SUMMARY and UPDATE

to

2009 INTEGRATED RESOURCE PLAN

Midwest Energy, Inc.

December 13, 2010

Executive Summary

This Update and Summary is intended to provide supplemental information to the Management and Board of Directors of Midwest Energy, Inc. in relation to the 2009 Integrated Resource Plan Report ("IRP"). It will provide an update on activities that have been conducted since the Plan was reviewed and ultimately published in 2009.

It will also supplement some of the information contained in the IRP and be provided to the Western Area Power Administration ("WAPA") in compliance with the requirements stemming from the hydro-power allocation made available to Midwest Energy, Inc. Specifically, this Update and Summary, along with the original IRP and its associated Appendices, ise intended to comply with the Western Area Power Administration Energy Planning and Management Program and Section 114 of the Energy Policy Act of 1992.

Midwest Energy, Inc. ("Midwest Energy") is organized as a not-for-profit utility under the laws of the State of Kansas, and is authorized to provide public utility services related to the generation and delivery of electric energy and the delivery of natural gas to customers in its certified service territory of central and western Kansas. With respect to the delivery of electric energy, Midwest Energy currently serves approximately 48,600 electric retail customers, several municipal wholesale electric customers, and operates a transmission network in Kansas. Such transmission facilities are operated under the Open Access Transmission Tariff of the Southwest Power Pool, of which Midwest Energy is a long-time member. Additional information on Midwest Energy can be found in the Appendices to the IRP.

While this Update and Summary is intended to supplement the original IRP, it will not repeat information that is available in that document. The following documents are specifically referenced and incorporated herein:

- 2009 Integrated Resource Plan Report – December 17, 2009
- 2009 Integrated Resource Plan Report Appendices – December 17, 2009

Significant progress has been made since the release of the IRP in late 2009. As discussed further in this Update and Summary, the IRP was used to provide guidance in the development and execution of new long-term power supply agreements intended to replace expiring power supply agreements. The new agreements were completed and executed, and are now being utilized to provide reliable and affordable electric service to the customer-owners of Midwest Energy, Inc.

Other recommendations from the IRP relating to the expansion of Midwest Energy's power supply portfolio have been incorporated into the long-term planning process at Midwest Energy. These recommendations, related to development of new generating resources, utilization of renewable resources and compliance with mandated renewable portfolio standards, and the incorporation of energy efficiency and demand-side projects are all being considered as Midwest Energy continues to shape its power supply requirements going forward. This Summary and Update will provide additional current information on these topics.

Load Forecast Update

In connection with the development of the IRP, the load and energy growth rates for Midwest Energy were forecast as indicated in Exhibit 7 of the IRP and supported in the Appendices. In summary, energy sales were forecast to grow at an average annual rate of 1.05 percent in the near term (2009-2015) and 0.45 percent over the long term (2016-2030). Peak demand was projected to grow at an annual rate of 0.53 percent over the period 2010-2030.

Referring to Exhibit 14 in the Appendices it is noted that the total peak demand for 2010 was projected to be 339MW. In retrospect, the actual peak load served by Midwest Energy, including the effects of a load management pilot project for irrigation customers, was 354MW comprised of 316MW of retail firm load, 6MW of firm wholesale municipal load, and 32MW of non-firm wholesale municipal load. Noting Exhibit 7 of the IRP, the total firm demand was projected to be 312MW compared to the actual firm demand of 322MW.

This represents a significant departure from the forecast, though a single year does not provide definitive indication that the forecast validity has been compromised. For example, it is not yet clear whether the dramatic increase in peak demand is a long-term feature, or whether it was a combination of various coincident factors, including weather and system conditions. Midwest Energy will develop a new complete load forecast in early 2011 that will capture the following information to update load and energy projections:

- Existing customer loads and emerging growth patterns.
- New major loads (>500kW each) added to the system in the past two years, of which there have been several.
- Other new loads added throughout the various customer classes.
- New major loads committed to be served beginning in late 2010 (>11MW).
- New major loads anticipated to be served in 2011-2012 (~15MW).
- The impact of current and anticipated efficiency programs and demand-side management programs.

This updated forecast will be integral to an assessment of the need for additional generating capacity in 2011 and beyond in order to maintain adequate reserve margins.

Resource Requirements Update

The development of the 2009 IRP was intended to satisfy several planning objectives, including two immediate objectives:

- Determine the amount and type/fuel of generating capacity required to serve the anticipated load obligations.
- Provide direction in the development of new long-term power supply agreements to replace those agreements that were set to expire between 2010 and 2013.

The IRP provided guidance in both of these respects. The following were highlights of that guidance provided by the IRP, along with the current progress with respect to each area:

- Amount and type of generating capacity
  - The IRP recommended that Midwest Energy move forward with the development of an additional 25MW of generating capacity at the Goodman Energy Center (GMEC) by 2015. Planning work in this regard will get underway in 2011, with an emphasis on re-assessing the market conditions and expected energy/capacity prices, and an assessment of current generation technologies, expected environmental policy development, and permitting requirements. In 2012 we will finish these assessments, plus examine financing options and look at the impact on the overall finances of Midwest Energy.
  - The IRP also recommended the development of a new generating facility, possibly utilizing the same internal combustion technology from GMEC, with a target of 50MW of new capacity by 2015, and a possible addition of 25MW later in the decade. As noted above in connection with the possible build-out at GMEC, Midwest Energy will begin in 2011 to examine various facets of the construction of a new generating facility.
  - Additional recommendations in the IRP related to the continued development of renewable resources. The IRP recognized that Midwest Energy had already contracted for the purchase of up to 49MW of wind energy. Though not explicitly referenced, it also recognized the availability of approximately 3MW of summer hydro-power capacity under an appropriation from the Western Area Power Administration. Midwest Energy continues to purchase energy under these agreements, and takes note of the recommendations in the IRP that (i) additional renewable energy will be required to meet future state or federal mandates, and (ii) sometime after 2020 it may be economical to purchase additional wind energy resources beyond those required in a renewable energy standard.
- Long-term Power Supply Agreement Replacement
  - Midwest Energy completed a process that began with an open RFP process begun in 2008, to solicit proposals for new long-term power supply agreements. Two new agreements, totaling 255MW of firm generating capacity, were negotiated and executed with Westar Energy. These agreements became effective on June 1, 2010 and replaced the four existing contracts with Westar Energy. Though they did include significant increases in demand charges, the rates are consistent with market conditions. The energy prices realized under these two new agreements have been consistent with or better than original projections, and they provide reliable, affordable and environmentally responsible energy for sale to our retail customers.
  - As noted above, actual load growth may be exceeding the projections upon which the IRP was developed. Several new major loads have or soon will be added to the system which could not have been anticipated in 2009. Midwest Energy is planning to update its load forecast as noted previously in order to support further review of the capacity portfolio.

The current supply portfolio for firm resources is summarized in Table 1 below:

Table 1
Current Electric Resource Portfolio

Resource	Rated Capacity, MW	Accredited Capacity, MW	Primary Fuel	Expiration
Jeffrey Participation Agreement – Westar Energy	135	135	Coal	6/1/2025
Units Most Likely Agreement – Westar Energy	120	120	Coal and Gas	6/1/2016
Goodman Energy Center	76	76	Gas	N/A
Colby Combustion Turbine	13	13	Gas and Diesel	N/A
Great Bend Plant	6	6	Gas and Diesel	N/A
Bird City Peaking Units	2	2	Diesel	N/A
Smoky Hill Wind (1)	49	0	Wind	12/31/2028
City of Oakley	4.4	4.4	Gas and Diesel	12/31/2013
City of Sterling	4.5	4.5	Gas and Diesel	12/31/2019
WAPA Hydro	3.1	3.1	Hydro	9/30/2024
Totals	**413**	**364**		

(1) Pursuant to the SPP Criteria, this non-dispatchable resource is not eligible for accreditation as a firm generating resource until additional operating data is available. When accredited according to the SPP Criteria, it is anticipated it will represent approximately 4-5MW of firm capacity.

The IRP acknowledged that the potential for development of either a federal or state renewable energy standard was considered in the development of the IRP. Since that time, the State of Kansas has adopted a Renewable Energy Standard. At a high level, this standard is based on nameplate capacity of resources and peak demand. Midwest Energy is required to have renewable capacity amounting to 10% of its firm retail load obligation by 2010, 15% by 2016, and 20% by 2020.

Based on the peak firm retail load of 316MW in 2010, Midwest Energy has a total of 51MW of renewable capacity, which represents 16% of the peak. As the load continues to grow it is likely that some additional renewable capacity will have to be acquired prior to 2016, and nearly certain that additional renewable resources will be required prior to 2020 to comply with the Kansas requirements. Midwest Energy has already engaged in discussions with wind energy developers and is reviewing proposals for additional wind energy resources that appear likely to be available prior to 2016.

Midwest Energy is pursuing both energy efficiency and demand response programs to supplement its supply side resources. The Cooperative's flagship energy efficiency program is How$mart® which provides money for energy efficiency improvements such as insulation, air sealing and new heating and cooling systems. How$mart® uses a "whole house" approach that identifies the best energy saving opportunities in both the thermal shell and heating/cooling systems. Participating customers repay the funds through energy savings on their monthly utility bills.

How$mart® program features include:

- No up-front capital is required for qualifying investments. (Customers have the option of "buying-down" the cost of non-economic improvements when the projected savings will not cover the entire cost.)
- A monthly How$mart® surcharge covers the cost of qualifying improvements. The surcharge is always less than the projected savings.
- The How$mart® surcharge is tied to the location. If customers move or sell the property, the next customer pays the surcharge. (Full disclosure to subsequent customers is required.)

How$mart® program results through November, 2010 (41 months since pilot program roll-out) include:

- 496 completed projects
- Midwest Energy's investment is $2,717,000 ($5,477 per project; excludes program operating costs).
- Customers have added $716,000 ($1,443 per project) to cover non-economic improvements.
- Projected savings are 867,000 kWh/year and 129,000 therms/year, enough for 87 and 160 homes, respectively. (In other words, improving six homes saves enough electricity for one more; improving three homes saves enough gas/propane for one more.)
- Program variations allow for geothermal heating/cooling and commercial lighting upgrades, all included in the values above.

How$mart® has received considerable national recognition:

- 2009 "Environmental Innovations in Business" from Environmental Defense Fund
- 2010 "Ace Award for Outstanding Conservation & Stewardship" from Apogee Interactive
- 2010 "Quality Achievement in Program Design and Implementation" Award from Association of Energy Service Professionals

The IRP concluded that Midwest Energy could effectively implement up to 16MW of demand response. Toward that potential, two demand response programs were introduced in 2010. Customers are given a bill credit for allowing loads to be interrupted up four hours per day for up to 20 days per year.

- An irrigation pump curtailment pilot program with 45 pumps resulted in a net load reduction of 1.5 MW.
- A new commercial/industrial interruptible rate was adopted by one customer that subscribed to load reduction of approximately 1.5 MW.

PRIMARY PLANNING OBJECTIVES, CONSTRAINTS, AND METRICS

Five primary considerations drive the planning for and acquisition of electric energy resources for Midwest Energy.

Preserve Competitive Rates (Cost)

Preserving competitive rates is a common objective for utilities. 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). The 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)

Fuel and power price volatility, as well as uncertainty around energy demand and capital costs, can result in significant changes in portfolio 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 standard deviation of the NPV of costs (or each year's cost where appropriate). This represents a metric of how wide the distribution of costs can get for each portfolio. The lower the standard deviation, the less exposed the portfolio is to market volatility.

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 reserve margin criterion, such as the 13.6% planning reserve margin used by Midwest Energy.

CO_2 Emission Liability

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.

Renewable Generation

Specific regulations concerning both federal and statewide RPS standards for utilities in Kansas will drive renewable resource additions. Midwest Energy is committed to meeting these requirements. Increasing generation from renewable resources will also directly result in reduced CO_2 emissions for the portfolio.

Environmental Issues

While significant debate continues about the science behind the global warming issues, the utility industry has already seen a significant impact on resource planning. It is quite clear that it will be increasingly difficult to construct new coal-fired generating resources, and that emissions restrictions on existing coal plants will continue to tighten. Though the appetite for so-called cap-and-trade programs appear to have diminished for now, it remains prudent to factor these issues into any resource planning program. The IRP does exactly that, testing a number of different regulation and cost scenarios to develop portfolio recommendations that stand up to a variety of outcomes.

For now, natural gas seems to be the preferred fuel for new dispatchable generation facilities. This too was factored into the development of the IRP. In fact, as noted above, the new generation proposed for further consideration by Midwest Energy is all gas-fired.

There also remains little doubt that renewable resources should be and will remain an important part of a generation resource portfolio. Midwest Energy already includes a significant amount of wind energy in its portfolio, along with a small amount of hydro-power. The potential for additional wind resource development in Kansas is quite large – among the largest of any state in the US. Conversely, there is very little potential for the development of any new hydro-power resources in Kansas, so the only option for Midwest Energy is to rely on allocations from federal power marketing agencies going forward.

Solar energy may well have an expanded future in the power supply portfolio, but that role appears to be several years off. As noted in the IRP, it appears that large-scale solar developments in Kansas are at least a decade away. Even so, Midwest Energy does have an item in its 2011 Business Plan to measure customer interest in a community solar farm and begin initial planning and design efforts. This project will demonstrate both the technical viability of solar resources and the implications for customer integration and rate impacts.

As state and federal regulations continue to impact electric energy generation it is important to maintain some amount of flexibility in portfolio development. Midwest Energy has addressed this in two ways through the long-term power supply agreements:

- The Units Most Likely agreement is a fleet-based agreement, and has a term of only six years. This gives us some flexibility to adjust our portfolio and fuel mix in as little as six years, even though the Jeffrey Participation agreement has a term of fifteen years.
- Both of the new power supply agreements also have some terms in them related to the review of costs associated with the installation of emission control equipment and the prudence thereof.

Both of these contingencies were recommended in the IRP and ultimately adopted in the executed contracts.

The How$mart® energy efficiency program is generating environmental benefits. CO2 savings from projects completed through November 1, 2010 are estimated at 28,900 tons over 20 years.

Action Plan Update

The plan of action suggested in the IRP (see IRP Policies and Action Plan) was built on the outlook for the period 2010 through 2030. Most of the significant recommendations provided in the IRP are intended to be implemented in the 2015-2017 timeframe, except for those related to additions of economic wind energy and solar energy, which extend beyond 2020.

The specific Action Plan items recommended in the IRP and their current status are summarized below:

- **Negotiate PPAs:** By the beginning of 2010, finalize negotiations of new PPAs for baseload and UML type contracts with the preferred supplier. Due to the attractiveness of owned peaking resources, UML contracts should be negotiated with the shortest lengths possible. The baseload contract should be negotiated for at least fifteen years but should include reopeners for maximum volume flexibility.
  - *This Action Item has been completed in conformance with the recommendations. The two new contracts were effective as of June 1, 2010.*

- **Implement Pilot Demand Response Programs:** Initiate further exploration of the cost-effectiveness of DR programs, particularly in the form of agricultural load shedding and interruptible rates, to better assess the potential of DR programs as a feasible substitute for new peaking capacity.
  - *As noted elsewhere in this document, a pilot demand response program in the form of commercial and irrigation load control was launched in 2010. The irrigation program met with good overall success, and will be expanded in 2011.*

- **New Local Gas-Fired Generation:** By approximately 2015, expand GMEC and build 50 MW of new peaking capacity. Build an additional 25 MW by approximately 2020.
  - *The 2011 Business Plan includes several activities related to planning for the potential addition of new generating capacity. These activities are discussed elsewhere in this report.*

- **Renewable Energy:** Beyond 2015, increase the proportion of MWE's energy mix provided by renewable energy sources. By around 2018, a total of 50 MW of new wind is needed to meet RPS. In 2024 and beyond, add economic additional wind capacity on the order of 50 MW and replace the Smoky Hills contract when it expires. Throughout the planning horizon, continue to track the cost and efficiencies of wind and solar and take advantage of economic opportunities as they arise.
  - *Midwest Energy currently meets the Kansas Renewable Energy Standard, and is in position to meet it in 2016, depending on actual load growth between 2010 and 2016. As noted herein, Midwest Energy is also having discussions with wind energy developers in regard to the purchase of additional wind energy resources.*

- **GHG Emissions Reductions:** Protect Midwest Energy as much as possible against imprudent risk management of carbon and fuel cost exposures. Prudent management language should be included in new contractual arrangements.
    - *The terms of the two new long-term power supply agreements include terms consistent with these recommendations.*

As noted previously, significant steps will be taken in 2011-2012 to address the following:

- Re-assessment of load forecast and resulting need for capacity.
- Market conditions for capacity purchases.
- Need for short-term additions to the supply portfolio to meet growing demand.
- Assessment of current technologies available for new generation constructed by Midwest Energy.
- Continued expansion of the utilization of demand side resources as a key element in meeting load obligations.
- Siting, permitting, and financing requirements for new generating resources.

With regard to the possible development of new generating resources by Midwest Energy, current planning envisions completion of these steps during 2012, with a decision regarding the construction of new generating resources to be made by the end of 2012 or early in 2013.

To the extent additional resources are required to meet growing load obligations in the near term, these resources will be acquired through a competitive process to the extent practicable, probably during 2010. This process is subject to the availability of SPP transmission resources to import additional capacity into the Midwest Energy system.

Midwest Energy will continue to promote the How$mart® energy efficiency program across its territory. We will also be cooperating with the Kansas Energy Office in 2011 and its Take Charge Challenge effort to further stimulate program interest in four towns served by Midwest Energy.

Demand response efforts will be expanded. Midwest Energy's business plan sets a target of 7MW of demand response capability in 2011. Most of that is expected to be in the irrigation sector. Reaching that value will require the revision of the program tariff with the Kansas Corporation Commission.

On-Going Resource Plan Assessment

A Resource Plan is intended to be a living document. As such, it is imperative that Midwest Energy continually assess its progress in regard to the actions proposed in the IRP, and that it be prepared to modify and adapt the plan as conditions change. The IRP completed in 2009 will not have an indefinite life. It is anticipated that enough exogenous conditions will change that the IRP will need to be completely redone as early as 2012 or 2013.

Although not an all-inclusive list, the following issues could change substantially over the next 2-4 years, and thereby impact the validity of the current IRP:

- Prices for natural gas and coal, including transportation;
- Emissions requirements for both coal-fired and gas-fired generating resources, existing and new;
- Inception of new climate control legislation, including cap-and-trade protocols, emissions allowance trading, etc.
- Technology developments related to emissions control, unit efficiency or capital cost changes;
- Retirement of existing generating units;
- Changes in customer energy use patterns, efficiency/conservation practices, and overall load growth;
- Further penetration of demand-side management technologies and customer acceptance;
- Development of additional renewable generating resources on a regional or national basis, as well as technology improvements in wind, solar and other so-called green resources;
- Continued appetite for transmission grid expansion;
- General economic factors, including interest rates, access to capital, and customer preferences.

Midwest Energy will use several metrics to assess whether its business practices are consistent with the current IRP. For example, it will obviously continue to measure the energy sales and demand requirements of its customer base, and comparing those requirements to available generating resources. In both the long-term and the near-term this will play a significant role in a determination of the need for additional generation capacity, either owned or purchased.

With respect to energy efficiency programs like How$mart® Midwest Energy will strive to keep the program fresh and viable. Since the program is based on the concept that energy efficiency improvements funded in the program must pay for themselves over time, assessment of those expected changes in energy use is a key metric in assessing and operating the program.

In a similar fashion, Midwest Energy will continue to look for ways to expand the use of load control technologies. In the first year of use in 2010 the eligible participants were limited to electric irrigation customers that met specific criteria. The technology deployed allows for the measurement of load interruption success, and this will continue to be a key metric in annual assessments of the efficacy of the program. These annual assessments will form the basis for expansion of, or changes to, the demand-side management programs.

During 2011 and into 2012 Midwest Energy will be working directly on the steps enumerated previously related to market condition assessment and generation expansion planning. As each of these steps are executed there will be a need to re-assess whether the Cooperative is still following the guidance provided in the IRP, and indeed whether it should continue to follow those recommendations. This will lead to decisions as to whether to move forward with construction of one or more generating resources, and to a decision as to when the next update of the IRP is required.

Additionally, the Western Area Power Administration requires that entities with hydro allocations file an annual report to update their progress in meeting the recommendations of their respective integrated resource plans. Midwest Energy is no different. That annual update process includes several quantitative assessments related to resource availability, load growth, and energy efficiency/demand response program utilization.

In general, the various Action Items summarized above, and detailed in the IRP documents, are themselves the benchmark for continual review of the progress toward meeting the recommendations provided in the IRP.

Public Participation in Resource Planning

Midwest Energy is a customer-owned cooperative. That means the company is entirely focused on meeting the needs of its customer-owners, without the distraction of meeting the needs of a separate group of owners not served by the cooperative. The actions taken by Midwest Energy are governed by a member-elected Board of Directors. Their involvement includes review of the annual and long-term business plans, review/approval of the annual budget, updates on progress in the operation of all facets of the business, approval of plans to change rates, etc.

This approval process includes the Integrated Resource Plan itself, as well as decisions to execute contracts, build major new facilities, borrow funds, and other strategic decisions. As elected representatives of the customer-owners, their objective is to ensure that the Cooperative acts in the best interests of the customer-owners.

In regard to the IRP, federal regulations also require that Midwest Energy post its updates or revisions to its IRP for public review and comments. Historically, Midwest Energy has updated its resource plans at intervals of roughly three years. The most recent update was completed in 2009, and submitted to WAPA for review and publication in 2010.

In connection with this process, Midwest Energy also published the IRP on its web site, with a reference found on the home page. Furthermore, Midwest Energy published formal legal notices of the availability of the IRP for review and comment in all three daily newspapers covering portions of our service territory (Hays, Great Bend and Colby) as well as several other weekly newspapers. The public comment period for the IRP began on November 1 and concluded on November 30.

As a further aid to customer involvement and understanding, two programs were presented immediately following the Annual Meeting of Members of Midwest Energy on November 15 in Hays. The first of these programs provided an overview of the energy efficiency programs utilized by Midwest Energy, including the How$mart® program. Interest in this program remains high, as evidenced by the strong participation of customers and national recognition of the program itself. A number of questions about the program were asked and answered during the presentation.

Immediately following, a presentation was provided on resources planning in general and the IRP developed by Midwest Energy in particular. This presentation included the recommendations included in the plan, progress to date in meeting those recommendations, and plans for continuing to utilize the plan. Several questions regarding the IRP were asked by those in attendance and are summarized below:

1. Is Midwest involved in the Sunflower Holcomb Plant project?
   A. We are not directly involved in the proposal to build the plant, and have no contract with them regarding the proposed plant.
2. Regarding demand at peak information — there is an increase in base energy, yet population is shrinking. How is all of that factored into the IRP?
   A. Per-customer usage is rising in my cases. For example: home usage is up due to added appliances; More homes are air conditioned; Oilfield pumping has increased; Increase in commercial/industrial use, including new ethanol plants.
3. How do you model for increased growth?
   A. Look at load/growth over the past several years (history). Develop forecast based on historical trends, and at other specific new loads that may be coming into area, e.g. commercial/industrial growth.
4. Is growth in technology driving energy needs?
   A. Yes. For example, in some cases a larger LDC TV may use more energy than an older and smaller tube television.
5. Is there an incentive for irrigation to run at non-peak hours?
   A. Yes, if irrigation is run at peak times it will cost more. Irrigation running during non-peak hours gets a cost break through the energy charge.
6. In the load control program, is irrigation shut down manually or is it done automatically?
   A. Irrigation wells can be shut down remotely through the load control program.

Though we did receive some questions, we did not receive any other comments during either the presentation or directly to Midwest Energy in any other format or venue as of December 15, 2010. We do know that the web page containing the links to the IRP Report, IRP Executive Summary, and the Appendices to the IRP had 97 page reviews, of which 68 were from unique sources.

The Board of Directors of Midwest Energy has previously reviewed the IRP report in some detail, and has been kept apprised of the progress on various Action Items since it reviewed the IRP in October 2009. At the December 20, 2010 Board Meeting the Board of Directors received this Update and Summary, and executed a formal resolution accepting the Resource Plan as updated. A copy of such resolution is attached for reference, along with a letter indicating approval of the IRP by the senior management of Midwest Energy, Inc.

Midwest Energy, Inc.

Resolution for discussion and adoption at a meeting of the Board of Directors of Midwest Energy, Inc. on December 20, 2010.

WHEREAS, the Board of Directors (the "Board") of Midwest Energy, Inc. (the "Company") has previously reviewed the 2009 Integrated Resource Plan at its regular meeting on October 19, 2009; and

WHEREAS, the Board has received various updates on progress related to the Action Items included in the 2009 Integrated Resource Plan since October 2009 including a report presented at the December 20, 2010 Board meeting updating and summarizing the current status of activities pursuant to the 2009 Integrated Resource Plan; and

WHEREAS, the Board has considered all matters it deemed necessary or appropriate to enable it to review, evaluate and reach an informed conclusion as to acceptability of the 2009 Integrated Resource Plan as updated and contemplated herein, and has determined that the 2009 Integrated Resource Plan as updated is acceptable to and in the best interests of the Company, and desires to approve the 2009 Integrated Resource Plan as updated.

NOW, THEREFORE, the Board adopts the following resolutions:

RESOLVED, that the Board hereby approves the 2009 Integrated Resource Plan as updated for the overall direction of activities related to maintaining a long-term power supply portfolio that will continue to provide reliable, cost effective and environmentally responsible energy supply; and further

RESOLVED, that the Board hereby authorizes and directs Earnest A. Lehman, as President and General Manager of the Company, and William N. Dowling as Vice President Energy Management and Supply of the Company to execute such planning activities as are necessary to ensure reliable electric energy supply consistent with the 2009 Integrated Resource Plan as updated; and further

RESOLVED, that all actions taken and all agreements, instruments, reports and documents executed, delivered or filed through the date hereof in the name and on behalf of the Company in connection with, and consistent with, any of the foregoing resolutions hereby are approved, ratified and confirmed in all respects.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the seal of said Company this twentieth day of December 2010.

Keith Miller

Keith Miller, Secretary

PACE

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2009 Integrated Resource Plan Report

Prepared for:

Midwest Energy Incorporated

December 17, 2009

PACE

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EXHIBITS

EXECUTIVE SUMMARY

Over the next couple of years, the bulk of Midwest Energy's ("MWE") energy supply must be replaced, as its Purchase Power Agreements ("PPAs") with the current supplier will expire in 2010 and 2013. Since MWE has limited amounts of its own generation, much of this supply will have to be negotiated in new or renegotiated power supply contracts. In this 2009 Long Range Resource Plan ("LRRP"), MWE identifies its preferred plan for satisfying its future electric power requirements. The plan consists of its existing generating units, the expansion of the Goodman Energy Center ("GMEC"), new peaking capacity similar to GMEC, additional wind capacity, and two types of contracts: unit-contingent baseload coal and Units Most Likely[1] ("UML") PPAs over the next twenty years. This Preferred Resource Plan best satisfies the multiple objectives of meeting MWE'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 Long Range Resource Plan updates MWE's 2005 LRRP and was designed to answer a number of critical questions:

1. What is the proper mix of baseload (coal-fired) generation to have in the energy supply portfolio?
2. What is the best term (length) of PPAs for baseload and UML power contracts?
3. How much wind or other renewable generation is economic beyond that required to meet Federal and Statewide Renewable Portfolio Standards?
4. Is expansion of the GMEC part of the preferred portfolio, and if so, when should expansion occur?
5. Should MWE build additional peaking capacity of the GMEC type, and if so, when?
6. How much Demand Response ("DR") is cost effective?
7. PPAs may carry restrictions with them that are related to requiring high load factors and resale limitations. How important are these factors in the decision of the amount of baseload and UML capacity to acquire?

The 2009 LRRP resulted from a structured, two-stage process. Phase I consisted of the screening of several technology (peaking, solar, and wind) options, and two types of PPAs. It evaluated the optimal mix of baseload versus UML contracts ranging from 0 to 100 percent, and evaluated over 100 portfolios, representing combinations of these technology additions and contract options over the planning horizon. The number of uncertainties considered in the Phase II "risk" stage of the process is measured in the thousands, as uncertainty in load, coal and gas prices, dispatch for technology choices, carbon prices, capital costs for technologies, and power prices for net purchases and sales were quantified and considered. Twenty portfolios were explicitly considered in the risk analysis. This not only included a representative range of baseload and UML PPAs, but also considered combinations of incremental peaking generation, expanding GMEC, as well as wind and solar additions in excess of those needed to comply with RPS.

[1] This type of contract is priced based on the marginal resource used to serve MWE's load. The capacity cost component is based on the supplier's estimate of the fixed costs associated with the units most likely to serve the contract throughout the year.

Pace also completed a high-level analysis of the cost-effective potential of DR options in the MWE service territory. The purpose of the analysis was to identify the amount of load reduction that is possible at a cost lower than a new peaking resource. The results presented in this report are focused on the recommended amount of peaking capacity compared to baseload and renewables. It is important to recognize, however, that the successful implementation of DR programs can substitute the need for some peaking capacity.

Quantum scenarios representing regulatory uncertainty regarding carbon legislation were also explicitly considered. The Phase II "risk analysis" reveals the strengths and risks associated with each portfolio by exposing them to a wide range of conditions. This allows for the evaluation of portfolios across a range of outcomes and under extreme conditions.

PREFERRED RESOURCE PLAN

The Preferred Resource Plan represents a slight reconfiguration of MWE's existing electricity portfolio over the next 20 years. The Preferred Resource Plan consists of enough wind resources to meet existing and planned RPS requirements and also includes 50 MW of additional economic wind generation between 2020 and 2025. The plan includes the expansion of the Goodman Energy Center by 25 MW around 2015 and 75 MW from a new local gas-fired peaking capacity similar to GMEC in the 2015-2020 time frame. The implementation of DR programs, however, could delay the need for new peaking capacity by a few years. The preferred contract mix is initially a roughly equal split between baseload and UML, although new peaking additions or DR programs would significantly reduce UML capacity amounts in the intermediate to longer term. Flexibility is inherent in this generation mix since there is little difference in expected costs between 45 and 60 percent of baseload capacity, though higher baseload capacity carries higher market risk and more exposure to carbon price volatility. Exceeding 60 percent baseload generation is uneconomic, particularly if there are restrictions on load factor or restrictions on resale that would restrict MWE's ability to sell excess baseload power in the SPP market.

Long term contracts for baseload generation are warranted, particularly if some flexibility (reopener provision) is built in over the course of the term to address carbon risk and the desire to add new renewable resources when economic. Through time, volatility of carbon related costs is expected to grow. On one hand, if carbon prices do not alter the overall cost-effectiveness of coal-based generation longer term contracts are clearly preferred. If allowance prices for carbon are highly volatile, however, pass-through mechanisms could make baseload contracts very expensive. Contractually, mechanisms that either limit cost pass-through, or at least require prudent carbon risk management, will limit the risk of a long-term PPA for baseload power. In addition, wind power is expected to become economic after 2020. Hence, reopeners should be considered in the baseload contract to reduce the generation level over time to accommodate economic wind purchases.

The minimum viable contract terms for both baseload and UML contracts is 5 years in order to ensure Midwest retains its so-called "rollover" rights to extend the transmission service as required to deliver the resource. By 2015, expanding GMEC, building additional peaking generation capacity, and implementing some DR programs are all economic options. Hence, MWE needs to either negotiate a series of five-year contracts or have a longer term contract with a reopener that will allow MWE as much flexibility as needed to reduce its volume of UML purchases and avoid unnecessarily high demand charges.

Key elements of the incremental changes to MWE's current portfolio in the Preferred Resource Plan include:

- **Renewable Energy Additions:** The Preferred Resource Plan adds 50 MW of wind generation after 2020, beyond the 50 MW required for meeting its RPS obligations by 2030.
- **New Owned Generation:** The Preferred Resource Plan adds a new 50 MW gas-fired peaking capacity similar to Goodman around 2015 and an additional 25 MW around 2020.
- **Upgrades of Existing Generation:** A 25 MW expansion of the GMEC is added around 2015.
- **Demand Response Programs:** Around 16 MW of load reduction are possible at a cost lower than a new peaker. If implemented successfully, this can reduce the need for new peaking capacity by 16 MW or delay the construction by a few years. It may also replace existing owned generating resources that are later determined to be candidates for retirement.

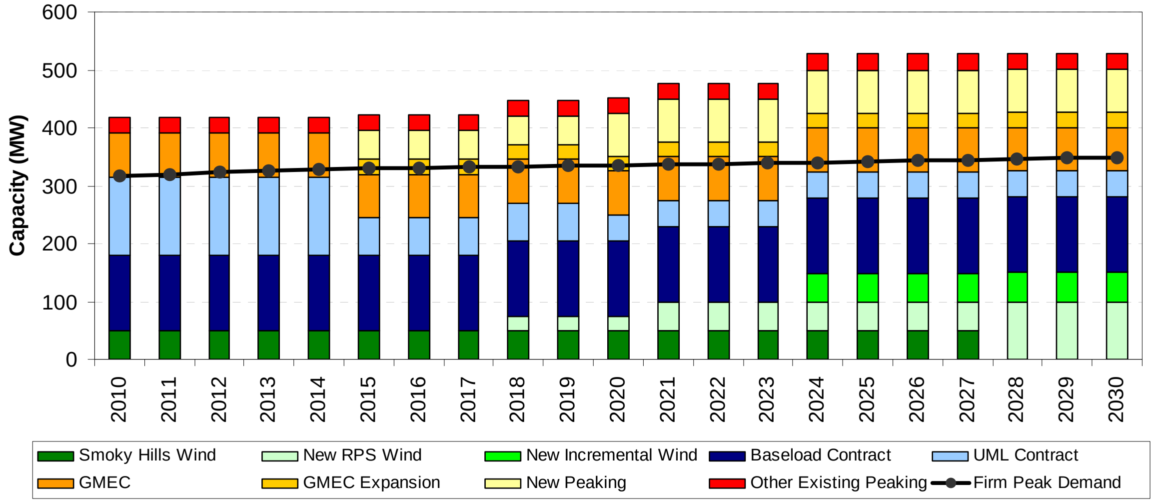
It is explicitly recognized that financing and permitting requirements, as well as the success of DR programs may impact the development schedule for the expansion at GMEC and/or the development of a new generating facility if it is determined that simultaneous development is not the most prudent course of action.

Exhibit 1 provides a summary of the Preferred Resource Plan as it is expected to evolve over time, with unit additions relative to the existing portfolio shown by installation date. The changes summarized in the table are incremental to the existing portfolio. This Exhibit 1 also shows the expected peak firm loads for the study period relative to the total resources expected to be available, including the non-dispatchable wind resources. As shown in Exhibit 2, cost-effective DR programs can substitute for peaking requirements.

Exhibit 3 illustrates the expected resource generation mix for MWE in 2016 and 2030 under the Preferred Resource Plan. No assumptions were included regarding the substitution of DR programs for new peaking resources. Exhibit 4 displays the generation mix in 2030 if the DR is included.

Exhibit 1: Summary of Preferred Resource Plan

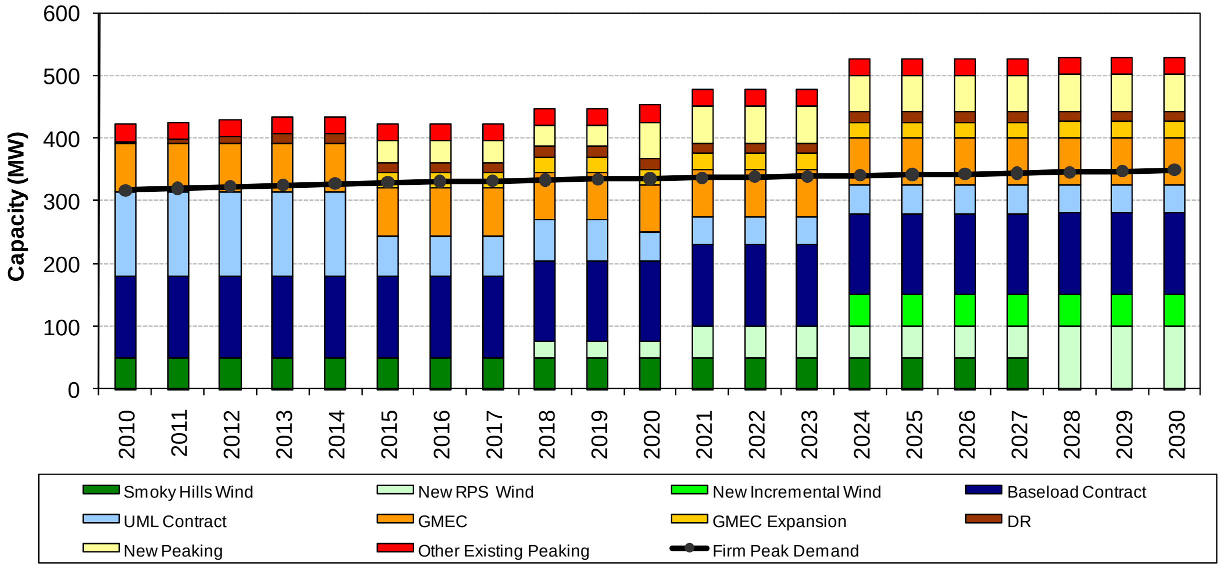
Portfolio Item	2010-2014	2015-2019	2020-2024	2025-2030
Baseload Contract	130 (20 years)			
UML	135 (5 years)	65 (5 years)	45 (10 years)	
GMEC Expansion		25		
New Peaking		50	25	
RPS Wind		25	25	50
Incremental Wind			50	



Baseload contract should consider reopeners for maximum volume flexibility
Source: Pace

Exhibit 2: Summary of Preferred Resource Plan Including DR

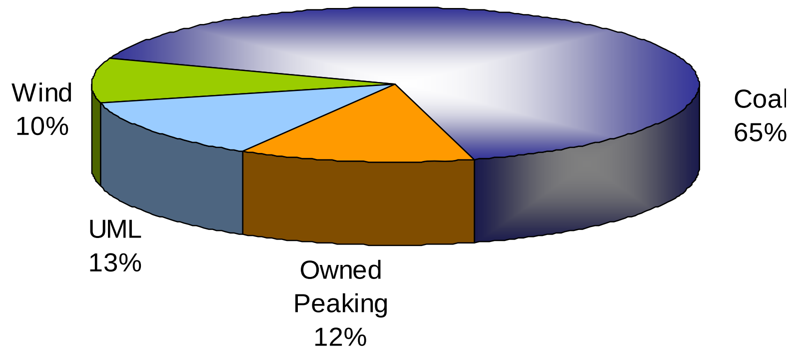
Portfolio Item	2010-2014	2015-2019	2020-2024	2025-2030
Baseload Contract	130 (20 years)			
UML	135 (5 years)	65 (5 years)	45 (10 years)	
GMEC Expansion		25		
DR	16			
New Peaking		35	25	
RPS Wind		25	25	50
Incremental Wind			50	



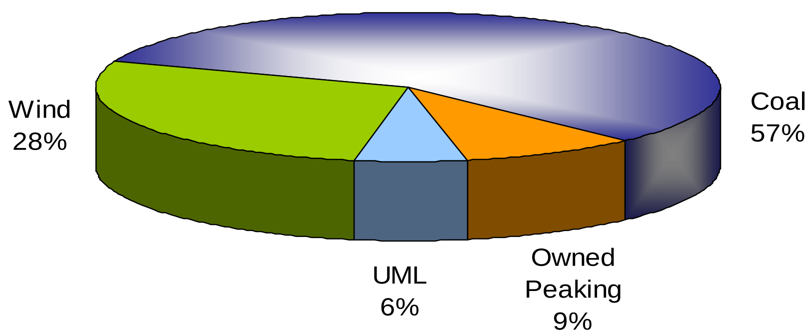
Baseload contract should consider reopeners for maximum volume flexibility
Source: Pace

Exhibit 3: Energy Mix of the Preferred Resource Plan (2016 and 2030)

2016

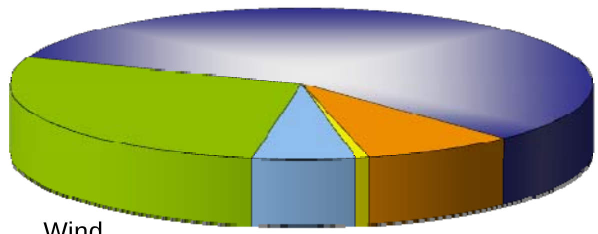


2030



Source: MWE and Pace

Exhibit 4: Energy Mix of the Preferred Resource Plan Including DR (2030)



Source: MWE and Pace

IRP POLICIES AND ACTION PLAN

Development of the Preferred Resource Plan considered a wide range of potential options and was evaluated against two main criteria:

- Competitive Rates (measured in lowest present value of revenue requirements and levelized resource costs)
- Rate Stability (measured as the standard deviation in the range of costs)

The Preferred Resource Plan consists of a range of generation additions through PPAs, owned peaking capacity, and renewable wind generation. The recommended contract and resource mix:

- Will result in the lowest achievable cost;
- Achieves maximum flexibility to adapt to market and regulatory conditions and preserve negotiation leverage;
- Exceeds the expected goals for renewable generation and moderates exposure to carbon allowance prices, a risk that can be managed through contractual provisions.

The Preferred Resource Plan calls for several action items to meet the planning objectives. These can be summarized as follows:

- **Negotiate PPAs:** By the beginning of 2010, finalize negotiations of new PPAs for baseload and UML type contracts with the preferred supplier. Due to the attractiveness of owned peaking resources, UML contracts should be negotiated with the shortest lengths possible. The baseload contract should be negotiated for at least fifteen years but should include reopeners for maximum volume flexibility.
- **Implement Pilot Demand Response Programs:** Initiate further exploration of the cost-effectiveness of DR programs, particularly in the form of agricultural load shedding and interruptible rates, to better assess the potential of DR programs as a feasible substitute for new peaking capacity.

- **New Local Gas-Fired Generation:** By approximately 2015, expand GMEC and build 50 MW of new peaking capacity. Build an additional 25 MW by approximately 2020.
- **Renewable Energy:** Beyond 2015, increase the proportion of MWE's energy mix provided by renewable energy sources. By around 2018, a total of 50 MW of new wind is needed to meet RPS. In 2024 and beyond, add economic additional wind capacity on the order of 50 MW and replace the Smoky Hills contract when it expires. Throughout the planning horizon, continue to track the cost and efficiencies of wind and solar and take advantage of economic opportunities as they arise.
- **GHG Emissions Reductions:** Protect MWE as much as possible against imprudent risk management of carbon and fuel cost exposures. Prudent management language should be included in new contractual arrangements.

PLANNING ENVIRONMENT AND KEY DRIVERS

MWE has provided reliable and economical electric service in its service territory for over fifty 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 MWE to reduce greenhouse gas emissions and increase its renewable portfolio associated with serving its customers' energy needs, although the exact reductions in GHG and increases in renewable requirements that ultimately will be required are still unknown.
- MWE is restricted by available transmission capacity from diversifying its portfolio by contracting with anyone other than a limited number of interconnected suppliers for a significant share of its current power supply. This could result in restrictions in new PPAs (on minimum load factors or resale restrictions) that can affect its options for minimizing costs and market risks.
- The costs of serving MWE's electricity requirements will inevitably increase in the future because new energy resources are more expensive than the current supply mix.

The manner in which MWE addresses each of these concerns could have a significant impact on the rates that MWE charges its customers and how well it achieves its environmental objectives. MWE 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 process included the following key steps:

- Assessing the critical trade-offs between costs and risks 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 MWE should take.

KEY DRIVERS AFFECTING MWE'S IRP OPTIONS

Integrated Resource Planning for electric utilities like MWE is a complex undertaking, accompanied by significant risk and uncertainty. Commitments made by utilities to specific resource options such as new power plants typically last 20 years or more, and PPAs may last anywhere from 5 to 20 years. 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. The key issues driving the choices that MWE 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, including those associated with baseload contracts
- Significant exposure to potential cost increases
- Evolving regulatory and environmental challenges
- Ongoing technology advances opening new opportunities
- Contract leverage that suppliers may have with MWE, and that may restrict its options

- Limited contracting options and transmission access rights due to its geographic location

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 MWE's resource planning needs.

Environmental Considerations

Senate leaders anticipate releasing their comprehensive climate and energy bill this fall after the House of Representatives passed The American Clean Energy and Security Act of 2009 ("ACES") on June 26, 2009. From these bills, MWE can begin to anticipate what their future challenges will be as a power provider under a carbon-regulated economy. The following is a brief summary of some of the issues MWE will face under carbon and clean energy regulation.

Federal Renewable Electricity Standard

A Renewable Electricity Standard ("RES") places an obligation on electricity suppliers requiring that a certain percentage of electricity sold be derived from alternative or renewable energy resources. Both the House (ACES) and the Senate have proposed Federal RES bills which, as drafted, would require electricity suppliers that deliver more than 4,000,000 MWhs annually to their retail customers to comply with renewable generation targets. Although there is still uncertainty around the standards and renewable energy levels, as currently drafted, MWE would be exempt from such federal obligation as its annual retail sales are well below 4,000,000 MWhs.

States such as Kansas with existing renewable standards will be permitted to continue to implement and administer their own standards, with the federal standard acting as the floor, requiring a minimum level of renewable generation.

Carbon Regulation: Cap-and-Trade

Regulated entities under a cap-and-trade regime are required to submit government-issued emissions allowances equal to the number of tonnes of $CO_{2(e)}$ that they emitted the previous year. The leading climate change bills over the past few years, including ACES, place the point of regulation at the point of fossil fuel combustion. MWE generates some of its own electricity from its gas-fired peaking units and will be required to retire emissions allowances from the emissions that result from those units. MWE will not be required to submit allowances for the emissions that result from the electricity that they purchase from any third-party generator, which is the source of the majority of MWE's delivered electricity.

MWE will, however, be subject to increases in costs for the electricity that they purchase. The leading bills, to a varying degree, provide protections against drastic electricity rate spikes in the form of free allowance allocations. ACES provides a pool of allowances for all Load Serving Entities ("LSEs") which would be divided based in part on historical emissions and in part on historical electricity deliveries. The method for distributing allowances to LSEs is a point of some contention. Suppliers who rely on high carbon generation technologies (coal) prefer allowances to be distributed based solely on historical emissions, and LSEs who rely on lower carbon generation technologies (nuclear) prefer heavier weighting based on electricity deliveries.

In addition to the allowances MWE would receive from the pool of LSEs, they may receive additional allowance allocations as a “Small LDC” as they fall under the “Small LDC” threshold of 4,000,000 MWh annual deliveries. All told, under ACES, MWE would receive a distribution of allowances that will cover approximately 85%-90% of their increased costs in the early years of the program. The allowances are to be used for the benefit of the retail ratepayer – what exactly constitutes a “benefit” would ultimately be determined by the state regulator.

It is safe to assume that the third-party generator with whom MWE contracts will pass through some or all of the carbon compliance costs to MWE. The ACES drafters presumed that carbon costs would be passed through from generator to LSE as evidenced by the fact that the point of regulation (the generator) is different from the point of free allowance allocation (the LSE). Moving forward, Midwest will need to specifically address carbon issues in their contracts in order to limit ambiguity and future litigation.

It should be noted that under ACES, merchant coal generators receive free allowance allocations designed to offset some of their emissions and subsequent compliance costs in the early years. Designed to lessen the cost impact from dispatching merchant coal under carbon regulation, the allocation scheme may apply to MWE’s supplier and could potentially lessen the compliance costs that are passed through to MWE.

MIDWEST ENERGY SITUATION ASSESSMENT

MWE is an electric and natural gas cooperative utility serving parts of central and western Kansas. MWE owns and operates a small amount of generation capacity and therefore supplies the majority of its member's electrical capacity and energy needs through a portfolio of supply contracts. These contracts essentially expire between now and 2013 (beginning in 2010) and will need to be replaced in some form: either with new power purchase agreements, generation development, DR programs, ownership participation or alternative means in order to meet the capacity and energy requirements of its customers.

MWE is subject to the regulatory jurisdiction of the Kansas Corporation Commission in matters related to the provision of retail and wholesale electric service and the siting of transmission and generation facilities. MWE is a member of the Southwest Power Pool ("SPP") and relies on the transmission coordination and market rules of this regional transmission organization.

The SPP was approved by the FERC in 2004 as a Regional Transmission Organization ("RTO") in order to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP RTO consists of 26 balancing authorities and manages transmission in eight states including, Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Members consist of a mix of Investor Owned Utilities ("IOUs"), cooperatives, municipalities, state agencies, independent transmission companies, independent power producers and marketers. In 2008, three members based in Nebraska, which include Nebraska Public Power District ("NPPD"), the Omaha Public Power District ("OPPD"), and Lincoln Electric System ("LES") joined SPP.

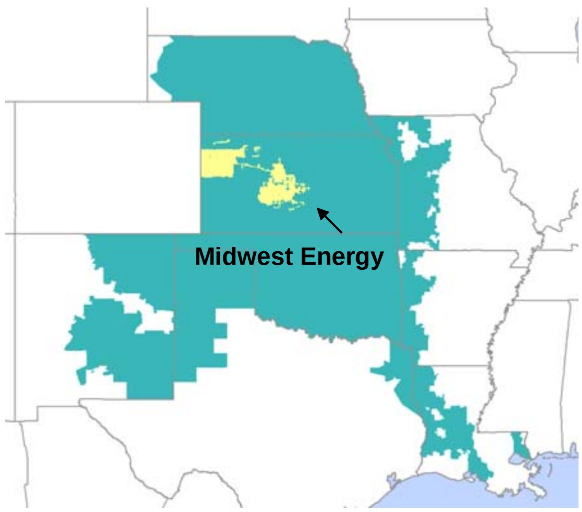
MWE does not operate as an independent control area. Rather, control area services are purchased from another entity. However, MWE does operate and maintain its own transmission system, having interconnections with Westar Energy, Mid-Kansas Electric Cooperative, and Sunflower Electric. Furthermore, MWE independently contracts for and schedules all capacity and energy purchases, and also schedules operation of its owned generating resources as needed.

MWE is committed to proactively considering the implications of its resource decisions on member rate levels and rate stability and in maintaining its long term financial health. The electricity market and interrelated energy markets are uncertain and volatile owing to load growth variability, generating capacity availability, regional and localized transmission availability, and the increasing price volatility associated with natural gas and coal fuels, among other factors. It is prudent for MWE to proactively consider its resource supply options in advance of the expiration of its current supply portfolio as the resource choices that are made will underpin their rate stability and rate competitiveness well in to the future. In this regard, MWE has contracted Pace Global Energy Services ("Pace") to assist with development of a Long-Range Resource Plan (the "LRRP") to supply electric capacity and energy covering the period 2010 through 2030.

COMPANY PROFILE

MWE manages a service territory of nearly 80,000 electric and natural gas customers with an average retail load of slightly more than 150 MW and a peak load around 300 MW. MWE's service territory within the context of the SPP geographic footprint is shown in Exhibit 5.

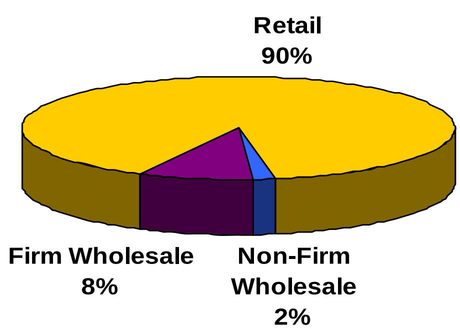
Exhibit 5: MWE's Service Territory



Source: MWE and Pace

MWE's load is composed of three separate segments: Retail Sales, Firm Wholesales, and Non-Firm Wholesales. Retail Sales are the largest component, accounting for approximately 90% of total energy. Retail Sales in combination with Firm Wholesales compose the load levels that set reserve requirements. Exhibit 6 displays MWE's expected customer energy sales mix for 2009.

Exhibit 6: MWE's Expected 2009 Customer Mix



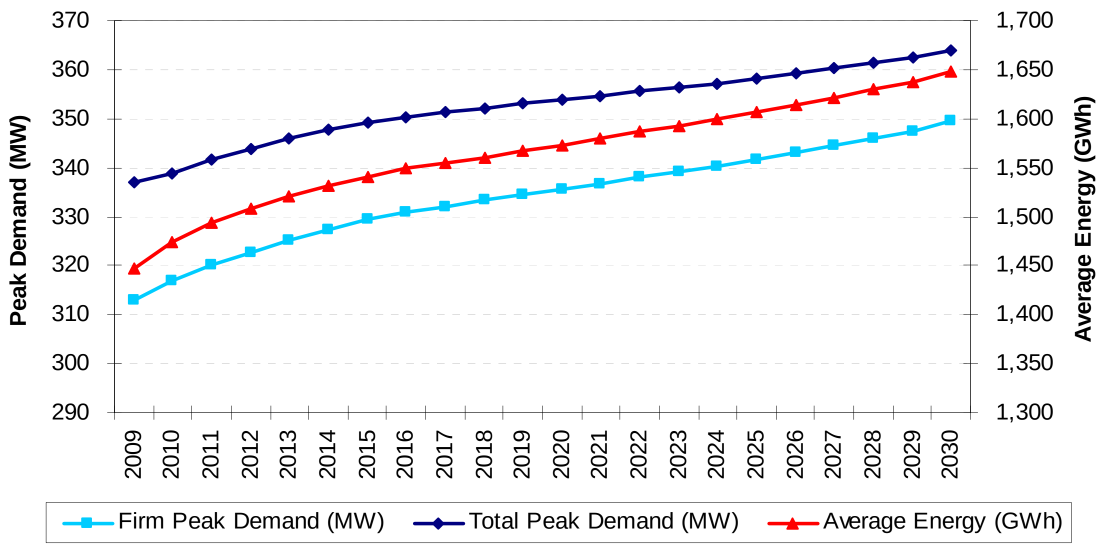
Source: MWE and Pace

LOAD GROWTH

MWE provided their long-term forecast of electricity sales to Pace. Average energy growth over the near term (2009-2015) has an estimated average annual rate of 1.05 percent, and long-term growth (2016-2030) has an estimated average annual rate 0.45 percent. Peak load is projected to grow at an average annual rate of 0.53 percent during the 2010-2030 period compared with sales growth of 0.62 percent during that period.

Exhibit 7 presents the forecasted average energy and peak load for MWE with and without non-firm wholesales.

