Review of Utility Resource Plans in the West
Resource Strategies for a "Hybrid" Market

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Overview of Presentation

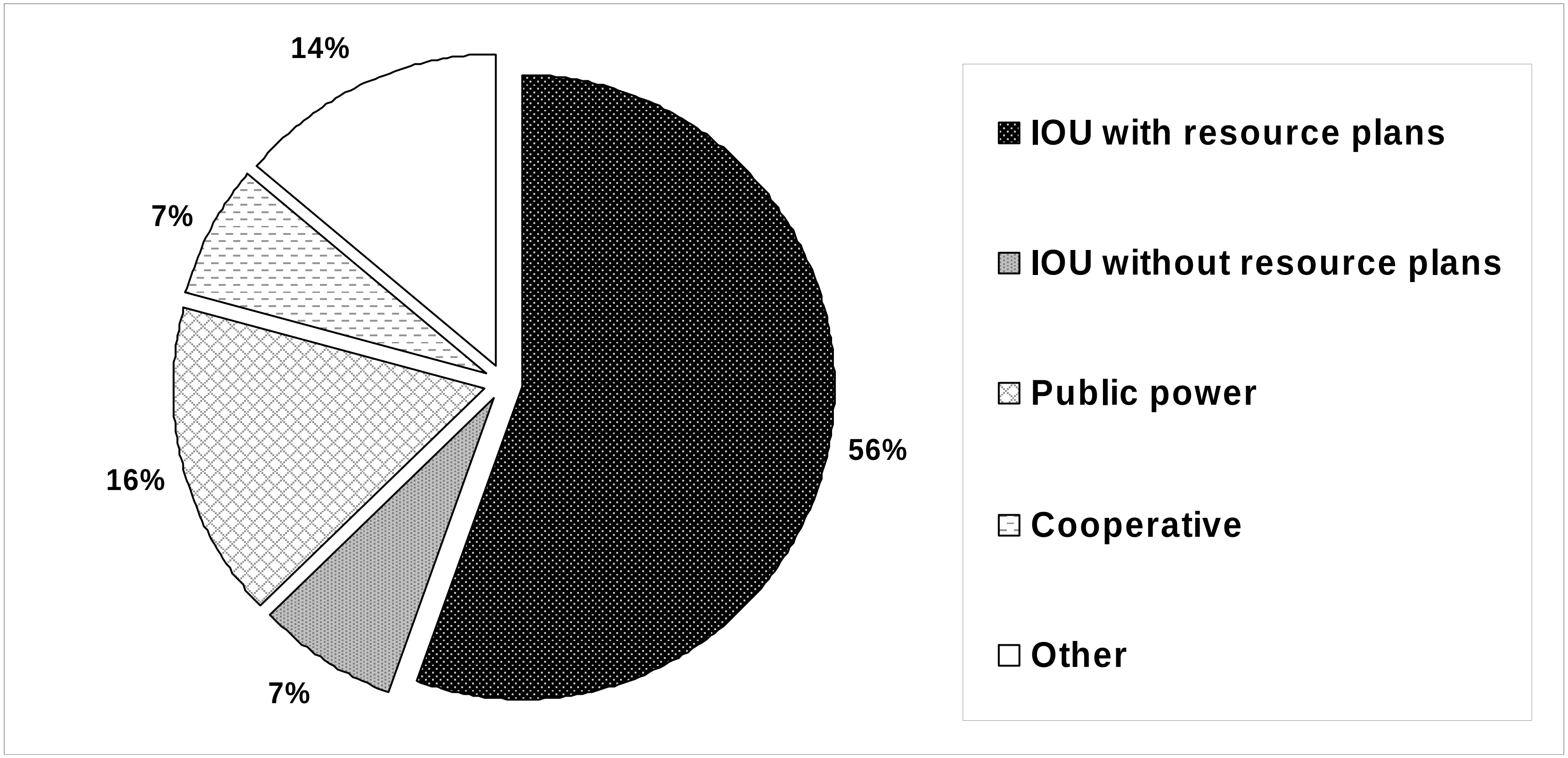
- Project overview: scope, objectives, approach
- Resource Assessment, Need & Adequacy
- Treatment of Risk in IRP Plans
- Natural gas price risk
- Treatment of Energy Efficiency and Demand Response
- Treatment of Renewable Energy

Project Scope and Objectives

- **Project scope: Comparative analysis of 12 recently filed Integrated Resource Plans (IRP) in the Western U.S.**

- **Project objectives: Review & analyze emerging issues:**
  - Treatment of conventional & emerging resource options
  - Risk analysis & portfolio management
  - Regulatory & market conditions
  - Reserve adequacy criteria
- **Summarize how the plans handle these issues, and identify best practices and recommendations**
- **Create information tools for CREPC that can facilitate work on related projects**

The Extent of IRP in the West



Resource Assessment and Adequacy in Utility IRP

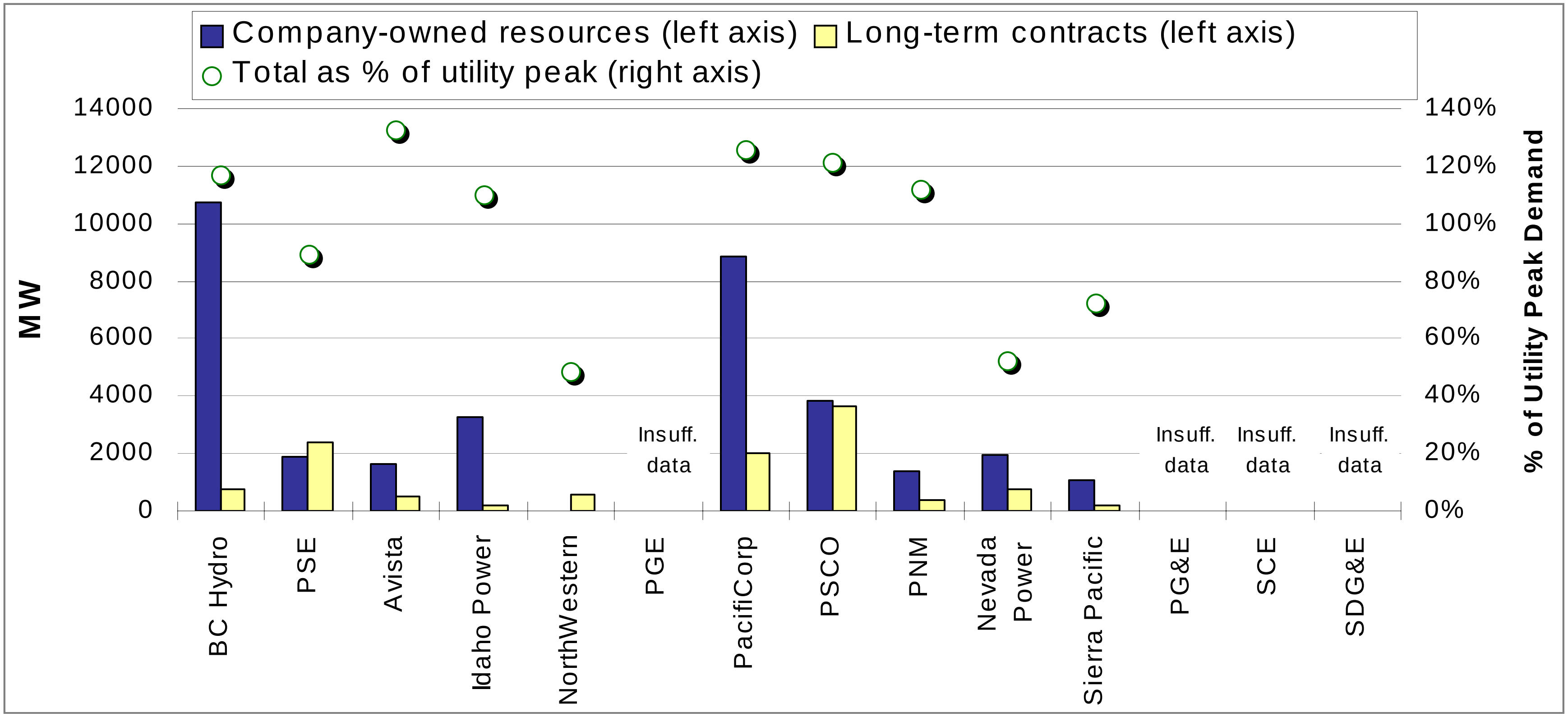
Resource Assessment and Adequacy

- Resource Adequacy:
  - What adequacy criteria & reserve margins are used by utilities?
- Resource Assessment in Western IRP Plans
  - Utility's forecasted load growth?
  - How do the utilities propose to address resource needs, and within what timeframe?

Utility Approaches to Determine whether *Capacity* Resources are Sufficient

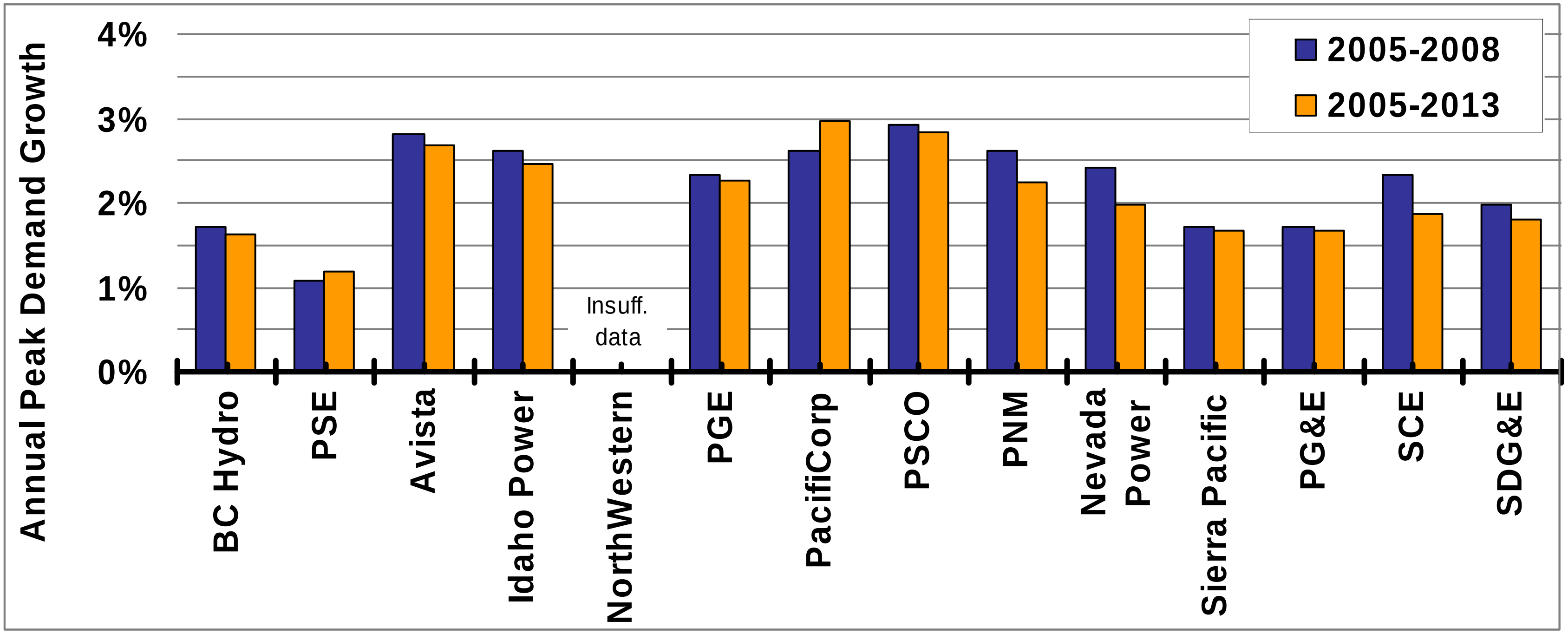
Approach to RA	Metric	Utility	Reserve Margin
WECC "Minimum Design Performance"	**Greater of R, or the Largest Risk + 5% of Load Responsibility**	Sierra Pacific	**No numeric planning margin is specified.**
	Two Largest Risks	Idaho Power	**Reserves to cover loss of Idaho Power's share of two Bridger units equates to a 12% margin.**
	1-in-10 Year LOLP	Nevada Power PSCO	**Maintain 12% and 17% reserves, respectively.**
State RA Requirements	**Minimum Requirement**	PG&E SCE SDG&E	**Maintain resources to meet a planning reserve margin of 15-17%**
Alternative Approaches	**Temperature**	PSE	**Maintain resources to meet peak load plus operating reserves for a 16° F hour, or ~14.5-15% reserves.**
	No Specified Metric Stated in Resource Plan	Avista	**Planning margins are 10% of the peak hour load plus 90 MW, a reserve margin of ~ 15%**
		NWE	**Quantity of long vs. short-term capacity resources is optimized as part of the portfolio analysis.**
		PacifiCorp	**Maintain sufficient capacity resources to meet a reserve margin of 15%**
		PGE	**Maintain a 6% planning margin on top of 6% operating reserve, for a 12% margin.**

Utilities' Existing Long-Term Resources



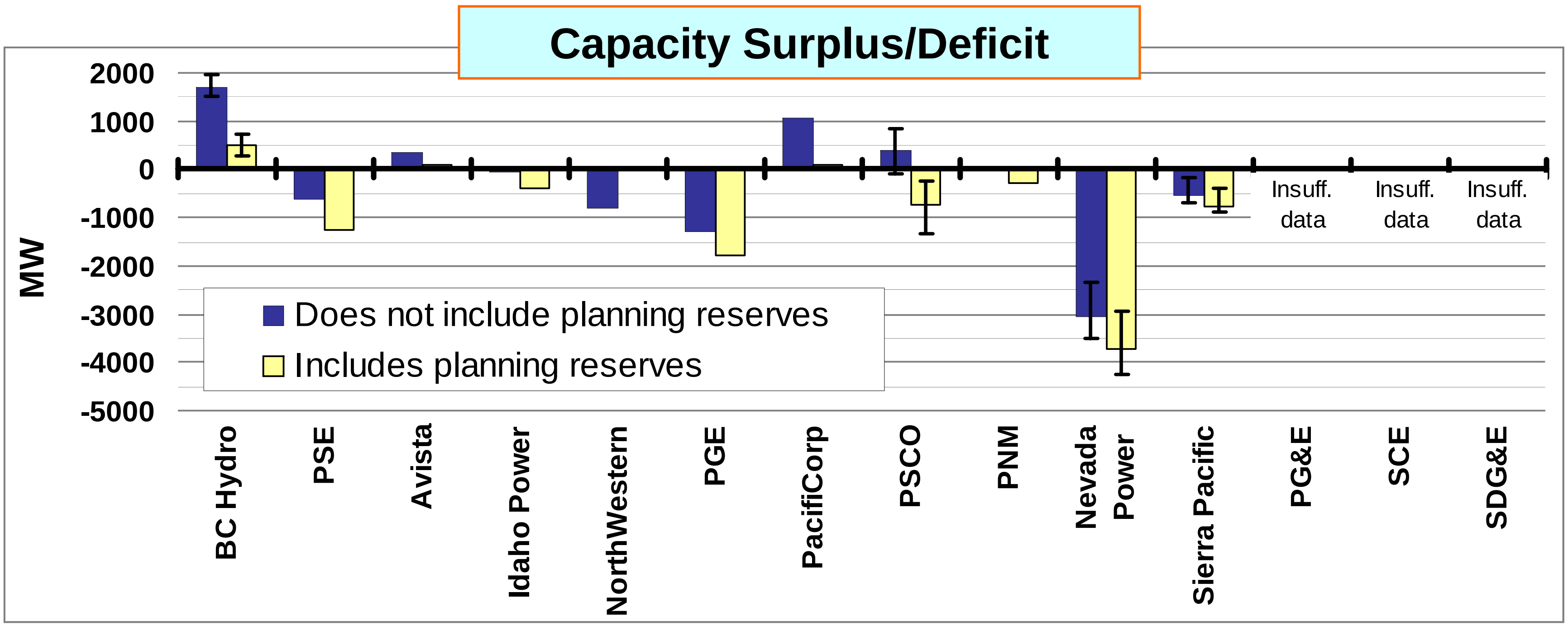
- **Long-term resources include utility-owned generation and contract resources (QFs, PPAs, seasonal exchanges)**
- **Short-term contracts (<5 yrs) and market purchases fill in any remaining resource need**

Retail Peak Demand Growth by 2008, 2013



- Average growth across West = 2.2% (2005-2008), 2.1% (2005-2013)
- Major issues/uncertainties:
  - Population growth (ID, NV)
  - National and regional economic trends/recovery
  - Load serving obligations and retail market development (OR, MT, NV)

