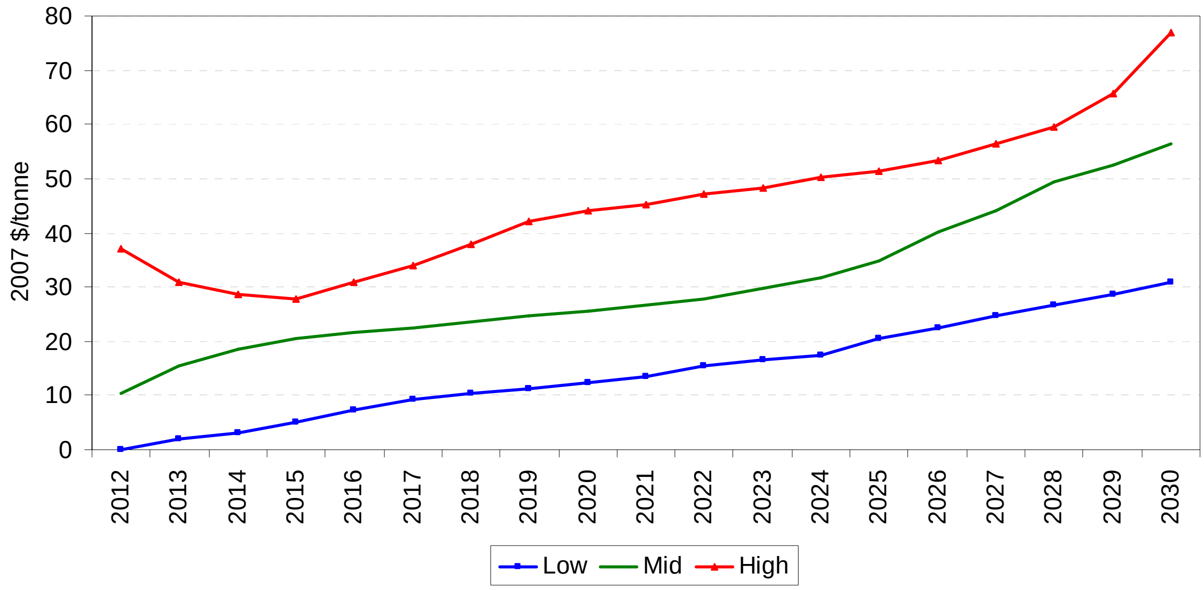
Pace's range of expected carbon pricing represents costs mitigated through price control measures and/or other market forces to prevent major near-term shifts in the power generation supply. All forecasts are supported by representative pricing demonstrated in other active regulated and voluntary carbon market pricing. Pace develops a range of cases (summarized in Exhibit 58), based on the general drivers described below. For this analysis, the Mid Case has been used.

Low Case – The low case represents low to moderate carbon caps with an initial compliance period starting around 2013. It assumes significant direct allocations and liberal offset provisions allowing for a large share of the supply side of the market to be covered by offset project reductions.

Mid Case – The mid case reflects either moderate to stringent carbon caps with flexible compliance provisions or a scenario of low to moderate caps with more stringent compliance provisions implemented in 2012.

High Case – This case represents the earliest expected impacts of carbon compliance costs either through early (2012) commencement of the initial compliance period or active pre-compliance trading. The initial uptick and curvature represents inflation from market speculation and the availability of banking once the compliance market is in effect. Higher prices in the latter years of the forecast period result from constrained offset provisions limiting the flexibility through which compliance can be achieved and / or rigorous carbon caps.

Exhibit 58: National Carbon Market Pricing Projections



Source: Pace

Exhibit 59: CO_2 Compliance Costs (2007$/tonne of CO_2)

Year	Cost
2009	0
2010	0
2011	0
2012	10
2013	15
2014	18
2015	21
2016	22
2017	23
2018	24
2019	25
2020	26
2021	27
2022	28
2023	30
2024	32
2025	35
2026	40
2027	44
2028	49

Source: Pace

REGIONAL MARKET AREA DEFINITION AND TRANSMISSION (PHASE II MODELING STRUCTURE)

WECC REGION

The Northern and Southern California power markets are a part of the Western Electricity Coordinating Council ("WECC"), the largest of the ten regional councils of the North American Electric Reliability Council ("NERC"). WECC was formed in 2002 by the merger of the Western Systems Coordinating Council ("WSCC"), the Southwest Regional Transmission Association ("SWRTA"), and the Western Regional Transmission Association ("WRTA"). The service area of WECC extends from the Canadian provinces of Alberta and British Columbia to the Northern portion of Baja California, including all or a portion of the 14 states in between. As shown in Exhibit 60, WECC's territory is divided into four major areas—Northwest Power Pool (US and Canada), Rocky Mountain Power Area, Arizona/New Mexico/Southern Nevada, and California-Mexico. The region is made up of 159 members, comprised of large and small transmission owners, end users, and state and provincial regulators.

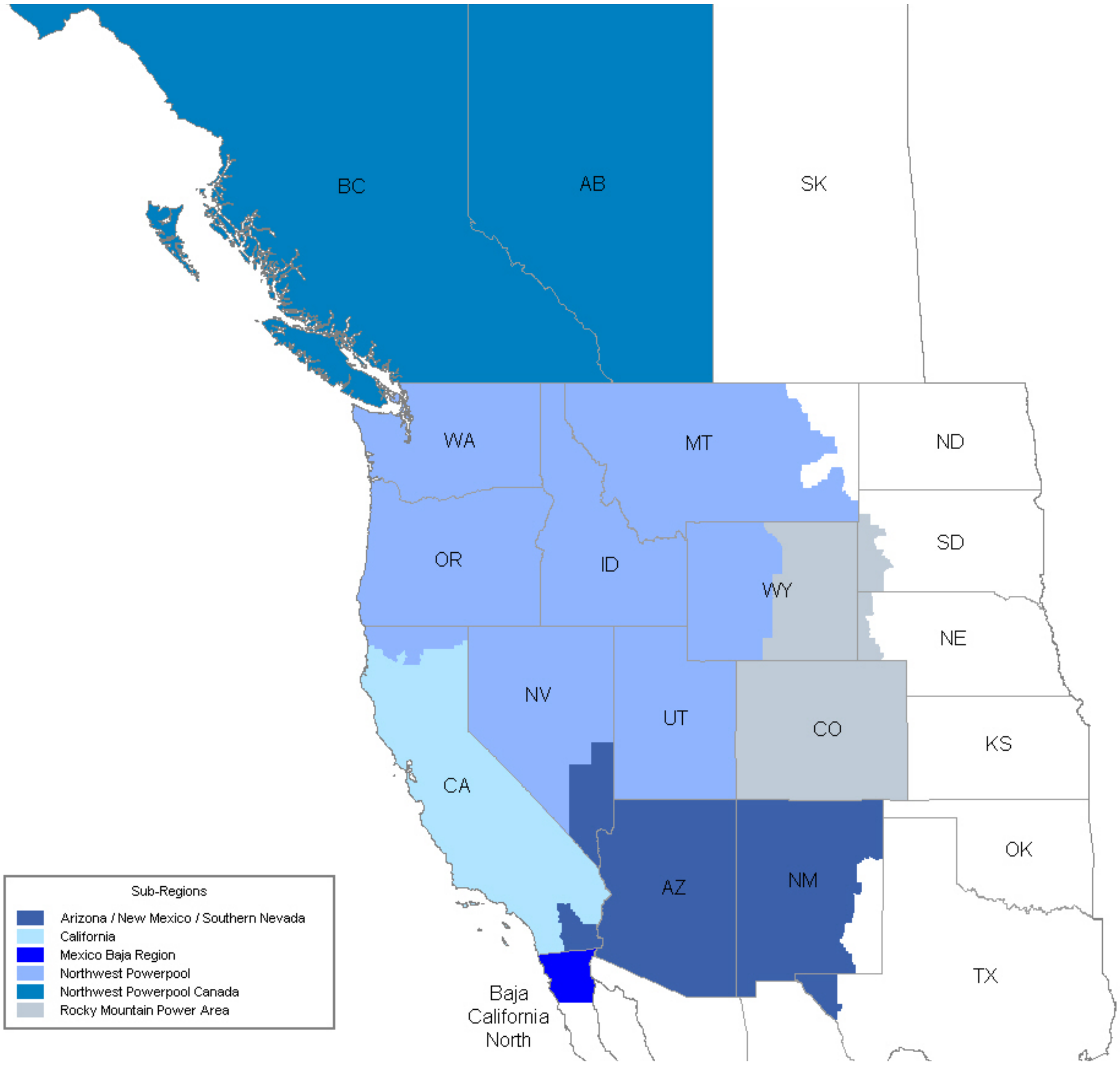
CALIFORNIA MARKET STRUCTURE

Approximately 80% of utility companies in the state of California belong to the CAISO control area. Like other RTOs, CAISO is designed to facilitate commercial transactions and provide liquidity and transparency to market prices. The CAISO is attempting to implement its Market Redesign and Technology Upgrade ("MRTU") discussed in detail in sections to follow. Pace believes that the MRTU will not be implemented until the first quarter of 2009 at the earliest, given ongoing delays in implementing software systems to management bidding and settlement functions.

CAISO is divided into two pricing zones—North Path 15 ("NP-15") and South Path 15 ("SP-15")—which are defined around a major north-south power transmission corridor called Path 15 located in Central California. Path 15 forms an important intertie in exporting the fossil capacity from the south to the hydro-dominated north region. In late 2000 and early 2001, Path 15 became severely congested, leading to two days of rotating outages in California. Since then, Path 15 has been identified as a major factor affecting system reliability, and the flow on this path greatly impacts the amount of new generation and market clearing prices on either side. Exhibit 61 displays the major pricing zones in the CAISO along with the location of the Pasadena service territory.

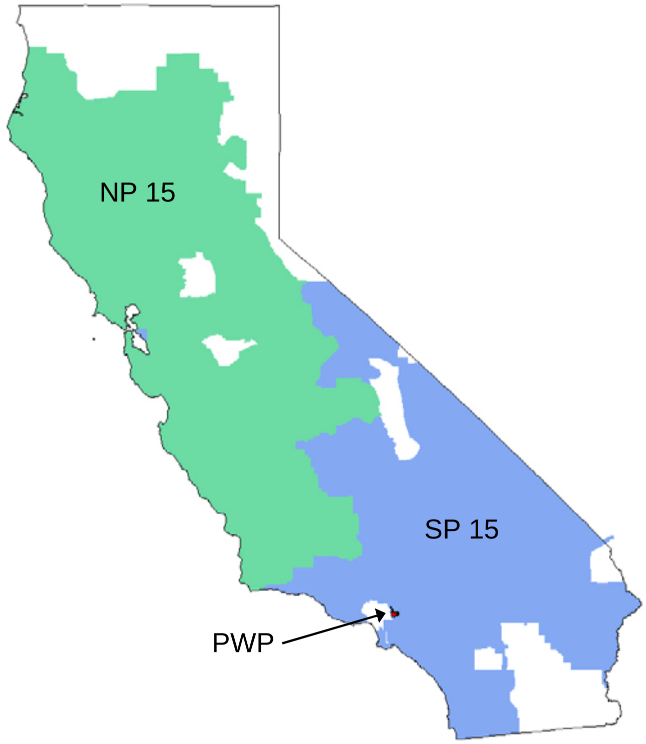
California is dedicated to being an innovative global leader in energy policy. The State desires to adequately respond to the challenge of climate change while still promoting and accommodating economic growth, and has sought to balance these objectives through a comprehensive approach using both pricing and program options that look to reduce the State's overall greenhouse gas footprint. Improvements to energy efficiency, and demand side management, as well as aggressive Renewable Portfolio Standards and cap-and-trade or carbon tax pricing, are some of the tools that are being pursued used to reach these goals. Legislation such as AB 32 (discussed in detail in the Environmental Section) has marked a change in California's energy policy and created a new path which others will follow in the future.

Exhibit 60: WECC Sub-Regional Designation



Source: Pace and Energy Velocity©

Exhibit 61: California ISO Control Area by Congestion Zones



Source: Pace and Energy Velocity©

CALIFORNIA MARKET REDESIGN AND TECHNOLOGY UPGRADE (MRTU)

The CAISO launched a program in 2001 to identify the flaws and inefficiencies that made the market vulnerable to manipulation in the early 2000s. The Market Redesign and Technology Upgrade ("MRTU") has been in development since 2001 and represents important, but incremental improvements to the CASIO market structure that are ultimately expected to produce a market structure comparable to the established ISO markets in the Northeast US.

The MRTU foundation is in the full network model ("FNM"), which is designed to allow CAISO to accurately model the entire grid on a day-ahead and real time basis. A financially binding Day-Ahead Market coupled with Resource Adequacy ("RA") requirements and Locational Marginal Pricing ("LMP") all based upon the FNM, should result in greater market efficiency that will provide more accurate energy price signals to all market participants. Furthermore, the complete MRTU will allow the CAISO to continue to achieve its goals of providing safe reliable energy at efficient prices.

The MRTU's implementation has experienced extremely slow progress, and will not be put into operation until the first quarter of 2009 at the earliest. Its delay could extend even longer due to ongoing software problems. Also, more innovations as seen in Eastern ISO markets such as longer than 1–year forward resource adequacy requirements, or organized capacity markets are not likely to come into service in California before 2012.

Full Network Model

The Full Network Model ("FNM") has been developed to replace the existing, less-sophisticated transmission network model. The FNM will allow the CAISO operators to model the actual flow of power on the entire network by taking into account all known transmission limitations and flows. The FNM will allow for more efficient dispatch of generators by providing a more complete view of transmission system congestion. The FNM will also allow the CAISO schedulers to anticipate congestion based on bids in the Day-Ahead Market and react accordingly.

Integrated Forward Market

The Integrated Forward Market ("IFM") establishes a forward market for energy, ancillary services, and transmission congestion management. The creation of a financially-binding Day-Ahead Market for energy is an important component of the CAISO MRTU. Currently, the CAISO anticipates day-ahead market activity; however, the lack of financial responsibility allows for submission of infeasible day-ahead schedules and creates inefficiencies in the market.

The day-ahead market in the IFM will allow schedulers to dispatch both energy and ancillary service requirements simultaneously based on the lowest cost of service, and it will also allow time for schedulers to plan for transmission congestion and identify constraints ahead of real-time activity. Moreover, the day-ahead market is expected to allow for more efficient Demand Side Management ("DSM") programs. MRTU allows for DSM loads to be treated as supply in the day-ahead, real-time, and ancillary services markets. Price signals from the IFM will allow for more efficient use of DSM as operators can evaluate the costs and benefits from interruptible demand. DSM increases system reliability by allowing for reductions in peak energy demand. Because demand response moderates price volatility for all customers, the use of DSM can limit the potential of market power abuse.

Locational Marginal Pricing

Locational Marginal Pricing ("LMP") allows for greater pricing granularity and more accurate price discovery in electricity markets. LMP is based on location nodes across the transmission grid where the incremental cost of electricity service is established. The cost of energy at each node is comprised of generation costs and transmission congestion costs. The use of LMP provides clear signals to market participants which allows for efficient infrastructure expansion and DSM planning.

LMP will also establish marginal congestion costs, which reflect the cost of moving energy between nodes. By capturing the true cost of power supply, including transmission congestion at each node, the ISO schedulers can dispatch the least cost generation to fulfill energy and ancillary service requirements. Once implemented, the MRTU LMP design will allow suppliers to be paid their LMP-specific price; wholesale customers, however, will be provided insulation against location-specific price volatility by continuing to pay an aggregated zonal price for energy.