Exhibit 7: MWE Peak Demand and Energy Forecast



Source: MWE and Pace

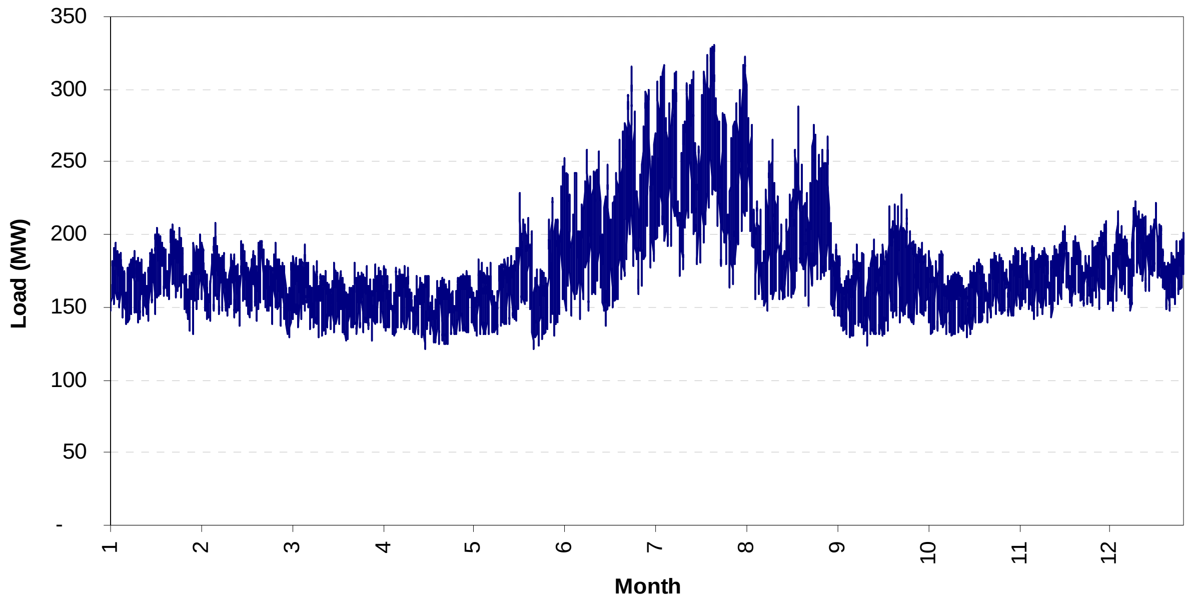
MWE's load forecast was used throughout the screening analysis described in later sections of this report. In addition, Pace developed stochastic bands around the energy and peak demand projections provided by MWE. Details on load uncertainty and stochastic methodology can be found in the appendix.

Hourly Load Projections

To arrive at the granularity of load growth projections needed for the analysis, Pace's methodology applies growth factors derived from the MWE 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 MWE (2008 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 8 displays the hourly load profile for 2008. The MWE system is strongly summer peaking, with highest loads expected during the July-August time period.

Exhibit 8: 2008 Hourly Load Profile for MWE



Source: MWE and Pace

EXISTING SUPPLY RESOURCES

MWE owns a total of 102 MW of peaking capacity. 76 MW of this is from the new natural gas-fired generation at the Goodman Energy Facility. The capacity owned by MWE is detailed in Exhibit 9. For purposes of this study it is assumed that this owned capacity will remain in service throughout the study period.

Exhibit 9: MWE's Existing Generating Resources

Plant Name	Owned Capacity (MW)	Online Year	Ownership (%)	Fuel	Unit Type
Great Bend	9	1950	100	Gas/Oil	IC
Bird City	4	1965	100	Oil	IC
Colby	13	1970	100	Gas/Oil	GT
Goodman Energy Center	76	2008	100	Gas	IC

Source: MWE and Pace

Contract Summary

In addition to peaking capacity, MWE currently has four PPAs. The four PPAs are due to expire in 2010 and 2013. Any new contract negotiated with a supplier will supersede the existing contracts. In order to meet renewable portfolio standards, MWE entered into a contract for wind from Smoky Hills in 2008 for 49 MW. A summary of the existing contracts is shown in Exhibit 10. Additional detail is provided in the confidential appendices to this report.

Exhibit 10: MWE's Existing Contracts

Contract Name	Type	Capacity (MW)	Expiration
WPPA	Peaking	30	5/31/2013
PPA	Peaking	60	5/31/2013
WP	Baseload	40	5/31/2013
P	Baseload	125	5/31/2010
Smoky Hills	Wind	49	1/31/2028

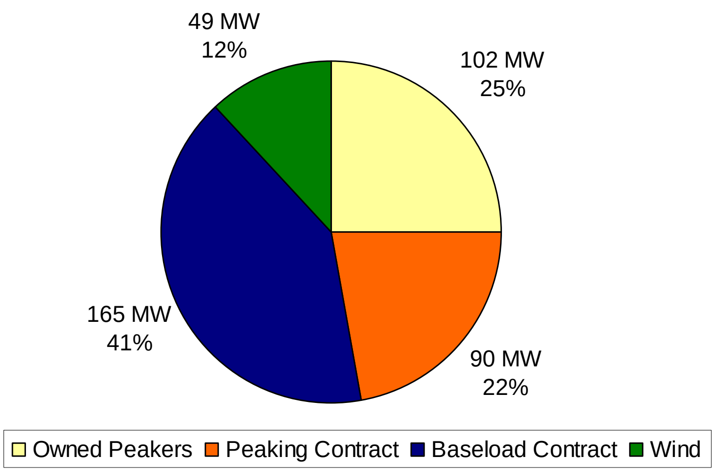
Source: MWE and Pace

Although MWE's owned capacity is all fueled by oil or natural gas, it purchases coal-fired power generation under its existing PPAs. This makes up over 45 percent of its capacity needs. Its peaking contracts represent about 25 percent of its capacity needs.

MWE's contracts with the existing supplier are all tied to specific plants or groups of units. Any new contract for baseload capacity negotiated between MWE and a supplier is expected to be similar in nature to the current contracts. A summary of the integrated portfolio, including contracts, is shown in Exhibit 11.

Exhibit 11: MWE Portfolio Summary by Capacity

Plant Name	Type	Primary Fuel	Start	End	Capacity (MW)
Great Bend	IC	Gas	1950		9
Bird City	IC	Gas	1965		4
Colby	GT	Gas	1970		13
Goodman Energy Center	IC	Gas	2008		76
WPPA	Peaking Contract	Gas		5/31/2013	30
PPA	Peaking Contract	Gas		5/31/2013	60
WP	Baseload Contract	Coal		5/31/2013	40
P	Baseload Contract	Coal		5/31/2010	125
Smoky Hill	Wind Contract	Wind		1/1/2028	49



Source: MWE and Pace

As MWE's contracts expire, one of the key questions facing MWE is whether to extend or replace these contracts, and if so, for how long and in what proportion. Many factors affect the evaluation of the future mix:

- Baseload contracts may require a high load factor: By imposing a high load factor requirement, the supplying party could force MWE to take energy even when not required to meet load. Since load and market prices are uncertain, this can result in having to pay for power that MWE cannot use.
- Restrictions on reselling power under the contracts: Supplying parties could also prohibit the resale of excess power from the negotiated contracts. In combination with a high load factor requirement, this can constitute a significant risk to MWE when load is low.
- Carbon legislation can impact the economic viability of baseload coal relative to other options over time.

- Renewable technology development will have an impact on the proper mix. Although solar technology is not currently economic, it is expected to become more economic by the end of the Study Period. As market prices increase, wind generation economics will also improve.
- Additional owned peaking capacity may provide value as a hedge against market conditions and some types of contracts.
- The successful implementation of DR programs may reduce the need for new peaking capacity.

Current negotiations with suppliers will replace peaking contracts with a "Units Most Likely" contract ("UML"). Instead of linking the energy charge to a single unit or a group of units, the UML contract charges MWE the cost of the incremental unit used to meet MWE's load after the third party's load and other obligations have been served.

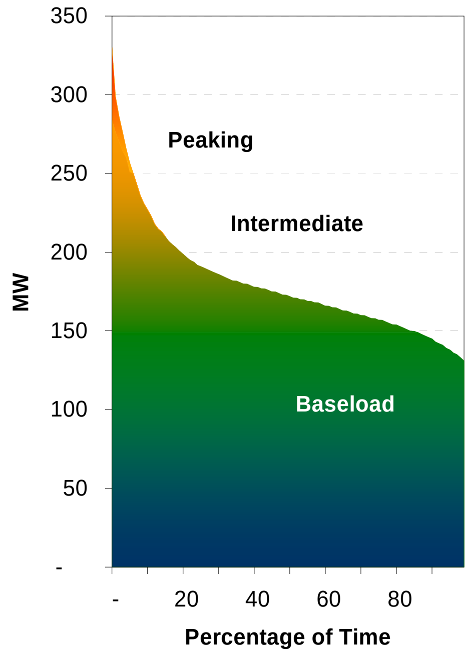
The UML contract currently under negotiation is based upon the dispatch of the third party's generating capacity. The energy component of the contract is determined by the variable cost of the marginal unit that serves MWE. The capacity component is determined by the third party's estimate of the units that will most likely be dispatched to serve MWE's load. The structure of the UML contract requires some modeling of the supplier's system. Details on the assumptions and simulation analyses relevant to this contract type can be found in the confidential appendices to this report.

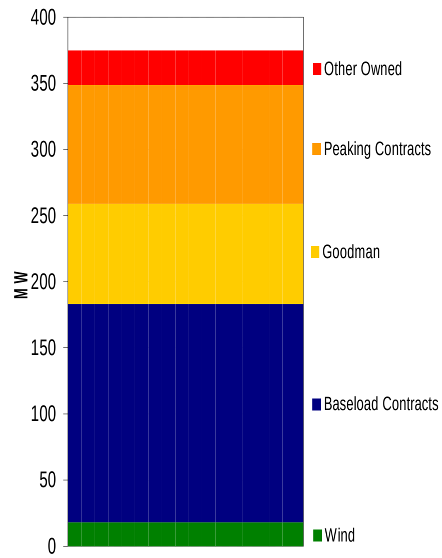
SUPPLY AND DEMAND BALANCE

Exhibit 12 presents the 2008 load duration curve for MWE alongside their current existing resources and contracts. The full capacity of all resources and contracts is assumed, unless the resource is wind. In that case, average annual capacity factors were used to display average generation levels over the course of a year. Current generating capacity under four contracts, totaling 255 MW, are due to expire over the next few years.

The evaluation of new contracts and capacity additions will aim to optimize the energy and capacity cost profile of each option against MWE's load profile.

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



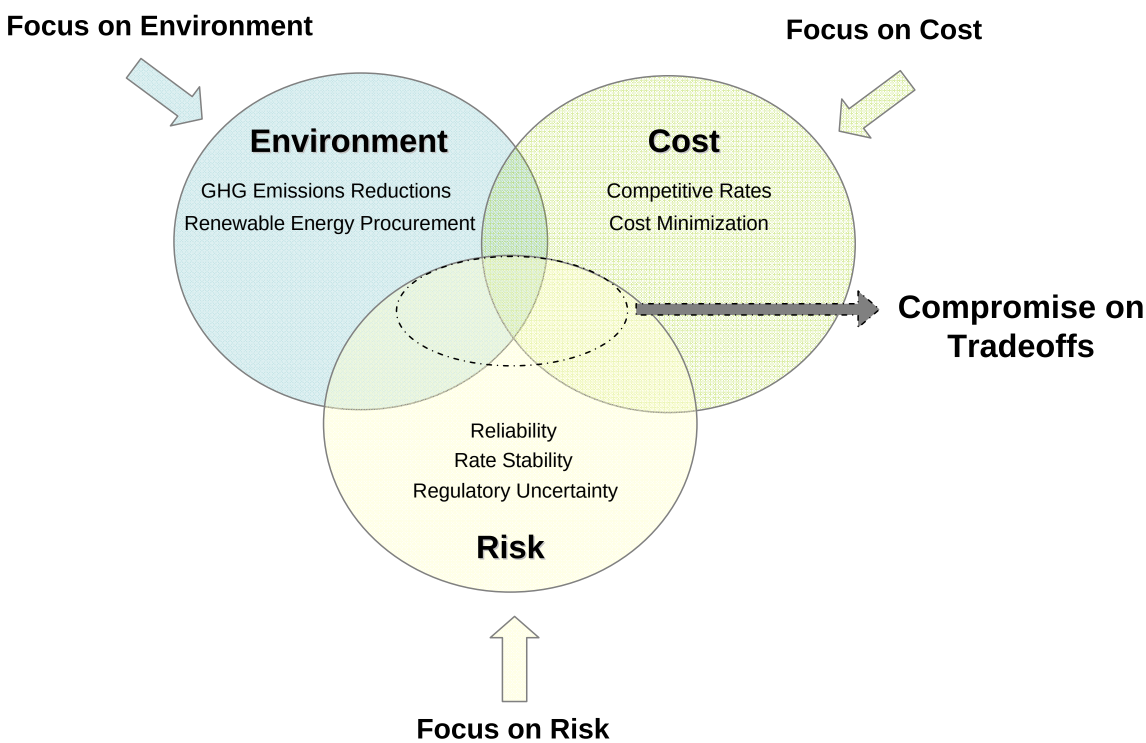


Source: MWE and Pace

PLANNING OBJECTIVES AND METRICS

To properly evaluate resource decisions, the planning objectives were identified early in the resource planning process. Even with the appropriate metrics identified for each planning objective, the tradeoffs associated with resource decisions represent a big challenge for resource planning. Exhibit 13 displays three commonly competing objectives. As is shown, focus on any one objective can move the resource plan away from focus on the others.

Exhibit 13: Competing Planning Objectives



Source: Pace

The following section describes the list of planning objectives that were identified 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

Preserve Competitive Rates (Cost)

Preserving competitive rates is a common objective for utilities. 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)

Fuel and power price volatility, as well as uncertainty around energy demand and capital costs, can result in significant changes in portfolio 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 standard deviation of the NPV of costs (or each year's cost where appropriate). This represents a metric of how wide the distribution of costs can get for each portfolio. The lower the standard deviation, the less exposed the portfolio is to market volatility.

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 reserve margin criterion, such as the 13.6% planning reserve margin used by MWE.

CO_2 Emission Liability

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.

Renewable Generation

Specific regulations concerning both federal and statewide RPS standards for utilities in Kansas will drive renewable resource additions. MWE is committed to meeting these requirements. Increasing generation from renewable resources will also directly result in reduced CO_2 emissions for the portfolio.

Manage Contract Risks on Sales

In the case of MWE, an important consideration is whether its PPAs will allow them to re-sell excess power back into the market. If sales from contracted energy are restricted and load is less than anticipated, MWE might be in a position where it is paying for power it cannot use or re-sell. Restrictions on load factor and resales are considered in the construction of portfolios and analyzed directly in the analysis.

ANALYSIS OF BASELOAD VS. UML TRADEOFFS (PHASE I SCREENING ANALYSIS)

The resource planning approach taken in this 2009 LRRP consists of two major phases. The first phase is designed to screen all feasible contract and resource options that meet MWE's energy requirements. The screening process includes a representation of all expected market conditions and planning constraints (RPS standards, existing resources, contract requirements and minimum lengths). These options are evaluated based on MWE's objectives, energy and regulatory requirements, as well as specific contract options offered by the preferred supplier. A number of portfolios are then selected to be further evaluated during the "risk" phase of the analysis.

The goals of the screening analysis are to:

1. Eliminate technologies that are not economically feasible for MWE during the planning horizon;
2. Identify capacity additions required to meet expected RPS standards;
3. Concentrate on the most cost-effective mix of Baseload and UML contracts over time;
4. Provide insight into the timing of generation or PPA additions for consideration in the risk analysis;
5. Provide guidance into the implications of PPA restrictions that might affect the construction of a limited number of portfolios in the risk analysis.

SCREENING ANALYSIS

Screening analyses were performed with a customized screening tool in a deterministic rather than probabilistic or stochastic framework. The screening analysis is able to rapidly evaluate key metrics for all contract combinations and a variety of technology combinations within the framework of MWE's operations.

Screening Process

The screening process was performed in accordance with Exhibit 14. As is noted, the screening analysis incorporated a detailed representation of portfolio resources, MWE demand (load), and all relevant costs such as fuel prices, power prices, environmental compliance costs, and fixed and variable operating charges. The screening analysis evaluated different contract options from the preferred supplier as well as alternative resources for ownership or contract.

The key elements of the process can be summarized as follows:

1. Reference case assumptions for load, costs of existing capacity, capacity additions, and contract and fuel costs were developed (these are described in detail in the Appendices)

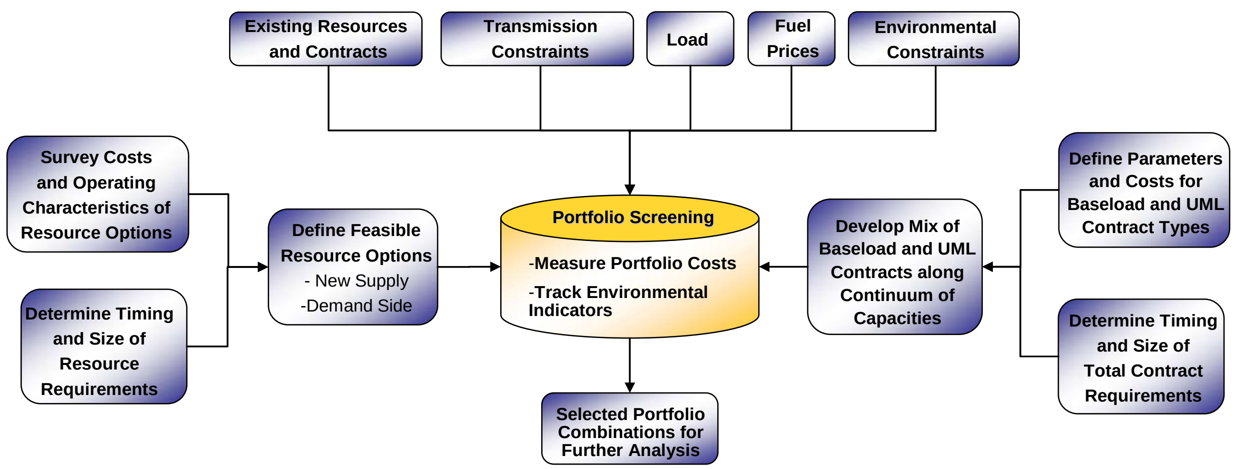
2. Contract options were evaluated across a continuum of capacity mixes for baseload and "units most likely" ("UML") based on Reference Case conditions. The full range of

contract options from 100% of UML to 0 percent baseload (and corresponding 0% to 100% baseload) was assessed.

3. Incremental wind, solar and peaking combinations during each of three time periods (2010-2015, 2015-2020 and 2020-2025) were assessed to see which reduced portfolio costs in comparison to the optimal baseload/UML generation mix and during which time periods.
    a. Based on operational profiles, wind replaced baseload contract capacity, while solar and new (GEC type) peaking capacity replaced UML capacity.

4. Candidate portfolio combinations were selected for evaluation in the full risk analysis.

Exhibit 14: Process Diagram for Screening Analysis



Source: Pace

Contract Options

Two types of contracts were evaluated:

- Baseload Unit-Contingent Coal-Fired Generation: MWE currently has baseload, unit-contingent coal-based contracts. These contracts contain a fixed capacity charge, with variable costs associated with actual costs of plant generation. Using existing baseload contracts as a guide, Pace evaluated a representative coal-fired plant within the preferred supplier's fleet to track operations and costs associated with this contract.
- Units Most Likely ("UML") Generation: This type of contract allows MWE to purchase energy from the preferred supplier at their marginal cost of serving MWE's load, after the supplier's native load requirements and other obligations are met. Analysis of this contract type requires full simulation of the supplier's portfolio mix and load requirements in order to simulate the hourly cost of energy.

Resource Options

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

- Wind (considered a baseload but intermittent supply option)
- Solar photovoltaic
- Goodman Energy Center ("GMEC") Expansion (a peaking option)
- Additional peaking capacity similar to GEC (a peaking option)

Capital cost estimates and operating profiles were developed for these resource options from a combination of information from Pace technology assessments from consulting projects and public reports, as shown in Exhibit 15. These estimates were combined with financing assumptions and tax rules summarized in Exhibit 16 to develop appropriate cost comparisons. The gas-fired peaking options were structured assuming ownership by MWE, while the renewable options were assumed to be constructed by a private developer and contracted through a power purchase agreement. Operational parameters were applied and specified at the hourly level, where appropriate.

Exhibit 15: Operating and Cost Parameters for New Resource Options

Technology	Early Capital Cost	Mid Capital Cost	Late Capital Cost	VOM	FOM	Heat Rate	Block Size
	2008$/kW	*2008$/kW*	*2008$/kW*	*2008$/MWh*	*2008$/kW-yr*	*Btu/kWh*	*MW*
GMEC Expansion	755	722	714	4.00	13.20	8,600	25
New Peaker (Wartsila)	795	760	751	4.00	13.20	8,600	25
Wind	2,103	2,080	2,052	0	20.45	na	25
Solar PV - Si	5,096	3,625	2,594	0	5.99	na	30

Source: Pace

Exhibit 16: Reference Case Financing and Tax Benefit Assumptions

Technology	Equity/ Debt Ratio	Return on Equity	Interest Rate	WACC (ROR)	PTC	ITC	Levelized Recovery Requirement	Levelized Recovery Requirement
	%	%	%	%	$/MWh	$/kW-year	$/MWh	$/kW-year
Expansion Peaker	40	11.31	5.25	7.67	-	-	59*	77
New Peaker	40	11.31	5.25	7.67	-	-	62*	81
Wind	50	15	8.25	11.63	20	-	57**	184
Solar PV - Si	50	15	8.25	11.63	-	22.5	126 (2021) 99 (2026)***	222 (2021) 175 (2026)

* 15% capacity factor assumption
** 37% capacity factor assumption
*** 20% capacity factor assumption

Source: Pace

SCREENING RESULTS

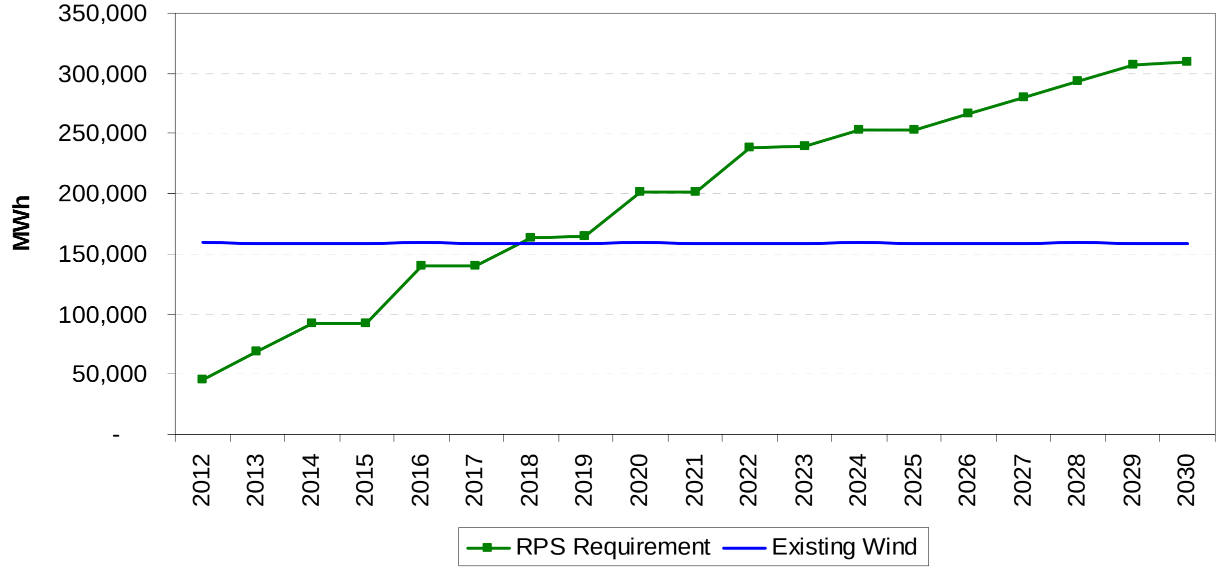
The key conclusions of the initial resource screening were:

- o In order to meet projected federal Renewable Portfolio Standard requirements by 2030, MWE will need to add about 50 MW of wind capacity (at a 37% capacity factor) to its portfolio (in addition to replacing the current Smoky Hills contract at expiration).
- o The lowest cost mix of baseload versus UML type contracts is between 40 and 60 percent baseload.
- o Additional peaking capacity at the Goodman Energy Center or elsewhere is cost effective early in the Study Period.
- o New wind additions beyond RPS requirements should be delayed beyond 2020, but may be cost effective thereafter, as price expectations for natural gas prices and carbon compliance costs increase.
- o New solar additions do not appear cost-effective during the Study Period.

RPS Requirements

Exhibit 17 shows that expected Federal RPS requirements of 25 percent by 2030 will require additional renewable generation beyond the existing Smoky Hills wind contract by 2018. Although MWE is long renewable capacity at the moment, a gap between the expected requirements is expected to develop and grow over time. By 2030, a total of about 50 MW of new wind capacity (at a 37% capacity factor) is required to meet this expected standard (which includes an option that 25% of the requirement could be met by energy efficiency). As a result, Pace has included incremental 25 MW wind additions in 2018 and 2021 in its portfolio development.

Exhibit 17: Expected Renewable Generation Requirements vs. Existing Supply



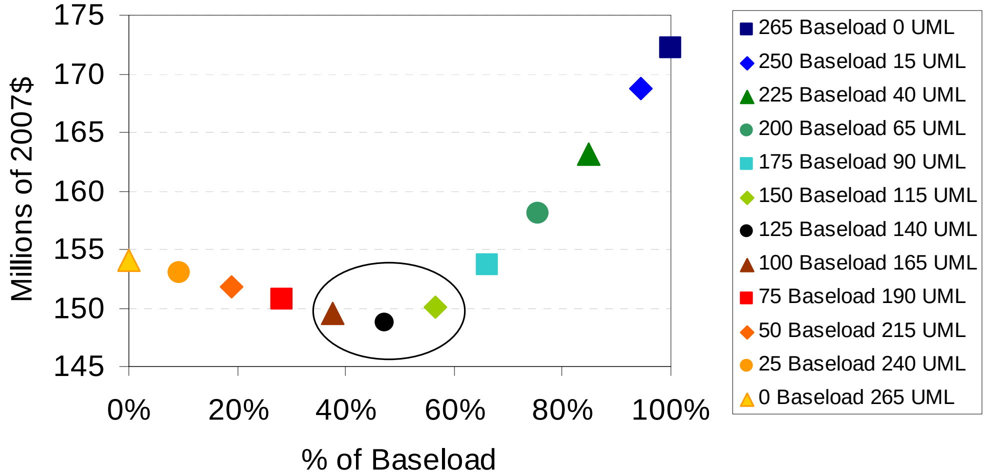
Source: Pace

Baseload vs. UML Mix

Pace evaluated the most cost-effective mix of baseload and UML capacity by testing a continuum of options from 100 percent of capacity requirements served by baseload and 0 percent UML to 0 percent baseload and 100 percent UML. It was determined that a mix containing between 40 percent and 60 percent baseload capacity (100 to 150 MW) is the most cost-effective, with 50 percent being the preferred option in the screening analysis. This is displayed in Exhibit 18.

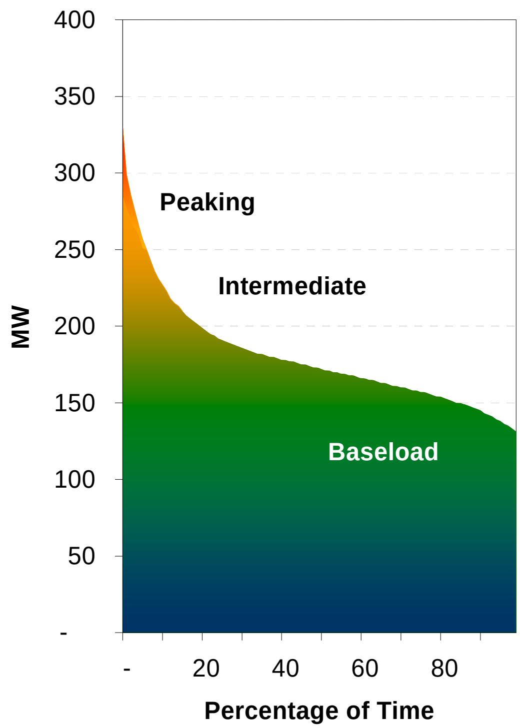
This mix of contract types is the most effective and efficient way to meet MWE's load profile, which is shown in load duration form in Exhibit 19. Too much baseload capacity with high fixed capacity charges would result in an oversupply for many hours of the year, leading MWE to pay for energy and capacity that it does not need. Too little baseload capacity would force MWE to pay for the UML supplier's marginal gas-fired resources at a higher variable cost than coal-fired baseload resources when loads are low.

Exhibit 18: Baseload vs. UML (2026-2030)



Source: Pace

Exhibit 19: Load Duration Curve

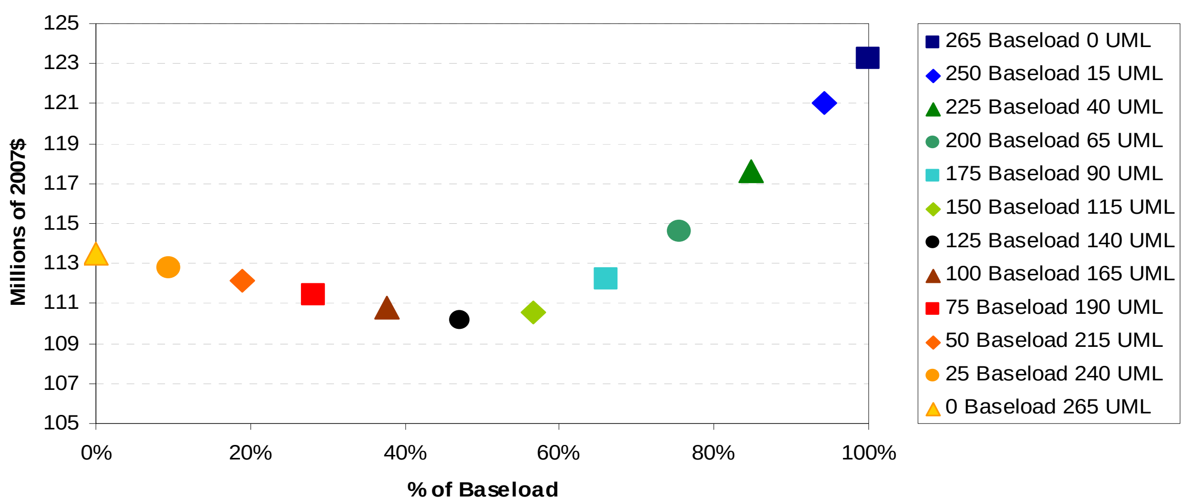


Source: Pace

Certain restrictions may be introduced in negotiations that could either require high load factors on the baseload contracts or restrict sales. In the screening analysis, we considered how one or the other of these types of restrictions might affect the targeted level of baseload generation relative to UML generation.

Higher Load Factor Requirement: A high load factor requirement means that MWE must take energy from the baseload contract every hour at a level close to available output. Under such an arrangement, MWE may be able to sell some of the excess generation to an off-taker at a discount to cost. When analyzing this scenario, Pace has credited MWE with the ability to sell 80% of its excess power at 80% of its cost. A PPA that requires a commitment to high (98 percent) load factors but allows limited re-sales (at a discount to market) results in optimal baseload portfolio percentages of around 50 percent, as displayed in Exhibit 27.

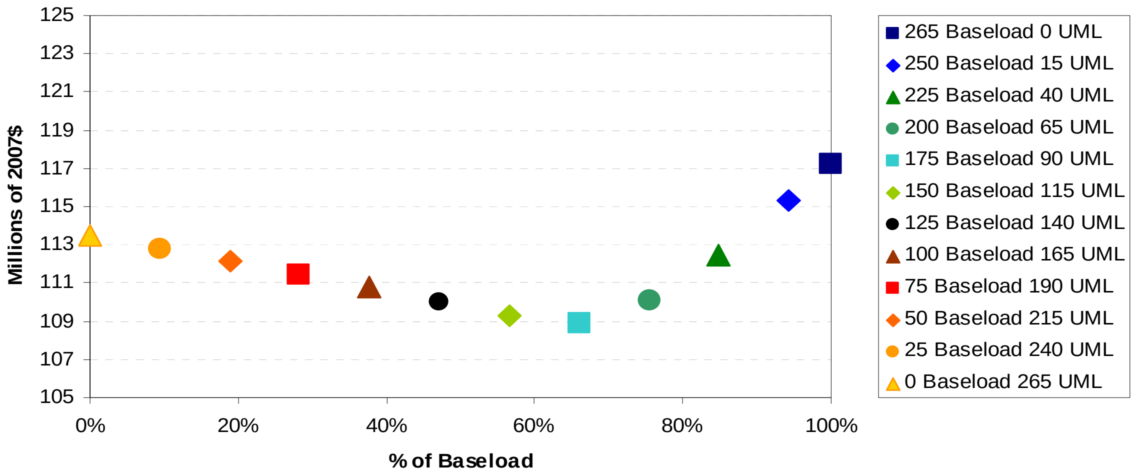
Exhibit 20: Impact on Reference Case of High Load Factor



Source: Pace

Restricting Resales: In analyzing a total restriction of sales, Pace has simulated a scenario where MWE would be required to take only 90 percent of the baseload energy (90% load factor), but be unable to sell any of it back. This means that excess energy beyond load requirements in any hour would be paid for even if unused. Under these conditions, the optimal baseload percentage increases to a number closer to 70 percent. This is shown in Exhibit 21. As discussed later, uncertainty in load and market conditions can change these findings.

Exhibit 21: Impact on Reference Case of Sales Restriction



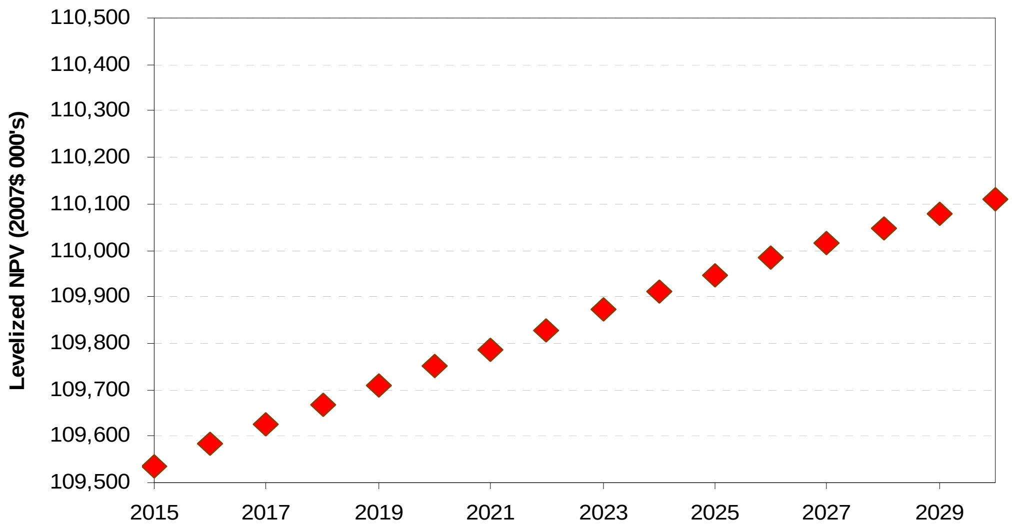
Source: Pace

Incremental Capacity Additions

Pace examined the cost-effectiveness of additional natural gas-fired peaking capacity additions to MWE's portfolio. The analysis tested the costs and ideal timings for expanding the Goodman Energy Center and adding more peaking power plants. All additional peaking capacity was simulated through replacement of an equal amount of UML capacity. It was concluded that additions of gas-fired peaking capacity (both expansion of GEC and additional capacity of a similar nature) or DR programs provide an effective hedge against potential high costs of UML generation, reducing generation costs.

Pace's analysis indicates that the best timing is as early as feasible, since peaking capacity additions are lower cost than projected UML contract costs throughout the entire Study Period. Exhibit 22 summarizes the total net present value of portfolio costs for different scenarios that add incremental peaking capacity for each of the years between 2015 and 2030. As can be seen, the scenario that adds peaking capacity earliest is most cost-effective. This suggests that the length of the UML contract should be structured around the time needed to expand the current peaking capacity or construct a new plant.

Exhibit 22: NPV of Additional MWE Owned Peaking Capacity over Time

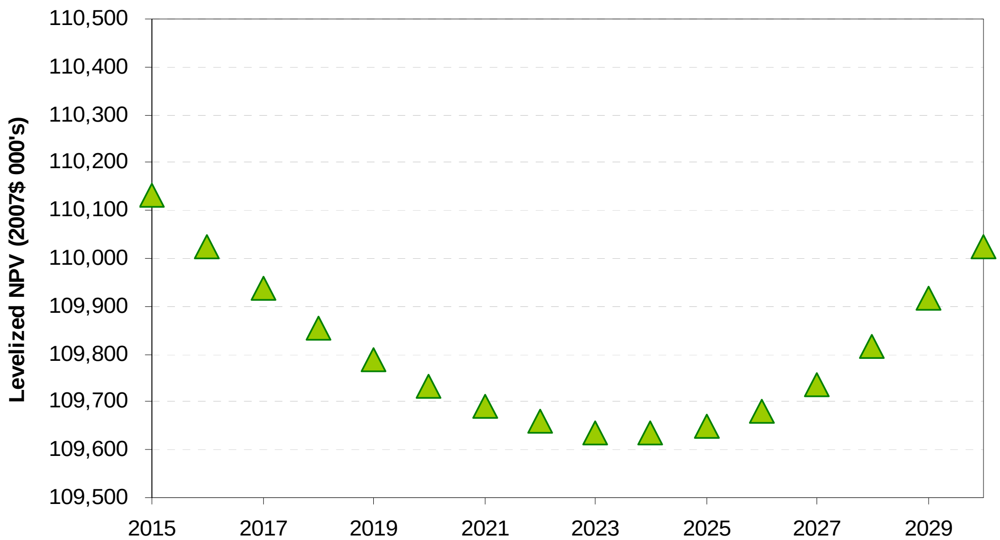


Source: Pace

Pace also examined the cost-effectiveness of adding renewable capacity additions above and beyond those required to meet expected RPS targets. Similar to the tests for additional peaking capacity, the analysis examined the effects on cost of new wind or solar PV expansion over time, from 2015 to 2030. Incremental wind additions replaced baseload contract capacity on a firm reserve credit basis, while incremental solar additions replaced UML capacity. This is due to the expected operational profiles of these two renewable types.

Although solar additions become more economic over time, they are never expected to result in a net benefit in total portfolio costs over the planning horizon. Incremental wind capacity additions (between 25 and 50 MW) beyond that required to meet Federal RPS standards ("economic wind additions"), however, may reduce portfolio costs. Exhibit 23 displays the net present value of total portfolio costs for different scenarios with wind additions in each of the years between 2015 and 2030. This shows that the optimal timing for new economic wind additions is between 2021 and 2025. Low initial gas and coal costs make wind cost-prohibitive in the near term versus MWE's current portfolio and contract options, but rapidly rising cost expectations for both natural gas and carbon compliance make wind more economic after 2020.

Exhibit 23: NPV of Additional Wind Capacity over Time

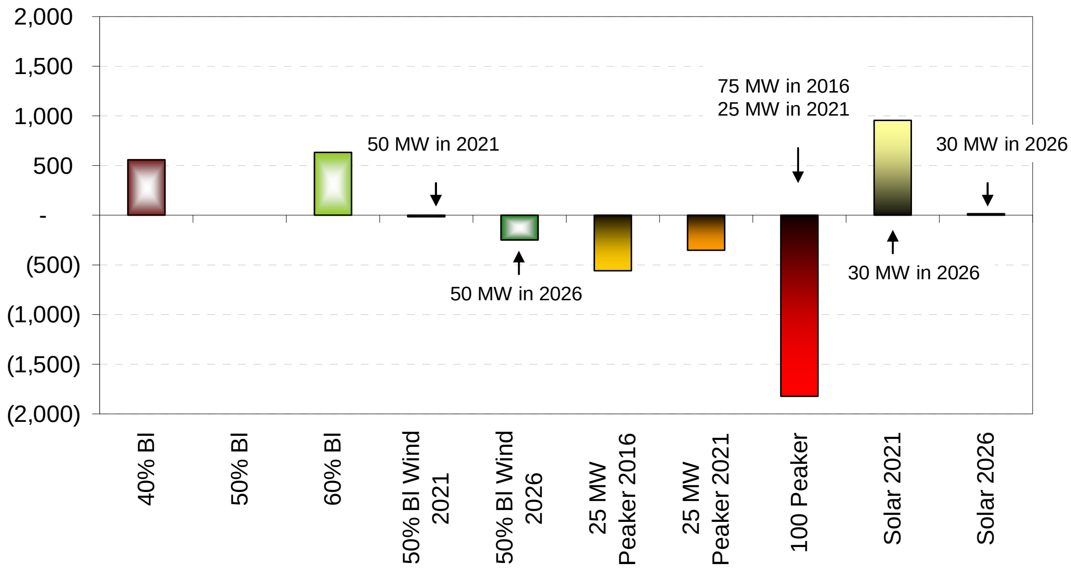


Source: Pace

Screening Conclusions

Pace's screening analysis concluded that the optimal mix between baseload and UML contracts is around 50 percent each, depending on load factor and sales restriction considerations. Incremental natural gas-fired peaking capacity additions are likely to reduce costs as soon as they can be brought into service. New economic wind additions are not cost-effective until after 2020 and new solar additions are not cost-effective throughout the Study Period. To display these results and compare their magnitude on a net present value basis, Pace has shown the relative portfolio cost outcomes for a variety of capacity mixes against a reference scenario with 50 percent baseload and 50 percent UML in Exhibit 24. In this display, positive values indicate additional portfolio costs, while negative values indicate lower costs and a benefit to the portfolio.

Exhibit 24: Screening Analysis Results (NPV in $000)



Source: Pace

CANDIDATE PORTFOLIOS FOR RISK ANALYSIS

With the resource screening analysis conclusions guiding portfolio development, specific details regarding MWE'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.

The Phase I analysis resulted in the creation of twenty distinct portfolios that examine different baseload and UML capacity mixes, various sales and load factor restrictions, and different timing and capacities for incremental additions. The twenty selected portfolios are summarized in Exhibit 25 as incremental additions to the existing MWE portfolio.

The details of each of the incremental portfolio options referenced in Exhibit 25 are as follows:

- The first 5 portfolios consider only baseload and UML supply options for meeting MWE's load using 40%, 50%, 60% and 70% baseload capacity. High load factors (98%) with some limitations to the ability to re-sell excess baseload energy were used in the 40-60% cases. Lower load factors (90%) with a complete prohibition to sell back excess baseload energy were used for the 60-70% baseload cases, consistent with the screening analysis results.
- The next five cases focus on the 50% baseload option with high load factors and resales but backed down the contract capacities for increments to wind (in either 2021 or 2024), GMEC expansion, incremental peakers in 2015 and 2020 or solar (in 2027).
- The final ten cases focused on the 60% baseload option under two different load factor/resale combinations and the same increments to wind or peakers (including the GMEC expansion).

As mentioned before, although not explicitly simulated in the Risk Analysis, effective DR programs can displace the need for some peaking capacity.

Exhibit 25: Phase II Portfolios (Incremental to Existing Peaking and RPS Generation)

Portfolio Number	Portfolio Name	Baseload %	Load Factor	Sale Back	Wind	GMEC Expansion	New Peaker	Solar
1	40% Baseload	40%	98%	80% at 80%				
2	50% Baseload	50%	98%	80% at 80%				
3	60% Baseload	60%	90%	None				
4	60% Baseload	60%	98%	80% at 80%				
5	70% Baseload	70%	90%	None				
6	50% Bl Wind 2021	50%	98%	80% at 80%	50 MW in 2021			
7	50% Bl Wind 2024	50%	98%	80% at 80%	50 MW in 2024			
8	50% Bl Peaker 2015	50%	98%	80% at 80%		25 MW in 2015		
9	50% Bl 100 MW Peaker	50%	98%	80% at 80%		25 MW in 2015	50 MW in 2015/ 25 MW in 2020	
10	50% Bl Solar 2027	50%	98%	80% at 80%				Solar 2027
11	60% Bl Wind 2021	60%	90%	None	50 MW in 2021			
12	60% Bl Wind 2024	60%	90%	None	50 MW in 2024			
13	60% Bl Peaker 2015	60%	90%	None		25 MW in 2015		
14	60% Bl 100 MW Peaker	60%	90%	None		25 MW in 2015	50 MW in 2015/ 25 MW in 2020	
15	60% Bl Solar 2027	60%	90%	None				Solar 2027
16	60% Bl Wind 2021	60%	98%	80% at 80%	50 MW in 2021			
17	60% Bl Wind 2024	60%	98%	80% at 80%	50 MW in 2024			
18	60% Bl Peaker 2015	60%	98%	80% at 80%		25 MW in 2015		
19	60% Bl 100 MW Peaker	60%	98%	80% at 80%		25 MW in 2015	50 MW in 2015/ 25 MW in 2020	
20	60% Bl Solar 2027	60%	98%	80% at 80%				Solar 2027

Source: Pace

OUTSTANDING RISK 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:

- Load is highly uncertain. Hence, the PPA restrictions evaluated in Phase I could be greatly influenced by the possibility that load could be less than expected, which would potentially make both high load restrictions and restricting resales more expensive.
- Fuel market volatility and carbon legislation on coal-based generation costs through high allowance values could affect the optimal mix of baseload generation or at least the timing and term of the baseload PPAs.
- The evaluation of wind, solar, and owned peaking capacity additions is affected by uncertainties in capital costs relative to the contracting options, as well uncertainties in market drivers that affect the contract costs.

For all of these reasons, we evaluated the list of portfolio combinations around the following uncertainties.

- Evaluation of the exposure of all of the portfolio options to statistically quantifiable risk factors:
  - Customer demand and regional load
  - Coal and Natural gas prices
  - Power market prices
  - Capital costs for resource additions (peaking natural gas turbines, wind, and solar)
  - Capacity costs for the baseload and UML contracts

- Evaluation of certain portfolio options in the context of quantum events through scenario analysis that explore the:
  - Emerging state/regional/federal carbon policy constraints and valuation

QUANTITATIVE AND RISK ASSESSMENT OF PROPOSED PORTFOLIOS (PHASE II)

RISK INTEGRATED RESOURCE PLANNING APPROACH

MWE, 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 resources and contracts perform throughout their operational lives. 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 MWE to severe market volatility or severe negative effects associated with an impending regulatory change. The tradeoffs between costs, risks, 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 LRRP took a risk-based approach to resource planning.[2] The first phase screened all the feasible resource and contract options through an analysis that included a representation of all expected market conditions and planning constraints (RPS standards, reliability requirements, and feasible contract parameters). These options were evaluated based on cost performance and were developed around minimum requirements for RPS and reserve margin.

The portfolios in Phase I were constructed to capture a broad spectrum of baseload and UML contract mixes, as well as owned versus contracted supply resources. The portfolios included additional economic natural gas-fired peakers and renewables when appropriate and factored in different timing possibilities. This allows MWE 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. Exhibit 26 illustrates the details of the Phase I and Phase II components of the 2009 IRP process.

Objectives for Review in Risk Analysis

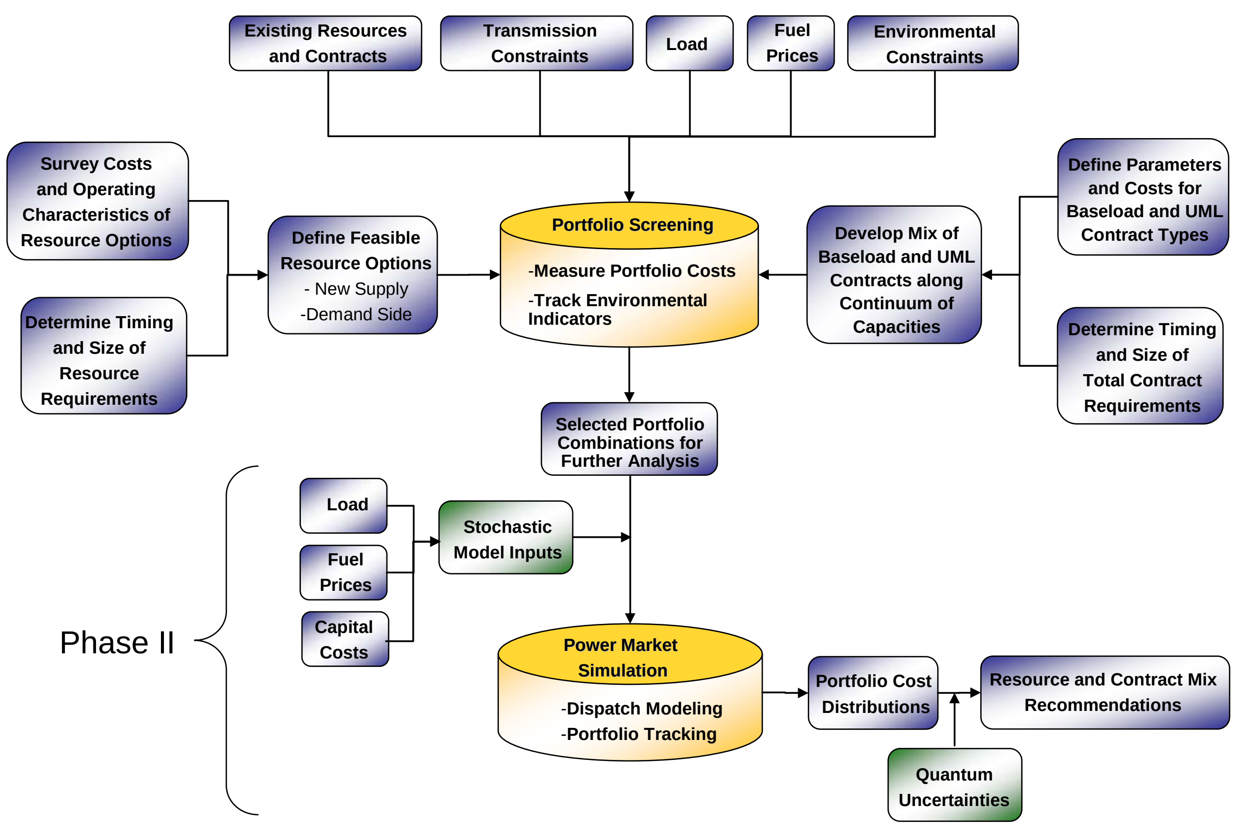
The Phase II process is intended to re-examine several analyses from the screening phase to test the robustness of the preliminary conclusions under an uncertain environment. This will lead to selection of a portfolio (or range of portfolios) that best meets MWE's objectives across a range of market and regulatory outcomes. The major objectives of the Phase II analysis include:

- Re-evaluation of the proper mix of baseload versus UML generation, without additional renewables beyond required for meeting RPS requirements.

[2] 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.

- o Consideration of whether adding renewables beyond RPS requirements is cost-effective (adding wind in either 2020 or 2025 and reducing baseload coal PPA)
- o Consideration of expanding GMEC by 25 MW in 2015 (Reducing UML PPA)
- o Consideration of additional increments of owned peaking capacity in 2015 and 2020 (reducing UML PPA)
- o Evaluation of portfolio performance under a high carbon scenario

Exhibit 26: 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 (quantum) 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, observed relationships between key market drivers and outcomes, and expectations for future market and technological change 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.

The effects of fuel, load, and capital cost uncertainty on the portfolios were quantified by simulating the hourly operations of all portfolio resources over the study horizon under 500 different load, fuel, and capital cost combinations. As stated previously, these distributions were based upon historical statistical analyses of load, fuel prices, and capital costs. Fuel price uncertainty was primarily quantified through evaluation of historical volatility in natural gas and coal market prices. Energy and peak demand uncertainty was evaluated through regression analysis around key determinants of load and uncertainty analysis around energy efficiency and demand side measures. Capital cost uncertainty was 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. Technology change and uncertainty was also accounted for, by representing expected declines in capital costs for solar technology and to a lesser degree peaking and wind capacity over time. Details on the construction of these distributions are provided in an appendix.

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:

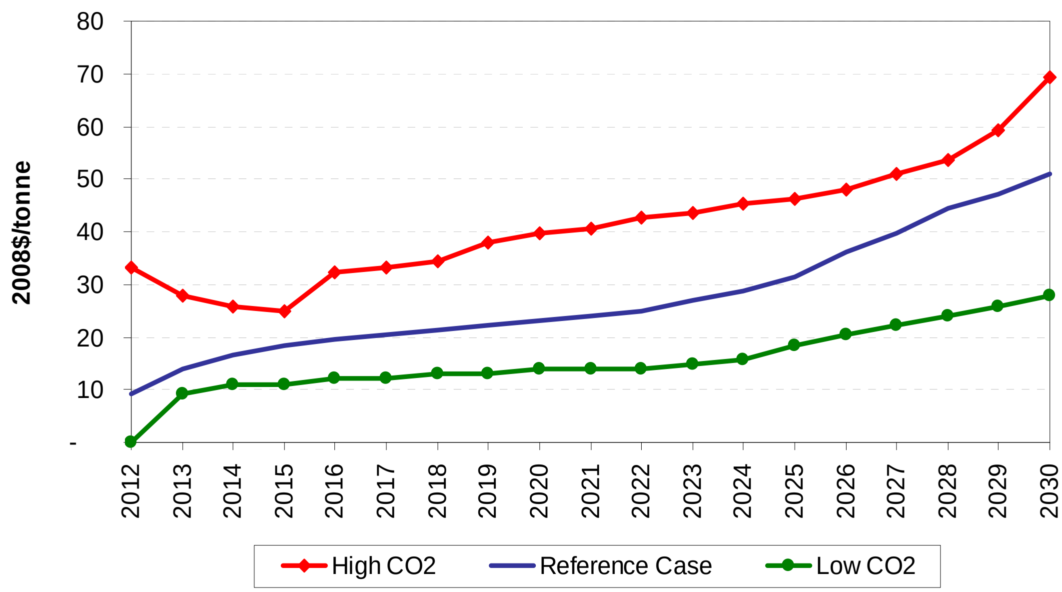
- High CO_2 Cost Scenario
- Low CO_2 Cost Scenario

Regulatory Risk Associated with Higher and Lower CO_2 Allowance 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 or contract. Pace's analysis included the evaluation of all portfolio costs under a high and low CO_2 case. Exhibit 27 displays the annual CO_2 compliance costs assumed in the reference, high, and low CO_2 case. Portfolios with a larger share of coal-intensive generation will face a relatively greater cost 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 the different CO_2 scenarios.

To place the concept of higher and lower CO_2 costs into its proper context, the scenarios were developed around a consistent set of market factors, including gas prices, load and other capacity expansion considerations. For example, legislation that results in higher carbon costs will also likely result in more coal plant retirements, higher near term gas demand and prices, and eventually lower overall demand for gas as more renewables are able to be placed in the generation mix. Additional detail on these assumptions can be found in the appendix to this report.

Exhibit 27: CO_2 Costs for Reference Case and High Case



Source: Pace

PORTFOLIO RISK ASSESSMENT RESULTS

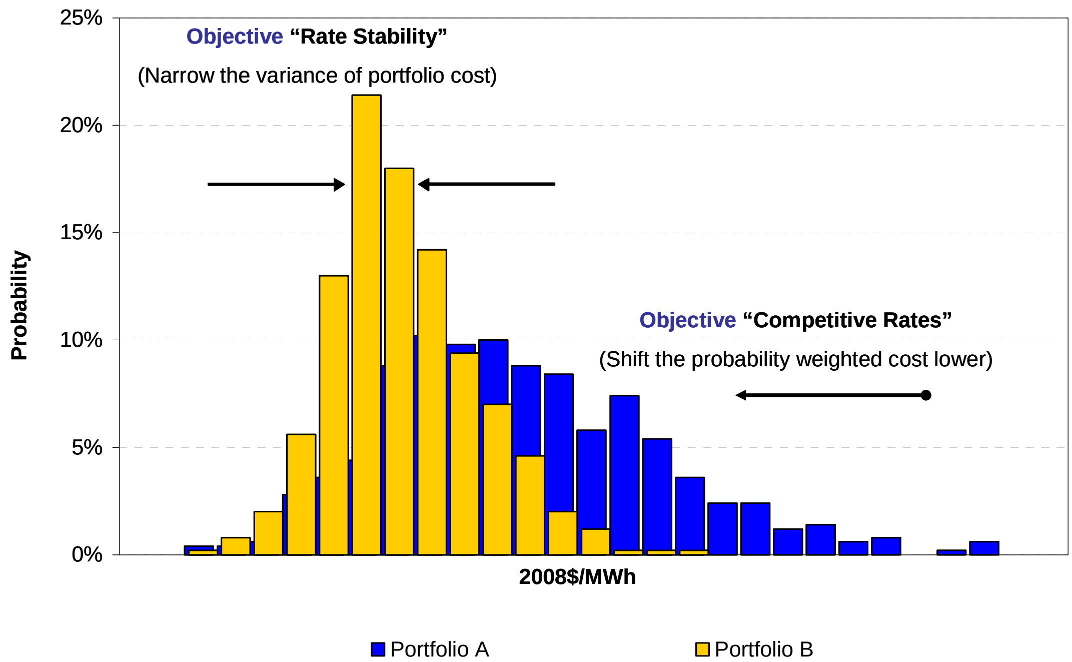
The quantification of risks within the Phase II analysis was performed first through stochastic analysis. This analysis quantified distributions around the total costs of each of the portfolios. Key result metrics included the net present value of portfolio costs (computed as a levelized annuity price per MWh) and the width of the distribution (the standard deviation). Additional scenario analyses were then performed to measure the exposure of each of the portfolios 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 “reference 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 28 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 28: 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, which is a measure of how costly the portfolio can get (enumerated as the standard deviation of the distribution).