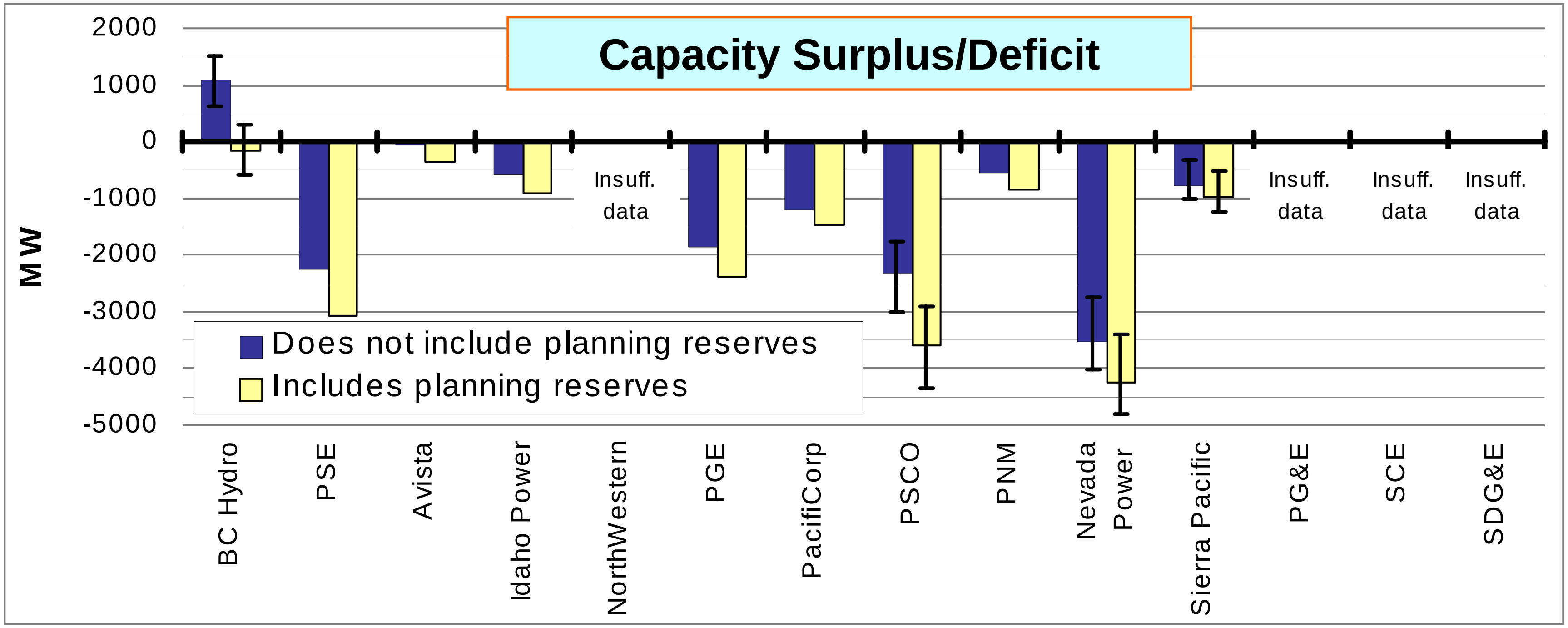
How Large are Utilities' Projected Resource Needs in 2008?



Without Planning Reserves	17%	-13%	19%	-2%	-69%	-32%	12%	6%	-1%	-55%	-30%	*	*	*
With Planning Reserves	5%	-26%	4%	-12%	n/a	-44%	1%	-11%	-16%	-67%	-42%	*	*	*

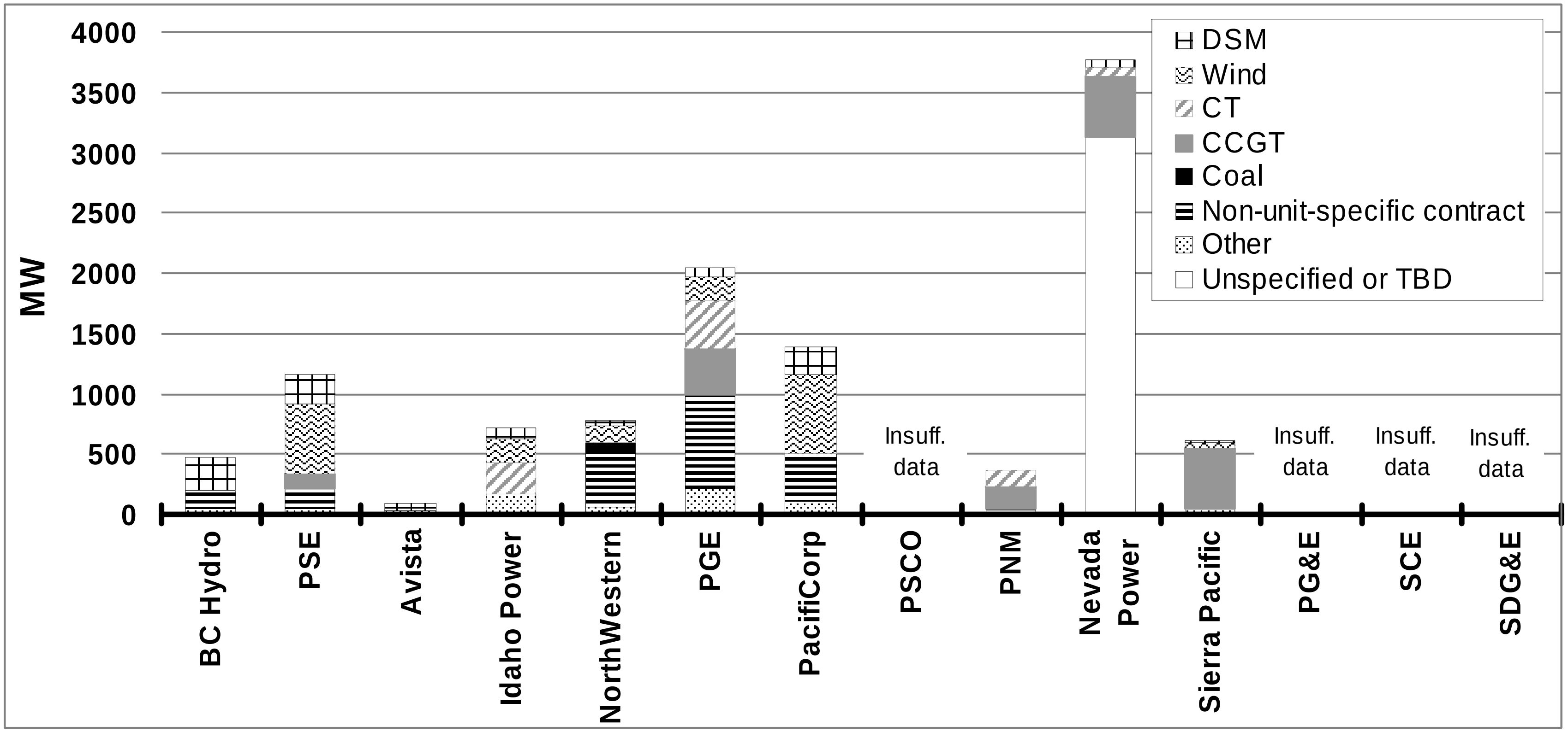
- **Projected difference between existing plus already-planned supply and forecasted peak demand**
- **"Error bars" indicate range based on high/low load forecasts**

How Large are Utilities' Projected Resource Needs in 2013?



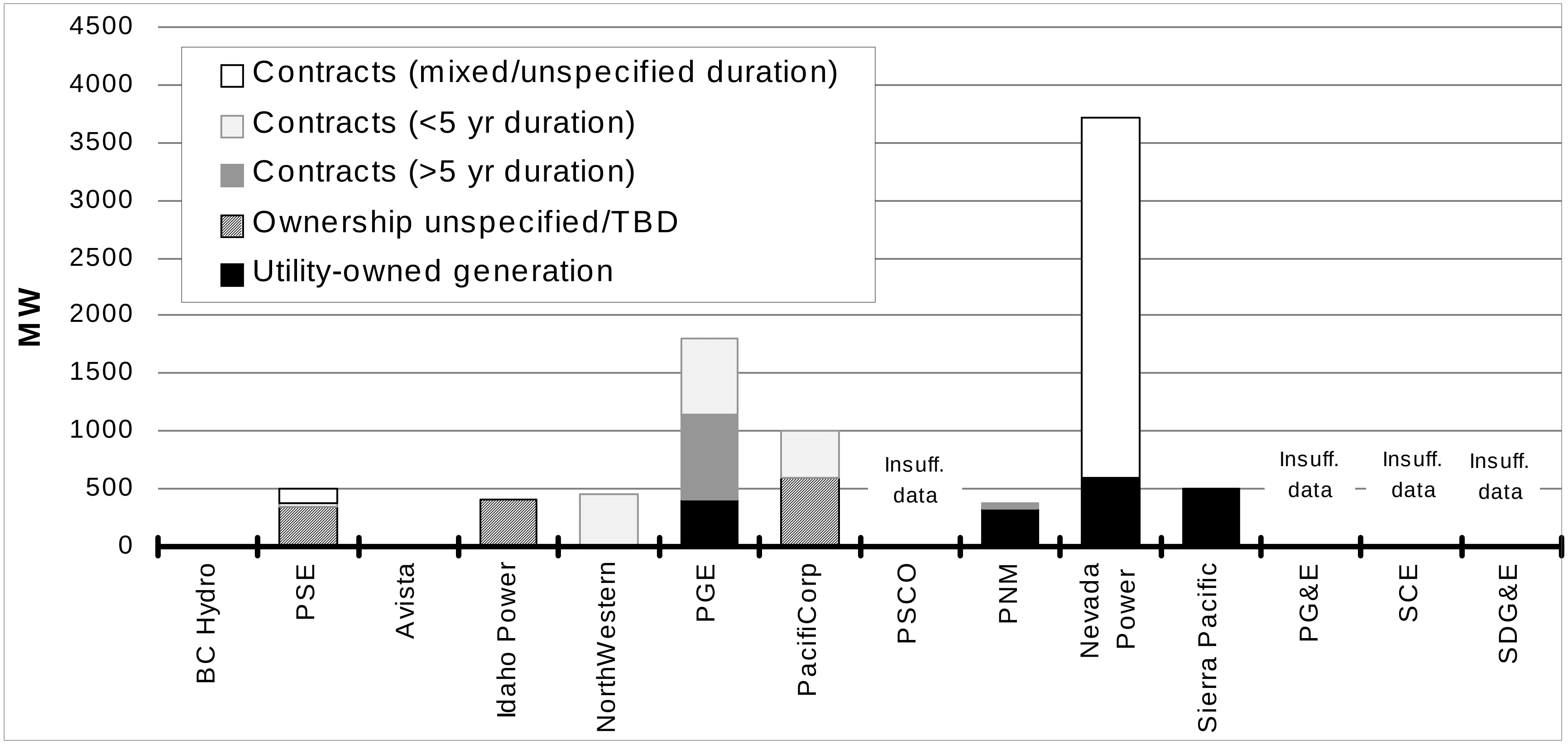
Without Planning Reserves	10%	-44%	-4%	-16%	*	-42%	-11%	-30%	-29%	-58%	-40%	*	*	*
With Planning Reserves	-1%	-59%	-18%	-24%	*	-54%	-13%	-47%	-44%	-70%	-50%	*	*	*

New Resources Proposed through 2008: Resource Types



- **New additions are a combination of company-owned resources, contracted resources, and resources of unspecified ownership, depending on the plan.**

New Resources Proposed through 2008: Ownership Type and Contract Length



- **Resource ownership specified in IRP or determined following RFP (PacifiCorp, PGE)**
- **Contract resources: PPAs, seasonal exchanges, tolling contracts, shaped products, etc.**

Treatment of Risk in IRP Plans

General Treatment of Risk in Utility IRPs

Least-Cost Supply Planning → **Least-Cost Supply-Demand Planning Incorporating Social Costs** → **Cost and Risk Minimization/ Risk Management**

Deterministic Modeling — **Scenario Analysis** — **Stochastic Modeling**

Three Different Kinds of Risk:
Each Merits Different Analysis Techniques

- Risk impacts and probabilities can be quantified (e.g., short-term gas price risk) → stochastic or scenario analysis
- Risks impacts can be quantified, but probabilities cannot be easily quantified (e.g., carbon regulations) → scenario/stress analysis
- Risks impacts and probabilities that cannot be quantified (e.g., FERC market redesign) → qualitative analysis

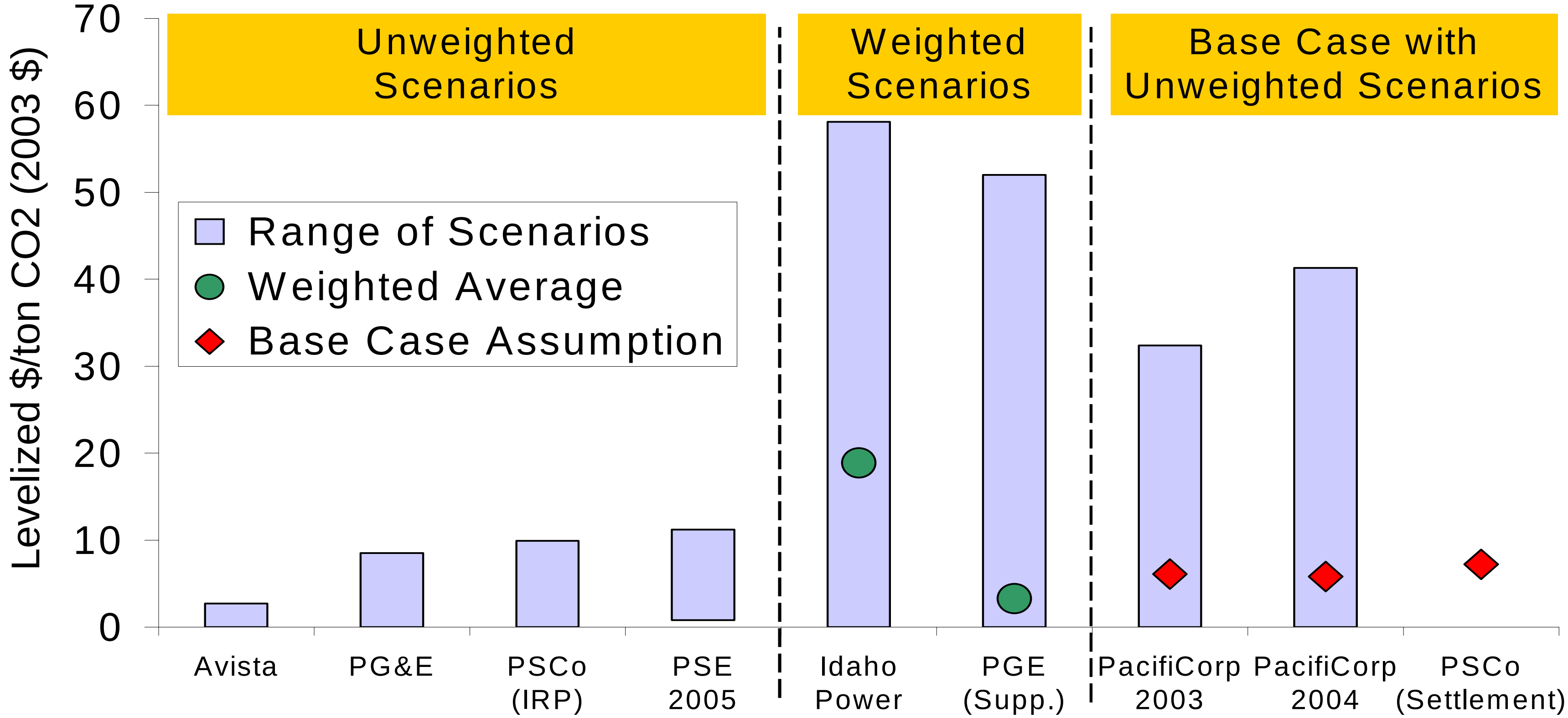
What Risks Are Addressed by Scenario or Stochastic Analysis in Western IRPs?

