System Adequacy with Intermittent Resources: Capacity Value and Economic Distortions

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LOLEWG Presentation

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Reference: C. Bothwell and B.F. Hobbs, "Crediting Renewables in Electricity Capacity Markets: The Effects of Alternative Definitions upon Market Efficiency," Working Paper, Johns Hopkins University (Posted on CAISO MSC Website: http://www.caiso.com/Documents/BriefingonRegionalResourceAdequacyInitiative-MSCBothwellHobbs_WorkingPaper-June2016.pdf

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Outline

- Motivation
- Renewable Counting Practices
  - ISO Survey of Practices
  - Alternative Methods
  - Numerical Comparison
- Market Distortions in Methods
  - Model Formulation
  - Results
- Economically Efficient Capacity Value
  - Method
  - Results
- Issues
- Conclusions

Motivation

- Wind & solar generation are intermittent
- What each contributes to meeting peaks is variable and uncertain
- Is there a counting mechanism that results in an economically efficient portfolio? (Sends the correct price signal for investment – not just between resource types, but within similar resources.)

Hypothesis: Consequences of Inaccurate Counting of Wind and Solar Capacity

- If we *under credit* capacity in adequacy studies, then might:
  - Might build too much *or* too little of capacity type in question
  - Build capacity of other types that doesn't get used, and increase reliability beyond standard
- If *over credit* capacity, then might:
  - Might build too much *or* too little of capacity type in question
  - Build too little of everything, and lower system reliability below standard
- If *don't differentiate* crediting of renewable capacity by location, might:
  - Insufficiently diversify renewable portfolio
  - Bias renewable portfolio towards high capacity factor resources rather than resources that truly contribute to system adequacy

Principles

Minimize the social cost of investment given long-term operation:

1. Set Credit/MW_i to **"equalize the reliability value of 1 MW of capacity"** (Ontario System Operator, 2014). *Need to recognize:*
   - *Marginal contributions:* incremental decrease in LOLP or Expected Unserved Energy (EUE) from a MW of renewable ≠ average decrease from all renewables
   - *Diminishing returns*: resource type's marginal contribution decreases as penetration increases (and so is less than average contribution)
   - *Location*: due to resource diversity, a variable renewable at one location will have a different marginal contribution than elsewhere
   - *Shifts of time of system vulnerability:* that periods when system reliability is at most risk may *not* be at system (load) peak & will change with renewable penetration
2. Set RM at level such that the reliability standard (e.g., 1 day in 10 years) is just met (given the assumed Credit/MW_i values)
   - Ideally, have demand curve that recognizes diminishing value of RA

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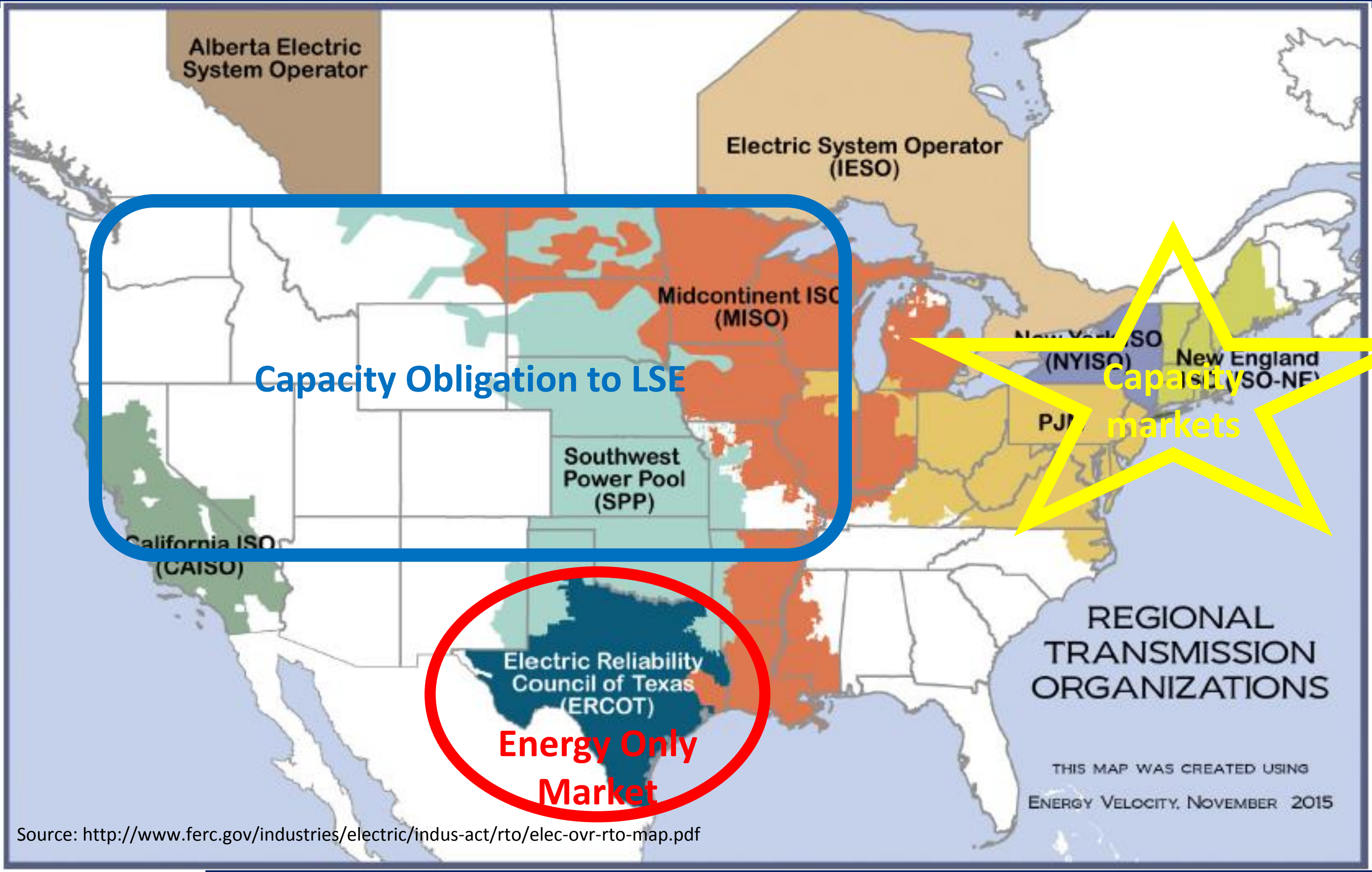
Primary Methods: Two Parts