Congestion Revenue Rights

Under the current CAISO market design, financial transmission rights are limited to the transmission flowing between adjacent zones or external interconnection points. The zone-based pricing does not provide a mechanism to observe transmission congestion occurring within a zone.

Congestion Revenue Rights ("CRR") are the financial vehicle the CAISO has established to allow end-use customers to mitigate congestion price risk. Congestion revenues are a product of market participants' paying a premium to lock in their day-ahead schedule on the transmission grid. This premium reflects the additional economic benefits provided by the transmission network. CRRs allow for the distribution of the congestion revenue back to those who have embedded costs in establishing and maintaining the transmission network. CRRs are based only on the IFM settlement and not the real-time market. CRRs therefore provide an incentive for market participants to bid into the IFM instead of relying on the real-time market.

CRR are based on the difference in prices between pricing nodes specified in the CRR contract and can be either obligations or options (i.e., reflecting congestion in either one or both directions between the nodes). The value of a CRR is settled hourly in the IFM. The CAISO will distribute CRRs to Load Serving Entities ("LSEs"), such as utilities, free of charge to offset their expected congestion costs. CRRs will also be distributed to transmission asset owners who do not recover costs through a regulated tariff. Following the allocation of CRRs to eligible end users, the CAISO will hold an auction where qualified parties can bid to buy or sell CRR obligations or options.

Resource Adequacy and Capacity Market

The California Public Utility Commission ("CPUC") has adopted a structure of system-wide and local resource adequacy requirements ("RA") applicable to jurisdictional LSEs, including the investor-owned utilities, competitive electric service providers and community choice aggregators. All RA requirements are designed to ensure that LSEs have procured, in advance, sufficient generating capacity to meet forecasted demand plus a reserve margin to account for contingencies such as load volatility and resource outages, throughout the year. The RA requirements are calculated using a planning reserve margin of 15-17% and a load forecast developed by the California Energy Commission. LSEs may contract independent generators, as well as firm imports and dispatchable demand response to provide RA capacity.

The current RA program, as based upon bilateral contracts, does not provide adequate transparency to the market. It is only a one year ahead system, so critics have claimed that it does not provide a clear signal to the market of future pricing to spur development of new generation resources, and as a result does not encourage proper resource planning. However, the current program has allowed the CPUC oversight to ensure system reliability on a year-to-year basis.

The CPUC and stakeholders are actively involved in establishing and evaluating a new market structure for the RA program. Discussions regarding the long-term RA program design are on-going. These discussions by market participants and regulators have focused on the incentive mechanism that would be employed by a Long-Term RA program. Two alternative market designs have been proposed to provide the incentive for new capacity: bilateral trading and a centralized capacity market. Both alternatives will likely have a forward procurement requirement of three to fours years. The CPUC has been unable to make a choice between the two different models and will most likely continue to take comments and hold workshops until a decision is reached, which is anticipated to be the end of 2008.

SRAC and MIF

The Short Run Avoided Costs ("SRAC") formula and the Market Index Formula ("MIF") are two different methods by which California utilities can pay Qualifying Facilities ("QF") for delivered energy. The creation of these formulas came as a result of the 2000-2001 energy crisis in which utilities did not make payments for delivered energy and capacity. The SRAC formula is administratively set and has a regulated market heat rate. The MIF, by contrast, was created as a way to transition to a more market based system. This formula is based 50% on the market and 50% is administratively set.

Non-ISO Markets

Within WECC, only California has instituted a centrally coordinated power market. The other areas within WECC have purposely decided not to adopt the market design put forth by the Federal Energy Regulatory Commission. Operations of the electric grid in the area of WECC not controlled by the CAISO are operated by individual control areas. These controls areas are responsible for providing schedules that balance load, production, imports, and exports. They are also responsible for acquiring ancillary services to support the grid.

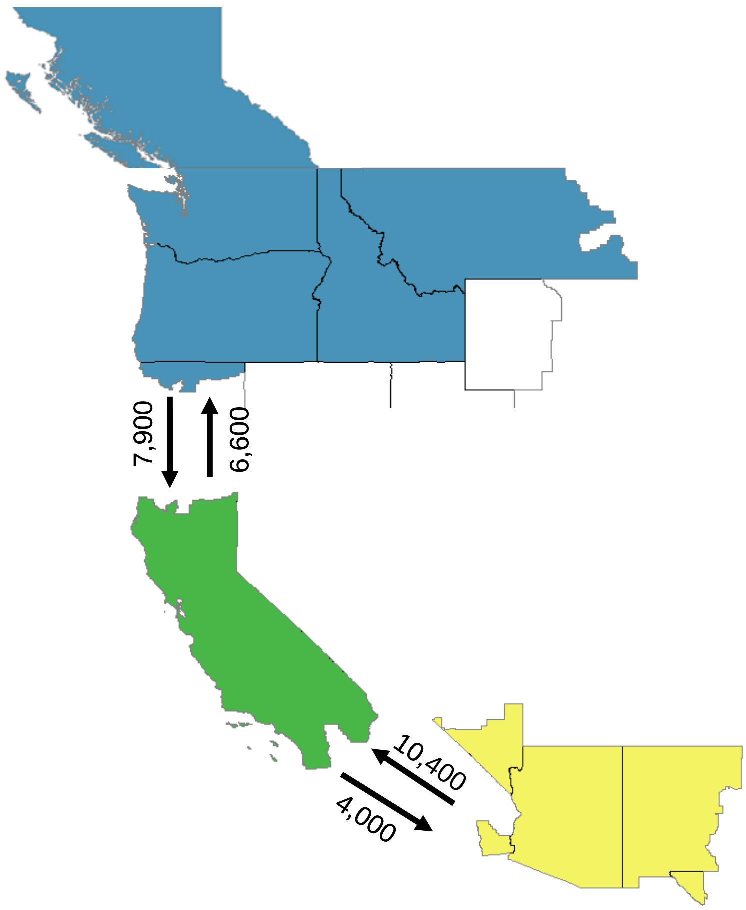
These markets remain highly regulated and are not subject to any ISO oversight or control. Load-serving entities ("LSE") are vertically-integrated utilities that build and operate power plants, transmission, and distribution systems within their service territory and are subject to the authority of state or local oversight. Utilities are allowed to enter into short-term, bilateral trades, but longer-term power purchase agreements or self-build options require competitive bidding or public review. In Arizona, regulators only approve such agreements upon comparison of these bids with the self-build option.

In the absence of a centralized system operator as in CAISO, there is currently no open capacity trading market outside CAISO, making it necessary to purchase capacity only through bilateral contracts between market participants. Without the price discovery and transparency afforded by a centralized clearly market, the market's perception of the value of capacity is very difficult to determine.

TRANSMISSION INTERCHANGE

Pace develops its price forecasts based on regional designations that represent areas with persistent and significant transmission congestion, which are the cause of long-term price divergence. For purposes of simulating the market area in Phase II analysis, Pace models three distinct pricing zones in the Western Interconnect. These include most of the Northwest Power Pool, California, and Arizona-New Mexico-Southern Nevada. Exhibit 62 provides a representation of Pace's modeling regions for WECC and the inter-regional transfer capability between California and the neighboring states/regions.

Exhibit 62: Inter-Regional Transfer Capability



Source: Pace

All electricity supply and demand within California, including each transmission area's native load and capacity, as well as neighboring and interconnected regions, are included in Pace's modeling systems. The transfer capabilities represented are based on data obtained from recent NERC Seasonal Reliability Assessments, the respective regional Reliability Assessments for the power market areas within the modeled regional consolidation, and historical wholesale transactions as reported to the Federal Energy Regulatory Commission ("FERC").

REGIONAL DEMAND

This section discusses Pace's regional forecasting methodology. For information on Pace's Pasadena specific load forecast please see Appendix E Load Forecast.

CALIFORNIA REGIONAL DEMAND PROFILE

The peak load of major utilities in the state of California is shown in Exhibit 63. Southern California Edison ("SCE"), serving southern California, had the highest peak load in 2006 at 21,642 MW. Pacific Gas & Electric ("PG&E") was close behind with 21,226 MW. These two utilities make up approximately 67 percent of the peak load of the region.

Exhibit 63: Major Utilities' Peak Load in 2006 (MW)

Utility	Peak Load (MW)
Southern California Edison	21,642
Pacific Gas & Electric	21,226
Los Angeles Department of Water and Power	6,102
San Diego Gas & Electric	4,474
Sacramento Municipal Utilities District	3,280
Dept of Water Resources – South	1,113
Modesto Irrigation District	707
WAPA - Mid Pacific (CVP)	665
Turlock Irrigation District	614
Anaheim Public Utilities Dept.	593
Riverside Utilities Dept	588
Northern California Power Agency	518
Santa Clara Electric Dept	486
Dept of Water Resources - North	341
Glendale Public Service Dept	335
Pasadena Water and Power Dept	313
Burbank Public Service Dept	307
Redding Electric Dept	253
Metropolitan Water District of Southern CA	222
Vernon Municipal Light Dept	197

Source: Pace and Energy Velocity

To ensure the accuracy of demand projections in our power market modeling, Pace developed an independent energy and peak demand forecast for each of its model regions, including the PWP territory. The following section presents Pace's forecasting method and our forecast of future energy demand.

PACE'S INDEPENDENT LOAD FORECASTING METHODOLOGY

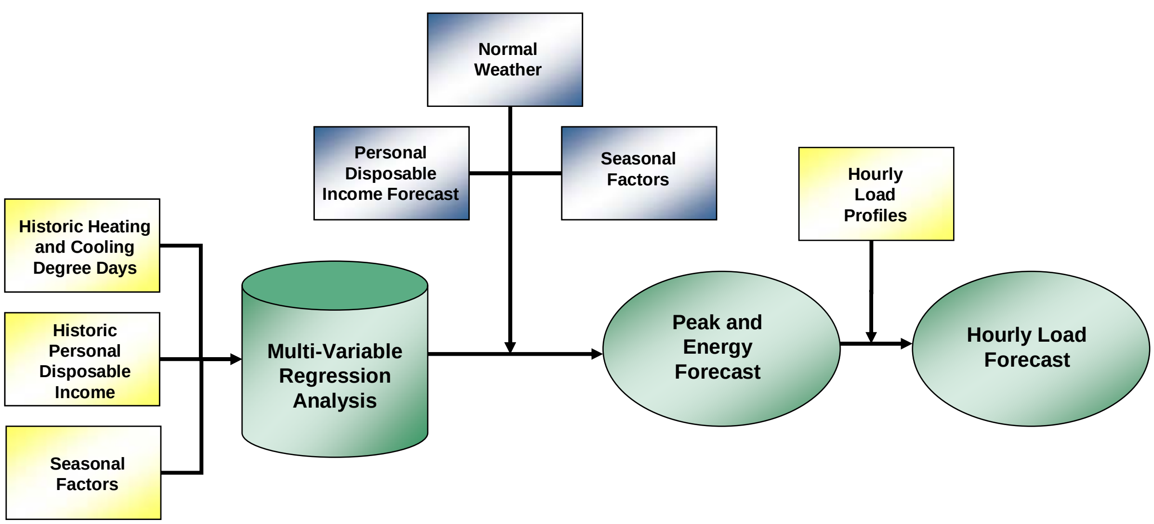
Pace's independent demand forecast for the WECC region and the California market was developed according to the methodology illustrated in Exhibit 64. This methodology has two primary components. The first is the use of econometric models to forecast annual peak demand and energy levels based on changes in income, heating and cooling degree days, and other factors. The second component of the methodology is the translation of historical hourly demand levels and forecasted peak demands to create hourly load projections for each forecast year.

Typically, the most accurate means of projecting future demand is not realized solely by analyzing past trends in peak and energy demand, but by analyzing the underlying factors, which drive the consumption of electricity. This approach is often referred to as a "bottom-up" analytical approach. As shown in Exhibit 64, the foundation of Pace's load forecasting methodology is a bottom-up econometric approach.

To generate this demand forecast, Pace:

- Established the historical relationship between net energy for load, disposable income, and heating and cooling degree days in the WECC power market. Pace's regression analysis indicated a strong correlation between electricity demand and these indicators. Specifically, the analysis produced an adjusted R^2, or "fit", of 0.926 for WECC-US. Therefore, regression results show that at least 92.6% of changes in electricity demand can be explained by changes in these specified indicators.
- Forecasted a base demand case based on the historical trends of income and heating and cooling degree days.
- Calculated seasonal energy and summer/winter peaks according to historical usage patterns and load factors.

Exhibit 64: Pace Load Forecasting Methodology



Source: Pace

Other issues considered with respect to Pace's independent forecast include:

- Normal weather conditions are assumed with no factors included to simulate extreme weather conditions.
- The forecast incorporated all demand and energy reductions from utility dispatchable and non-dispatchable demand-side management ("DSM") programs as published in utility demand forecasts.

DEMAND FORECAST RESULTS

Pace projects that WECC's average annual growth rate for the Study Period will be 1.2 percent. The Southern Nevada and Arizona regions are expected to have the highest average annual growth rate among WECC regions over the Study Period at 2.99 and 2.36 percent, respectively. Average annual demand growth in California is expected to be about 1 percent over the Study Period. This is slightly lower then the 1996 to 2006 historical average of 1.9 percent. Oregon-Washington-Idaho ("OWI") and Montana are projected to have the lowest average annual growth rates. Exhibit 65displays Pace's forecast for energy demand for the entire WECC region, while Exhibit 66 shows the forecast for California.

Exhibit 65: Energy Forecast for WECC (GWh)

Year	WECC
2008	753,600
2009	754,866
2010	765,712
2011	773,508
2012	791,342
2013	795,527
2014	805,718
2015	815,901
2016	835,585
2017	835,283
2018	846,421
2019	856,782
2020	874,723
2021	878,043
2022	885,623
2023	896,688
2024	916,050
2025	918,377
2026	928,678
2027	939,819
2028	956,115

Source: Pace

Exhibit 66: Pace's California Region Demand Forecast

Year	Energy Demand	Peak Demand
	GWh	MW
2008	306,638	57,283
2009	309,606	57,984
2010	313,272	58,670
2011	316,864	59,343
2012	321,190	60,002
2013	323,818	60,646
2014	327,175	61,275
2015	330,453	61,888
2016	334,494	62,486
2017	336,754	63,068
2018	339,780	63,634
2019	342,718	64,185
2020	346,441	64,719
2021	348,323	65,235
2022	350,995	65,735
2023	353,573	66,218
2024	356,960	66,684
2025	358,451	67,132
2026	360,861	67,583
2027	363,286	68,038
2028	366,652	68,494
2008-2015 CAGR	1.07%	1.11%
2008-2028 CAGR	0.90%	0.90%
2015-2028 CAGR	0.80%	0.78%

Source: Pace

HOURLY LOAD FORECASTING

The forecast of overall energy growth is not the only element needed to accurately characterize future energy levels. The characterization and replication of daily, weekly, and seasonal load variations significantly impact the usage, type and cost of resources required by a utility system. The last step in Paces load forecasting methodology therefore is the projection of hourly demand values.

Pace's methodology applies annual growth factors derived from our peak demand and energy forecasts to the actual 8,760 hours of load occurring in a utility system. In this way, our market modeling system contains the highest level of detail to reflect not only the cost to serve certain levels of load but also how hourly changes impact the use of different types of generation units.

Pace uses an Hourly Load Module tool to translate annual peak demand and energy growth factors into future hourly demand for a given Study Period. The translation process is a two-step process:

- Step 1: The first step involves aggregating actual utility hourly loads as reported to the FERC. This aggregation creates an integrated hourly system load profile for the WECC region.
- Step 2: The second step involves applying annual growth factors and seasonal peak demand forecasts to the base system hourly load file (created in Step 1) to create an hourly demand file for each year in the Study Period.