	Natural gas prices	Load growth	Electricity spot prices	Hydro variability	Departing load	Market structure	Carbon dioxide	Other emission regs
Avista	X	X	X	X	X	-	X	-
Idaho Power	X	X	x	X	-	-	X	X
Nevada power	X	X	X	-	X	-	-	-
NWEnergy	X	X	X	X	X	-	-	-
Pacifcorp	X	X	X	X	X	-	X	X
PG&E	X	X	X	X	X	X	X	-
Portland General	X	X	X	X	-	-	X	-
PSCo	X	X	X	-	-	-	-	-
PSE	X	X	X	X	-	-	-	-
SDG&E	X	X	X	-	X	-	-	-
Sierra Pacific	X	X	X	X	X	-	-	-
SCE	X	X	X	X	X	X	-	X

Western Resource Plans Are Increasingly Evaluating Carbon Regulatory Risk

- 7 of 12 considered risk during portfolio selection in latest round of resource plans, representing 30% of western electricity supply
- Minimum of 10 of 12 plans will consider this risk in next round (due to recent CPUC rulings): 42% of western electricity supply
- Two outliers: Nevada Power, Sierra Pacific
- For those utilities considering this risk already…
  - Approaches vary
    - Carbon scenarios but with no probabilities attached: Avista, PG&E, PSCo (original IRP), PSE 2005
    - Carbon scenarios with probabilities attached: Idaho Power, PGE
    - Included in base-case, sometimes with scenarios of varying regulatory stringency: PacifiCorp, PSCo (settlement)
  - Range of assumed carbon costs is wide, and some utilities are not evaluating a sufficiently broad range of scenarios (e.g., Avista)

Methods and Approach to Carbon Risk Evaluation Vary



We recommend that…

- all utilities evaluate carbon risk
- a greater level of consistency in evaluation approaches be sought
- a broad range of possible regulatory environments be considered

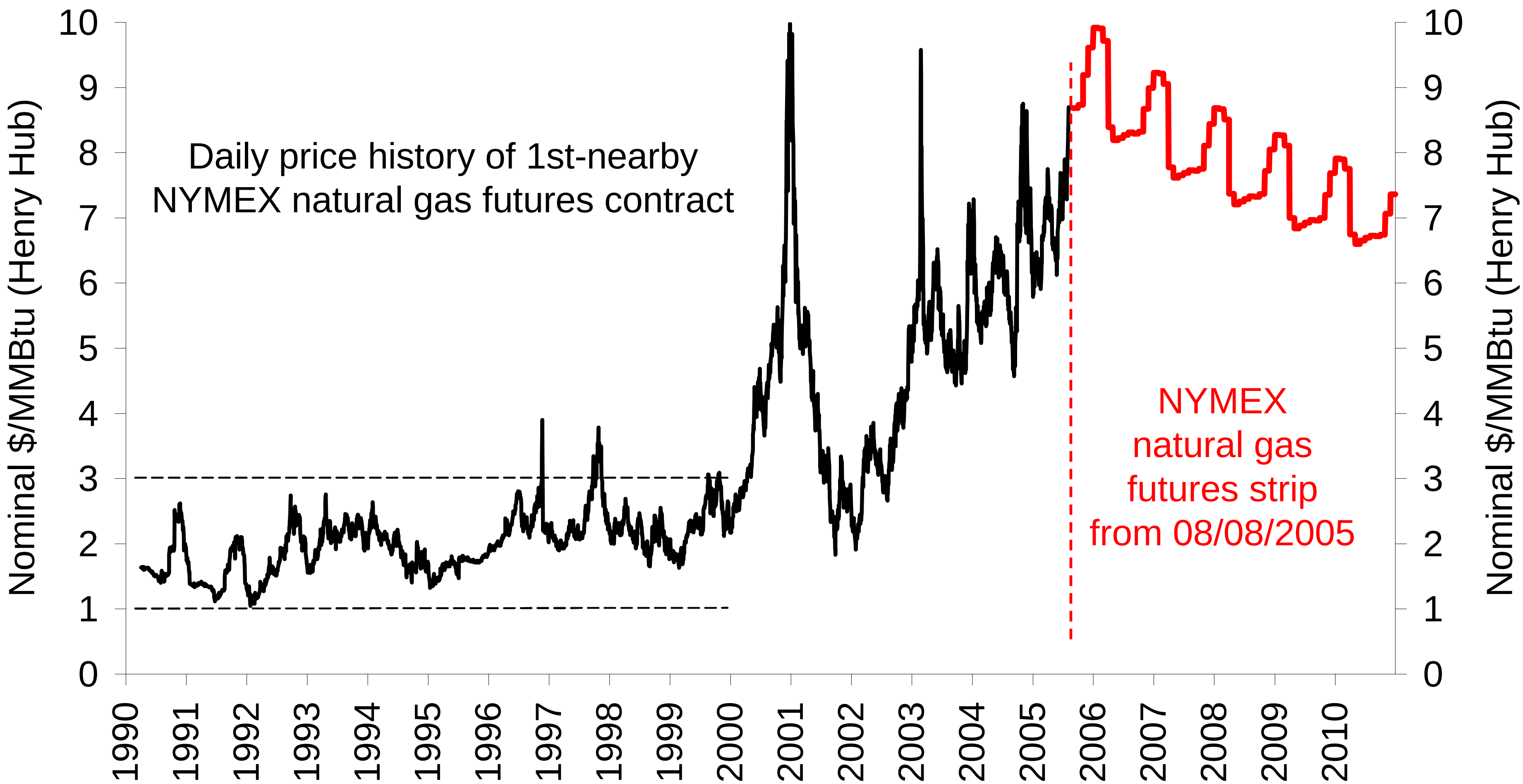
Treatment of Natural Gas Price Risk

Topics

Summarize treatment of natural gas price risk in Western utility resource plans

- **Motivation - Why Does Natural Gas Price Risk Matter?**
- **Treatment of Natural Gas Price Risk in Western IRPs**
  - Base-case gas price forecasts
  - Sensitivity analysis for gas price risk
    - Long-term risk
    - Short-term risk
  - Stochastic analysis for short- and long-term gas price risk
  - Other Issues
- **Best Practices, Recommendations, and Open Issues**

Natural Gas Prices are High and Volatile

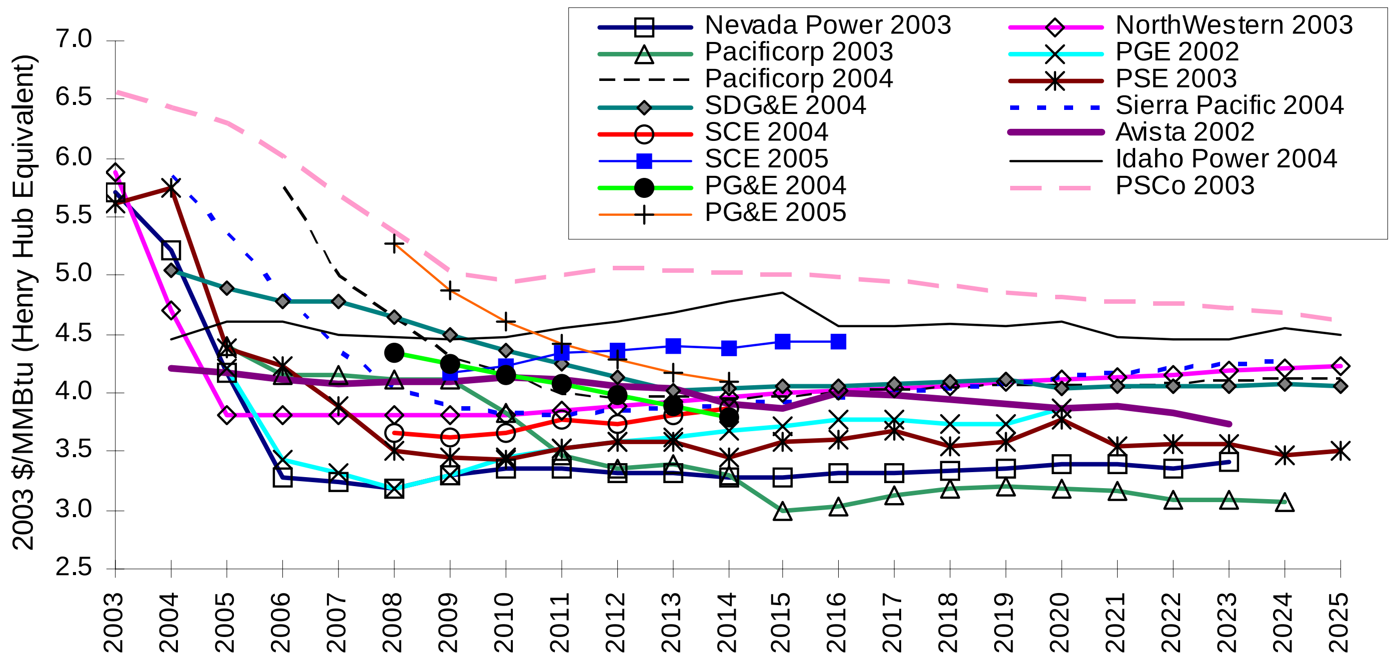


Source: NYMEX

Mitigating Gas Price Risk Poses Challenges

- Gas-fired generation is still expected to play a major role in new capacity additions
- A variety of tools can be used to mitigate price risk, but because mitigation options are not “ideal”, no single solution will do!
  - **Coal Generation:** environmental damages, risk of future carbon regulations, and heightened environmental restrictions
  - **Renewable Energy and Energy Efficiency:** question over how much of a contribution they can provide
  - **Gas Storage and Fuel Switching:** can be useful for short-term price fluctuations
  - **Fixed-Price Gas Hedging:** useful for short-term risk exposure, but long-term hedges (both fixed-price gas and, consequently, fixed price gas-fired power) are illiquid and subject to credit risk

Base-Case Natural Gas Price Forecasts Vary Considerable Among Resource Plans



Key Conclusions

- ***Use an Up-to-Date Forecast:*** Long-term levelized natural-gas price expectations have risen by ~\$1/MMBtu over just the last 2 years
- ***Benchmark Early-Year Prices to the NYMEX Forward Curve:*** Forward prices are arguably the best predictor of future prices, and forecasts that are not consistent with NYMEX (SCE, Avista) merit an explanation

Little Weight Should Be Placed on Base-Case Forecasts

- The history of gas-price forecasting is dismal
- Utility resource plans are responding to this challenge with scenario and, more recently, stochastic analysis, but…
- Scenarios sometimes overly timid (PSE, PSCo, Nevada Power)
- Stochastic analysis difficult to critique due to inconsistent approaches and data release

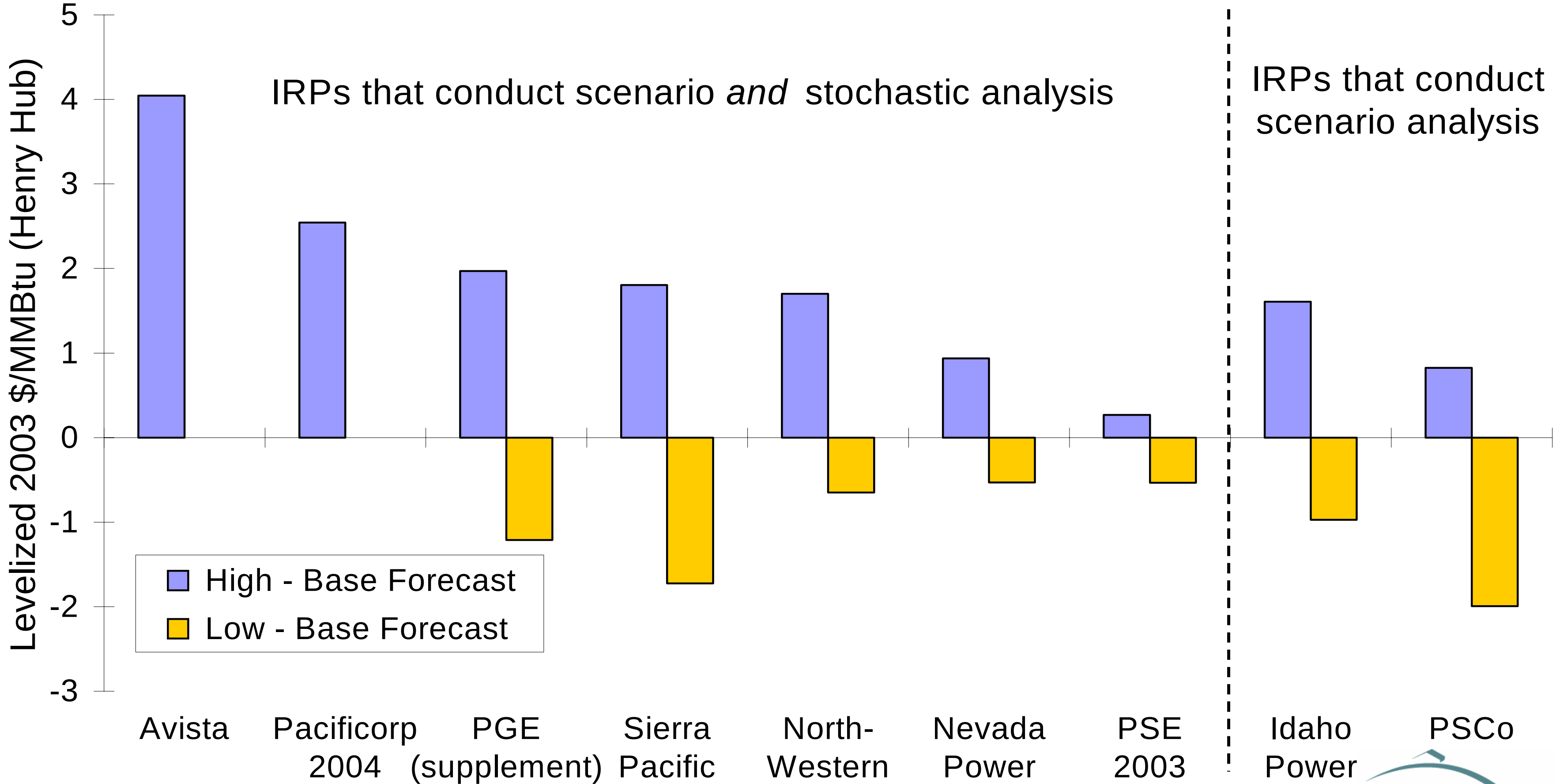
Utility	Scenario Analysis	Stochastic Analysis
Avista	✓	✓
Idaho Power	✓	
Nevada Power	✓	✓*
NorthWestern	✓	✓
PacifiCorp	✓**	✓
PG&E		✓
PGE	✓	✓
PSCO	✓	
PSE	✓	✓
SDG&E		✓
Sierra Pacific	✓	✓*
SCE		✓

* Stochastic analysis only conducted for short-term energy plan, not long-term resource portfolios.

** Only for PacifiCorp's 2004 IRP

Treatment of Long-Term Gas Price Uncertainty: Sensitivity Analysis

A number of IRPs conduct only sensitivity analysis, while others do so as a *supplement* to stochastic analysis. Range of high/low sensitivity cases, relative to base, varies across plans:



Treatment of Long- and Short-Term Gas Price Uncertainty: Stochastic Analysis

- **Stochastic analysis is increasingly used to evaluate short- and long-term gas price (and other) risks in Western IRPs**
- **A range of potential gas price forecasts are developed in conjunction with other key variables (electricity prices, hydro availability, etc)**

- **Northwestern Energy**
- **Avista**
- **PSE**
- **PacifiCorp**
- **Portland General Electric**
- **Southern California Edison**
- **Pacific Gas & Electric**
- **San Diego Gas & Electric**

Basecase gas prices, and other stochastic variables → Application of statistical methods → Numerous, unique sets of input data (probability distributions) → Statistical sampling, and numerous iterations by the model → Several hundred unique sets of results

Best Practices and Recommendations: Suggestions for Characterizing Gas Risks

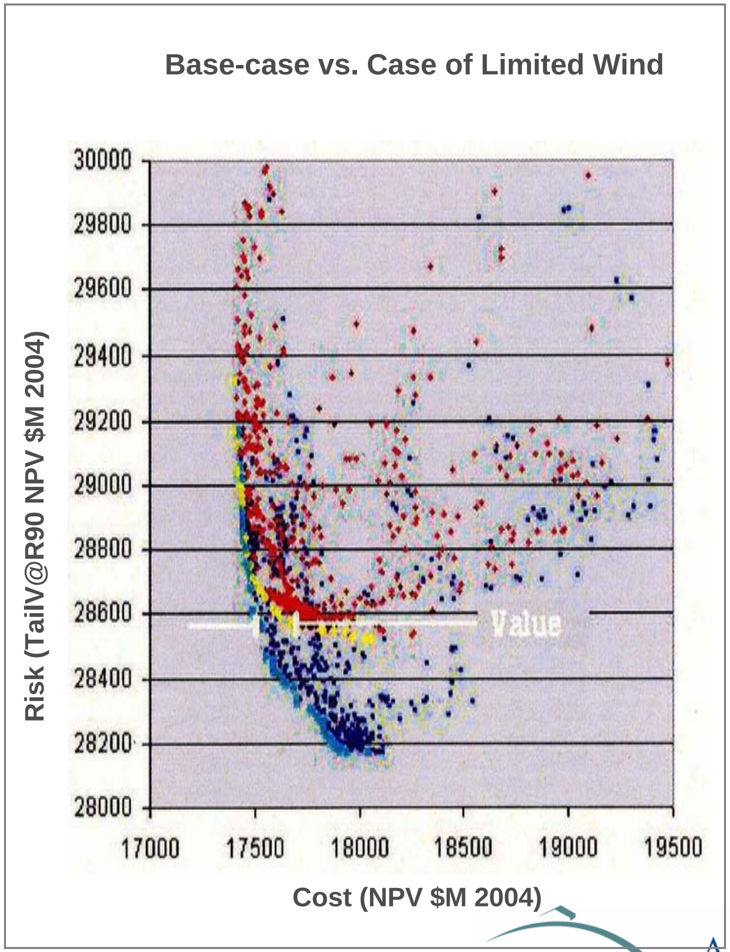
- **Risk analysis tools have become sophisticated:** use them
- **Forward markets arguably are the best predictor of gas prices:** if utility price forecasts diverge significantly from 5-year NYMEX forward curve, an explanation is warranted
- **Future gas prices are highly uncertain:** be humble, and do not put much weight on the base-case forecast
- **Interactions between different risk elements affecting gas prices are important:** consider linkages between gas costs, hydro availability, weather, load, etc.