- How is it done:
  - Counting method
  - Number of hours used
  - Application to resource or producer
- What data is used:
  - Historical or projected
  - Length of time
  - Deterministic, probabilistic or stochastic

North American RTO/ISOs



Source: http://www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf

Wind Capacity Counting Methods

- Capacity Factor During Peak Hours (an average)- PJM, NYISO & IESO
  - Attempts to consider load by choosing hours when high load typically occurs but too broad
- Top 5, Top 20 load hours - ERCOT
  - Considers load but not the load-wind-solar net effect
  - Not broad enough, could miss the net effect
- $50^{th}/10^{th}$ Percentile of seven days surrounding peak load – entso-e
  - Not broad enough, could miss the net effect
- Capacity Factor at Peak Load – IESO (five consecutive hours)
  - Can miss the net effect
- Exceedance- CAISO (70%), ISO-NE (median)
  - Better than averages at reflecting skewed data
  - Again very broad with too many hours, misses actual correlation with load
- ELCC – Effective Load Carrying Capability – MISO (CAISO considering)
  - Considers all 8760 hours historical net effect on reliability, not adaptive to future
  - Measured in time (LOLP & LOLE), not lost load (MWh)
  - Gives wind the same value in all hours, doesn't preserve capacity factor

ISO Survey: Capacity Contribution

Survey of Renewable Capacity Counting Practices

Market[2]	Primary Procurement	Resource	Rating Frequency	Capacity Contribution Method	Annual Pk Hours Used	Historical Data	Difference by Location
CAISO	LSE	wind, solar	Monthly	Level reached 70% of monthly peak hours	140-155 per month	Avg 3 years	by facility, class adjusted
entso	Country	wind, solar	Annual	50th percentile (normal), 10th (extreme)	35 per year around peak	14 year	by country
ERCOT		wind	Summer, Winter	Average during 20 highest load hours	20(summer) 20(winter)	Avg 10 years	two regions
ERCOT		solar	Summer, Winter	100% until 200 MW then like wind	[illegible]		all same
IESO		wind, solar	Summer, Winter, Shoulder monthly	Capacity factor: top 5 contiguous demand hours	5 (each period)	Median 10 years	all same
ISO-NE	ISO	wind, solar	Summer, Winter	Median during peak hours	610(summer) 486(winter)	Avg 5 years	by facility
MISO	LSE	wind	Annual	Annual ELCC study, all hours	8760	Avg 10 years	by class then facility adjust
MISO	LSE	solar	Summer	Seasonal peak hours	276	Avg 3 years	
NYISO	LSE	wind, solar	Summer, Winter	Capacity factor during peak hours	368(summer) 360(winter)	Current year	by facility
PJM	LSE	wind, solar	Summer	Capacity factor during peak hours	368	Avg 3 years	by facility

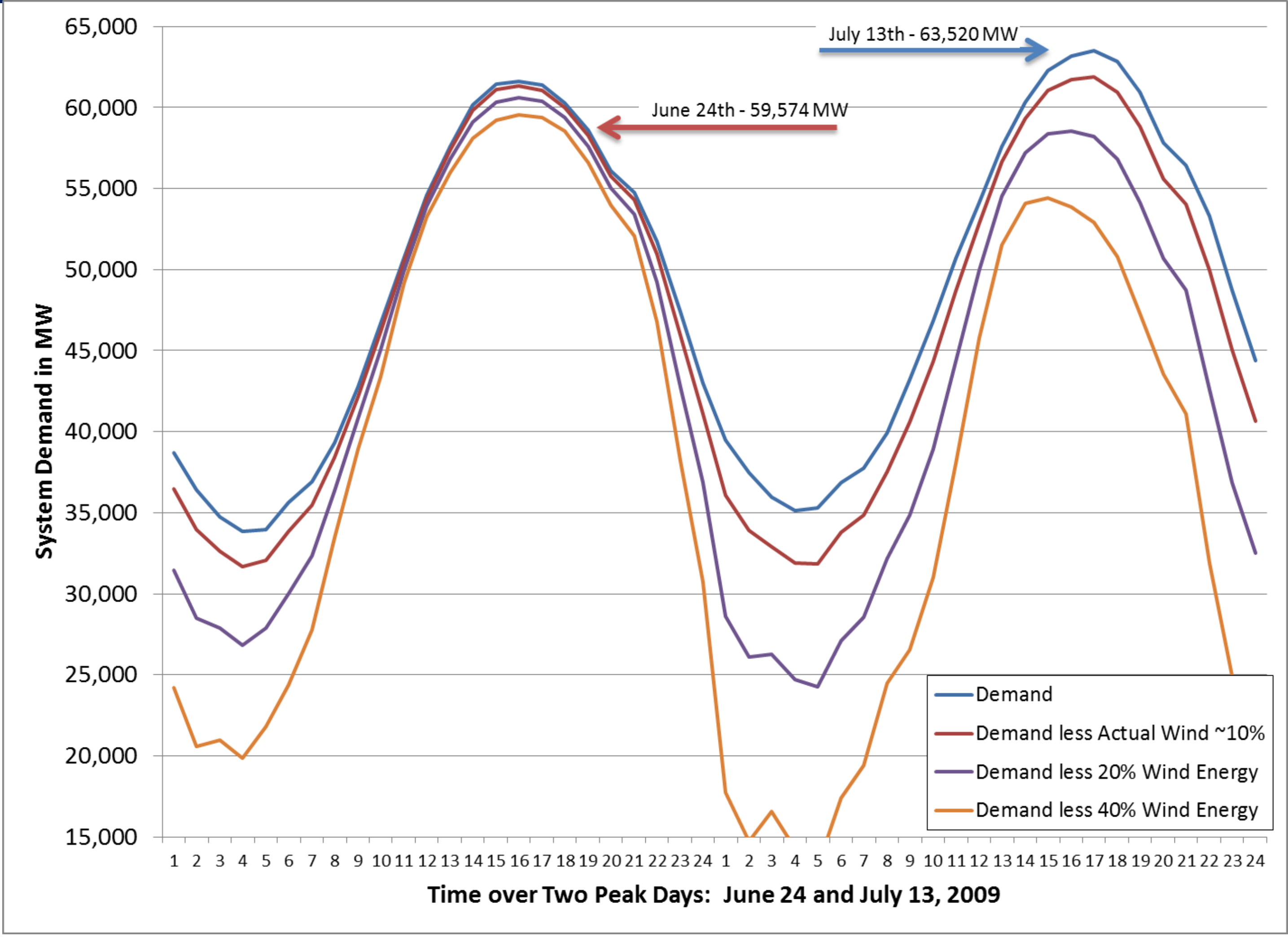
NO INDUSTRY STANDARD

Another Method: Peak Shift

Or “**Residual Load**”

