Electricity & Natural Gas GHG Modeling

Methodology & Key Revisions

April 21st, 2008

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Agenda

- Background and overview of project status
- Stage 1 model improvements/changes
  - Summary of major changes in response to comments
  - Hot topics: CHP and wind costs
- Stage 2 modeling of energy deliverer decision
  - Regulation: RPS and demand-side resources
  - Markets: CO_2 markets and allocations
- Implications of cap and trade for CA's electricity sector

Next Steps: Process

- Tomorrow: Preliminary E3 GHG Calculator analysis of allowance allocation scenarios
- Public CPUC workshop of model results and how to create scenarios using the GHG Calculator (May 6th)
- Final model posted for comments (May 10th)
- Comments on Stage 2 model (May 27th)
- Reply Comments on Stage 2 model (June 10th)

Energy and Environmental Economics, Inc. (E3)

- San Francisco-based firm established in 1993
- Electric and natural gas utility sectors
- Practice areas
  - Energy efficiency and building standards
  - Distributed generation, demand response and CHP
  - Integrated resource planning
  - Transmission planning and pricing
  - Retail rate design

CPUC, CEC, ARB Project Team

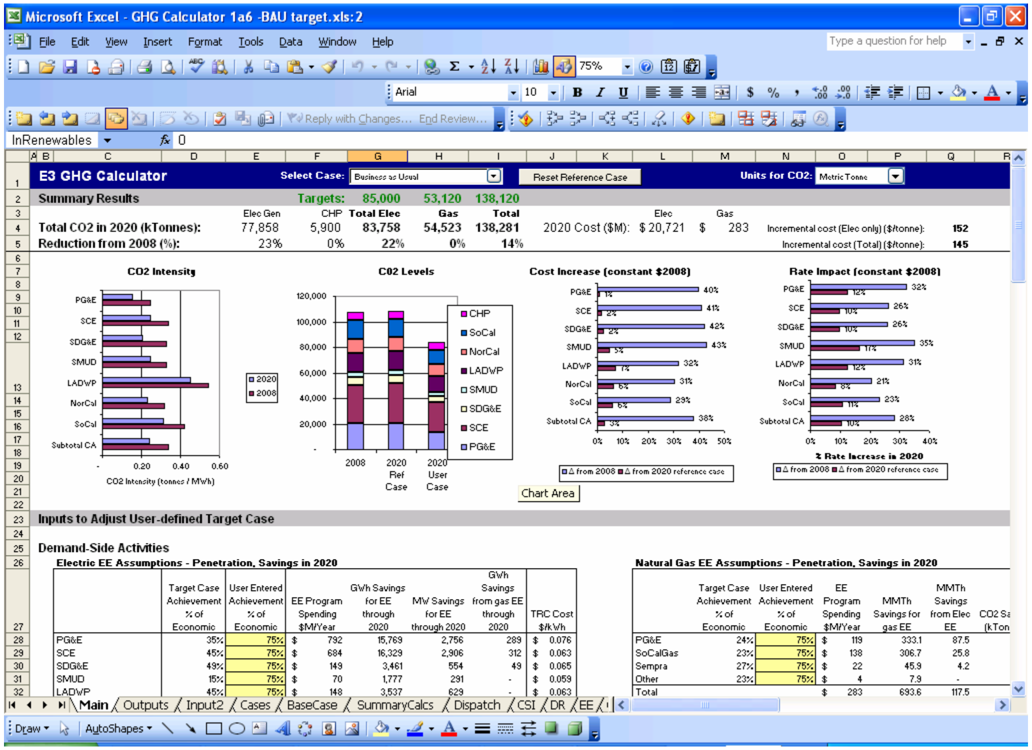
- Energy and Environmental Economics, Inc.
  - Prime, Development of the non-proprietary tool, Integration, GHG Policy
- PLEXOS Solutions LLC
  - State-of-the-art production simulation model
- Schiller Associates, Steven Schiller Lead
  - Advisor on California GHG policy and energy efficiency
- Dr. Ben Hobbs, Johns Hopkins University
  - Academic advisor, World-renowned electricity simulation expert
- Dr. Yihsu Chen, UC Merced
  - Academic advisor, Emerging capability at UC Merced

Project Overview

- Joint CPUC, CEC, ARB effort to evaluate AB32 compliance options in California's electricity and natural gas sectors
- Model estimates the cost and rate impact of multiple scenarios relative to reference case
- Project timeline designed to fit into 2008 Scoping Plan process for AB32
- Deliverables
  - Non-proprietary, transparent, spreadsheet-based model using publicly available data
  - Report on results and sensitivities / scenarios
  - Stakeholder process leading to CPUC/CEC proposed decision
  - Model output to be used as an input to the ARB