Best Practices and Recommendations: Resource Portfolio Considerations

- **Develop portfolio choices that mitigate risks:** portfolio choices to mitigate risk need to be well specified
  - Numerous portfolios should be considered: risks should be identified and analyzed, and mitigation options should be explored
  - Subset of portfolios should be designed to explore impact of certain resources on gas risks (e.g., a portfolio focusing on increased renewables and gas – relative to base portfolio) is not likely to show the beneficial effects of renewables on risk reduction)
- **Multiple hedging options exist:** understand the options and their limitations
  - short-term uncertainty can be hedged through natural-gas-based derivatives, fixed-price gas contracts, and gas storage
  - long-term uncertainty may be hedged physically through non-gas resources

Issues to Discuss with your PUC on cost vs. risk

- **Portfolio Selection: Balancing Cost and Risk**
  - Acting as agents on behalf of customers, regulators arguably need to provide guidance to utilities on cost/risk preferences: risk management goals, performance, and expectations must be established
  - What analysis needs are necessary to better understand this tradeoff, and should that analysis be pursued jointly?

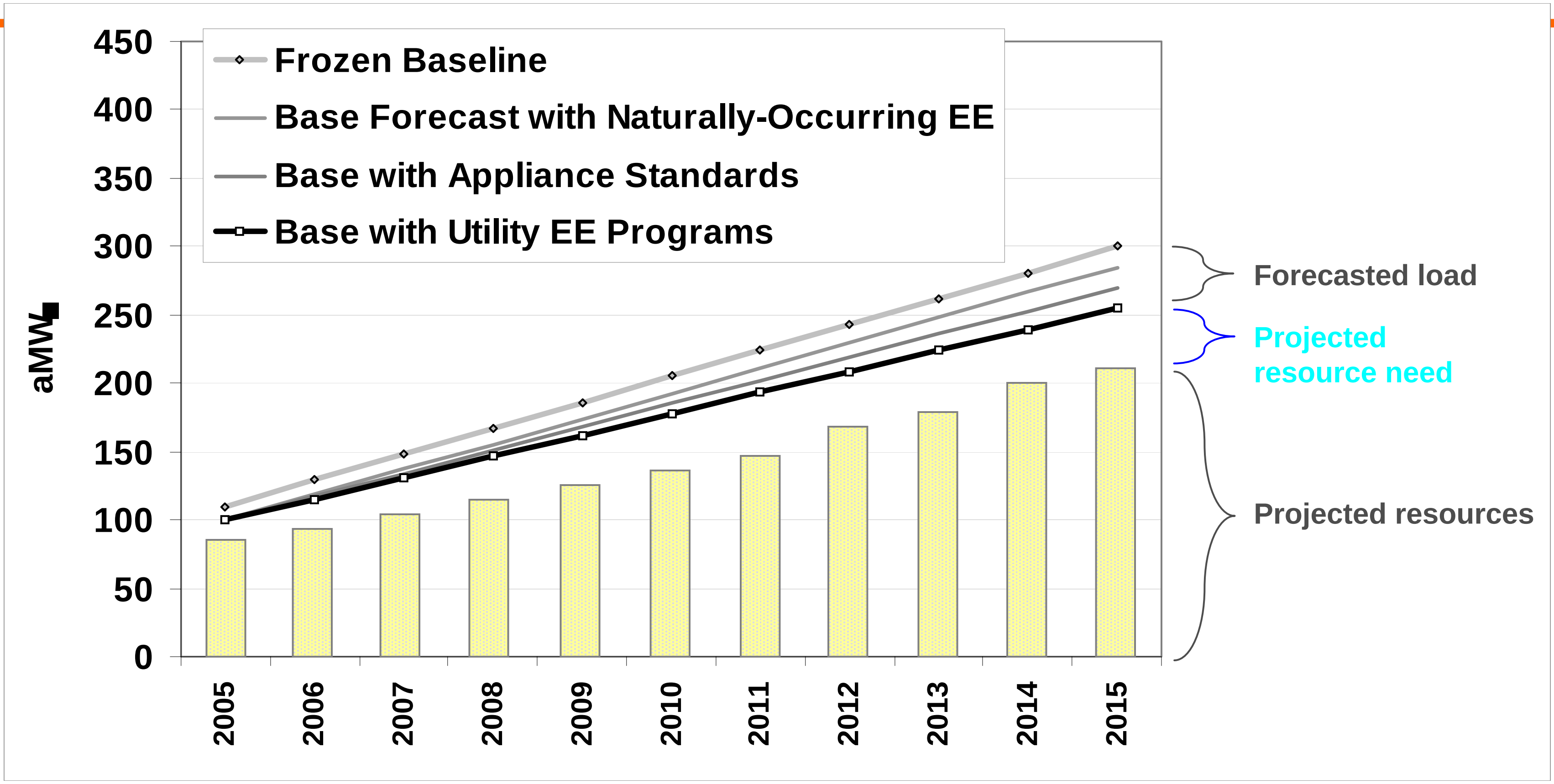


Treatment of Energy Efficiency and Demand Response

Energy Efficiency Topics:

- **Treatment of Energy Efficiency (EE):**
  - **Why does treatment of EE matter?**
  - **To what extent are utilities relying on EE?**
  - **How is EE treated and assessed?**
- **What improvements could be made in the consistency of reporting on loads & resources data to facilitate resource assessment**?

Establishing the "Resource Need"
Schematic of standard approach



- Magnitude of Resource Need often defined as difference between forecasted load and projected resources
- Energy efficiency "resources" often imbedded in the load forecast
  - Difficult to assess impact of EE and distinguish between naturally-occurring EE, utility EE programs and other EE strategies (codes, standards).

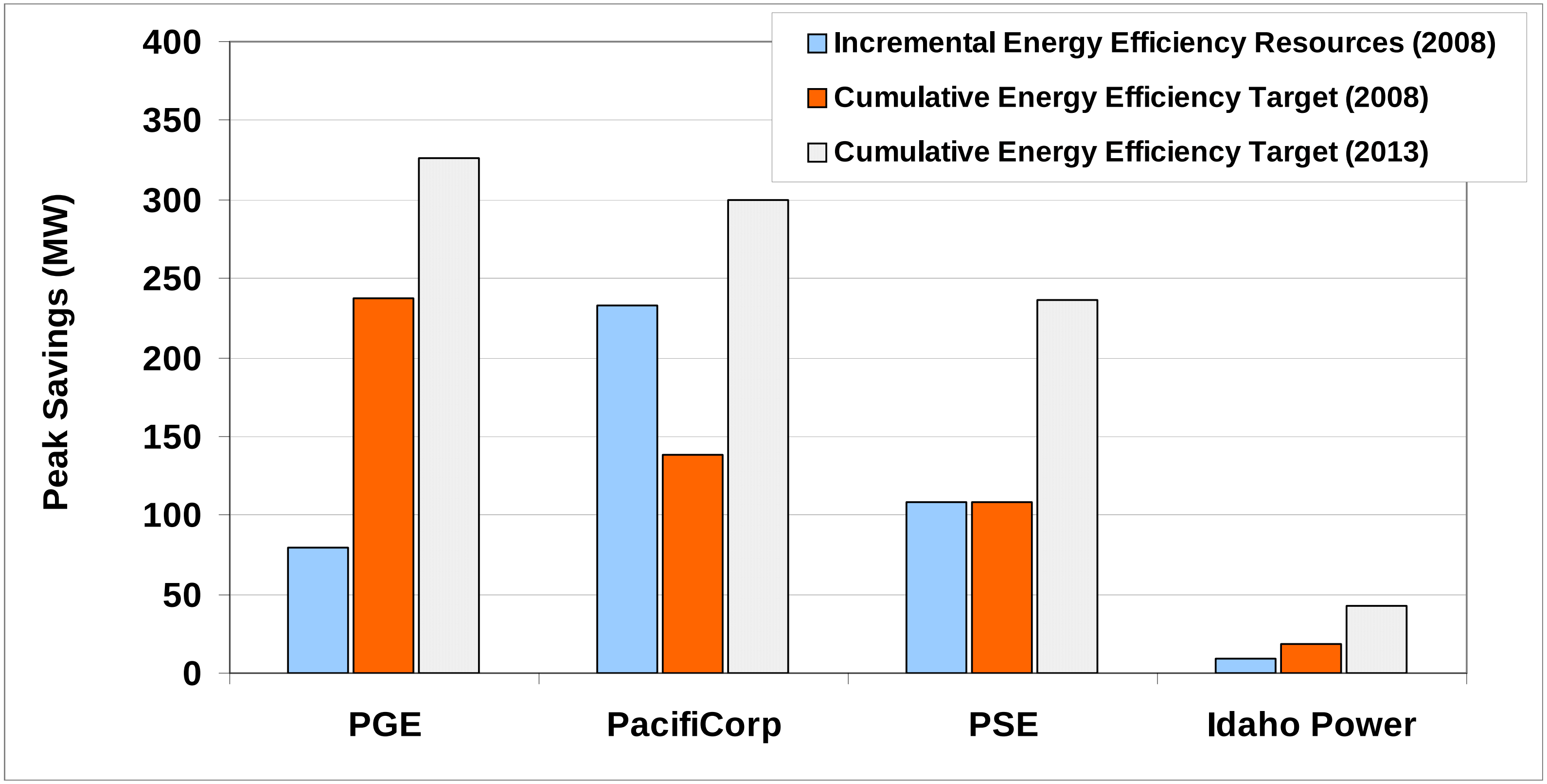
Accounting for Energy Efficiency Resources: Caveats

- For comparison with other capacity resources, the energy efficiency resource values are reported in terms of summer coincident peak savings (MW):
  - **Note: utilities generally do not provide MW values in their plans.**
  - **LBNL calculated MW values for some resource plans from aMW and/or MWh savings data using simple load factor adjustments, based on data from the Pacific Northwest.**
- Thus, accuracy of EE peak savings data should be considered "ballpark" estimates (+- 5 to 15%)
  - **Reflects LBNL estimates rather than utility projections.**

Why Does Treatment of Energy Efficiency in the Resource Plans Matter?

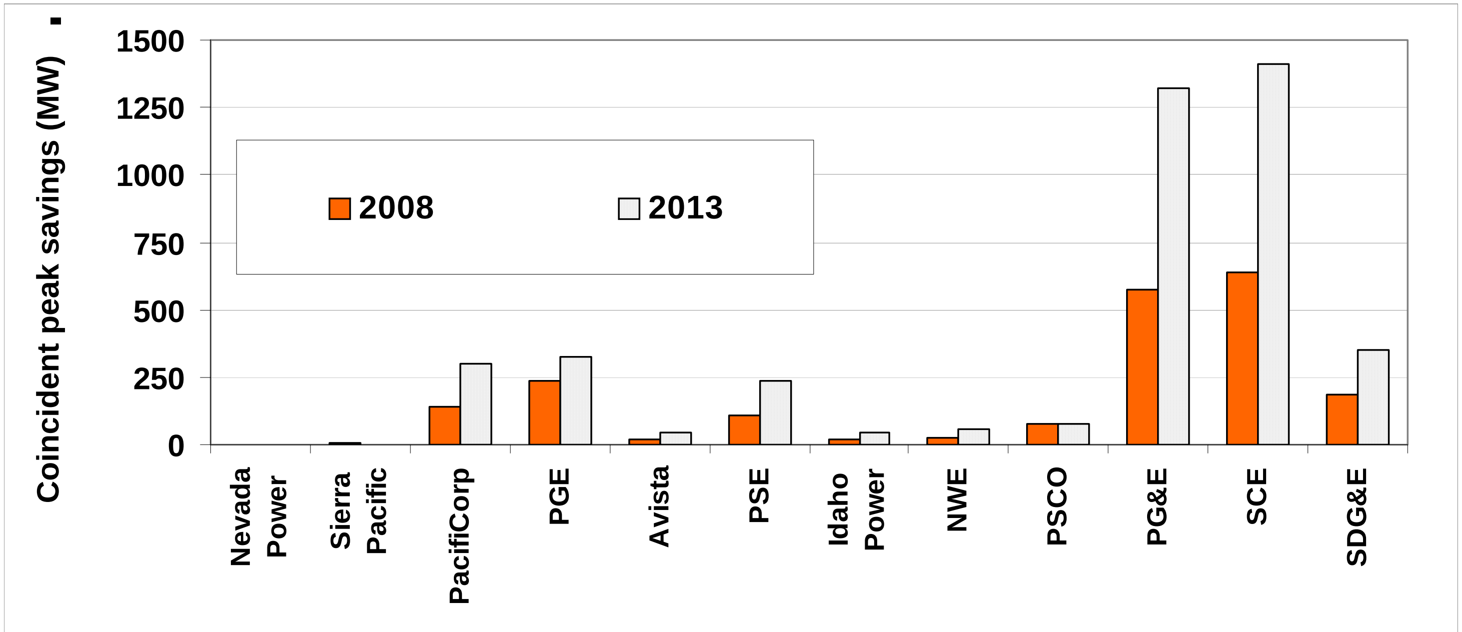
- EE is or is likely to become a significant resource
  - In some states, the cumulative EE impacts may approach or exceed the level of resource adequacy requirements
  - WGA is examining the feasibility of and actions that would be needed to increase EE by 20% by 2020
- EE affects the *level* of supply resources needed to meet resource adequacy requirements
- Inconsistencies in EE treatment and insufficient EE data across individual utility resource plans contribute to uncertainty of regional or west-wide resource assessments and determinations of resource adequacy

Incremental EE Additions in Plans vs. Cumulative Targets for Energy Efficiency



- Incremental EE Resources:
  - **Sum of annual impacts for new EE programs from plan date to 2008**
  - **Used by utilities in their portfolio modeling**
- Cumulative EE targets:
  - **Found in plan; not always consistent with incremental EE resource values**

Many Utilities only report Mid- and Long-Term Cumulative Targets for Energy Efficiency Resources



% of peak dem. growth (2008):	<1 %	1 %	7%	59%	13%	50%	8%	80%	12%	20%	23%	26%

Note: Efficiency values are shown as coincident peak savings, reflecting LBNL estimates rather than utility projections. For California's utilities, the percent of peak demand growth reflects only incremental energy efficiency additions.