- Considers Load only in the hours that really matter
- Doesn’t miss the net impact

- ***Gross Peak:* Wind given high credit**
- ***Net Peak:* Wind actually provides little capacity**



Capacity Method Performance

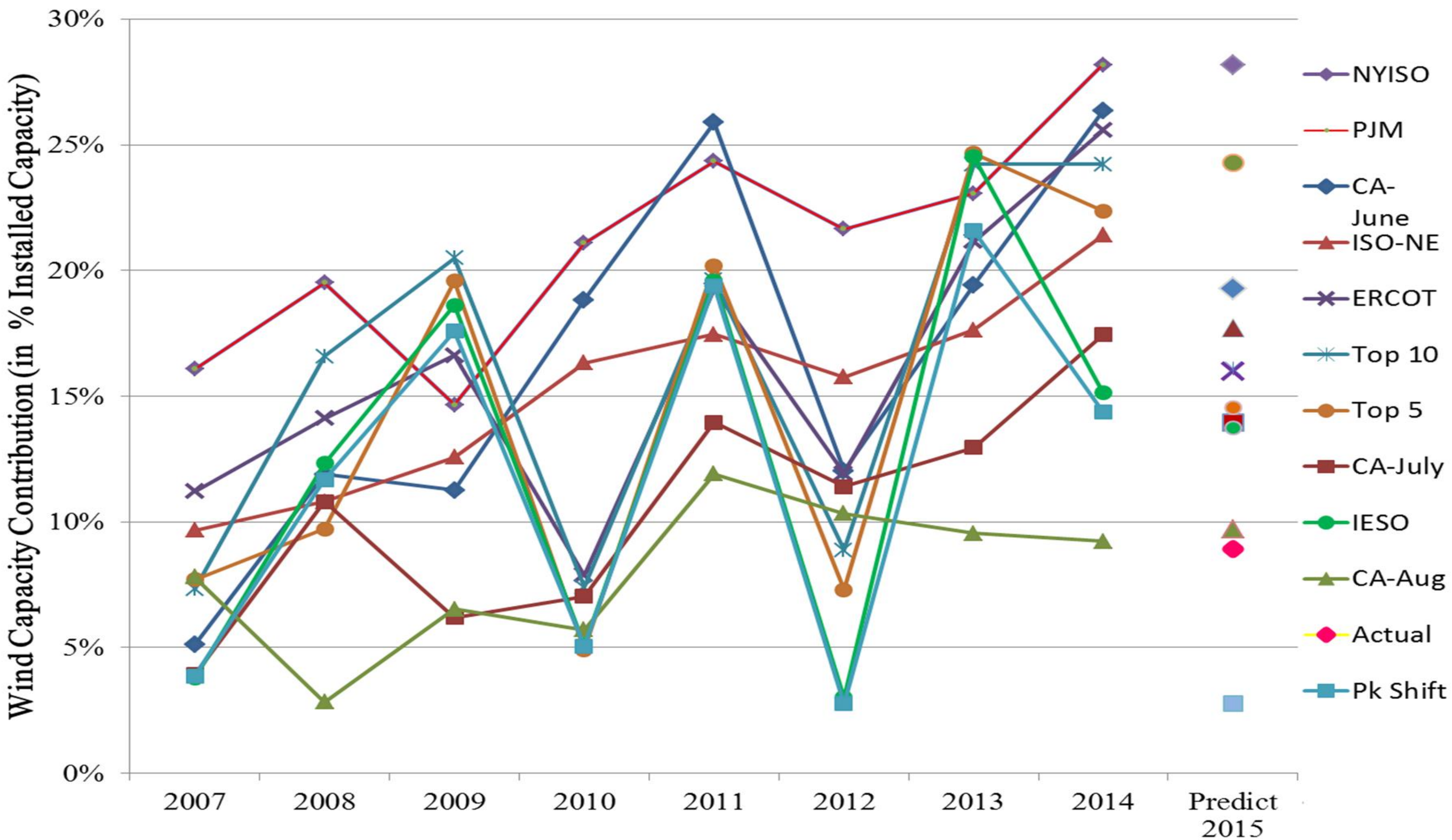
Capacity Values using ERCOT wind and load data

Method	2007	2008	2009	2010	2011	2012	2013	2014
CA-June	232	964	1009	1775	2539	1331	2176	3369
CA-July	178	877	556	663	1368	1261	1452	2231
CA-Aug	354	230	584	538	1167	1143	1069	1181
ERCOT	509	1145	1489	743	1886	1320	2371	3271
Top 10	332	1345	1837	699	1926	982	2714	3098
Top 5	350	788	1755	463	1981	808	2764	2861
At Peak	175	947	1653	477	2154	305	2418	1939
IESO	172	1000	1668	482	1921	332	2749	1937
ISO-NE	439	877	1127	1540	1712	1744	1977	2739
PJM	730	1582	1313	1988	2388	2395	2584	3605
NYISO	730	1582	1313	1988	2388	2395	2584	3605
Pk Shift	175	947	1576	477	1901	305	2418	1838
AtNet	175	947	493	477	1569	305	2418	1576

ERCOT Annual Wind Characteristics

Installed (MW)	4541	8111	8962	9430	9805	11068	11205.5	12791
Average (MW)	1194	2406	2191	2861	3305	3690	3782	4562
Capacity Factor	26.3%	29.7%	24.4%	30.3%	33.7%	33.3%	33.8%	35.7%
Maximum (MW)	3628	6434	6088	7035	7549	9247	9715	11769
Max Factor	79.9%	79.3%	67.9%	74.6%	77.0%	83.5%	86.7%	92.0%

Capacity Value for Adequacy



Capacity Value for Adequacy

	Capacity (MW)	% Installed	Method
CA-June	2464	19.26%	Averge Three Years 2012-2014
CA-July	1782	13.93%	Averge Three Years 2012-2014
CA-Aug	1241	9.70%	Averge Three Years 2012-2014
ERCOT	2042	15.97%	Average 10 Years
Top 10	2059	16.09%	Average 10 Years
Top 5	1862	14.56%	Average 10 Years
At Peak	1607	12.56%	Average 10 Years
IESO	1757	13.74%	Median 10 Years
ISO-NE	2267	17.72%	Average 5 Years
PJM	3107	24.29%	Average 3 Years
NYISO	3605	28.18%	Previous Year
Pk Shift	353	2.76%	Minimum
At Net	353	2.76%	Minimum