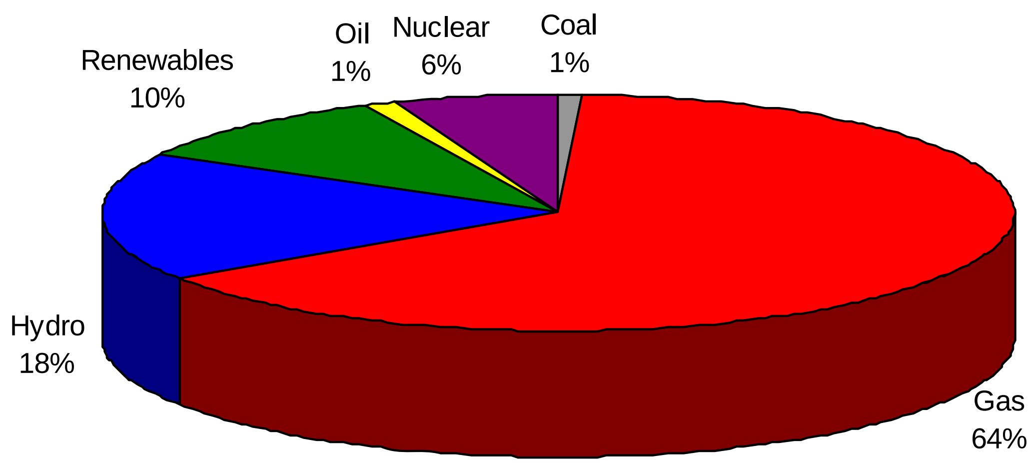
The result of this process is an hourly demand shape that replicates actual market fluctuations and allows for representative dispatch patterns of the generating resources in the market.

REGIONAL MARKET SUPPLY PROFILE

EXISTING GENERATING CAPACITY PROFILE

Exhibit 67 displays the installed capacity profile of the entire CAISO region. The region's capacity is predominantly gas-fired, with such capacity making up about 64% of the total. The remainder is primarily comprised of a mix of hydro (18%), renewable (10%), and nuclear (6%).

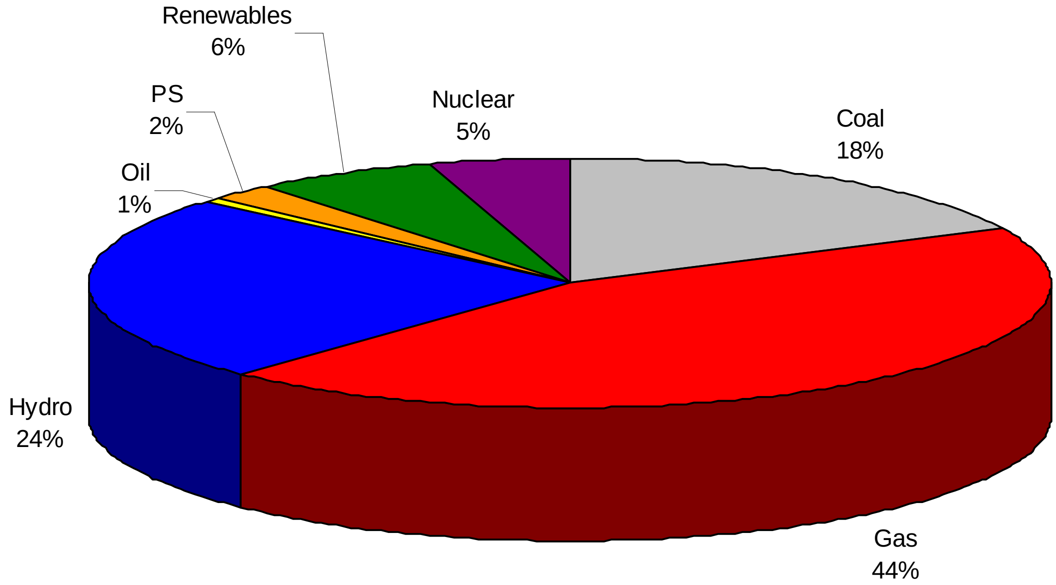
Exhibit 67: Installed Capacity Profile – CAISO



Source: Pace and Energy Velocity®

WECC has a different capacity profile then CAISO, as is seen in Exhibit 68. The whole of WECC, although still dominantly gas driven, has a larger share of hydro capacity and substantially more coal resources. The total installed capacity currently operating or available throughout this region is around 200,000 MW.

Exhibit 68: Installed Capacity Profile – WECC

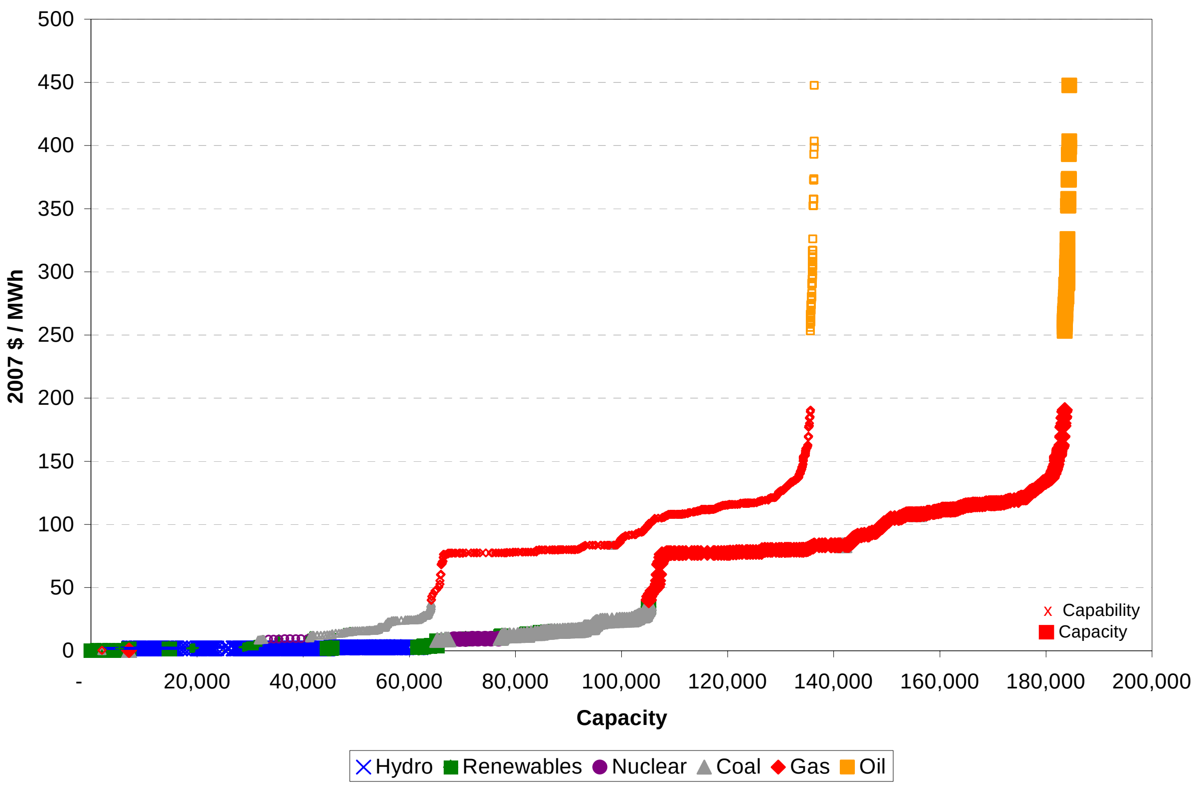


Source: Pace and Energy Velocity®

SUPPLY CURVE

Exhibit 69 displays existing supply curves for WECC for 2008 based on both the capacity and capability of the installed resources in the region. While the capacity line represents total average installed capacity, the capability line represents the average capacity available after maintenance, forced outage rates, seasonal derates, capacity factor expectations for hydro and intermittent resources are taken into account.

Exhibit 69: WECC Supply Curve



Source: Pace and Energy Velocity®

Nuclear Unit Assessment

As shown in Exhibit 70, there are four nuclear plants in the WECC region, two of which are located in California—Diablo Canyon (2,248 MW) and San Onofre (2,232 MW). Both Diablo Canyon and San Onofre nuclear plants have contributed reliable power to meet the state's load. In 2007, both nuclear power plants in California generated nearly 36,000 GWh of electricity, approximately 13% of California's total energy requirements.

The other nuclear plants in WECC are located in Arizona and Washington. The Palo Verde nuclear generating facility is the largest nuclear plant in the U.S., with PWP owning a share.

Exhibit 70: WECC-US Nuclear Units

Name	Utility	Sub-Region	NRC License Expiration	Winter Capacity (MW)
Columbia Generating Station	Energy Northwest	OWI	Dec-23	1,138
Diablo Canyon 1	Pacific Gas & Electric	CANo	Sep-21	1,124
Diablo Canyon 2	Pacific Gas & Electric	CANo	Apr-25	1,124
Palo Verde 1	Arizona Public Service Co.	AZ	Dec-24	1,292
Palo Verde 2	Arizona Public Service Co.	AZ	Dec-25	1,292
Palo Verde 3	Arizona Public Service Co.	AZ	Mar-27	1,292
San Onofre 2	Southern California Edison Co.	CASo	Feb-22	1,116
San Onofre 3	Southern California Edison Co.	CASo	Nov-22	1,116
			Total Nuclear Generating Capacity	**9,493**

Source: Pace, Energy Velocity, and Nuclear Regulatory Commission

Pace reviewed unit operations and down-time, historic plant performance, and recent market trends to assess the future of nuclear capacity in WECC. The operational licenses of all nuclear plants in the WECC region are currently due to expire prior to the end of the Study Period. However, from 2001 to 2007, the nuclear units shown in Exhibit 70have run at an average capacity factor of more than 81%. Given such operations and current license expiration dates, Pace's analysis has assumed that all nuclear units will continue to operate throughout the entire Study Period.

The outlook for nuclear power has become more optimistic recently due to concerns over carbon emissions from fossil fuel generated power and the energy balancing complexity associated with intermittent power from renewable sources. Nuclear units stand to benefit from changing public opinion and government support for clean power as well as pending climate legislation, which could allow for the possible utilization of carbon permits as a secondary income stream for nuclear generation.

The Nuclear Regulatory Commission's condensed permitting process, which eliminates the risk that a new permitted plant would not be allowed to operate due to a failure to receive its conditional operating license, has helped initiate this change in outlook for the industry. Also supporting the recent surge in planned nuclear expansion is the US federal incentives offered in the Energy Policy Act of 2005.

Due to the need for base load capacity that does not emit carbon dioxide and due to the existence of certain sites in the region that have potential for expansion, Pace expects that approximately 3,000 MW of nuclear capacity will be built in WECC over the Study Period. Exhibit 71 outlines the currently proposed nuclear capacity in WECC.

Exhibit 71: WECC-US Proposed Nuclear Units

Name	Utility	Sub-Region	Online Date	Winter Capacity (MW)
Idaho Energy Complex	Alternative Energy Holdings	ID-S	12/31/2016	1600
Transition Power Nuclear	Transition Power Development LLC	UT	1/1/2018	1500

Source: Pace, Energy Velocity, and Nuclear Regulatory Commission

ANNOUNCED CAPACITY ADDITIONS

Consistent with the market approach to capacity additions, Pace conducts its forecasts of market prices under a scenario that considers publicly announced project development activities, in addition to un-announced but required capacity additions in response to market conditions.

Pace evaluated all projects based on status of permitting, financing, and construction through a review of regulatory agencies queues and trade press, discussions with market participants, and general activity in the market.

Recently completed and announced development projects in California are shown in Exhibit 72. In its Reference Case analysis, Pace includes only projects that are operational, under construction, or have obtained the proper financial support to proceed with construction. Approximately 80 percent of the announced expansion is gas-fired. New wind capacity accounts for 13 percent and the remaining 7 percent is a mix of other renewables.

Exhibit 73 shows announced projects in California that are not explicitly reflected in our Reference Case, because Pace believes that their current stage of development does not provide sufficient evidence to assume project completion. The permitted and proposed projects listed below account for more than 16,500 MW of potential generating capacity in the market. The vast majority of this capacity is either natural gas-fired or renewable. Proposed and permitted hydro capacity accounts for 18 percent, while solar and wind comprise 16 percent and 12 percent, respectively. California regulations requiring renewable generation are spurring significant renewable capacity proposals.

Exhibit 72: CA Recently Completed and Announced Capacity Additions (Included in Reference Case)

Owner Name	Plant Name	Fuel Type	Unit Type	Plant Region	Plant Status	Online Date	Winter Capacity (MW)
Iberdrola Renewables Inc	Dillon Wind WT 1-45	WIND	WT	CASo	Operating	4/7/2008	45
Imperial Irrigation District	Niland Combustion Turbine Project	NG	CT	CASo	Operating	5/1/2008	93
Ameresco Inc	Ox Mountain Landfill (IC1-6)	LFG	IC	CANo	Operating	6/1/2008	11
Inland Empire Energy Center LLC	Inland Empire Energy Center (1-2)	NG	CC	CASo	Operating	6/1/2008	810
San Diego County Water Authority	Olivenhain Hodges Pumped Storage	WAT	PS	CASo	Under Const	12/31/2008	40
Enxco Windfarm IV	Shiloh II Wind	WIND	WT	CANo	Under Const	12/31/2008	150
Ormat Technologies Inc	Brawley Geothermal	GEO	GE	CASo	Under Const	1/1/2009	50
Los Angeles Dept of Water & Power	Pine Tree Wind	WIND	WT	CASo	Under Const	1/1/2009	120
Otay Mesa Generating Co LLC	Otay Mesa	NG	CC	CASo	Under Const	5/30/2009	593
PG&E Corp	Gateway Generating Station	NG	CC	CANo	Under Const	6/1/2009	530
						Total Capacity Additions	2,442

Source: Pace and Energy Velocity©

Exhibit 73: CA Major Permitted and Proposed Plants (not included in Reference Case)

Owner Name	Plant Name	Fuel Type	Unit Type	Plant Region	Plant Status	Online Date	Winter Capacity (MW)
MMC Energy	Escondido	NG	GT	CASo	Permitted	6/1/2009	50
Energy Investor Funds LP	Panoche Energy Center	NG	GT	CANo	Permitted	8/1/2009	400
Pacific Gas & Electric Co	Colusa Generating Station	NG	CC	CANo	Permitted	4/1/2010	660
Caithness Blythe II LLC	Blythe II	NG	CC	CASo	Permitted	8/1/2010	520
Calpine Corp	Russell City	NG	CC	CANo	Permitted	6/30/2011	403
GE Energy Financial Services Inc	Russell City	NG	CC	CANo	Permitted	6/30/2011	217
Midway Power LLC	Tesla Power Project	NG	CC	CANo	Permitted	6/30/2012	570
Walnut Creek Energy LLC	Walnut Creek Energy Park	NG	GT	CASo	Permitted	6/1/2013	500
Coram Energy Group Ltd	Coram Tehachapi	WND	WT	CASo	Proposed	1/1/2009	93
Harper Lake LLC	Harper Lake Energy Park	SUN	SS	CASo	Proposed	6/1/2009	160
Aero Energy LLC	Windstar I	WND	WT	CASo	Proposed	9/30/2009	120
AES Corp (The)	Daggett Ridge Wind Farm	WND	WT	CASo	Proposed	10/1/2009	80
Bethel Energy Corp	Bethel Solar 1	SUN	SS	CASo	Proposed	12/31/2009	100
Chevron USA Inc	Richmond Cogeneration Project	NG	CC	CANo	Proposed	12/31/2009	60
Eastern Desert Power LLC	Eastern Desert Power Wind	WND	WT	CASo	Proposed	12/31/2009	51
enXco Inc	Pacific Wind	WND	WT	CASo	Proposed	12/31/2009	206