- Cumulative *targets* were either identified elsewhere in plans (or in parallel documents in CA)
  - Were not necessarily used in resource portfolio modeling?
  - In later years, often based on top-down EE goals rather than "bottom-up" EE programs

Treatment of EE in Western Resource Plans:
Two Approaches

- **EE treated as a load modifier vs. fully valued as a resource**
  - Approach #1 (Load Modifier): EE implicit or assumed to be in the base load forecast, but not necessarily clearly identified in terms of how much or which types of EE
  - Approach #2: EE clearly identified as a resource, and EE then reduces the initial base load forecast explicitly
- **Which types of EE resources are considered and addressed in the load forecast (and how are they addressed)**
  - "Naturally-occurring" EE
  - Utility ratepayer-funded EE programs
  - Appliance standards
  - Building codes

Inconsistencies in EE Treatment and Insufficient Data on EE in Western Resource Plans

- Short/mid-term program plans vs. longer-term EE/DSM cumulative targets
- Incremental future EE impacts vs. accounting for cumulative impacts of past or current EE resources?
- Planning horizon tends to be short for EE resources vs. 10-15 years for resource plans
- Very limited data on capacity (MW) impacts
  - More data presented as aMW, but still not complete
- Unclear how the *level* of EE resources is determined
  - May be based on other factors (budgets, prior agreements, etc.)?
  - Generally does not appear to be based on EE potential or cost-effectiveness analysis
- Cost-effectiveness approaches and avoided costs
- Lack of transparency, including redaction of key data

Demand Response Resource Acquisitions Through 2010

Utility	DR Activities	2010 Target (MW)	% of Peak Growth
Avista	Residential TOU discussed, but determined to be not economically viable at present.	-	-
Idaho Power	No DR programs identified in 2002 IRP, but a residential A/C direct load control program has subsequently been initiated.	-	-
Nevada Power	Continued expansion of A/C direct load control program. Additional projects proposed for study, including C&I RTP.	9	1%
NorthWestern	No DR resources in current plan, but intention to include DSM activities that encourage load shifting within future plans.	-	-
PacifiCorp	Introduce a new A/C direct load control program and an irrigation load control pilot, and potentially new interruptible/curtailment tariffs, pending results of further study.	154	14%
PGE	Existing residential TOU pilot will be expanded, and large customer RTP pilot will be offered, but capacity not explicitly valued. Dispatchable and fixed-term DR from large customers may be pursued. Residential DLC programs considered, but determined to be uneconomic.	-	-
PSE	A preliminary study indicated >200 MW cost-effective potential for winter peak clipping. No action items indicated in IRP.	-	-

Treatment of Renewable Energy

Renewable Energy Topics

Summarize Western utility resource plan treatment of renewable energy (RE), based on compilation, summary, and analysis of resource plan assumptions and methods

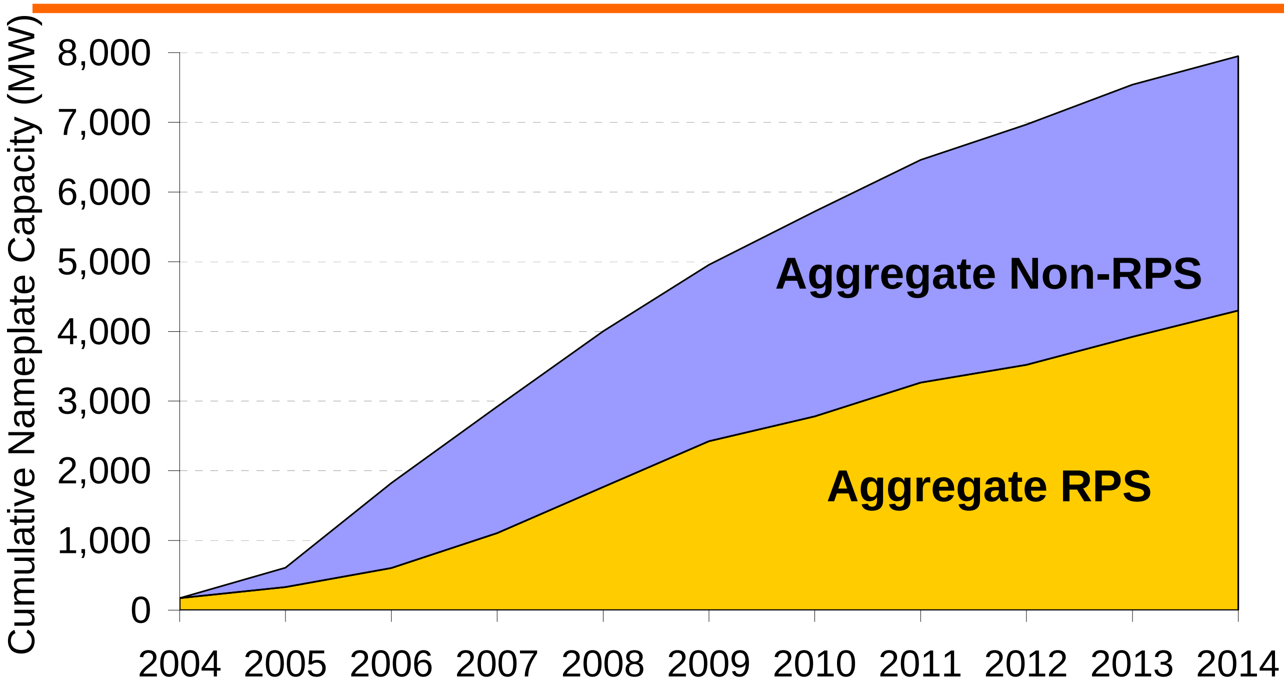
- Planned Renewable Energy Additions in Western Resource Plans
- Portfolio Construction
- Wind Power Cost and Performance Assumptions
  - Busbar costs, transmission costs, integration costs, capacity value
- Balancing Cost and Risk
- Conclusions

Western Utility Resource Plans Included in Our Sample

Resource plans from utilities subject to a Renewables Portfolio Standard (RPS)	PG&E, SCE, SDG&E, Nevada Power, Sierra Pacific
Resource plans in which no regulatory requirements compel RE additions	Avista, Idaho Power, NorthWestern*, Portland General (PGE), PacifiCorp, Puget Sound (PSE), PSCo*

*PSCo's and NorthWestern's most-recent resource plans preceded each state's RPS

Western Resource Plans Are a Major Source of Demand for New Renewable Energy



Non-RPS:

Wind accounts for 93% of new capacity in 2014

RPS:

Resources often unspecified

New Renewables Capacity in 2014 (MW)

	PG&E	Pacifi-Corp	SCE	PSE	SDG&E	PSCo	Idaho Power	Nevada Power	PGE	North-Western	Sierra Pacific	Avista
Non-RPS	0	1,420	0	745	115	500	450	0	195	150	0	75
RPS	2,150	NA	1,021	NA	630	NA	NA	361	NA	NA	137	NA
Total	2,150	1,420	1,021	745	745	500	450	361	195	150	137	75

Planned Renewable Energy Additions Are Affected By…

- How candidate portfolios are assembled and defined
- What assumptions are made for the cost and performance of renewable energy
- The degree to which and how electricity sector portfolio risks are considered
  - Natural gas price risk
  - Environmental compliance risk
- How tradeoffs between the expected cost and risk of different portfolios are made

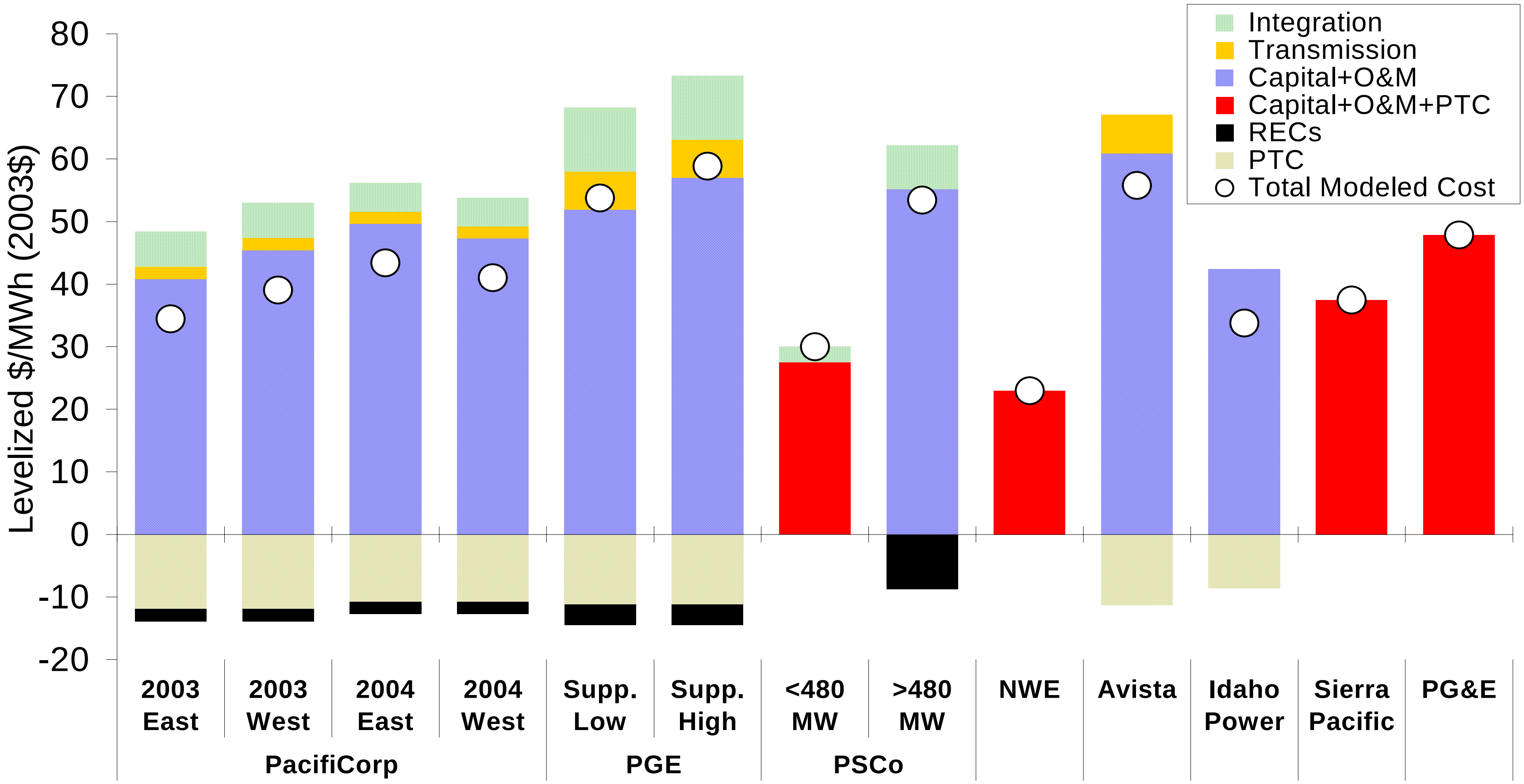
Construction of Candidate Portfolios

One of the goals of resource planning is to evaluate different possible resource portfolios

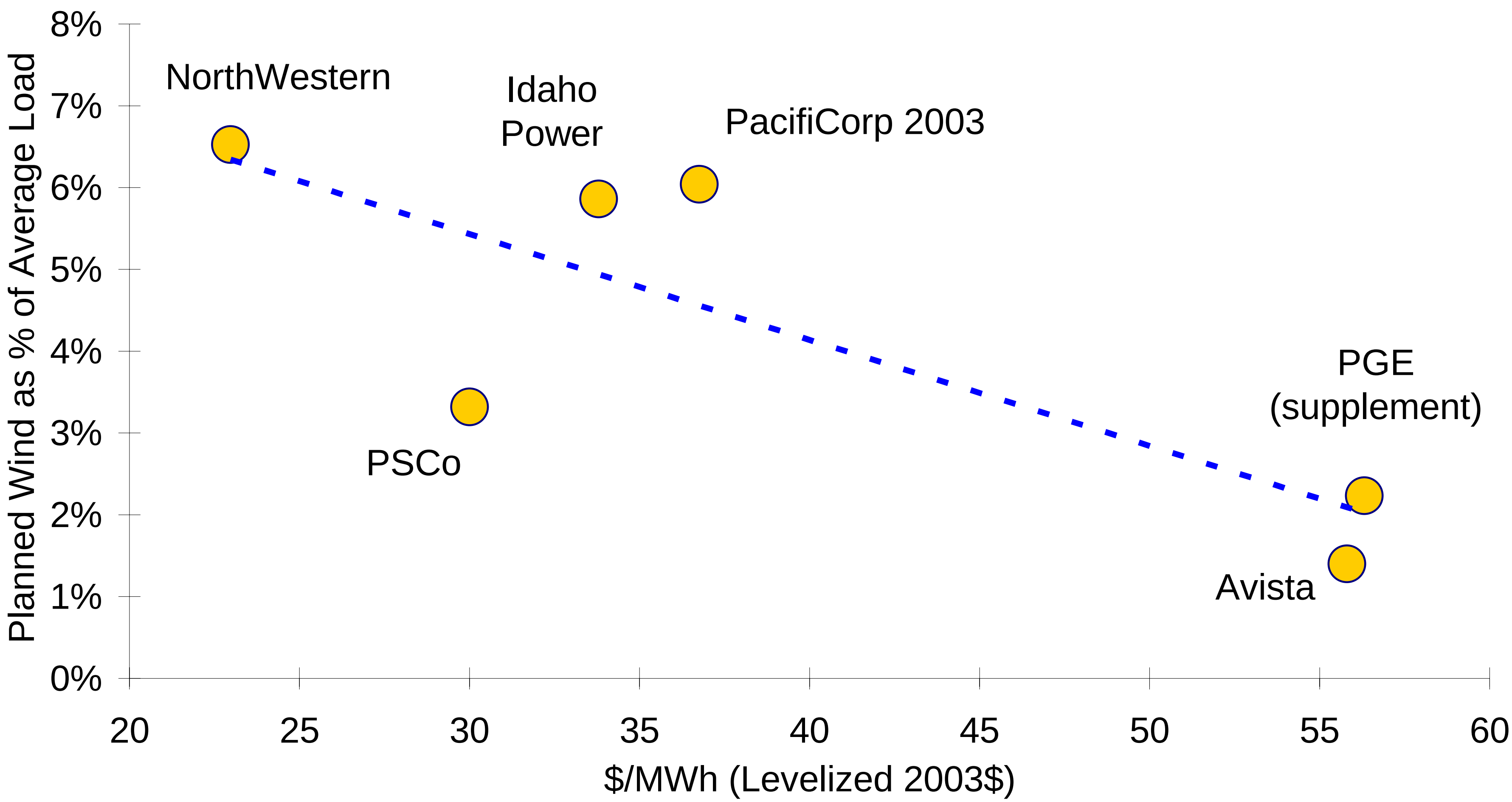
- Most plans create the candidate portfolios by hand, making the composition of these portfolios all the more important
  - Avista and PSCo use an optimization process to construct portfolios
- Resource plans in states with RPS obligations frequently do little to analyze the potential value of exceeding the obligations; the RPS “caps” planned RE additions
  - SCE, Nevada Power, Sierra Pacific, PG&E (original plan)
- Many plans only include wind power in candidate portfolios, with other renewable resources screened out at an earlier phase
- Many of the plans exogenously cap the maximum amount of wind additions, in some cases at very low levels, effectively pre-defining the amount of wind ultimately selected

Wind Power Cost and Performance Assumptions Vary Considerably Among the Plans

Total modeled cost for wind, including capital and O&M, PTC, integration, transmission, and RECs, ranges from $23/MWh to $59/MWh



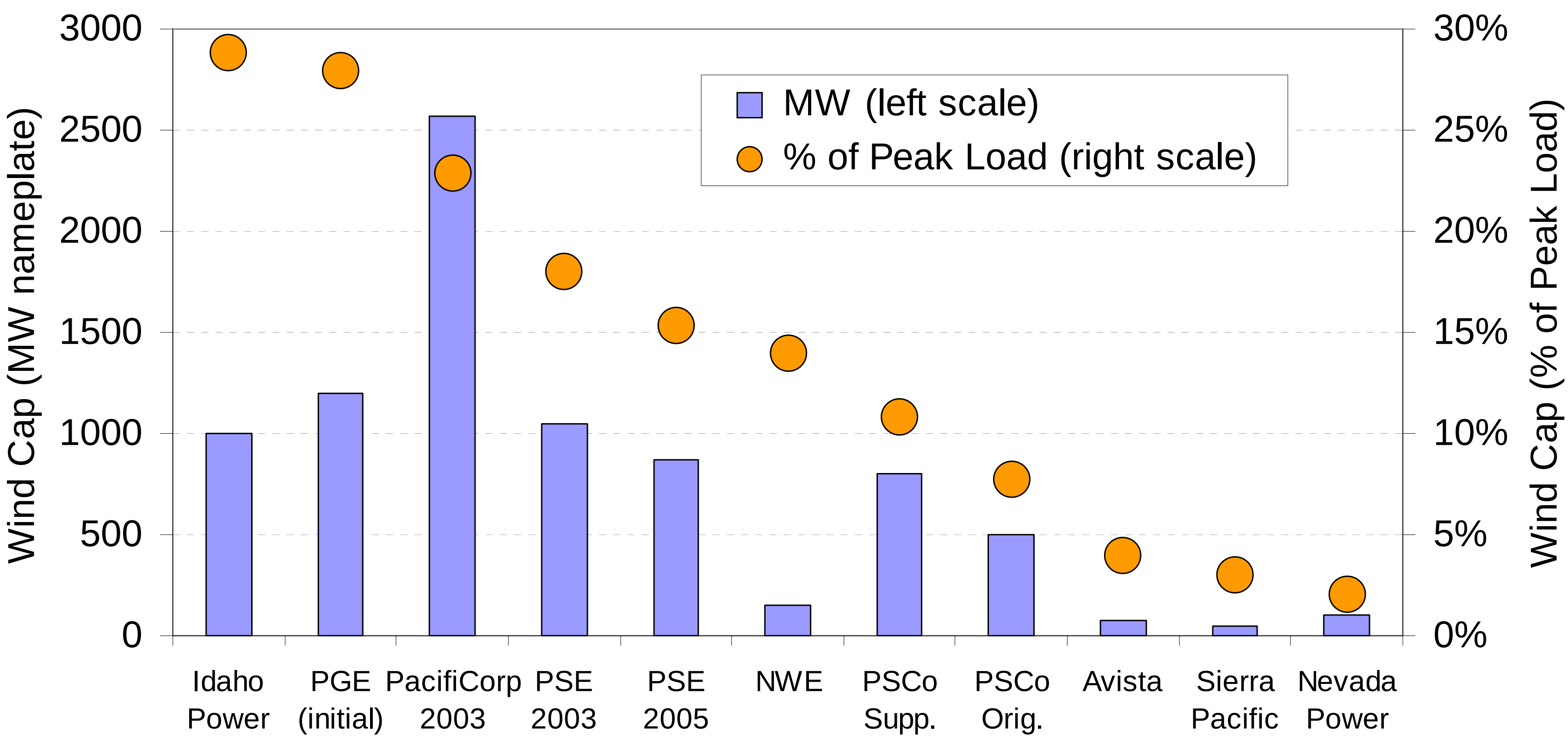
Total Cost Matters: Wind Additions Generally Higher When Modeled Costs Are Lower



Are the Assumptions Underlying Total Modeled Wind Power Costs Reasonable?