MISO ELCC: 33% coastal, 14% west

Actual ERCOT performance in 2015 was 1442 MW or 8.9% of nameplate

Worst case – 2163 MW shortage, 4% of peak load

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Market Designs Considered & Potential Distortions

- ERCOT system, existing coal & new other capacity, USDOE costs, 10 yrs of load, wind (3), & solar data
- Economic ideal: Let customer decide, no price cap → prices can reach VOLL = $10,000/MWh
  - No capacity market (reserve margin constraint)
- *Market simulations* include:
  - Energy market *price cap*
    - $1200/MWh in market simulations << VOLL
  - Capacity Mechanisms *to make up for overly tight price cap*
    - Various Capacity Credit rules
    - "WCap", "SCap" = wind, solar capacity credit
  - RPS
- Distortions:
  - Gen mix
  - Costs
  - *Not* reliability; in each case, adjust RM to achieve optimal EUE (MWh "unserved energy")

Methodology: Equilibrium Model

Simulate market with *equivalent* single optimization problem (static optimization over 87,600 hours for 10 years): Objective: MINIMIZE ***Total Generation Cost***

$$= \sum_{g \in G} FC_g * x_g + \sum_{h \in H, g \in F} VC_g * e_{h,g} + \sum_{h \in H} ue_h * PC - \sum_{h \in H, g \in W} WS * ce_{h,g}$$

Market Simulations:

1. Ideal Case: all cost terms = social costs
2. Market Distortion Cases:
   - *Investment tax credits* distort investment costs
   - *RPS and production tax credits* distort renewable curtailment costs
   - *Energy price cap* lowers apparent unserved energy cost

Compare solutions by calculating *social costs*:

– Substitute Value of Lost Load (VOLL =~$10K/MWh) for price cap and unserved energy cost

Methodology: Equilibrium Model

Market Clearing Constraints:

$\Sigma_{g\in G}\, e_{h,g} + ue_h = DM_h \qquad \forall h\in H$ (2)

$\Sigma_{g\in F}\, x_g *(1\text{-}FOR_g) + \Sigma_{g\in W}\, x_g * WCC_g + \Sigma_{g\in S}\, x_g * SCC_g$
$\geq PD * (1 + RM)$ (3)

$\Sigma_{h\in H,\, g\in(W,S)}\, e_{h,g} \geq \Sigma_h\, DM_h * RPS$ (4)

Minimum Thermal On-line Constraint:

$\Sigma_{g\in F}\, e_{g,h} \geq DM_h * MG \qquad \forall\ h\in H$ (5)

Generator Constraints:

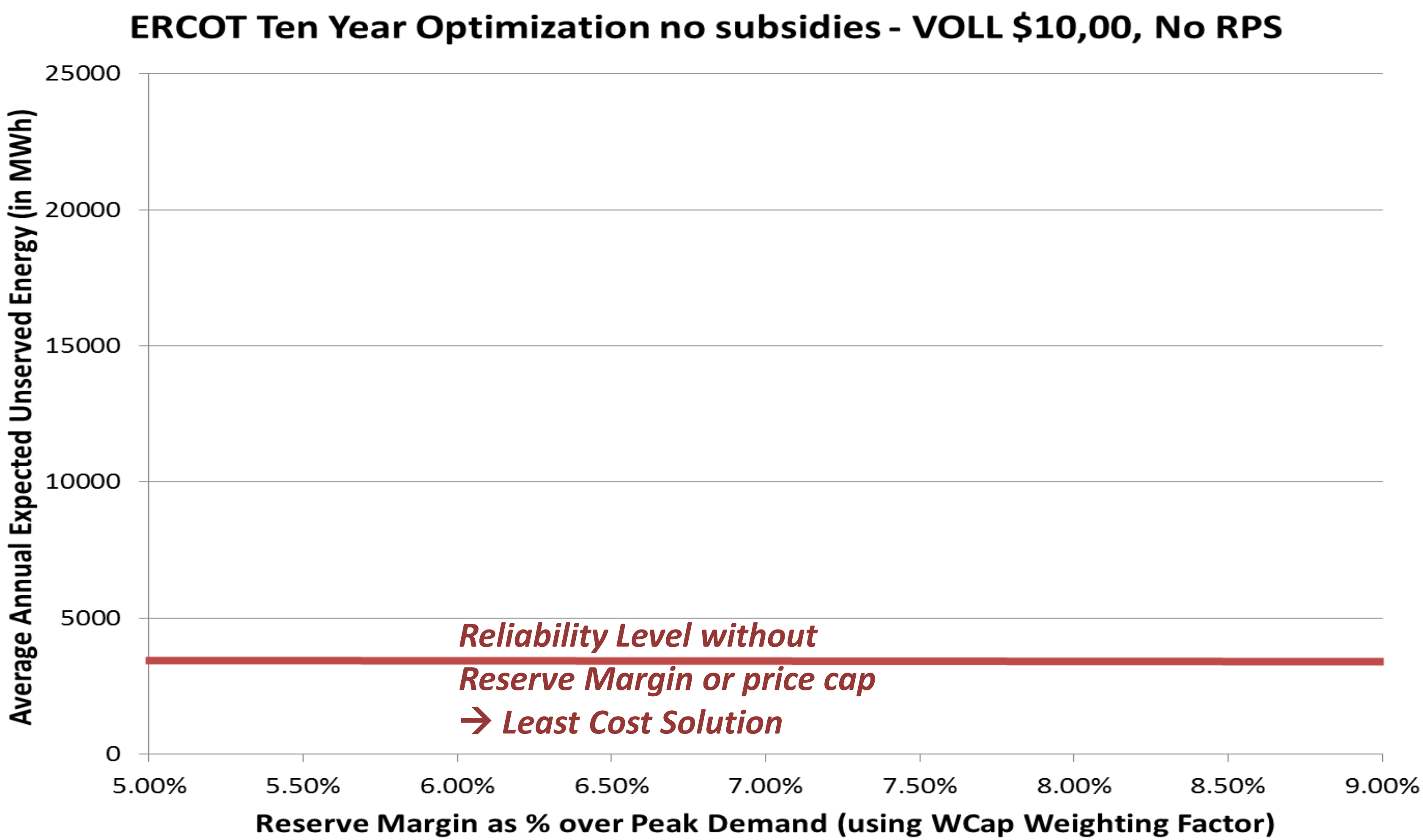
$e_{h,g} \leq x_g *(1\text{-}FOR_g) \qquad \forall\ g\in F;\ h\in H$ (6)