Owner Name	Plant Name	Fuel Type	Unit Type	Plant Region	Plant Status	Online Date	Winter Capacity (MW)
FPL Energy LLC	West Fry Wind	WND	WT	CASo	Proposed	12/31/2009	51
Ormat Technologies Inc	Brawley Geothermal	GEO	GE	CASo	Proposed	12/31/2009	200
Chevron California Renewable Energy	Chevron Wave Energy	WAT	HT	CANo	Proposed	1/1/2010	57
Vulcan Power Co	Northwest Military Pass Geothermal Project	GEO	GE	CANo	Proposed	1/1/2010	90
E I Colton LLC	Agua Mansa Power Project	NG	CC	CASo	Proposed	6/30/2010	116
Palmdale CA (City of)	Palmdale Gas Solar Hybrid	NG	CC	CASo	Proposed	6/30/2010	500
Intergen North America	Ocotillo Energy Project	NG	GT	CASo	Proposed	8/1/2010	455
Sacramento Municipal Utility District	Consumnes	NG	CC	CANo	Proposed	12/1/2010	500
Enpex Corp	San Diego Community Power Project	NG	CC	CASo	Proposed	12/31/2010	750
Geysers Power Co LLC	Geysers	GEO	GE	CANo	Proposed	12/31/2010	80
Harper Lake LLC	Harper Lake Energy Park	SUN	SS	CASo	Proposed	12/31/2010	500
Iberdrola Renewables Inc	Manzana Wind Project	WND	WT	CASo	Proposed	12/31/2010	300
SES Solar One LLC	SES Solar One	SUN	SH	CASo	Proposed	12/31/2010	500
Golden Gate Energy Co	San Francisco Bay Tidal	WAT	HT	CANo	Proposed	1/1/2011	1,000
Sacramento Municipal Utility District	Solano Wind (SMUD)	WND	WT	CANo	Proposed	1/1/2011	114
Solel MSP 1 LLC	Mojave Solar Park	SUN	SS	CASo	Proposed	1/1/2011	553
Western Wind Energy Corp	Western Wind Barstow	WND	WT	CASo	Proposed	1/1/2011	100
BP Amoco PLC	Carson Hydrogen Power Project	PC	IGCC	CANo	Proposed	6/1/2011	250
Edison International	Carson Hydrogen Power Project	PC	IGCC	CASo	Proposed	6/1/2011	250
Mirant Marsh Landing LLC	Marsh Landing Generating Station	NG	GT	CANo	Proposed	7/1/2011	380
Martifer Renewables	Coalinga Hybrid	SUN	SS	CASo	Proposed	12/31/2011	107
Esolar	Esolar Power Tower	SUN	SS	CASo	Proposed	1/1/2012	105
Northern California Power Agency	Lodi Energy Center	NG	CC	CANo	Proposed	1/1/2012	255
Optisolar Inc	Topaz Solar Farm	SUN	PV	CASo	Proposed	1/1/2012	550
Mirant Marsh Landing LLC	Marsh Landing Generating Station	NG	CC	CANo	Proposed	6/1/2012	550
Continental Cogeneration Services	Continental Cogeneration Los Banos	NG	CC	CANo	Proposed	7/1/2012	275
Mirant Willow Pass LLC	Willow Pass Generating Station	NG	CC	CANo	Proposed	7/1/2012	550
BPUS Generation Development LLC	Mulqueeney Ranch PS	WAT	PS	CANo	Proposed	12/31/2012	280
Competitive Power Ventures	CPV Vacaville	NG	CC	CANo	Proposed	12/31/2012	500
Esolar	Esolar Power Tower	SUN	SS	CASo	Proposed	1/1/2013	140
Eagle Crest Energy Co	Eagle Mountain PS	WAT	PS	CASo	Proposed	1/1/2014	1,300
Allco Wind Energy	Alta Wind Energy Center	WND	WT	CASo	Proposed	12/31/2015	500
Oak Creek Energy System Inc II	Alta Wind Energy Center	WND	WT	CASo	Proposed	12/31/2015	500
						Total Proposed and Permitted Capacity	16,546

Source: Pace and Energy Velocity©

Recently completed and announced development projects for the rest of WECC are shown in Exhibit 74. Approximately 50 percent of the new expansion is expected to be gas-fired. Unlike California, the region at large is still building coal power plants and these new plants account for about 35 percent of the total new capacity. Wind projects account for 13 percent. Exhibit 75 shows 26,503 MW of announced projects in the rest of WECC that are not reflected in our Reference Case. Gas accounts for only 9 percent of this amount, while wind makes up for almost 50 percent of the proposed capacity additions at around 12,800 MW. Coal and Hydro capacity account for roughly 17 percent each.

Exhibit 74: WECC Recently Completed and Announced Capacity Additions Excluding CA (Included in Reference Case)

Owner Name	Plant Name	Fuel Type	Unit Type	Plant State	Plant Status	Online Date	Winter Capacity MW
Simpson Tacoma Kraft Co	Simpson Tacoma Biomass	BLQ	ST	WA	Under Const	6/30/2009	55
Mission Energy Co	Mountain Wind	Wind	WT	WY	Operating	7/31/2008	60.9
PacifiCorp	Marengo Wind	Wind	WT	WA	Under Const	1/1/2009	70.2
Mountain Wind Power II LLC	Mountain Wind II	Wind	WT	WY	Under Const	9/30/2008	79.8
Cheyenne Light Fuel & Power Co	Wygen II	Coal	ST	WY	Operating	1/10/2008	90
UniSource Energy Corp	Black Mountain Generating Station	Gas	GT	AZ	Operating	5/31/2008	90
Windtricity Ventures LLC	Goodnoe Hills Windfarm	Wind	WT	WA	Operating	7/14/2008	94
Arizona Public Service Co	Yucca	Gas	GT	AZ	Operating	6/30/2008	96
Iberdrola Renewables Inc	Pebble Springs Wind	Wind	WT	OR	Under Const	11/30/2008	99.5
Black Hills Power Inc	Wygen III	Coal	ST	WY	Under Const	6/1/2010	100
Arlington Wind Power Project LLC	Rattlesnake Road Wind	Wind	WT	OR	Under Const	1/1/2009	102.9
Platte River Power Authority	Rawhide	Gas	GT	CO	Operating	6/13/2008	128
El Paso Electric Co	Newman	Gas	GT	TX	Under Const	5/1/2009	140
Valencia Energy Facility	Valencia Energy Facility	Gas	GT	NM	Operating	5/30/2008	140
Idaho Power Co	Evander Andrews	Gas	GT	ID	Operating	3/11/2008	170
Peetz Table Wind Energy LLC	Peetz Wind (FPL)	Wind	WT	CO	Operating	1/9/2008	199.5
Newmont Mining Corp	TS Power Plant	Coal	ST	NV	Operating	6/1/2008	200
Public Service Co of Colorado	Fort St Vrain	Gas	GT	CO	Under Const	6/1/2009	261
Intermountain Rural Electric Association	Comanche (CO)	Coal	ST	CO	Under Const	10/1/2009	262.5
Wayzata Investments Partners	Mint Farm Energy Center	Gas	CC	WA	Operating	1/31/2008	315
Basin Electric Power Coop	Dry Fork Station	Coal	ST	WY	Under Const	1/1/2011	357.665
Salt River Project	Springerville Generating Station	Coal	ST	AZ	Under Const	12/31/2009	400
Public Service Co of Colorado	Comanche (CO)	Coal	ST	CO	Under Const	10/1/2009	487.5
Invenergy Grays Harbor LLC	Grays Harbor Energy	Gas	CC	WA	Operating	4/25/2008	650
Nevada Power Co	Clark (NV)	Gas	GT	NV	Operating	7/16/2008	720
						Total Capacity Additions	5369.465

Source: Pace and Energy Velocity©

PACE

Exhibit 75: WECC Major Permitted and Proposed Plants Excluding CA (not included in Reference Case)

Owner Name	Plant Name	Fuel Type	Unit Type	Plant State	Plant Status	Online Date	Winter Capacity MW
Lifeline Renewable Energy	Shepherds Flat Wind Farm	Wind	WT	OR	Permitted	12/31/2008	303.00
BP Alternative Energy	Greenlight Akron Wind Energy	Wind	WT	CO	Permitted	12/31/2008	200.00
Ida Therm LLC	Willow SpriGass Geothermal	GEO	GE	ID	Permitted	1/1/2009	100.00
Horizon Wind Energy	Kittitas Valley Wind	Wind	WT	WA	Permitted	3/31/2009	120.00
Windy Point Partners	Windy Point	Wind	WT	WA	Permitted	5/31/2009	136.60
Portland General Electric Co	Biglow Canyon	Wind	WT	OR	Permitted	6/1/2009	149.50
Montgomery Energy Partners LP	Great Falls Energy Center	Gas	CC	MT	Permitted	6/30/2009	262.00
Foresight Wind Energy LLC	Sunshine Wind Energy Park	Wind	WT	AZ	Permitted	6/30/2009	60.00
Teton Power LLC	White Mountain Wind (WY)	Wind	WT	WY	Permitted	12/31/2009	54.00
Portland General Electric Co	Biglow Canyon	Wind	WT	OR	Permitted	12/31/2010	174.80
Deseret Power Electric Coop	Bonanza	WC	AB	UT	Permitted	12/31/2010	110.00
Lifeline Renewable Energy	Shepherds Flat Wind Farm	Wind	WT	OR	Permitted	1/1/2011	303.00
El Paso Electric Co	Newman	Gas	CC	TX	Permitted	5/1/2011	288.00
Nevada Power Co	Harry Allen (NV)	Gas	CC	NV	Permitted	6/1/2011	520.00
Windy Point Partners	Windy Point	Wind	WT	WA	Permitted	12/31/2011	350.00
Nevco Energy Co	Sevier Power Project	Coal	AB	UT	Permitted	12/31/2011	250.00
Lifeline Renewable Energy	Shepherds Flat Wind Farm	Wind	WT	OR	Permitted	1/1/2012	303.00
Southern Montana Electric Generation	Highwood Generation Station	Coal	AB	MT	Permitted	1/1/2012	187.50
Great Falls (City of) MT	Highwood Generation Station	Coal	AB	MT	Permitted	1/1/2012	62.50
Shell Wind Energy	Cotterel Mountain	Wind	WT	ID	Permitted	1/1/2014	97.50
Windland Inc	Cotterel Mountain	Wind	WT	ID	Permitted	1/1/2014	97.50
Iberdrola SA	Huerfano Wind	Wind	WT	CO	Proposed	12/31/2008	250.00
Foresight Wind Energy LLC	Owaissa Wind Project	Wind	WT	NM	Proposed	12/31/2008	120.00
Invenergy LLC	Willow Creek Wind Project	Wind	WT	OR	Proposed	12/31/2008	72.00
Judith Gap Energy LLC	Judith Gap Wind Farm	Wind	WT	MT	Proposed	12/31/2008	52.50
Invenergy Wind LLC	Vantage Wind Project	Wind	WT	WA	Proposed	1/1/2009	103.50
Green Borders Geothermal LLC	Green Borders Geothermal	GEO	GE	NV	Proposed	1/1/2009	65.00
Clipper Windpower Inc	ShootiGas Star Wind Project	Wind	WT	KS	Proposed	3/1/2009	105.00
Tasco EGasineeriGas Inc	Stockton Bar	Wind	WT	UT	Proposed	3/1/2009	70.00
Foresight Wind Energy LLC	High Lonesome Wind Ranch	Wind	WT	NM	Proposed	6/30/2009	100.00
Rocky Mountain Power	High Plains Wind (WY)	Wind	WT	WY	Proposed	6/30/2009	99.00
BP Alternative Energy	Golden Hills Wind Farm	Wind	WT	OR	Proposed	12/31/2009	400.00
H2o Providers LLC	Phantom Canyon	Water	HY	CO	Proposed	12/31/2009	370.00
Madison Valley Renewable	Norris Hill Wind Farm	Wind	WT	MT	Proposed	12/31/2009	150.00

Owner Name	Plant Name	Fuel Type	Unit Type	Plant State	Plant Status	Online Date	Winter Capacity MW
Energy LLC							
Mountain Island Energy LLC	Rabbit Hill Wind Farm	Wind	WT	ID	Proposed	12/31/2009	120.00
GE Energy Financial Services Inc	Aragonne Mesa	Wind	WT	NM	Proposed	12/31/2009	77.00
Klondike Wind Power III LLC	Klondike III	Wind	WT	OR	Proposed	12/31/2009	76.50
Coalorado Green HoldiGass LLC	Coalorado Green Windfarm	Wind	WT	CO	Proposed	12/31/2009	75.00
Pioneer Ridge LLC	Pioneer Ridge	Wind	WT	UT	Proposed	12/31/2009	70.00
Coalorado State University	CSU Green Power Project	Wind	WT	CO	Proposed	12/31/2009	65.00
Evergreen Wind Power Partners	Larch Mountain Wind	Wind	WT	WA	Proposed	12/31/2009	58.50
Windland Inc	American Falls Wind	Wind	WT	ID	Proposed	1/1/2010	200.00
Hook Canyon Energy LLC	Hook Canyon Pumped Storage	Water	PS	UT	Proposed	1/1/2010	60.00
Vulcan Power Co	Vulcan Power Nevada Geothermal	GEO	GE	NV	Proposed	6/1/2010	62.00
Intermountain Wind	Double X Wind	Wind	WT	WY	Proposed	6/30/2010	500.00
Horizon Wind Energy	Martinsdale Coalony Wind	Wind	WT	MT	Proposed	6/30/2010	300.00
Montgomery Energy Partners LP	Great Falls Energy Center	Gas	GT	MT	Proposed	6/30/2010	125.00
Ida Therm LLC	China Cap Geothermal	GEO	GE	ID	Proposed	6/30/2010	50.00
Pacific Hydro Inc	Steel Park Wind	Wind	WT	AZ	Proposed	9/30/2010	102.00
Western Wind Energy Corp	Steel Park Wind	Wind	WT	AZ	Proposed	9/30/2010	98.00
Greenhunter Wind Energy LLC	Wheatland Wind	Wind	WT	WY	Proposed	12/31/2010	390.00
Green Energy Wind LLC	Nambe Pueblo Wind	Wind	WT	NM	Proposed	12/31/2010	300.00
Res Americas Inc	Cedar Point Wind	Wind	WT	CO	Proposed	12/31/2010	300.00
Southern Ute Growth Fund	Wheatland Wind	Wind	WT	WY	Proposed	12/31/2010	210.00
Renewable Energy Systems Ltd	China Mountain Wind	Wind	WT	NV	Proposed	12/31/2010	100.00
Sierra Pacific Resources	China Mountain Wind	Wind	WT	NV	Proposed	12/31/2010	100.00
Rocky Mountain Power	Seven Mile Hill Wind	Wind	WT	WY	Proposed	12/31/2010	99.00
Rocky Mountain Power	McFadden Ridge Wind	Wind	WT	WY	Proposed	12/31/2010	88.50
Exergy Development Group LLC	Coald SpriGass Wind Park	Wind	WT	OR	Proposed	12/31/2010	80.00
Mountain Wind Power LLC	Bridger Butte Wind Project	Wind	WT	WY	Proposed	12/31/2010	79.80
Exergy Development Group LLC	Castle Rock Wind Park	Wind	WT	OR	Proposed	12/31/2010	70.00
Exergy Development Group LLC	Yahoo Creek Wind Park	Wind	WT	ID	Proposed	12/31/2010	70.00
SDS Lumber Co	Saddleback Mountain Wind	Wind	WT	WA	Proposed	12/31/2010	70.00
Nevada Geothermal Power Inc	Black Warrior Geothermal	GEO	GE	NV	Proposed	12/31/2010	50.00
Southeast Idaho Energy LLC	Southeast Idaho Energy	Coal	IG	ID	Proposed	1/1/2011	520.00
Nevada Wind LLC	Pah Rah Wind	Wind	WT	NV	Proposed	1/1/2011	150.00
US Geothermal	Raft River Geothermal	GEO	GE	ID	Proposed	1/1/2011	50.00
TransCanada Corp	Coolidge GeneratiGas Station	Gas	GT	AZ	Proposed	5/1/2011	574.99
PPL Montana LLC	Rainbow (MT)	Water	HY	MT	Proposed	5/31/2011	60.00