GHG Calculator

- Based in Excel
- Uses only publicly available data
- Calculates scenarios rapidly
- Non-proprietary



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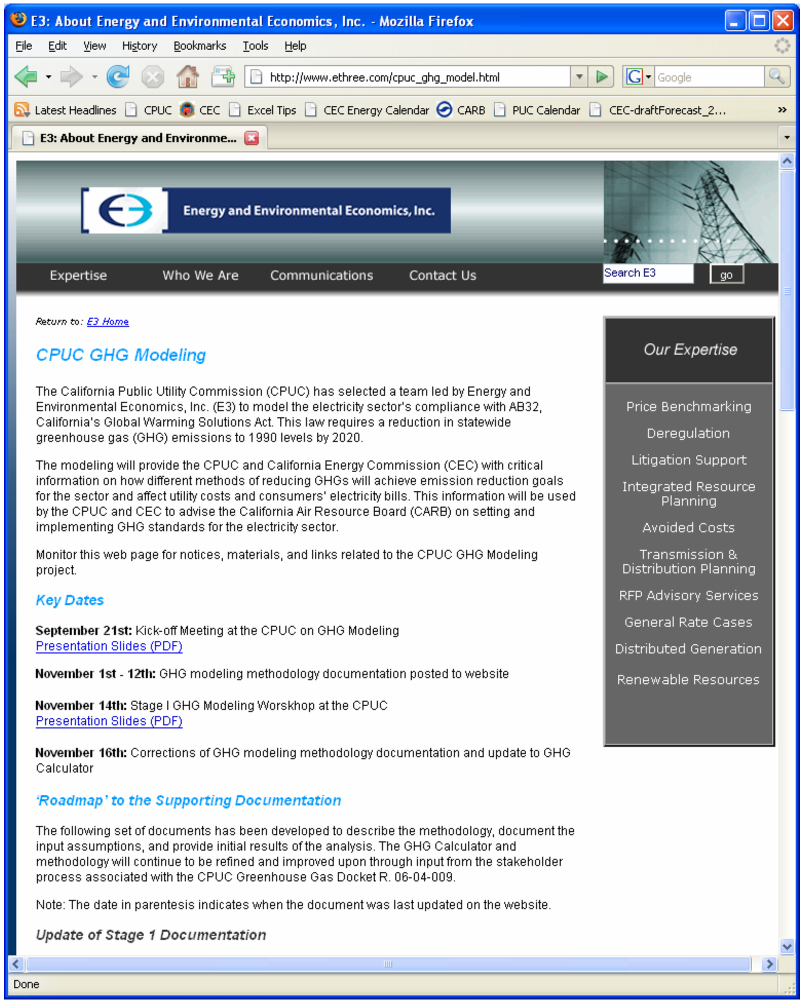
Model Updates Posted on the Web



- Project Website
- Workshop updates & past presentations
- Calculator available for download
- Documentation of methodology and inputs
- www.ethree.com

Two Stages

- Stage 1 (through 2/08): Statewide cost and average rate impact of meeting an electricity and natural gas sector GHG emissions cap
  - Stakeholder comments / reply comments January 2008
  - Revisions to Stage 1 results following stakeholder comments
- Stage 2 (12/07 – 8/08): Cost and average rate impact to LSEs of a combined regulatory/carbon market approach to meeting AB32
  - LSE-specific rate and cost impacts of different policy approaches
  - Impacts of auction/allocation of emission permits, methods for auction revenue recycling, offsets
  - Informs CARB June 2008 decision for 'burden sharing' of GHG reductions among all CA sectors and future decisions on allocation of GHG permits within the electricity sector