Key Findings

The key findings of the risk analysis are:

- The optimal baseload percentage mix is between 50 and 60 percent (125 to 150 MW), maintaining some ability to sell excess power;
- The expansion of GMEC is warranted, as is additional natural gas-fired peaking capacity;
- The economic addition of wind generation in or around 2024 is favorable, but only depending on resale provisions for the baseload contract;
- Solar additions are not cost-effective incremental additions to the portfolio.

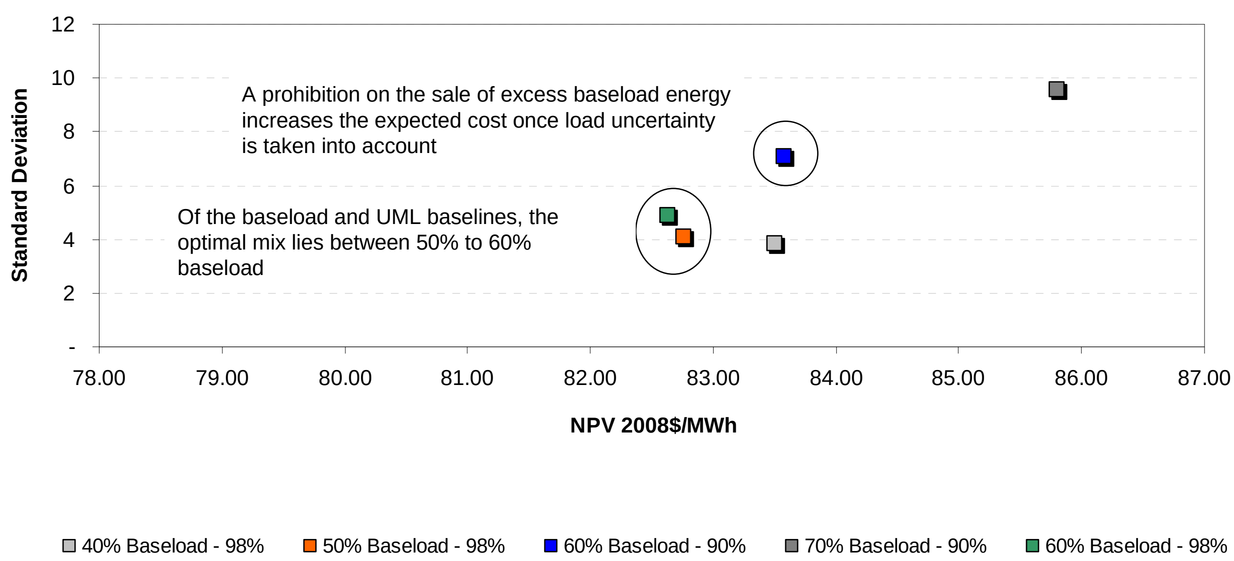
- o The impact of higher carbon costs raises the costs of all portfolios substantially, but doesn't change the optimal portfolio combination. In fact, due to less baseload, the 50 percent portfolio is less exposed to higher CO_2 prices than those portfolios with 60 percent baseload.

Baseload-UML Mix and Sales Restrictions

The risk analysis indicates that the optimal baseload percentage mix is between 50 and 60 percent, as long as some ability to sell excess power is retained. Exhibit 29 displays the expected costs and standard deviation of the targeted range of baseload and UML mixes. The horizontal axis displays the net present value of total portfolio costs from 2015 to 2030 in 2008$/MWh, and the vertical axis shows the standard deviation, the key measure of risk.

As can be seen, the least cost portfolio option (the one furthest to the left in Exhibit 29) has a baseload percentage at about 60 percent. However, the 50 percent portfolio option has only a slightly higher expected cost (slightly to the right) with a slightly lower risk profile (slightly lower). Lower baseload percentages (40%) are clearly higher costs. The prohibition to sell back any excess energy assumed for the higher baseload percentages result in both higher expected costs and higher risk.

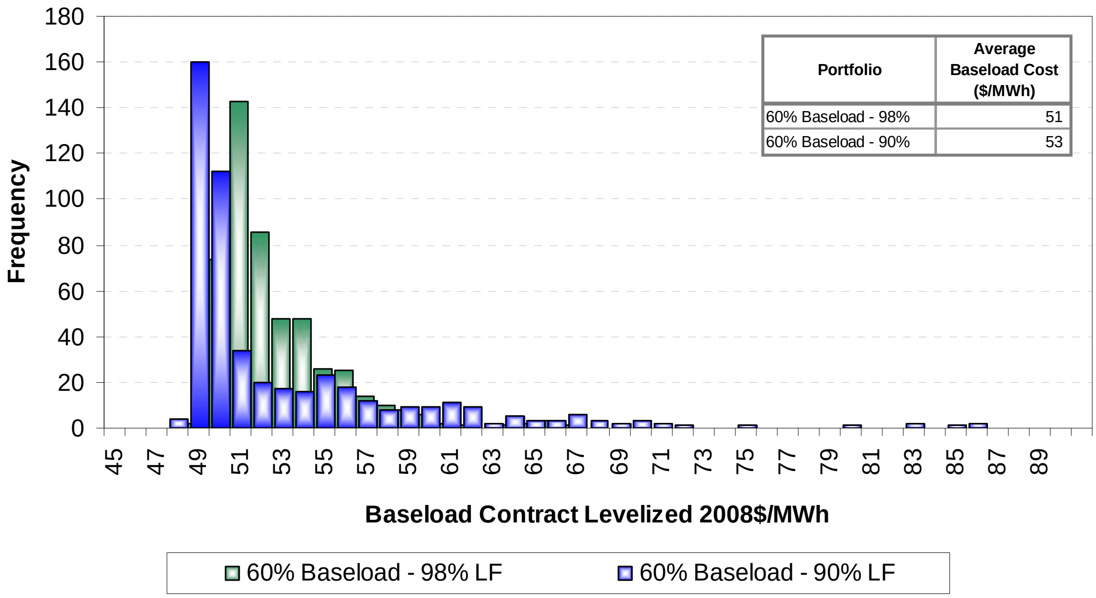
Exhibit 29: Cost vs. Risk for Different Baseload-UML Portfolio Options



Source: Pace

Increasing the baseload percentage increases portfolio risk for two primary reasons. First of all, increasing baseload generation results in more excess supply for MWE under low-load conditions. This excess supply must be sold for a loss or not sold at all. As load uncertainty is included in the Phase II risk analysis, Pace has found that larger amounts of baseload capacity put the portfolio at greater risk of having excess energy that must be sold at a discount or lost completely. Therefore, the inability to resell any excess baseload power can result in higher cost, if load growth is lower than expected. This is the case for the 60 percent baseload case with a prohibition on sales and a 90 percent load factor requirement, which in Exhibit 29 is to the right (higher cost) and above (higher risk) the 60 percent baseload case with resales and a 98 percent load factor requirement. This increase in the width of the distribution when resales are prohibited is shown in Exhibit 30.

Exhibit 30: Baseload Energy Cost Distributions for 60% Baseload with and without Resale



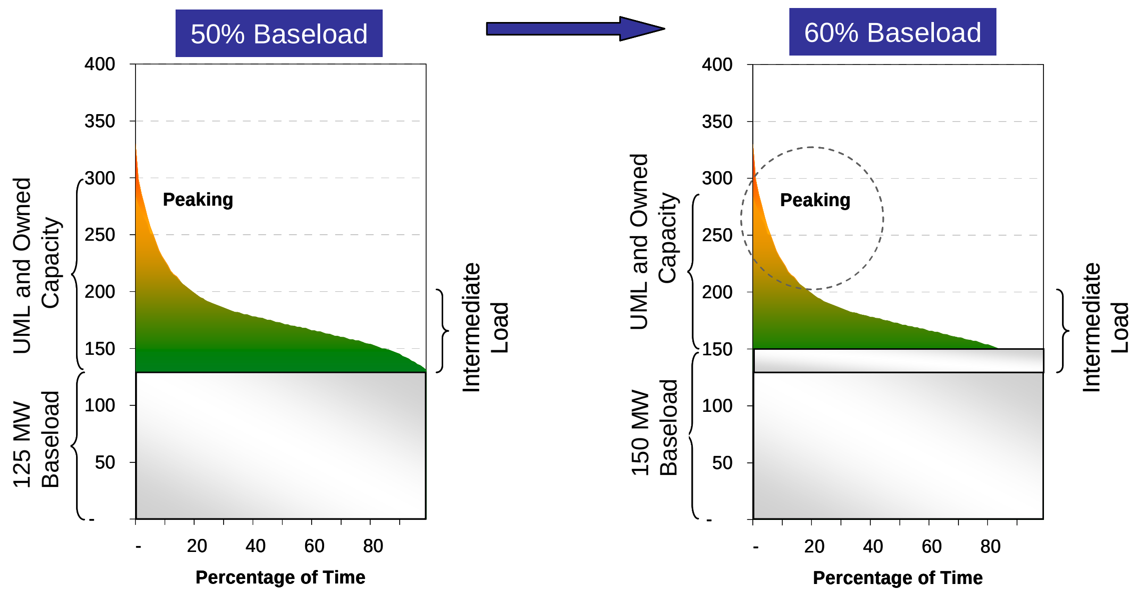
Source: Pace

Second, portfolios with additional baseload capacity are also more risky because they reduce the UML share. A reduction in the UML percentage effectively pushes the capacity mix of the UML contract towards a higher-cost and more volatile section of the counterparty's supply curve. Exhibit 31 illustrates the underlying drivers of the increase in UML energy cost volatility.

As an example, if 50 percent of the contracted capacity requirements for MWE are served with the UML contract (the other 50 percent with a baseload contract), MWE would likely use UML energy to serve intermediate and peaking load requirements. If the percentage of contracted baseload was increased, however, the UML contract would be used to serve less of the intermediate load requirements. In its place, the additional baseload energy would be used for some intermediate load hours. The remaining UML energy would, therefore, be composed of a larger percentage of peaking hours. Because peak energy prices are often more volatile, the risks associated with the UML contract are also greater, at least in regard to overall average cost, when it is relied upon only during peak periods. Exhibit 32 shows the distribution of the resulting $/MWh of the contracted UML energy for the 50 percent and 60 percent baseload portfolios.

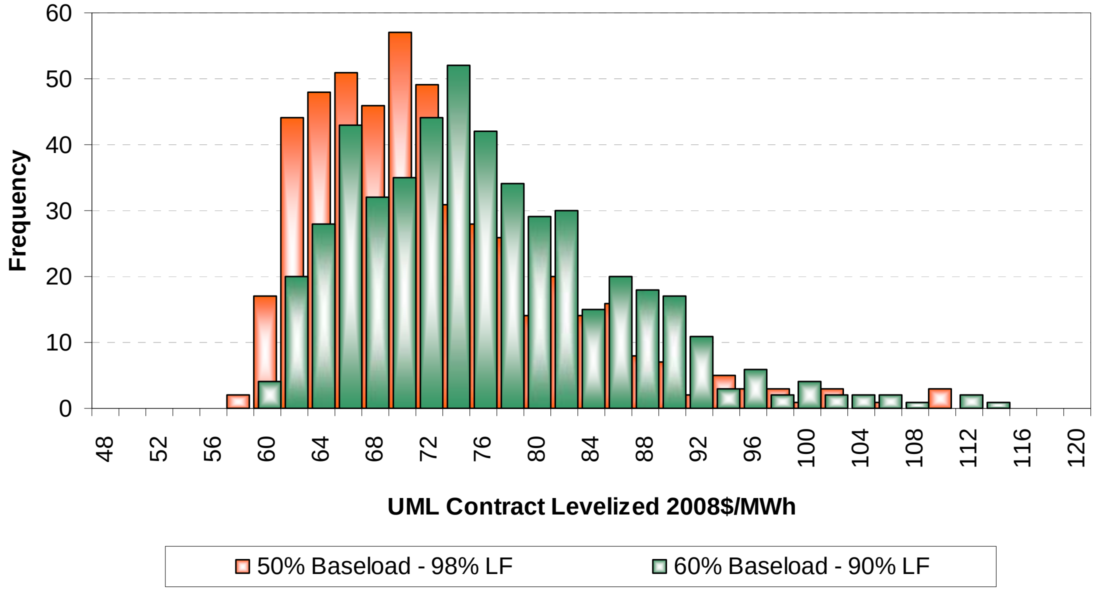
Exhibit 31: Underlying Drivers of the Increase in Risk Associated with UML Energy

1. If the baseload contract is increased by 25 MW, the UML contract is reduced by 25 MW
2. More of the intermediate load hours that were before supplied by the UML contract will now be supplied by the baseload contract
3. This results in the use of the UML contract for a larger percentage of peaking hours and a smaller percentage of intermediate load hours
4. Because peaking energy is more volatile, and this now constitutes a bigger percentage of the UML energy, this increases the risk associated with the UML contract



Source: Pace

Exhibit 32: UML Energy Cost Distributions for 50 and 60 Percent Baseload Portfolios



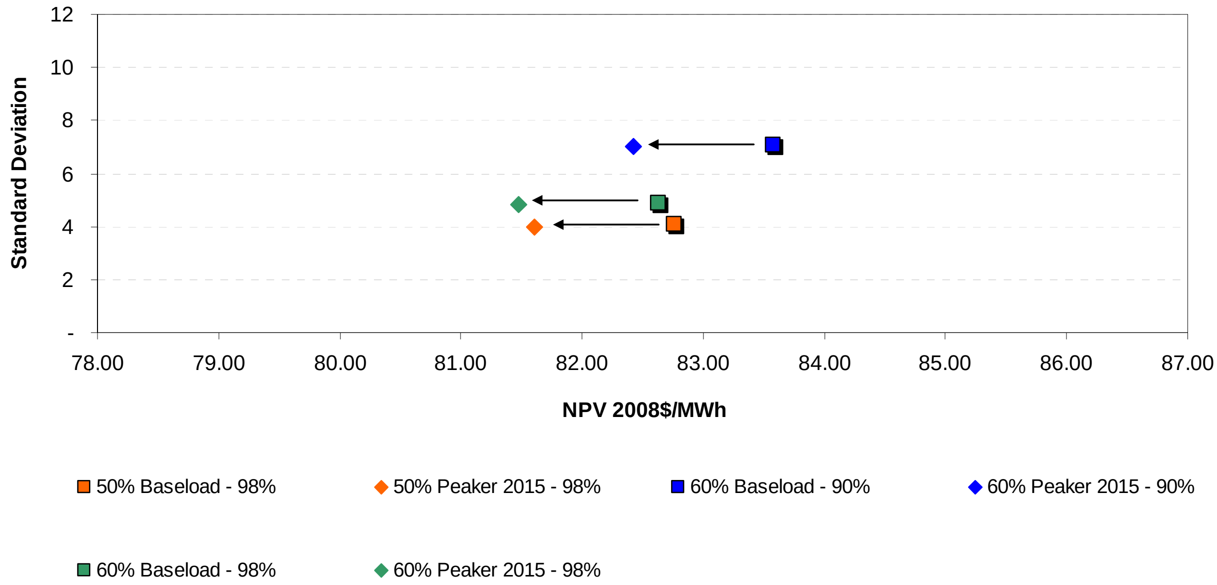
Source: Pace

Natural Gas Peaking Expansion

The expansion of GMEC is warranted, as is additional natural gas-fired peaking capacity. As shown in Exhibit 33, the expansion of GMEC reduces portfolio costs by just over $1/MWh on a levelized basis. It does this with no appreciable increase in risk. This is because additional owned peaking capacity reduces the portfolio's reliance on the UML contract during the most volatile peak periods, as well as the more stable intermediate times. Furthermore, capital cost uncertainty associated with new construction is offset by the market uncertainty from the UML that is avoided, as well as the avoided uncertainty around capacity charges in the UML contract.

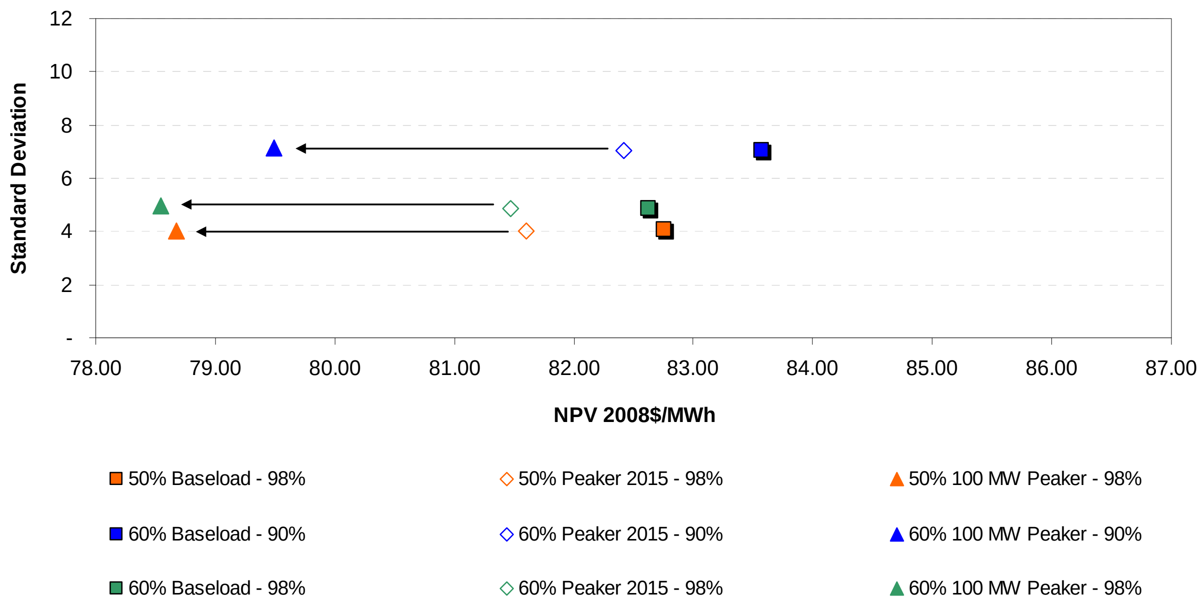
Additional natural gas peaking capacity beyond the GMEC expansion is more cost-effective than UML contract capacity. This is true with new capacity additions as early as 2015 and with total incremental additions beyond GMEC of 75 MW (a total of 100 MW of new gas-fired peaking capacity). GMEC-type generation is more efficient than the likely capacity available from system power at nearby interconnected utilities after they meet their own load. Exhibit 34 displays the cost and risk impact on the portfolios of adding a total of 100 MW of new peaking capacity to each of three baseload-UML combinations. The impact on the net present value of total portfolio costs is around $4/MWh when compared to the reference points.

Exhibit 33: Cost vs. Risk for Portfolios that Include GMEC Expansion



Source: Pace

Exhibit 34: Cost vs. Risk for Portfolios that Include Additional Peaker Expansion



Source: Pace

Demand Response Programs

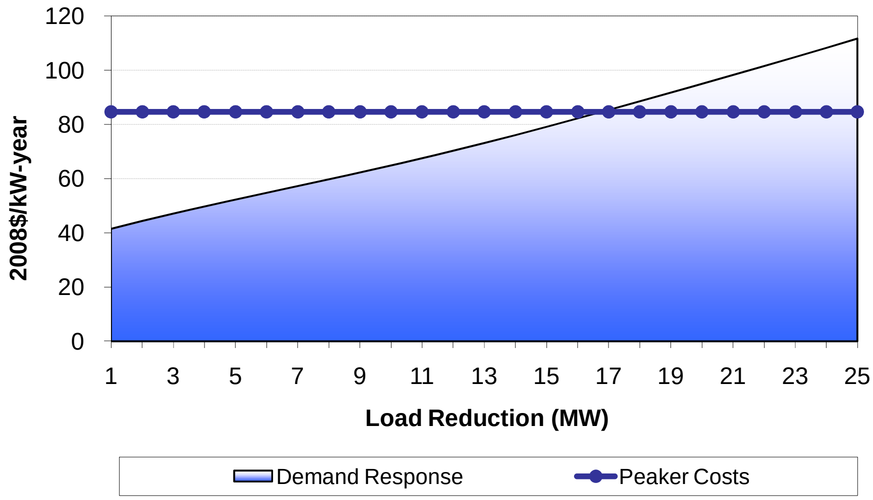
The successful implementation of DR programs can reduce a utility's need for peaking generation. To assess the cost-effectiveness of DR, it is pertinent to compare its levelized costs to the costs of a new peaking unit. Pace performed a high-level analysis of the effectiveness of DR programs to displace or delay some of the need for new peaking capacity. Given MWE's customer base and load profile for each customer class, Pace considered five types of DR programs in its analysis:

1. Agricultural Load Shedding
2. Thermostat Control – Residential
3. Thermostat Control – Small Commercial and Industrial
4. Direct Load Control/Advanced Metering Infrastructure ("AMI") – Residential
5. Direct Load Control/AMI – Small Commercial and Industrial

To estimate the costs and expected kW savings for each of these programs, Pace relied on publicly available information from several sources. The details of this analysis are shown in the confidential appendices to this report.

Exhibit 35 illustrates the costs associated with achieving different levels of load reduction compared to the costs of a new peaking plant. Under the simulated reference case conditions, the analysis indicates that roughly 16 MW of load reduction could be achieved at a cost lower than a new peaker built by MWE. This indicates that there is potential to further decrease utility costs by implementing some DR programs and delaying the need for new peaking capacity.

Exhibit 35: Levelized Cost Comparison of Demand Response vs. Peaking Capacity



Source: Pace

The composition of the cost-effective mix of DR programs (16 MW) is shown in Exhibit 36. In summary:

- The agricultural load shedding program accounts for roughly 8 MW of the mix

- An additional 8 MW of load reduction are the result of a combination of residential and small commercial and industrial thermostat control
- Direct load control and price response through AMI does not account for a significant amount of load reduction in a cost-effective mix

Exhibit 36: Composition of 16 MW of Cost-Effective Demand Response

Program	Customer Class	Eligible Customers	Per Customer Reduction	Per Customer Cost	Customer Participation Rate	Total Utility Savings	Cost to Utility		
Name	*Name*	*#*	*kW*	*Total $*	*%*	*MW*	*$*	*$/kW*	*$/kW-year (10 years)*
Agricultural Load Shedding Program	Irrigation	680	22.4	6,080	66%	8.0	4,025,405	501	**74**
Thermostat Control - Residential	Res	29,719	0.5	515	26%	3.8	2,435,192	641	**94**
Thermostat Control - Small C/I	SmCI	12,423	0.8	545	42%	4.1	2,429,569	595	**87**
Direct Load Control/AMI - Residential	Res	29,719	0.3	370	0%	0.0	82	923	**136**
Direct Load Control/AMI - Small C/I	SmCI	12,423	0.4	400	2%	0.1	71,721	888	**130**

Source: Pace

Due to MWE's customer composition, an irrigation load shedding program is expected to yield the most cost-effective demand reductions. Consistent with these results, MWE is moving forward with a pilot load shedding irrigation program. The program will be rolled out in 2009 and should constitute a good basis for the further evaluation of the cost effectiveness of other DR programs.

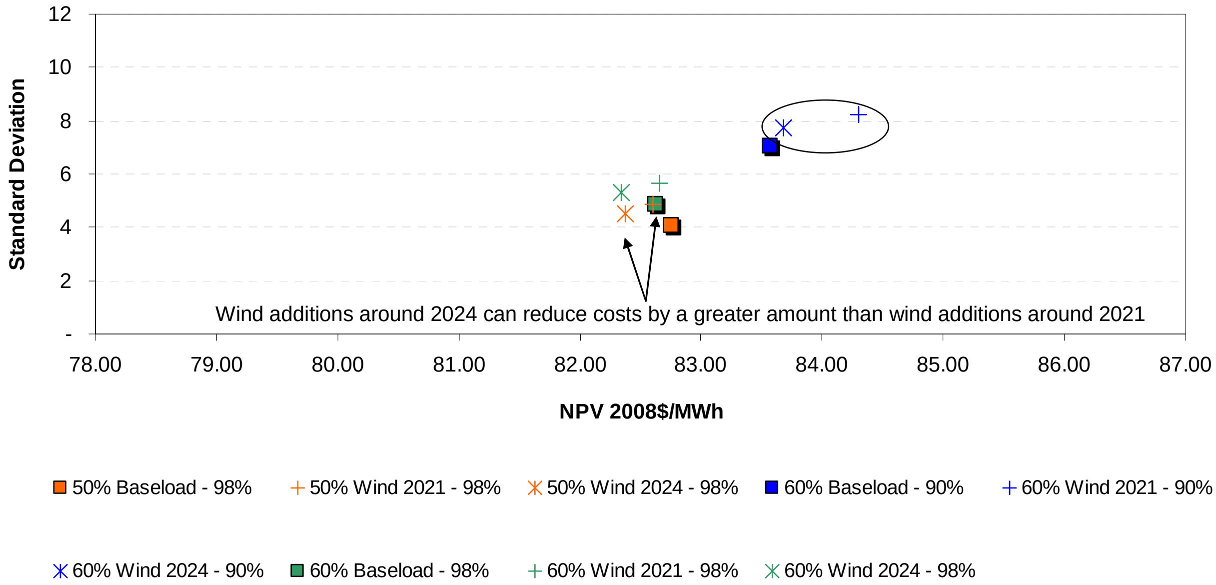
The amount of load reduction achieved through DR programs does not invalidate the results of the screening and risk analysis in any way. It can, however, delay the need for new peaking capacity, result in a smaller-size peaker, or replace existing generating resources that may be retired.

Wind Expansion

The economic addition of wind generation in or around 2024 is favorable, depending on resale provisions for the baseload contract. Adding wind capacity in 2024 reduces portfolio costs with an insignificant increase in risk relative to a coal-based baseload PPA. Adding wind in 2021 exhibits both higher expected cost and risk to adding wind in 2024. This is due to the fact that the cost-effectiveness of wind is dependent on increasing natural gas and carbon compliance costs. The one exception to this result is under conditions where resales are not available. This is because a greater percentage of coal baseload can result in too much excess energy when wind is blowing and under conditions where demand levels are low. Without the ability to sell back excess energy, additional wind capacity can increase the risk and associated cost of wind portfolios.

Exhibit 37 summarizes these results by showing the comparative cost outcomes of adding wind in 2024 versus 2021 for each of three Baseload-UML contract combinations. In addition, as can be seen in the case with 90% load factor and no ability to resell power, the addition of extra wind capacity can actually lead to increased costs and significantly higher risks.

Exhibit 37: Cost vs. Risk for Portfolios that Include Wind Additions

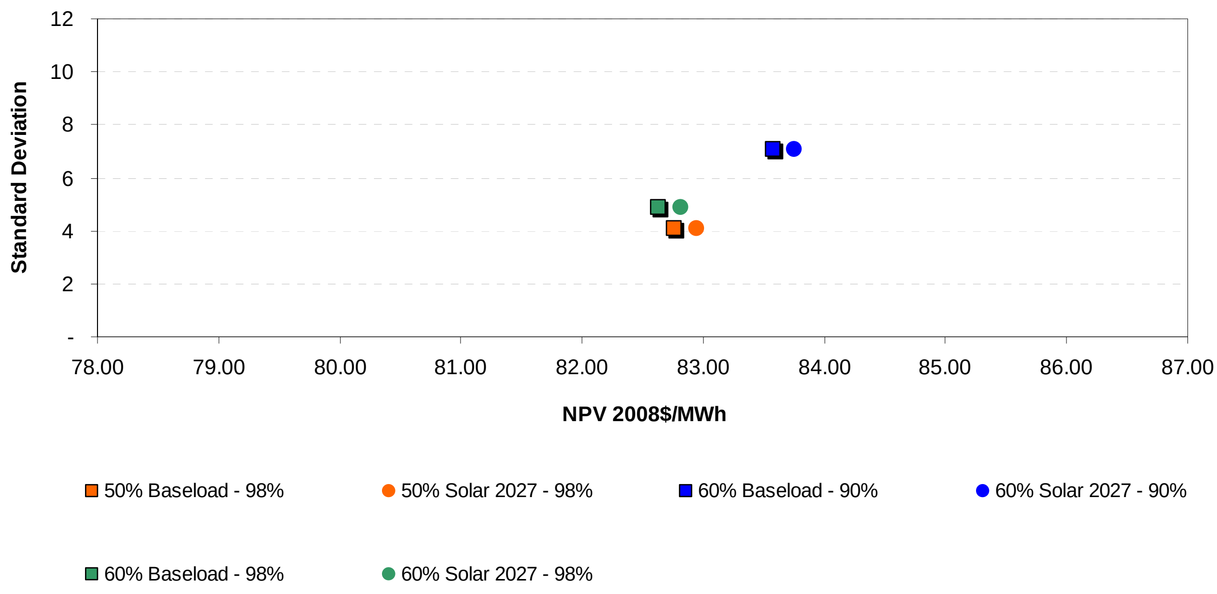


Source: Pace

Solar Expansion

Solar additions are not cost-effective incremental additions to the portfolio. Adding solar capacity, even in the out years of the Study Period, does not serve to lower the expected value of portfolio costs. Although solar generation could provide a hedge against uncertain natural gas prices and UML contract costs and although the capital costs associated with solar installations are expected to decline over time, the relatively high costs and associated uncertainty serve to make portfolios with solar additions more costly. Exhibit 38 shows that solar additions serve to increase portfolio costs under each of the baseload-UML capacity mix scenarios.

Exhibit 38: Cost vs. Risk for Portfolios that Include Solar Additions



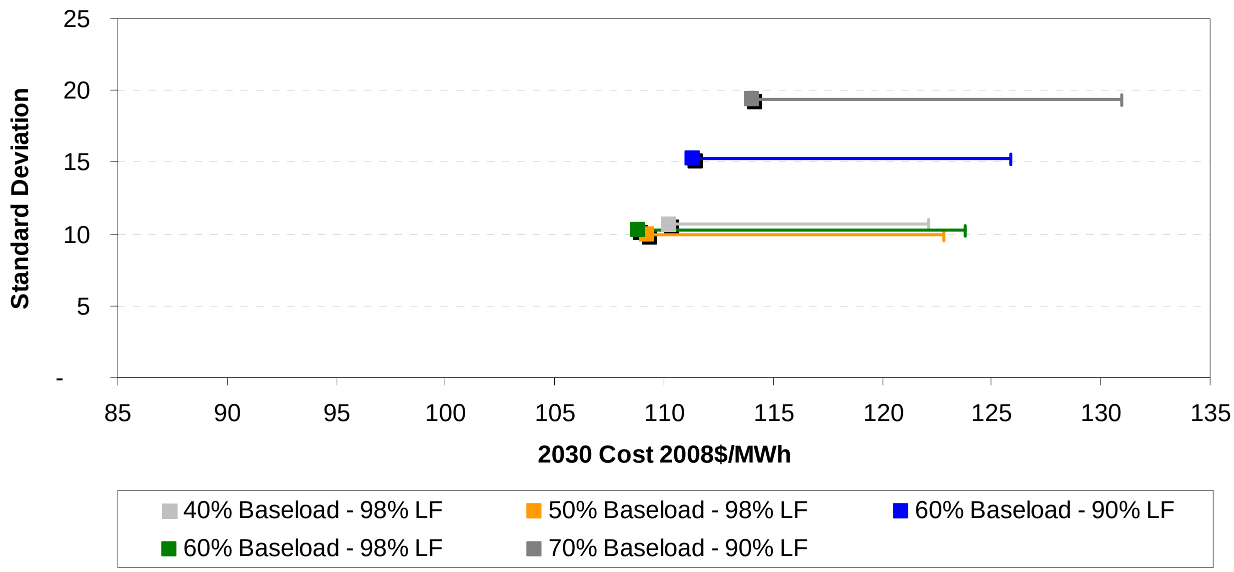
Source: Pace

High CO_2 Scenario Analyses Results

As mentioned before, Pace evaluated the exposure of all portfolios to risks associated with several quantum scenarios. The impact of higher carbon costs raises the costs of all portfolios substantially, but doesn't change the optimal portfolio combination. In fact, due to less baseload, the 50 percent portfolio is less exposed to higher CO_2 prices than those portfolios with more baseload.

Exhibit 39 shows the impact on costs for each of the baseload-UML combinations under high CO_2 prices in the year 2030. The risks associated with high CO_2 prices are directly related to the amount of coal in the portfolio (the amount of baseload contract share). Portfolios that contain less coal-intensive baseload limit their exposure to high CO_2 prices, while portfolios that have more baseload coal face a more significant cost risk if CO_2 prices are higher than anticipated.

Exhibit 39: Impact of High CO_2 Scenario on Different Baseload Options



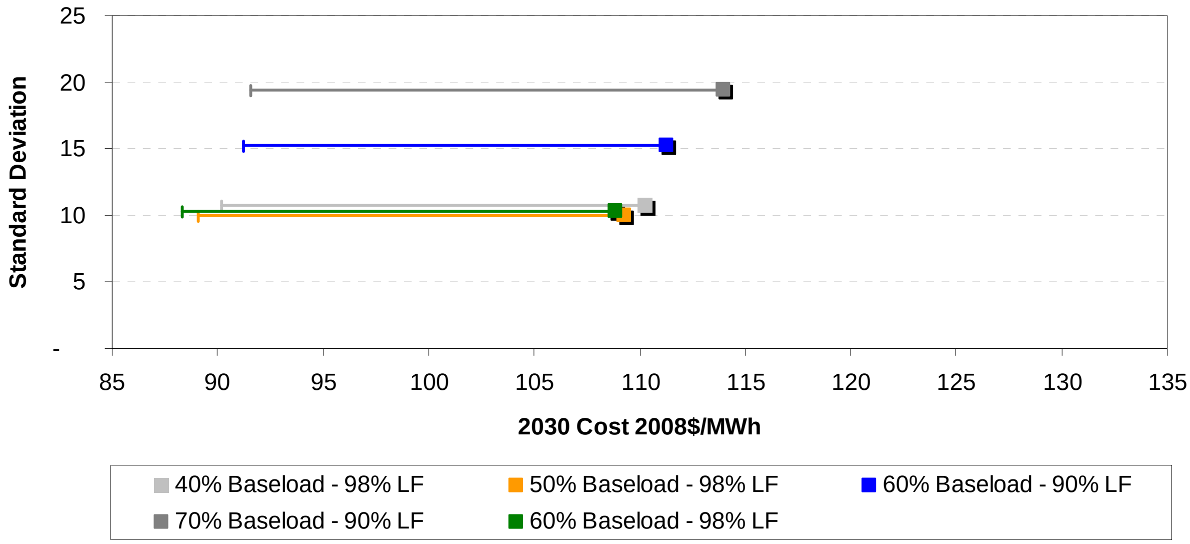
Source: Pace

Low CO_2 Scenario Analyses Results

The impact of lower carbon costs decreases the costs of all portfolios substantially, but, like the high CO_2 case, doesn't affect the optimal portfolio combination. Under lower CO_2 prices, the 60 percent portfolio is less exposed to higher CO_2 prices and is slightly preferable to the other options.

Exhibit 39 shows the impact on costs for each of the baseload-UML combinations under low CO_2 prices in the year 2030. As with the high CO_2 case, the risks associated with high CO_2 prices are directly related to the amount of coal in the portfolio. Portfolios that contain more coal-intensive baseload will benefit more from reduced CO_2 prices.

Exhibit 40: Impact of Low CO_2 Scenario on Different Baseload Options



Source: Pace

Summary and Conclusions

- The risk analysis confirms that a baseload contract share between 50 and 60 percent is the most cost-effective portfolio option for MWE. The analysis also indicates that there are some cost and risk tradeoffs between the 50 percent and 60 percent baseload options, especially with regard to the ability to resell excess energy. The risk analysis concludes that the more cost-effective and less risky baseload contracts contain provisions to resell energy, even at the expense of a higher load factor.

- The addition of around 100 MW of peaking capacity results in cost savings from both the 50 percent and the 60 percent baselines.

  - Effective DR programs can further reduce these costs by displacing or delaying the need for some incremental peaking capacity.

- As an increment to required renewable capacity expansion, the addition of wind during the last few years of the Study Period can also reduce costs when compared to the baseline, but only if sales restrictions are not prohibitive.

- High CO_2 costs expose 60 percent baseload portfolios to slightly higher cost outcomes than portfolios with only 50 percent baseload.

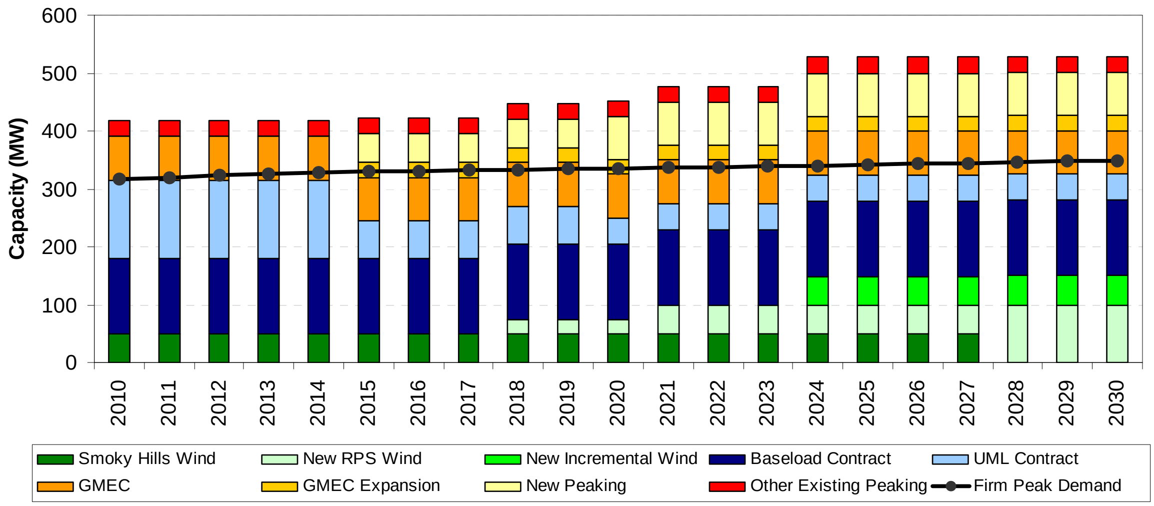
- In all cases examined, the increase in risk associated with procuring a higher percentage of baseload capacity outweighs any potential cost savings of going to 60% baseload. Based on the risk analysis, a 50% baseload option with peaking capacity additions during the next few years and wind additions to meet RPS requirements and during the last few years of the Study Period is the preferred portfolio.

ACTION PLAN

Exhibit 41 summarizes the recommended portfolio action plan by time period as well as the projected annual capacity mix of the entire portfolio over time. The table indicates timing of incremental capacity or contract additions with contract length, where appropriate. This recommended resource plan maintains a significant measure of flexibility to adapt to market conditions and future regulations. Exhibit 42 illustrates the wind generation from the recommended plan against the simulated RPS compliance targets for MWE.

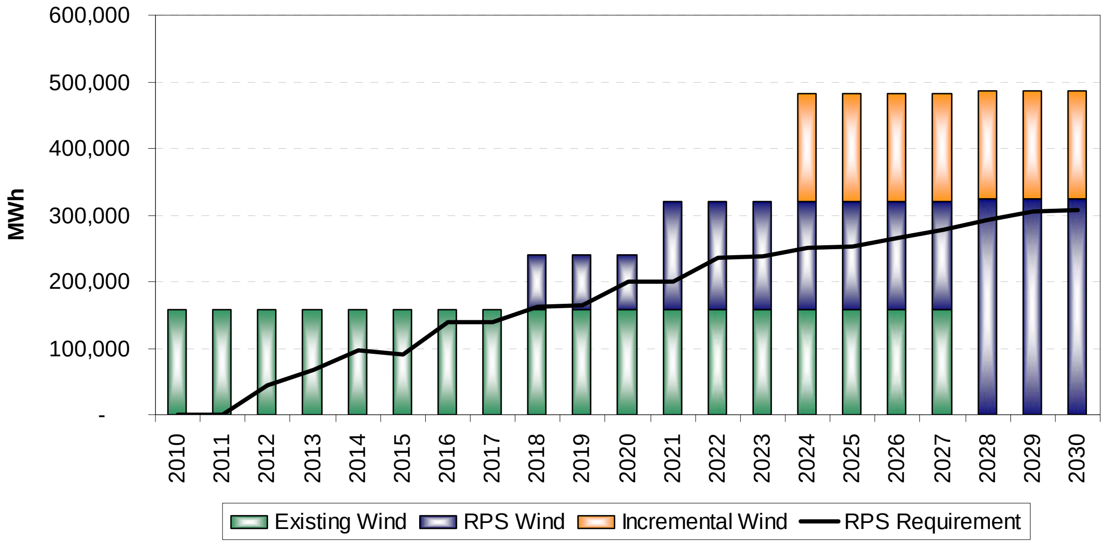
Exhibit 41: Recommended Portfolio Action Plan and Resulting Capacity Mix

Portfolio Item	2010-2014	2015-2019	2020-2024	2025-2030
Baseload Contract	130 (20 years)			
UML	135 (5 years)	65 (5 years)	45 (10 years)	
GMEC Expansion		25		
New Peaking		50	25	
RPS Wind		25	25	50
Incremental Wind			50	



Source: Pace

Exhibit 42: RPS Compliance vs. Targets



Source: Pace

The recommended plan includes the following key elements, which will require MWE to take specific actions to begin reconfiguring its existing portfolio over the next several years:

- **Negotiate PPAs:** By the beginning of 2010, finalize negotiations of new PPAs for baseload and UML type contracts with the preferred supplier. Due to the attractiveness of owned peaking resources, UML contracts should be negotiated with the shortest lengths possible. The baseload contract should be negotiated for at least fifteen years.
- **New Local Gas-Fired Generation:** By approximately 2015, expand GMEC and build 50 MW of new peaking capacity. Build an additional 25 MW by approximately 2020. Lead times will require that approvals, permits, and construction schedules be in development in 2011 for the early expansions. Successful implementation of DR programs can result in less or delayed need for new peaking capacity.
- **Demand Response Programs:** There is evidence that some amount of load reduction can be achieved cost-effectively. Pace recommends pursuing the implementation of the agricultural load shedding pilot program and interruptible rates.
- **Renewable Energy:** Beyond 2015, increase the proportion of MWE's energy mix provided by renewable energy sources to meet likely RPS requirements. By 2021, a total of 50 MW of new wind is needed. In 2024 and beyond, add economic additional wind capacity on the order of 50 MW and replace the Smoky Hills contract when it expires. Throughout the planning horizon, continue to track the cost and efficiencies of wind and solar and take advantage of economic opportunities as they arise.
- **GHG Emissions Reductions:** Protect MWE as much as possible against imprudent risk management of carbon and fuel cost exposures. Prudent management language should be included in new contractual arrangements.

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2009 Integrated Resource Plan Report Appendices

Prepared for:

Midwest Energy Incorporated

December 17, 2009

PACE

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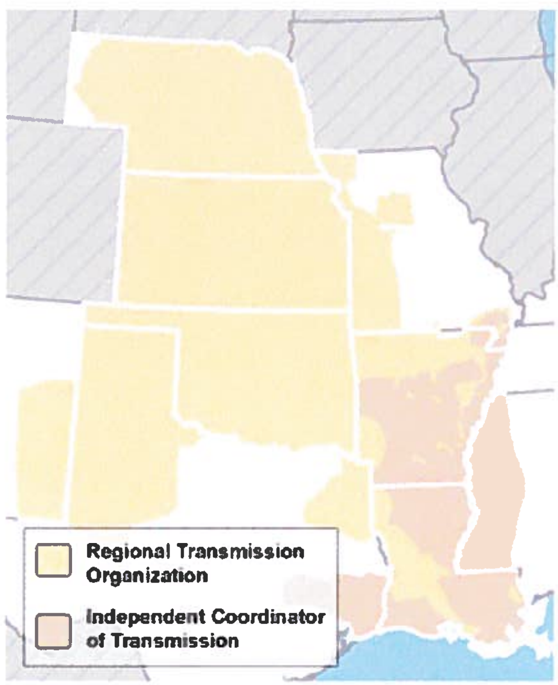
EXHIBITS

REGIONAL MARKET DEFINITION AND OVERVIEW

SPP OVERVIEW

The Southwest Power Pool ("SPP") is a founding member of the North American Electric Reliability Council ("NERC"). NERC develops and maintains reliability standards, which apply to bulk power system owners, operators and users. SPP became a NERC Regional Entity ("RE") in 2007 and has the responsibility to enforce reliability standards for users, owners and operators of the bulk power system in the SPP RE footprint. The SPP RE is bordered by four NERC REs which include the SERC Reliability Corporation ("SERC"), the Midwest Reliability Organization ("MRO"), the Western Electric Coordinating Council ("WECC"), and the Texas Regional Entity ("TRE"). The SPP RE footprint includes all or part of Arkansas, Kansas, Louisiana, Missouri, Mississippi, Nebraska, New Mexico, Oklahoma and Texas, as outlined in Exhibit 1.

Exhibit 1: Southwest Power Pool Footprint



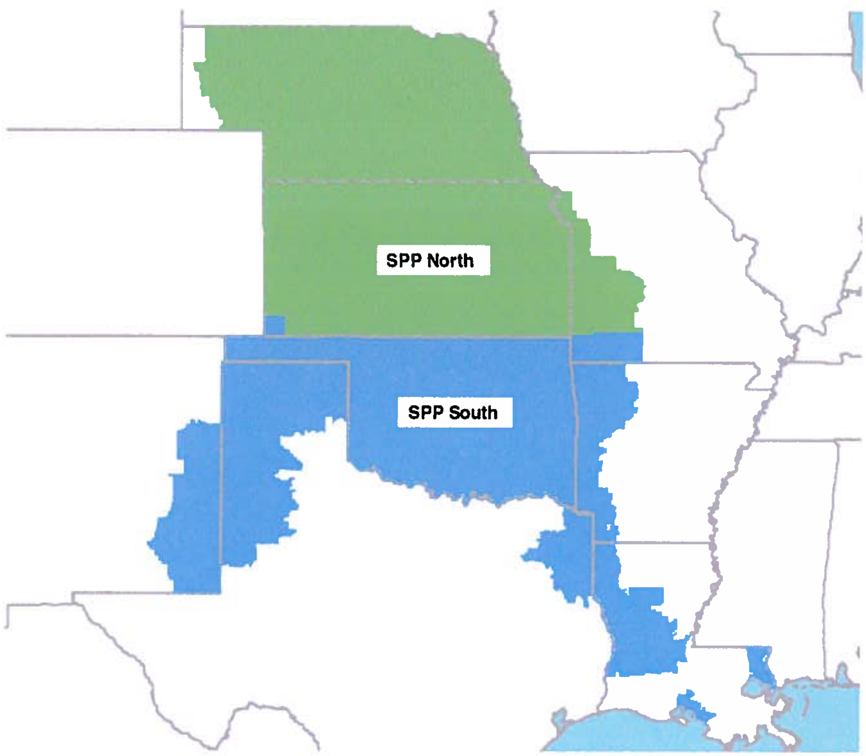
Source: www.spp.org

All Registered Entities of SPP must comply with the Federal Energy Regulatory Commission ("FERC")-approved NERC and SPP Regional Standards. Regional Entities include SPP Members, as well as users, owners and operators of the Bulk Electric System in the SPP Region.

The SPP was approved by the FERC in 2004 as a Regional Transmission Organization ("RTO") in order to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP RTO consists of 26 balancing authorities and manages transmission in eight states including Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma and Texas. There are 53 members included in these eight states as well as Mississippi, highlighted in Exhibit 1, which serve approximately 5 million customers. Members consist of a mix of Investor Owned Utilities ("IOUs"), cooperatives, municipalities, state agencies, independent transmission companies, independent power producers, and marketers. In 2007, three members based in Nebraska joined SPP: Nebraska Public Power District ("NPPD"), the Omaha Public Power District ("OPPD"), and Lincoln Electric System ("LES"). NPPD and OPPD are state agencies, while LES is a Municipality.

Pace simulates the SPP market area as two distinct congestion zones based on the NERC sub-regions of SPP North and SPP South. This does not include the Entergy regions in Arkansas, Louisiana, Missouri and Mississippi that are part of the SPP RE footprint. These two regions, outlined in Exhibit 2, are evaluated separately due to the presence of expected significant and persistent transmission congestion and price divergence.

Exhibit 2: Pace SPP Modeling Regions



Source: Pace and Energy Velocity®

SPP Operational Overview

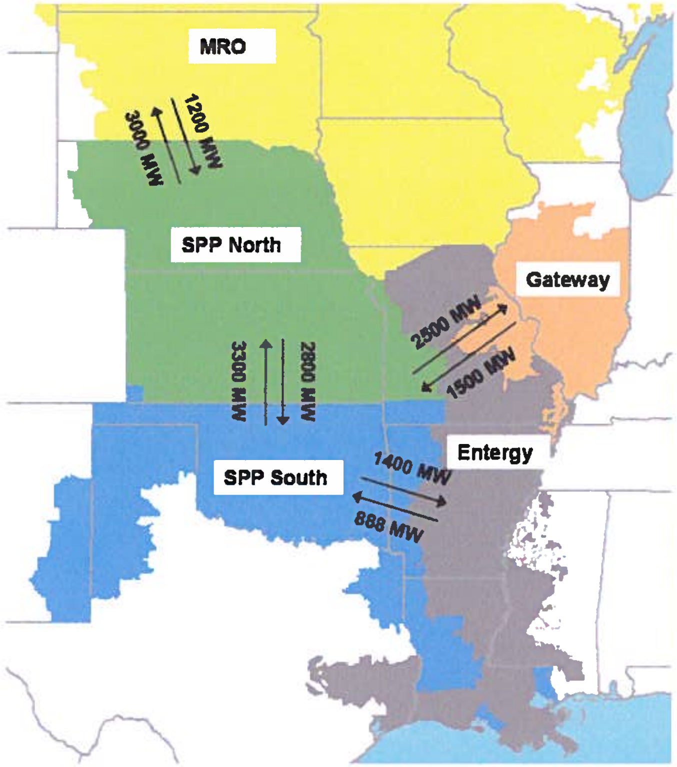
SPP launched the SPP Energy Imbalance Service ("EIS") in February of 2007. The EIS helps manage the difference between the scheduled and actual delivery of energy to and from the transmission system over any single hour. All Market Participants ("MPs") must purchase this service from SPP. A Market Participant ("MP") is defined as any Transmission Customer that has signed a service agreement under SPP's Open Access Transmission Tariff ("OATT") or that has generation or load connected to SPP transmission facilities. The MP is responsible for submitting resource plans, ancillary service capacity plans, offer curves, and is financially responsible to SPP for settlements.

Currently, Locational Imbalance Prices ("LIP") are calculated on a real time basis. This is done every five minutes and then averaged to an hourly settlement price. Hourly prices are reflective of the incremental cost of delivering energy to specific locations on the grid. The LIP is the price to provide the least-cost incremental unit of energy at a specified location. SPP is also in the process of developing a Day-Ahead Market and an Ancillary Services Market, which are tentatively scheduled to begin in the second half of 2012.

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, Pace models two distinct pricing zones in SPP: SPP North and SPP South. Pace also simulates the interconnection of additional congestion zones to SPP. Exhibit 3 provides a representation of Pace's modeling regions for the Mid Continent and the inter-regional transfer capability between SPP and the neighboring states/regions.

Exhibit 3: Inter-Regional Transfer Capability



Source: Pace and Energy Velocity®

Significant build out of wind in the Region is expected to lead to regional transmission expansion over the next several years. Pace has reviewed all proposed transmission projects in the region, including the SPP Extra High Voltage ("EVH") Overlay Plan which would transfer up to 20 GW of wind generation to eastern SPP. Based on this analysis, and Pace's expectations for wind expansion throughout SPP, the following transmission upgrades are included in Pace's Reference Case:

- SPP to Gateway: 1,500 MW in 2017
- SPP to Entergy: 1,500 MW in 2020
- SPP to Gateway 1,500 MW in 2025

REGIONAL DEMAND

Electricity prices in a given market are highly dependent on electricity demand. Pace developed an independent energy and peak demand forecast for each of its model regions, including the SPP zones. This section presents Pace's forecasting methodology as well as the projected national and SPP demand forecasts.

SPP REGIONAL DEMAND PROFILE

The peak load of major utilities in SPP is shown in Exhibit 4. Oklahoma Gas & Electric had the highest peak load in 2008 at 6,590 MW followed by Southwester Public Service Co. at 5,502 MW. Both utilities serve regions in SPP South. These two make up approximately 43% of the peak load in SPP.

Exhibit 4: Major Utilities' Peak Load in 2008 (MW)

Utility	Peak Load (MW)	NERC Sub Region
Oklahoma Gas & Electric Co	6,590	SPP South
Southwestern Public Service Co	5,502	SPP South
Kansas City Power & Light Co	3,580	SPP North
Westar Energy	2,868	SPP North
CLECO Power	2,839	SPP South
Kansas Gas & Electric Co	2,628	SPP North
KCP&L Greater Missouri Operations Co	2,219	SPP North
Empire District Electric Co	1,152	SPP North
Midwest Energy	362	SPP North
Golden Spread Electric Coop	220	SPP South

Source: Pace and Energy Velocity®

PACE'S INDEPENDENT LOAD FORECASTING METHODOLOGY

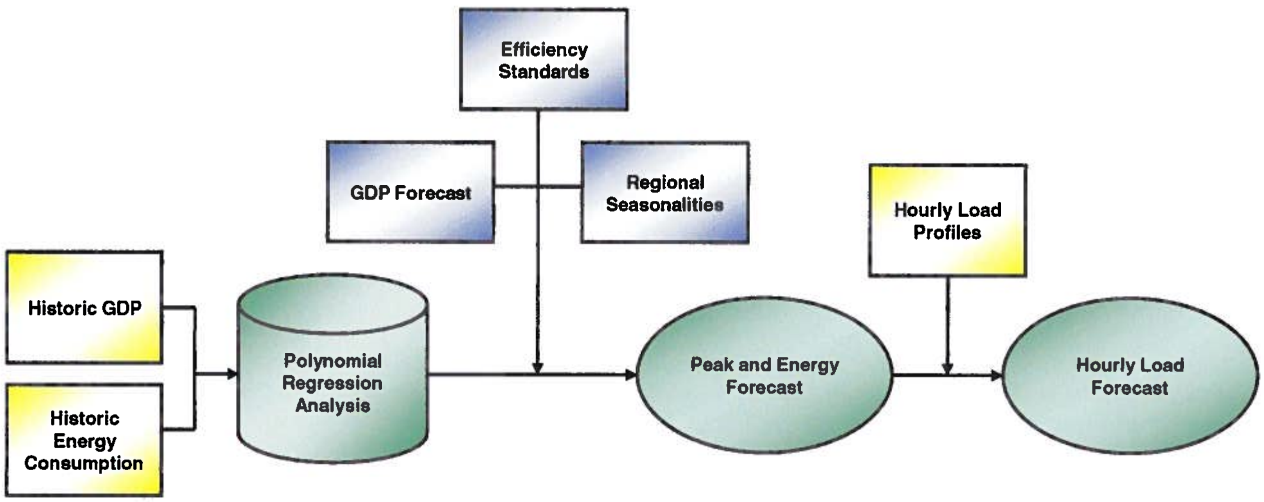
Pace's independent demand forecast was developed according to the methodology illustrated in Exhibit 5. As shown, the foundation of Pace's load forecasting methodology is an econometric approach. This methodology has two primary components. The first is the use of econometric models to forecast annual peak demand and energy levels based on changes in GDP. The second component of the methodology is the translation of historical hourly demand levels and forecasted peak demands to create predicted hourly load for each forecast year.