Owner Name	Plant Name	Fuel Type	Unit Type	Plant State	Plant Status	Online Date	Winter Capacity MW
APS	Solana GeneratiGas Station	Sun	SS	AZ	Proposed	6/30/2011	280.00
Great Northern Power Development LP	Nelson Creek (MT)	Coal	AB	MT	Proposed	10/1/2011	250.00
NT Hydro	Abert Rim Pumped Storage	Water	PS	OR	Proposed	11/1/2011	182.00
Eugene Waterer & Electric Board	Carmen Hydro	Water	HY	OR	Proposed	12/31/2011	104.50
Mountain Wind Power LLC	Bridger Butte Wind Project	Wind	WT	WY	Proposed	12/31/2011	79.80
Idaho Power Co	Shoshone Falls	Water	HY	ID	Proposed	12/31/2011	64.00
Avista Corp	Reardan Wind Project	Wind	WT	WA	Proposed	12/31/2011	50.00
Bull Mountain Development Co	Bull Mountain	Coal	IG	MT	Proposed	1/1/2012	300.00
Citizens Energy Services Corp	Dine Wind Project	Wind	WT	AZ	Proposed	1/1/2012	200.00
Newberry Volcano LLC	Newberry Volcano	GEO	GE	OR	Proposed	1/1/2012	90.00
New Solar Ventures	DemiGas Solar (NM)	Sun	PV	NM	Proposed	6/1/2012	150.00
Solar Torx	DemiGas Solar (NM)	Sun	PV	NM	Proposed	6/1/2012	150.00
Vulcan Power Co	Vulcan Power Nevada Geothermal	GEO	GE	NV	Proposed	6/1/2012	118.00
SkyFuel LLC	SolarDunes	Sun	SS	CO	Proposed	6/1/2012	100.00
Power Co of WyomiGas LLC	Anschutz Wind Project	Wind	WT	WY	Proposed	6/30/2012	1,000.00
Great Northern Power Development LP	Nelson Creek (MT)	Coal	AB	MT	Proposed	10/1/2012	250.00
United Power Corp (The)	Bryant Mountain Pumped Storage	Water	PS	OR	Proposed	12/31/2012	1,175.00
Nevada Wind LLC	Wilson Creek Wind	Wind	WT	NV	Proposed	12/31/2012	750.00
Foresight Wind Energy LLC	Grapevine Canyon Wind	Wind	WT	AZ	Proposed	12/31/2012	500.00
EcoSphere Energy	EcoSphere IGCC	Coal	IG	MT	Proposed	12/31/2012	170.00
Mountain Wind Power LLC	Bridger Butte Wind Project	Wind	WT	WY	Proposed	12/31/2012	79.80
Intermountain Wind	Boswell SpriGass Wind	Wind	WT	WY	Proposed	1/1/2013	700.00
Mountain Island Energy LLC	Soda SpriGass Power Plant	Coal	AB	ID	Proposed	1/1/2013	250.00
Southwest Public Power Resources Group	SPPR Pinal County Project	Gas	CC	AZ	Proposed	6/30/2013	620.00
Great Northern Power Development LP	Nelson Creek (MT)	Wind	WT	MT	Proposed	10/1/2013	60.00
Power Co of WyomiGas LLC	Anschutz Wind Project	Wind	WT	WY	Proposed	12/31/2013	1,000.00
Wallula Resource Recovery LLC	Wallula Energy Resource Center	Coal	IG	WA	Proposed	12/31/2013	700.00
Montgomery Energy Partners LP	Great Falls Energy Center	Coal	IG	MT	Proposed	12/31/2013	275.00
PUD No 1 of Okanogan County	Shankers Bend Hydro	Water	HY	WA	Proposed	12/31/2013	84.00
Principle Power Hydro LLC	McKenzie River Hydro Project	Water	HY	OR	Proposed	12/31/2013	83.00
SkyFuel LLC	SolarDunes	Sun	SS	CO	Proposed	1/1/2014	900.00
Citizens Energy Services Corp	Dine Wind Project	Wind	WT	AZ	Proposed	1/1/2014	300.00
Utah Division of Waterer Resources	Hurricane Cliffs Pumped Storage	Water	PS	UT	Proposed	12/31/2014	300.00
Mountain Island Energy LLC	Soda SpriGass Power Plant	Coal	AB	ID	Proposed	1/1/2015	250.00
Intertie Energy Storage LLC	Klamath Pumped Storage	Water	PS	OR	Proposed	6/30/2015	1,000.00

Owner Name	Plant Name	Fuel Type	Unit Type	Plant State	Plant Status	Online Date	Winter Capacity MW
	Project						
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	1/1/2017	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	9/15/2017	103.20
WashiGaston Wave Co	Grays Harbor Ocean Energy	Wind	WT	WA	Proposed	1/1/2018	270.00
WashiGaston Wave Co	Grays Harbor Ocean Energy	Water	HT	WA	Proposed	1/1/2018	149.00
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	5/31/2018	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	2/15/2019	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	10/31/2019	103.20
Sierra Pacific Power Co	Ely Energy Center	Coal	IG	NV	Proposed	1/1/2020	1,000.00
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	7/15/2020	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	3/31/2021	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	12/15/2021	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	8/31/2022	103.20
PUD No 2 of Grant County	Priest Rapids	Water	HY	WA	Proposed	5/15/2023	103.20
Total Capacity Permitted or Proposed							26,503.29

Source: Pace and Energy Velocity©

Announced Capacity Retirements

Pace also reviews the operating status of the existing power plants in the California power region and retires plants based on information from the trade press, commercial databases, and discussions with market participants. Exhibit 76 lists the plants which are recently retired or planning to retire from California. For Pace's analysis, it has been assumed that no additional capacity will be retired during the Study Period. Although California has increased the regulatory pressure on coal-based generation, Pace does not believe that this will force coal units into early retirement. Current market fundamentals suggest that markets around California can and will absorb excess coal generation currently used in California.

Exhibit 76: CA Capacity Announced for Retirement

Owner Name	Plant Name	Fuel Type	Unit Type	Plant Region	Plant Status	Retirement Date	Winter Capacity (MW)
E I Colton LLC	Agua Mansa Power Project	Gas	GT	CASo	Operating	6/29/2010	47
Imperial Irrigation District	El Centro	Gas	ST	CASo	Operating	4/30/2009	42
MMC Energy	Escondido	Gas	GT	CASo	Operating	5/30/2009	44
Southern California Sunbelt Developers Inc	Edom Hill	Wind	WT	CASo	Operating	12/31/2008	11
Total Capacity Announced for Retirement							144

Source: Pace and Energy Velocity©

FUEL MARKET ASSESSMENT

Pace developed fuel price forecasts for each major fuel (#2 distillate fuel oil, #6 residual fuel oil, natural gas, coal, and uranium) used in power generation for the entire WECC market area. The remainder of this section summarizes Pace's outlook for each fuel market and presents the Reference Case assumptions for fuel prices.

PRICE RELATIONSHIPS BETWEEN THE FUEL MARKETS

The petroleum, natural gas, and coal markets each have their own distinct pricing dynamics. However, fuel interchangeability in some end-use applications and oil-based natural gas pricing conventions in Europe and Asia create value linkages that can often overshadow other value considerations, creating a degree of price correlation. An example is the New England heating market, where fuel oil and natural gas compete for market share. Although short-term fuel switching capability is limited to the largest residential and commercial heating systems, the price of heating oil provides a soft cap on natural gas prices in the region. While gas prices usually move independently of heating oil prices, there are times when the two trade in close correlation on spot markets. Similarly, while coal-gas-oil interchangeability is limited to a relatively small number of large boilers, an increase in oil and gas prices allow coal producers to raise prices without fear of market share loss, creating another weak but evident link. In general, the correlation of price drivers of oil and gas markets is closer than that of fundamentals driving coal pricing in the U.S.

For the past 20 years, the North American gas market has been generally a self-contained and independent commodity market, with prices governed by local supply and demand balances on a daily basis. Regional markets are well integrated by an extensive system of pipeline infrastructure and the high level of transparent transactional activity that provides a reliable price discovery mechanism. As a result, the average statistical correlation between price changes in the gas and oil markets has been moderate during the last five years. Observed historic correlations show only a moderate link between spot prices for gas and oil.

On the other hand, European (other than British) and Asian gas markets, which developed under far more constrained circumstances, have traditionally used crude oil and oil product prices as a fair-value metric for pricing both pipeline gas and liquefied natural gas ("LNG"). As the U.S. gas market increases its reliance on LNG to cover domestic production shortfalls, it finds itself competing on price for marginal LNG cargoes with suppliers whose alternative markets price gas against an oil index. This phenomenon is expected to create a growing gravitational pull on the U.S. gas market to align itself with world LNG markets in the 2010-2015 timeframe, and thus with the oil price indices that have historically governed those markets. When domestic gas is in short supply, U.S. buyers must meet or beat the location-adjusted price of LNG in the rest of the world, drawing the entire North American gas market into closer price correlation with prevailing global oil prices. Consequently, Pace believes that the statistical correlation between spot gas and oil prices will become stronger as the U.S. begins to rely more heavily on imported LNG to meet its domestic demand.

The tightly integrated global oil market is least affected by the price of other fuels. For this reason, Pace's assumptions for the petroleum market are presented first.

PETROLEUM

Pace forecasted petroleum prices for the products used by power generators in the California region. When world refinery capacity is sufficient to meet the demand for products, product prices are largely determined by world crude oil prices (i.e., refining margins are not volatile). At other times, product prices are more directly affected by the supply and demand balance for each product, causing product prices and margin levels to be very volatile in both cyclical and seasonal patterns. The principal U.S. crude oil marker is West Texas Intermediate ("WTI") crude oil in Cushing, Oklahoma, which is the crude oil listed on the New York Mercantile Exchange ("NYMEX"). Pace forecasts the price of WTI and uses this price as the basis for forecasting U.S. and world prices of petroleum products.

Oil Demand

Demand for petroleum liquids rose by 6.0 to 6.5 MMBbl/day between 2003 and 2007 at an average annual growth rate that was double the rate of growth from 1980 through 2003. China and the Middle East, which had only 13% of global demand at the beginning of the decade, accounted for 50% of the growth as China's economy soared and petrodollars went to economic and industrial development projects. Conservative estimates are that nearly 0.7 MMBbl/day have been removed from Middle East oil exports in the past five years and diverted for electric power production. The U.S., which consumed a 25% of global demand at the beginning of the decade, accounted for another 13% of the total growth during that period. The remaining OECD countries, which accounted for 37% of global demand at the beginning of the decade, added only about 1% of the total growth.

In Pace's Reference Case, the long-run growth rate in world GDP is expected to moderate to 3.5-4.0% per year, and demand for oil is expected to moderate about 1.4% per year. Despite this slowing of the growth rate, the effect of compounding translates to a higher average increase of approximately 1.45 MMBbl/day per year.

Oil Supply

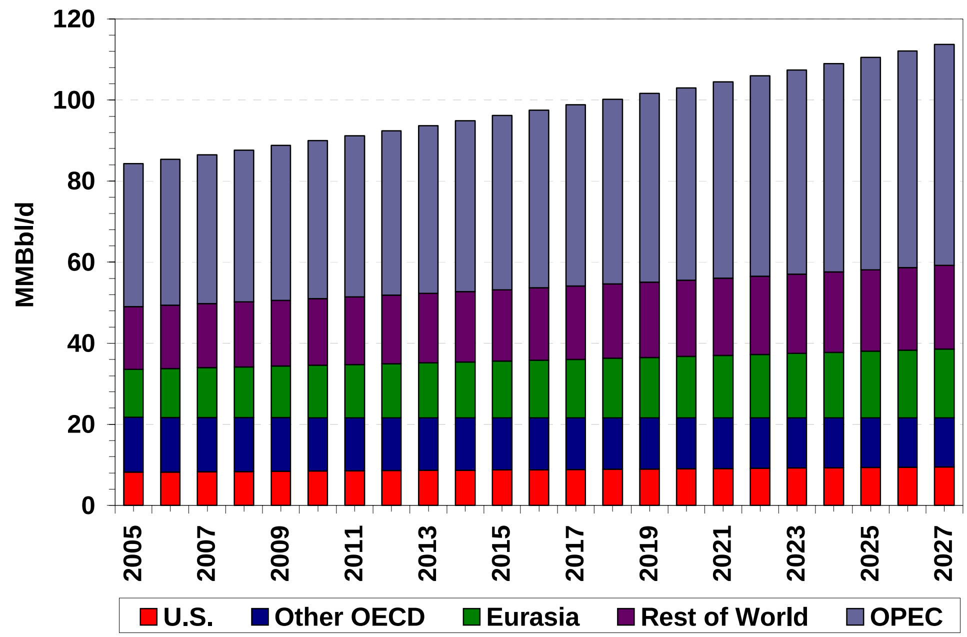
During the period 2003-2007, production of petroleum liquids increased from 5 to 6 MMBbl/day, creating a relative shortfall of supply increasing from 0.5 to 1.0 MMBbl/day by 2007. Stocks that were built up in 2004 and 2005 began to be drawn down in 2006 and, based on preliminary estimates, were drawn down another 0.5 MMBbl/day to 1.0 MMBbl/day in 2007.

Non-OPEC supply grew at less than 0.4 MMBbl/day per year over this period, with production declines from the U.K., Norway, Mexico, and the U.S. being offset primarily by production increases from Canada, Brazil, Kazakhstan, Russia, and China. OPEC, despite fast growth of over 2 MMBbl/day per year from 2003-2005, reversed course and cut production in 2006 and 2007. The reduction in 2007 exacerbated the already tight conditions in the market and contributed to the increase in global prices, and a late-year increase in production was not enough to stem the rising prices. Furthermore, the more-recent announcements by Saudi Arabia that it would increase production have been undercut by threats of production cuts from other OPEC members.

Non-OPEC supply has historically shown a stronger price response than has demand, with each 10% increase in price yielding, on average, a 2.5% net increase in net new supply. But new supplies take years to develop, are increasingly costly, and require a higher expected market price to warrant investment. Nevertheless, prices have risen rapidly for several years and may now be bearing fruit. Production levels have been steadily rising in Canada, Brazil, China, Sudan and CIS states; ethanol production has been increasing; Russia has identified development opportunities in eastern Siberian resources; and drillers in the U.S. are poised to start exploiting shale oil resources and increase exploration and production activities in the Gulf. These factors should help to stabilize or lower prices as they come on line.