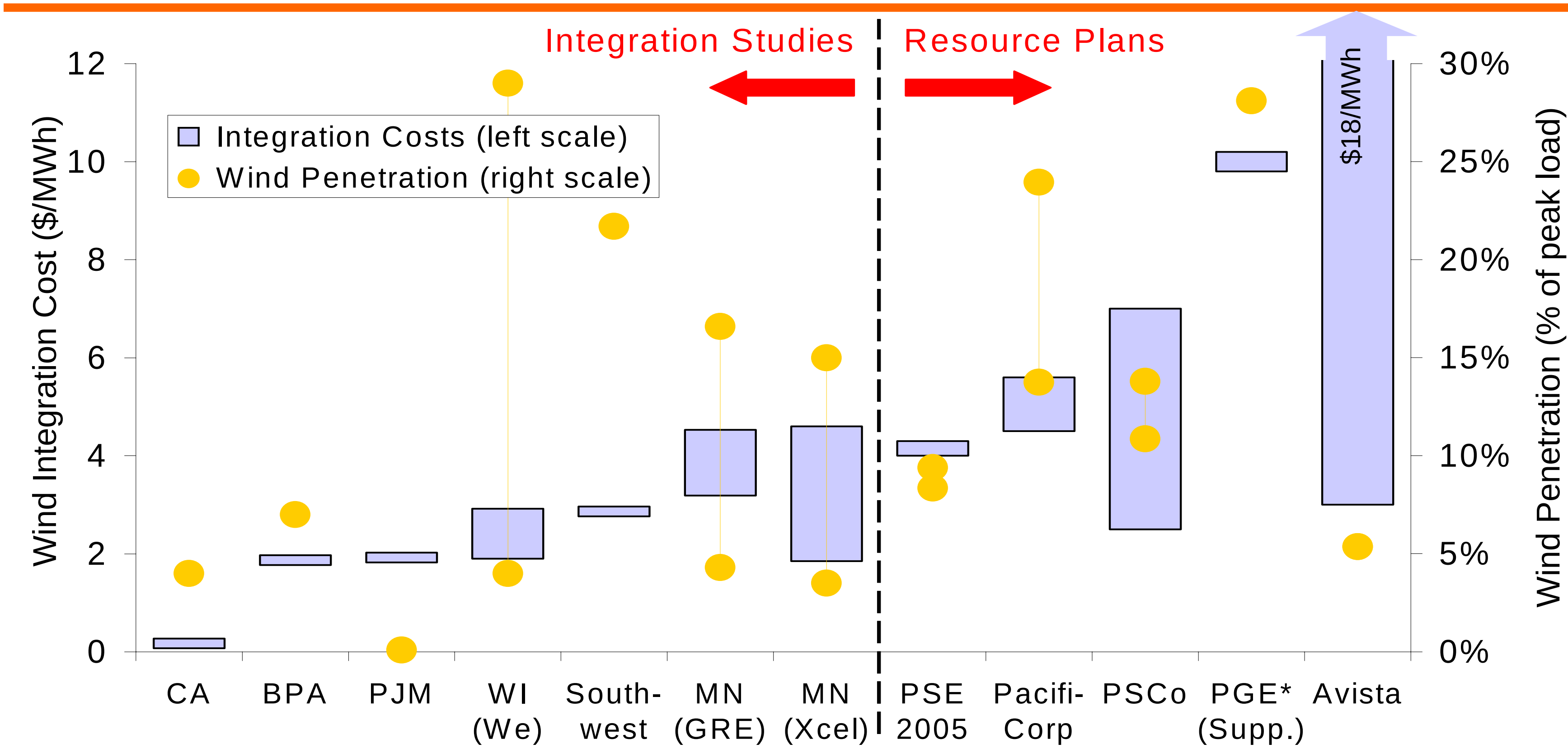
- **Busbar Costs: Capital, O&M, PTC**
  - Capital and O&M assumptions are reasonable at: $41-$61/MWh
  - PTC is undervalued by some resource plans (by ~$7/MWh), but many plans overstate the likelihood of PTC renewal over a length time horizon, and do not evaluate risk of expiration
- **Transmission Costs**
  - Plans often include expected transmission wheeling costs, but do not try to carefully evaluate transmission expansion needs
- **Integration Costs**
  - The science of quantifying integration costs has improved considerably, and these costs are being evaluated in an increasingly sophisticated way within utility resource plans, but…
  - Some utilities still appear to be over-estimating this cost, and others have established very low limits to wind penetration due to arguably exaggerated concerns about integration difficulties

Exogenous Build Limits "Cap" the Amount of Wind Selected by Some Resource Plans



NWE, PSE 2003, PSCo, and Avista all chose portfolios with wind at the cap (Sierra Pacific and Nevada Power do not report RE additions by technology, but presumably would also hit their low caps)

Integration Costs Assumed in Resource Plans Compared to Recent Analytic Literature

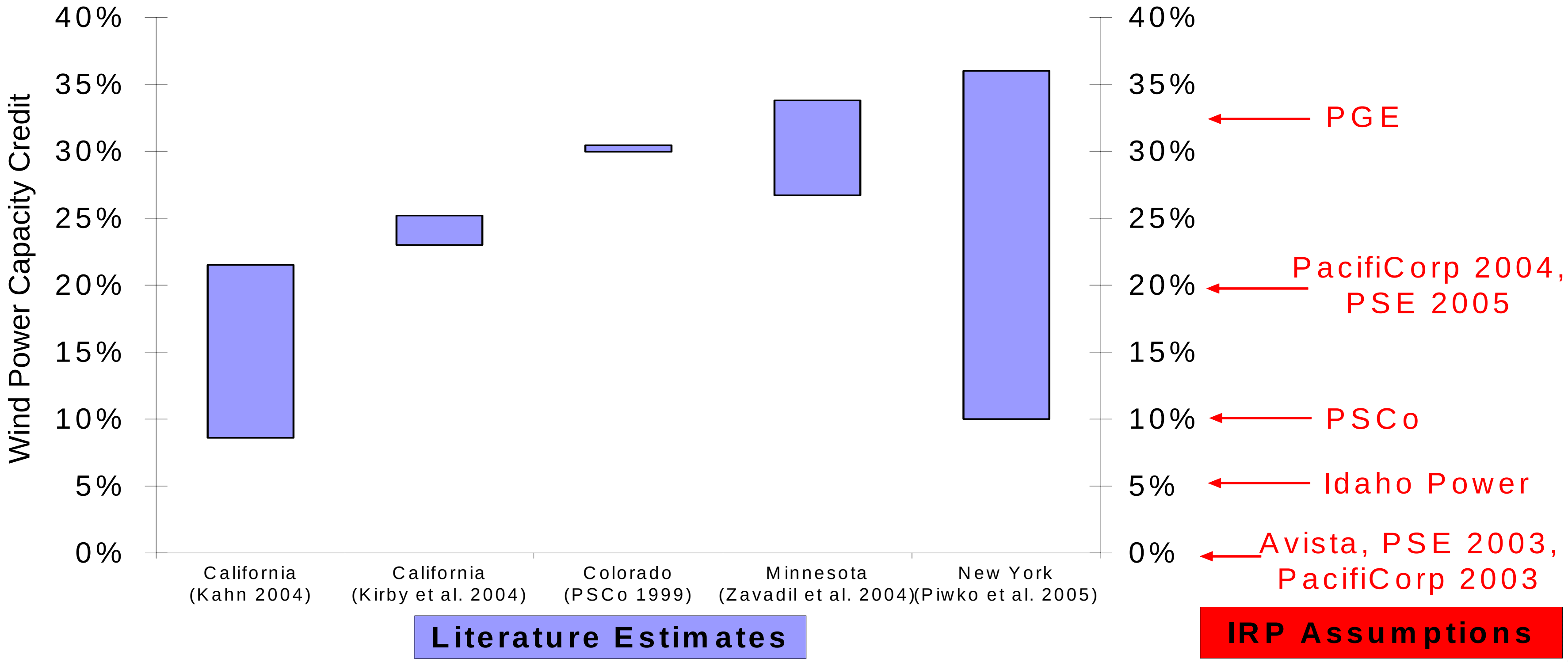


**PGE's supplemental IRP estimates the cost of creating a flat, base-load block of power out of variable wind production, rather than simply the cost of integrating variable wind production. As such, its cost estimates are not directly comparable to the others.*

Some resource plans set strict limits on wind penetration due to concerns about integration costs: Avista (75 MW, 4% of peak load), Nevada Power (100 MW, 2% of peak load), and Sierra Pacific (50 MW, 3% of peak load)

Resource Plan Capacity Value Assumptions Are Low Compared to Recent Literature

- Though less dependable than other resources, wind provides *some* capacity value
- ELCC is the most widely recognized method for determining capacity value
- Most utility plans did not use ELCC to calculate capacity value
- Many plans assumed lower capacity value than suggested in the literature



Balancing Cost and Risk: Concerns for Renewable Energy

- Plans often model RE primarily as wind power, assume a low capacity value, and apply low-limits to wind penetration
  - → Many of the hand-crafted "renewables" portfolios are weighted heavily towards gas-fired generation, thereby exhibiting as much or more exposure to gas-price risk than other portfolios (e.g., PacifiCorp, Idaho Power, PSE)
  - → Pushes portfolio choice towards coal more than renewable energy
- Fuel risk is often analyzed quantitatively ***early*** in the modeling process, while carbon risk (where included) is typically analyzed through scenario analysis ***later*** in the process and in a way that has less effect on portfolio choice
- Result is that RE portfolios are sometimes not considered low risk, and are sometimes "prematurely" weeded out at an early phase of the analysis

Renewable Energy Summary: Where Do We Go From Here…

Western resource plans are becoming increasingly sophisticated, and have begun to consider RE as a serious resource option.

But improvements are still possible and needed:

1) Resource plans in RPS states should consider evaluating renewable resources as an option above and beyond the level required to satisfy RPS obligations.
2) Resource planners may wish to explore a broader array of renewable resource options.
3) The value of the federal production tax credit for renewable energy, and its risk of permanent expiration, could be more consistently addressed on an after-tax basis.
4) Methods for evaluating wind integration and transmission costs, and capacity value, should continue to be refined and applied at successively higher wind penetration levels.

Renewable Energy Summary: Where Do We Go From Here…(Cont.)

5) Exogenous caps on wind penetration should potentially be eliminated, especially as analysis of wind integration and transmission costs, and capacity value, improve.
6) Resource plans would ideally evaluate a broad range of possible fuel costs, and subject a large number of candidate portfolios to such analysis (and risk analysis more generally).
7) Environmental compliance risks could be more consistently and comprehensively evaluated.
8) Steps should be taken to ensure that each risk has, as is warranted or appropriate, an opportunity to impact portfolio selection.
9) Utilities and regulators should conduct research to evaluate ratepayer risk preferences.
10) Though there may be instances in which redaction of commercially sensitive information is warranted, more consistent and comprehensive data presentation in utility resource plans would allow for far better external review.