$e_{h,g} \leq x_g * AVAIL_{h,g} \qquad \forall g\in W,S;\ h\in H$ (7)

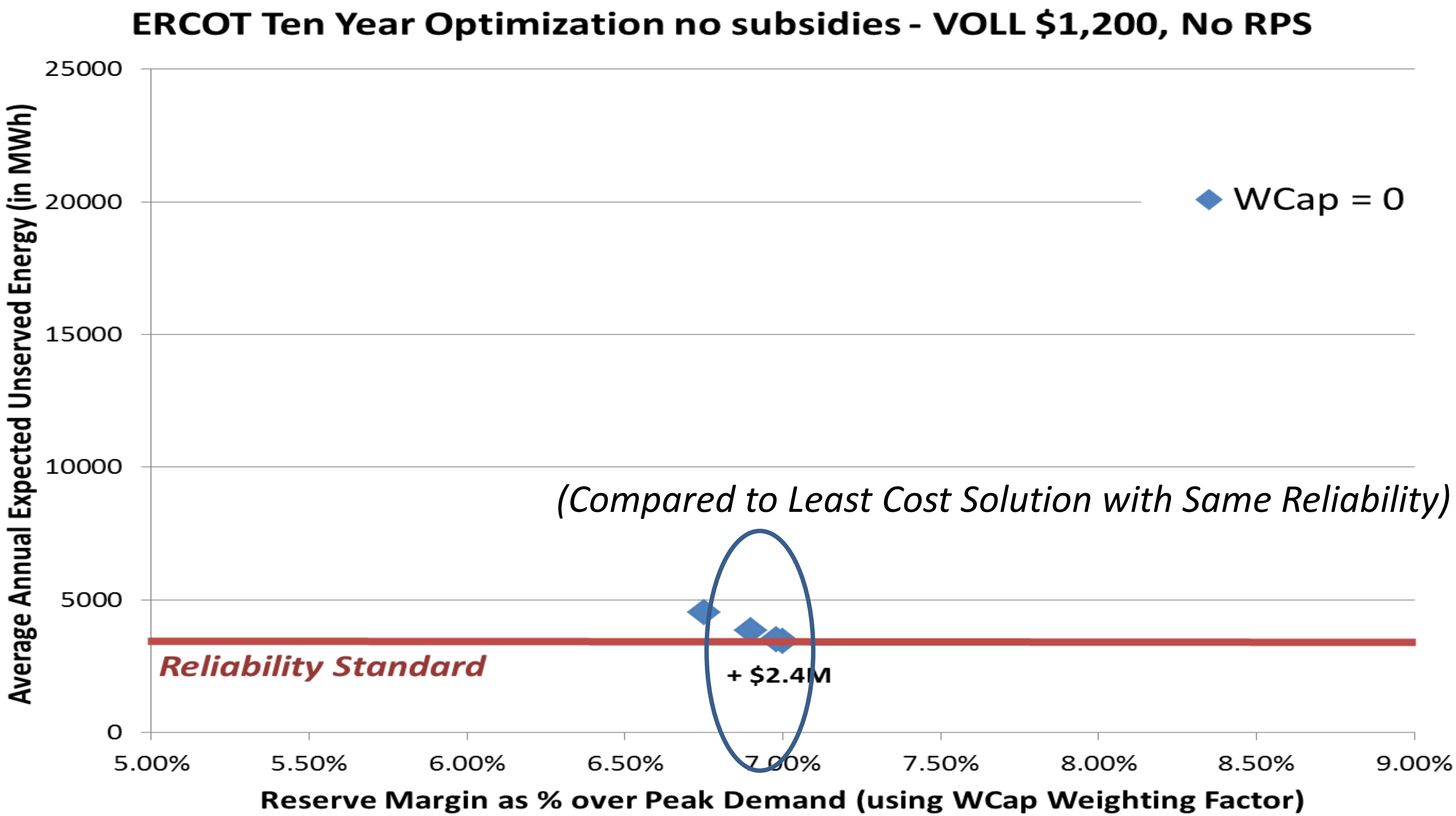
$x_{Coal} \leq PD * 0.45$ (8)

$\Sigma_{h\in H}\, e_{g,h} \leq x_g * AF_g \qquad \forall\ g\in F$ (9)

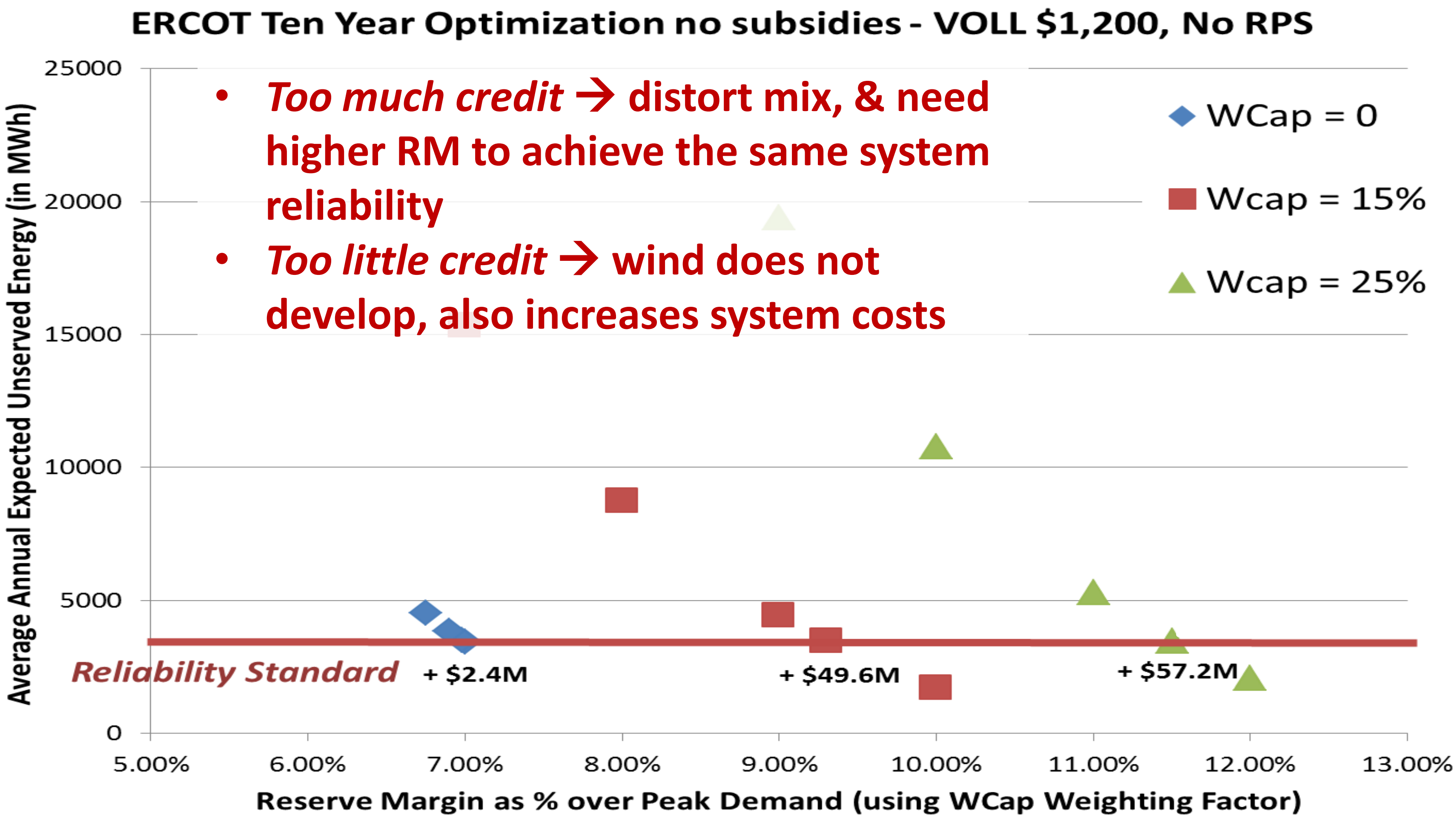
Market Simulation: ERCOT System (3 wind sites, solar, fossil against 50 GW peak load)