There are two elements of risk to this view. First, national policies – environmental restrictions on drilling, laws against foreign investment, or regressive tax structures - have stymied investment in new oil resources. Second, OPEC has often acted as the swing supplier, changing production in response to non-OPEC supply. With high prices and inelastic demand, the cartel does not have an incentive to help reduce prices, so increased production from non-OPEC supplies could be met with constrained production by OPEC.

Exhibit 77: Forecast of World Oil Supply



Source: Pace

If non-OPEC production does not materialize at the forecasted rates, OPEC will have to produce more, or limited world supplies will likely lead to supply-rationing and higher prices. In Pace's expected price forecast, OPEC increases its production from 35.4 MMBbl/day in 2007 to 37.5 MMBbl/day in 2010 and then to 42.5 MMBbl/day by 2020. The balance of supply needed to clear the market is met by non-OPEC sources and coal-to liquids.

WTI Crude Oil Prices

The world has sufficient oil resources to meet world oil demand for decades, but rapid growth in demand and delays in new investments have created a climate of potential near-term shortages and high prices. This means that government decisions in the OPEC and in non-OPEC countries as well as unexpected supply disruptions are expected to be the main drivers of short-run oil price dynamics.

The price of oil set new highs in 2008, with market participants, overseers, and observers citing numerous structural factors and speculative behaviors as the underlying reasons for this upward climb. This constant stream of claims include insights about the value of the dollar, changes in weekly inventory reports, inconsistent reports and statements from OPEC members, and political and/or military events in some producing nations. This steady diet of observations about volatility begs the question of why crude prices have risen relentlessly since early 2003 after languishing in the $20-$40 range for almost two decades.

Most of the increase stems from market fundamentals - demand has outpaced supply and the dollar has lost ground against other major currencies. The former pushes prices up globally and the latter makes crude more expensive in dollars than in other currencies. Expectations also play a role – Pace's analysis shows that if world GDP growth continues at the historically high rate of 5% per year and if OPEC continues to hold the line on production increases, then prices could remain well above $110 range over the next few years. However, if expectations about demand growth and OPEC production moderate, with global GDP growth dropping back to its long-run average of 3.5% per year and annual increases of OPEC output of 1.0 MMBbl/day, market fundamentals could support a retrenchment in prices back to a range of $50 as supply constraints ease.

In Pace's reference case, average annual prices for benchmark WTI crude oil, shown in Exhibit 78, are projected to be about $80/bbl in the 2011-2012 time frame and then rise steadily thereafter to $100 by 2020 and $120 by 2028. These prices are predicated on demand and supply assumptions discussed below and also on an expectation that petroleum supplies will be augmented by a significant expansion of coal-to-liquid ("CTL") capacity in the latter years of the forecast period.

Exhibit 78: WTI Crude Oil Expected Price Forecast

Year	WTI Price Forecast	
	(2007 $/barrel)	*(2007 $/MMBtu)*
2009	103.50	17.77
2010	90.58	15.55
2011	76.56	13.14
2012	79.74	13.69
2013	83.18	14.28
2014	86.89	14.92
2015	90.90	15.60
2016	95.21	16.35
2017	94.05	16.15
2018	97.23	16.69
2019	100.71	17.29
2020	101.59	17.44
2021	104.85	18.00
2022	102.59	17.61
2023	104.84	18.00
2024	107.39	18.44
2025	110.36	18.95
2026	113.61	19.50
2027	117.23	20.12
2028	121.24	20.81

Source: Pace

Refined Product Price Forecast

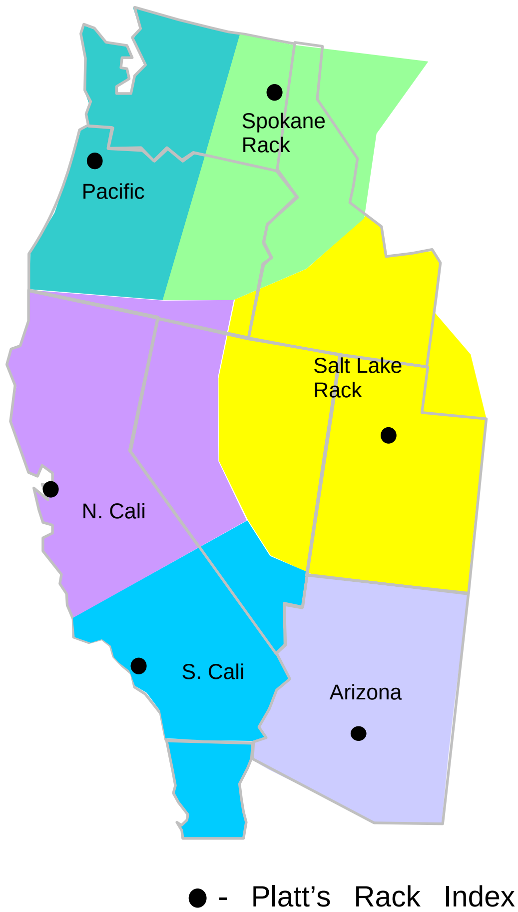
Under normal market conditions the prices of all petroleum products are largely determined by the price of crude oil. Over 95% of the historic variance in the price of No. 2 fuel oil and over 85% of the historic variance in the price of No. 6 fuel oil is explained by changes in the price of WTI crude oil. Pace has developed regression equations to predict the refined product prices as a function of the level of WTI crude prices. The prices rise when WTI prices rise due to the higher cost of producing petroleum products. Exhibit 79 shows Pace's refined oil product forecast delivered to California. Exhibit 80 illustrates the geographic designation of Pace's California oil regions.

Exhibit 79: California Oil Price Forecast ($2007/MMBtu)

Year	San Francisco Rack (N. Cali)	LA Rack (S. Cali)
	#2 LS - #2	*#2 LS - #2*
2009	22.45	22.55
2010	19.61	19.71
2011	16.50	16.60
2012	17.20	17.30
2013	17.96	18.06
2014	18.77	18.87
2015	19.65	19.75
2016	20.60	20.70
2017	20.34	20.45
2018	21.04	21.14
2019	21.81	21.91
2020	22.00	22.10
2021	22.72	22.82
2022	22.22	22.32
2023	22.71	22.82
2024	23.27	23.38
2025	24.19	24.29
2026	24.55	24.66
2027	24.92	25.03
2028	25.29	25.40

Source: Pace

Exhibit 80: Pace Fuel Oil Forecast Regions



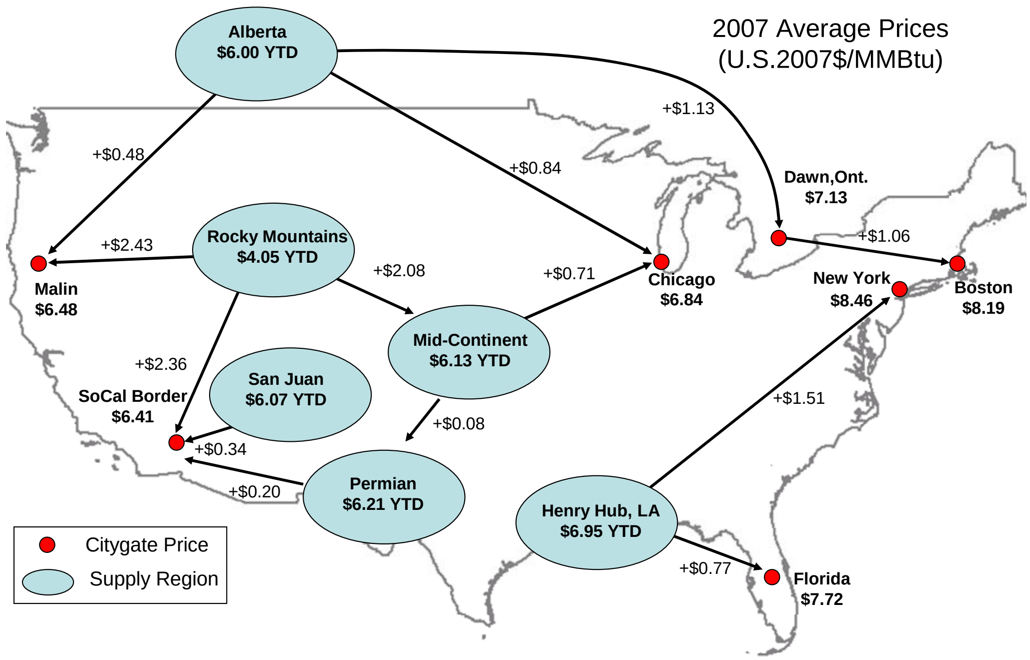
Source: Pace

NATURAL GAS

The principal location for natural gas trading in the U.S. is the Henry Hub in Louisiana. Due to the volume of physical trading at this location, Henry Hub has also become the location for financial market trading on the NYMEX. Pace forecasts the U.S. market price for natural gas at the Henry Hub and then forecasts regional gas prices based on basis differentials from the Henry Hub to these other locations. The forecasted basis differentials are based on changes in regional supply and demand for gas and transportation and storage capacity available to clear the regional markets for gas. Regional basis rises when local production declines and the cost of transporting gas between regions increases and when rising demand causes pipeline and storage utilization to grow (widen). On the other hand, increases in local production, the available pipeline and storage capacity relative to demand for transportation and storage cause the basis differentials to decline (to narrow). The map in Exhibit 81 shows the regional basis is the difference between the price in a regional market and the price at Henry Hub.

PACE

Exhibit 81: North American Average Gas Market Prices in 2007YTD (2007$/MMBtu)



Source: Pace® and Platts.

Henry Hub Price Forecast

North American gas supply has not been sufficient to meet North American gas demand in nine of the past ten years, and imports of liquefied natural gas accounted for approximately 15-20% of total annual U.S. net imports between 2003 and 2007. Prior to that, LNG accounted for less than 5% of imports and less than 1% of U.S. demand. Natural gas prices also experienced a transition at that period. During 1998-2002, the average monthly price for the benchmark Henry Hub price was $3.19/MMBtu, and prices exceeded the $5 mark less in less than 15% of the months. In contrast, prices from 2003-2007 averaged $6.77/MMBtu and prices were less than $5 in only 10% of the months. Pace believes that this turning point marked the end of the long era of low-cost gas in North America.

- Since 1994, increasing rates of drilling have been necessary to maintain the existing level of U.S. gas production. Productivity is declining in existing wells and the prospects now available for new conventional production are limited. Substantial gas resources remain for more costly unconventional production.
- Through 1999, imports of pipeline gas from Canada expanded rapidly and enabled the U.S. to maintain stable prices. Canadian supplies continued to rise at a slower rate through 2002 and have since stayed steady at around 3.6 trillion cubic feet per year (+/-5%). Since then, and despite high prices and much higher rates of drilling, North American production had fallen from its highwater mark and only showed signs of renewed vigor in 2007 when dry production reached 19.3 Tcf, a level that had not been seen 2000-2001.

- Going forward, North American gas prices are expected to be elevated by (1) the increased costs of incremental North American exploration and production, including unconventional technologies and (2) the price of imported LNG, which in turn is linked directly to the price of oil.

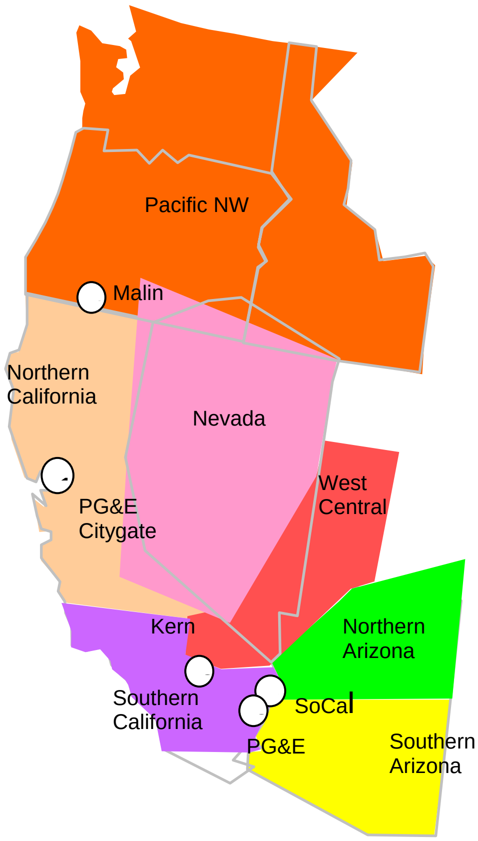
Over the 2008-2013 timeframe, annual consumption is projected to increase by 1.2% in the residential/commercial sectors, by 2.5% in the power sector, and to decline by 0.1% in the industrial sector. In this new era of higher-cost gas, industries that formerly used low-cost gas to produce materials are no longer competitive and production of these materials is moving to other parts of the world where low-cost gas is still available.

Average spot prices at the Henry Hub in 2009 are expected to be under $9/MMBtu (2007$) and in the near term are expected to decline until 2011. Pace anticipates prices at Henry Hub to rise to near the $10/MMBtu mark around the 2017-2018 time frame as the rise in domestic supply as a result of increased production in existing fields and development of some unconventional resources, such as the Barnett Shale is outpaced by domestic demand. Also factoring into the expected rise to the $10/MMBtu mark is an increase reliance on LNG. Because enhanced recovery through horizontal drilling and development of the shale plays is not expected to provide for steady long-term growth in domestic supply, LNG should gain a larger share of the supply market over the long run. As LNG becomes more important, U.S. prices should rise and Pace's Reference case projects that average annual gas prices will likely be in-between the $10-11/MMBtu range toward the end of the forecast period.

Regional Basis

The delivered gas price forecast incorporates general price differentials and the cost of transportation to WECC gas price sub-regions, as depicted in Exhibit 82.

Exhibit 82: Pace Natural Gas Price WECC Sub-Regions



Source: Pace and Platts

Each gas price region is defined by its primary liquid supply source, interstate transporter, and that transporter's applicable market-based transportation rates. The regional basis from the Henry Hub to these gas price regions is driven primarily by the following fundamentals:

WECC

- Power generators in the Pacific Northwest have access to Western Canadian supply via border interconnects at Kingsgate and Sumas and transportation on Northwest Pipeline and PG&E Gas Transmission, and Gas Transmission Northwest. Pace Global assumes a $0.38/MMBtu average annual transportation rate in this region from the border points.
- Northern California receives most of its supply from Western Canada and the Rocky Mountains via Malin and must pay a $0.60/MMBtu delivery charge to PG&E to utilize both its Transmission and Distribution system.
- The Southern California market area receives supply primarily at the California/Arizona border and utilizes interruptible transportation on Southern California Gas Co. or San Diego Gas & Electric at an average rate of approximately $0.38/MMBtu to move the supply to the burner tip.

- The Nevada markets receive supply from Rocky Mountain supply via both Northwest Pipeline and Paiute Pipeline and Western Canadian Supply via Tuscarora Pipeline.
- The Northern Arizona and Southern Arizona regions receive supply from the San Juan and Permian basins respectively. Maximum tariff rates apply for transportation service into these regions due to the captive nature of these markets to El Paso Natural Gas. The transportation rate for both Northern and Southern Arizona is approximately $0.55 throughout the forecast period.
- The Kern Market region receives supply from the Rocky Mountain Supply Basin via Kern River Transmission. Market-based rates on Kern are driven by the cost of gas at the Southern California border.
- Markets in the Permian region receive supply primarily from the Permian production basin and are captive to El Paso Natural Gas Pipeline; therefore these markets will pay maximum tariff rates for transportation services, which are approximately $0.41/MMBtu.
- San Juan consumers receive supply primarily from the San Juan supply basin and transport it via El Paso Natural Gas and Transwestern Gas Transmission at maximum tariff rates, which average $0.37/MMBtu.
- The Rocky Mountain power projects rely primarily on indigenous supply via numerous interstate and intrastate pipelines. Pace Global assumes a $0.48/MMBtu average annual transportation rate for delivered supply.
- The Northern Rockies region receives much of its supply from Western Canada via border interconnects and transportation on Northwestern Energy. The annual average transportation rate on Northwestern is $0.48/MMBtu.
- Markets in a majority of the Dakotas are served by Williston Basin Interstate Pipeline ("WBIP") using supply primarily from the Rocky Mountains. The annual average transportation rate on WBIP is $0.47/MMBtu.