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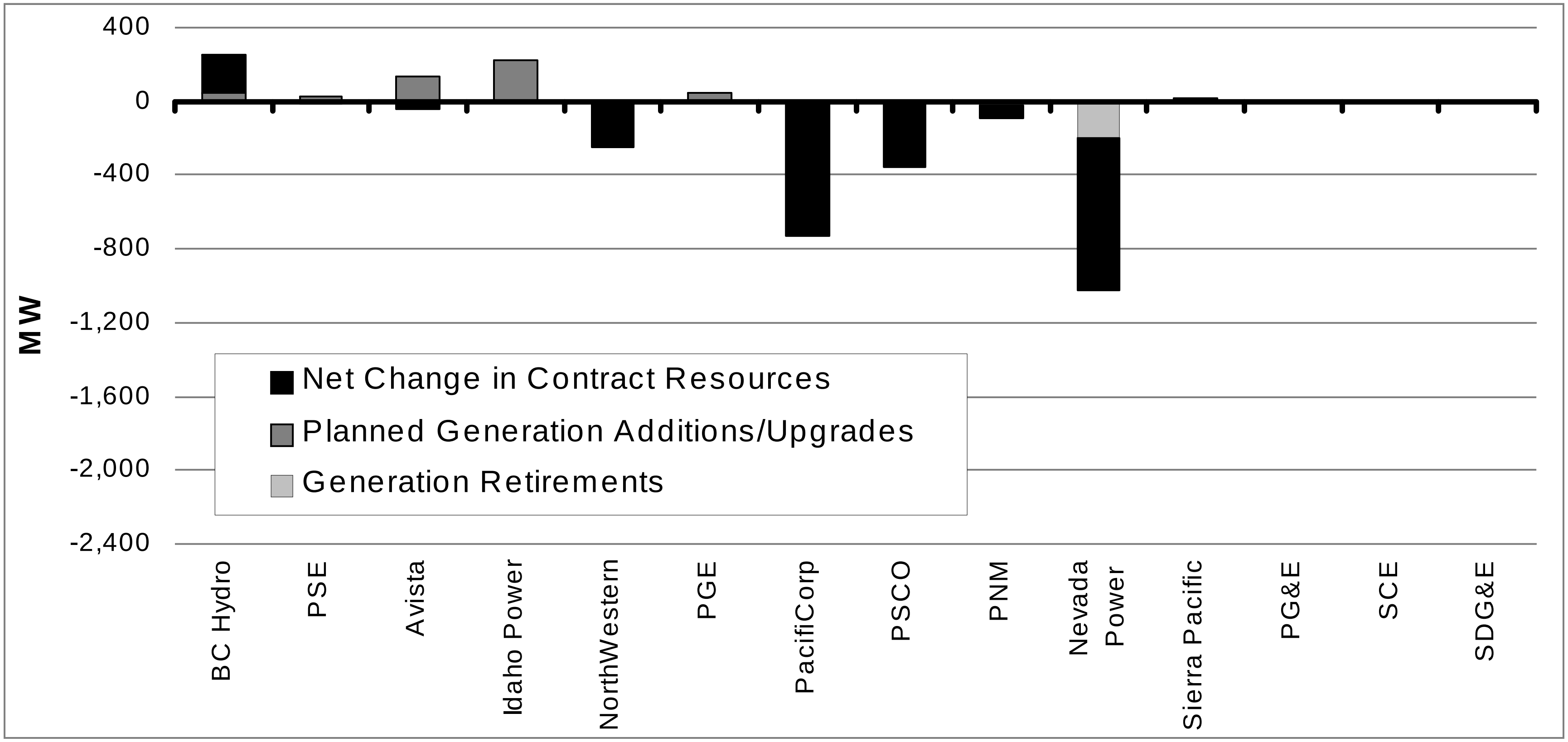
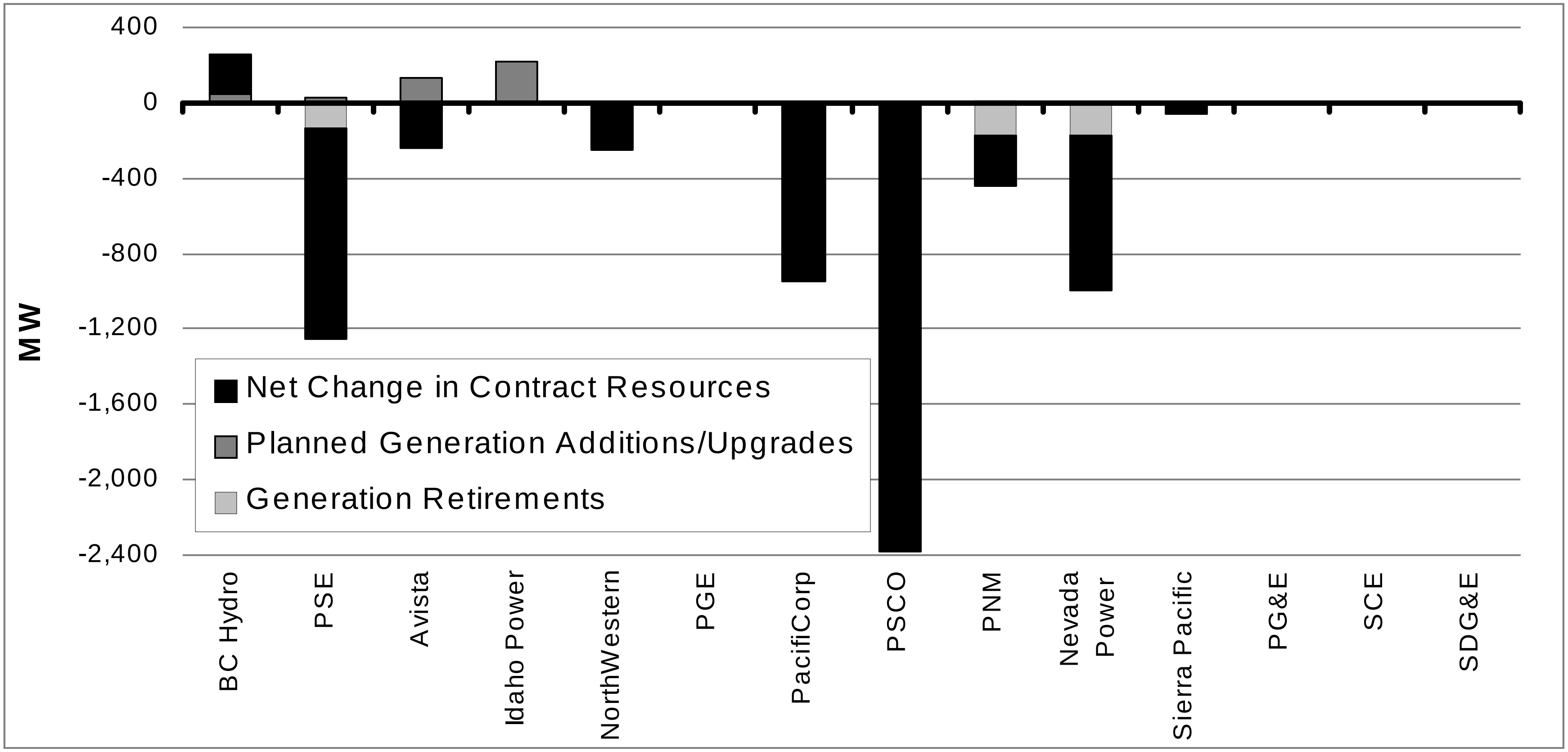
BACKGROUND SLIDES

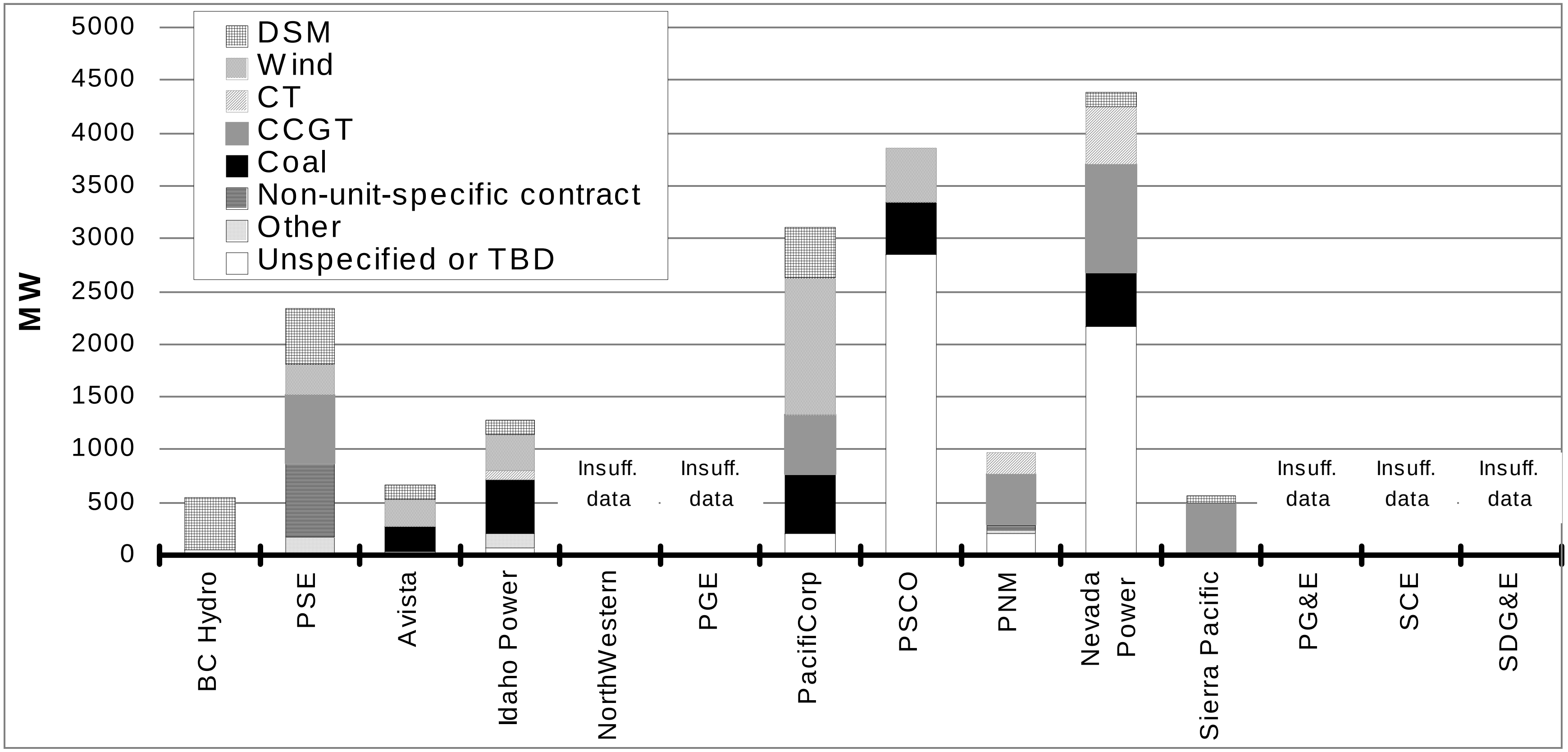
Changes to Utilities' Existing Resource Base: 2005-2008



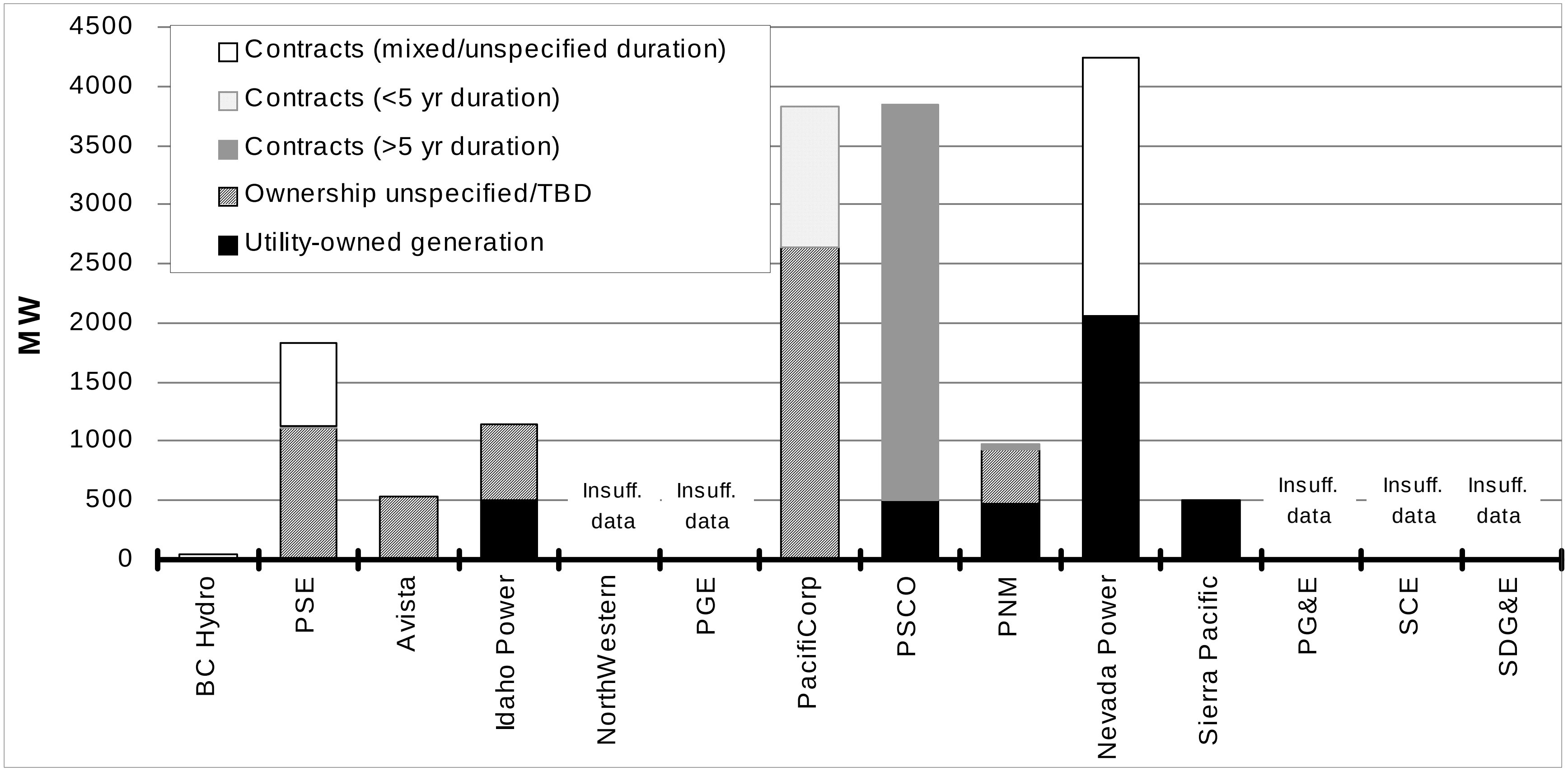
Changes to Utilities' Existing Resource Base: 2005-2013



New Resources Proposed through 2013: Resource Types

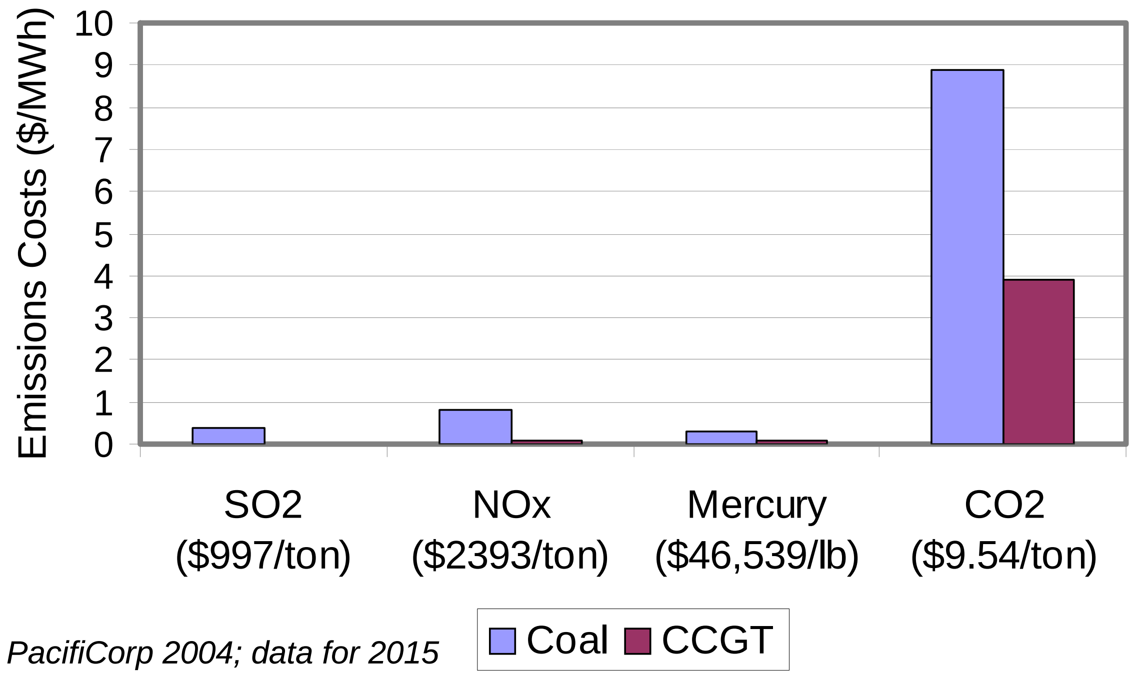


New Resources Proposed through 2013: Ownership Type and Contract Length



Environmental Regulatory Risk

Environmental regulations are likely to change over the course of electric supply investments, and utility planning should evaluate these risks, and mitigate them if cost-effective to do so



PacifiCorp 2004; data for 2015

Risk of carbon regulation – at the state or federal level – is likely the most important to consider, but risk of strengthened regulations of SO2, NOx and mercury also deserve note

Resource Plans Do Not Devote As Much Attention to Other Environmental Regulatory Risks