Stage 1 Key Qs

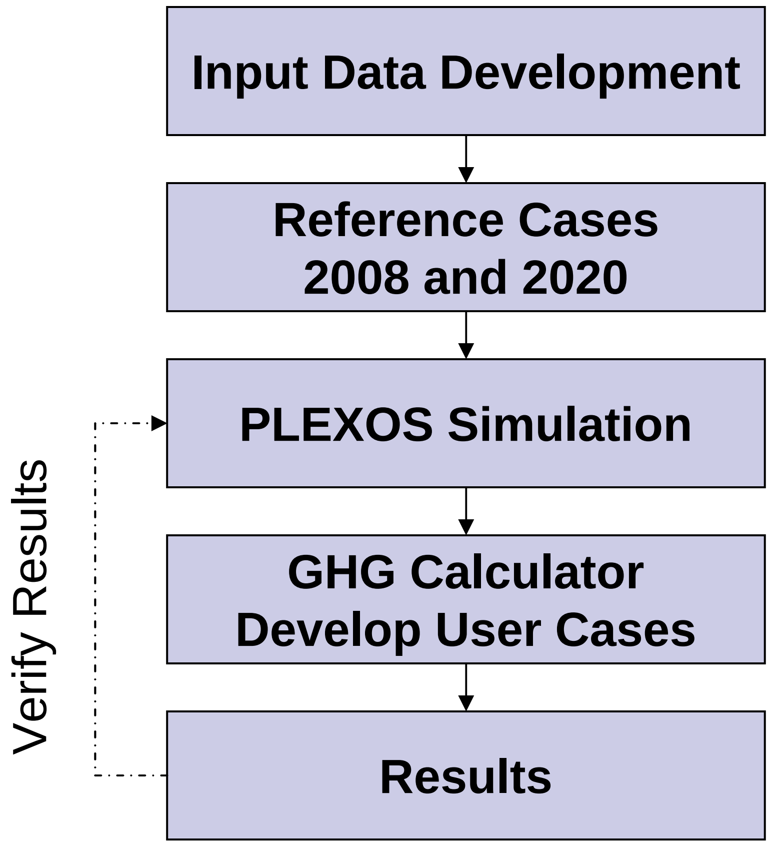
- How much will various policy options reduce CO_2 emissions?
- How will these policy options affect electricity rates?
- *Underlying question: At what electricity sector target level do incremental improvements get expensive?*

Stage 2 Key Qs

- What is the cost to the electricity sector of complying with AB32 under different policy options for California?
- What is the cost to different LSEs and their customers of these options?
- *Underlying question: What option has the best combination of cost, fairness and enforceability?*

Stage 1 Review and Revisions based on Party Comment

Stage 1 Analysis Approach



EE & RE Supply, Costs, Load Forecasts

Loads & Resources for 2020
Business As Usual, Aggressive Policy

WECC-wide Simulation
Summary Dispatch, Costs, Emissions

Select Resources to add or remove from reference case

Δ Reference and User Case
Emissions, Rates, and Costs

Building the Reference Cases

- Forecast energy and loads to 2020 for all WECC Zones
- Adjust California load forecast for EE and distributed resources
  - Estimate embedded EE, behind-the-meter PV, CHP in California load forecast
  - Modify California load forecast for 5% demand response
- Add lowest cost renewable mix to hit RPS requirement
  - For all regions outside of California
  - To meet California 20% or 33% RPS, depending on scenario
- Add / subtract conventional resources to maintain existing reserve margins in each WECC zone
  - Add CCGT to balance energy
  - Add CT to balance capacity

Characterization of Resources

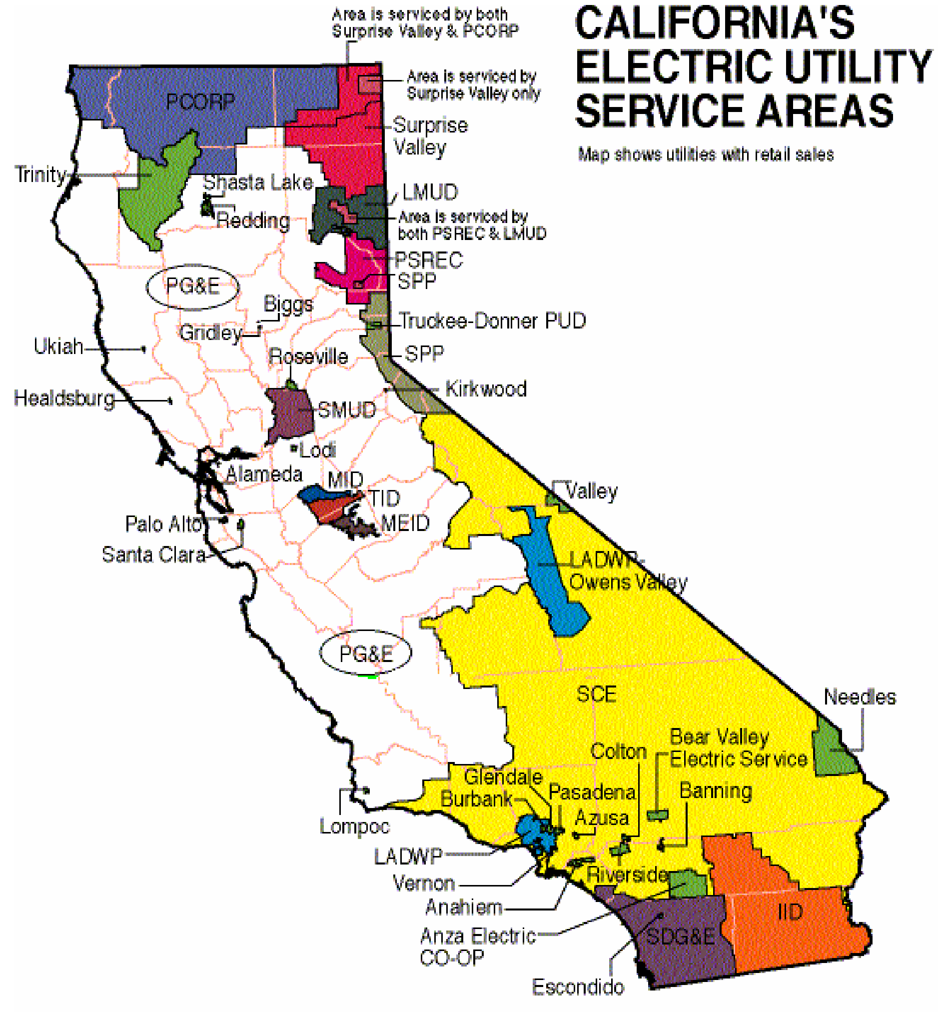
- Existing and Planned Western (WECC) Resources
- Energy Efficiency by LSE
- Solar PV, Demand Response, Small CHP by LSE
- Large Scale Renewable Energy
  - Developed by zone
  - Developed by transmission size and configuration
- New Large Scale Generation
  - Gas CCCT, Gas CT, Nuclear, Coal IGCC, Coal IGCC w/ CCS, Coal ST, Large CHP