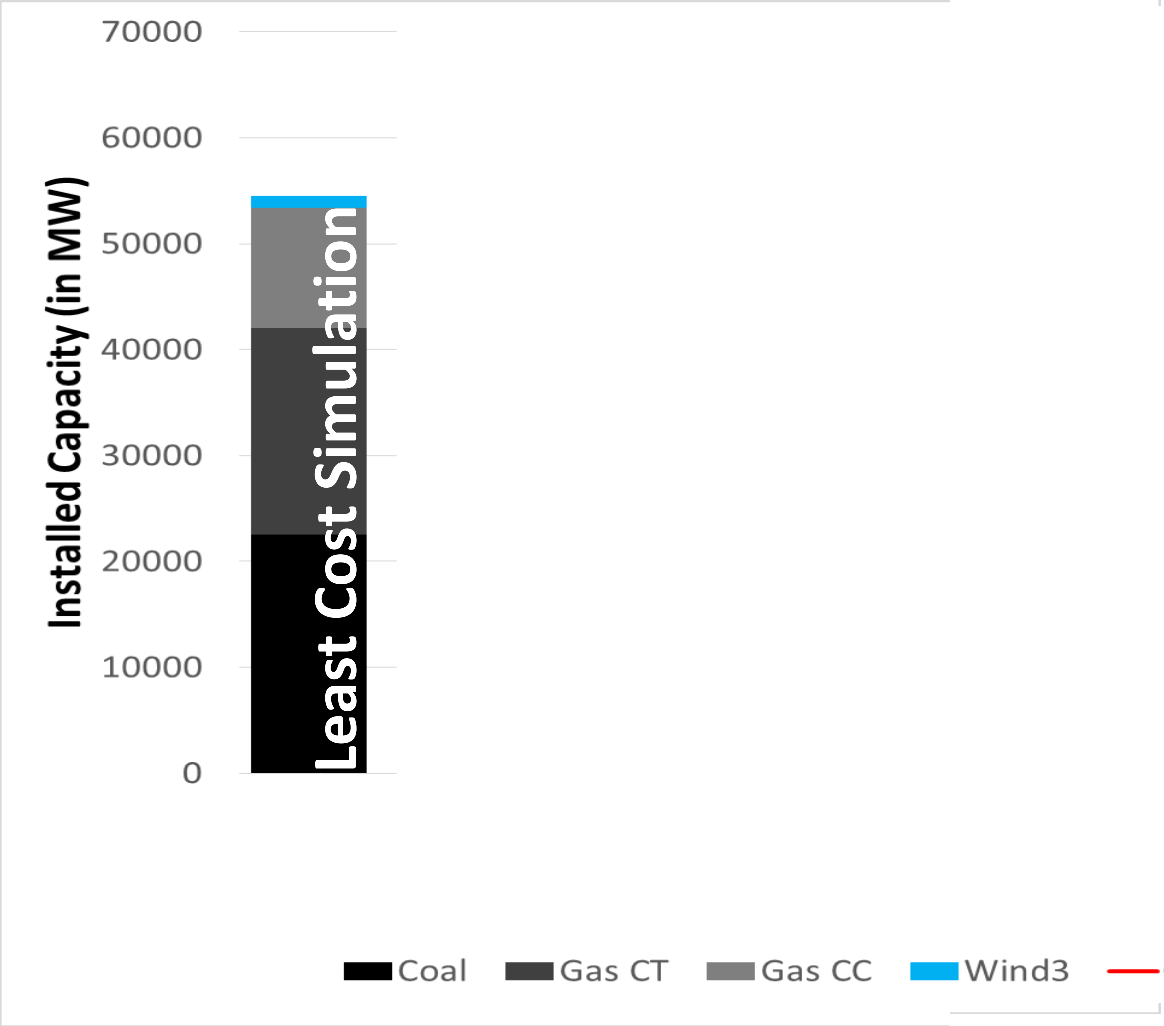
Market Simulations with Zero Wind Capacity Credit