To generate this demand forecast, Pace:

- Established the historical relationship between net energy for load and GDP. Pace used the best-fitting econometric relationship between these two variables in order to project a national load over the Study Period. Pace's regression analysis indicated a strong correlation between electricity demand and GDP. Specifically, the analysis produced an adjusted R^2, or "fit", of 0.997.

- Forecasted demand based on the historical trends of GDP and energy consumption and projected GDP growth.
- Calculated regional load growth based on historic growth patterns in all modeled regions.
- Defined bounds around resulting regional growth rates based on regional characteristics and known drivers of historic energy demand trends.
- Calculated seasonal energy and summer/winter peaks according to historical usage patterns and load factors.

Exhibit 5: Pace Load Forecasting Methodology



Source: Pace

Pace's near term load forecast is greatly impacted by the current economic recession. Pace used an independent GDP forecast (Moody's) and the best-fitting econometric relationship between GDP and electricity consumption to project national load over the Study Period. Based on Moody's GDP forecast, the economic recession is not expected to last beyond 2009. By 2011 GDP growth is expected to be well above 3.5 percent and remain high until 2014. Long-term GDP growth is assumed around 2.5 percent.

Pace reviews existing state-level efficiency mandates, historic penetration levels for Demand Response ("DR") programs in all modeled regions, as well as the potential for federal programs when assessing future demand growth trends. For the Reference Case assumptions, limited additional efficiency improvements in the form of mandated state or federal programs are assumed as part of the demand forecast. The uncertainty surrounding the penetration level of these programs, however, is fully captured in the stochastic bands constructed around the Reference Case assumptions for regional energy and peak demand. Details on this methodology are provided later in this section.

Demand Forecast Results

As mentioned above, Pace's load forecast methodology explicitly captures historical trends in the energy intensity of the economy. Historically, electricity consumption has grown at a lower rate than GDP. Pace's forecast assumes that the rate of electricity consumption will continue to grow at a much lower rate than the GDP.

Based on Pace's load forecast methodology and underlying GDP growth assumptions, Pace forecasts SPP demand to grow at an average rate of 1.53 percent per year between 2009 and 2015. The forecasted demand is then expected to slow to 0.65 percent from 2015-2030. Over the course of the forecasted Study Period, average load in SPP is expected to grow at a rate of 0.9 percent per year.

Pace projects an annual load factor based on historic trends and efficiency assumptions. These load factors are applied to the average energy forecasts in order to derive a peak load forecast. For SPP, peak load is projected to grow similarly to the average load under the Reference Case assumptions.

Exhibit 6: Energy Forecasts for SPP

Year	SPP	
	Energy (GWh)	Peak (MW)
2004	*180,396*	*36,719*
2005	*188,090*	*37,449*
2006	*189,105*	*39,280*
*2007**	*218,405*	*44,792*
2008	*222,128*	*46,300*
2009	219,508	45,878
2010	222,567	46,411
2011	227,142	47,473
2012	232,662	48,491
2013	235,998	49,320
2014	238,848	49,801
2015	240,476	50,254
2016	242,497	50,537
2017	244,317	51,055
2018	246,428	51,378
2019	247,390	51,696
2020	248,921	51,875
2021	250,459	52,337
2022	252,580	52,659
2023	253,554	52,982
2024	255,111	53,160
2025	256,675	53,634
2026	258,837	53,959
2027	259,824	54,290
2028	261,408	54,470
2029	262,999	54,951
2030	265,203	55,283
Growth Rate (2004-2006)	**2.39%**	**3.43%**
Growth Rate (2007-2009)	**1.70%**	**3.37%**
Growth Rate (2009-2015)	**1.53%**	**1.53%**
Growth Rate (2015-2030)	**0.65%**	**0.64%**
Growth Rate (2009-2030)	**0.90%**	**0.90%**

Source: Pace
*Nebraska members join SPP in 2007

LOAD UNCERTAINTY AND RISK

Electricity demand is subject to several known and quantifiable risk factors and any forecasting and planning processes should account for the those risks. Historically, those risks can be separated into:

- Long-term risk factors, mainly the growth in the population and economic activity which drive the acquisition and use of electricity using equipment, the amount of commercial

and residential floor space and the general level and demand for electricity from manufacturing and other industrial processes
- Short-term risk factors mainly driven by the weather.

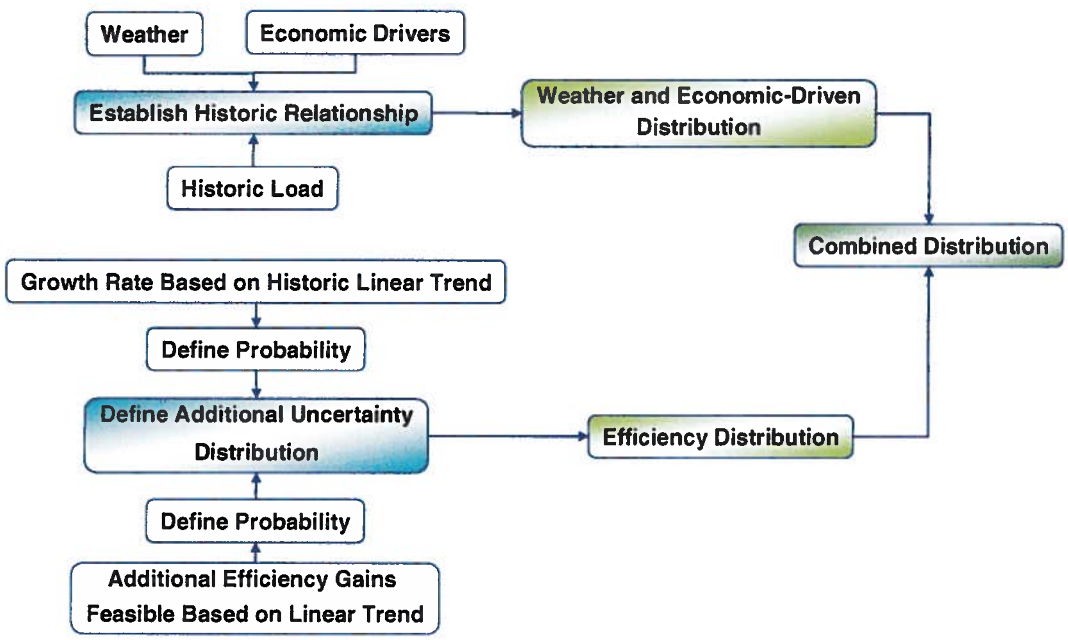
The nature and magnitude of these risks can be analyzed and understood using historical data to derive the relationship between various measures of economic activity, historical weather, and observed energy sales and peak demand.

Going forward, the size and success of ongoing and expected future initiatives to reduce energy demand by encouraging energy efficiency creates significant risk to power demand that cannot necessarily be understood by analyzing historical data.

Pace's methodology for the development of load stochastics incorporates specific analysis aimed at capturing all quantifiable sources of load uncertainty, both from historic relationships and from analysis on expected future trends. The first step focuses on establishing the historic relationship between weather, economic drivers, and load. The second step is designed to capture uncertainty around the trend of decline of the energy intensity of the economy, and the level of penetration of efficiency and DR measures.

Exhibit 7 presents a schematic of process, and a detailed description follows.

Exhibit 7: Demand Risk Modeling Overview

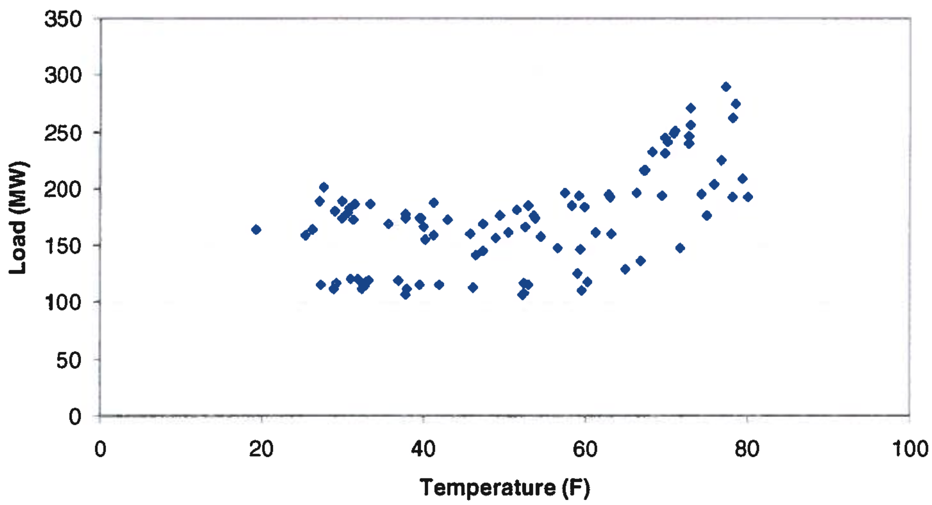


Source: Pace

Step 1: Establish Historic Relationship between Weather, Economic Drivers, and Load

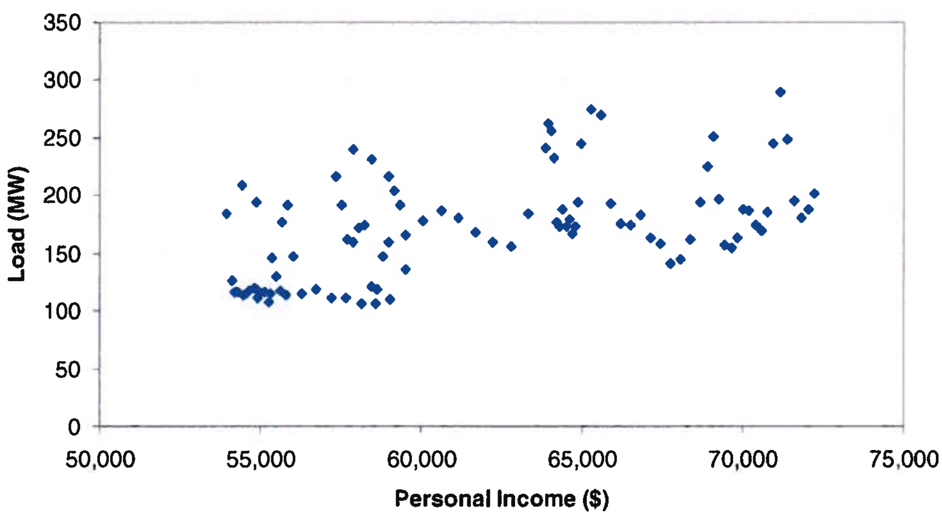
The relationship between energy sales (MWh), peak load (MW), and economic activity is well understood and the parameters of those relationships can be estimated using historical data. Exhibit 8 and Exhibit 9 below show scatter plots of monthly energy sales and monthly average temperature and quarterly personal income for MWE's territory. As can be seen, the relationships are strong (as measure by the R^2 statistic, but there is considerable unexplained variation.

Exhibit 8: Load vs. Temperature



Source: Pace

Exhibit 9: Energy Demand vs. Personal Income 1979-2009



Source: Pace

The first step in the process is to estimate a statistical relationship between historical energy sales (or peak load) and the economic and weather variables that drive demand. Specifically, for MWE's load we have estimated an equation of the form:

[redacted]

Where

[redacted]

The estimated regression parameters are shown in Exhibit 10.

Exhibit 10: Regression Equation-Peak Load and Energy Sales

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: Pace

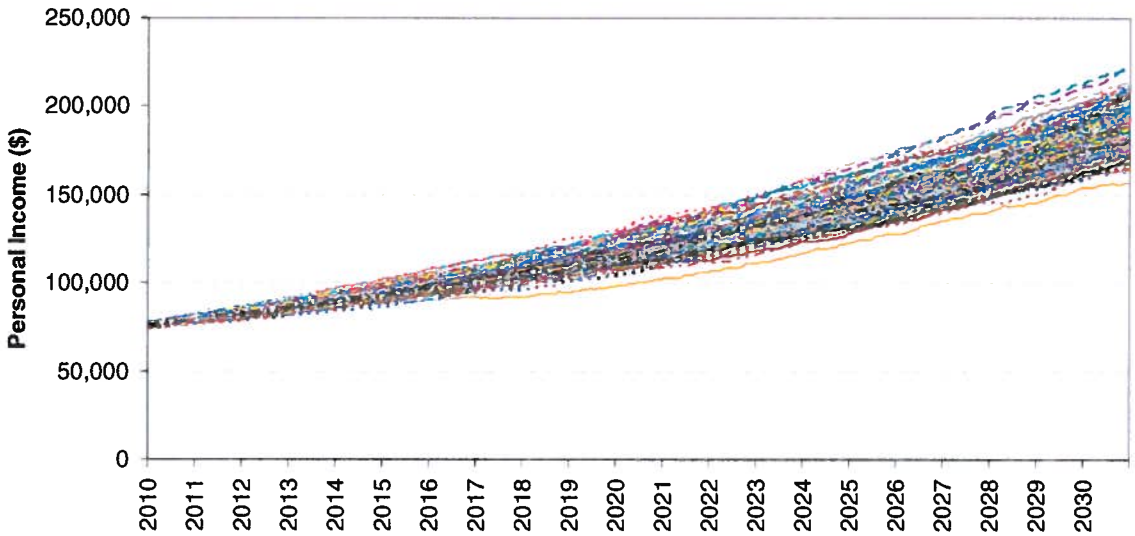
With MWE's load forecast as a guide, the results of the regression equation were used to simulate future electricity sales and peak demand across multiple scenarios using simulated temperature, personal income, residential meters, and commercial employment. Simulated series for personal income are derived using the following process

[redacted]

Where:

[redacted]

Exhibit 11: Simulated Personal Income



Source: Pace

Residential meters and commercial employment are simulated in a similar manner.

Monthly average temperatures are simulated as

[redacted]

Where [redacted] a random term, drawn from a normal distribution with zero mean and historical standard deviation.

The mean and standard deviation of the temperature distributions for each month are shown in Exhibit 12.

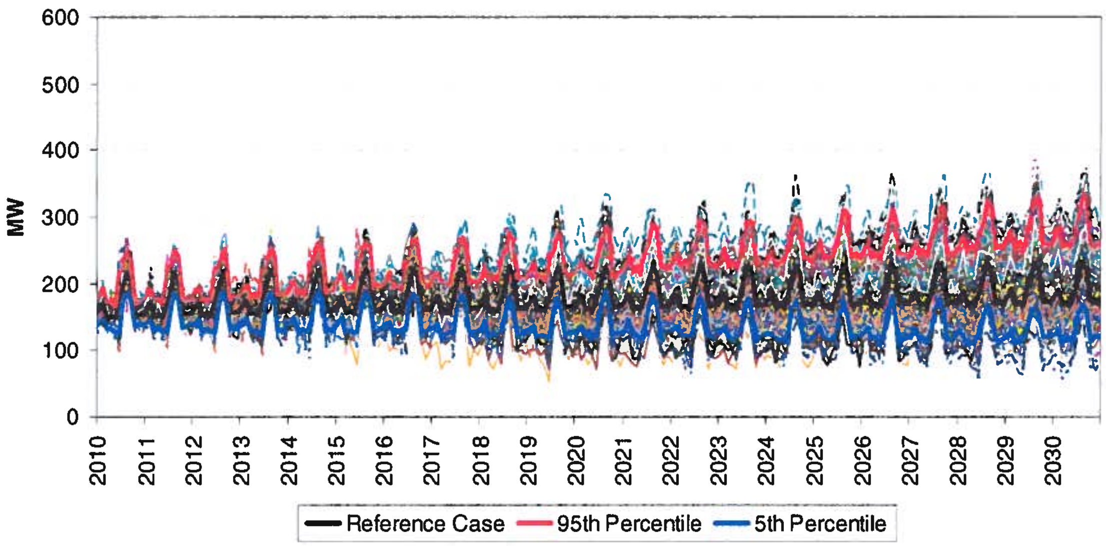
Exhibit 12: Average Monthly Temperatures and Standard Deviations

Month	Mean	Standard Deviation
January	29.45	5.20
February	30.42	3.23
March	40.17	4.45
April	50.57	2.49
May	60.46	1.71
June	67.58	6.25
July	77.57	2.22
August	72.80	2.17
September	63.17	4.12
October	52.10	3.22
November	39.99	2.05
December	30.72	2.61

Source: Pace

This process results in a range of stochastic paths around the Reference Case average energy and peak demand (provided by MWE). The stochastic bands for MWE's total energy sales in average MW are illustrated in Exhibit 13. A table with the corresponding annual sales in GWh is also shown in Exhibit 13. The peak demand stochastics (in MW) are shown in the graph and table in Exhibit 14. The Reference Case and 95th and 5th percentiles are provided for context.

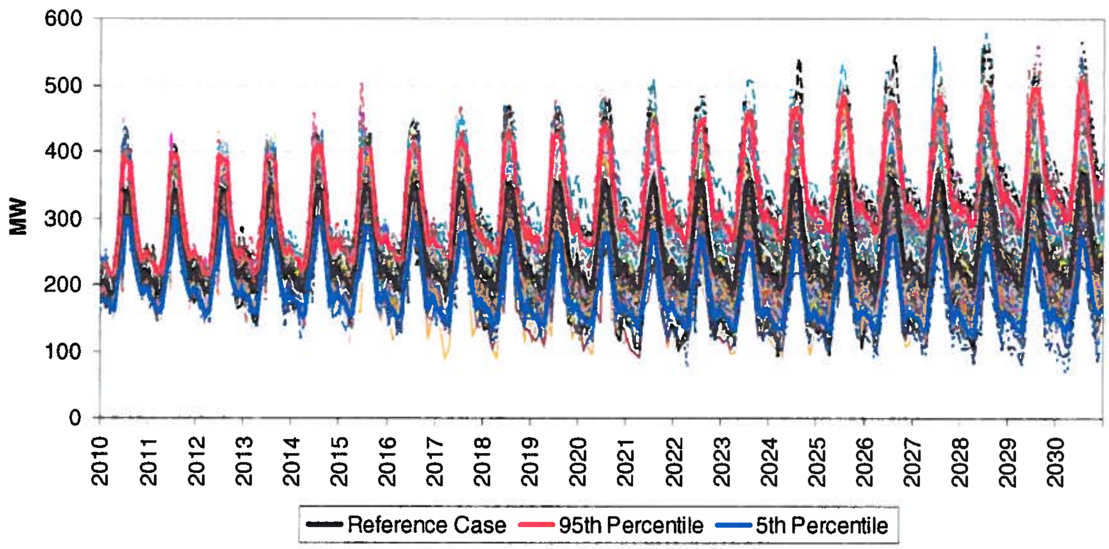
Exhibit 13: Total Energy Sales Stochastic Bands for MWE (Average MW and GWh)



Sales Stochastic Bands (GWh)			
Year	**95th Percentile**	**Forecast**	**5th Percentile**
2010	1,704	1,474	1,279
2011	1,730	1,493	1,278
2012	1,745	1,511	1,274
2013	1,773	1,520	1,260
2014	1,817	1,531	1,266
2015	1,876	1,541	1,253
2016	1,897	1,553	1,258
2017	1,921	1,555	1,221
2018	1,980	1,561	1,210
2019	2,014	1,569	1,191
2020	2,050	1,577	1,208
2021	2,102	1,579	1,206
2022	2,144	1,586	1,190
2023	2,162	1,594	1,163
2024	2,215	1,603	1,139
2025	2,277	1,604	1,156
2026	2,280	1,613	1,151
2027	2,309	1,621	1,159
2028	2,380	1,633	1,123
2029	2,418	1,637	1,133
2030	2,440	1,648	1,148

Source: Pace

Exhibit 14: Total Peak Demand Stochastic Bands for MWE (MW)



Peak Stochastic Bands (MW)			
Year	95th Percentile	Forecast	5th Percentile
2010	396	339	304
2011	397	342	303
2012	395	344	301
2013	394	346	299
2014	412	348	301
2015	406	349	289
2016	413	350	294
2017	416	351	279
2018	432	352	282
2019	428	353	273
2020	445	354	279
2021	446	355	282
2022	448	356	273
2023	462	356	266
2024	468	357	270
2025	485	358	273
2026	473	359	275
2027	482	360	274
2028	491	361	264
2029	496	362	266
2030	507	364	274

Source: Pace

A similar methodology was used to define the uncertainty around regional load (SPP-North) and the load of the simulated counterparty of MWE's PPAs.

Step 2: Define Uncertainty around the Trends in the Energy Intensity of the Economy and Efficiency

In some cases, the simulated monthly peak load and energy sales derived in Step 1 are adjusted to reflect potential drift in the overall efficiency of energy consumption. The size of the adjustment is simulated using an approach in which each load forecast simulation incorporates a continuous improvement in usage efficiency based on a random draw for that simulation.

[redacted]

Where:

[redacted]

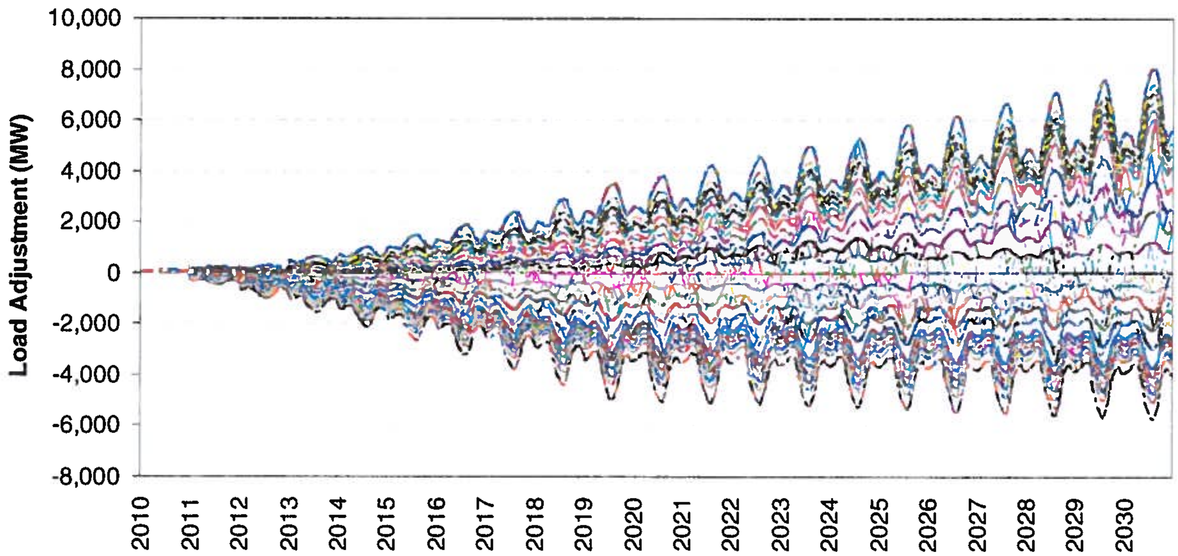
The application of Step 2 of the load forecast methodology depends on the expected vulnerability of a specific region to changes in efficiency measures. Pace's Reference Case load forecast for SPP incorporates expected changes in the energy intensity of the economy. It captures trends and projected efficiency improvements based on historical data and Pace's regression analyses. Pace recognizes, however, that there is significant uncertainty around the trend and level of further efficiency improvements. Under the current regulatory environment, for example, the advent of a federal efficiency program is increasingly likely. On the other hand, a slowing economy might result in the abandonment of any incremental conservation and DR measures. To capture this range of uncertainty Pace developed an additional range of uncertainties based on market knowledge, historical data, and judgment for the regional load stochastics.

The probability distribution for these draws is defined by the subjective likelihood of various efficiency improvement scenarios. Specifically the scenarios include

- 19 percent reduction in energy use by 2030 (5^{th} percentile) – Based on estimates of technically feasible efficiency reductions
- 14 percent reduction in energy use by 2030 (25^{th} percentile) – Based on estimates of economic efficiency reductions
- 23 percent increase in energy use by 2030 (75^{th} percentile) – Based on the electricity consumption growth rates in SPP over the last 7 years

The projected path of energy demand changes from for SPP-North under each of these scenarios is illustrated in Exhibit 15.

Exhibit 15: Load Growth under Various Efficiency Scenarios



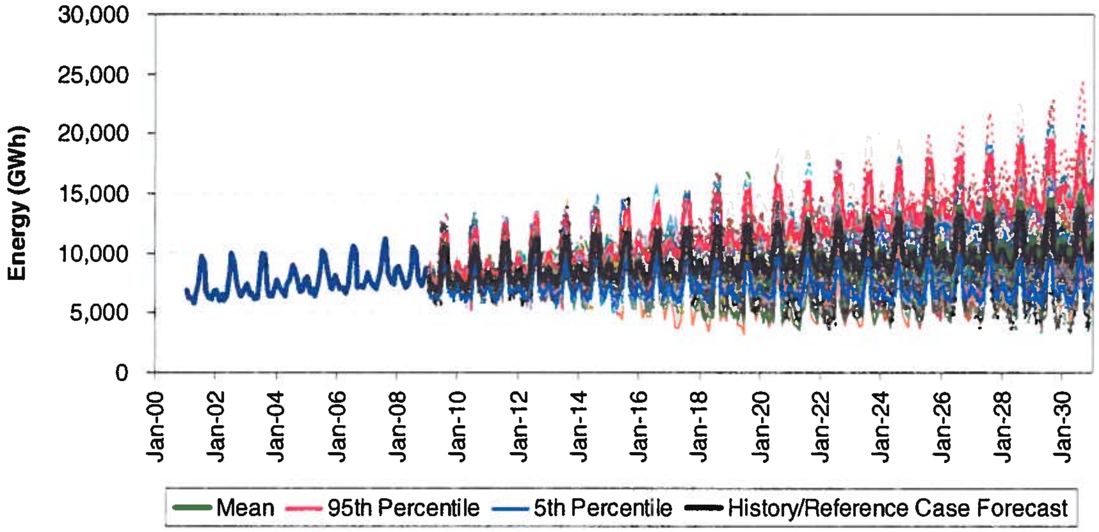
Source: Pace

The load used in month m for a simulation scenario is equal to the sum of the load (based on simulated economic and weather variables) and the efficiency adjustment

[redacted]

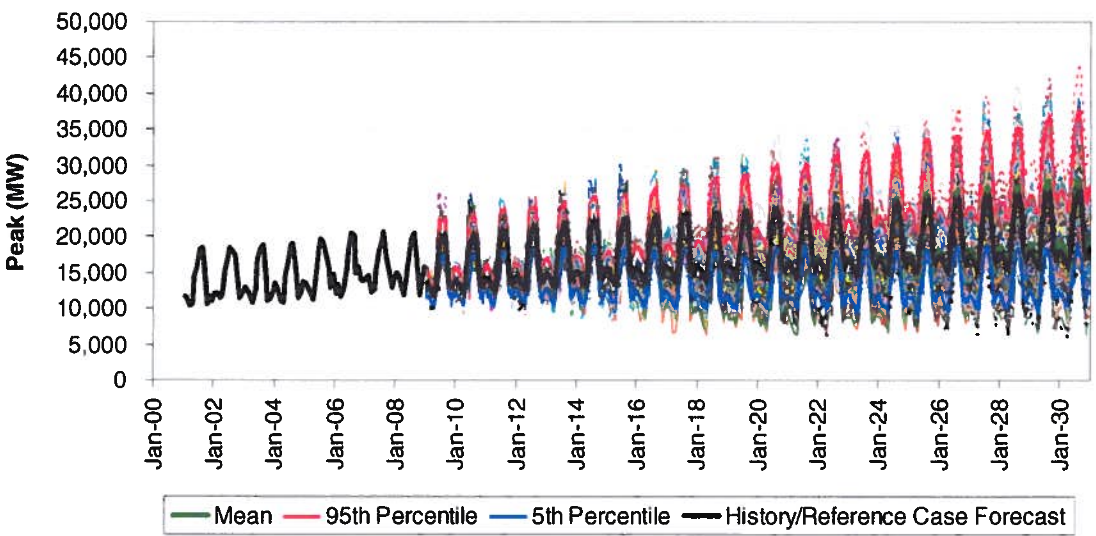
For some regions, therefore, the load stochastics are the combination of two independent distributions (the one created in step 1 and the additional distribution created in step 2). The use of the second distribution depends on Pace's assessment of the vulnerability of a region or utility to uncertainty around efficiency measures. In the case of the regional demand used for this analysis, Pace has combined the weather and economic-driven distribution (step 1) with the additional efficiency uncertainty distribution (step 2) to get to the final bands around SPP load. The resulting energy and peak demand stochastics for SPP-North are shown in Exhibit 16 and Exhibit 17, respectively.

Exhibit 16: SPP-North Combined Monthly Energy Stochastics (GWh)



Source: Pace

Exhibit 17: SPP-North Combined Monthly Peak Demand Stochastics (MW)



Source: Pace

No additional efficiency uncertainty was embedded into the load stochastics used for MWE's load. For this analysis, the uncertainty bands around MWE's load are based solely on the historic relationship between weather, economic drivers, and average and peak demand outlined in Step 1 above.

HOURLY LOAD FORECASTING

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. Therefore, Pace projects hourly demand profiles in order to account for seasonal variations in load.

Pace's methodology applies annual growth factors derived from 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 reflects 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 for every case simulated. 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 all relevant market areas.
- 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 profile for each year in the Study Period.

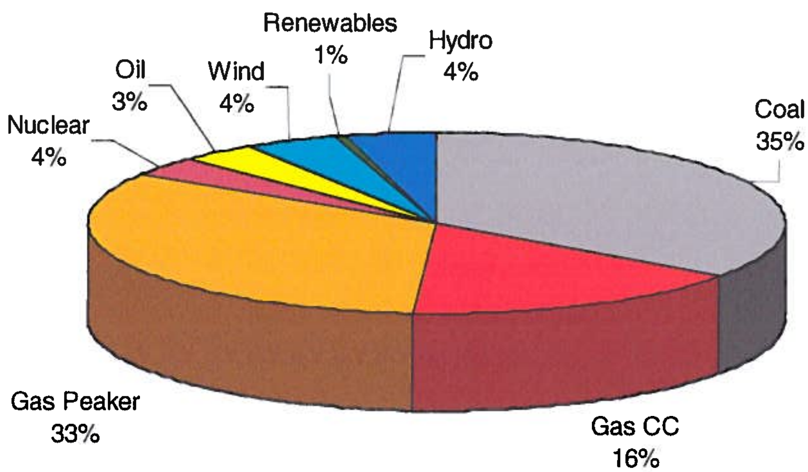
The result of this process is an hourly demand shape that replicates actual market fluctuations and allows for representative dispatch patterns of the generating resources in the market. Load stochastics will alter monthly inputs and will be translated to the hourly profile to simulate hourly load variation for each iteration, in each year of the Study Period

REGIONAL MARKET SUPPLY PROFILE

EXISTING GENERATING CAPACITY PROFILE

Exhibit 18 displays the installed capacity profile of the entire SPP region. The region's capacity consists of mostly gas and coal resources, comprising approximately 50% and 35%, respectively, of the total. The remainder is a mix of hydro (4%), wind (4%), nuclear (4%), oil (3%) and renewables (1%).

Exhibit 18: Installed Capacity Profile – SPP



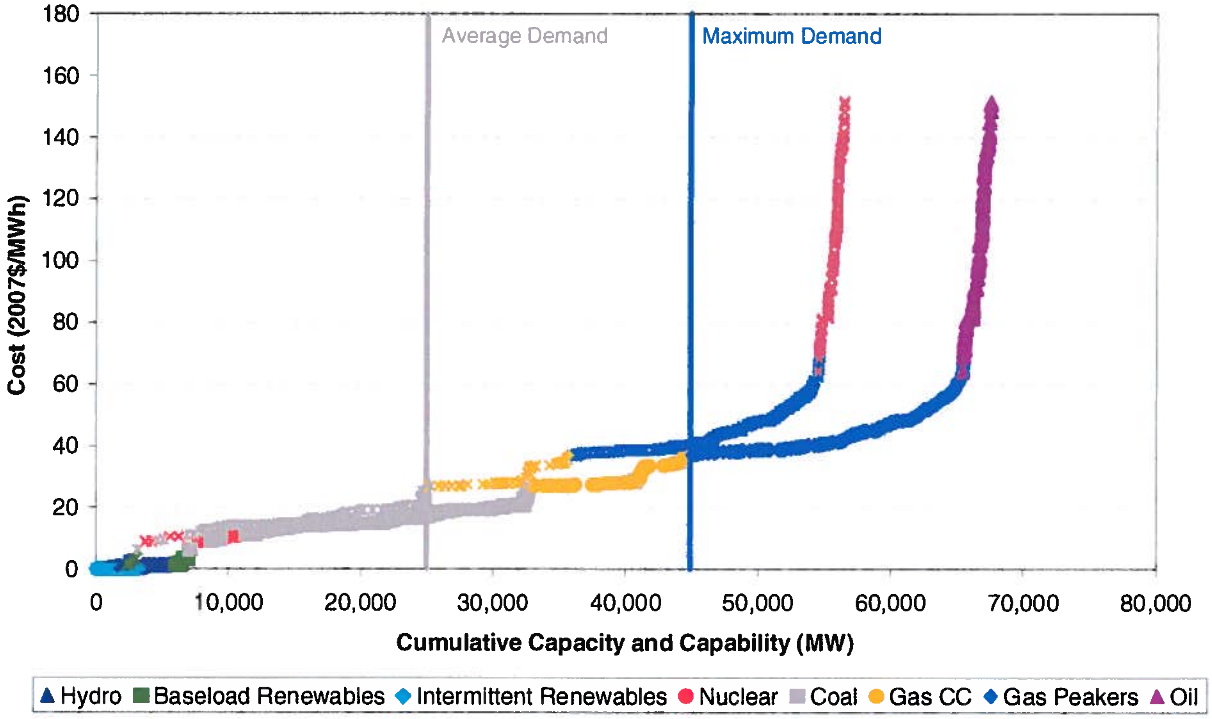
Source: Pace and Energy Velocity®

For characterization of the existing capacity in Pace's simulation tools, Pace utilized plant and unit specific data as reported to FERC and the EIA detailing variable O&M, fixed O&M, fuel costs (adjusted for market delivered prices), capital expenditures, heat rate efficiency, and summer and winter capacity. Given that capital costs are not reported at the plant level, Pace has developed a methodology for allocating utility-level embedded costs to each major power plant in the region.

Supply Curve

Exhibit 19 displays an existing supply curve for SPP for 2009 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, and capacity factor expectations for hydro and intermittent resources are taken into account.

Exhibit 19: SPP 2009 Supply Curve



Source: Pace and Energy Velocity®

Nuclear Unit Assessment

As shown in Exhibit 20, there are three nuclear plants in the SPP region, one of which is located in Kansas (1,190 MW). The other nuclear plants within SPP are located in Nebraska.

Exhibit 20: SPP-US Nuclear Units

Name	Utility	State	NRC License Expiration	Winter Capacity (MW)
Cooper	Nebraska Public Power District	Nebraska	1/18/2014	786.1
Fort Calhoun	Omaha Public Power District	Nebraska	8/9/2033	492
Wolf Creek Generating Station	Kansas City Power & Light Co	Kansas	3/11/2025	559.3
Wolf Creek Generating Station	Kansas Electric Power Coop Inc	Kansas	3/11/2025	71.4
Wolf Creek Generating Station	Kansas Gas & Electric Co (Westar)	Kansas	3/11/2025	559.3
			Total Nuclear Generating Capacity	**2,468**

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 SPP. The operational licenses of most of the nuclear plants in the SPP region are currently due to expire prior to the end of the Study Period. However, from 2001 to 2008, the nuclear units shown in Exhibit 20 have run at an average capacity factor of more than 88%. 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.

In recent years, the outlook for nuclear power has become more positive 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. As a result, a large number of nuclear applications have been submitted to the Nuclear Regulatory Commission ("NRC") in the past few years.

The Nuclear Regulatory Commission's ("NRC") 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 some change in outlook for the industry. Also supporting the recent surge in planned nuclear expansion are US federal incentives offered in the Energy Policy Act of 2005.

One major concern with the resurgence of nuclear power is the magnitude of new applicants the NRC is currently facing. Approximately 34 GW of new capacity have been filed in the last few years and another 2 GW of applications are expected to be filed in 2010. Currently, the NRC expects about an 8 year time lapse between an application submittal and the reactor online date. It is very likely that bottlenecks will occur during the application review process due to the number of new applications in the queue. In addition to slowed application review, there may be a large wait for manufacturers to assemble new reactors due to the loss of infrastructure in the United States over the last 30 years. Furthermore, there are concerns related to security and waste storage which will need to be addressed before moving forward with nuclear expansion in the United States. These factors may make it more difficult for new reactors to come online within the next 10 years.

Currently, only one plant in SPP has submitted a letter of intent to the NRC expressing an interest in submitting an application. Amarillo Power, a Texas-based utility, has notified the NRC of an interest in building a 2-unit nuclear plant, but no official application has been submitted to the NRC at this time. Therefore, Pace does not feel that any new nuclear units will come online in the next 10-15 years. Pace assumes that one nuclear plant expansion (1,100 MW) will occur in the outer years of the Study Period in SPP.

Exhibit 21: SPP Proposed Nuclear Units

Name	Utility	Sub-Region	Online Date	Winter Capacity (MW)
Amarillo Nuclear	Amarillo Power	Texas	6/1/2016	2,700

Source: Pace, Energy Velocity®, and Nuclear Regulatory Commission

Consistent with the market approach to capacity additions, Pace has conducted its analysis of market prices under a scenario that considers publicly announced project development activities in addition to generic capacity additions in response to market conditions.

CAPACITY EXPANSION ASSESSMENT

Announced Capacity Additions

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

Exhibit 22 lists the under construction projects in the entire SPP region that Pace included in the Reference Case forecast. Pace reviews the development stage of all announced units in the market and includes or excludes resources based on two different criteria: the need for additional capacity in the region and the stage of development of the units. For this region, Pace includes all units under construction in its Reference Case.

As shown, approximately 2,700 MW of generating capacity are currently under construction in the market and scheduled to be online by 2011. Additionally, 3,700 MW of capacity have been completed since 2008, with the majority of this new capacity coming from wind.

Exhibit 22: Recently Completed and under Construction Plants (in the Reference Case)

Owner	Project Name	Unit Type	Plant Status	Online Date	Plant State	Winter Capacity (MW)
Lea Power Partners LLC	Hobbs Generating Station	Gas	Operating	9/26/2008	NM	600
Public Service Co of Oklahoma	Riverside (OK)	Gas	Operating	6/1/2008	OK	170
Public Service Co of Oklahoma	Southwestern	Gas	Operating	3/4/2008	OK	170
Westar Energy Inc	Emporia Power Plant (KS)	Gas	Operating	6/11/2008	KS	330
Westar Energy Inc	Emporia Power Plant (KS)	Gas	Operating	2/26/2009	KS	340
Midwest Energy Inc	Goodman Energy Center	Gas	Operating	6/5/2008	KS	51
Midwest Energy Inc	Goodman Energy Center	Gas	Operating	9/5/2008	KS	25
Omaha Public Power District	Nebraska City Unit 2	Coal	Operating	5/1/2009	NE	663
Autry Technology Center	Autry Technology Center	Wind	Operating	1/5/2009	OK	0
Clear Wind Renewable Power Inc	Buffalo Bear Wind Farm	Wind	Operating	1/26/2009	OK	19
Cloud County Wind Farm LLC	Meridian Way Wind Farm	Wind	Operating	12/1/2008	KS	201

Owner	Project Name	Unit Type	Plant Status	Online Date	Plant State	Winter Capacity (MW)
Cow Branch Wind Power LLC	Cow Branch Wind Energy Project	Wind	Operating	3/3/2008	MO	50
Elkhorn Ridge Wind LLC	Elkhorn Ridge Wind	Wind	Operating	3/16/2009	NE	81
Farmers City Wind LLC	Farmers City Wind	Wind	Operating	6/30/2009	MO	146
Flat Ridge Wind Energy LLC	Flat Ridge Wind Farm	Wind	Operating	3/5/2009	KS	50
Glen Coble & Sons Inc	Coble & Sons Wind Farm	Wind	Operating	5/1/2008	NE	0
High Plains Wind Power LLC	Wege Wind Energy Farm	Wind	Operating	3/31/2008	TX	10
JD Wind 10 LLC	JD Wind 10	Wind	Operating	7/1/2008	TX	10
John Deere Wind Energy	JD Wind 11	Wind	Operating	7/1/2008	TX	10
John Deere Wind Energy	JD Wind 7	Wind	Operating	7/1/2008	TX	10
John Deere Wind Energy	JD Wind 8	Wind	Operating	7/1/2008	TX	10
John Deere Wind Energy	JD Wind 9	Wind	Operating	7/1/2008	TX	10
Majestic Wind Power LLC	Majestic Wind Farm	Wind	Operating	1/28/2009	TX	80
Noble Great Plains Windpark LLC	Noble Great Plains Windpark	Wind	Operating	12/29/2008	TX	114
Red Hills Wind I LLC	Red Hills Wind Project	Wind	Operating	3/12/2009	OK	80
Red Hills Wind Project II LLC	Red Hills Wind Project	Wind	Operating	3/12/2009	OK	44
Signal Wind Energy LLC	Sunray Wind Farm	Wind	Operating	2/16/2009	TX	9
Smoky Hills Wind Farm LLC	Smoky Hills Wind Farm	Wind	Operating	1/30/2008	KS	101
Smoky Hills Wind Project II LLC	Smoky Hills Wind Farm	Wind	Operating	10/3/2008	KS	150
Valero Energy Corp	McKee Wind Farm	Wind	Operating	3/31/2009	TX	9
Westar Energy Inc	Central Plains Wind Farm	Wind	Operating	4/14/2009	KS	99
Westar Energy Inc	Flat Ridge Wind Farm	Wind	Operating	3/5/2009	KS	50
Wind Capital Group	Loess Hills Wind Farm	Wind	Operating	4/19/2008	MO	5
Western Farmers Electric Coop	Anadarko (OK WFEC)	Gas	Under Const	8/1/2009	OK	135
Signal Wind Energy LLC	Sunray Wind Farm	Renew	Under Const	8/1/2009	TX	41
Arkansas Electric Coop Corp	Elkins	Wind	Under Const	9/1/2009	AK	60
Dewind Swi Wind Farms LLC	Little Pringle Wind Farm	Renew	Under Const	9/1/2009	TX	20
CLECO Power LLC	Rodemacher	Coal	Under Const	9/1/2009	LA	660
Clear Wind Renewable Power Inc	Sleeping Bear Wind Farm	Wind	Under Const	9/30/2009	OK	21
Solomon Forks Wind LLC	Solomon Forks Wind Farm	Renew	Under Const	11/1/2009	KS	108
Community Wind Energy	Crofton Hills Wind Farm	Wind	Under Const	12/31/2009	NE	42
NextEra Energy Resources LLC	Elk City Wind (NextEra)	Wind	Under Const	12/31/2009	OK	99
Red River Environmental Products	Red River Cogeneration	Other	Under Const	1/1/2010	LA	20
Oklahoma Gas & Electric Co	OU Spirit	Wind	Under Const	3/1/2010	OK	100
Empire District Electric Co (The)	Iatan 2	Coal	Under Const	6/1/2010	MO	102
KCP&L, Kansas Electric Coop	Iatan 2	Coal	Under Const	6/1/2010	MO	748
Goodland Energy Resources	Goodland Energy Resources	Wind	Under Const	9/1/2010	KS	22
Springfield MO (City of)	Southwest	Coal	Under Const	10/1/2010	MO	300
Nebraska City Utilities	Whelan Energy Center	Coal	Under Const	1/1/2011	NE	220
Total Capacity (MW)						**6,393**

Source: Pace, Energy Velocity® and EIA

PACE

Exhibit 23 (below) lists the plants which are proposed to be built in the SPP region, but are not included in our Reference Case study. Pace assumes that some of the permitted and proposed plants shown in Exhibit 23 will be built to comply with regional and federal RPS. As discussed later in this document, Pace expects 15,000 MW of renewable capacity to come on-line in SPP to satisfy the RPS requirement through the end of the Study Period. Other fossil plants shown in the exhibit are not included in Pace's Reference Case due to the uncertainty associated with their on-line dates. Moreover, coal-fired plants have faced increasing environmental scrutiny from local bodies and/or environmental groups.

Exhibit 23: Major Permitted and Proposed Plants (not included in the Reference Case)

Project Name	Owner	Unit Type	Status	Plant State	Online Date	Winter Capacity (MW)
Dewind Swi Wind Farms LLC	Big Pringle Wind Farm	Wind	Permitted	9/30/2009	TX	200
Hays Wind LLC	Hays Wind	Wind	Permitted	12/31/2011	KS	200
Holt County Wind LLC	Grande Prairie Wind Farm	Wind	Permitted	12/1/2009	NE	100
Nacel Energy	Blue Creek Wind Energy Project	Wind	Permitted	7/31/2010	TX	10
Nacel Energy	Blue Creek Wind Energy Project	Wind	Permitted	9/1/2010	TX	10
Nacel Energy	Blue Creek Wind Energy Project	Wind	Permitted	12/1/2010	TX	10
TradeWind Energy	Caney River Wind Farm	Wind	Permitted	9/1/2010	KS	200
Waste Management Inc	Tontitown Landfill	LFG	Permitted	12/30/2010	AR	5
Amarillo Power	Amarillo Nuclear	Nuclear	Proposed	6/1/2016	TX	1,350
Amarillo Power	Amarillo Nuclear	Nuclear	Proposed	6/1/2016	TX	1,350
Babcock & Wilcox Technical	B&W Pantex Wind	Wind	Proposed	9/30/2011	TX	8
Baryonyx Corp	Dallam Ranch Wind	Wind	Proposed	7/31/2011	TX	150
Baryonyx Corp	Dallam Ranch Wind	Wind	Proposed	8/31/2012	TX	150
Bost1 Hydroelectric LLC	Red River Hydro Project	Hydro	Proposed	8/1/2010	LA	16
Caddo Lake Hydro LLC	Caddo Dam Hydroelectric Project	Hydro	Proposed	12/31/2012	LA	1
Chermac Energy Corp	No Mans Land I	Wind	Proposed	12/31/2010	OK	80
Chermac Energy Corp	No Mans Land II	Wind	Proposed	12/31/2010	OK	80
Chermac Energy Corp	Red River Salt Fork Wind I	Wind	Proposed	12/31/2011	TX	80
Chermac Energy Corp	Red River Salt Fork Wind II	Wind	Proposed	12/31/2011	TX	80
Cielo Wind Power	Lubbock Wind Ranchtm	Wind	Proposed	6/30/2011	TX	8
Clipper Windpower Inc	Clipper Wind Project	Wind	Proposed	6/1/2010	TX	400
Clipper Windpower Inc	Shooting Star Wind Project	Wind	Proposed	1/1/2010	KS	105
Community Energy Inc	Community Energy's Atchison	Wind	Proposed	12/31/2009	MO	400
CPV Renewable Energy Co	Keenan Wind Farm II	Wind	Proposed	6/30/2010	OK	150
Dempsey Ridge Wind Farm LLC	Dempsey Ridge Wind Farm	Wind	Proposed	6/30/2010	OK	224
Earth Power Energy Co LLC	Earth Power Wind Project	Wind	Proposed	7/31/2010	TX	19
Flat Water Wind Farm LLC	Flat Water Wind Farm	Wind	Proposed	10/31/2010	NE	60
General Electric Co	Rush County Wind Farm (GE)	Wind	Proposed	3/31/2011	KS	50
Generation Energy	Black Mesa Wind (OK)	Wind	Proposed	6/1/2010	OK	42
Gestamp Wind North America	North Buffalo Wind Farm	Wind	Proposed	1/1/2012	OK	255
Gestamp Wind North America	North Buffalo Wind Farm	Wind	Proposed	1/1/2013	OK	255
Gestamp Wind North America	North Buffalo Wind Farm	Wind	Proposed	1/1/2014	OK	255

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Project Name	Owner	Unit Type	Status	Plant State	Online Date	Winter Capacity (MW)
Golden Spread Electric Coop Inc	Holcomb East	Coal	Proposed	12/31/2014	KS	510
Goodland Wind LLC	Goodland Wind	Wind	Proposed	12/31/2009	KS	81
Greensburg KS (City of)	Greensburg Wind Project (KS)	Wind	Proposed	3/1/2010	KS	13
Happy Whiteface Wind LLC	Happy Whiteface Wind Farm	Wind	Proposed	12/31/2013	TX	239
Haywood County (TN)	West Tennessee Solar Farm	Solar	Proposed	1/1/2011	TN	5
Higher Power Energy LLC	Brock Wind Farm	Wind	Proposed	3/31/2010	TX	20
Higher Power Energy LLC	Haynes Wind Farm	Wind	Proposed	3/1/2010	TX	200
Higher Power Energy LLC	Herford Wind Farm	Wind	Proposed	1/1/2012	TX	200
Higher Power Energy LLC	Herford Wind Farm	Wind	Proposed	1/1/2013	TX	200
Higher Power Energy LLC	Herford Wind Farm	Wind	Proposed	1/1/2014	TX	100
Holt County Wind LLC	Grande Prairie Wind Farm	Wind	Proposed	6/1/2011	NE	200
Holt County Wind LLC	Grande Prairie Wind Farm	Wind	Proposed	9/1/2010	NE	200
Horizon Wind Energy	Reno County Project	Wind	Proposed	1/1/2012	KS	200
Hydro Green Energy LLC	Louisiana 17	Hydro	Proposed	1/1/2013	LA	5
Hydro Green Energy LLC	Louisiana 18	Hydro	Proposed	1/1/2013	LA	5
Iberdrola Renewable Energies	Conestoga Wind Project	Wind	Proposed	1/1/2010	KS	198
Iberdrola Renewables Inc	Ness County Wind Farm	Wind	Proposed	6/30/2012	KS	100
Iberdrola SA	Chetolah Crossing Wind Project	Wind	Proposed	1/1/2011	KS	200
Iberdrola SA	Saline Wind Project	Wind	Proposed	1/1/2011	KS	200
ICG Aeolian Energy	Rooks County Wind Farm	Wind	Proposed	6/30/2011	KS	50
Johnson County Wastewater (KS)	Douglas L Smith Middle Basin	Biomass	Proposed	12/31/2010	KS	4
JW Prairie Windpower LLC	Munkers Creek Wind Farm	Wind	Proposed	9/30/2010	KS	150
JW Prairie Windpower LLC	Nemaha County Wind Farm	Wind	Proposed	9/30/2010	KS	130
Kansas City Power & Light Co	Spearville Wind Energy Facility	Wind	Proposed	6/30/2010	KS	48
Kiamichi Hydro LLC	Hugo Dam Hydroelectric Project	Hydro	Proposed	10/1/2011	OK	3
Lindale Renewable Energy LLC	Lindale Renewable Energy	Biomass	Proposed	6/1/2012	TX	50
Lock Hydro Friends Fund XXVIII	Red River Lock & Dam No 2	Hydro	Proposed	1/1/2014	LA	23
Luminant	Briscoe County Wind Project	Wind	Proposed	1/1/2011	TX	3,000
Majestic Wind Power LLC	Majestic Wind Farm	Wind	Proposed	12/31/2009	TX	80
Midwest Wind Energy	Conestoga Wind	Wind	Proposed	6/30/2011	NE	80
Midwest Wind Energy	Laredo Ridge Wind	Wind	Proposed	3/30/2011	NE	100
Midwest Wind Energy	Oteo County Wind Project	Wind	Proposed	6/1/2010	NE	80
Morgan City LA (City of)	Morgan City	Gas	Proposed	9/1/2011	LA	100
Nacel Energy	Channing Flats Wind Energy Center	Wind	Proposed	6/1/2010	TX	10
Nacel Energy	Channing Flats Wind Energy Center	Wind	Proposed	11/30/2010	TX	10
Nacel Energy	Hedley Pointe Wind Farm	Wind	Proposed	3/31/2010	TX	10
Nacel Energy	Leila Lakes Wind	Wind	Proposed	6/30/2011	TX	10
Nacel Energy	Leila Lakes Wind	Wind	Proposed	11/30/2011	TX	10
Nacel Energy	Swisher County Wind Farm	Wind	Proposed	3/31/2010	TX	10
Nacel Energy	Swisher County Wind Farm	Wind	Proposed	5/31/2010	TX	10
Nebraska Public Power District	NPPD Ainsworth Wind	Wind	Proposed	12/1/2010	NE	15
Nennescah Wind LLC	Nennescah Wind	Wind	Proposed	9/1/2010	KS	150
Ninnescah Wind Farm LLC	Ninnescah Wind Farm	Wind	Proposed	3/31/2010	KS	150

Project Name	Owner	Unit Type	Status	Plant State	Online Date	Winter Capacity (MW)
Noble Great Plains Windpark LLC	Noble Great Plains Windpark	Wind	Proposed	12/31/2009	TX	126
Northwest Arkansas Conservation	Northwest Arkansas Wastewater	Biomass	Proposed	12/31/2009	AR	50
Oologah Lake Dam Hydro LLC	Oologah Lake Dam Hydro	Hydro	Proposed	1/1/2013	OK	8
Oologah Lake Dam Hydro LLC	Oologah Lake Dam Hydro	Hydro	Proposed	1/1/2013	OK	21
Pacific Winds LLC	Bluebonnet Wind Farm	Wind	Proposed	12/31/2010	TX	100
Pacific Winds LLC	Pioneer Wind Farm	Wind	Proposed	12/31/2010	KS	72
Pacific Winds LLC	Revolution Wind Farm	Wind	Proposed	12/31/2010	KS	95
Pacific Winds LLC	Soaring Wind Farm	Wind	Proposed	3/31/2011	OK	73
Perry Dam Hydro LLC	Perry Dam Hydroelectric Project	Hydro	Proposed	12/31/2012	KS	2
Pomme de Terre Hydro LLC	Pomme de Terre Dam Hydroelectric	Hydro	Proposed	12/31/2012	MO	3
Prairie Breeze Wind Energy LLC	Prairie Breeze Wind	Wind	Proposed	12/31/2010	NE	80
RES Americas Inc	Lyon County Wind (Res)	Wind	Proposed	10/31/2011	KS	131
Rosebud Sioux Commission	Owl Feather War Bonnet Wind Farm	Wind	Proposed	12/31/2009	SD	30
Scandia Wind Southwest LLC	Mariah Wind Project	Wind	Proposed	1/31/2012	TX	999
Scandia Wind Southwest LLC	Mariah Wind Project	Wind	Proposed	1/31/2013	TX	999
Scandia Wind Southwest LLC	Mariah Wind Project	Wind	Proposed	1/31/2014	TX	999
Sunflower Electric Power Corp	Holcomb East	Coal	Proposed	12/31/2014	KS	385
Taloga Wind LLC	Taloga Wind	Wind	Proposed	6/30/2010	OK	130
Terrebonne Parish Consolidated	Houma	Gas	Proposed	3/1/2010	LA	50
TradeWind Energy	Atchison County Wind	Wind	Proposed	6/30/2010	MO	400
TradeWind Energy	Honey Creek Wind Project	Wind	Proposed	1/1/2012	AR	150
TradeWind Energy	Shuteye Creek Wind Project	Wind	Proposed	9/30/2010	MO	150
TradeWind Energy	Shuteye Creek Wind Project	Wind	Proposed	3/31/2011	MO	150
United States Dept of Energy	Pantex Renewable Energy Project	Wind	Proposed	12/31/2012	TX	75
USACE Little Rock District	Ozark	Hydro	Proposed	4/1/2014	AR	20
USACE Little Rock District	Ozark	Hydro	Proposed	4/1/2010	AR	20
USACE Little Rock District	Ozark	Hydro	Proposed	4/1/2011	AR	20
USACE Little Rock District	Ozark	Hydro	Proposed	4/1/2012	AR	20
USACE Little Rock District	Ozark	Hydro	Proposed	4/1/2013	AR	20
Valero Energy Corp	McKee Wind Farm	Wind	Proposed	3/31/2010	TX	41
Waste Management Inc	Rolling Meadows Landfill	LFG	Proposed	1/1/2010	KS	6
Wind Capital Group	Selkirk Wind Project	Wind	Proposed	9/30/2010	KS	100
Wind Capital Group	Wildcat Ridge Wind Farm	Wind	Proposed	1/1/2012	MO	300
Windthorst 1 LLC	Windthorst I	Wind	Proposed	12/31/2009	TX	51
Wood Products Energy Inc	Wood Products Energy Olla Project	Biomass	Proposed	6/1/2010	LA	21
Wood Products Energy Inc	Wood Products Energy Winnfield	Biomass	Proposed	1/1/2010	LA	3
Total Capacity						**19,358 MW**

Source: Pace, Energy Velocity® and EIA

Pace's capacity expansion process is an iterative process guided by market knowledge, observed trends, expected regulatory constraints, and detailed analysis on the economic feasibility of different types of generation assets.