Exhibit 83 provides a summary of Pace's independent forecast of annual Henry Hub and delivered prices to each respective WECC fuel sub-region.

Exhibit 83: WECC Natural Gas Price Forecasts (2007 $/MMBtu)

Year	Henry Hub ($/MMBtu)	Southern California ($/MMBtu)	Socal ($/MMBtu)
2009	8.78	8.52	8.14
2010	8.65	8.56	8.37
2011	7.13	7.30	6.93
2012	7.48	7.72	7.35
2013	7.86	8.08	7.71
2014	8.27	8.48	8.11
2015	8.71	8.89	8.52
2016	9.00	9.16	8.78
2017	9.15	9.29	8.91
2018	10.00	10.13	9.74
2019	10.26	10.37	9.99
2020	10.20	10.29	9.91
2021	10.58	10.66	10.28
2022	9.98	10.05	9.66
2023	10.15	10.18	9.80
2024	10.36	10.38	10.00
2025	10.61	10.62	10.23
2026	10.90	10.91	10.52
2027	11.23	11.26	10.87
2028	10.40	10.46	10.08

Source: Pace

COAL

Power generation accounts for 91% of coal consumption in the U.S. Strong demand for coal in the power sector, and reduced coal production in U.S. mines due to rationalization, have caused moderately large increases in spot coal prices and smaller increases in contract prices in recent years. Beginning in late 2007 and continuing into mid-2008, rising coal prices in the European markets and the falling value of the U.S. dollar combined to make exports from the eastern basins of the U.S. competitive in the European markets. High netback prices led to a general escalation of spot prices in the U.S. as suppliers reacted by selling steam coal into the export market.

Average capacity factors of existing coal-fired power plants have risen substantially over the last ten years, reaching around 73% nationally in 2007. With the availability of coal-fired capacity in the region ranging from 75 to 90%, coal consumption (tons) in existing plants is expected to increase over time for two reasons. First, slowly rising off-peak load growth is likely to cause some incremental generation in coal plants. Second, coal consumption is likely to increase as lower Btu western coals replace eastern coals in some plants.

Demand growth for coal is also expected as new coal-fired power plants are constructed in the near term. Pace forecasts for expected prices for coal and natural gas indicate that new coal plants are potentially competitive in many parts of the United States. However, the specific conditions in each power market, regional environmental regulations or sentiment, the coal transport situation, and the financial characteristics of the potential investor all affect whether a new coal plant is an attractive investment option relative to gas in a particular location. Pace believes that current uncertainty regarding future carbon compliance and the recent reluctance of regulators to approve new coal plants will result in limited coal-fired capacity expansion in the medium term.

On the supply side, the geographic center of U.S. coal production is shifting westward. While coal production is currently increasing throughout the country, the largest increases are in the Powder River Basin ("PRB"), where coal production costs are substantially lower than elsewhere. PRB coal is increasingly penetrating eastern coal markets and this trend is forecast to continue.

The factors that created the immediate surge in U.S. prices between late 2007 and Spring 2008 can be traced to weather and equipment-related supply disruptions in Australia, Indonesia, China, and South Africa. By the start of 2008, prices in Asia and Europe had already risen 30-45% over prices in early autumn. Wintertime transportation disruptions in China's coal producing regions and reductions in available exports from Australia, Indonesia, and South Africa from winter storms and equipment failures tightened the global supply squeeze, increasing prices in Europe and Asia by another 30-60% and pushing the effective netback price well above the spot prices that had prevailed during 2007. Prices for eastern coals rose from about $60 in early January to over $80 in March and close to $120 by late June.

While the export production levels are expected to return to normal in the mid-term and ease the supply restrictions, coincident global price increases in oil and natural gas are expected to lead to higher prices for coal paid by power plants in, which in turn is expected to keep the netback price for eastern U.S. coals at levels exceeding the incremental mine cost in many years. Absent a steep reversal of gas prices in Europe, U.S. coal will continue to be competitive and prices in the U.S. markets will continue to be influenced by global coal markets to a greater degree than in the past several years

In the subsequent parts of this section, Pace provides an analysis of national coal supply and demand trends, a summary of its Free on Board ("FOB") price forecasts, an overview of regional supply basins, and historical coal consumption profiles for the FRCC market area.

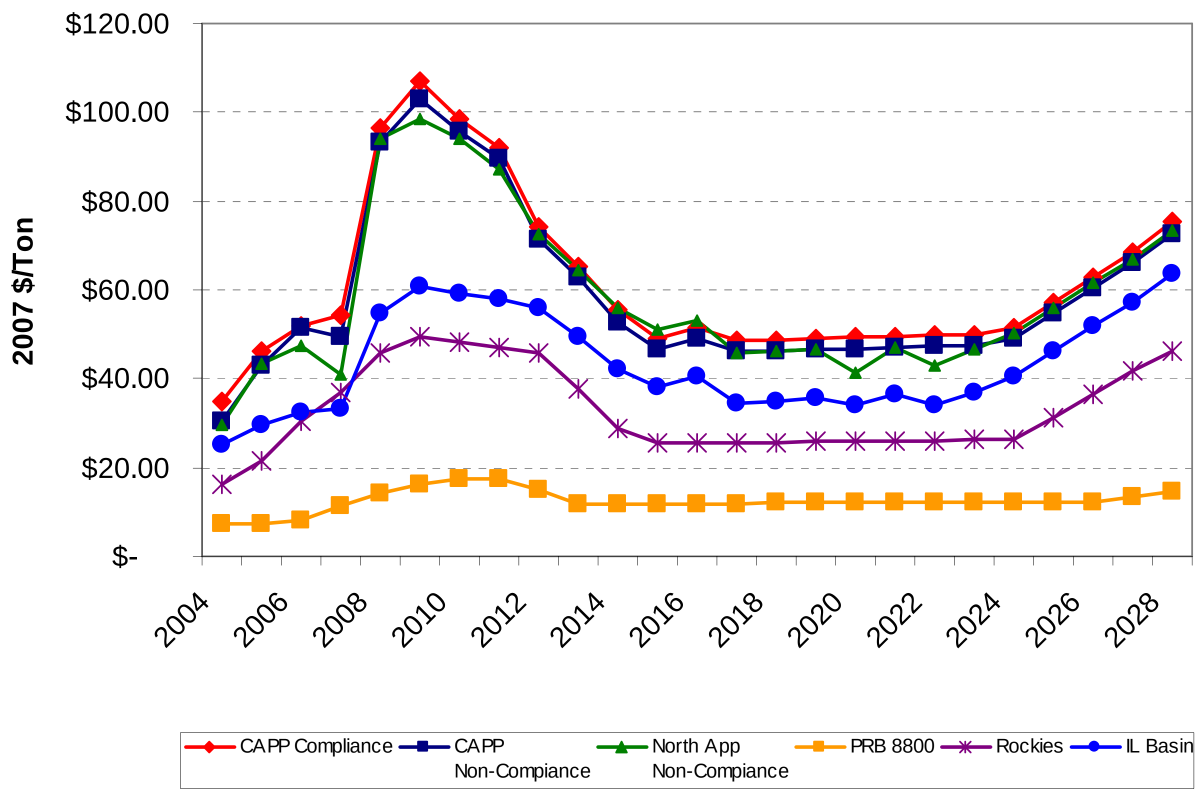
Coal Price Forecast Summary

Pace reviews international, national and coal supply region specific trends in supply, demand, SO_2 allowance prices, and incremental mining costs to forecast an average FOB price for each relevant coal supply region and sulfur grade.

Exhibit 84 shows Pace's FOB price forecast for the major coal basins throughout the country in $/ton. Exhibit 85 shows Pace's forecast in 2007$/MMBtu for the major supply region for generators in WECC. As illustrated, Pace expects that eastern low-sulfur coals will retain their considerable price premium in the marketplace relative to high-sulfur coals for a very long time. This is a result of growing coal consumption, the tightening limits on SO_2 emissions, and the continuing depletion of Central Appalachia ("CAPP") compliance coal reserves. Pace also expects that eastern coals will maintain a premium over other coals as a result of European demand for U.S. coal exports.

The U.S. coal market is split into markets for coal used in scrubbed and unscrubbed plants. The current large low-sulfur premium is expected to remain until 2015 when the new cumulative installed scrubbing capacity is forecast to approach 100 GW. At that time, the high-sulfur and medium-sulfur coals are forecast to sell at prices that reflect the cost differences of using lower sulfur coals in the scrubbed plant coal market (i.e., costs associated with lower limestone/lime usage and less sludge disposal).

Exhibit 84: Reference Case FOB Coal Price Forecast (2007$/ton)



Source: Pace and Platts

Exhibit 85: Pace FOB Coal Price Forecast for WECC (2007 $/MMBtu)

Year	PRB ($/MMBtu)	PRB ($/MMBtu)	Rockies Comp. ($/MMBtu)
Lb SO2/MMBtu	*0.80*	*0.80*	*0.80*
Btu/Lb	*8,800*	*8,400*	*11,700*
2008	0.81	0.61	1.96
2009	0.92	0.71	2.11
2010	0.99	0.79	2.06
2011	0.99	0.80	2.01
2012	0.85	0.69	1.96
2013	0.67	0.50	1.61
2014	0.67	0.50	1.23
2015	0.68	0.50	1.09
2016	0.68	0.50	1.09
2017	0.68	0.50	1.09
2018	0.68	0.50	1.10
2019	0.68	0.50	1.10
2020	0.68	0.50	1.11
2021	0.68	0.50	1.11
2022	0.68	0.50	1.12
2023	0.69	0.50	1.12
2024	0.69	0.50	1.13
2025	0.69	0.50	1.33
2026	0.69	0.50	1.56
2027	0.75	0.57	1.79
2028	0.82	0.64	1.98

Source: Pace

Delivered Coal Prices

Pace forecasts delivered coal prices by adding forecast transportation costs to regional FOB basin level forecasts of coal price. In developing plant-level coal price forecasts, Pace examines the coal purchasing characteristics underlying each coal-fired power plant, as well as the overall market for steam coal, to determine the likely delivered coal costs to each plant in the future. Pace reviews FERC Form 423 and Form EIA-423 data on coal deliveries to each of the facilities as reported in Global Energy's Energy Velocity® database. Trends in the applicable transportation markets are then reviewed and used to develop escalation rates by mode of transportation, primarily rail, barge, and truck.

An environmental compliance optimization model is then used to determine the mix of coal consumption for each plant by coal supply region and sulfur grade (compliance[2] or non-compliance). This is done within the context of environmental emission constraints, unit-level retrofit/environmental compliance options, and transportation constraints between each basin to

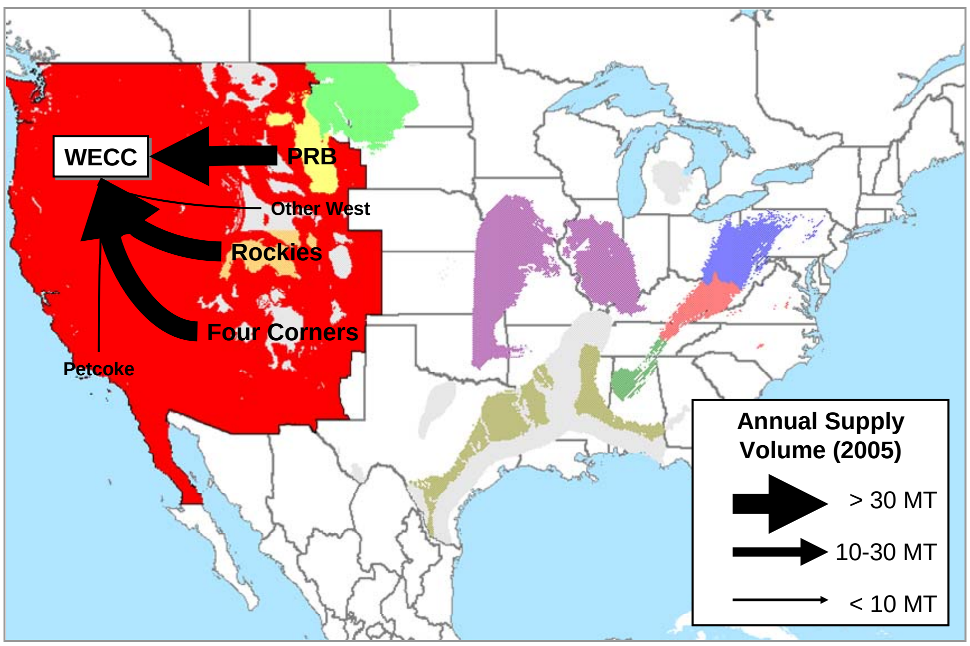
[2] Compliance coal contains less than or equal to 1.2 lbs SO_2/MMBtu, which is the average emissions rate that electricity generators were required to meet by January 1, 2000, under the Clean Air Act Amendments of 1990 ("CAAA").

each coal-fired power plant. A coal consumption profile was developed in this manner for the study region, indicating the shares of coal consumption by sulfur grade and coal supply region. Finally, the forecasted FOB prices and transportation rates are combined to generate a delivered coal price forecast for each generating unit.

Regional Supply Basins Serving WECC

Generators in WECC purchase coal from the following supply regions: PRB, Rockies, Four Corners, and other western mines. Exhibit 86 presents the location of the primary supply regions in relation to WECC and the approximate annual volumes supplied, and Exhibit 87 presents recent market fundamentals and Pace's price forecast drivers for coals consumed in WECC.

Exhibit 86: WECC Coal Supply Regions



Source: Pace and Energy Velocity©

Exhibit 87: WECC Coal Commodity Forecast Fundamentals

Commodity	Consumption Patterns in 2007		Shipping	Forecast Drivers Key Assumptions
Region	*Million Tons*	*% of Tons*	*Avg. Miles*	
PRB 8,800 Btu/lb	47.55	37.54%	623	Ample production capacity has kept PRB prices relatively low over the past few years. Due to increased demand, PRB prices are expected to rise slightly in the short term as producers and railroads invest in mine and transportation infrastructure to support increased regional demand.
Rockies 11,000 Btu/lb	34.02	26.85%	291	Increased demand for Rockies coal is expected due to its advantageous environmental qualities. The price of this coal is dependent on its netback differential to Central Appalachian compliance coals that will tend to drive down the price to incremental mining cost due to increased scrubbing of coal.
Four Corners 11,000 Btu/lb	32.55	25.69%	95	Much of this coal is produced at mine mouth with relatively constant demand. Coal produced in this region must be priced competitively vis-à-vis PRB coal on a netback basis.
Other West 6,500 Btu/lb	12.30	9.71%	314	Demand for these products is assumed to be relatively constant. Coals produced in the western US must be priced competitively vis-à-vis PRB coal on a netback basis.
Petcoke 6,501 Btu/lb	0.26	0.21%	0	Petcoke is a byproduct of the refining process and is used primarily as an opportunity fuel by the majority of consumers. Petcoke prices are constrained by the prices for other non-compliance coals on a netback basis.
Total	126.68			

Source: Pace and Energy Velocity

Environmental Impact of Coal-Fired Generation

Coal-fired power plants emit a variety of air pollutants, including sulfur dioxide, nitrogen oxides, carbon dioxide, mercury, and particulate matter, into the atmosphere. Emissions from coal-fired plants are significantly higher than those for other generating units for each of these pollutants, and hence coal generators face higher costs (realized or potential) associated with current and projected emission control policies.