Seven LSEs Modeled in CA

1. PG&E
2. SCE
3. SDG&E
4. SMUD
5. LADWP
6. Other Northern
7. Other Southern

Stage 2 adds:

8. Water Agencies



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Stage 1 Key Revisions Based on Stakeholder Comments (1)

- Energy Efficiency
- Load forecast revision
  - Loss factors, PV, pumping load adjustment, non-California-based IOUs
- Wind
  - integration costs: lower cost
  - capacity: increased from 10% to 20% on-peak
  - capital costs: higher cost

Stage 1 Key Revisions Based on Stakeholder Comments (2)

- New natural gas generation:
  - higher CT and CCGT capital costs to reflect recent increases
- Higher natural gas prices
- Combined heat and power
- Generator assignment to LSE
  - Water agencies and pumping load broken out separately, 67.8% share of Reid Gardner assigned to water agencies
  - LADWP's 21% share in Navajo coal plant expires in 2019 instead of 2020
  - Identified some generation as CHP per party comments

Revised Energy Efficiency

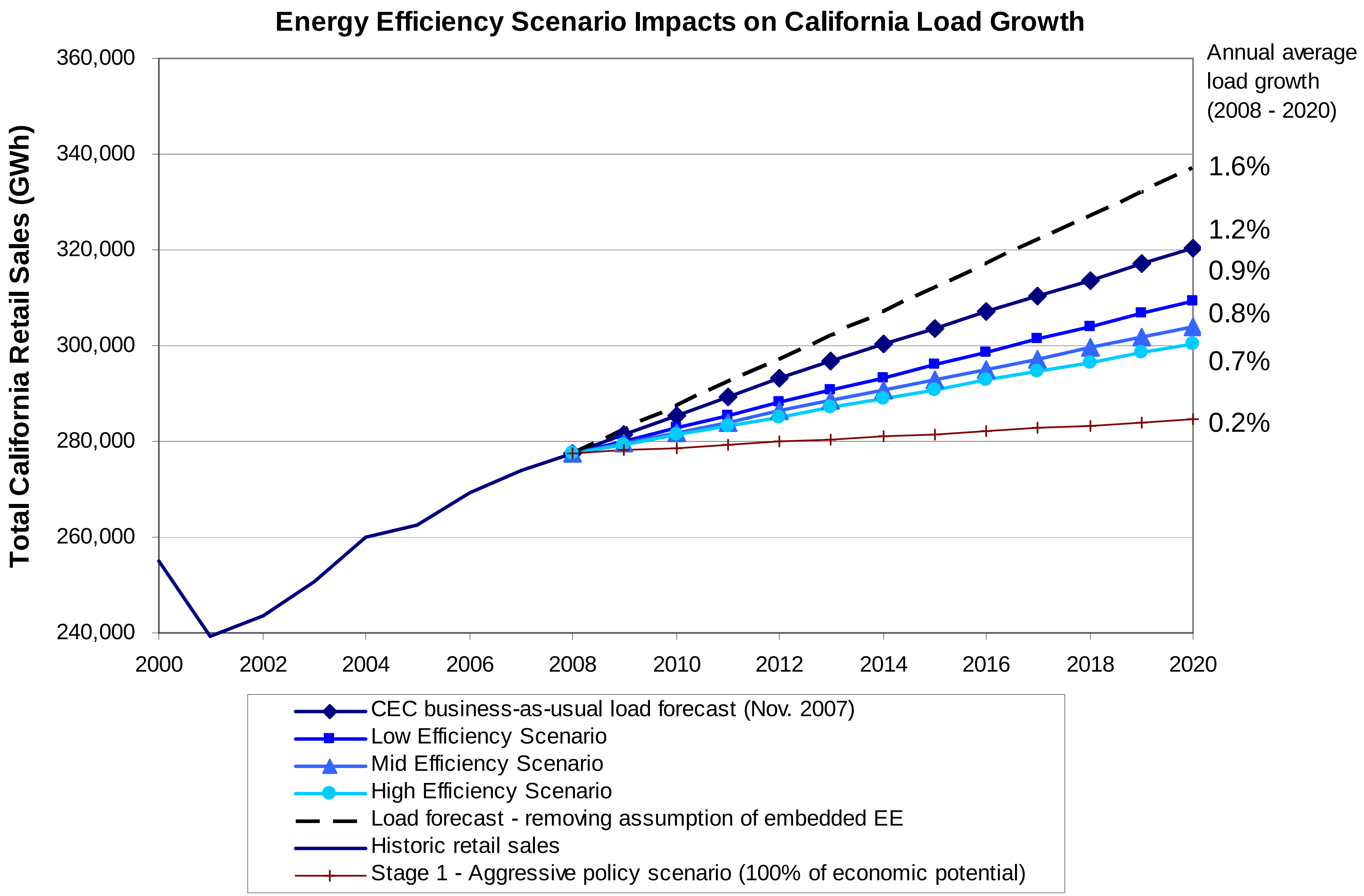
- New low, mid and high scenarios for EE savings
  - For IOUs, scenarios are based on cumulative savings from mandates (T24 & Federal standards, BBEES, Huffman Bill) and IOU programs from the 'CPUC Goals Update Study', March 2008
  - For POUs, scenarios use AB 2021 filings extrapolated linearly to 2020 for 'mid' utility program scenario. Savings from mandates are estimated based on load growth and proportional scaling of savings from IOUs in the 'CPUC Goals Update Study.'
- Costs are under review