Pace considered all currently under construction plants in the Reference Case forecast. All permitted and proposed plants were analyzed to determine development trends in the market. This, in combination with the economic performance and regulatory feasibility of different plant additions is used as the building block for Pace's capacity expansion. This analysis informs the type and timing of capacity expansion assumed to meet RPS and reliability requirements in the region.

Dynamic Expansion

In addition to capacity needed to meet RPS requirements and regional reliability standards, Pace incorporates the dynamic simulation of additional economic capacity in all long-term forecasts. With this approach, incremental expansion is expected when economic conditions provide a sufficient rate of return for new units. Where net energy and capacity revenues together justify build of a new unit on the basis of a historic trend, a new unit is built. Sustained positive returns, generally stimulated by falling reserve margins and rising prices are expected to lead to capacity additions. The magnitude of the capacity expansion depends on the achieved Return on Investment ("ROI") specific to the type of generating plant.

Pace's dynamic build logic is illustrated in Exhibit 24. This graphic illustrates how new capacity comes on according to economic signals – these units are shown under the legend "Economic Expansion" (the units labeled "Additional Expansion" reflect announced units or units built on the basis of RPS or reliability requirements). For example, following an expected widening in system reserve margins over the period to 2009-2011, the system is expected to tighten during the 2011-2013 timeframe. In this example, we project that rising margins in the period 2011-2013 will send a signal causing a new plant to come online around the 2015 time frame.

Following a temporary capacity glut, rising plant margins during the 2015-2018 period are unlikely enough to provide an unequivocal signal to new plant developers. In this case, a full build phase is not supported until the period from 2023-2026. From 2021, declining plant margins set in, reflecting the overbuild cycle.

The dynamic expansion methodology is currently applied to incremental gas and wind builds in the region, and is employed in both the Reference Case and stochastic simulations. This allows all market simulations, whether deterministic or stochastic, to incorporate the reactive behavior observed in the market to periods of sustained margins.

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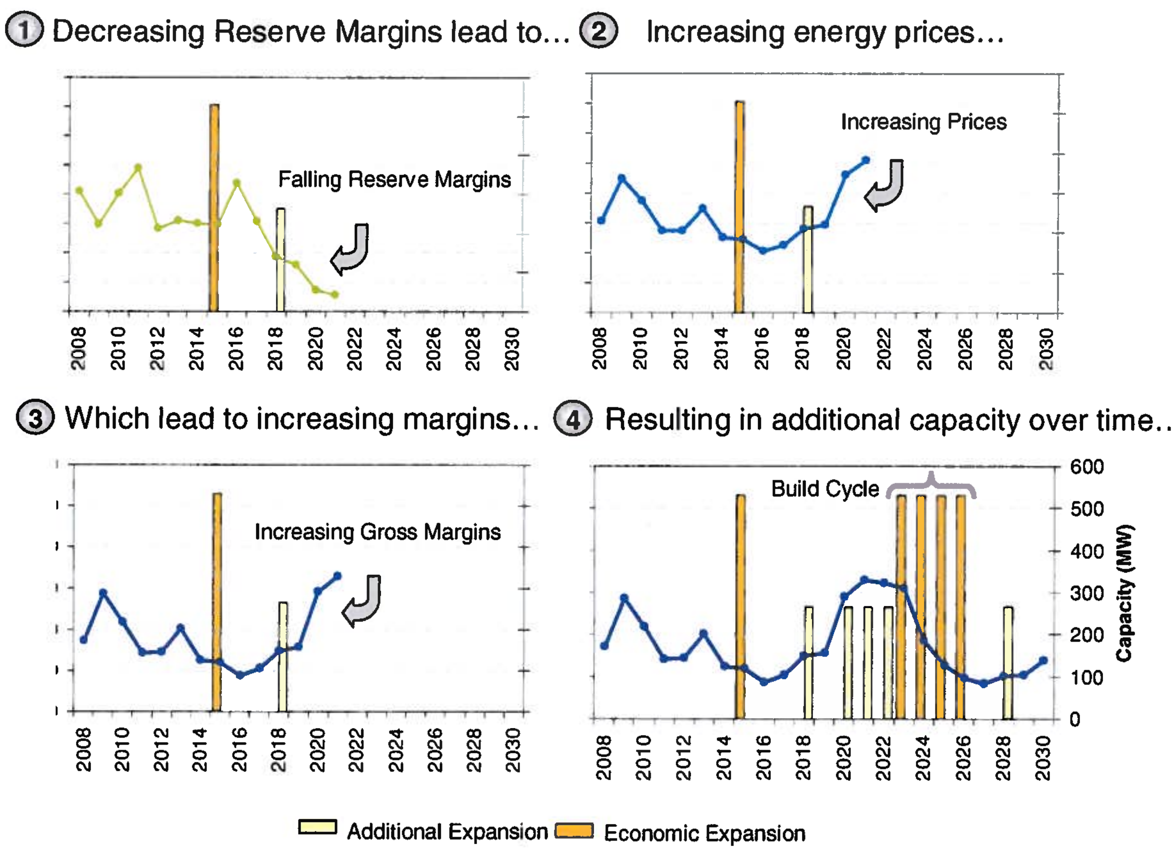
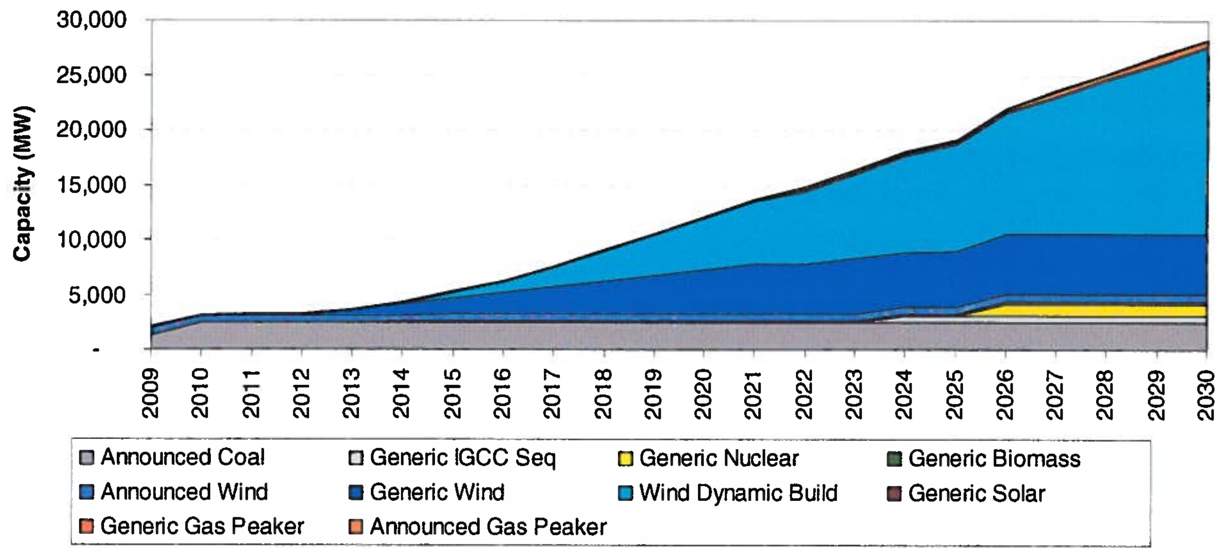
Exhibit 24: Dynamic Build Simulation Logic



Source: Pace

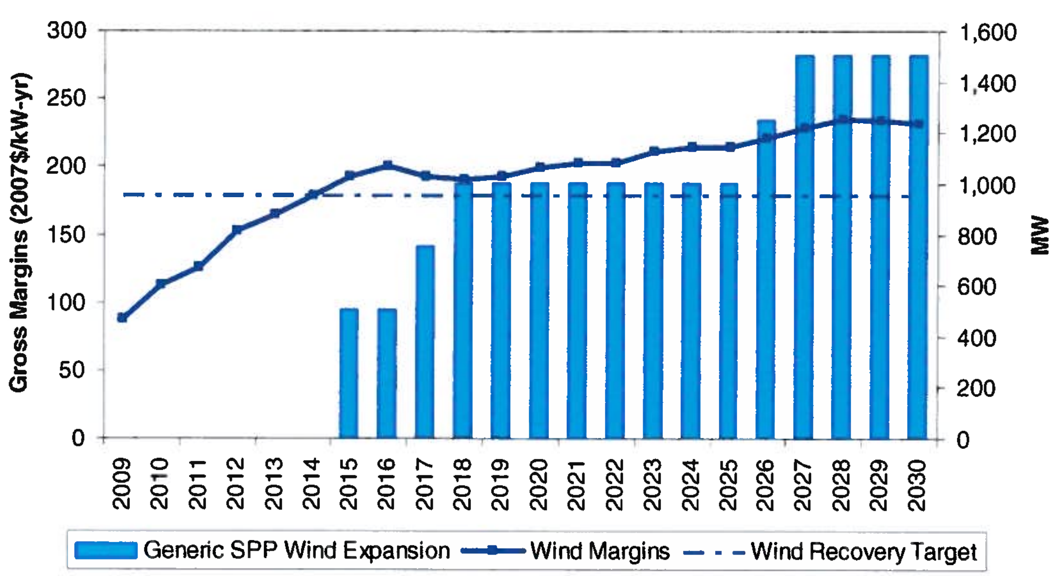
As outlined in Exhibit 25, under the Reference Case simulations, Pace expects that approximately 28,000 MW of new capacity will come online by 2030 throughout SPP driven by RPS requirements, reliability requirements, and favorable plant margins. Out of the 28,000 MW of capacity additions in the SPP market, 17,000 MW of wind capacity are expected to be driven solely by wind economics. As outlined in Exhibit 26, increasing gas prices and emission compliance costs result in an increasing ROI for wind over time, resulting in significant wind expansion over the Study Period.

Exhibit 25: Expected Capacity Additions



Source: Energy Velocity® and Pace

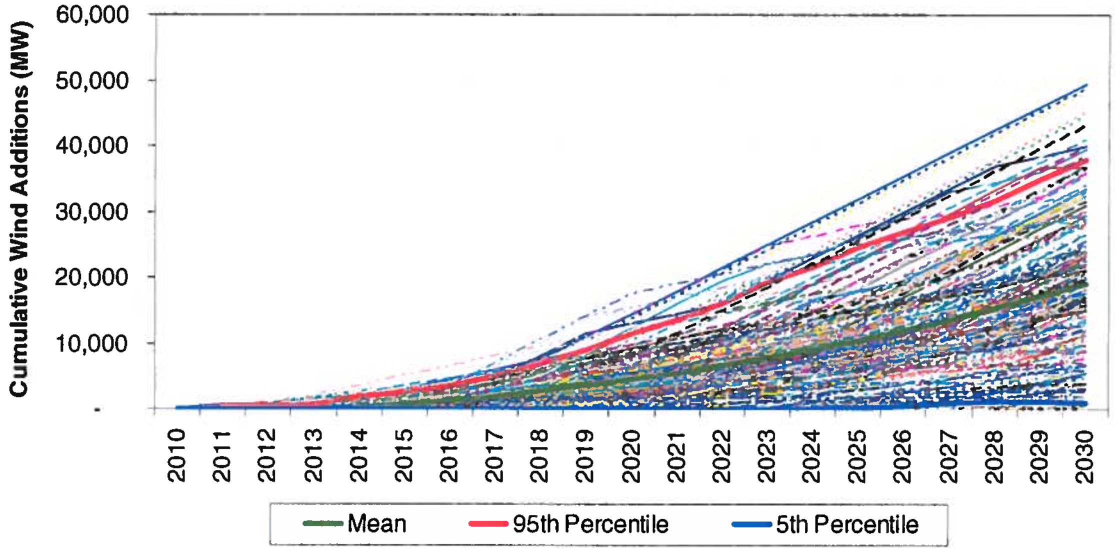
Exhibit 26: Reference Case Dynamic Wind Additions



Source: Pace

The uncertainty around load, gas prices, and capital costs embedded in the stochastic analysis results in a corresponding range of wind margins over the Study Period. This uncertainty is captured in Pace's simulation and reflected in the range of economic wind additions across all iterations. Exhibit 27 illustrates the range of wind expansion across a representative set of 250 iterations from the risk analysis. The expected value of the distribution is around 19,000 MW of cumulative wind additions by 2030.

Exhibit 27: Dynamic Wind Additions in Risk Analysis



Source: Pace

Announced Capacity Retirements

As outlined in Exhibit 28, there were approximately 90 MW of capacity retirements in 2007, but there have been no major retirements in the last few years.

Exhibit 28: Recent Capacity Retirements (included in Reference Case)

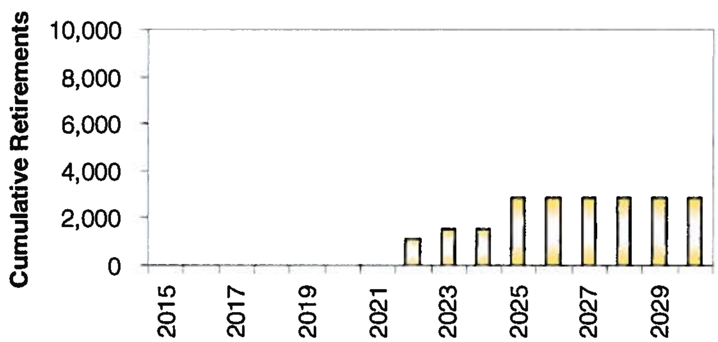
Project Name	Owner	Retirement Date	Unit Type	Winter Capacity (MW)
Ponca City Refinery	Conoco Inc	1/31/2007	ST	9
Ponca Diesel	Ponca City OK (City of)	4/30/2007	IC	1
Greensburg	Greensburg KS (City of)	5/31/2007	IC	7.3
Exxon Hawkins Gas Plant	Exxon Mobil Production Co	6/30/2007	IC	10.36
Mangum	Mangum Utility Authority	9/30/2007	IC	0.2
Westroads Shopping Center	General Growth Properties	11/30/2007	IC	1.81
Ellis (KS)	Midwest Energy Inc	12/31/2007	IC	5
Calpine Pryor Inc	Calpine Pryor Inc	12/31/2007	CC	54
Westroads Shopping Center	General Growth Properties	11/30/2007	IC	0.99
Benkelman	Benkelman NE (City of)	12/31/2007	IC	0.2
Total Capacity				**1,267.1**

Source: Pace, Energy Velocity® and EIA

In addition to the announced retirements, Pace reviews all proposed retirement dates and the expected operational life spans for older units. Pace anticipates that the older, less efficient units will be more heavily impacted by increased carbon compliance costs. In addition, the advent of new regulatory policy surrounding emission compliance might create additional pressure for older, uncontrolled plants to retire rather than make significant capital investments to retrofit for pollution control.

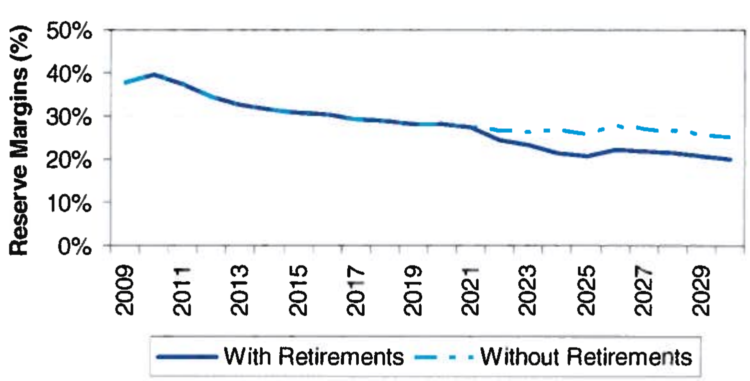
Based on Pace's assessment of the existing generation fleet in the SPP market, we expect that approximately 2.9 GW of gas-fired generation will retire by 2030, as outlined in Exhibit 29. Exhibit 30 illustrates the impact of these retirements on regional reserve margins.

Exhibit 29: SPP Reference Case Retirements



Source: Pace

Exhibit 30: SPP Reserve Margins



Source: Pace

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 SPP market area. The remainder of this section summarizes Pace's outlook for each fuel market and presents the Reference Case assumptions for fuel prices. The methodology used to develop stochastic bands around gas and coal prices is outlined at the end of this section.

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, when demand is high and supplies are tight, the two commodities 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. Conversely, a fast drop in natural gas prices to low levels, such as those prevailing in 2009, can induce some fuel switching as well as changes in the merit order dispatch of power generators and put downward pressure on coal prices. In general, the price correlation of oil and gas markets has been closer than that of gas and coal markets in the U.S., but excursions from any established pricing relationship among the fuels can be prolonged and significant if the supply/demand balances in any two commodities are out of step.

Generally speaking, the crude oil market is truly a global market, with prices adjusted consistently for location value and product quality. Price deviations only arise due to a mismatch between the availability of a particular grade of crude and market demand or compatible refinery capacity. Oil is easily and cheaply transported by pipe, rail, truck or ship and is easy to store in above-ground tanks. Natural gas, by contrast, is relatively difficult and expensive to transport and store, requiring high-pressure pipelines and underground reservoirs to contain and control the gaseous fuel. Therefore, natural gas markets have historically been geographically demarcated by integrated production, transmission, storage and distribution systems that are self-contained and largely isolated from other such systems.

In Europe and Asia, the natural gas industry was created and managed primarily by central governments, large state-sanctioned monopolies and a handful of dominant suppliers of both pipeline gas and ocean-borne liquefied natural gas ("LNG"), a super-cooled fluid with 600 times the energy density of vapor-phase natural gas. In such concentrated and controlled markets, crude oil and oil product prices have been used as a fair-value metric for pricing both domestic gas supplies and imported volumes. By contrast, the North American gas industry emerged from the independent efforts of thousands of privately-owned producers, pipelines, local distributors and major consumers, and has been predominantly self-sufficient through its evolution over the past 200 years. Therefore, in the 20+ years since wellhead price decontrol came to the U.S. and Canada, the North American gas market has been a generally 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 statistical correlation of price changes in gas and oil markets has been evident but loose over the last five years.

This loose correlation may be tightening in coming years, however, if and when marginal sources of domestic gas supply prove inadequate to meet domestic demand or too expensive to compete with imported LNG. Given the depth and breadth of the economic recession, the global LNG market is temporarily oversupplied and suppliers are price takers, but this situation will last a few years at most. If domestic production fails to keep up with demand, and the U.S. gas market increases its reliance on LNG to cover shortfalls, it will find itself competing on price for marginal LNG cargoes for international suppliers whose alternative markets price gas against an oil index. As long as North America remains just an off-season dumping ground for surplus LNG on world markets, any increase in the statistical correlation of North American gas prices and world oil prices will be modest. If and when the U.S. starts competing for LNG cargoes during periods of high demand (all major LNG markets are in the Northern Hemisphere), however, there will be a growing gravitational pull on the U.S. gas market to align itself with world LNG market pricing. In light of the many independent market developments needed to produce this effect, the timing and sequencing of its occurrence is impossible to predict with any accuracy, but increasing North American statistical price correlation between oil and gas could be evident as early as 2012 or might be deferred for a decade or more if domestic gas resources are aggressively developed.

As the global oil market is least affected by the price of other fuels, Pace's assumptions for the petroleum market are presented first.

PETROLEUM

WTI Crude Oil Prices

After hovering between $20 and $40/bbl for two decades, crude oil prices have shown significant increases in volatility during the past five years. In the past year alone, the market value of a barrel of West Texas Intermediate ("WTI") crude oil has varied by roughly $110, with crude prices hovering around $60-70/bbl today after touching $147/bbl in July 2008, before dropping to below $40/bbl in January and February of this year. Market fundamentals were a significant part of the large price swings, but clearly the worsening financial and economic downturn – first in the U.S. but quickly spreading around the world –, and the value of the US dollar relative to other currencies have played a substantial role.

Exhibit 31: WTI Crude Oil Expected Price Forecast (2008 $)

Year	WTI Price Forecast	
	(2008 $/barrel)	*(2008 $/MMBtu)*
2009	44.95	7.72
2010	49.93	8.57
2011	58.93	10.12
2012	61.93	10.63
2013	71.91	12.35
2014	75.91	13.03
2015	82.90	14.23
2016	84.90	14.57
2017	89.89	15.43
2018	92.89	15.95
2019	95.89	16.46
2020	101.88	17.49
2021	103.88	17.83
2022	107.87	18.52
2023	109.87	18.86
2024	111.87	19.20
2025	114.86	19.72
2026	116.86	20.06
2027	119.86	20.58
2028	121.86	20.92
2029	123.85	21.26
2030	125.85	21.61

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 percent of the historic variance in the price of No. 2 fuel oil and over 85 percent 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.

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 percent of global demand at the beginning of the decade, accounted for 50 percent 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 25 percent of global demand at the beginning of the decade, accounted for another 13 percent of the total growth during that period. The remaining OECD countries, which accounted for 37 percent of global demand at the beginning of the decade, added only about 1 percent of the total growth.

As noted above, the U.S. economy preceded that rest of the world into economic recession during 2008, and oil consumption was down 6 percent on average for the year versus 2007. The OECD as a whole saw oil demand fall 3.6 percent, while global demand fell by less than 1 percent, given damped but positive growth in Chinese demand and continued demand growth in other non-OECD countries, particularly the Middle East. The most recent data from the UU DOE Energy Information Administration ("EIA") show U.S. April 2009 crude demand down 6.3 percent from year-ago figures and global demand down about 5.5 percent, or 4.8 MMbbl/d, from year-ago figures. Pace anticipates 2010 to be a year of weak oil demand recovery at best for the OECD nations, with essentially flat demand for crude oil versus 2009, with total global consumption increasing slightly to approximately 2005 demand levels of 84 MMbbl/d.

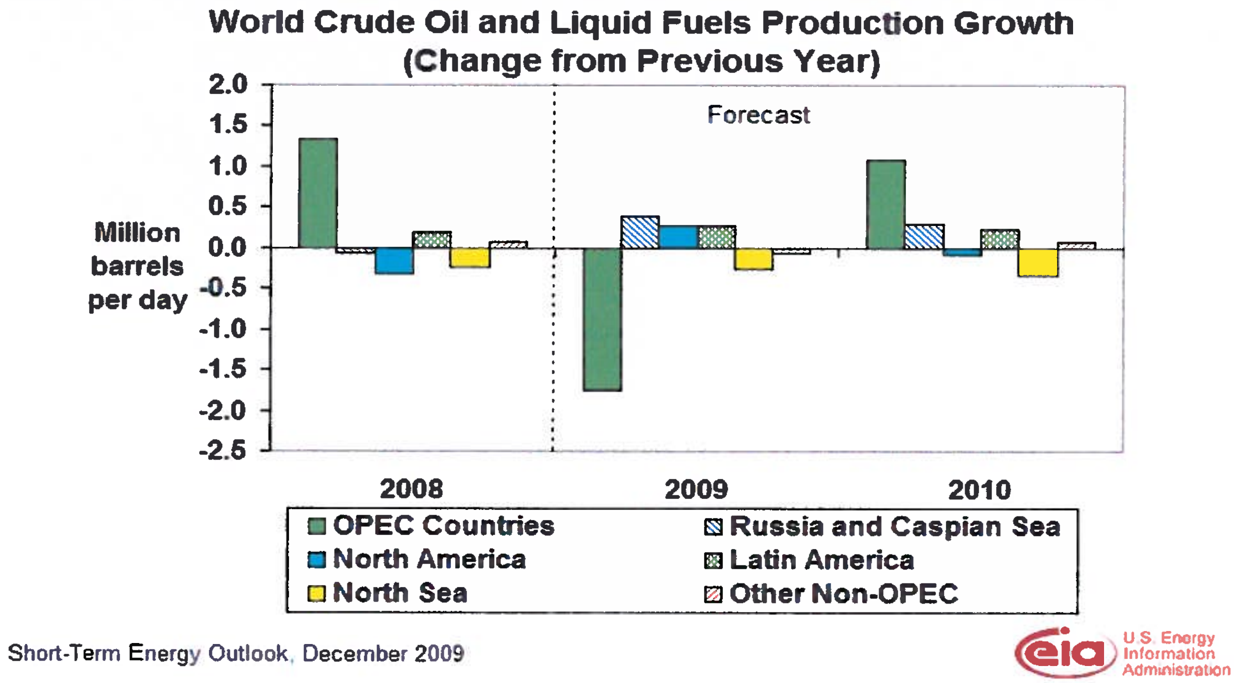
Oil Supply

During the period 2003-2007, production of petroleum liquids increased by 5 to 6 MMBbl/day, creating a relative shortfall of supply of 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 by itself to stem the rising prices during the first half of 2008.

As can be seen in the recent EIA update below on non-OPEC oil production, the steadily climbing oil price from 2003 into 2008 has borne fruit in terms of new production in 2009 and 2010, but these gains are largely offset by major declines anticipated for Mexico's Cantarell Field and aging North Sea properties. Bright spots include initial production from Brazil's massive deepwater discovery, Tupi, scheduled to eventually produce 1 MMbbl/d, and the long-delayed BP Thunder horse platform in the deepwater Gulf of Mexico, now approaching its design capacity of 250,000 bbl/d, adding 3 percent to total U.S. production.

Exhibit 32: Near-term Changes in Non-OPEC Production Capacity



Source: USDOE EIA

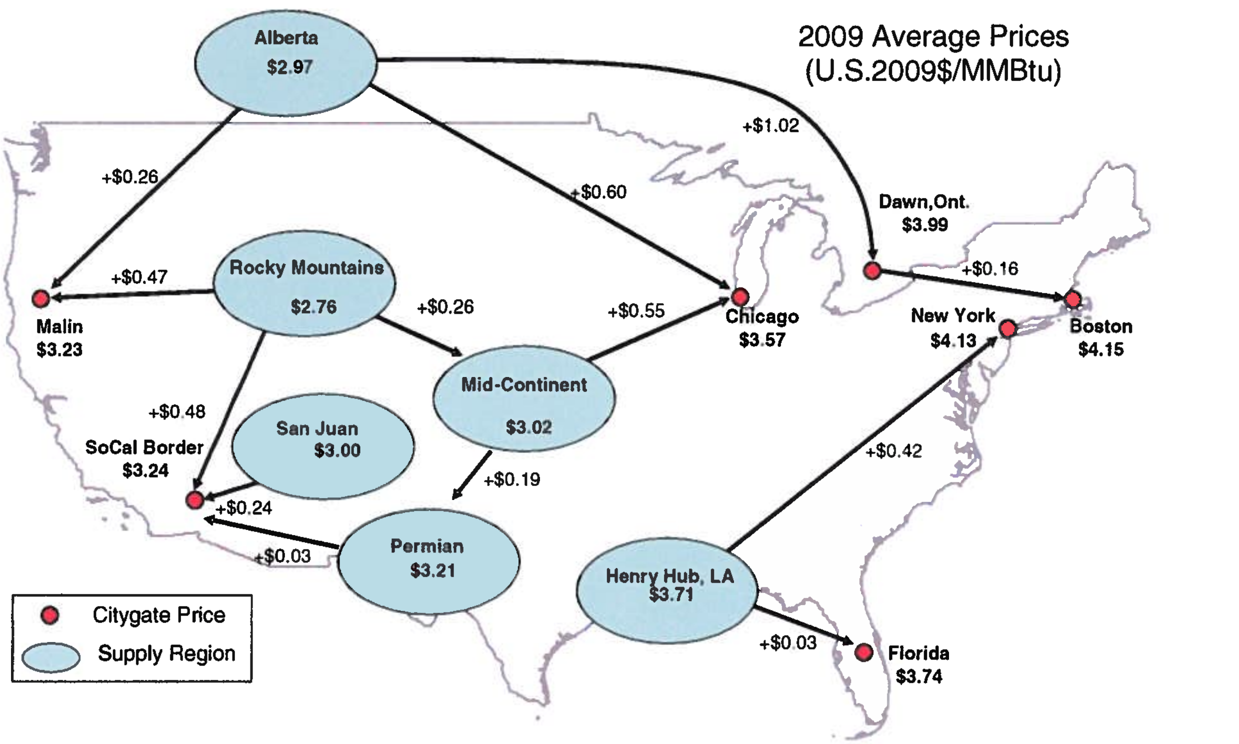
OPEC production for 2009 through April has averaged only 33.2 MMbbl/d, down 7 percent from average 2008 production, in recognition of record-high inventory levels in the U.S. and elsewhere. Pace foresees only a slight increase in OPEC production for the remainder of 2009, increasing by about 1 MMbb/d in 2010 as Asian and Middle Eastern demand continues to grow. Current OPEC spare capacity stands at a recent high of about 6 MMbbl/d and should increase in June 2009 when Saudi Arabia brings the 1.2 MMbbl/d Al Khurais Field on line.

Still, all this spare capacity could be quickly absorbed by growing Asian demand for transportation fuels and the economic recovery. If price expectations remain below $60/bbl, non-OPEC production will once again begin to decline as the big opportunities for new supplies from deepwater or unconventional resources will be difficult to economically justify. Pace scenario analyses on future oil supplies range from a benign forecast of stable to weakly declining demand as the OECD focuses on import reductions and China constrains transportation fuel demand growth to a more troubling outlook in which sustained growth in oil product demand outstrips sustainable production rates.

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. Regional gas prices are based on basis differentials from the Henry Hub to other delivery locations. Regional basis rises (widens) when local production declines and the cost of transporting gas between regions increases and when rising demand causes pipeline and storage utilization to grow. Conversely, 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 33 shows the flows of gas and the prevailing market prices for the major North American trading hubs as of June 1, 2009. The regional basis is the difference between the price in a regional market and the price at Henry Hub.

Exhibit 33: North American Average Natural Gas Prices in 2009 ($/MMBtu)

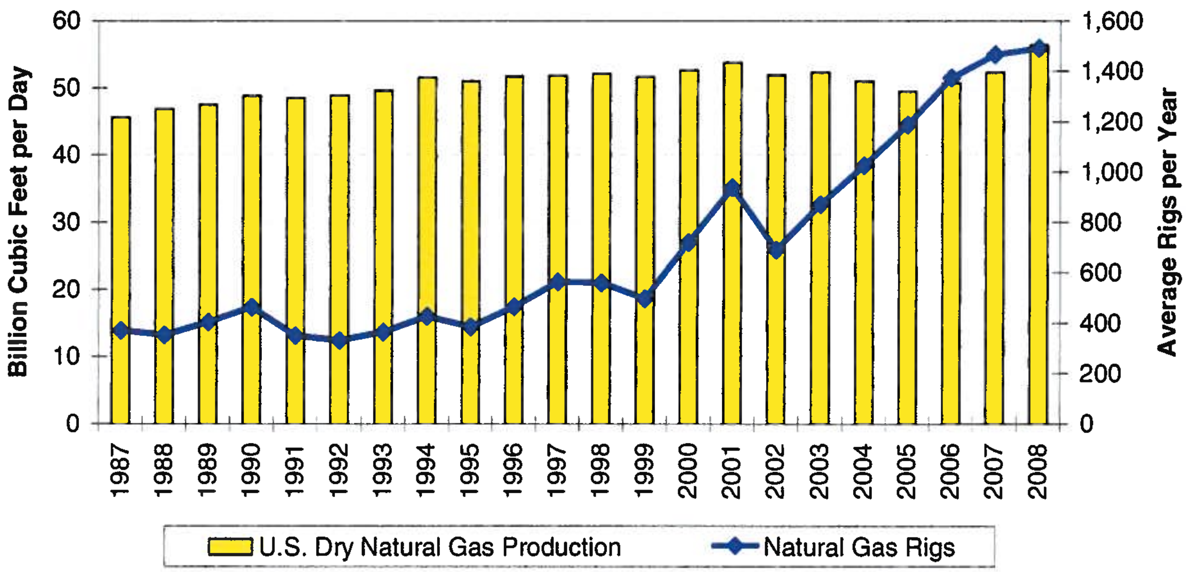


Sources: Pace and Platts

Henry Hub Price Forecast

Over the past 16 months, assumptions about long-term natural gas supply sources have changed dramatically. Due to a price-driven U.S. drilling boom for unconventional onshore gas supplies and the technological advances it supported and sustained, the idea that North American gas supply was in irrevocable decline was resoundingly disproved. As oil and gas prices rose and then fell during 2008, reports on aggregate U.S. production and drilling and production results from a growing list of hydrocarbon basins long thought technically and economically unsuitable for commercial gas development kept surprising the natural gas industry. According to the EIA, total U.S. marketed gas production rose from 52.8 Bcf/d in January 2007 to over 60 Bcf/d in April 2009, a cumulative 14 percent increase in the face of declining expectations. Today, the U.S. market is "oversupplied" by 2-3 Bcf/d, not counting shut-in wells in the Rocky Mountains bottlenecked behind inadequate pipeline infrastructure.

Exhibit 34: U.S. Natural Gas Production and Drilling Rig Count



Sources: Rig count – Baker Hughes; production – EIA.

Prices have responded. A collapse in drilling activity has accompanied this price collapse. Because of the rapid deliverability declines observed in the shale gas wells that are the proximate cause of the oversupply situation, market observers are awaiting declines in total marketed production in the coming months, bringing the supply/demand balance into better balance, which should bolster prices. Pace would then expect to see drilling activity for shale gas begin to increase as prices climbed past $6.00/MMBtu, allowing for unavoidable logistical lags.

However, a combination of weak economic recovery, ample gas in storage and rising LNG imports from a global market that is also experiencing a supply glut – again due to the combination of weak demand and fast-growing LNG production and transportation capacity stimulated by a decade of increasing price expectations – could keep spot prices at or below $4.00/MMBtu during the off-season for heating demand for several years as increasing LNG imports replace declining North American production capacity as drilling activity remains subdued by the weak price environment.

Longer term on the supply side, North American gas producers and LNG importers are going to be competing for market share in a volatile price environment. Given the inherent commercial and logistical lags for major increases in drilling activity and the fact that natural gas liquefaction plants generally will continue operating at near capacity in both down and up markets, LNG will tend to flow into North American markets as domestic deliverability declines and prices steadily rise until growing domestic production from increased drilling activity sends the opposite price signal. Under these circumstances, significant multi-year price cycles would be added to seasonally cyclical price movements and short-term volatility in shaping long-term market prices. The extent and duration of these multi-year cycles would be attributed in part to global LNG pricing as well as domestic market conditions, periodically drawing the North American market into at least temporary alignment with European and Asian markets until growing domestic deliverability created competition once again for market share.

On the demand side, major long-term uncertainties include the power sector response to eventual mandatory carbon emissions limits and whether industrial gas demand will recover and grow or stagnate and decline as heavy industry continues to relocate and the domestic petrochemical industry sees its market share erode as new production capacity is built closer to cheaper sources of feedstock. On the power generation side, a rapid implementation schedule for achieving interim targets for carbon emissions reductions could induce a "dash to gas" and an exodus from older coal-fired plants, leading to a rapid increase in gas demand. A massive investment in wind power would make gas-fired generation the most practical source of standby and supplemental power as wind speeds and electric load vary. Demand swings on regional gas transmission systems will have lasting effects on system operations as well as pipeline and storage capacity pricing.

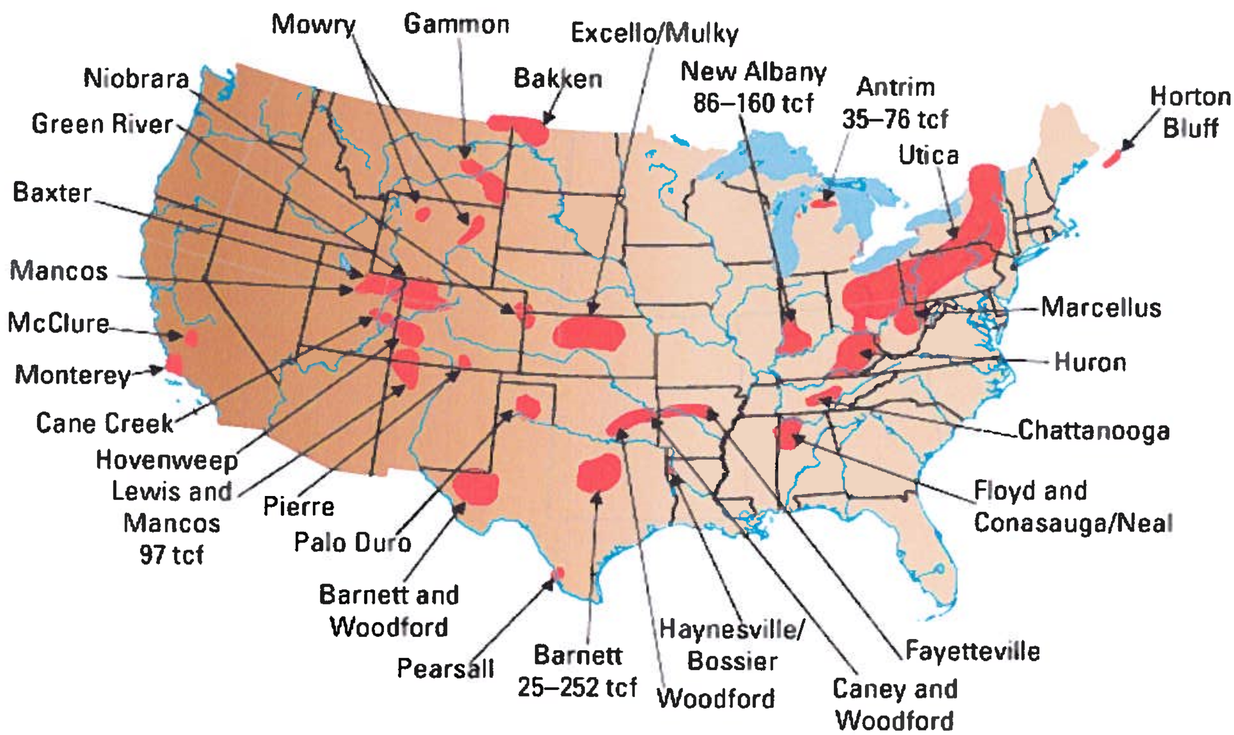
Pace's scenario-based gas demand forecasts for the Northeast U.S. over the next 20 years range from a modest decline, assuming coal remains a viable economic and regulatory option for new base load generating capacity, to a roughly 10 percent increase above current average daily demand should gas-fired generation shoulder a larger share of the electricity load. With average Henry Hub prices over the 2009-2014 period ranging from $4.66/MMBtu to $10.83/MMBtu across the four scenarios considered.

Regional Basis

New and emerging domestic production regions, the ongoing reconfiguration of the North American gas transmission network, and growing LNG import capacity on the Atlantic Seaboard and Gulf Coast will all work to reshape prevailing price disparities among local markets in coming years. Exhibit 35 illustrates the major gas-bearing shale formations in the US. Production in some of these regions will lead to changing gas price differentials across the US.

Exhibit 35: Major Gas-Bearing Shale Formations in the U.S.

Major US shale basins.

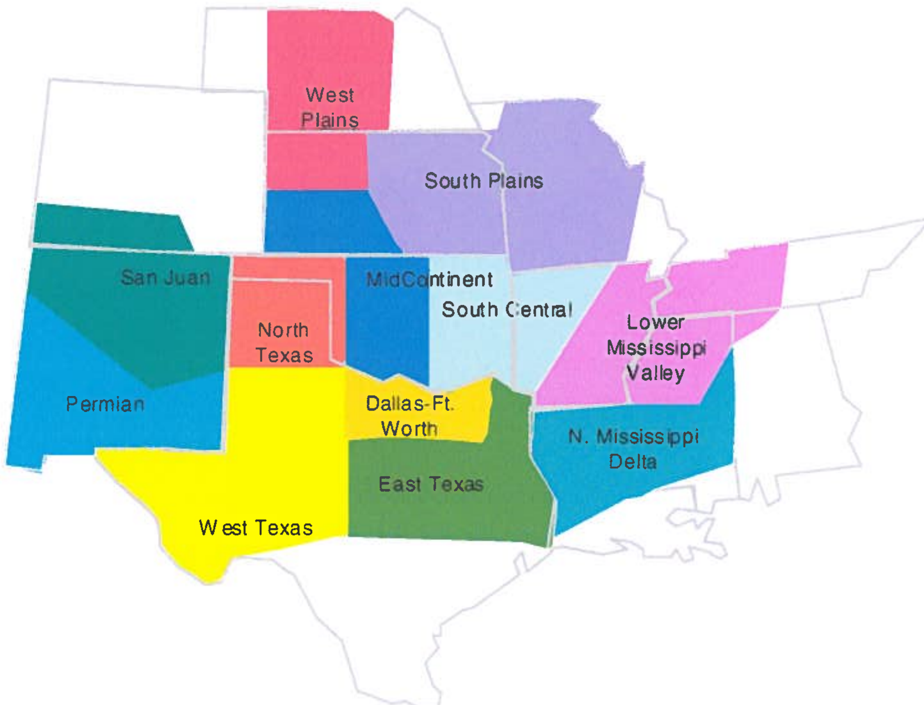


Source: Schlumberger

The completion of the Rockies Express – East pipeline later this year will also add to downward basis pressure. Adding about 1.5 Bcf/d of year-round delivery capacity, the Rockies Express will be the first direct link between the gas deliverability surpluses currently depressing gas prices throughout the Rockies and high-priced East Coast markets. The producers financing the pipeline construction hope to raise their wellhead prices enough to cover the cost of transcontinental transportation, but basis effects are always felt on both ends of a new interconnection between major supply and demand nodes.

Pace's delivered gas price forecast incorporates general price differentials and the cost of transportation to SPP and Kansas gas price sub-regions, as depicted in Exhibit 36. Developments in the pipeline sector will change the basis differentials.

Exhibit 36: Pace Gas Price SPP Region



Sources: 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:

- OneOk is the dominant transporter of natural gas in the West Plains region, which primarily receives supply in the Mid-Continent basin. Pace Global projects a market-based average annual rate of \$0.35/MMBtu to reflect the cost of transporting gas on OneOk to regional delivery points.
- Moving gas within the Lower Mississippi Valley region requires an inter-zone short-haul transportation service on ANR, NGPL, Texas Gas, Trunkline, Tennessee Gas, or Texas Eastern. Tariff-based transportation rates on these pipelines will be around \$0.25/MMBtu annually, placing delivered supply in the region at a \$0.07/MMBtu premium to Henry hub and a \$0.14/MMBtu premium to Northern Mississippi Delta deliveries.
- Generation units located in the Northern Mississippi Delta require short-haul, intra-zone transportation from production points and supply pools in the Gulf Coast producing region.
- Market-based transportation rates for pipelines delivering supplies to the Mid-Continent area averaged \$0.31/MMBtu over the forecast period. This supply is primarily delivered by the Natural Gas Pipeline Company of America.

Exhibit 37 provides a summary of Pace's independent forecast of annual Henry Hub and delivered prices to each respective SPP fuel sub-regions.

Exhibit 37: SPP Natural Gas Price Forecasts (2008 $/MMBtu)

Year	Henry Hub	N. Mississippi Delta	Lower Mississip pi Valley	Mid-Continent	West Plains
2009	4.21	4.29	4.39	3.37	3.41
2010	5.59	5.65	5.75	4.94	5.12
2011	6.22	6.33	6.44	5.86	5.90
2012	6.39	6.55	6.66	6.15	6.19
2013	6.45	6.60	6.71	6.18	6.22
2014	6.96	7.12	7.22	6.70	6.74
2015	7.89	8.04	8.15	7.63	7.67
2016	8.48	8.63	8.74	8.20	8.24
2017	8.19	8.35	8.45	7.91	7.95
2018	7.60	7.76	7.86	7.31	7.35
2019	7.95	8.10	8.20	7.67	7.71
2020	8.95	9.09	9.19	8.65	8.69
2021	9.56	9.70	9.81	9.29	9.33
2022	9.35	9.48	9.58	9.04	9.08
2023	10.51	10.64	10.75	10.24	10.28
2024	10.87	11.00	11.10	10.58	10.62
2025	10.51	10.63	10.74	10.21	10.25
2026	10.74	10.86	10.96	10.44	10.48
2027	11.03	11.15	11.26	10.74	10.78
2028	11.24	11.36	11.46	10.95	10.99
2029	11.43	11.55	11.66	11.15	11.19
2030	11.63	11.76	11.86	11.35	11.39

Source: Pace

COAL

Power generation accounts for 93 percent 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, had caused moderately large increases in spot coal prices and smaller increases in contract prices in 2007 and 2008. 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 large escalation of spot prices in the U.S. as suppliers reacted by selling steam coal into the export market.

Recently that trend has reversed itself and market prices have plummeted. The surge in prices was due to increased demand in India and China as well as supply disruptions in Australia and South Africa. But the global recession has had a profound effect on developing nations and the "bubble" of demand for coal, steel and other products has at least temporarily burst. Coal prices have fallen rapidly back towards pre 2007 levels and as export demand disintegrated, the production increases that occurred from higher prices had no place to go. Domestic inventories have swelled and many mines are being shut down for a lack of market.

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 coupled with an increase in worldwide demand for coal. By the start of 2008, prices in Asia and Europe had already risen 30-45 percent 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 percent and raising prices there enough that U.S. coals become competitive in these markets. Prices for eastern coals rose from about $60 in early January to over 80 $2007 in March and above 120 $2007 throughout most of the summer. Prices have since fallen to the 40-50 $2007/ton range due to the global economic slow down. There are currently few coal transactions for near term delivery and many producers in the Appalachian basins are shutting-in production.

The coal market is in the process of "right sizing" to meet domestic demand. Once production drops back to levels consistent with domestic demand, market prices will stabilize throughout the country. The markets that had the biggest surges, the Appalachian region (both Northern and Central), and the Rockies (Colorado primarily), have had the biggest declines. When prices doubled, mom and pop operations sprouted up to take advantage of the market surge and larger suppliers expanded production. That trend is now being reversed.

National Coal Supply, Demand, and Forecast Assumptions

Overcapacity in the coal industry throughout most of the 1990s resulted in low prices, which forced smaller producers to either exit the industry or be acquired by larger, financially stronger players. These low prices also resulted in the closure of many mines and limited investment in new productive capacity.

High natural gas prices between 2003 and 2008 promoted the increased dispatch of coal-fired power plants. Between 2003 and 2005, coal consumption exceeded coal supply, resulting in a drawdown of inventories. However, U.S. coal production increased by approximately 27 million tons in 2006, allowing stocks to rebuild and then declined slightly in 2007; production slightly exceeded demand in 2008. The current global economic downturn has greatly depressed coal demand and prices, forcing many Appalachian producers to shut-in production. Additionally, gas prices have fallen back to low prices not seen since the 1990s. As long as gas prices remain low, coal demand will be negatively impacted. Some of the older less efficient coal units are being supplanted by gas to meet base and intermediate load demand at current gas prices. Over the longer term however, Pace expects that gas prices will rebound to prices in the $6-10 per MMBtu range with a return of market volatility. When this occurs, Pace expects that coal demand will rise, at least until carbon regulations push up coal plant's operating costs post 2012.

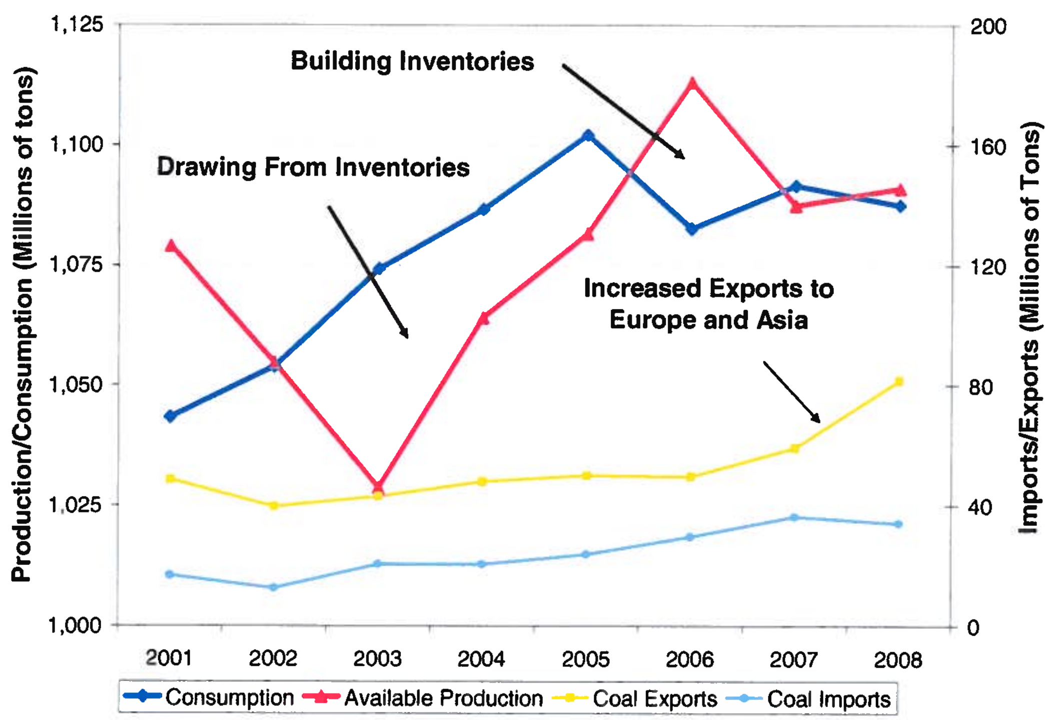
Once gas prices recover, Pace expects to return to relatively steady demand growth for coal over the next two decades, with the dominant market remaining the electric power industry. In

2008, power generation consumed an estimated 93 percent of U.S. coal production, while approximately 50 percent of U.S. net generation was fueled by coal.[1]

Pace expects future productivity increases in the Western U.S., primarily in the PRB, to exceed those in mines east of the Mississippi. Overall, further gains in mining productivity are expected, albeit at a lower rate than gains experienced throughout the 1990s, and are likely to prevent major supply shortages and/or coal price increases associated with deepening and depleting reserves, as well as real increases in the cost of inputs to production.

The domestic coal market is considerably less liquid than the natural gas or oil products market. Historically, electricity generators have purchased approximately 70-80 percent of their coal under contracts lasting one year or more in order to ensure security of supply. While it is likely that utilities will continue to use the spot coal market, Pace expects electricity generators to continue to opt for a significant proportion of term contracts, 1-5 years in duration, in order to reliably supply their plant portfolios.

Exhibit 38: Annual U.S. Coal Consumption and Production



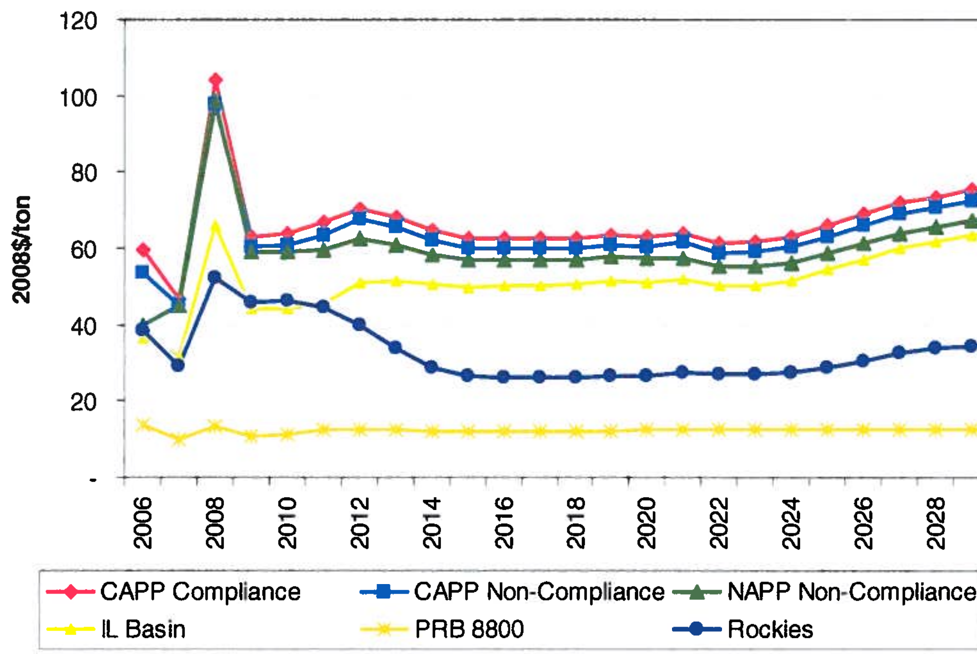
Sources: 2001-2008 EIA, Pace and Energy Velocity®

[1] Excludes cogeneration facilities reported in the EIA's industrial and commercial sectors.

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 39 and Exhibit 40 show Pace's FOB price forecast for the major coal basins throughout the country in $/ton and $/MMBtu, respectively.