Market Simulations with Zero, 15%, & 25% Wind Capacity Credits

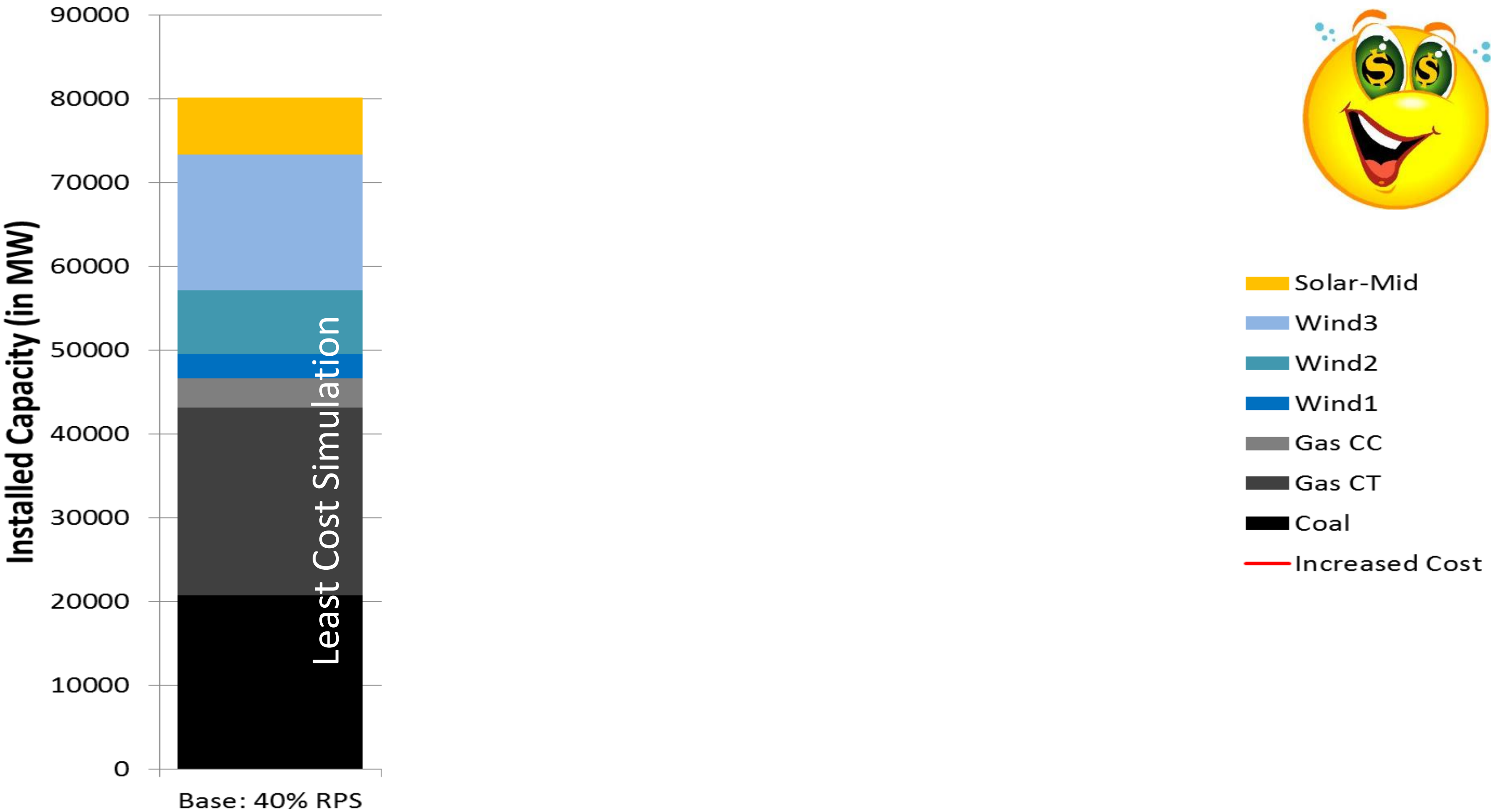


Market Simulations: Generation Mix & Cost Distortions with 0% RPS



Although cost impact is small, wind mix changes (gas mix changes minimally)

Cap Market Distortions Under 40% RPS



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Marginal Capacity Credits

Consider the capacity value only for hours with unserved energy:

Calculation of Producer Marginal Capacity Credits:

Incrementally change the capacity of each resource to find EUE impact.

pc_g = (EUE* - EUE)/EUEH

Note: 88 hours over 10 years,1-20 hours per year

Can subsequently calculate the required Reserve Margin

Reserve Margin:

RM = $[\Sigma_{g \in G} x_g * pc_g]$/PD - 1

Using the calculated producer capacity values and the reserve margin results in the original least cost portfolio → **Socially Optimal**

Marginal Capacity Credits

Resource	Annual Capacity Factor	Capacity Credit (% Installed Capacity) in Optimal Solution	
		Optimal 0% RPS	Optimal 40% RPS
Wind Site 1	36.7%	--	8.6%
Wind Site 2	34.5%	--	12.5%
Wind Site 3	42.3%	7.6%	4.0%
Solar Site 1	27.6%	--	28.2%
	Optimal RM:	-1.8%	-7.5%

Locational variation

Diminishing returns

RM is negative because of diminishing returns
Each resource has already been derated
(marginal RA contribution < average RA contribution)

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Issues

Still need to resolve time period for analysis

How to capture variability and correlations?