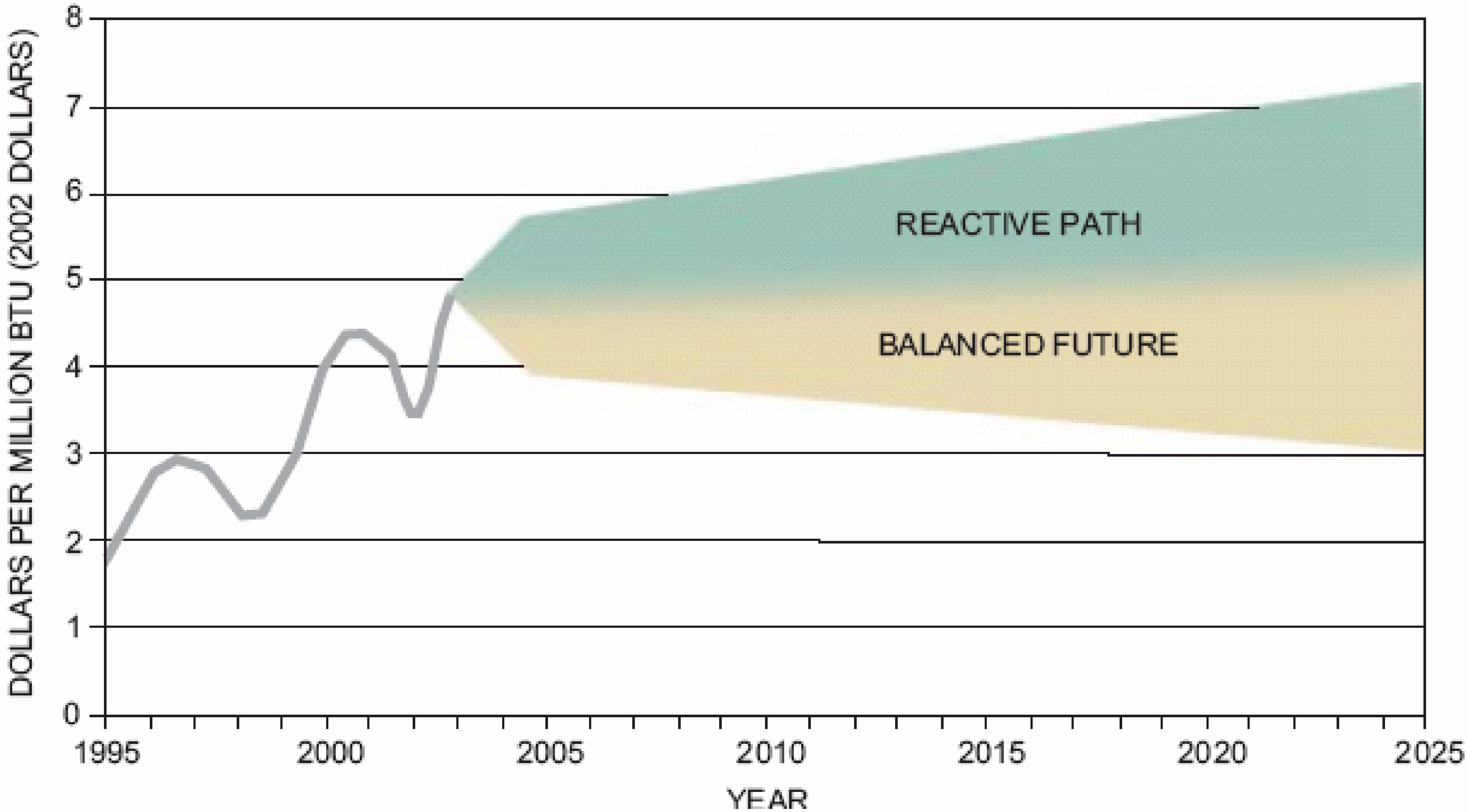
- Though not always stated, cost of complying with ***existing*** criteria air pollutant regulations is presumably included in all plans (though assumptions for the cost vary)
- Only ***two*** utilities in our sample appear to consider the very real possibility of strengthened ***future*** regulations:

Assumed Cost of Complying with Future Environmental Regulations

	SO2 (Levelized 2003 $/ton)	**NOx** (Levelized 2003 $/ton)	**Mercury** (Levelized 2003 $/lb)
PacifiCorp	Base: $675 Scenarios: $335-$708	Base: $1,604 Scenario: $264	Base: $31,192
PSCo (settlement)	Base: $796	Base: $796	Base: $9,954

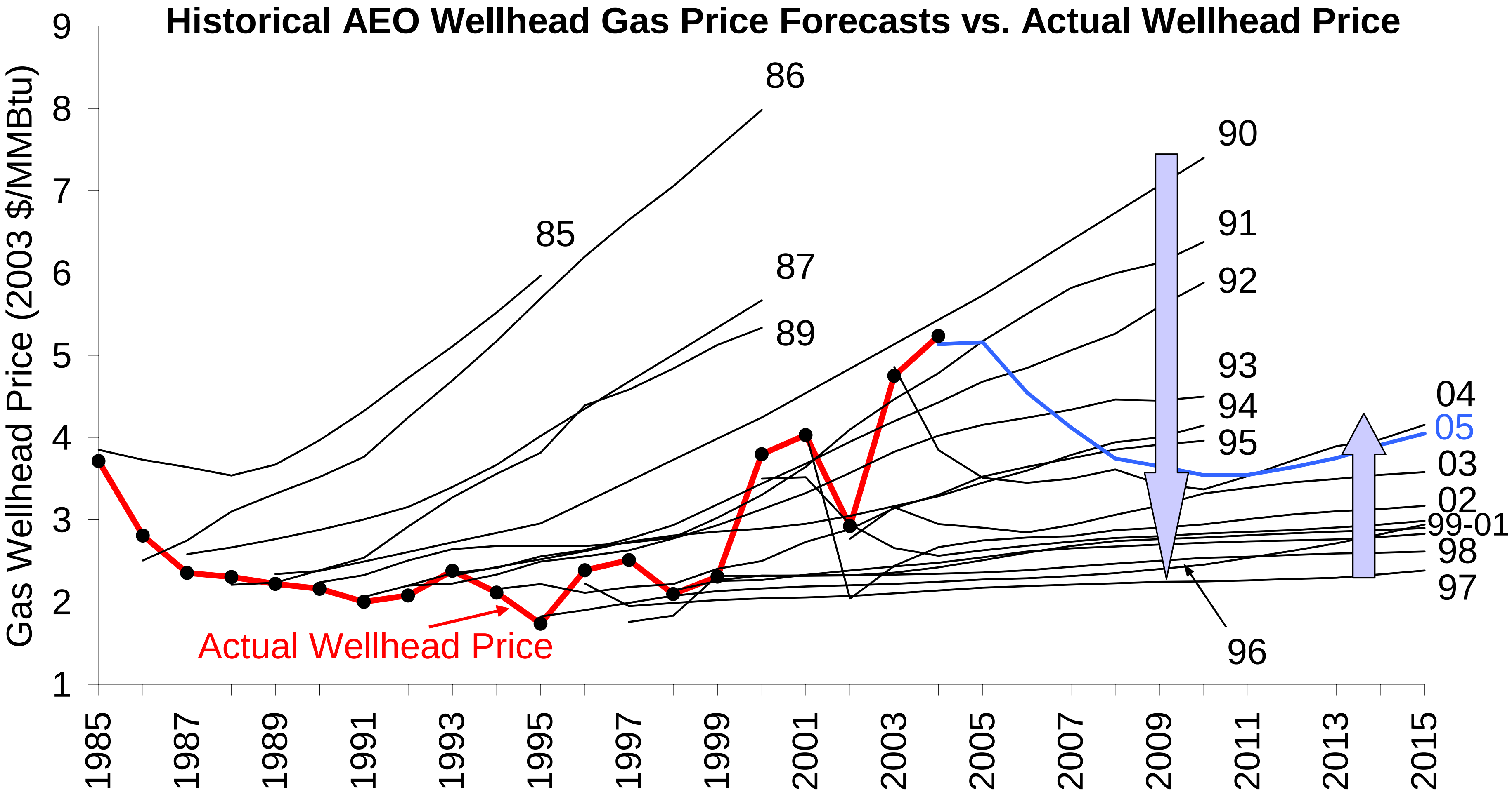
- Recent EIA analysis suggests that plausible allowance prices are $1,700/ton for NOx, $1,200/ton for SO2, and $35,000/lb for mercury
- A few other utilities (e.g., Nevada Power, Sierra Pacific) use mandated "externality values" to capture social costs beyond compliance costs, but these values are comparatively modest.

Future Gas Prices Are Expected to Remain Elevated, but Are Highly Uncertain



National Petroleum Council (2003)

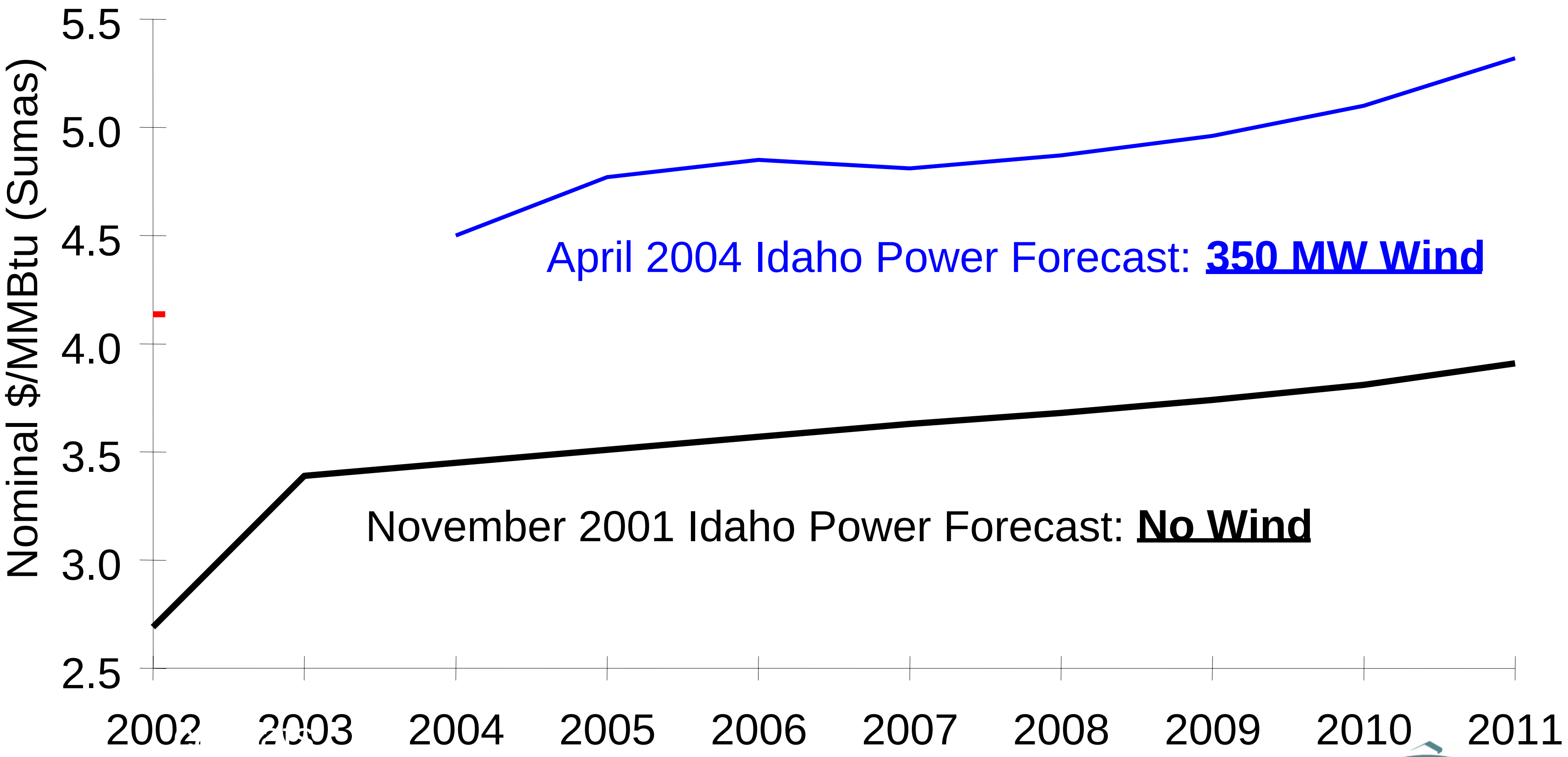
Gas Price Forecasts Are Unreliable



Source: EIA

The Base-Case Matters: Example from Recent Idaho Power IRPs

Higher gas prices and other factors led to increased wind in latest Idaho Power IRP



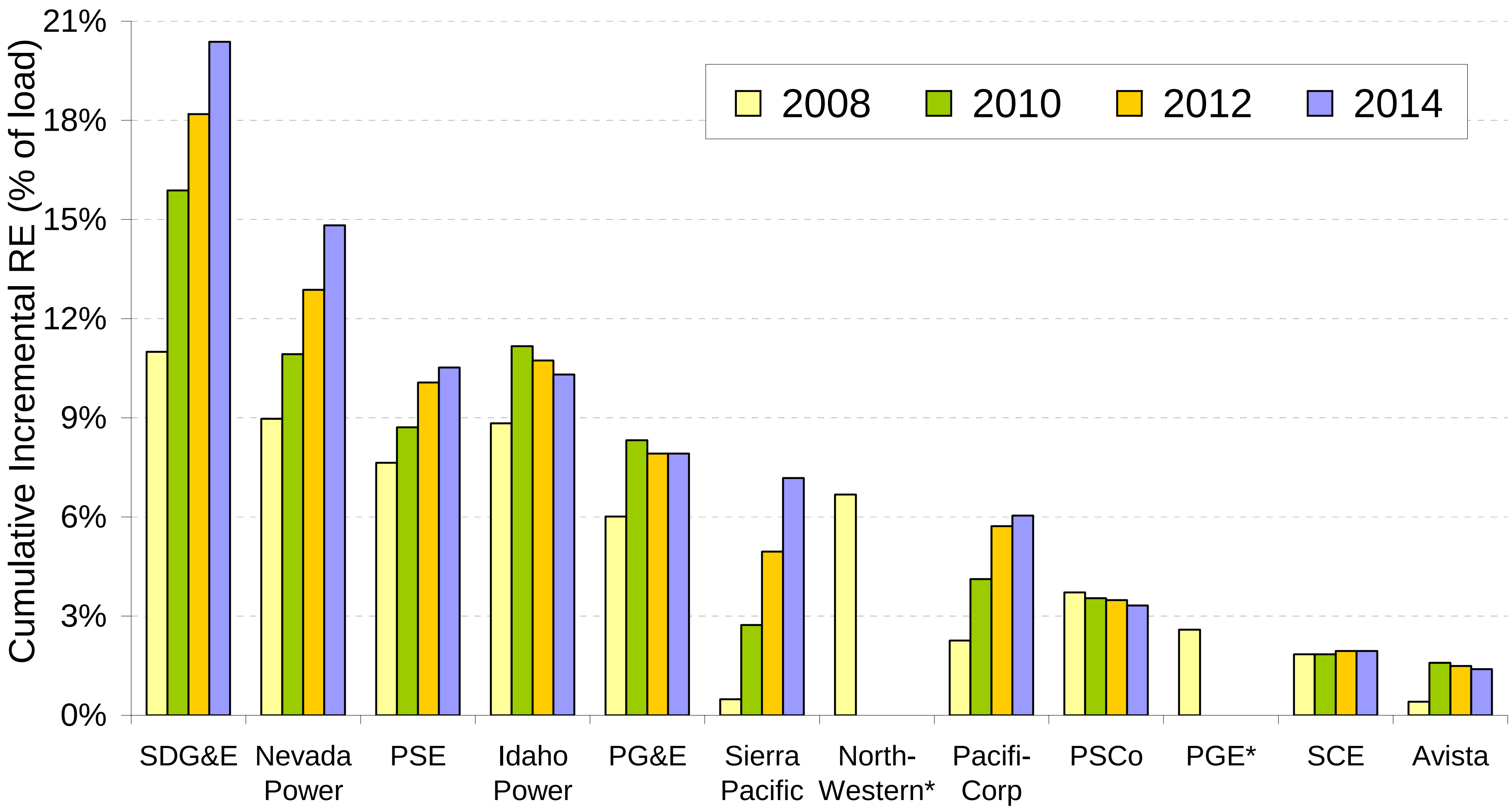
Treatment of Short-Term Gas Price Uncertainty: Sensitivity Analysis

- **Some utilities also conduct sensitivity analysis on short-term gas price volatility/shocks, e.g.:**
  - **Nevada Power**
    - Super-high gas and electricity prices in 2012 only
    - Gas delivered to SoCal $8.36/mmBtu as compared to $4.06/mmBtu in base case and $4.86/mmBtu in high case
  - **Sierra Pacific**
    - Super-high gas and electricity prices in 2012 only
    - Gas delivered to Malin $8.56/mmBtu as compared to $4.28/mmBtu in base case and $5.95/mmBtu in high case

Other Important - Yet Often Overlooked – Issues related to Gas Price Risk

- Impact of Reductions in Gas Demand on Gas Prices
  - Increasing number of studies show that increased deployment of RE and EE (or any non-gas resource) may dramatically reduce gas prices in near term, with more modest long-term effects
  - IRPs do not account for this potential *consumer* benefit of non-gas resources (this impact is only significant if viewed on a larger regional basis)
- Treatment of Risk Correlations
  - Gas prices plausibly correlated with hydro conditions, weather, load, oil/coal prices, spot electricity prices, etc.
  - Western IRPs treat these correlations inconsistently; correlations are most consistently addressed when stochastic simulation is used
- Selection of Discount Rate
  - Affects relative apparent cost of different cash flow streams, but no clear "right" approach: utility WACC, customer opportunity cost of capital, risk adjusted rates
  - Western IRPs typically use utility WACC, though some use variations

Planned Incremental Demand for RE Is Significant in Both RPS and non-RPS States



*PGE and NorthWestern's procurement horizons end in 2007, so only their 2008 values are shown.