Exhibit 39: Reference Case FOB Coal Price Forecast (2008$/ton)



Note: North Appalachia is identified above as ("NAPP").
Source: Pace and Platts

Exhibit 40: Pace FOB Coal Price Forecast (2008$/MMBtu)

Year	Central App. Comp. 12,500 Btu/lb	Central App. Non-Comp. 12,500 Btu/lb	Northern App. Non-Comp. 12,500 Btu/lb	Illinois Basin Non-Comp. 11,300 Btu/lb	PRB 8,800 Btu/lb	PRB 8,400 Btu/lb	Rockies Comp. 11,700 Btu/lb
Lb. SO_2/MMBtu	1.20	1.60	3.00	5.00	0.80	0.80	0.80
2009	2.52	2.41	2.37	1.96	0.61	0.54	1.95
2010	2.55	2.44	2.36	1.95	0.63	0.57	1.98
2011	2.67	2.54	2.38	2.02	0.71	0.63	1.91
2012	2.81	2.71	2.51	2.25	0.70	0.59	1.70
2013	2.72	2.62	2.44	2.28	0.70	0.58	1.44
2014	2.58	2.49	2.34	2.24	0.69	0.55	1.23
2015	2.50	2.40	2.28	2.20	0.69	0.56	1.14
2016	2.50	2.40	2.28	2.21	0.69	0.56	1.11
2017	2.50	2.40	2.29	2.23	0.69	0.56	1.11
2018	2.50	2.40	2.29	2.24	0.69	0.56	1.12
2019	2.54	2.44	2.31	2.27	0.69	0.56	1.13
2020	2.52	2.42	2.29	2.27	0.69	0.56	1.14
2021	2.56	2.46	2.30	2.29	0.70	0.56	1.16
2022	2.45	2.34	2.21	2.21	0.70	0.56	1.15
2023	2.46	2.36	2.21	2.22	0.70	0.56	1.15
2024	2.52	2.41	2.24	2.28	0.70	0.56	1.16
2025	2.63	2.52	2.34	2.40	0.70	0.56	1.22
2026	2.75	2.64	2.45	2.53	0.70	0.57	1.31
2027	2.87	2.76	2.55	2.65	0.70	0.57	1.40
2028	2.94	2.82	2.62	2.73	0.70	0.57	1.45
2029	3.01	2.90	2.68	2.81	0.70	0.57	1.47
2030	3.06	2.94	2.72	2.85	0.71	0.57	1.48

Source: Pace

Delivered Coal Prices

Pace forecasts delivered coal prices by adding forecast transportation costs to regional FOB basin level forecasts of coal price. As shown above, the basin level forecasts reflect the market outlook for various grades of coal in the three major coal-producing regions of the United States: Appalachia (West Virginia, Pennsylvania, Virginia, Eastern Kentucky, and Ohio), the Interior (Illinois, Indiana, and Western Kentucky), and the West (Wyoming, Montana, Colorado, Utah, New Mexico, and Arizona).

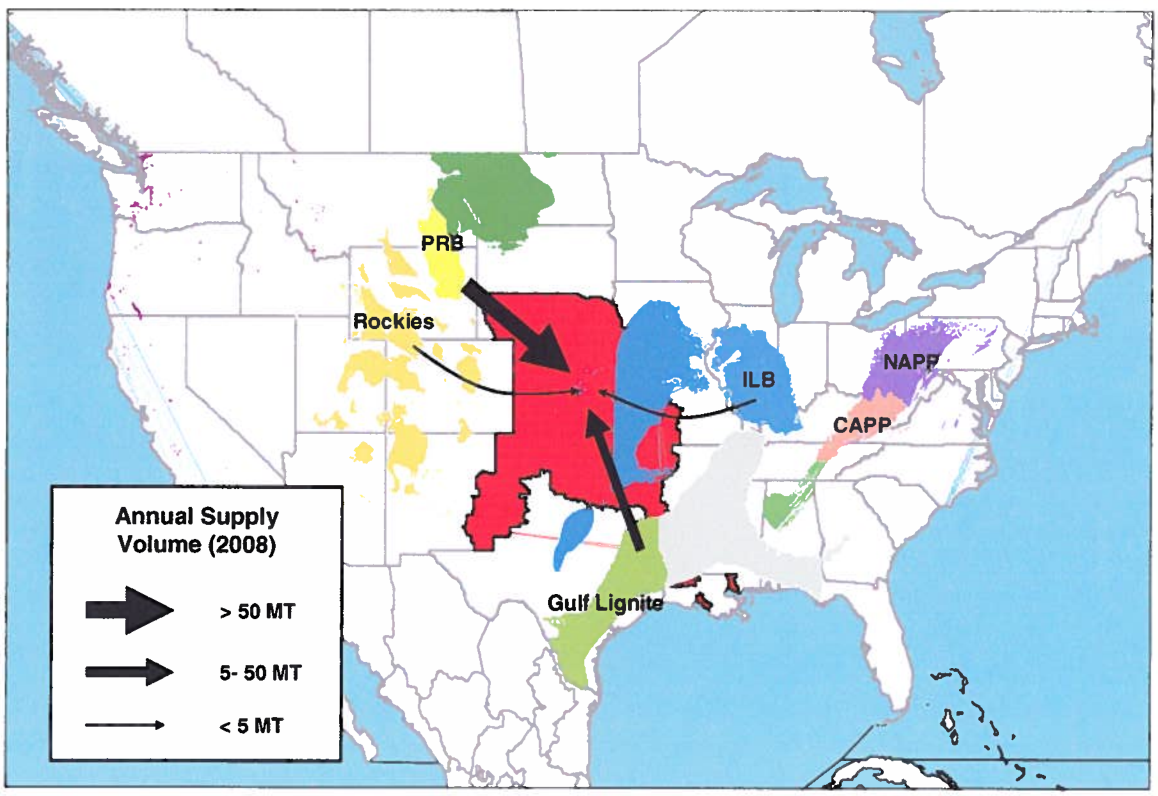
In developing plant-level coal price forecasts, Pace examines the coal purchasing characteristics underlying each coal-fired power plant, as well as the overall market for steam coal, to determine the likely delivered coal costs to each plant in the future. Pace reviews FERC Form 423 and Form EIA-423 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) over the Study Period. This is done within the context of environmental emission constraints, unit-level retrofit/environmental compliance options, and transportation constraints between each basin to 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 SPP

Generators in SPP purchase coal from the following supply regions: PRB, Gulf Lignite, Illinois Basin, and Rockies. Exhibit 41 below presents the location of the primary supply regions and the approximate annual volumes supplied for SPP. Exhibit 42 presents the recent market fundamentals, coal consumption patterns in SPP, and market drivers for coals consumed in the region.

Exhibit 41: Coal Supply Regions for SPP



Source: Pace and Energy Velocity®

[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").

Exhibit 42: Coal Commodity Forecast Fundamentals for SPP

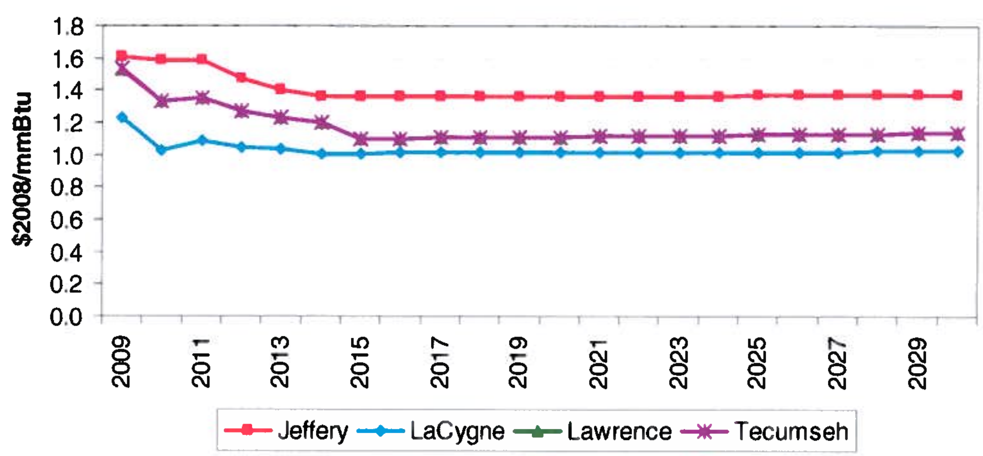
Commodity Region	Forecast Drivers
ILB	Pace expects an increase in ILB regional demand over the mid and long-term as more coal-fired capacity installs scrubbers and burns ILB coal as a more economic alternative to CAPP and NAPP non-compliance coals. ILB coal that is located on the water is sufficiently abundant to keep prices at competitive levels and hold down prices of NAPP and CAPP coal.
PRB	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	Increased demand for Rockies coal has gone away for the time being and investment has been cut back there. The region is a swing region in the west and its market is linked to export demand. The price of this coal is also a substitute in some markets for Central Appalachian compliance coals but since it is lower quality it can't move competitively long distances to eastern markets.
Gulf Lignite	Gulf Lignite is primarily consumed by mine mouth facilities and demand is likely to remain constant. CAIR restrictions may affect its competitiveness vis-à-vis PRB coals and erode market share over the long term due to gulf lignite's relatively high SO2 content. Pace Global projects prices will remain flat in real terms.

Source: Pace and Energy Velocity®

Coal Prices Delivered to Units Linked to Current Midwest Contracts

Pace applies its commodity price projections by plant based on their historical blend of coal deliveries and assumptions regarding transportation rates for movements by coal region to each plant. For the coal-fired units currently linked to unit-contingent baseload contracts for Midwest, Pace developed a long-term delivered price forecast for each of existing facilities based on Pace's commodity and transportation rate assumptions with sourcing inferred from existing contracts. Existing coal commodity and transportation contract pricing terms were overlaid onto the long-term projections. Exhibit 43 illustrates the Reference Case forecast for delivered coal to these units.

Exhibit 43: Delivered Coal Prices for Plants Currently Linked to Baseload Contracts



Source: Pace and Energy Velocity®

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 nuclear fuel prices have been relatively stable over the previous decade, although prices increased significantly in the latter part of 2007 into 2008.

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 than 20% of all uranium that entered the market between 1994 and 2005. On the world market, less than 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 41 GW of new nuclear units proposed in the United States. Of these, around 25 GW 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. This presents increased risk to a higher upward trend then that projected by Pace. 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.

Since nuclear fuel is a very small component of the total cost of nuclear generation, Pace has not developed a detailed forecast of the individual fuel components and instead uses a generic real escalation rate of one percent for fuel costs over the Study Period.

FUEL PRICE UNCERTAINTY FOR NATURAL GAS AND COAL

Significant price volatility in fuel markets has been observed over the last several years, driven by a wide range of "random" events, including natural disasters, supply discoveries, market bidding behavior, and macroeconomic forces. Rather than perform its analysis with one or a few natural gas and coal price projections, Pace models a statistically meaningful range of potential price outcomes that better capture the randomness and uncertainty of the market. In its analysis of fuel price uncertainty, Pace analyzes historical market volatility and behavior and propagates price paths that reflect such volatility and the log-normal distribution of prices observed in the market (prices are bounded more strongly on the low end, due to costs of production).

To project price paths for fuel prices such as natural gas and coal, Pace uses a mean-reverting process, outlined by the stochastic equation in Exhibit 44. The process employs a Monte Carlo simulation to randomly vary propagated monthly price paths from the expected price in accordance with historical volatility parameters, but draw them back to the mean with weakening force over time. Key elements of this process include:

- Volatility and mean reversion rates based on daily historical price data over the last five years;

- 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.

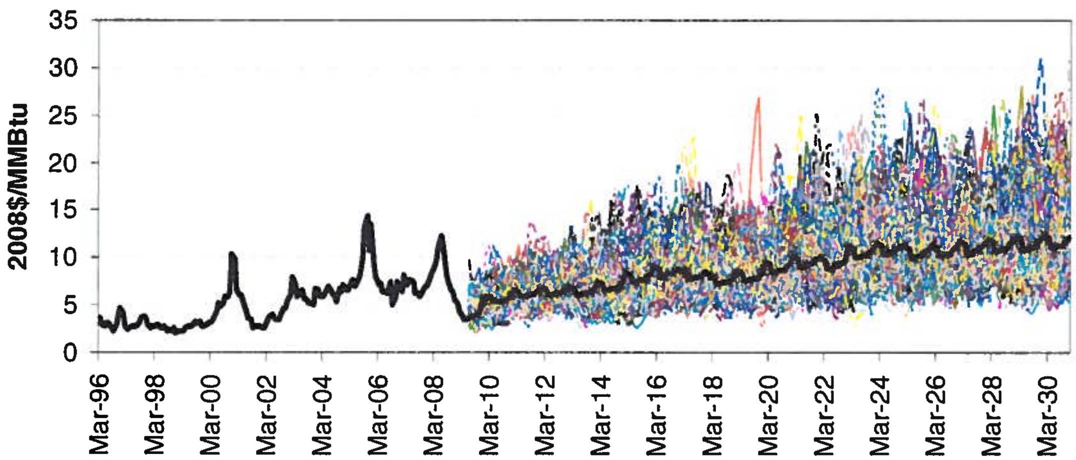
Exhibit 44: Fuel Price Stochastic Simulation Methodology

[redacted]

Source: Pace

Exhibit 45 displays a sample of 250 iterations for monthly natural gas prices at the Henry Hub, along with historical levels and the Reference Case. As can be seen, the distribution displays a log-normal shape, meaning that it is skewed to the high side. This is reflective of the likelihood of prices to deviate more on the high end of the expected value than on the low end.

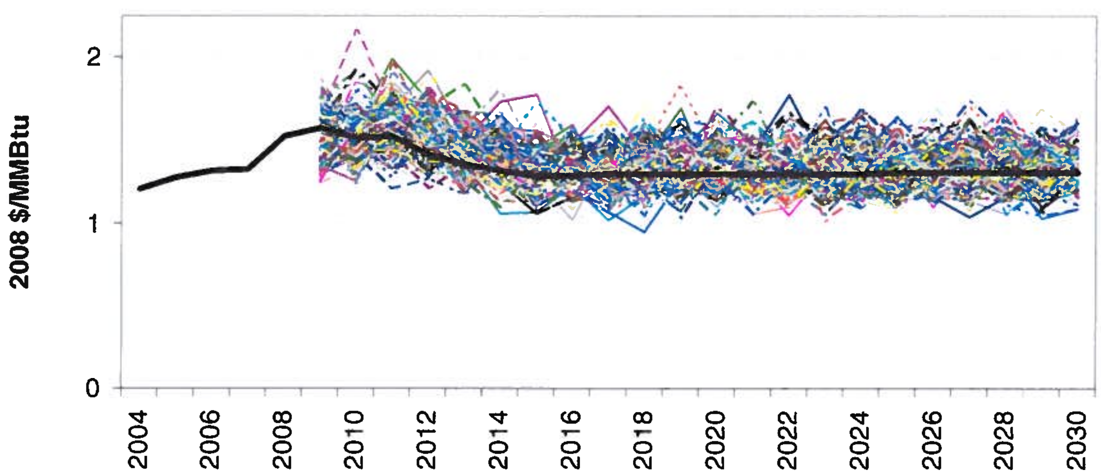
Exhibit 45: Natural Gas Price Uncertainty (Sample of 250 Iterations)



Source: Pace

Exhibit 46 displays a sample of 250 iterations for delivered annual coal prices to the plants in the supplier's fleet, along with historical levels and the reference case. Historical volatility of Powder River Basin ("PRB") coal was analyzed and used in constructing basin and transportation cost uncertainty. As can be seen, the volatility in PRB coal has been significantly lower than that of other fuels, particularly natural gas. This leads to expectations for a much narrower distribution of fuel prices around the reference case.

Exhibit 46: Coal Price Uncertainty (Sample of 250 Iterations)



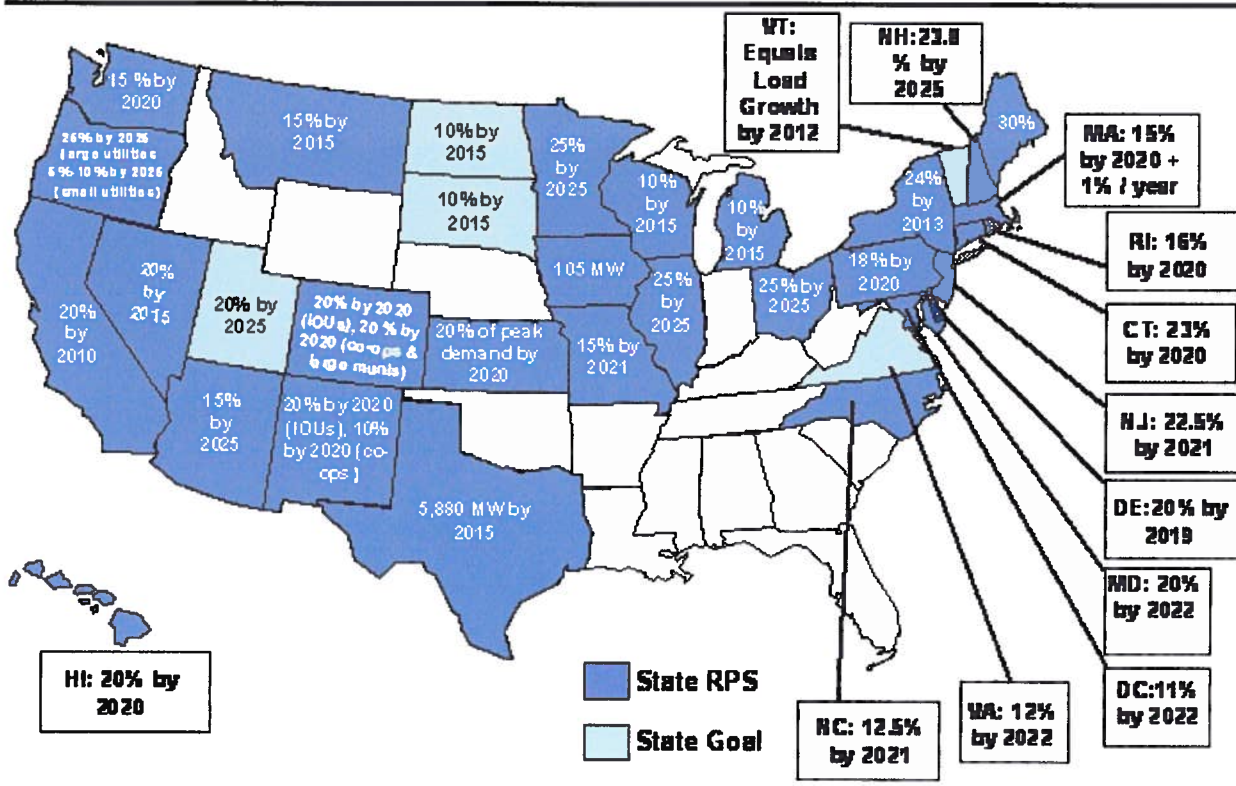
Source: Pace

KEY ENVIRONMENTAL LEGISLATIVE AND REGULATORY ISSUES AND POLICIES

RENEWABLE PORTFOLIO STANDARD

Renewable Portfolio Standards ("RPS"), also referred to as Renewable Electricity Standards ("RES") or Alternative Energy Portfolio Standards ("AEPS"), are regulated programs placing an obligation on electricity suppliers that a certain percentage of their electricity sold be derived from alternative or renewable energy resources. No comprehensive national RPS/RES exists in the U.S. at this time; however, the House of Representatives included a Federal RES in their American Clean Energy and Security Act ("ACES"), which passed the House on June 26, 2009. In total five separate federal RPS/RES bills have passed one house of Congress but have not reach full consensus on both sides. Even without a federal standard, more than half the states have adopted some form of state level RPS regulation. At this time, 29 states and the District of Columbia have enacted mandatory state-level RPS requirements; numerous state goals, and city and regional level RPS programs also exist.

Exhibit 47 State Level RPS Programs



Source: Database of State Level Incentives for Renewables and Efficiency

Each state level RPS dictates different compliance requirements, eligible renewable technologies, compliance dates, geographic restrictions of supply, and bundling requirements among other provisions. This variation in state requirements results in a patchwork of compliance requirements and cost levels. Kansas and several other surrounding Mid Continent states have enacted state level RPS programs that are expected to bring more renewable development to this region.

Kansas

In May 2009, House Bill (HB) 2369 established an RPS in Kansas which requires investor-owned utilities ("IOUs") and some electric cooperatives[3] to generate or purchase a certain amount of electricity from eligible renewable resources. The specific rules and regulations to administer the portfolio standard are still being drafted and should be completed within 12 months. However, the basic ground rules for the standard are set through HB 2369. Kansas' standard is based on generation capacity (kW) instead of retail electric sales (kWh) and the specific requirement schedule refers to the peak capacity demand based on the average of the previous three years. The compliance schedule is as follows:

- 2011-2015: 10% of peak demand
- 2016-2019: 15% of peak demand
- 2020 onward: 20% of peak demand

Currently, eligible technologies include wind, solar thermal, photovoltaics ("PV"), crops grown specifically for renewable generation, cellulose agricultural residues, plant residues, landfill gas, wood, existing hydropower, new hydropower of 10 MW or less and fuel cells. Additionally, each MW of eligible capacity installed in Kansas after January 1, 2000 will count as 1.1 MW for the purpose of compliance. The Kansas Corporation Commission ("KCC") will develop a system for issuing renewable energy credits ("RECs"), which will be eligible for use to meet a portion of Kansas utility requirements.

Pace has analyzed the renewable energy required under the current Kansas RPS rule and assumes that a more stringent Federal RPS will supersede this legislation. Due to the expectation of large scale wind development in this region, Pace assumes that Kansas utilities will be RPS compliant barring any major changes to the current Kansas RPS rule.

Colorado

Colorado was the first U.S. state to pass an RPS by ballot initiative in November of 2004. The original rule required utilities serving 40,000 or more customers to generate or purchase enough renewable energy to supply 10% of the retail electric sales. In March 2007, HB 1281 increased the RPS to include electric cooperatives and municipal utilities serving more than 40,000 customers. Eligible resources include solar-electric energy, wind, geothermal, biomass, landfill gas, animal waste, hydropower, recycled energy and fuel cells. For IOUs, at least 4% of the RPS standard must be generated by solar-electric technologies. There is no solar requirement for electric cooperatives or municipal utilities. Additionally, RECs may be used to satisfy the standard with eligible electricity generated in-state receiving 1.25 RECs for every kilowatt-hour generated.

[3] Electric cooperatives may be exempt from this legislation if they have fewer than 15,000 customers because the KCC does not have the authority to regulate electric cooperatives of this size.

Iowa

Iowa legislatures created an Alternative Energy Law ("AEL") in 1983 that has been subsequently amended in 1991 and 2003. The Iowa Utilities Board is responsible for overseeing the legislation which requires two investor owned utilities (Mid American Energy, and Alliant Energy Interstate Power and Light) to provide 105 MW of eligible renewable capacity. Eligible resources include solar, wind, small hydroelectric, and biomass including landfill gas, municipal solid waste, and anaerobic digestion. This obligation is currently mostly met by wind capacity.

The future of Iowa's RPS requirement at this time is unknown. The governor has set a non binding goal of 1,000 MW of wind capacity by 2010. This does not appear to be unattainable by Iowa, but a mandated increase of this magnitude could impact renewable credit availability in the region. Also, the Iowa Utilities Board has taken action to increase Alliant Energy's renewable requirements contingent on Alliant building new coal generation at their Southerland plant. The project is permitted, but the likelihood of it moving forward is unknown.

Missouri

The Missouri RES was established via ballot initiative in 2008. The standard requires investor owned utilities (municipal utilities and electric cooperatives are exempt) to supply 15% of their delivered electricity from eligible renewable recourse by 2021. There is an additional solar carve out of 2% of each interim portfolio requirement (i.e. in 2021, 0.3% of retail sales must be derived from solar electricity). Missouri also favors in-state generation, granting 1.25 REC multiplier for in-state generation.

New Mexico

Senate Bill (SB) 418, passed in March 2007, requires IOUs in New Mexico to generate a certain amount of total retail sales from renewable energy resources with a standard of 20% set for 2020. The New Mexico RPS rules specify to some degree which technologies IOUs must use to satisfy their renewable requirements. Beginning in 2011, 20% of the annual target must come from solar, 20% from wind, and 10% from either biomass or geothermal energy. Additionally, the bill sets a standard of 10% by 2020 for rural electric cooperatives. Furthermore, the bill sets a goal for utilities to achieve at least a 5% reduction in total retail sales to New Mexico customers, adjusted for load growth, by January 1, 2020. Utility compliance with the RPS rule is to be tracked the RECs and must be registered with the Western Renewable Energy Generation Information System ("WREGIS").

Texas

The state of Texas established a Renewable Portfolio Standard ("RPS") in February of 1999 that mandates renewable energy be part of the generating capacity mix. The current RPS requires 2,280 MW of renewable capacity by 2007, 3,272 MW by 2009, and 5,880 MW by 2015. Beyond 2015, Texas has no additional mandate, but rather a goal of 10,000 MW of renewable capacity by 2025.

Mid Continent States Summary

Colorado and Missouri currently meet their RPS requirements, but the outlook in the mid-term indicates that they may need more in-state generation. New Mexico currently falls short of its RPS but significant proposals of new wind and solar generation may help the state be RPS compliant in the long term. Texas and Iowa currently meet and exceed their RPS requirements and will likely continue to do so barring any major regulatory changes. As a region, there appears to be sufficient wind and solar resources to be in full compliance with state renewable portfolio standards.

Federal RPS / RES Outlook

The comprehensive climate and energy bill, The American Clean Energy and Security Act of 2009 (ACES), passed the House of Representatives in June of this year. Contained in the 1400 page bill is a federal RES mandating that 20% of retail electric suppliers' deliveries come from qualifying renewable electricity resources by 2020. Under the proposed RES, up to 40% of a retail electric supplier's renewable targets can be met through energy efficiency measures. In the Senate, Senator Bingaman has authored a bill that would also establish a federal RES. Under Bingaman's bill, 15% of retail electric suppliers deliveries would need to come from qualifying renewable energy by 2021. The Senate is scheduled to release their comprehensive energy and climate bill by the end of September, which will likely incorporate Senator Bingaman's existing federal RES language.

From these leading bills as well as past legislative attempts to pass a Federal RES, Pace is able to glean elements that will likely be a part of the a Federal RES. Compliance obligations with a federal RES are likely to begin in 2011 or 2012 with initial national renewable energy targets to be set somewhere between 3 percent and 6 percent for the early compliance years. As with state RPS, the federal standard will ramp up over time with compliance obligations reaching between 15 percent - 20 percent in the early 2020s. In both leading bills the RES would sunset in 2039, although that sunset date could be modified or extended by a future amendment.

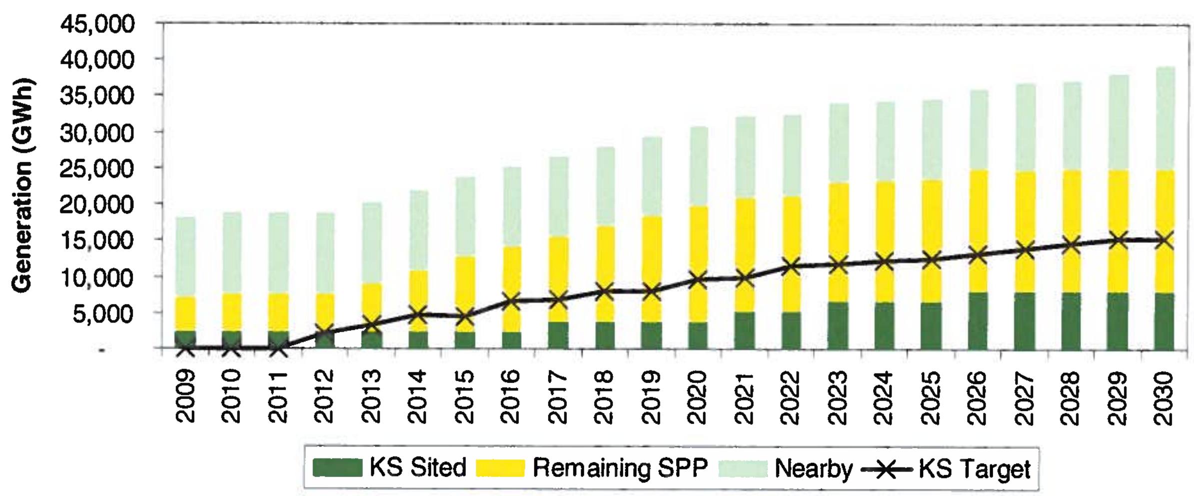
It appears that the Federal RES will allow for wind, solar, geothermal, and some biomass to qualify as renewable technologies for the renewable generation requirements. The leading bills include other technologies in their definition of "renewable," but vary in their treatment for sources such as, biogas, hydro power, and landfill gas, among others. Some electricity sources, such as municipal solid waste, the electricity generated with associated carbon capture and sequestration, and nuclear power, may not qualify as renewable, but may receive some other form of classification in which electricity generated from these technologies would be subtracted from a facilities total electricity baseline (the denominator of the renewable electricity / total electricity supplied fraction in determining a facilities renewable percentage).

In addition to renewable generation, a covered entity will be permitted to use energy savings from efficiency measures towards their compliance obligations. Energy efficiency measures will likely be permitted to account for somewhere between 25 percent - 40 percent of a covered utilities renewable requirements.

The federal RES will open up a national REC trading market that has the potential to significantly impact the existing value and integrity of the existing state programs. There are strong indications that if and when a Federal RES is passed, States will be permitted to continue to implement and administer their own renewable standards, with the federal standard acting as the floor – requiring a minimum level of renewable generation. However, many states might need to repromulgate their rules to be in line with federal legislation. The federal standard is expected to honor State compliance mechanisms (RECs/AECs, ACP payments, or renewable generation) to count towards Federal compliance, so long as the mechanisms meet the federal requirements. States would retain the right to choose to open their compliance access federally or simply keep the requirements to meet compliance requirements with local sources. Qualifying RECs may be used for compliance the year that the renewable energy was generated or may be "banked" and used in subsequent years (three years appears to be the limit for how long a REC can be "banked" under federal proposals).

Pace assumes that a Federal RES will be passed in the next few years, with passage before the end of 2009 still possible, and will be similar to the bills currently under review in Congress. It is not clear whether or how Federal and State standards will mix in the future. It is possible that states will reconsider their standards once Federal standards are promulgated. However, Pace believes that any state-level RPS with a stricter standing than the Federal will remain binding. Wind-rich regions, such as the Midwest and Mid Continent, will likely see a significant amount of growth under a Federal RPS, which could have considerable impacts on power prices and unit dispatch in these regions. Pace has reviewed the Federal RES targets to ensure enough compliant capacity is included in the long term forecast. As highlighted in Exhibit 48, Pace believes that with regional transmission capability, a federal RES target can be met within the state of Kansas.

Exhibit 48: Federal RPS Program



Source: Pace

EMISSIONS REGULATIONS

As environmental controls become ever more stringent and costly, assumptions about emission control requirements are becoming more important elements of power market forecasting. Emission control costs and emission allowance prices affect power generation fuel choice, new generation capacity decisions, and power generation variable cost. Pace includes assumptions about future SO_2, NO_X, mercury, and CO_2 emission controls and costs in the power market simulation process.

In 2005, in order to reduce the number of non-attainment areas, the U.S. Environmental Protection Agency ("EPA") issued the Clean Air Interstate Rule ("CAIR") which established additional SO_2 emission reduction requirements on top of those already required under the Clean Air Act. CAIR applied to 28 Eastern States and the District of Columbia. Electric generating units ("EGUs") in these states would be required to surrender two allowances per ton of SO_2 emitted starting in 2010 and 2.83 allowances per ton from 2015 onward, instead of the current one allowance per ton.

On July 11, 2008, however, the DC Circuit Court of Appeals struck down the Clean Air Interstate Rule, effectively eliminating the annual NO_x program and removing the increased surrender ratio requirement for SO_2 allowances. This ruling has significant implications for the value of emission allowances in the near term. Although a seasonal NO_x program still exists under the SIP Call, annual NO_x emissions in the CAIR footprint currently have no value under any federal program. And while the SO_2 caps in the Clean Air Act still hold, the elimination of CAIR has caused near term allowance prices to plummet, as the stricter, long-term caps are no longer binding.

The door is now wide open for new federal multi-pollutant regulation. Legislation is likely going to be required in order to achieve buy-in from market participants who will now be wary of EPA rulemaking in its absence. Pace expects that new legislation will resemble CAIR, due to its relatively broad-based support, but it is possible that more stringent bills will also be offered. It is possible that such legislation will be passed in the 2009 session of Congress. Senator Tom Carper has drafted language that may be included in the Senate's comprehensive energy bill. Carper's draft bill would expand the Title IV Acid Rain Program to include a Phase III for SO_2 and cover NOx nationwide. The SO_2 provision in the bill would ensure the validity of banked allowances, making each allowance worth a full ton of emissions. Under Carper's bill the overall cap would be tightened. Delays past 2009 are possible, particularly in the event that a four-pollutant bill covering SO_2, NO_x, mercury, and carbon were to be pursued. This could require a much longer period of time to gain passage.

Until a policy or rulemaking is clearly on the path to implementation, however, markets will likely flounder since more stringent compliance in the 2009-2011 timeframe is now in limbo. Pace's analysis uses forward market prices for SO_2 from *Argus* for 2008-2010 prices. Once new regulation is implemented, Pace expects that market pricing will tend towards previous expectations under CAIR. Therefore, Pace's long term price projections for SO_2 and NO_x allowances are based on the assumption of a regulatory structure similar in nature to CAIR. However, given recent regulatory developments, there is great uncertainty regarding the future of emission reductions programs and emission allowance prices.

Sulfur Dioxide (SO_2)

Pace has assumed plant-level SO_2 compliance strategy to include fuel substitution (high vs. low-sulfur coal) and wet and dry FGD retrofit options and has developed a comprehensive forecast of plant-level SO_2 emission rates; emission credit prices; and retrofit costs to those plants installing pollution control units as part of its power price forecasting process. Exhibit 49 displays Pace's SO_2 allowance price projections.

Exhibit 49: SO_2 Allowance Price Forecast (2008$/ton)

Year	SO2 ($/ton)
2009	74
2010	61
2011	289
2012	306
2013	325
2014	344
2015	256
2016	271
2017	282
2018	299
2019	318
2020	337
2021	358
2022	380
2023	403
2024	427
2025	454
2026	481
2027	511
2028	511
2029	511
2030	511

Source: Pace

Nitrogen Oxides (NO_x)

CAIR also established both a seasonal and an annual cap for emissions of NO_X. Under EPA's current regional credit trading program, the NO_X State Implementation Plan ("SIP") Call, power plant operators must surrender one credit for each ton of NO_X emitted during the ozone season (May through September). By 2009, CAIR would have expanded the geographic scope of the ozone season program and added an annual program. It mandated that generators surrender one NO_X *ozone* credit for each ton of NO_X emitted during the ozone season and a separate *particulate* credit for each ton of NO_X emitted during the course of a year. Given this, Pace projects NO_X emission credit prices for the seasonal and annual programs. Plant-level emissions and allowance credit prices are forecast simultaneously. Pace's modeling takes into account current plant retrofit configurations and allows gas and coal units to retrofit with SCR or SNCR technology. Pollution control retrofit decisions and their corresponding marginal costs are forecasted simultaneously, taking into account any co-benefits for mercury compliance. Exhibit 50 presents Pace's allowance price forecast.

Exhibit 50: NO_x Allowance Price Forecast (2008$/ton)

Year	NO_xCAIR Seas ($/ton)	NO_x Ann ($/ton)
2009	1,200	-
2010	1,025	45
2011	3,408	49
2012	3,431	54
2013	3,431	59
2014	3,474	64
2015	3,683	68
2016	3,832	71
2017	4,065	76
2018	4,311	80
2019	4,405	80
2020	4,503	84
2021	4,603	89
2022	4,705	94
2023	4,810	100
2024	4,916	106
2025	5,025	112
2026	5,136	119
2027	5,250	127
2028	5,250	127
2029	5,250	127
2030	5,250	127

Source: Pace

Mercury

In 2005, EPA issued the Clean Air Mercury Rule ("CAMR"), a national program that established a cap-and-trade program for coal-fired power plants set to begin in 2010. In February, 2008, the DC Circuit Court of Appeals vacated the cap-and-trade CAMR program, stating that the agency was wrong in failing to implement the strictest possible emissions limitations for each power plant. This ruling may delay certain pollution control plans in the near term, as coal-fired generators wait for regulatory clarity. However, a maximum achievable control technology ("MACT") rule is expected to be promulgated in the future, requiring large numbers of coal-fired generators to install pollution control retrofits.

Under a MACT standard, every generator will be required to meet an emission limit. Unlike a cap-and-trade system, a MACT standard would not allow generators to opt out of control and purchase allowances to meet their obligations. Instead, generators will be forced to incur additional capital costs of retrofitting. Although the operating cost of generators may increase after installing controls, the lack of an allowance market prevents the manifestation of any mercury emission compliance costs on a variable basis. Therefore, Pace assumes that mercury compliance costs will not directly affect plant dispatch or wholesale power prices.[4]

The magnitude of the retrofit capital costs and potential impacts to operating costs will hinge on the level at which the MACT requirement is set. MACT rules will force many plants that might not have retrofitted to install controls. For some plant configurations, plausible compliance options may include the installation of FGD and SCR controls, technologies that also remove significant quantities of SO_2 and NO_x, respectively, from flue gas streams.

Pace expects a moderate MACT emission standard on the order of 0.6 lb Hg/TBtu to be implemented. Variations in the stringency of the standard may result in a higher number of FGD and SCR retrofits than previously expected under the CAMR rules. If such a scenario unfolds, emissions of SO_2 and NO_x may be lower than anticipated, affecting the value of emission allowances in the long term. A very stringent MACT standard emission requirement will likely force more installations of activated carbon injection ("ACI") that could result in fewer emission removal co-benefits.

Although mercury emissions are not treated as a variable cost, Pace models the decision to install ACI and bag house mercury control options, and captures the operating costs associated with the use of such technologies. Pace also takes into account the mercury emission reduction co-benefits realized by the installation of an SCR and a wet scrubber on a coal-fired power plant.

Carbon Dioxide (CO2)

To date, the U.S. has declined to implement regulated carbon constraints either at the national level or through binding international climate change agreements such as the Kyoto Protocol. Carbon regulatory bills have been proposed sporadically in Congress since the mid 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 constituencies both domestically and internationally.

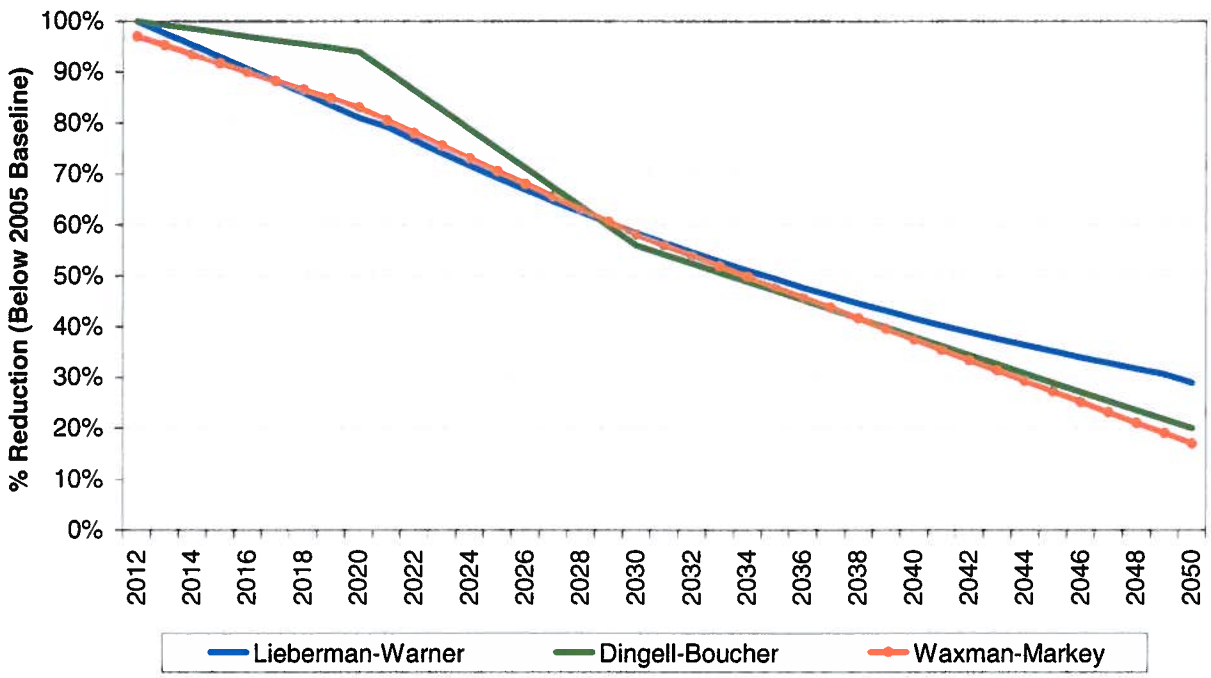
At this time, federal carbon regulation in the U.S. appears imminent. Pace expects the passage of federal carbon legislation sometime between the fourth quarter 2009 and first quarter of 2011, with compliance requirements likely to become effective in 2012 or 2013. Prominent policy mechanisms and how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

- **Carbon reduction targets** – Pace anticipates that U.S. carbon legislation will require significant carbon reduction caps over a long-term reduction timeframe. The latest Intergovernmental Panel on Climate Change ("IPCC") report states that this level would entail reducing greenhouse gas emissions 50 to 85 percent below 1990 emission levels by 2050. Exhibit 51 illustrates how three recent climate change bills have differed in how the overall cap declines over the course of regulation. The Waxman-Markey bill, the

[4] Note that Pace assumes that new market entrants will have the emission controls required to meet MACT standards. The costs associated with such controls are embedded in our capital cost assumptions.

current leading bill, has the most aggressive cap decline both in the early and late years of the cap.

Exhibit 51: Emission Reduction Trajectory under Prominent U.S. Climate Bills



Source: Referenced Legislation and Pace

- **Cap & trade** – Pace anticipates that any passed legislation will impart carbon reductions via a market-based cap & trade scheme. Virtually all U.S. carbon bills introduced to date call for a cap & trade system as opposed to a straight carbon tax.
- **Supply flexibility mechanisms** – Pace anticipates that the U.S. carbon legislation will include a number of different options for procuring supply of compliance instruments. These compliance 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 carbon trading schemes. Most importantly, Pace expects a healthy offset market with 20 percent - 50 percent of covered entities' compliance positions allowed to be covered with offsets supplied from reductions made from emission sources outside of the legislated cap.
- **Allowance price controls** – Pace expects the carbon market design to include provisions intended to mitigate against market price spikes. These market protections 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.

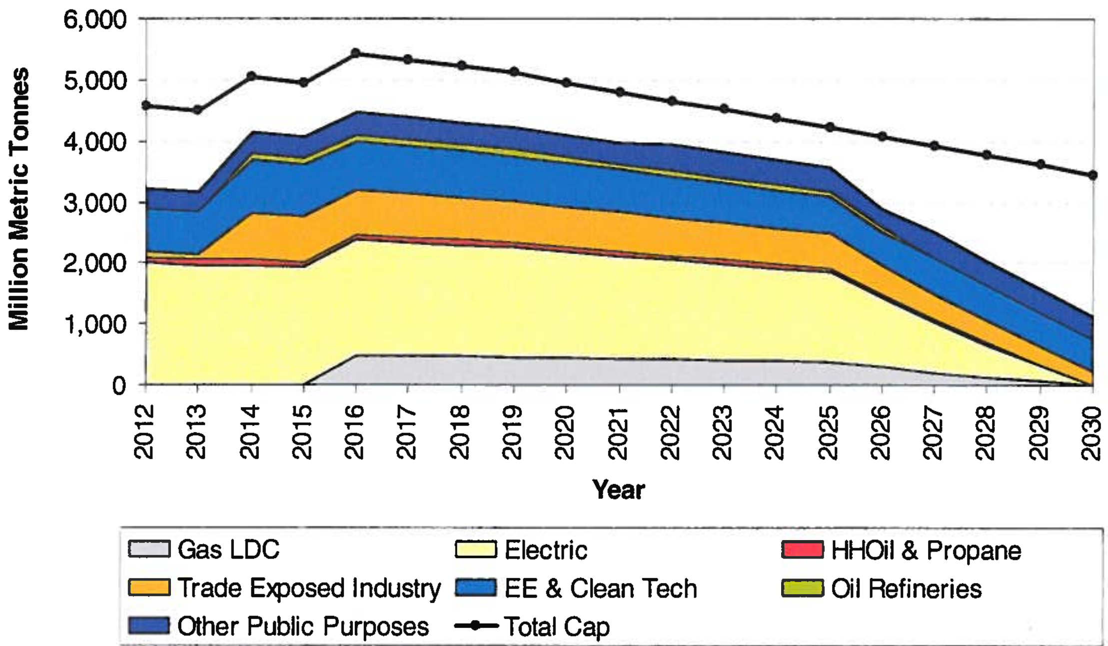
Waxman-Markey's American Clean Energy and Security Act of 2009

Pace does not base its assumptions or price models on any one piece of carbon legislation. Rather, the price inputs used and assumptions made are based on years of detailed tracking of all climate change bills while taking into account our expertise in environmental markets to arrive at what we believe to be fair and accurate forecast. That said, the leading federal climate bill to date is Rep. Waxman (D, CA) and Rep. Markey (D, MA) 'American Clean Energy and Security Act of 2009,' ("ACES") which passed the House June 26, 2009, marking it the first comprehensive climate bill to pass either house of Congress. The economy-wide carbon cap & trade bill calls for a reduction of GHG emissions 83 percent below 2005 levels by 2050, provides free allowance allocations to retail electric providers, and includes provisions for emissions allowance price controls. Pace believes that the emission reduction targets under the Waxman-Markey bill are relatively stringent compared to other proposed bills and that reduction requirements ultimately passed may be moderated somewhat (see Exhibit 51).

Electricity providers, enumerated industrial processes, and industrial processes that exceed a 25,000 mt $CO_{2(e)}$ threshold are covered "downstream" at the point of emission. Refiners and other fossil-fuel based liquid fuel producers and importers are regulated "upstream" along with producers and importers of GHGs. Natural gas Local Distribution Companies (LDCs) are regulated at the facility level and are responsible for the emissions from the combustion of their delivered natural gas.

Regulated entities will be required to submit allowances for each tonne of $CO_{2(e)}$ that they emitted the previous calendar year. The bill allocates approximately 85 percent of the total allowances to various sectors in the early years of the cap. The percentage of freely allocated allowances distributed each year remains fairly constant in the first 10 to 12 years of regulation, reducing at the same rate as the overall declining cap. Beginning in 2025, the allocations decline more rapidly, reaching zero for most sectors by 2030 (see exhibit 6). As fewer free allocations are distributed, entities will increasingly need to seek other methods for meeting their compliance position (i.e. buying allowances from auction, procuring from the market, investing in or procuring offset credits, or reducing emissions).

Exhibit 52: Free Allowance Allocation Summary under ACES



Source: Waxman-Markey ACES and Pace

The power/electricity sector receives 43.75 percent of the allowance pool in the initial years and 35 percent of the total allowances beginning in 2016 when natural gas LDCs are first regulated (resulting in a spike of the total number of allowances in the cap) . The electricity sector splits their allocated allowances amongst LSEs, merchant coal generators, and generators operating under long term power contracts – with the majority (about 85 percent of the allocations to the electricity sector) going to LSEs. LSEs are directed to use the value of these allowances "for the benefit of the retail ratepayer" however some ambiguity exists as to what constitutes a "benefit". The ultimate determination will likely be left to the state PUCs. As with most other sectors regulated under the cap, the power/electricity sector will stop receiving allowance allocations beginning in 2030.

An emission allowance may be "banked" and used in any subsequent year under the cap. Allowances can be "borrowed" one year forward at no interest (i.e. an allowance with a 2015 vintage number can be used toward 2014 compliance). Up to 15 percent of an entity's compliance obligation can be borrowed for emissions allowances for compliance years up to 5 years in the future, at 8 percent interest.

Along with using free allocations and purchasing allowances at an auction or through the market, covered entities can also procure offset credits to meet their compliance position. Offsets are compliance mechanisms, created through government approved projects that reduce GHG levels. Under this bill for each tonne of $CO_{2(e)}$ removed from the atmosphere through an offset project, the owner of the project would receive 1 offset credit that can be used to meet a covered entities compliance position. The types of offset projects that will be eligible to receive compliance credits is still largely unknown as the ultimate determination of project eligibility will be made by the EPA (or other like governmental agency) after a rulemaking procedure. Pace anticipates at this time that at a minimum offset project categories to be included in federal carbon legislation are likely to include including forestry (reforestation) and methane destruction projects

New Coal-Fired Power Plant Performance Standards

ACES amends the Clean Air Act ("CAA") by adding CO_2 reduction performance standards for new coal-fired generating units. The performance standards only apply to units that are "initially permitted" on or after January 1, 2009. Units that have been initially permitted prior to January 1, 2009 would be exempt from the performance standards under ACES. A unit is "initially permitted" (as opposed to "finally permitted") when an owner or operator of the unit has received a CAA preconstruction approval or permit, but there still exists the possibility for administrative review and/or appeal of such approval.

For covered generating units that are initially permitted between 2009 and 2020, a 50% reduction of CO_2 emitted by that unit must be achieved. The deadline for achieving a 50% reduction in CO_2 emissions is dependent on when the EPA makes a determination that Carbon Capture and Sequestration ("CCS") is commercially viable. The EPA will publish a finding of commercial viability once the following milestones have been achieved across the entire electricity generating sector:

1. There is a cumulative generating capacity of at least 4GW equipped with CCS technology;
2. There exists at least 2 electricity generating units which have a nameplate generating capacity of 250 MWs or greater, that successfully capture and sequester carbon into geological formations other than oil and gas fields; ***and***
3. There are units cumulatively capturing and sequestering in aggregate at least 12 million tons of CO_2 per year

The deadline for achieving a 50% reduction in CO_2 emissions (for units initially permitted between 2009 and 2020) will be the earlier of the following events:

1. 4 years from the date that EPA makes a finding of CCS's commercial viability (see above definition), or
2. January 1, 2025

Units that are initially permitted after January 1, 2020, will be required to achieve a 65% reduction in CO_2 emissions from that unit upon commencement of operations, regardless of EPA making a commercial viability finding.

If the EPA makes a determination at some point that the degree of emission reduction achievable, through the application of the best available technology, is lower than the requirements of this section, they may reduce the required emission reduction rate for new units. The Senate is debating the CCS portions in their bill, with many arguing for delayed CCS requirements for fear that CCS will not be commercially viable in the time frame established under the House bill. It is likely that the final CCS provisions of the Senate bill will be different than the current House provisions.

Carbon Compliance Cost Price Projections

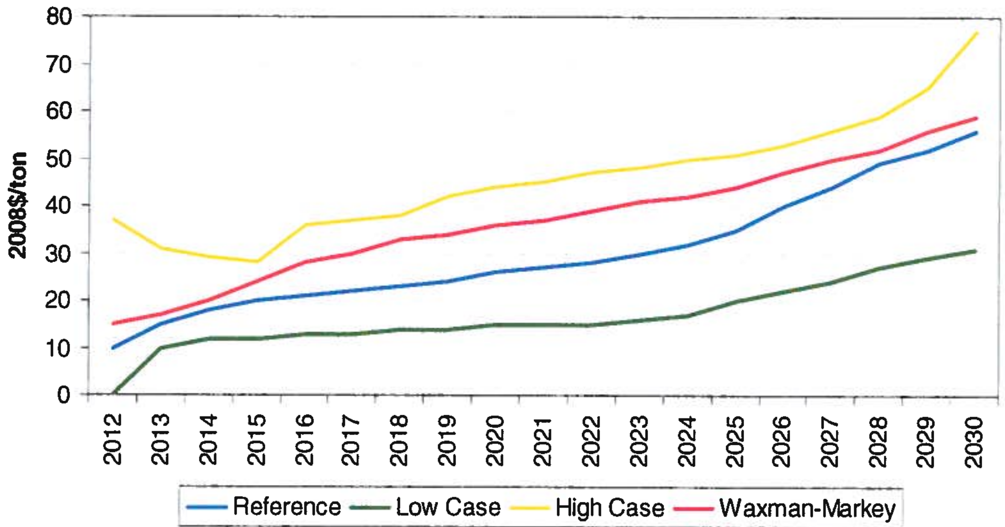
Pace's range of expected carbon pricing represents costs mitigated through price control measures and/or other market forces to prevent major near-term shifts in the power generation supply. All forecasts are supported by representative pricing demonstrated in other active regulated and voluntary carbon market pricing. Pace develops a range of cases (summarized in Exhibit 53 and Exhibit 54), based on the general drivers described below. For this analysis, the Mid Case has been used.

Low Case – This case represents low to moderate carbon caps with an initial compliance period starting around 2013. It assumes long term reduction targets to be less than 75 percent, significant direct allocations, and offset provisions allowing for 30 percent or more of the supply side of the market to be covered by offset project reductions.

Mid Case – This 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. Legislation under the Mid case is assumed to include provisions for 20-40 percent use of offsets, emission reduction requirements of approximately 75 to 80 percent by 2050, and moderate level of free allowance coverage to significantly impacted entities in the power and industrial sectors.

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 potential market reactions to compliance risk 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. In addition to speculative market price drivers, characteristics of legislation driving the High case include stringent ultimate reduction targets of 80 percent or greater by 2050, constrained use of offsets for compliance and limited free allowance allocations to covered entities.

Exhibit 53: National Carbon Market Pricing Projections



Source: Pace

Exhibit 54: CO_2 Compliance Costs (Nominal$/tone of CO_2)

Year	Reference	Low Case	High Case	Markey-Waxman
2012	10	0	37	15
2013	15	10	31	17
2014	18	12	29	20
2015	20	12	28	24
2016	21	13	36	28
2017	22	13	37	30
2018	23	14	38	33
2019	24	14	42	34
2020	26	15	44	36
2021	27	15	45	37
2022	28	15	47	39
2023	30	16	48	41
2024	32	17	50	42
2025	35	20	51	44
2026	40	22	53	47
2027	44	24	56	50
2028	49	27	59	52
2029	52	29	65	56
2030	56	31	77	59

Source: Pace

CAPITAL COST ASSESSMENT

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 55. 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 MWE.

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.