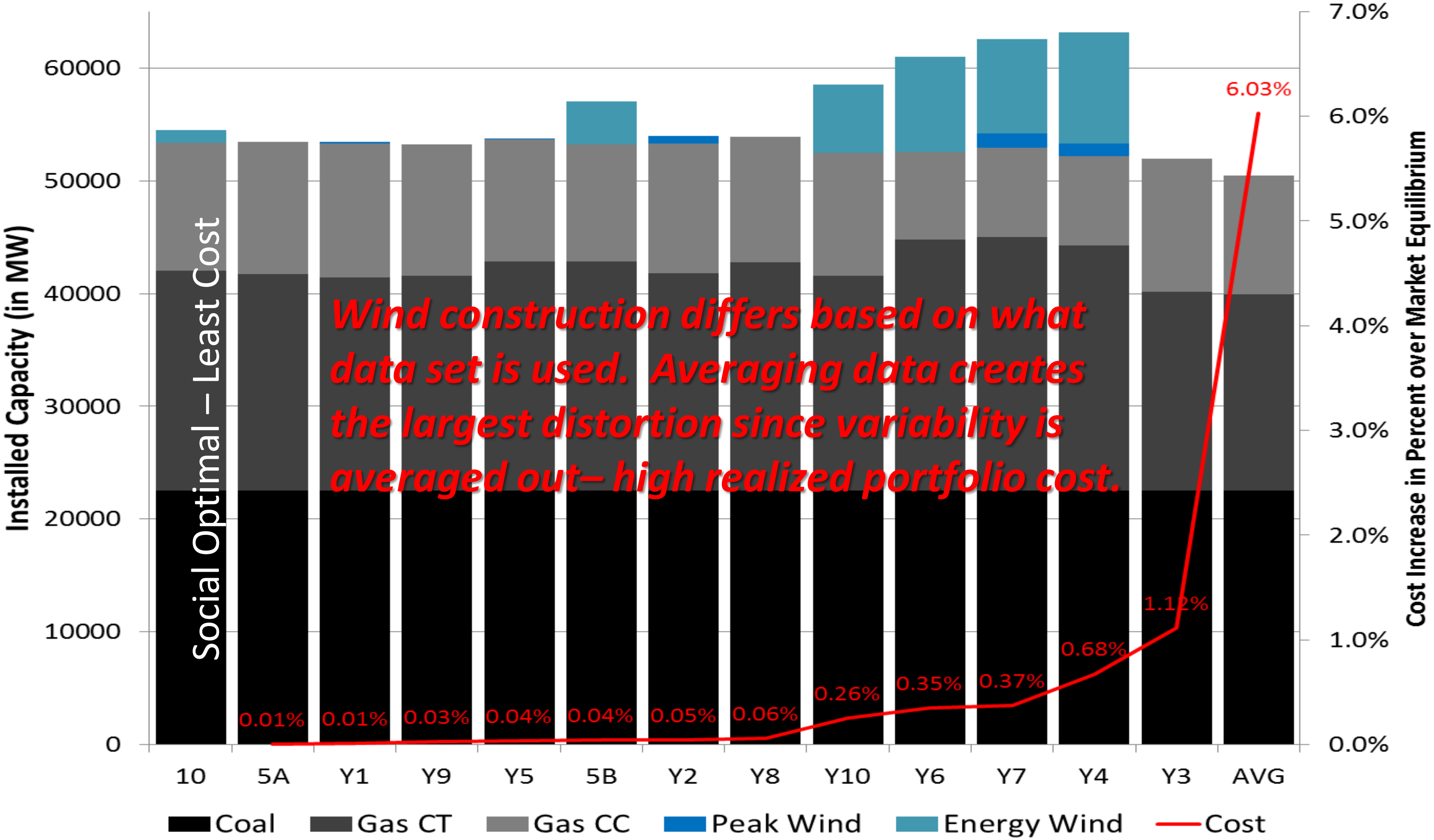
Allocation methods of resources

First in – chronological

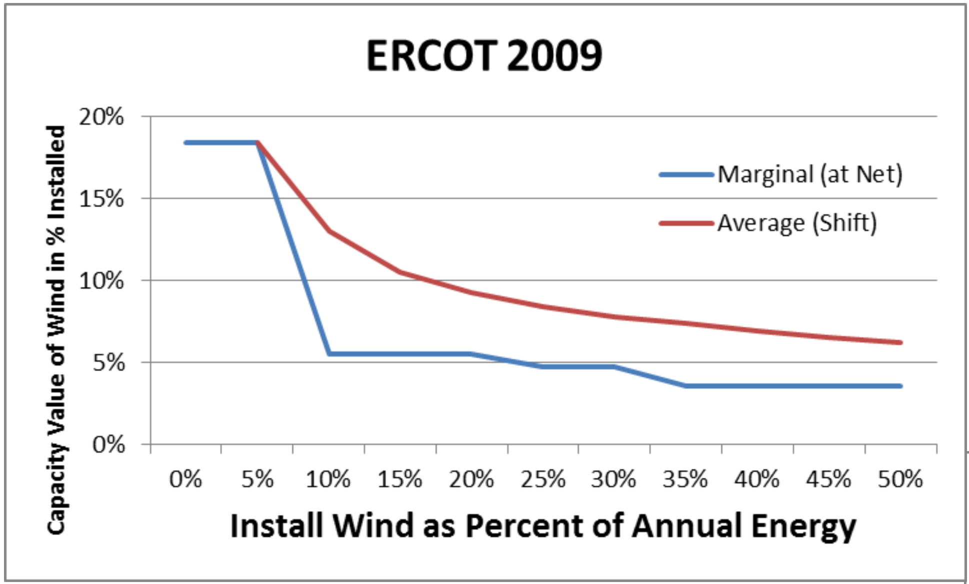
Market based – price clearing, lowest first

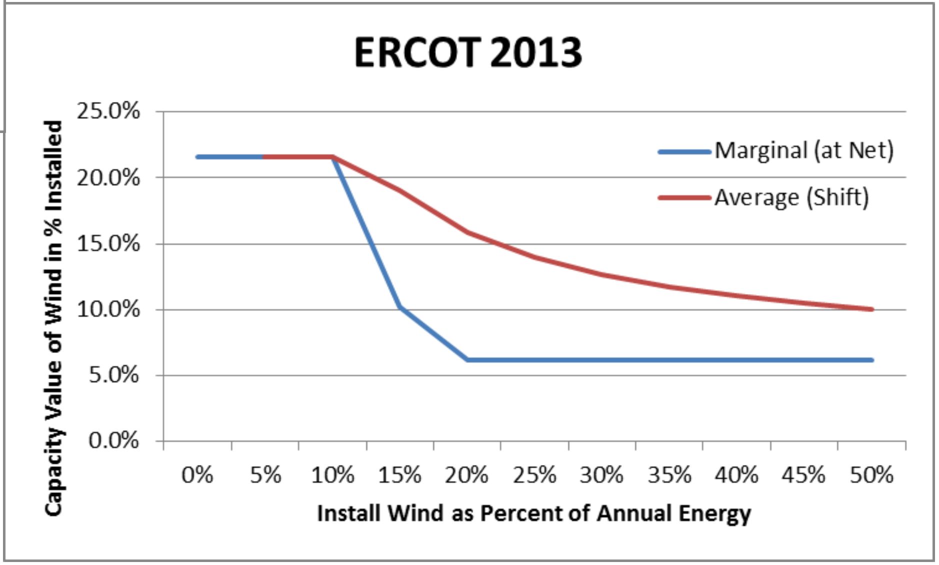
… other

Issues: Distortion due to Data



Issues: Average vs Marginal





Conclusions

Hypotheses confirmed:

- If wind capacity is *under counted*:
  - Overbuild: build capacity that isn't used, and distort mix of other renewables
- More $ distortion if wind capacity is *over counted*:
  - Build less of everything, including wind, except for solar
  - May miss reliability target
- If wind capacity at different locations is *not differentiated*:
  - Build more costly portfolio of high capacity factor wind and extra fossil
  - Increased curtailments

Each intermittent resource (individual wind or solar farm) should receive a capacity credit equal to its <u>marginal</u> contribution, accounting for temporal shifts in Net Peak Load

Conclusions

Implementing probabilistic RA criteria is challenging:

- Not just a "convolution" of plant outages/load
  - huge hydro role; reregulation constrained by environmental rules
  - flexibility limits (ramps, max # starts,…)
  - Demand response contributions
- Transmission constraints can affect
- Cannot interpret LOLP/EUE as actual load interruptions due to operator actions; just an ordinal index that can be used to rank plans in terms of reliability

Questions?