Revised Energy Efficiency Cost and Potential Note: Costs are currently under review

Revised Statewide Scenarios	BAU reference case	'Low' EE scenario	'Mid' EE scenario	'High' EE scenario
Total utility program costs including admin.	$605 M/yr	$887 M/yr	$1.5 billion/yr	$2.1 billion/yr
Utility program costs and BBEES ($/kWh)	$0.032/kWh	$0.041/kWh	$0.051/kWh	$0.065/kWh
T24 & fed. stndrds, Huffman Bill (AB 1109)	N/A	$0.010/kWh	$0.010/kWh	$0.015/kWh
Utility program energy savings (2008 – 2020)	16,450 GWh	14,056 GWh	21,638 GWh	21,738 GWh
T24 & fed. stndrds, BBEES, Huffman Bill (AB 1109) (2008 – 2020)	…	13,801 GWh	11,733 GWh	15,240 GWh
Incremental energy savings (2008 – 2020)	**16,450 GWh**	**27,857 GWh**	**33,371 GWh**	**36,978 GWh**
Stage 1 Statewide Scenarios	BAU reference case	N/A	75% of econ. potential	100% of econ. potential
Utility program costs including admin.	$775 M/yr	…	$2 billion/yr	$3 billion/yr
Incremental energy savings (2008 – 2020)	**22,977 GWh**	**…**	**44,345 GWh**	**59,126 GWh**

Load forecast revision

- CEC California Energy Demand 2008 – 2018 Staff Revised Forecast, Nov. 2007 (instead of Oct. 2007 forecast)
- Creation of eighth 'LSE' category: 'Water Agencies'
  - Central Valley Project (WAPA), California Department of Water Resources, Metropolitan Water District
- Includes CA portion of load from non-California based retail providers
- Adjustments to treatment of pumping load during peak demand
- Loss factor varies by LSE, now a user input