Exhibit 55: New Resource Technology Parameters (2008$)

Unit	Early Capital Cost	Mid Capital Cost	Late Capital Cost	FOM	VOM
	$/kW	*$/kW*	*$/kW*	*$/kW-yr*	*$/MWh*
CC (FA)	832	823	814	2.97	7.36
CC (FB)	810	801	792	2.97	11.22
GMEC Expansion	755	722	714	4.00	13.20
New Peaker (Wartsila)	795	760	751	4.00	13.20
IGCC	2,556	2,789	3,036	3.89	36.30
IGCC Seq	3,352	3,657	3,982	5.63	45.59
Nuclear	5,514	5,899	4,554	2.70	74.53
Biomass AD	6,654	6,748	6,841	15.58	50.64
Biomass Combustion	2,891	2,855	2,820	3.12	131.67
LFG	2,833	2,797	2,763	5.20	45.97
Wind	2,103	2,080	2,052	0.00	20.45
Solar PV - Si	5,096	3,625	2,594	0.00	5.99

Source: Pace

Resource Availability Assumptions

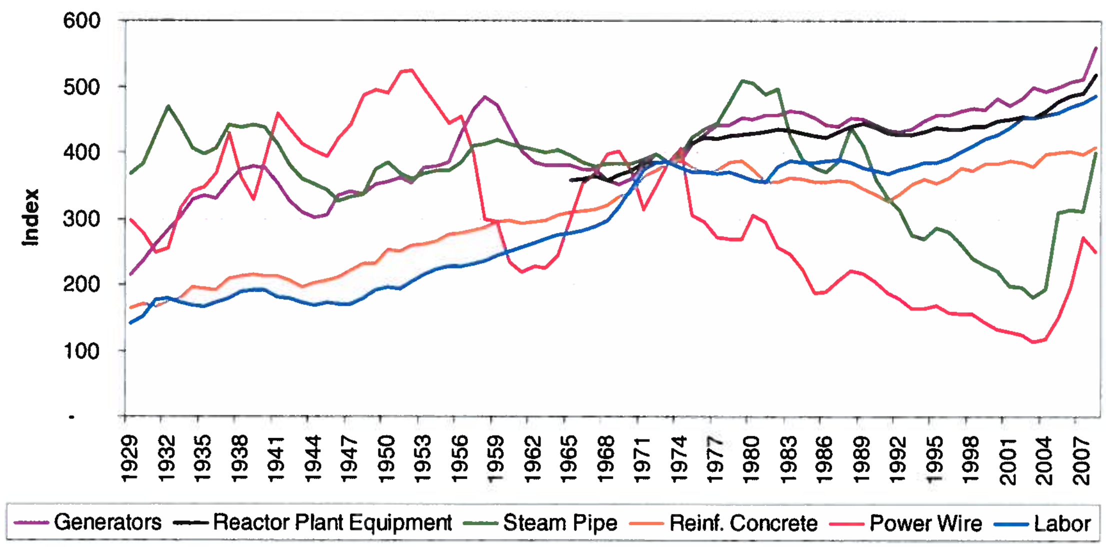
New resource additions were assumed to be available in accordance with historical maintenance, forced outage, and availability data. Intermittent resources were modeled in accordance with hourly capacity factor shapes, consistent with local availability profiles. Wind units were assumed to have a capacity factor of 37% and solar PV units a capacity factor of 22%.

CONSTRUCTION COST UNCERTAINTY AND RISK

Uncertainty in the projected cost of adding capacity to the power supply system can introduce significant risk to a forecasting or planning process. This uncertainty can be broken down into two factors:

- First, the various cost components will change over time, sometimes dramatically. The real value of the Handy-Whitman Index, the standard for utility construction costs, for 5 major cost categories (generators, reactor plant equipment, steam pipe, reinforced concrete, wire and labor) between 1929 and the present is shown in Exhibit 56.
- Second, although we expect that technology improvement will reduce the cost of power plant construction (given the cost of the various components) the cost trend and the timing of technology improvement is uncertain.

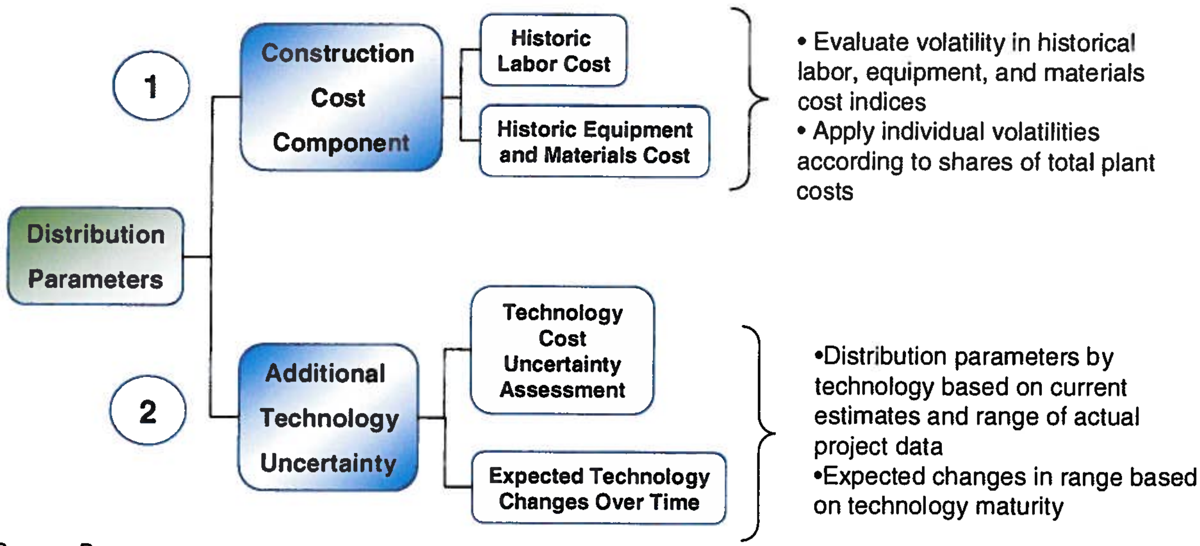
Exhibit 56: Historical Volatility-Power Plant Construction Cost Components



Source: Pace

An overview of the modeling approach for simulating construction costs is shown in Exhibit 57. Power plant construction cost is modeled as two components. The first reflects simulated values of labor, material, and equipment cost indices. The second reflects simulated improvement in the efficiency with which labor, materials, and equipment are used to build power plants. These two components are described in detail below.

Exhibit 57: Construction Cost Risk Modeling Overview



Source: Pace

Step 1: Construction Cost Component

A total construction cost index for each generation technology is computed as the weighed average of cost indices for labor materials and equipment.

[redacted]

[redacted]

Exhibit 58: Weighting Factors Construction Cost Elements by Generation Technology

	Weighting Factors			
Technology	**Equipment**	**Materials**	**Labor**	**Other**
CC	60%	6%	16%	18%
CT	60%	6%	17%	17%
Coal	49%	5%	28%	18%
IGCC	54%	5%	18%	23%
IGCC (W-Seg)	52%	5%	19%	24%
Nuclear	31%	16%	32%	21%
Biomass	38%	16%	14%	32%
Landfill	39%	15%	27%	19%
Wind	75%	7%	5%	13%
Small Solar	41%	26%	10%	23%
Large Solar	61%	11%	11%	17%
Geo	19%	19%	44%	18%

Source: Pace

The labor, material, equipment, and other cost indices are simulated using an approach in which real cost indices change in a random fashion

[redacted]

Where:

[redacted]

The simulated indices for materials, equipment, and other costs are constructed in a similar manner.

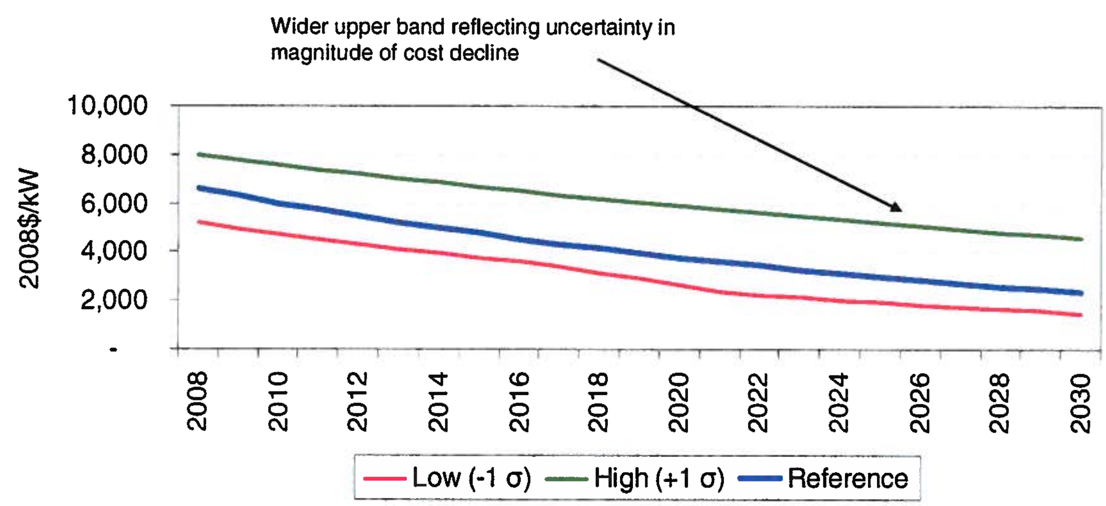
Step 2: Additional Technology Uncertainty

The second step in Pace's capital cost stochastic methodology was developed to capture the additional technology uncertainty associated with different types of plants. Mature technologies will experience little efficiency and cost improvements over time compared to newer technologies like solar PV, wind, and the new generation of nuclear plants. Pace estimated the parameters used to derive the additional technology uncertainty based on two components:

- The current range of geographically-normalized construction cost estimates for different technology types
- The expected changes in range based on technology maturity

Exhibit 59 illustrates this approach with an example of the technology uncertainty bands around the cost of solar PV. As illustrated, Pace's Reference Case assumptions for the cost of solar PV incorporate a significant decline over the next twenty years. Although this is consistent with the current trend, Pace recognizes that there is uncertainty around the timing and magnitude of any cost declines. As shown, Pace's stochastic bands for the cost of solar PV incorporate wide and skewed bands around the Reference Case projections.

Exhibit 59: Capital Cost Simulations-Solar Photovoltaic



Source: Pace

Based on these parameters, construction cost technology improvement is modeled as a percentage reduction relative to the previous year based on a random factor that changes from year to year. In a simulation,

[redacted]

Where

[redacted]

The mean and standard deviation of the technology improvement for each technology are shown in Exhibit 60.

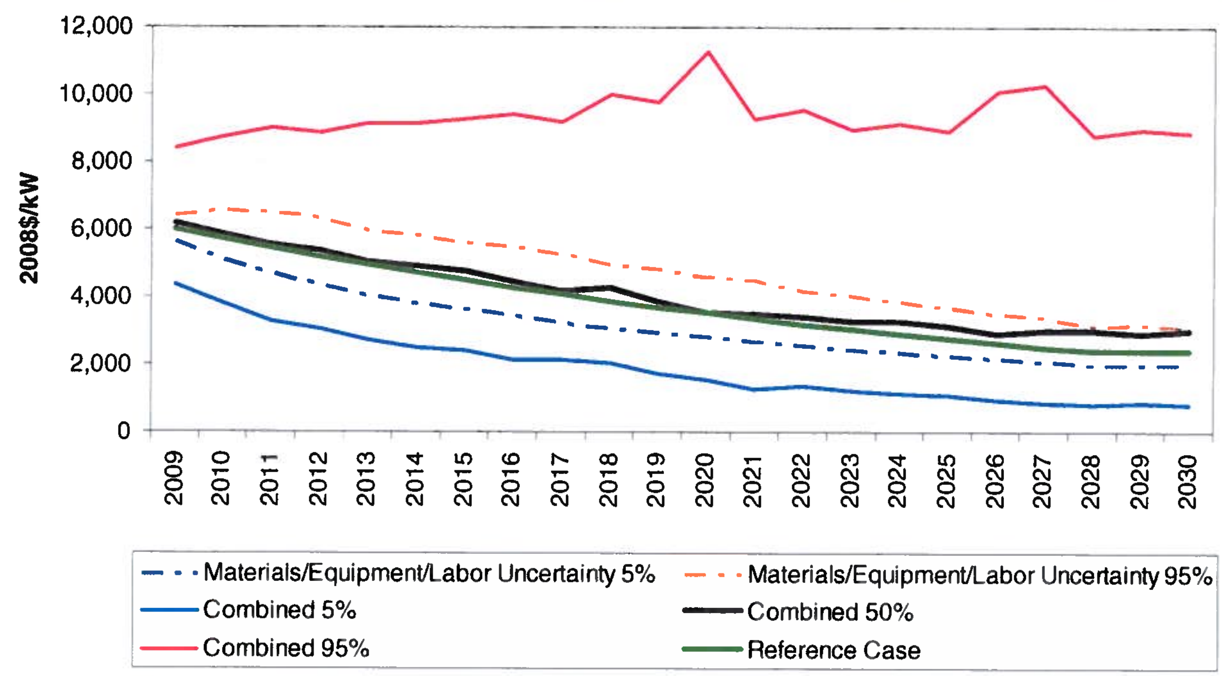
Exhibit 60: Mean and SD of Technology Improvement Factor by Technology

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Source: Pace

The results of Step 1 and Step 2 of the capital cost stochastic methodology are illustrated in Exhibit 61 for solar PV.

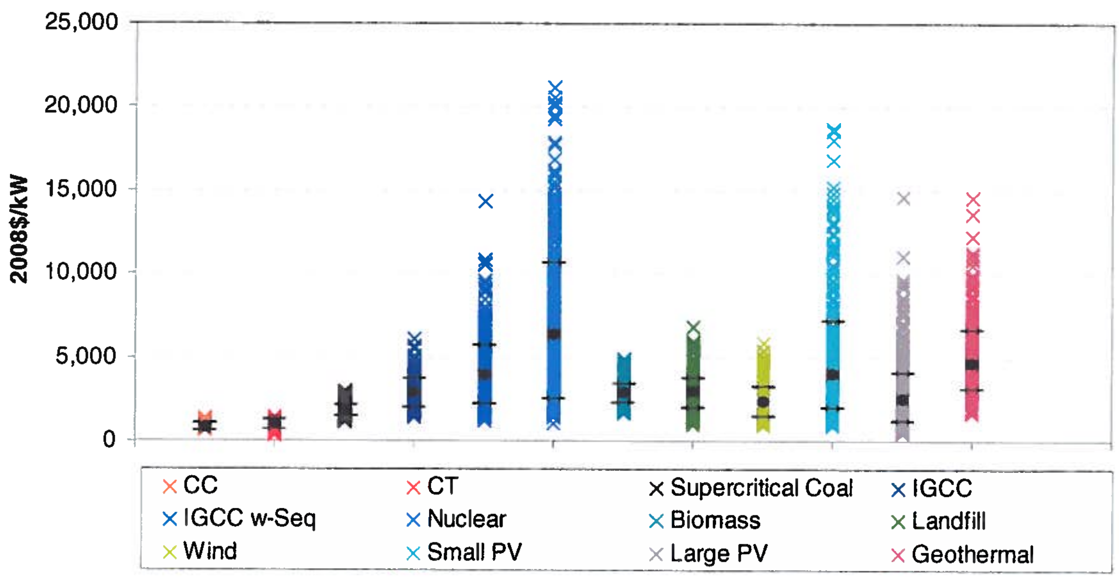
Exhibit 61: Capital Cost Simulations-Solar Photovoltaic



Source: Pace

The final result of this process is illustrated for all technologies in Exhibit 62 below. It shows the distribution of capital costs (in $/kW) in 2020 for each generation technology.

Exhibit 62: Distribution of Simulated Capital Costs-2020

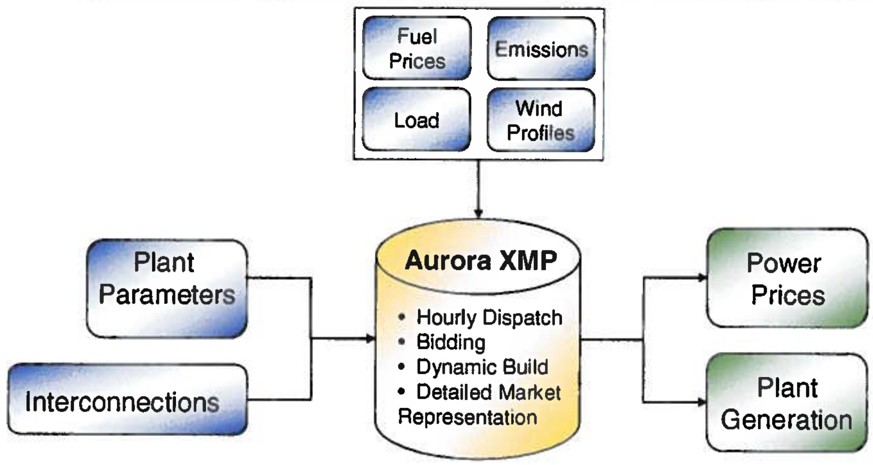


Source: Pace

REFERENCE CASE ENERGY PRICES

Pace's analysis of fuel and environmental markets, capital costs, power demand growth trends, transmission expansion, plant economics, and regulatory environment are integrated into a chronological dispatch model used to simulate the relationship between these drivers and regional power prices. Exhibit 63 provides an overview of the simulation process, inputs, and outputs. This process is employed for all Reference Case and stochastic simulations used in Pace's analysis.

Exhibit 63: Pace's Power Price Simulation Methodology

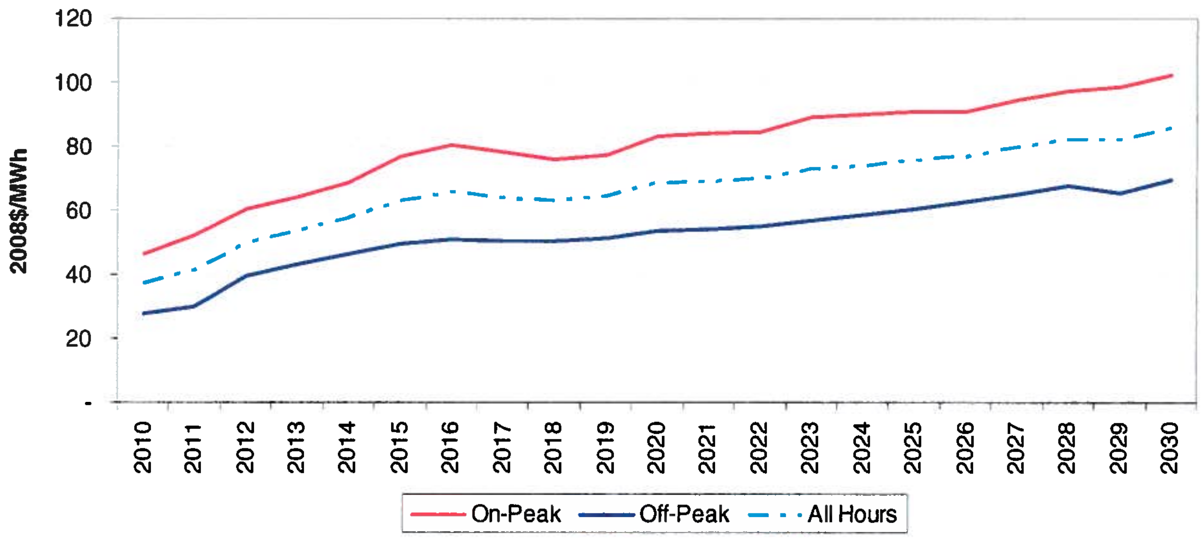


Source: Pace

Based on the Reference Case assumptions outlined in this document, Pace expects power prices to continue to steadily rise through 2030, as shown in Exhibit 64. On Peak prices ($2008) are expected to be around $46/MWh in 2010 and rise to $102/MWh by 2030, in line with expected increased gas prices and emission compliance costs. Off Peak prices ($2008) are expected to be $28/MWh in the near term and the rise to $69/Mwh by 2030.

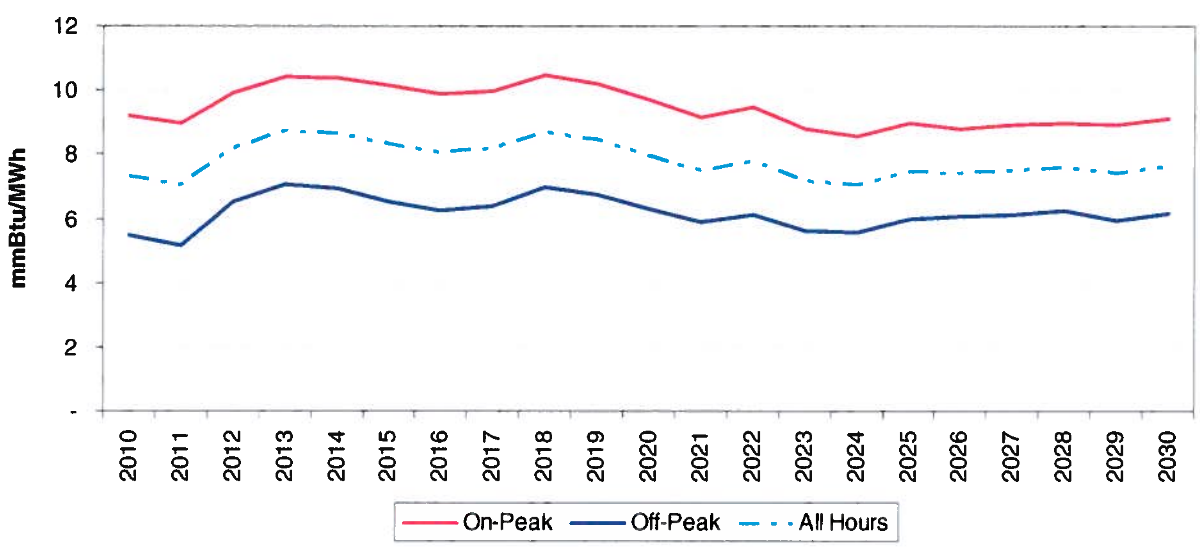
The annual system heat rate for SPP North is expected to decline through 2030 in line with increased renewable builds, as highlighted in Exhibit 65. The On Peak system heat rate is expected to be above 10 MMBtu/MWh throughout the next ten years, and then fall close to 9 MMBtu/MWh by 2030.

Exhibit 64: Annual Power Prices – SPP North



Source: Pace

Exhibit 65: Annual System Heat Rate – SPP North

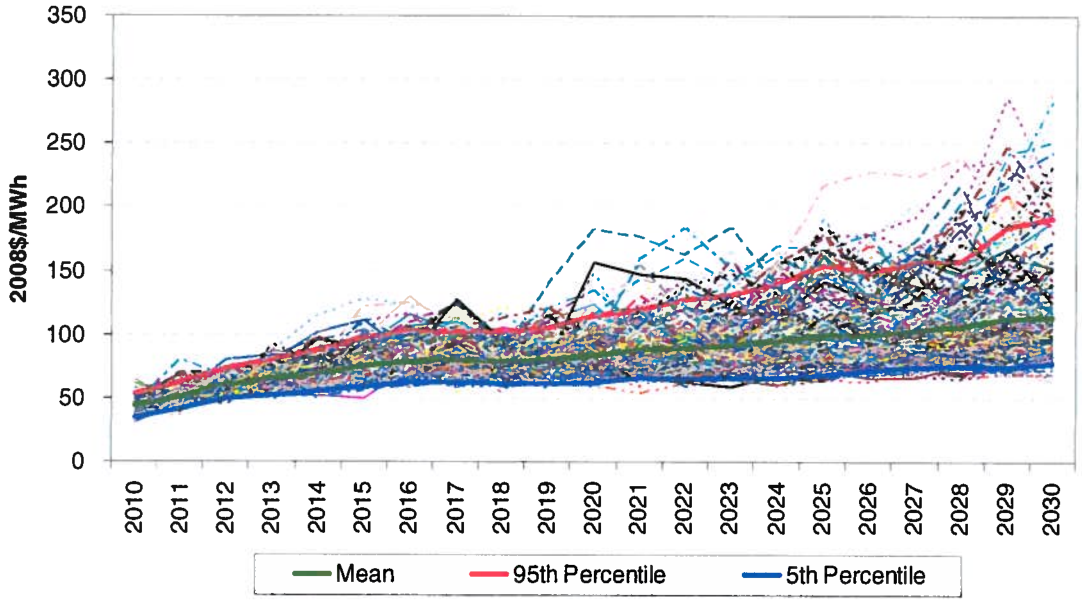


Source: Pace

As outlined throughout the document, the simulation of uncertainty around the main drivers of power prices and portfolio costs are at the core of Pace's analysis. The stochastic bands developed for load, fuel prices, and capital costs result in a corresponding distribution of power prices used, where appropriate, in the evaluation of portfolio costs. Exhibit 66 and Exhibit 67 illustrate the range of On Peak and Off Peak power prices for SPP-North simulated in Pace's Analysis.

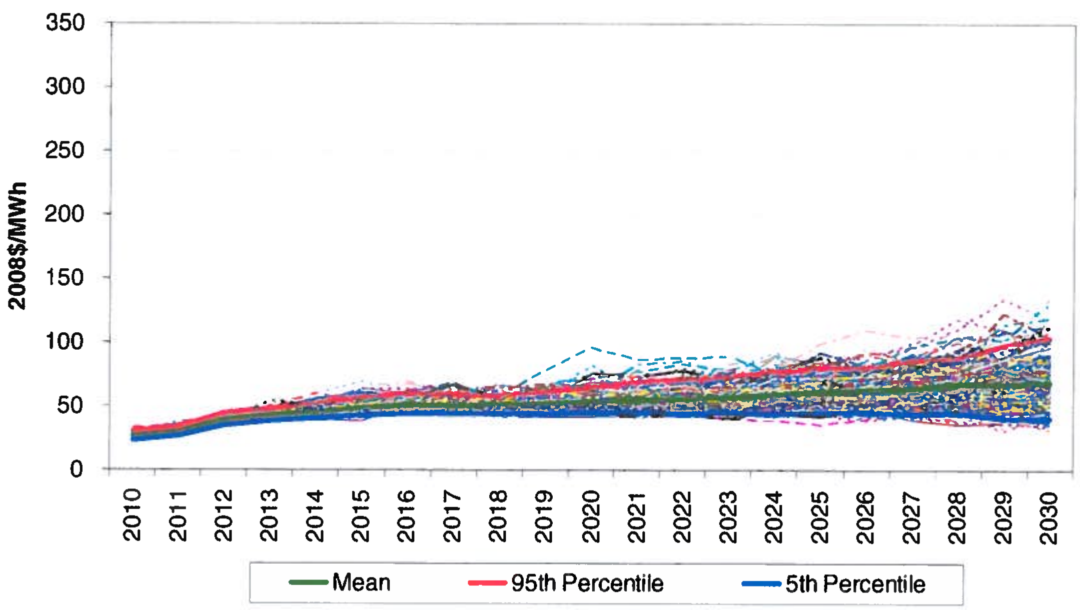
PACE

Exhibit 66: Distribution of On Peak Power Prices – SPP North



Source: Pace

Exhibit 67: Distribution of Off Peak Power Prices – SPP North



Source: Pace

MWE'S CONTRACT ASSESSMENT

EXISTING CONTRACTS

MWE currently has four PPAs with Westar Energy. The four PPAs with Westar are due to expire in 2010 and 2013. Any new contract negotiated with a supplier will supersede the existing contracts. In order to meet renewable portfolio standards, MWE entered into a contract for wind from Smoky Hills in 2008 for 50 MW. A summary of the existing contracts is shown in Exhibit 68.

Exhibit 68: MWE's Existing Contracts

Contract Name	Type	Capacity (MW)	Expiration	[redacted]	[redacted]
WPPA	Peaking	30	5/31/2013	[redacted]	[redacted]
PPA	Peaking	60	5/31/2013	[redacted]	[redacted]
WP	Baseload	40	5/31/2013	[redacted]	[redacted]
P	Baseload	125	5/31/2010	[redacted]	[redacted]
Smoky Hills	Wind	50	1/31/2028	[redacted]	[redacted]

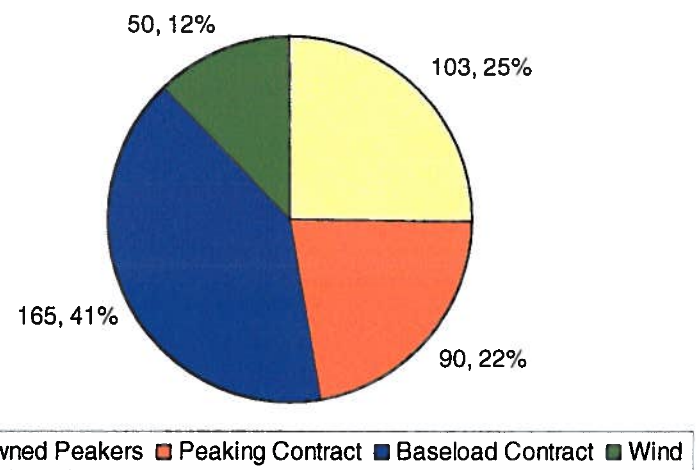
Source: MWE and Pace

Although MWE's owned capacity is all natural gas-fired, it relies on coal-fired power generation under its existing PPAs with Westar. This makes up over 45 percent of its capacity needs. Its peaking contracts represent about 25 percent of its capacity needs.

MWE's contracts with Westar are all tied to specific plants or groups of units. The WPPA is linked to Westar's Murray Gill and Gordon Evans plants. The PPA includes these and the LaCygne and Jeffrey coal generating stations. The baseload contracts are composed primarily of Westar's Jeffrey Plant, but Tecumseh and Lawrence are also tied to the contract and are backed up with steam turbines and combustion turbines. Any new contract for baseload capacity negotiated between MWE and a supplier is expected to be similar in nature to the current contracts. A summary of the integrated portfolio, including contracts, is shown in Exhibit 69.

Exhibit 69: MWE Portfolio Summary by Capacity

Plant Name	Type	Primary Fuel	Start	End	Capacity (MW)
Great Bend	IC	Gas	1950		10
Bird City	IC	Gas	1965		4
Colby	GT	Gas	1970		13
Goodman Energy Center	IC	Gas	2008		76
WPPA	Peaking Contract	Gas		5/31/2013	30
PPA	Peaking Contract	Gas		5/31/2013	60
WP	Baseload Contract	Coal		5/31/2013	40
P	Baseload Contract	Coal		5/31/2010	125
Smoky Hill	Wind Contract	Wind		1/1/2028	50



Source: MWE and Pace

As MWE's contracts expire, one of the key questions facing MWE is whether to extend or replace these contracts, and if so, for how long and in what proportion. Many factors affect the evaluation of the future mix:

- Baseload contracts may require a high load factor: By imposing a high load factor requirement, the supplying party could force MWE to take energy even when not required to meet load. Since load and market prices are uncertain, this can result in having to pay for power that MWE cannot use.
- Restrictions on reselling power under the contracts: Supplying parties could also prohibit the resale of excess power from the negotiated contracts. In combination with a high load factor requirement, this can constitute a significant risk to MWE when load is low.
- Carbon legislation can impact the economic viability of baseload coal relative to other options over time.

- Renewable technology development will have an impact on the proper mix. Solar technology is expected to become more economic over time. As market prices increase, wind generation economics will also improve.
- Additional owned peaking capacity may provide value as a hedge against market conditions and some types of contracts.

Current negotiations with suppliers would substitute peaking contracts with a "Units Most Likely" contract ("UML"). Instead of linking the energy charge to a single unit or a group of units, the UML contract charges MWE the cost of the incremental unit used to meet MWE's load after the third party's load and other obligations have been served.

The UML contract currently under negotiation is based upon the dispatch of the third party's generating capacity. The energy component of the contract is determined by the variable cost of the marginal unit that serves MWE. The capacity component is determined by the third party's estimate of the units that will most likely be dispatched to serve MWE's load.

NEW CONTRACT COST ASSUMPTIONS AND SIMULATIONS

The first step of the IRP process for MWE consisted of the evaluation of the optimal mix between two different types of contracts:

1. A unit-contingent coal baseload contract
2. A "Units Most Likely" ("UML") contract, priced based on the marginal cost of the unit used to meet MWE's load

The optimal mix between these two types of contracts depends not only on the hourly load profile and capacity requirements for MWE, but also on the energy and cost profile of the two different contract options. This section summarizes the main assumptions surrounding the energy and capacity cost components of these contract types.

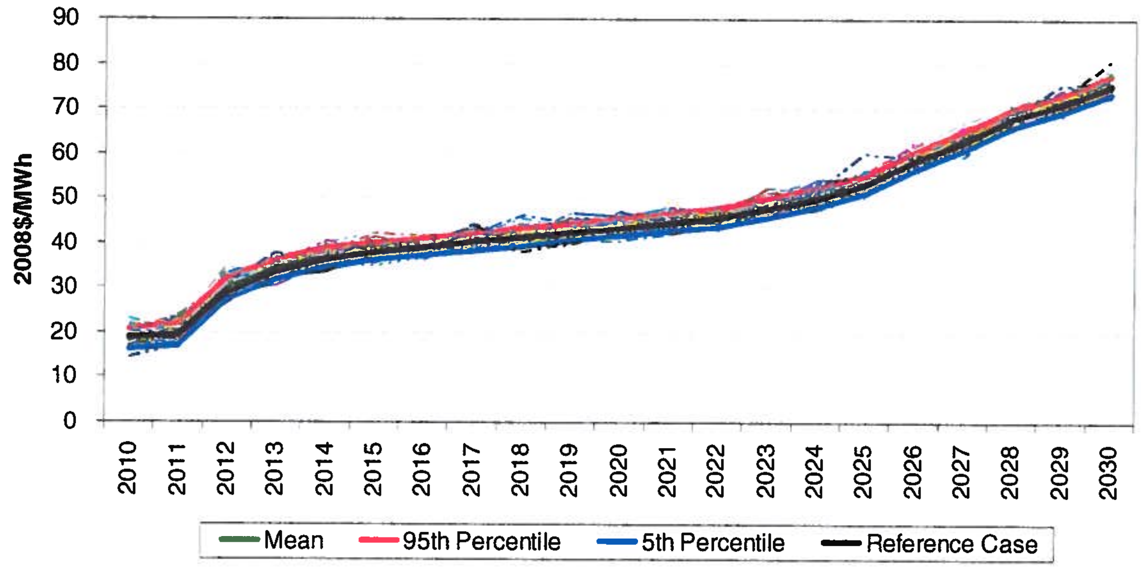
Unit-contingent Baseload Contract

Energy Cost Component

The variable cost component of this type of contract is based on the fuel and variable operating costs of a group of coal-fired baseload unit's in the preferred supplier's portfolio. Pace simulated the energy cost component of this contract based on the capacity-weighted average variable costs of the existing coal-fired units in the counterparty's portfolio. Consistent with the existing commodity contracts for the supplier's coal plants, Pace used the PRB basin forecast outlined in the Fuel Market Assessment section to estimate the fuel cost component of the contract.

Exhibit 70 illustrates the total variable costs simulated for the baseload contract. The uncertainty around the Reference Case forecast reflects the stochastic bands around the delivered coal prices associated with this contract. Pace's Reference Case carbon price is included in all variable cost projections for fossil-fueled capacity.

Exhibit 70: **Baseload Contract Energy Cost Component**



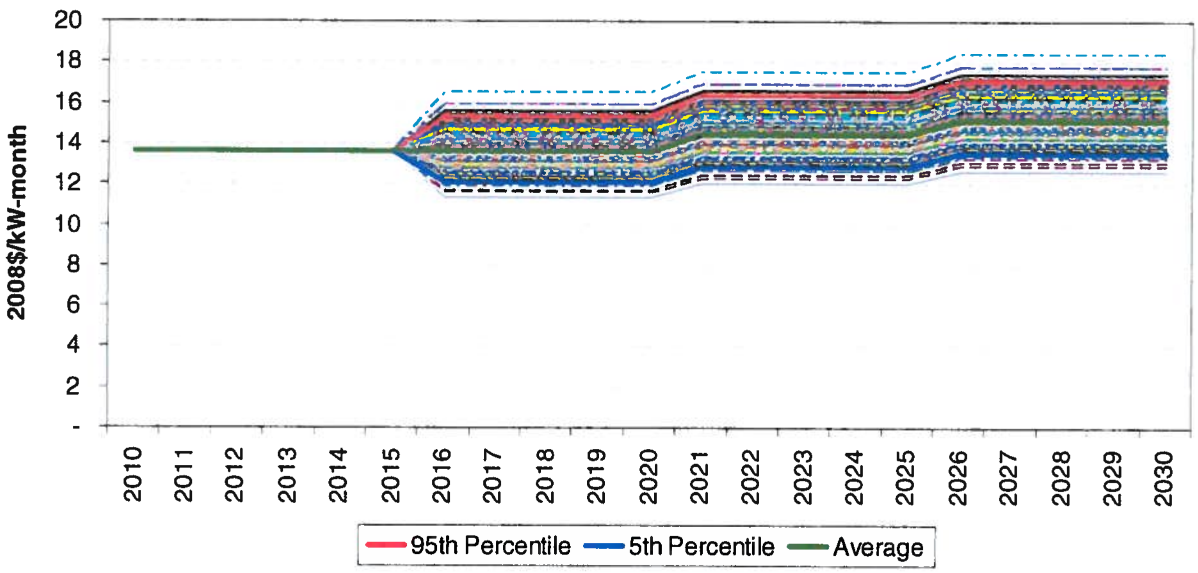
Source: Pace

Capacity Cost Component

Exhibit 71 illustrates the assumed capacity cost component of the baseload contract. Based on MWE's initial discussions with the preferred supplier, the capacity cost component would be set to $13.58/kW-month for the first year of the contract. Going forward, the capacity cost for the contract would be adjusted based on changes in the fixed costs and ongoing capital expenditures associated with maintaining the units specified in the contract.

Because a formal regulatory process is required to adjust the capacity cost component of the contract, Pace assumed that adjustments will only be made about every five years. At this point, the cost would be escalated to reflect approximately a 1% annual escalation rate. Pace also developed stochastics bands around this base escalation to reflect the uncertainty associated with the drivers of fixed costs and ongoing capital expenditures. These uncertainty bands were developed based on the historic volatility of labor, materials, and equipment associated with a typical coal-fired power plant. Exhibit 71 illustrates the resulting stochastic bands around the capacity cost component of the baseload contract.

Exhibit 71: Baseload Contract Capacity Cost Component



Source: Pace

UML Contract

Energy Cost Component

The energy cost component of the UML contract is based on the variable cost of the marginal unit dispatched to serve MWE's load. This unit will be determined by the supplier based on the hourly dispatch of its portfolio and the prior load serving obligations it is committed to. The energy cost component of the UML contract will, therefore, be driven by several factors:

1. **The counterparty's supply curve:** The counterparty's own supply curve will determine the hourly shape of the contract's energy cost. The generation and cost profile of new capacity additions will modify the shape of the supply curve and affect the energy cost component of the contract.

2. **The supplier's prior contractual obligations:** Because the pricing of the UML contract is based on the cost of the units dispatched to serve MWE's load, the counterparty's prior load-serving commitments will determine the point of intersection of MWE's load against the supply curve. Variations in the amount of load that precedes MWE can change the marginal plant used to price the energy component.

3. **The supplier's fuel and environmental compliance costs:** The variable costs associated with the marginal plant will be subject to fuel and environmental cost uncertainty. These costs will be fully passed through to MWE in the energy charge.

4. **MWE's own supply mix:** MWE's own supply curve will determine the profile of the used UML energy. If MWE's has other baseload options, the UML contract would likely be used for peaking energy needs. To the extent that MWE and the counterparty share similar load profiles

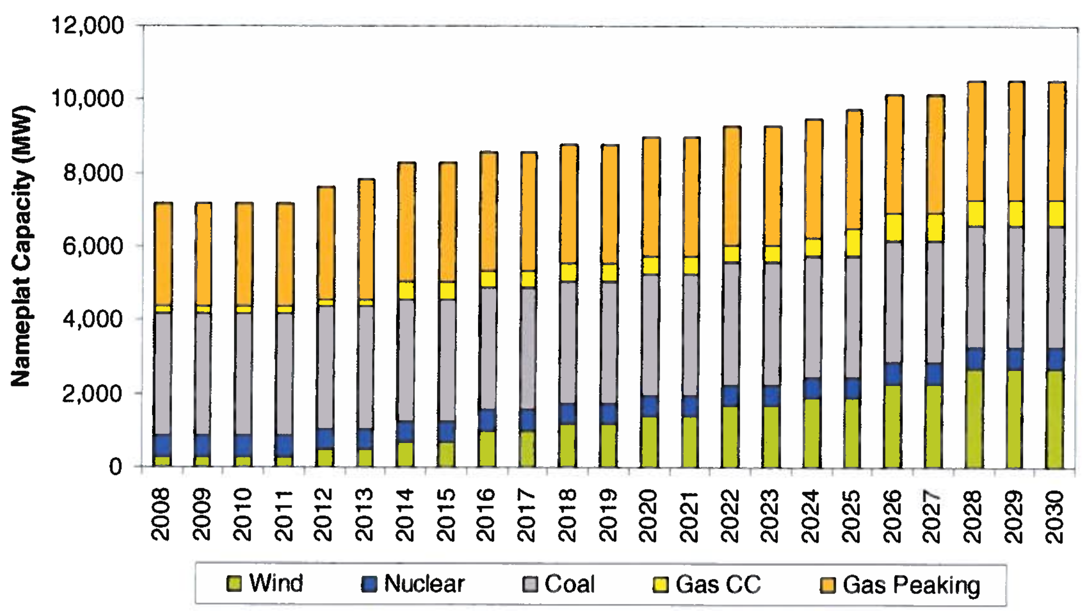
throughout the day, this would likely result in UML pricing reflective of gas-fired capacity for most of the peak hours. If, on the other hand, MWE is able to dispatch its own peakers during high load periods but has limited baseload options, the UML prices would reflect the variable cost of baseload and intermediate capacity.

5. **MWE's load:** Uncertainty in MWE's load will also affect the energy prices associated with the UML contract. Because the main drivers of load volatility for both MWE and the preferred supplier will likely be correlated due to geographical proximity, periods of high load in the MWE territory would likely result in the use of UML energy during corresponding periods of high marginal costs. Conversely, periods of low load will likely result in the availability of lower variable cost resources in the counterparty's supply curve.

Pace has performed detailed analyses to properly capture the relationships between all the drivers of UML pricing in the portfolio cost simulations. Fuel uncertainty was simulated for every coal and gas-fired resource in the supplier's portfolio. The counterparty's supply mix and prior load commitments were analyzed to simulate the expected energy costs associated with the UML contract over the study period.

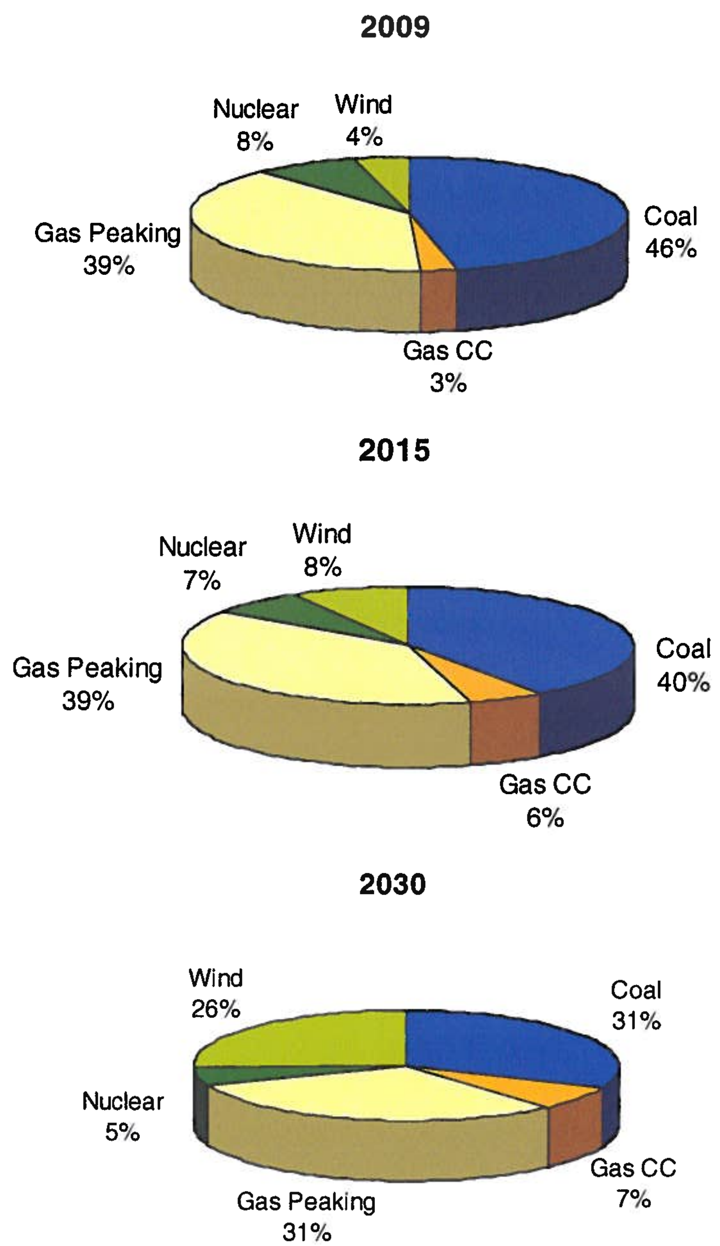
To properly capture the likely supply mix of the counterparty over time, Pace reviewed current expansion plans for the supplier and analyzed their RPS requirements over the next 20 years. Exhibit 72 and Exhibit 76 illustrate the simulated capacity mix of the preferred supplier over Study Period. Although, based on the prior contractual commitments of the counterparty, wind and nuclear capacity would unlikely set the energy price of the UML contract, capacity expansion at the bottom of the supply curve will shift the location of the plants used to serve MWE's load up the curve.

Exhibit 72: UML Contract Counterparty Simulated Capacity Additions



Source: Pace

Exhibit 73: UML Contract Counterparty Simulated Capacity Mix

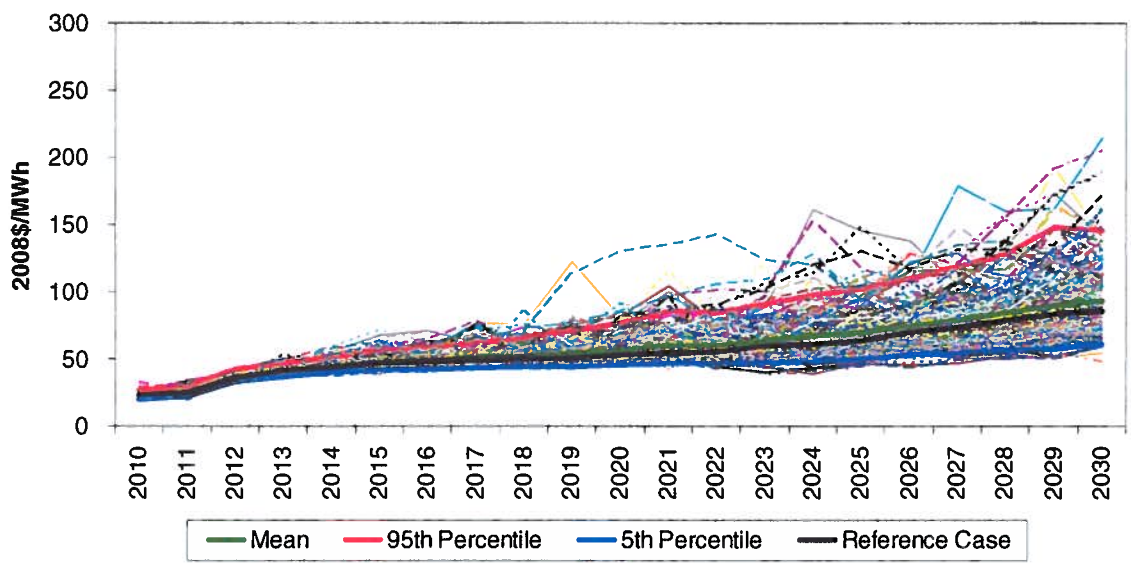


Source: MWE and Pace

As mentioned above, load uncertainty will also affect the pricing of the UML contract. To properly capture this, Pace developed stochastics around the prior load commitment of the preferred supplier. To ensure consistency and capture any relevant correlations between MWE and the counterparty's load, the average and peak load stochastics for both MWE and the counterparty incorporated all proper correlations based on historical data. Additional detail on the load stochastic methodology can be found in the Load Uncertainty and Risk section of this document.

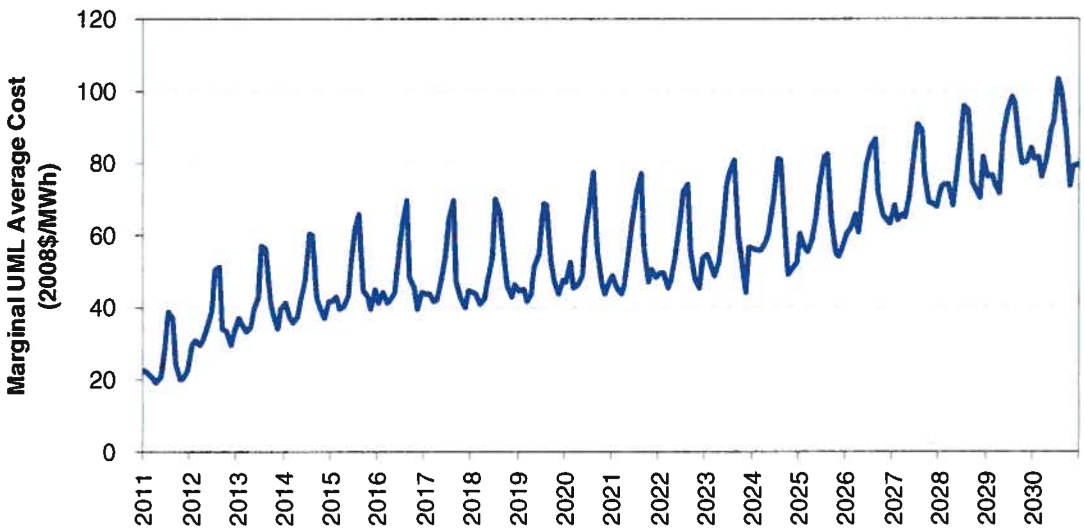
Exhibit 74 illustrates the resulting range of UML energy costs based on the counterparty's fuel and load uncertainties discussed above. Exhibit 75 illustrates the monthly seasonality associated with this contract. Both these graphs illustrate the energy costs to MWE under a 100% UML contract structure. The true cost volatility to MWE, however, will also be affected by the profile of the UML purchases. Exhibit 76 illustrates the resulting $/MWh energy costs for MWE under the 50% baseload portfolio baseline. As shown, the uncertainty range is skewed higher on the upside because the UML contract is only being used to serve a portion of MWE's energy needs (only 50% of it's capacity needs are contracted with UML). With 50% of baseload capacity coming from a different contract, in this case, the UML contract would only be called upon for intermediate and peaking energy requirements.

Exhibit 74: UML Contract Energy Cost Component



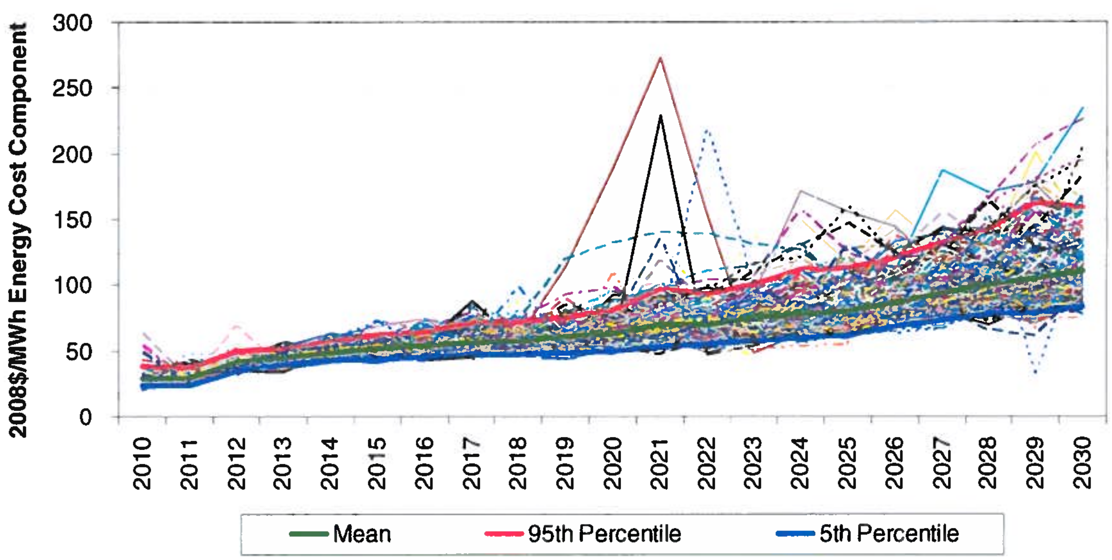
Source: Pace

Exhibit 75: UML Contract Monthly Seasonality



Source: Pace

Exhibit 76: $/MWh Cost of UML Contract for 50% Baseline Portfolio



Source: Pace

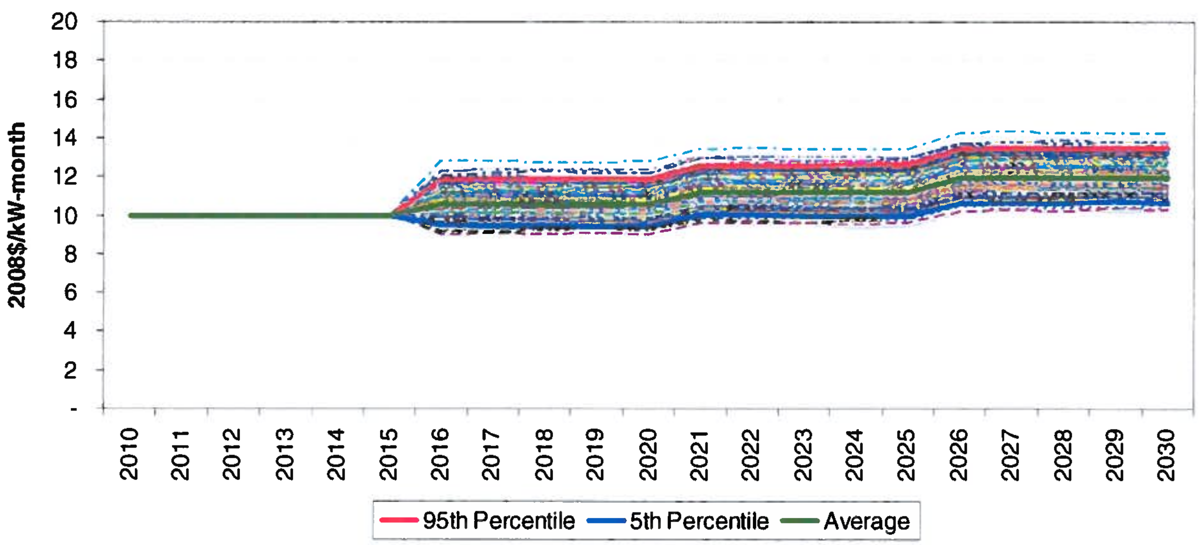
Capacity Cost Component

The capacity cost component of the UML contract will be defined by the counterparty based on their expectations of fixed and ongoing capital costs associated with the units "most likely" to serve MWE's load. Initially, it has been set at $9.95/kW-month. Like with the baseload capacity cost component, changes to these costs need to go through regulatory approval. For that reason, Pace has assumed that the capacity cost component will only be modified every few years. When the costs are modified, however, Pace assumed they would reflect roughly a 1% increase per year.

Similar to the Baseload contract, Pace developed stochastics bands around this base escalation to reflect the uncertainty associated with the drivers of fixed costs and ongoing capital expenditures. These uncertainty bands were developed based on the historic volatility of labor, materials, and equipment associated with the counterparties most likely units.

In addition to the fixed costs and ongoing capital expenditures for existing plants used to serve MWE's load, capital expenditures on new capacity would also be priced into the contract. The magnitude of those costs pass-throughs would depend on the amount of time the new additions are used to serve MWE's load, and the fixed cost of the units they are replacing. Pace's capital costs stochastic bands were applied to the UML's capacity charge based on estimates of the percentage of time new capacity additions would be used to serve MWE's load. The resulting range of capacity costs for the UML contract is illustrated in Exhibit 77.

Exhibit 77: UML Contract Capacity Cost Component



Source: Pace

QUANTUM SCENARIOS

CO_2 SCENARIO CONCEPT

Pace evaluated portfolios taking into account the impact of uncertainty around factors such as load, fuel, demand, and capital costs. The quantum scenarios around CO_2 are intended to address how portfolios might perform in a high or low CO_2 pricing environment. Pace believes that the best approach for evaluating this is through the development of an internally consistent view of power sector market drivers that could result from a world which contains a high or low CO_2 price. This internally consistent view of market drivers, which incorporates plausible demand growth outcomes, and governmental policy, then guides the development of Pace's projections for natural gas prices, environmental compliance costs, energy demand, and expansion expectations. Conducting scenario analysis in this way elucidates the potential performance of portfolios under possible market outcomes that not only address carbon prices, but also the secondary and tertiary effects of policies that achieve high and low carbon prices.