At this time, Pace believes that multi-pollutant emissions legislation targeting the power sector has the potential to disrupt regional supply demand balances due to fuel switching but is not likely to cause real declines in domestic coal consumption in the near to mid-term. Pace's current CO_2 compliance cost assumptions are outlined in the appendix on environmental regulation. The current outlook is expected to result in some shifting away from coal consumption, but in our Reference Case, carbon compliance costs are not expected to significantly alter the economics of build decisions in the near term.

Public Acceptance of New Coal-Fired Generation

Throughout the country, there are currently a large number of new coal-fired projects proposed by utilities and merchant generators. Although significant capacity is currently under construction or being proposed, public pressure has forced a large number of plans throughout the country to remain in the permitted or proposed stages or even become cancelled. While new coal plants are often economically attractive under current regulations, potential emissions risk and public resistance on environmental grounds have moderated the pace of expansion. Due in part to this reason, a total of 14,374 MW of capacity from proposed coal plants scheduled to come online between 2010 and 2014 has been cancelled in the last year in the WECC region.

There is significant recent anecdotal evidence of increased public pressure in some regions to halt or slow coal-fired generation development. Policies capping CO_2 emissions have been passed in the Northeast and California, effectively halting conventional coal expansion in these regions, and the state of California has also passed a law prohibiting new baseload power contracts with generators with CO_2 emissions greater than 1,100 lbs/MWh (the equivalent of an efficient gas-fired combined cycle unit. For this reason Pace believes that coal-fired generation will cease to be a source of new power for California and has assumed no new coal expansion in the state over the Study Period.

Pace conducts a detailed analysis of the economic feasibility and public acceptance of coal-fired generation in different regions across the US. Based on this analysis, Pace's Reference Case assumptions limit the addition of coal-fired capacity, even when economically feasible, in regions where environmental regulations and public resistance might create significant hurdles for the completion of these projects.

Development of Clean Coal-Fired Technology

In response to increasing opposition to coal development on environmental grounds, there has been significant activity within the industry to move towards cleaner coal technologies. In the near term, higher efficiencies are being sought from conventional coal combustion in order to reduce emissions.

Recent focus has also been paid to developing IGCC technology. Currently, two small IGCC units exist in the United States, and several more are being actively pursued. One IGCC unit has been proposed in California. This unit's primary fuel is designed to be pet coke and it is proposed to be one of the first larger scale units to make use of carbon capture technology.

The coal gasification process of IGCC allows for pollutants to be separated and captured more efficiently prior to combustion. This results in significantly lower emission rates for SO_2, NO_x, and Hg for IGCC units than conventional pulverized coal units. In addition to reducing SO_2, NO_x, and Hg emissions, IGCC technology has the potential to capture an isolated stream of CO_2. Once captured, this CO_2 could potentially be sequestered in underground aquifers or used in enhanced oil recovery projects. Sequestration may be an important technology choice in the context of a stringent national greenhouse gas policy. Pace's analysis of IGCC with sequestration technology indicates that it would be expected to capture CO_2 with 85-90%

efficiency, but would face costs that are significantly higher than those for a standard IGCC unit. In addition, overall operating efficiency would be expected to decrease around 25%.

Under the current Reference Case CO_2 compliance costs, Pace believes further development of sequestration technologies will be encouraged.

URANIUM

Due to the risk nuclear technology poses to society, uranium supply and demand is heavily regulated by international and national agencies. Price history, as reported by the EIA, indicates that uranium prices have been relatively stable over the previous decade. Between 1994, and 2005 the price of uranium U_3O_8 increased on average 1% per year in real terms.

The vast majority of uranium used in United States civilian reactors is sourced internationally, with over half being supplied from mines located in Canada and Australia. Uranium mined in the United States represents less then 20% of all uranium that entered the market between 1994 and 2005. On the world market, less then two-thirds of all uranium consumed by power plants is produced through mining. The remainder has been supplied from reprocessing decommissioned nuclear warheads.

Currently there are over 40 GW of new nuclear units proposed in the United States. Of these, 22 GW nationally are assumed by Pace to enter into service during the study period and therefore included the Reference Case assumptions. In the remainder of the world, 28 reactors are under construction. Japan, Russia, China, and India have on aggregate proposed over 100 nuclear reactors in recent years in order to meet their increasing demand for energy.

Supply is expected to be able to meet this increasing demand through expanded mines in Canada and Australia. In addition, marginal uranium ore reserves are expected to increasingly be sourced from African counties. Therefore, Pace projects uranium prices will increase annually by a1% real rate of escalation over the Study Period.

GLOSSARY

Anaerobic Digester - Digests organic waste in a machine that limits access to oxygen, thereby encouraging the production of methane which can then be used to generate electricity

Availability factor - The ratio of the time a generating facility is available to produce energy at its rated capacity relative to the total amount of time in the period being measured.

Avoided costs - The incremental cost to a utility for capacity and/or energy that could be avoided if another incremental resource addition such as energy efficiency were added that deferred or eliminated the need for the original addition

Base load - A resource that is most economically used by running at a capacity factor of 65% or greater on an annual basis. *See also* capacity factor.

Biomass - Refers to living and recently dead biological material that can be used as fuel to generate electricity

California AB 32— Assembly Bill ("AB") 32, the California Global Warming Solutions Act of 2006. AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020, which is estimated to require a 30% reduction relative to the GHG emissions levels in 2020 without any specific action to reduce emissions.

California ISO – The entity that controls the long-distance, high-voltage power lines that deliver electricity throughout much of California and between neighboring states and Mexico

Capacity – Generator output at a point in time, measured in MW or kW

Capacity Factor - Actual energy generated over a certain time period divided by theoretical ability to generate electricity over that same time period. Capacity factor is most often referenced as an annual calculation.

Carbon dioxide - Carbon dioxide (CO_2) is an important greenhouse gas because it is thought to contribute to global warming. While it is not currently a federally regulated pollutant, it is the subject of pending federal legislation. Pending legislation would seek to reduce production by penalizing power plants for its emission into the atmosphere.

CC – Combined Cycle

CO_2 – Carbon Dioxide

Combined Cycle – a power plant configuration that combines two distinct generation cycles to increase the output and efficiency of the plant. The combined cycle includes the generation from a combustion turbine generator (simple cycle) and the generation from a steam turbine generator powered by waste heat recovered from the combustion turbine (steam cycle).

Combined Heat & Power - The use of a heat engine or a power station to simultaneously generate both electricity and useful heat for domestic or industrial processes

Confidence bands – Measures of the probability of occurrence for a distribution of potential outcomes. For example, the 95% confidence band indicates the level at which 95% of observations are expected to be below and 5% above.

Demand – Electricity usage at a point in time, measured in MW or kW

Demand Response - A resource that is comprised of programs that compensate electricity users in exchange for the ability to interrupt or reduce their electric consumption when system demand is particularly high and/or system reliability is at risk

Demand-side resources – Resources that can be called on or developed to supply energy by means of reducing usage of energy by the end user. Energy efficiency and load management programs are examples of demand-side resources.

Distributed Generation - Electric generation that is sited at a customer's premises, providing energy to the customer load at that site and/or providing electric energy for use by multiple customers in contiguous distribution substation areas

EE – Energy Efficiency

Energy - Usage over a period of time, measured in GWh, MWh, or kWh

Energy Efficiency - Measures, including energy conservation measures, or programs that target consumer behavior, equipment or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services

Feed-in Tariff - An incentive structure to encourage the adoption of renewable energy development by providing a standing offer to buy power, at a specified price, to all qualifying projects.

Fixed costs - Costs that are independent of output or electricity generation

Forced outage rate - Percent of time a unit is not operational when it is expected to be in service

Geothermal - Electric generation fueled by heat from geologic formations. Geothermal qualifies as a renewable resource

GHG – Greenhouse gas

Heat rate - The ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units), to the energy output of that facility expressed in kilowatt-hours

IGCC - Integrated Gasification Combined Cycle plant

Landfill gas – A power generation facility fueled by the methane gas produced through decomposition of waste in a sanitary landfill. Landfill gas qualifies as a renewable resource.

Levelized cost - An economic assessment of the cost of an energy-generating system including all the costs over its lifetime including initial investment, operations and maintenance, cost of fuel, cost of capital, depreciation, and others. A levelized cost assessment computes a constant cost over a period of time that is equal to a stream of cost numbers that might vary year to year.

Loss of load probability - Percent of time load is un-served

Mean of the Distribution – The average value of a range of outcomes

Metrics – Ways by which to measure and evaluate key objectives. For example, CO_2 emissions are a metric used to evaluate the objective of environmental leadership.

Net Present Value (NPV) - The total present value (PV) of a time series of cash flows

Peak load - Occurs when demand for energy is at its greatest

Planning horizon - The future period for which a utility develops its IRP. Generally speaking, it is a period lasting 20 to 30 years.

Portfolio - A combination of resource additions/assets over the planning period that meet reserve margin criteria

Qualifying resource - A generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 (PURPA) and part 292 of the Commission's Regulations (18 C.F.R. Part 292), and which has obtained certification of its QF status

Quantum event – A game changing event that needs to be considered as "what if" event rather than as a distribution of outcomes associated with market volatility. "What if" events may be regulatory in nature (What if Congress passed an extreme carbon tax that eliminated all coal fired generation?) or transitional (What happens if your biggest supplier defaults?) or construction based (What if a major new transmission line were constructed?).

Reliability - The ability of the electric system to supply the demand and energy requirements of the customers when needed and to withstand sudden disturbances

Renewable - A generating resource that is based on a renewable fuel supply

RIRP sm – Risk Integrated Resource Planning, a methodology employed by Pace that evaluates utility decision-making in the context of multiple objectives and quantified uncertainty

RPS – Renewable Portfolio Standards, or policies that require utilities or other "load-serving entities" to meet a specified percentage, within a defined timeframe, of their customers' electrical requirements from qualifying renewable resources. The California RPS that is expected to prevail in the foreseeable future will require renewables to provide 33% of the resource mix by 2020.

RPS 2020 – A term used to designate the percentage of renewable generation used to meet customer electrical requirements in the year 2020. The year corresponds with California's expected 33% target.

Scenario - A combination of sensitivity values under which to evaluate portfolios

Sequestration - The storage of carbon dioxide in a solid material through biological or physical processes

Solar Photovoltaic – A solar technology that uses solar cells to directly convert sunlight into electricity

Solar Thermal – A solar technology that harnesses the sun's energy for thermal energy or heat. Existing technology is often referred to as Concentrating Solar Power and is deployed in trough or tower form

Stakeholder Advisory Group – A group formed in August, 2008 to advise on and directly participate in the PWP IRP process. The Group consists of ten members representing residents, business, non-profit organizations, environmental interests, the Environmental Advisory Commission, the Municipal Services Committee, and City government. Five members were appointed by the Mayor of Pasadena.

Standard Deviation - A measure of the dispersion of a collection of numbers. A large standard deviation indicates that the data points are far from the mean and a small standard deviation indicates that they are clustered closely around the mean

Stochastic analysis – An analysis that does not rely on deterministic input assumptions, but instead introduces random elements to evaluate the impacts of statistical uncertainty. Electricity demand, natural gas prices, and capital cost inputs were evaluated under stochastic analyses in the IRP.

Stochastic bands – Probability bands that quantify the range of potential outcomes from a stochastic analysis.

Supply / demand balance – A term used to characterize the relationship between expected peak electricity demand and existing supply available to serve it.

Traditional resources - Coal, nuclear, hydro and natural gas resources that have historically been the most commonly used to supply electricity

Un-served load – A condition that can exist when a utilities load can not be met by available generating resources causing a reduction in voltage or blackout

Upper tail - A value on a scale of 100 that indicates the percent of a distribution that is equal to or above 95% of the distribution (also referred to as 95th percentile)

Variable costs - Costs that are associated directly with the operations of a power plant and thus depend on the amount of power generated

Exhibit 2

Revised Renewable Portfolio Standard

For

City of Pasadena Water and Power Department

March 16, 2009

Pasadena Water and Power Renewable Portfolio Standard

(Revised March 2, 2009)

Objectives

PWP's Renewable Portfolio Standard (RPS) objectives are to reliably meet Pasadena's electric energy needs at stable and reasonable rates in an environmentally responsible manner. This policy is effectuated through an integrated resource plan that incorporates thermal resources, contracts, short-term purchases, and demand-side management programs in addition to renewable resources.

Specific RPS objectives include:

- Reduce the greenhouse gas emissions associated with PWP's portfolio of energy supply resources used to meet the electric demand of its retail customers;
- Meet or exceed the state mandate to encourage renewable resources;
- Obtain a diverse portfolio of cost-effective renewable resources;
- Encourage the development of local renewable resources; and,
- Minimize adverse impact of acquiring new renewable energy resources on customer electric rates.

Qualified Renewable Resources

- Renewable resources are defined as non-fossil fueled electric generating resources, including: biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, hydroelectric generation, digester gas, municipal solid waste, landfill gas, ocean wave, ocean thermal, tidal current, or renewable distributed generation on the customer side of the meter;
- Renewable components of system sales from other parties shall qualify to the extent they can be verified;
- Pasadena's existing Azusa hydroelectric entitlements shall qualify;
- Energy purchased by PWP from customer-owned cogeneration facilities using renewable fuels shall qualify;
- New hydroelectric projects must be less than 30 MW to qualify; and,
- Renewable resources may be located within the Western Electricity Coordinating Council region, and PWP may procure tradable renewable energy certificates associated with qualifying resources with or without the associated energy.

RPS Target

Renewable resources used to meet PWP's retail electric energy sales, including distribution losses, shall reach a minimum of 15% by year 2010; 33% by 2015, and 40% by 2020.

Strategies for Meeting PWP's RPS Objectives

- Procure new renewable resources through a combination of cost-effective long-term contracts, short-term purchases, and tradable renewable energy certificates;
- Seek resources which are cost effective and which will have minimal impact on customer energy costs;
- Mitigate rate impact of renewable resource premiums by utilizing funds from Green Rate programs and a portion of Public Benefits Charges as available;
- Renewable resources will be procured to the extent they fulfill unmet needs identified in PWP's Strategic Resource Plan and supplemental short-term resource needs. PWP will not terminate, abrogate, or otherwise end any existing long-term contract in order to meet the renewable target portion of its energy portfolio;
- Replacing part of existing base-loaded resources for limited periods with renewable resources will be considered if such sales or exchanges meet resource portfolio economic, risk, and reliability objectives;
- The Pasadena City Council shall consider rate impacts, including the cost of associated transmission to deliver the energy to PWP's service territory, when approving contracts for additional renewable resources.

Reporting RPS Performance

Beginning with energy sold in Pasadena for the period from July 1, 2003 to June 30, 2004, PWP will report the following information to its customers annually:

- PWP's resource mix used for retail electric sales, by fuel type, including each type of renewable resource in a form that is consistent with the Power Content Label;
- PWP's revenues from "Green Rates" and the use of these revenues for renewable energy resource purchase and development; and,
- PWP's expenditure of public benefits funds used for renewable energy and renewable resource development.