Note: 1990 – 2000 average annual CA retail sales growth rate: ~1.5%

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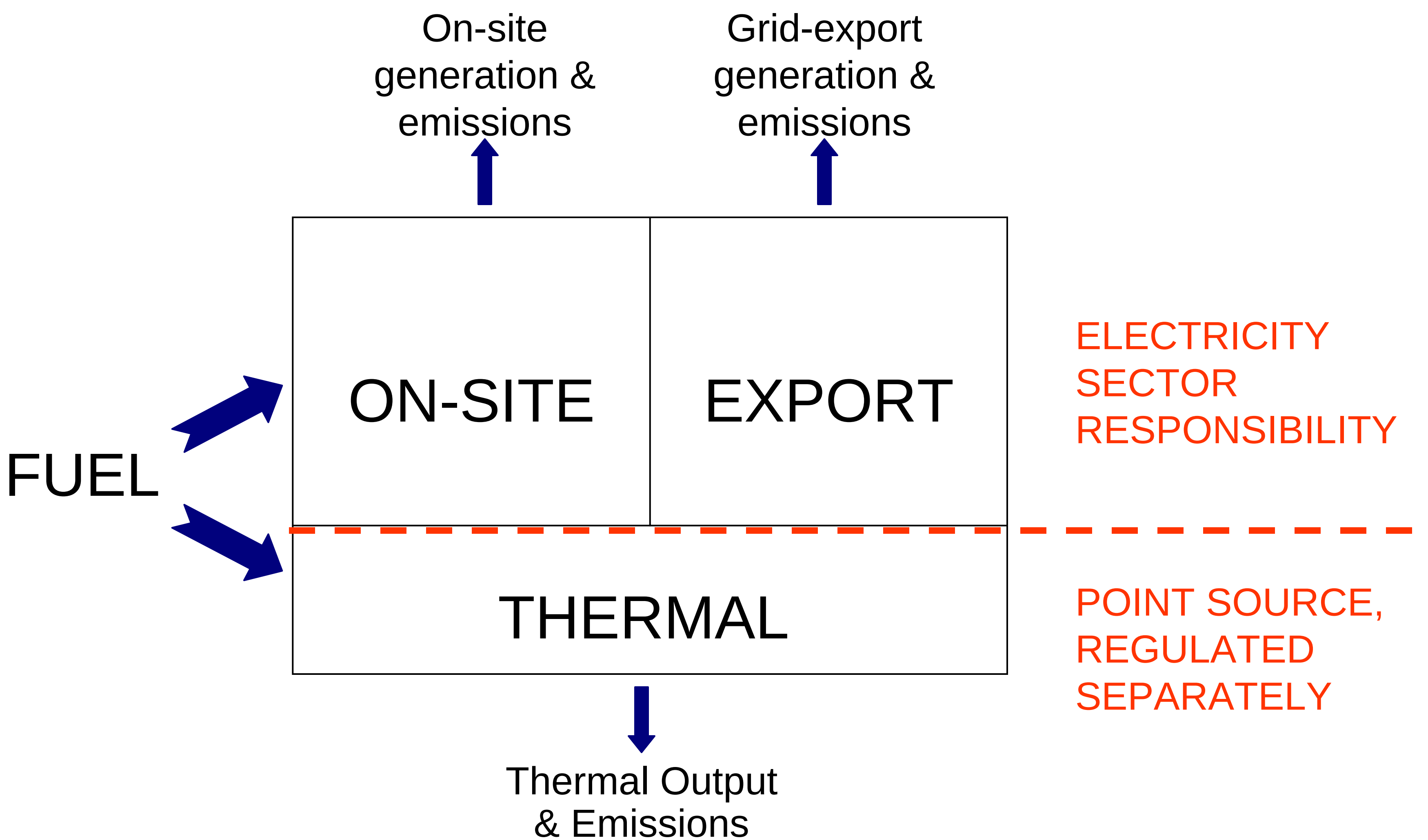
CHP in Stage 2 Model

- Adds CHP as new generation option
- Treats existing and new CHP units separately
- Accounts for CHP generation and emissions separately from non-CHP generation
- Provides user controls for cost, performance, and penetration assumptions for user cases
- Tracks overall efficiency and thermal emissions but does not include in electricity sector totals

CHP Output Assignment to Sectors



Existing CHP Fleet in Stage 2 Model

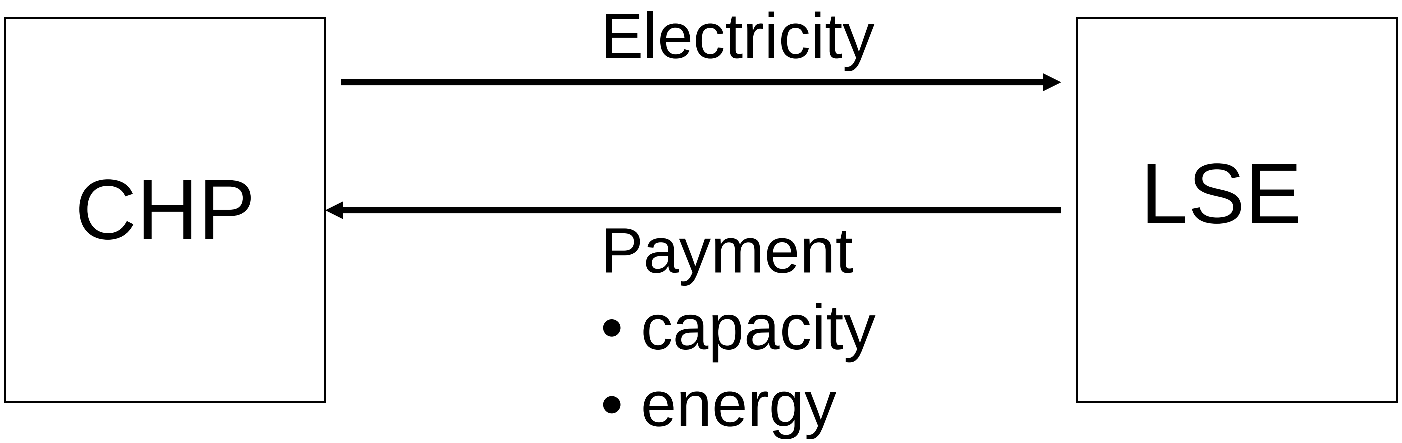
- On-site CHP: generation already embedded in load forecast so no adjustment is necessary
- On-grid CHP: many CHP units are not identified in WECC database, so CHP fleet generation is underestimated in the Plexos model
- This is corrected by adjusting CHP fleet generation and emissions to hit *expected values* based on historical data
  - Existing CHP generation and emissions in Plexos summarized, then adjusted in E3 calculator to expected value
  - Non-CHP generation decremented by the same amount in E3 calculator