CO_2 Quantum Scenario Description

The *Low* CO_2 state of the world was developed around an analysis of what market drivers would be under a low CO_2 pricing environment. This state is driven by the following assumptions:

- Economic growth policies trump environmental protection
- Lower national RPS and CO_2 reduction requirements
- Natural gas and coal fired capacity expansion is driven by less stringent environmental policies

The quantum scenario constructed around high CO_2 prices is referred to as the *High* CO_2 state of the world, and key drivers include:

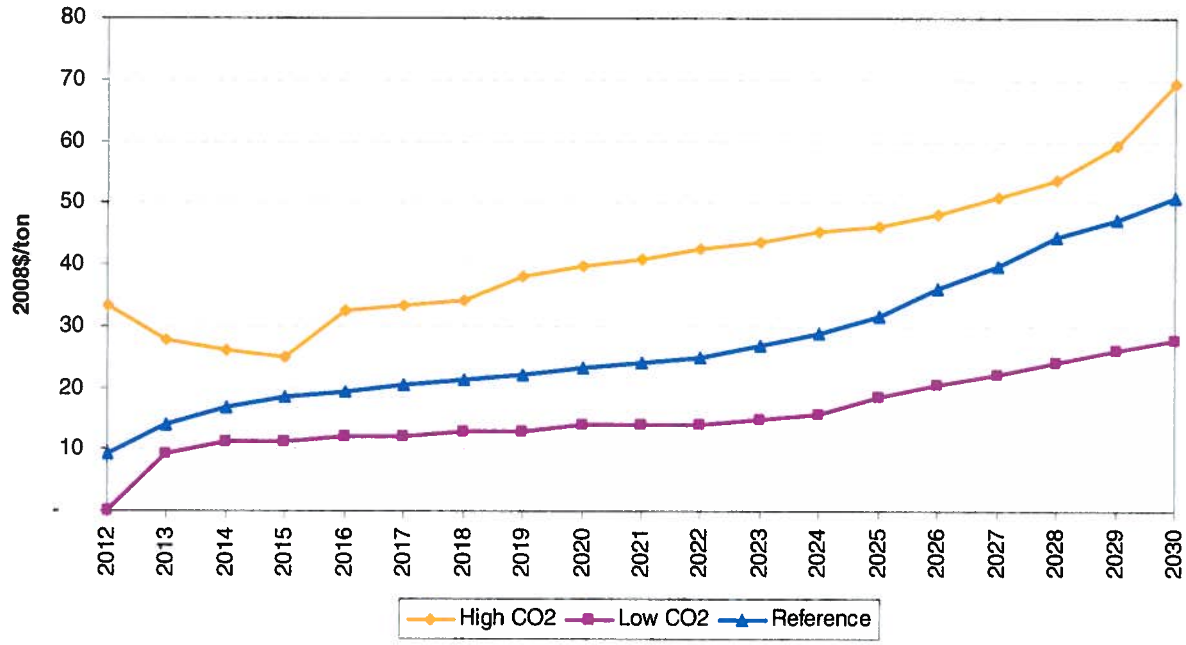
- Strong, centrally coordinated energy and environmental policies at the federal level, specifically around strict carbon dioxide cap-and-trade policy
- Aggressive renewable energy or demand side directives at the federal or state levels
- No new conventional coal-fired plants and closure of significant amounts of existing coal-fired plants
- Moderating demand for natural gas in the long run in both North America and throughout the world

DETAILS ON MARKET DRIVER ASSUMPTIONS

CO_2 Prices

The CO_2 price projections used in the high and low CO_2 quantum scenarios are shown in Exhibit 53. Characteristics of legislation driving the High case include stringent ultimate reduction targets of 80 percent or greater by 2050, constrained use of offsets for compliance and limited free allowance allocations to covered entities. The low CO_2 case assumes long term reduction targets to be less than 75 percent, significant direct allocations, and offset provisions allowing for 30 percent or more of the supply side of the market to be covered by offset project reductions. More detail about Pace's view on environmental legislation and CO2 pricing can be found in the Key Environmental Legislative and Regulatory Issues and Policies section of this report.

Exhibit 78: National Carbon Market Pricing Projections



Source: Pace

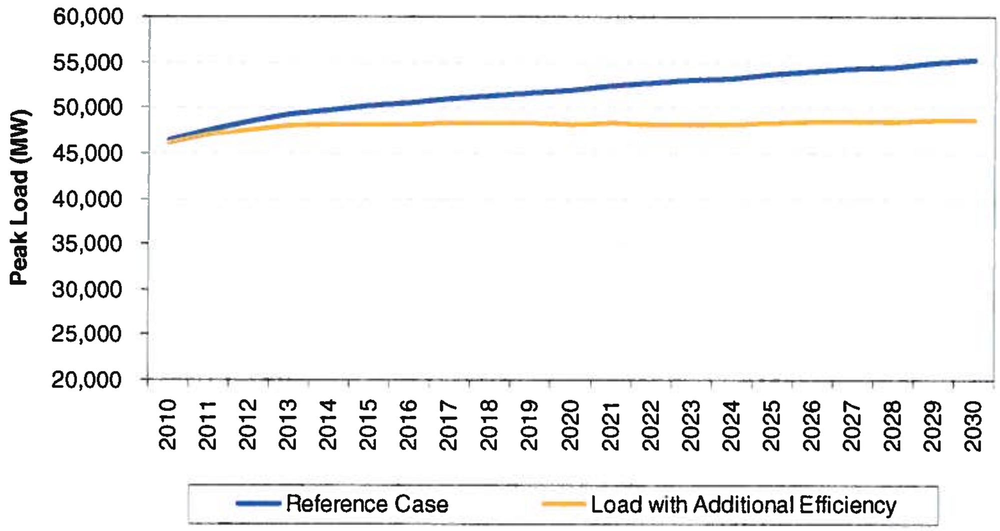
Demand

Electricity demand is strongly correlated with GDP growth. Pace has developed national and regional demand projections that tie directly to the underlying assumptions for economic growth.

Under the state of world scenario for high CO_2 prices, the regulatory drivers of stringent CO_2 legislation are also expected to drive more aggressive penetration of efficiency and DR measures. Pace has considered the impact of additional efficiency and demand side management on overall growth trends. To determine potential impacts of energy efficiency, Pace surveyed state level demand response and energy efficiency goals and also looked to historical actual demand reduction achievements in states that have had a longer history with these programs. Through this analysis, Pace capped state-level demand reductions at 0.5% per year and assumed about one quarter of the federal RPS standard will be met with efficiency measures. This resulted in relatively flat load growth nationally.

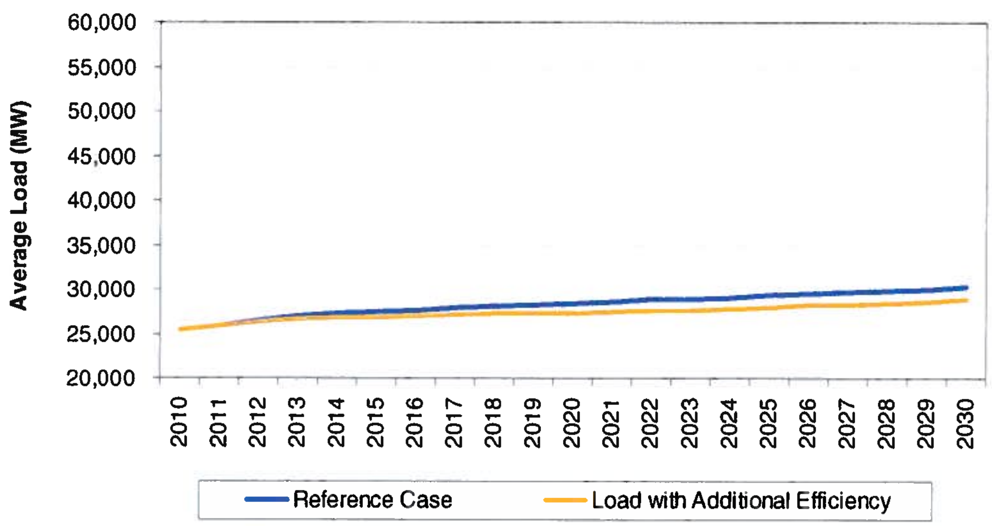
Exhibit 79 and Exhibit 80 display SPP peak demand and average load projections for the Reference Case, along with the impact of efficiency and demand side management improvements assumed under the High CO_2 case.

Exhibit 79: SPP Peak Demand Projections (MW)



Source: Pace

Exhibit 80: SPP Average Load Projections (MW)

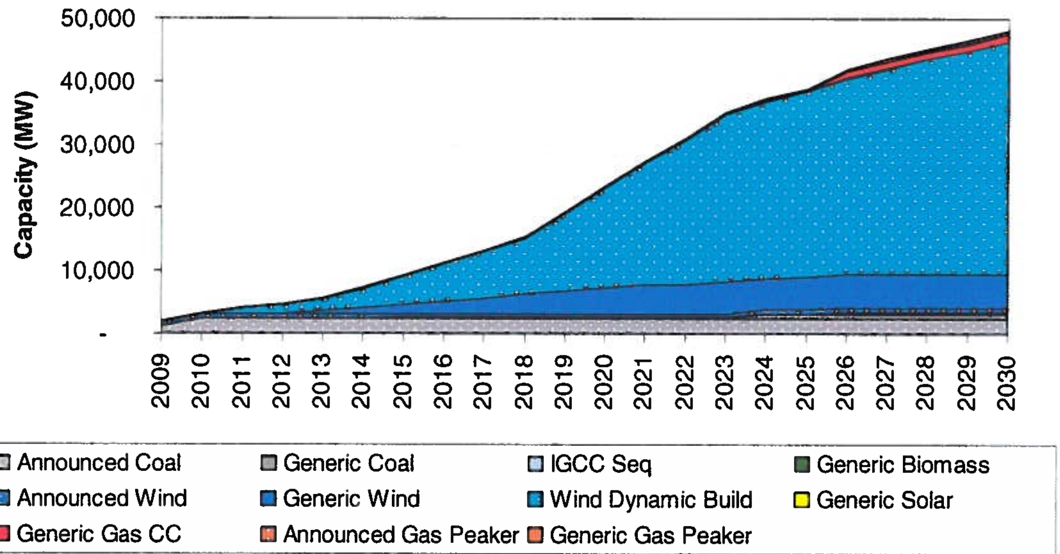


Source: Pace

Capacity Expansion

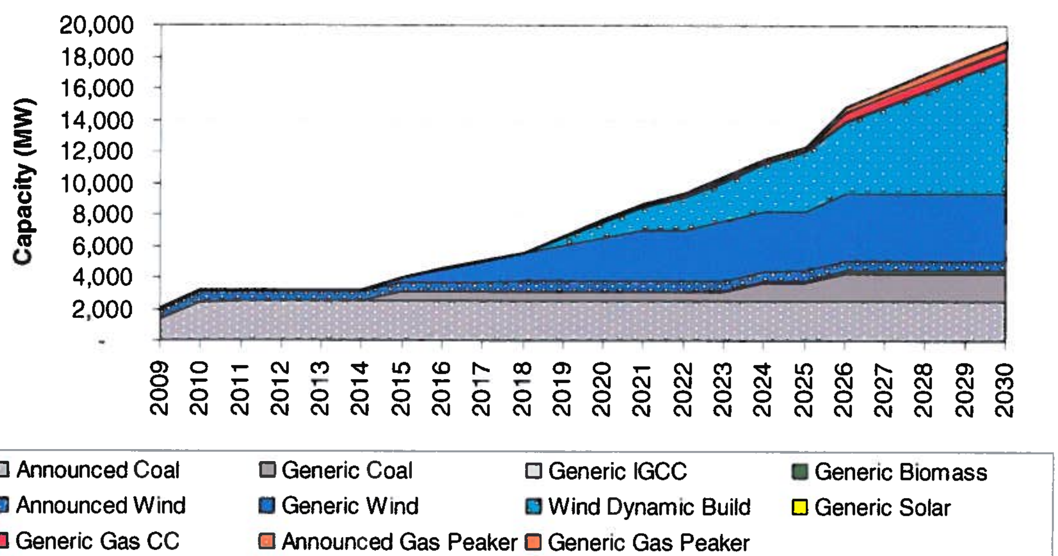
The combination of load expectations, policy outcomes, and technological assumptions are synthesized in generation expansion expectations. Exhibit 81 and Exhibit 82 detail the assumed capacity additions of SPP in the high and low CO_2 scenarios. A low price of CO_2, reduces renewable development, as natural gas and coal fired generation become more attractive and margins for wind plants decline. Higher cost of CO_2 emissions, by contrast, result in strong development of renewable and non-emitting capacity additions.

Exhibit 81: Expansion Plan High CO_2 Case



Source: Pace

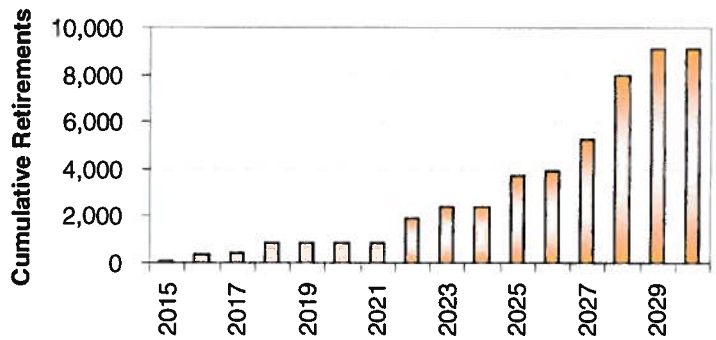
Exhibit 82: Expansion Plan Low CO_2 Case



Source: Pace

Higher CO_2 prices also reduce margins for less efficient plants in the market. Based upon a review of existing coal plants in SPP, Pace concluded that an additional 6,000 MW of coal capacity would retire over the Study Period as detailed in Exhibit 83.

Exhibit 83: Retirements High CO_2 Case

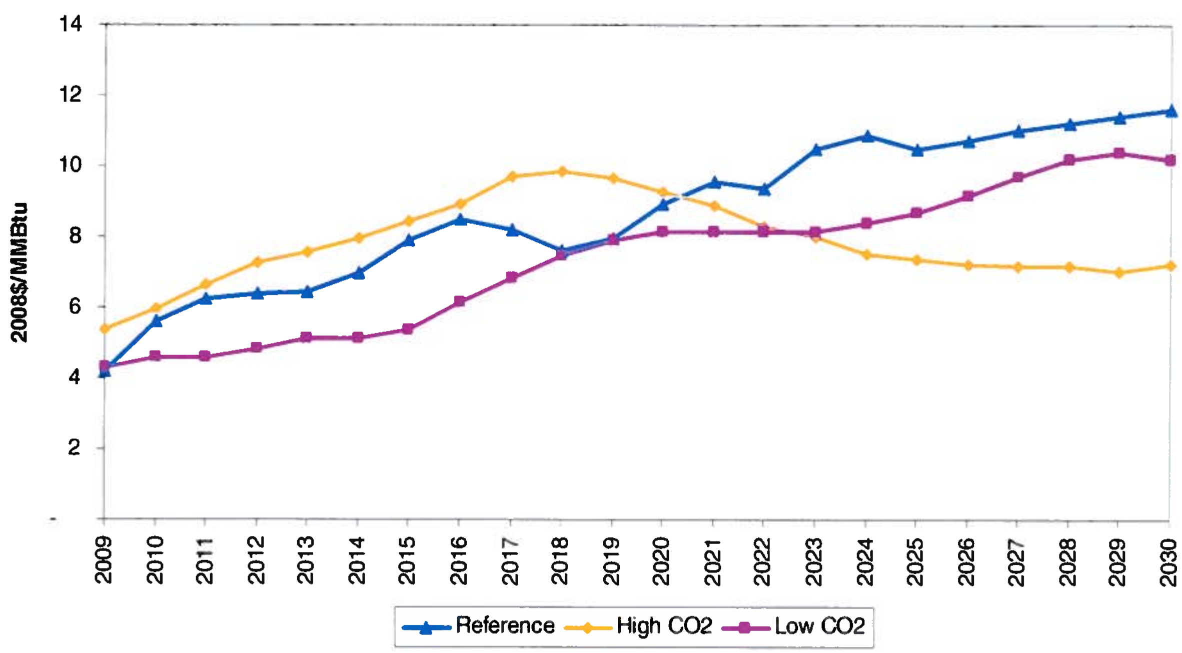


Source: Pace

Natural Gas Prices

Natural gas prices are a main driver behind power market clearing prices. Pace's projections by scenario are shown in Exhibit 84. The price of natural gas in the high CO_2 case is higher in the near term due to the energy sectors reliance on natural gas in order to meet increasing load in a carbon constrained environment. Over the long term, the decreased load growth due to efficiency gains, as well as the increased renewable additions, and non-conventional coal-fired capacity serve to reduce the overall demand for natural gas. In the low CO_2 case, continued reliance on coal-fired capacity to meet demand is expected to result in low gas demand over the Study Period. This is expected to result in lower gas prices compared to the Reference Case.

Exhibit 84: Natural Gas Price Projections (2008 \$/MMBtu)

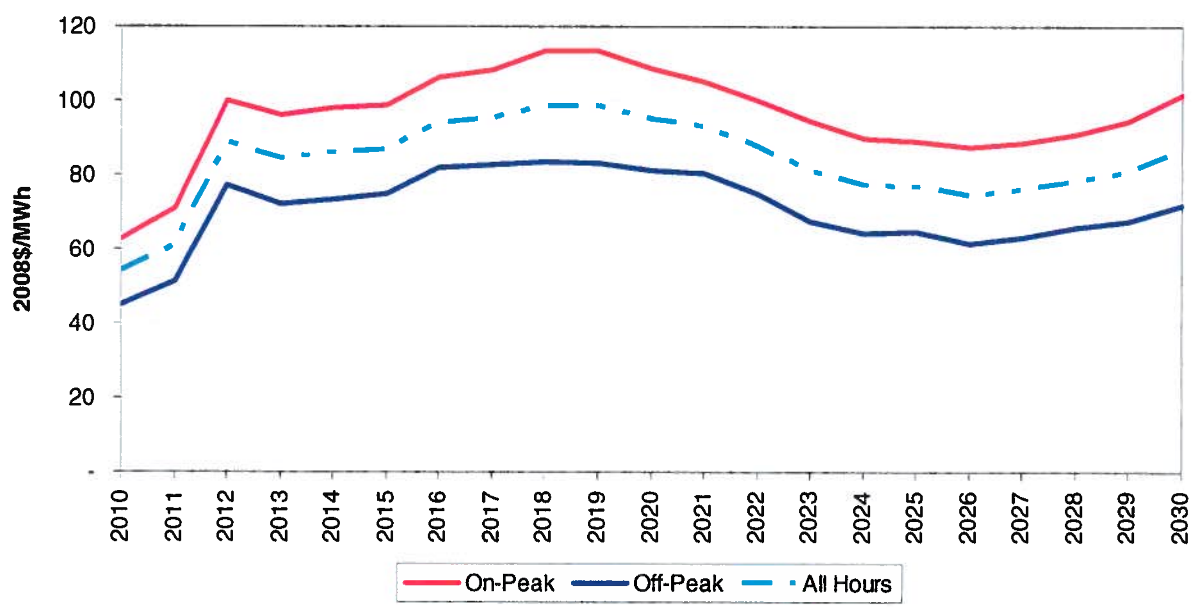


Source: Pace

Power Price Forecast

Pace's dispatch analysis indicates that power prices for the high CO_2 case will be cyclical over the study period, as shown in Exhibit 85. In the near term power prices spike upwards to an all hours price around ($2008) $89/MWh once a strict carbon regime comes online in 2012. Elevated carbon pricing and rising natural gas prices continue to pull average power prices upward to around $100/MWh. After about 2019, wind additions, decreased load from efficiency, and falling natural gas prices combine to place downward pressure on power prices. In the out years of the Study Period, prices begin to rise again as low energy margins cause inefficient coal capacity to retire.

Exhibit 85: Annual Power Prices High CO_2 Case

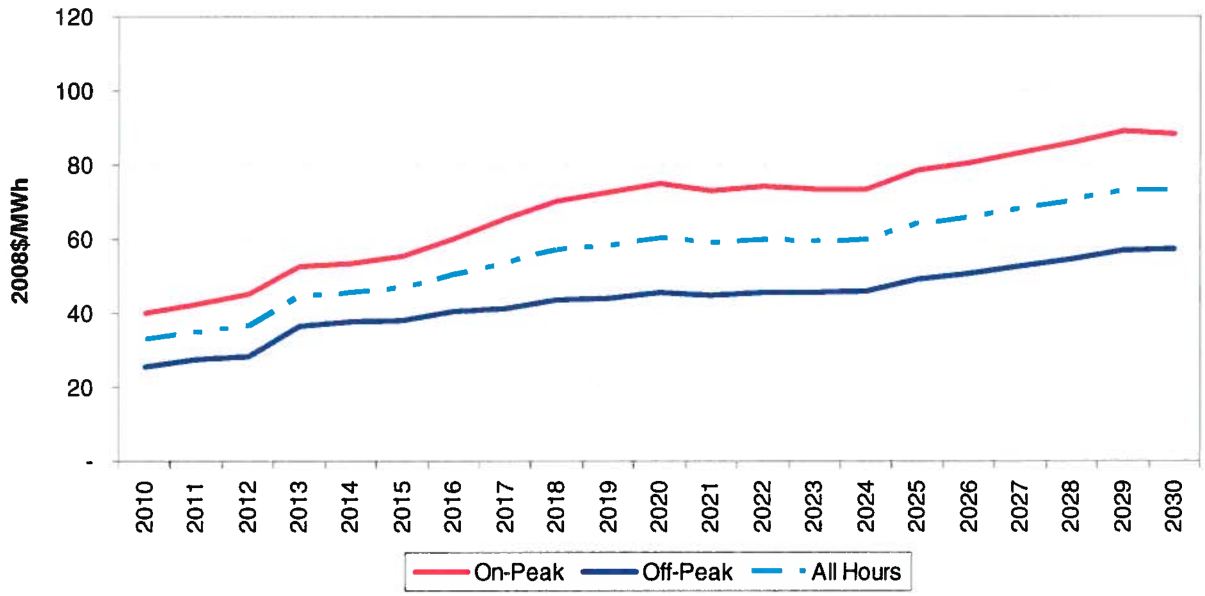


Source: Pace

For the low CO_2 scenario Pace's analysis shows that power prices will continue to steadily rise through 2030, as shown in Exhibit 86. On Peak prices ($2008) are expected to be around $40/MWh in 2010 and rise to $90/MWh by 2030 in line with expected moderate increases in the price of gas and emission compliance costs. Off Peak prices ($2008) are expected to be $26/MWh in the near term and the rise to $57/Mwh by 2030.

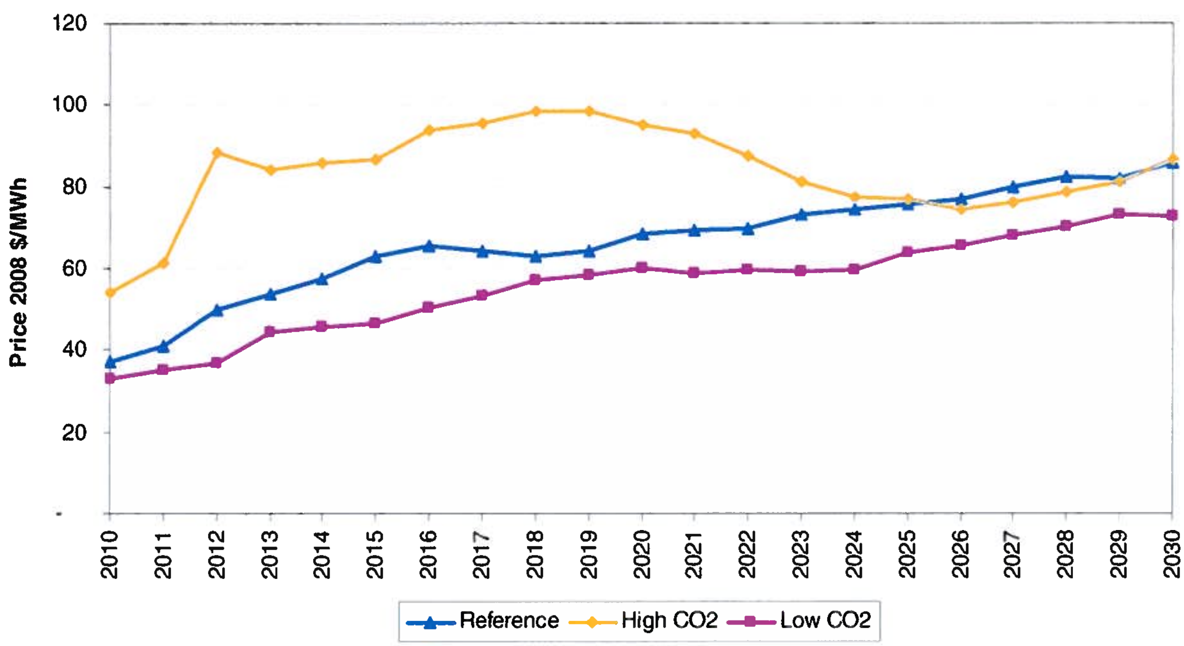
Exhibit 87 displays the average power prices for both cases, as well as the Reference Case. The decline in load and gas prices in the high CO_2 scenario push down power prices until retirements begin to occur in the out years. The low CO_2 case, similar to the Reference Case follows the trend of natural gas.

Exhibit 86: Annual Power Prices Low CO_2 Case



Source: Pace

Exhibit 87: Annual Power Prices All Hours Comparison



Source: Pace

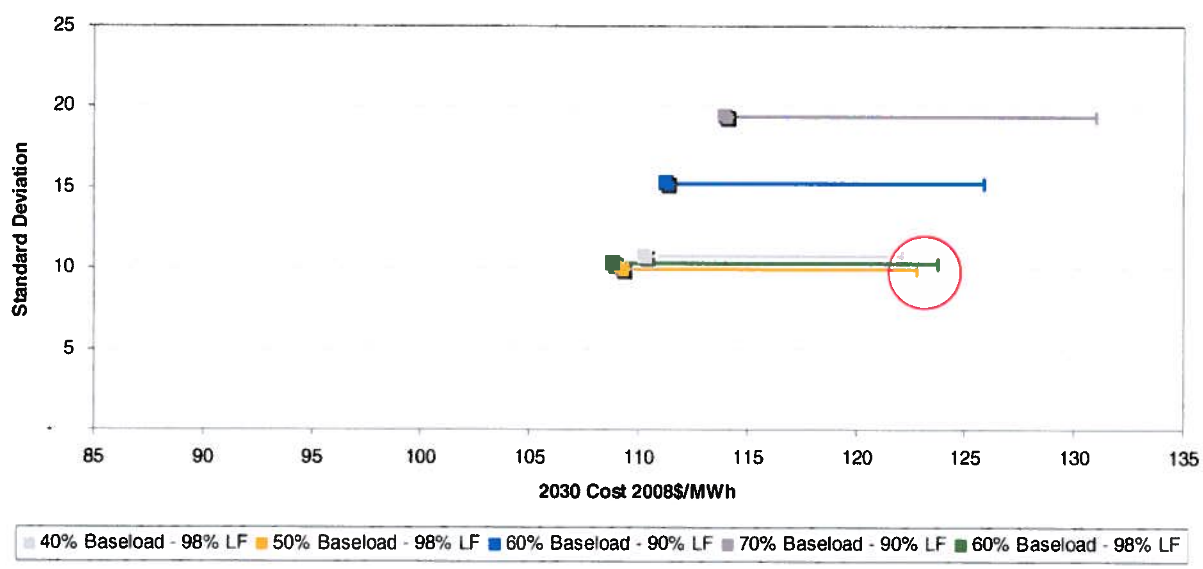
CO_2 QUANTUM SCENARIOS PORTFOLIO RESULTS

CO_2 Scenario Baseline Impact

The high CO_2 price impacts to the baseline portfolios in 2030 are shown in Exhibit 88. The error bars on each case show the cost of each portfolio under the high CO_2 case, compared to the expected value of the risk analysis. As expected, the average costs of all the portfolios increases. The portfolio composed of 70 percent baseload capacity has the largest impact to cost as it has the greatest exposure to CO_2 emissions. The 40 percent, conversely, shows the smallest impact.

In the Reference Case the 60 percent baseload portfolio was slightly less expensive that the 50 percent baseload case. However, in a high CO_2 price environment the additional baseload capacity suffers additional cost and becomes slightly more expensive than the 50 percent baseload portfolio.

Exhibit 88: High CO_2 Baseline Portfolio Impact - 2030

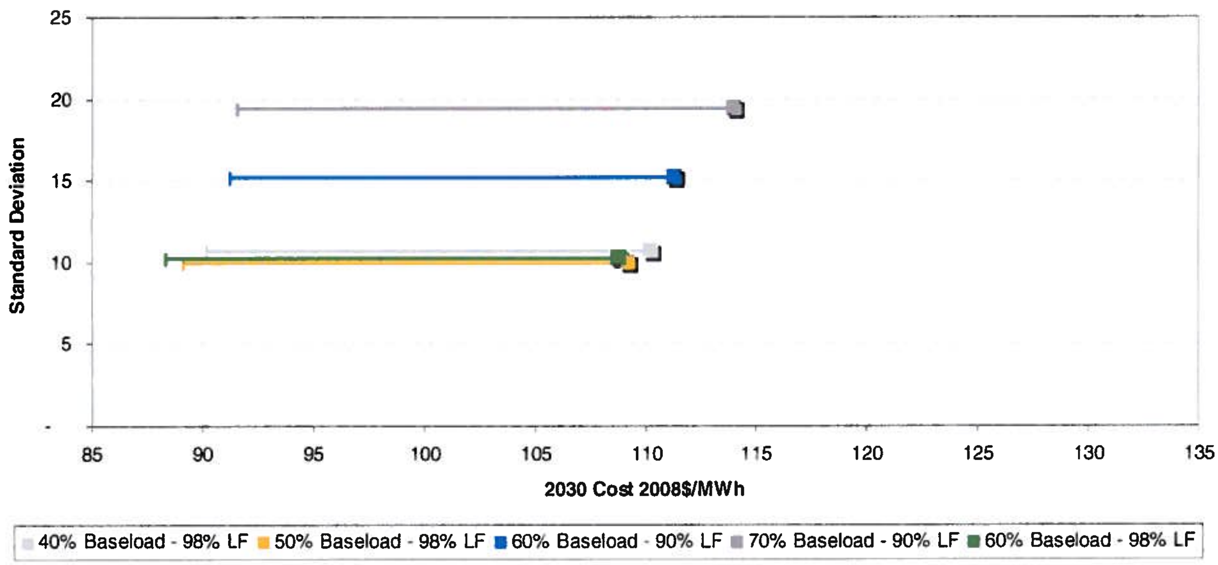


Source: Pace

Exhibit 89 illustrates the low CO_2 scenarios effect on the baseline portfolios. A lower CO_2 price assumption reduces costs for all portfolios. The 70 percent baseload portfolio achieves the greatest cost reductions, while the 40 percent baseload portfolio had more limited cost savings.

A lower CO_2 price scenario solidifies the cost advantage of 60 percent baseload over other options. This is, however, accompanied by greater risks, both in terms of CO_2 liability and market volatility, as discussed in the main RIRP report.

Exhibit 89: **Low CO_2 Baseline Portfolio Impact - 2030**

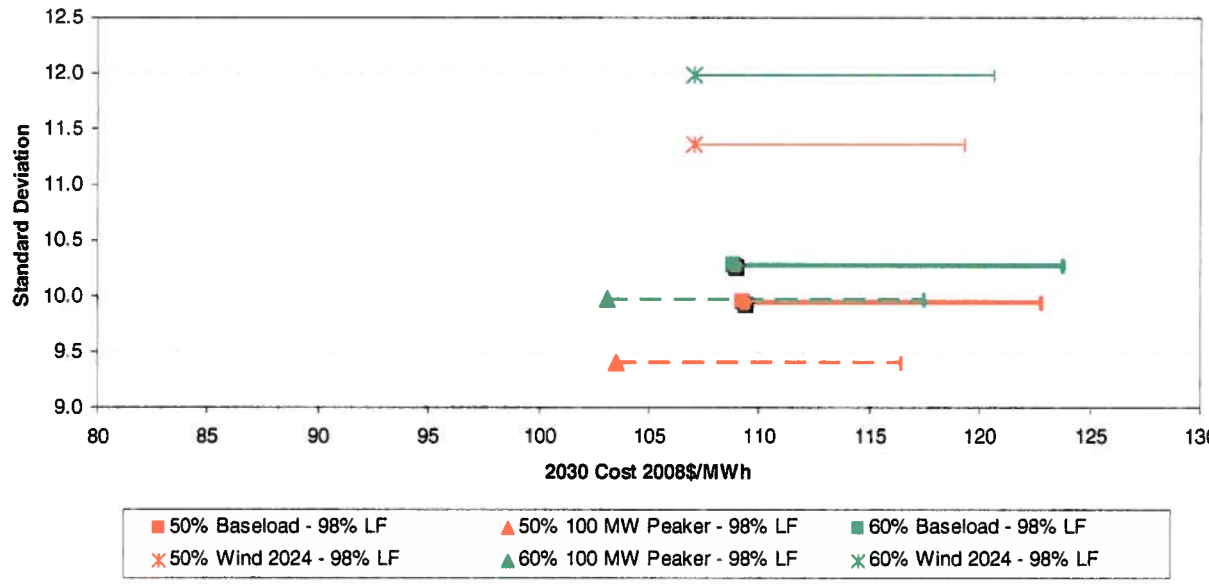


Source: Pace

CO_2 Scenario Select Portfolio Impact

The high CO_2 scenario has the most pronounced effect on the 60 percent baseload portfolios. Adding wind to portfolios mitigates some of the CO_2 exposure and help reduce the cost impact of a high CO_2 case. All the of 50 percent baseload portfolios look preferable in the high CO_2 scenario, but the increased costs between the 50 percent and 60 percent portfolio options are not substantial.

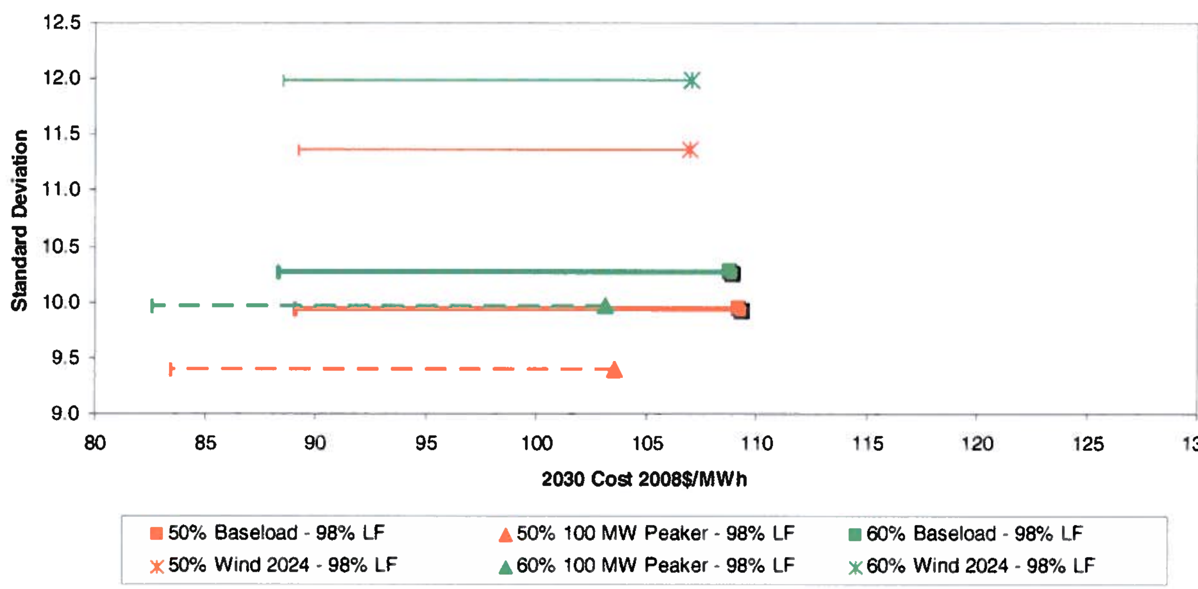
Exhibit 90: High CO_2 Select Portfolio Impact - 2030



Source: Pace

The higher baseload portfolios benefit from a reduction in CO_2 prices. The cost gains of adding wind to the portfolio are offset by the decreased exposure of the portfolios to CO_2 costs, resulting in slightly higher costs for the wind portfolios compared to the baseline.

Exhibit 91: Low CO_2 Select Portfolio Impact - 2030



Source: Pace

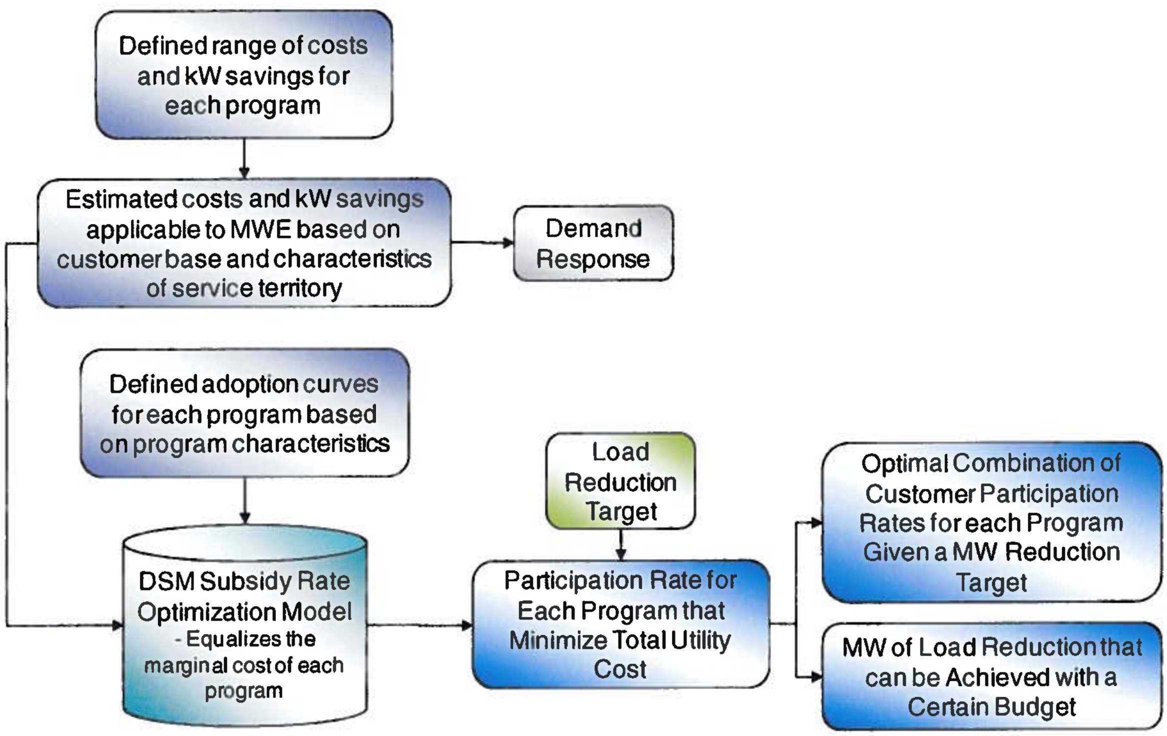
DEMAND RESPONSE ANALYSIS

As part of the RIRP, MWE requested a high-level analysis of the cost effectiveness of Demand Response ("DR") program options available in their service territory. Pace's analysis was based on publicly available information on costs and kW reductions by program. This section outlines the approach, assumptions, and results of the DR study.

APPROACH AND ASSUMPTIONS

Pace used an econometric approach to estimate the costs of achieving load reduction through different combinations of DR programs. Exhibit 92 illustrates the methodology and inputs used to establish the cost-effective amount of DR in MWE's territory.

Exhibit 92: DR Analysis Methodology



Source: Pace

The first step in the analysis was to define the DR programs available to MWE and their associated costs and expected savings. The DR programs feasible for a utility depend on drivers like the customer base and the coincidence of load across the system. MWE's system typically peaks in July, and roughly 10% of the coincident peak load is driven by irrigation. In 2008 the peak load was 308 MW.

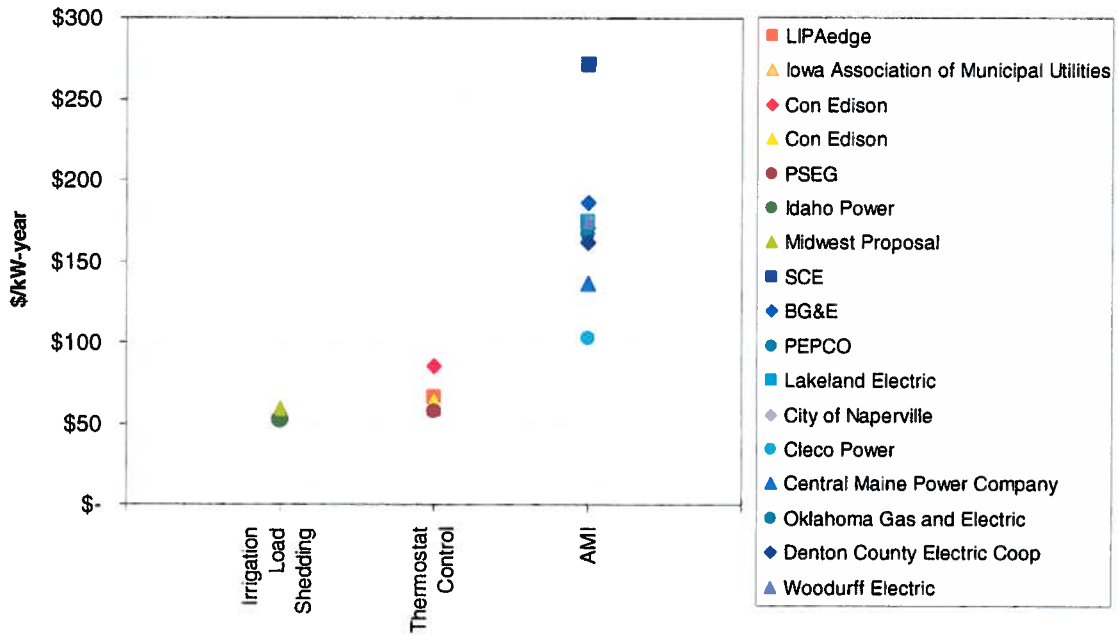
Given MWE's customer base and load profile for each customer class, Pace considered five types of DR programs in its analysis:

1. Agricultural Load Shedding

2. Thermostat Control – Residential
3. Thermostat Control – Small Commercial and Industrial
4. Direct Load Control/Advanced Metering Infrastructure ("AMI") – Residential
5. Direct Load Control/AMI – Small Commercial and Industrial

To estimate the costs and expected kW savings for each of these programs, Pace relied on publicly available information from several sources. To allow for a direct comparison, all available information on costs and savings were converted to a $/kW number and levelized over a 10-year horizon. Exhibit 93 illustrates the range of costs in $/kW-year for the three main types of DR programs considered in this analysis.

Exhibit 93: Range of Publicly Reported $/kW-year Cost by DR Program



* Reported costs levelized over a 10-year period

Source: MWE, DOE Grants for DSM programs, EPRI, utility reports, PUC testimonies, and Pace

The range of costs per kW shown in Exhibit 93 reflects the uncertainty surrounding both costs and expected kW savings. Geographic and population differences, as well as the current level of customer participation on different programs can also explain some of the cost differences across utilities.

The cost estimates Pace used for the analysis are shown in Exhibit 94. For the agricultural load shedding program, Pace used costs and savings consistent with a turnkey proposal recently submitted to Midwest for a pilot program. An initial participation rate at the given costs was evaluated to be consistent with published data and our understanding of MWE's service territory. The expected number of participating customers and load reductions for the pilot program were used to calibrate the parameters for the agricultural load shedding option.

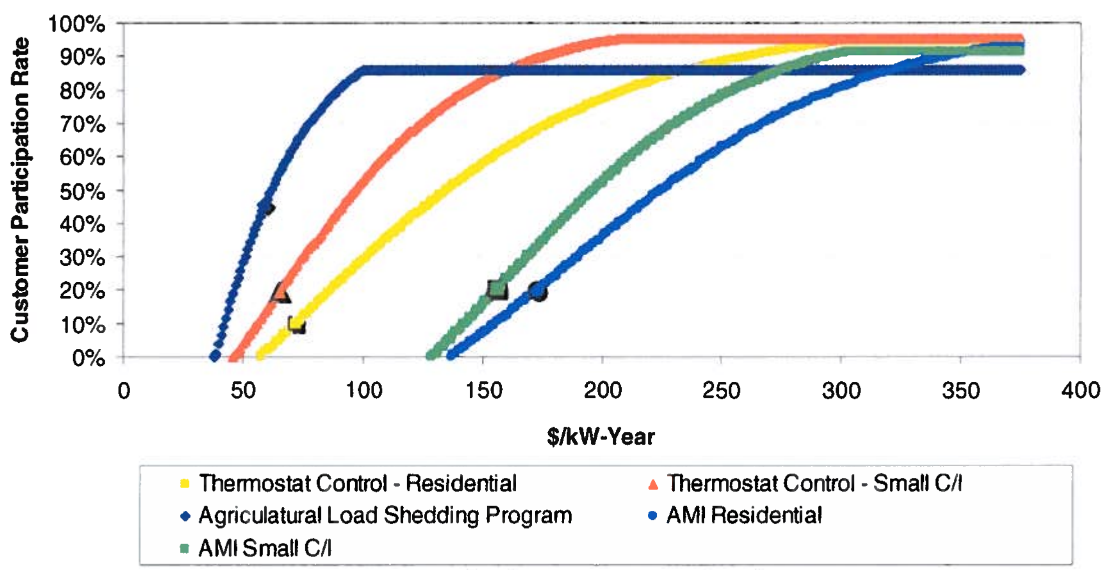
Exhibit 94: Reductions and Cost Assumptions by Program

Program	Customer Class	Customer Participation Rate	Eligible Customers	Per Customer Reduction	Per Customer Cost	Total Utility Savings	Cost to Utility		
Name	*Name*	*%*	*#*	*kW*	*Total $*	*MW*	*$*	*$/kW*	*$/kW-year (10 years)*
Agricultural Load Shedding Program	Irrigation	45%	680	22.4	6,080	5.5	2,216,065	400	**59**
Thermostat Control - Residential	Res	10%	29,719	0.5	515	1.5	711,590	484	**71**
Thermostat Control - Small C/I	SmCI	20%	12,423	0.8	545	1.9	835,997	440	**65**
Direct Load Control/AMI - Residential	Res	20%	29,719	0.3	370	1.8	2,081,265	1,172	**172**
Direct Load Control/AMI - Small C/I	SmCI	20%	12,423	0.4	400	1.0	1,025,281	1,056	**155**

Source: MWE, DOE Grants for DSM programs, EPRI, utility reports, PUC testimonies, and Pace

To define a comprehensive supply curve of options, it is necessary to establish the cost of increasing participation rates for each program. To estimate this, Pace defined an adoption curve for each program based on the observed range of costs and expected difficulty of increasing participation rates for each program. Exhibit 95 illustrates the adoptions curves used in the analysis. The large markers correspond to the starting costs and participation rates shown in Exhibit 94.

Exhibit 95: Program Adoption Curves for DR Programs



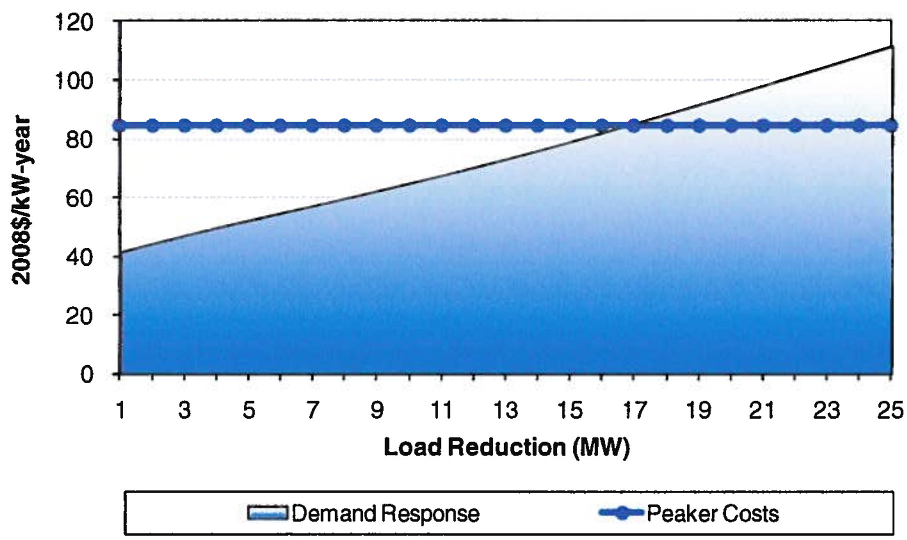
Source: MWE, DOE Grants for DSM programs, EPRI, utility reports, PUC testimonies, and Pace

The costs, savings, and penetration rates defined for each program result in a supply curve of options for every MW of load that needs to be reduced. Pace employs an optimization tool to define the least-cost combination of options for each MW of load reduction required. This tool equalizes the marginal cost of all programs, allowing the utility to meet its load reduction goals at the minimum cost. Using this methodology Pace can approximate the cost of achieving different levels of load reduction through DR programs.

RESULTS

The successful implementation of DR programs can reduce a utility's need for peaking generation. To assess the cost-effectiveness of DR, it is pertinent to compare its levelized costs to the costs of a new peaking unit. Exhibit 96 illustrates the costs associated with achieving different levels of load reduction compared to the costs of a new peaking plant. Under the reference case conditions, the analysis indicates that roughly 16 MW of load reduction could be achieved at a cost lower than a new peaker built by MWE.

Exhibit 96: Levelized Cost Comparison of DR vs. Peaking Capacity



Source: Pace

The increasing costs shown for the DR options are a result of the penetration curves used for each program and reflect the increasing costs associated with attracting new customers. The contribution of each DR program to the overall MWs reduced will depend on the shape of the individual supply curves. As mentioned above, Pace optimizes the mix of different programs to minimize the total costs to the utility for each MW of load reduction.

The resulting composition of the cost-effective mix of DR programs (16 MW) is shown in Exhibit 97. In summary:

- The agricultural load shedding program accounts for roughly 8 MW of the mix
- An additional 8 MW of load reduction are the result of a combination of residential and small commercial and industrial thermostat control
- Direct load control and price response through AMI does not account for a significant amount of load reduction in a cost-effective mix

Exhibit 97: Composition of 16 MW of Cost-Effective Load Reduction

Program	Customer Class	Eligible Customers	Per Customer Reduction	Per Customer Cost	Customer Participation Rate	Total Utility Savings	Cost to Utility		
Name	*Name*	*#*	*kW*	*Total $*	*%*	*MW*	*$*	*$/kW*	*$/kW-year (10 years)*
Agricultural Load Shedding Program	Irrigation	680	22.4	6,080	66%	8.0	4,025,405	501	**74**
Thermostat Control - Residential	Res	29,719	0.5	515	26%	3.8	2,435,192	641	**94**
Thermostat Control - Small C/I	SmCl	12,423	0.8	545	42%	4.1	2,429,569	595	**87**
Direct Load Control/AMI - Residential	Res	29,719	0.3	370	0%	0.0	82	923	**136**
Direct Load Control/AMI - Small C/I	SmCl	12,423	0.4	400	2%	0.1	71,721	888	**130**

Source: Pace

Due to MWE's customer composition and load profile, an irrigation load shedding program is expected to yield the most cost-effective demand reductions. Consistent with these results, MWE is moving forward with a pilot load shedding irrigation program. The program will be rolled out in the coming months and should constitute a good basis for the further evaluation of the cost effectiveness of other DR programs.

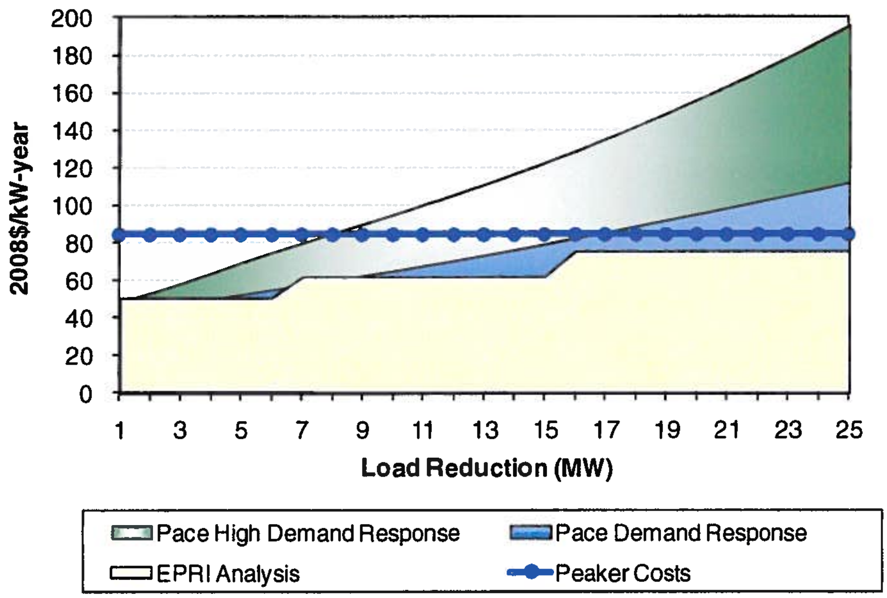
Sensitivity Analysis

As discussed before, there is significant uncertainty around the cost and kW reductions associated with DR programs. To capture the impact of some of these uncertainties on the cost-effective amount of load reduction achievable by MWE, Pace developed a low and a high case. Exhibit 98 illustrates the break-even costs of DR vs. peaking capacity for three different sets of cost, savings, and penetration rate parameters.

The High DR Costs line illustrates the costs of achieving different levels of MW reductions under a set of assumptions that assume lower kW savings and flatter penetration rates (more investment is needed to attract new customers). The yellow area reflects the costs of achieving different MW of load reduction according to a recently published EPRI study. This report presents a very macro-level assessment of DR potential in the US with little detail on the costs associated with each type of program. Although it is important to recognize this analysis as another data point, in Pace's view, it represents a very aggressive view and not fully applicable to the MWE service territory. The blue area in the graph corresponds to the parameters discussed earlier in this section and illustrated in Exhibit 98.

As Exhibit 98 illustrates, although there is significant uncertainty associated with the number of MW that can be reduced through DR at a cost below $85/kW-year, there is evidence to suggest that between 7 and 16 MW of load reduction con be achieved cost effectively.

Exhibit 98: DR Cost Sensitivity Analysis



Source: Pace

The amount of information available on the penetration rates of DR programs is currently very limited. Data availability is expected to increase as more utility programs are implemented over the next several years. Pilot programs like the agricultural load shedding program MWE is currently pursuing are needed to test the economics and penetration rates for these programs and determine more precisely how much load reduction can be achieved through DR.