New CHP Units in Stage 2 Model

- Two categories of new CHP
  - > 5 MW nameplate = “Large” CHP (cogen)
  - < 5 MW nameplate = “Small” CHP (self-gen)

Cost and Emissions Assumptions for CHP					
		<5MW CHP		>5MW CHP	
Assumed Technology		**3MW Gas Recip**		**IW Gas Turbine w/ Cl**	**Source**
Installed Cost $/kW	$	950	$	700	CEC 2005 Potential Study
Emissions Control (AT) Cost $/kW	$	275	$	90	CEC 2005 Potential Study
Total Installed Cost $/kW	$	1,225	$	790	Calculated
Total Installed Cost $2008/kW	$	1,952	$	1,259	Consistent Inflation Assumption
Gross Heat Rate, Btu/kWh		9,700		9,220	CEC 2005 Potential Study
Net Electric Heat Rate, Btu/kWh		5,561		6,031	CEC 2005 Potential Study
Thermal Output, Btu/kWh		3,281		3,189	CEC 2005 Potential Study
Assumptions		<5MW CHP		>5MW CHP	Source
Peak load reduction		60%		100%	Itron SGIP Study for small CHP; CEC for large CHP
Capacity Factor		40%		85%	Itron SGIP Study for small CHP; CEC for large CHP
% Electric used on-site		100%		25%	Assumption based on CEC Load Forecast and EIA
Fuel for Electricity		57%		65%	<5MW CEC Forecast; >5MW 2003 EIA
Fuel for Thermal		43%		35%	Calculated

CHP Payments by LSEs for Electricity



Payments based on most recent CPUC QF ruling:

Large CHP:

•capacity = $91.97/kW-yr

•energy = market price

Small CHP:

•capacity = $31.32/kW-yr

•energy = market price

CHP Penetration Levels

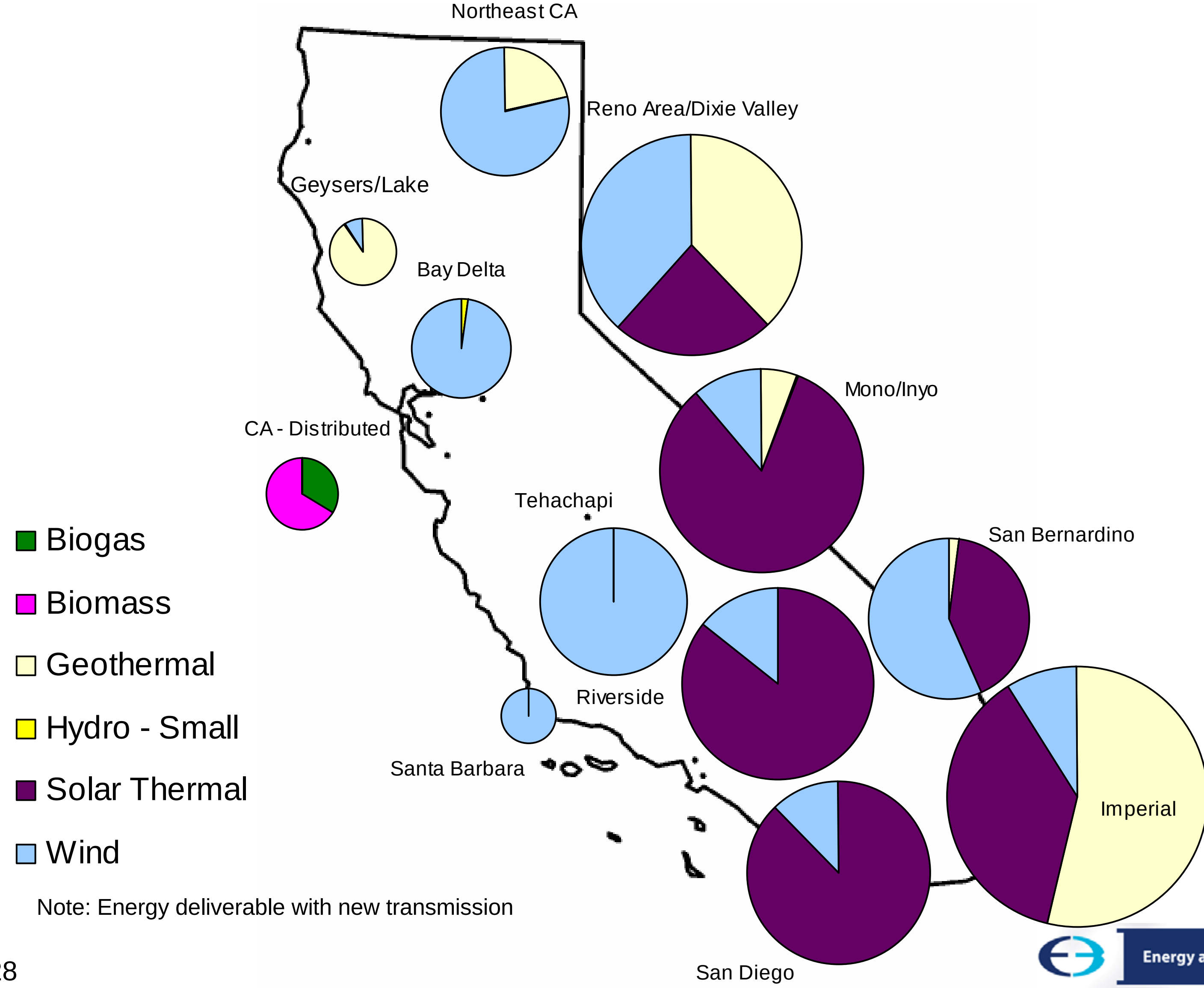
- Business as usual

Business as Usual Forecast for New CHP			
	<5MW CHP	>5MW CHP	Source
Nameplate Capacity (MW)	292	0	Derived based on ITRON on-peak value
Peak load reduction (MW)	175	0	CEC Forecast '08-'18 Forecast, Form 1.4, pg 42
Behind the meter usage (GWh)	1035	0	CEC Forecast '08-'18 Forecast, Form 1.2, pg 40
Exported to Grid (GWh)	0	0	
Capacity Factor	40%	0	Itron SGIP Study
% Electricity Consumed On-site	100%	0	

- Aggressive policy

Aggressive Policy Case Forecast for New CHP			
	<5MW CHP	>5MW CHP	Source
Nameplate Capacity (MW)	1,574	2,804	CEC 2005 Potential Study, Moderate Market case
Peak load reduction (MW)	944	1,682	Calculated based on Itron & CEC on-peak values
Behind the meter usage (GWh)	3,350	3,132	Calculated using percent of use on-site
Exported to Grid (GWh)	-	9,395	Calculated using percent of use on-site
Capacity Factor	40%	85%	Itron SGIP Study for small CHP; CEC for large CHP
% Electricity Consumed On-site	100%	25%	Assumption based on CEC Load Forecast and EIA

CA Renewable Resource Zones



Note: Energy deliverable with new transmission

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Renewables Modeled by Zone

- User selects transmission capacity to each zone
- Calculator estimates costs of renewables
  - Busbar cost
  - Transmission
  - Integration
  - System Balancing

		Total Renewable Resources (MW)	Reference Case MW	User Selelected MW
1	Alberta	5,193	-	-
2	Arizona-Southern	5,699	-	-
3	Bay Delta	2,963	-	-
4	British Columbia	4,118	-	-
5	CA - Distributed	874	-	-
6	CFE	4,873	-	-
7	Colorado	5,337	-	-
8	Geysers/Lake	698	-	-
9	Imperial	5,824	2,339	2,339
10	Mono/Inyo	5,658	-	-
11	Montana	5,415	-	-
12	NE NV	1,403	-	-
13	New Mexico	5,509	-	-
14	Northeast CA	3,099	-	-
15	Northwest	5,534	-	-
16	Reno Area/Dixie V	5,658	-	-
17	Riverside	5,825	-	-
18	San Bernardino	5,658	-	-
19	San Diego	5,824	-	-
20	Santa Barbara	558	-	-
21	South Central Nev	5,699	-	-
22	Tehachapi	5,824	4,394	4,394
23	Utah-Southern Ida	5,564	-	-
24	Wyoming	5,398	-	-

Screen 'capture' from GHG Calculator

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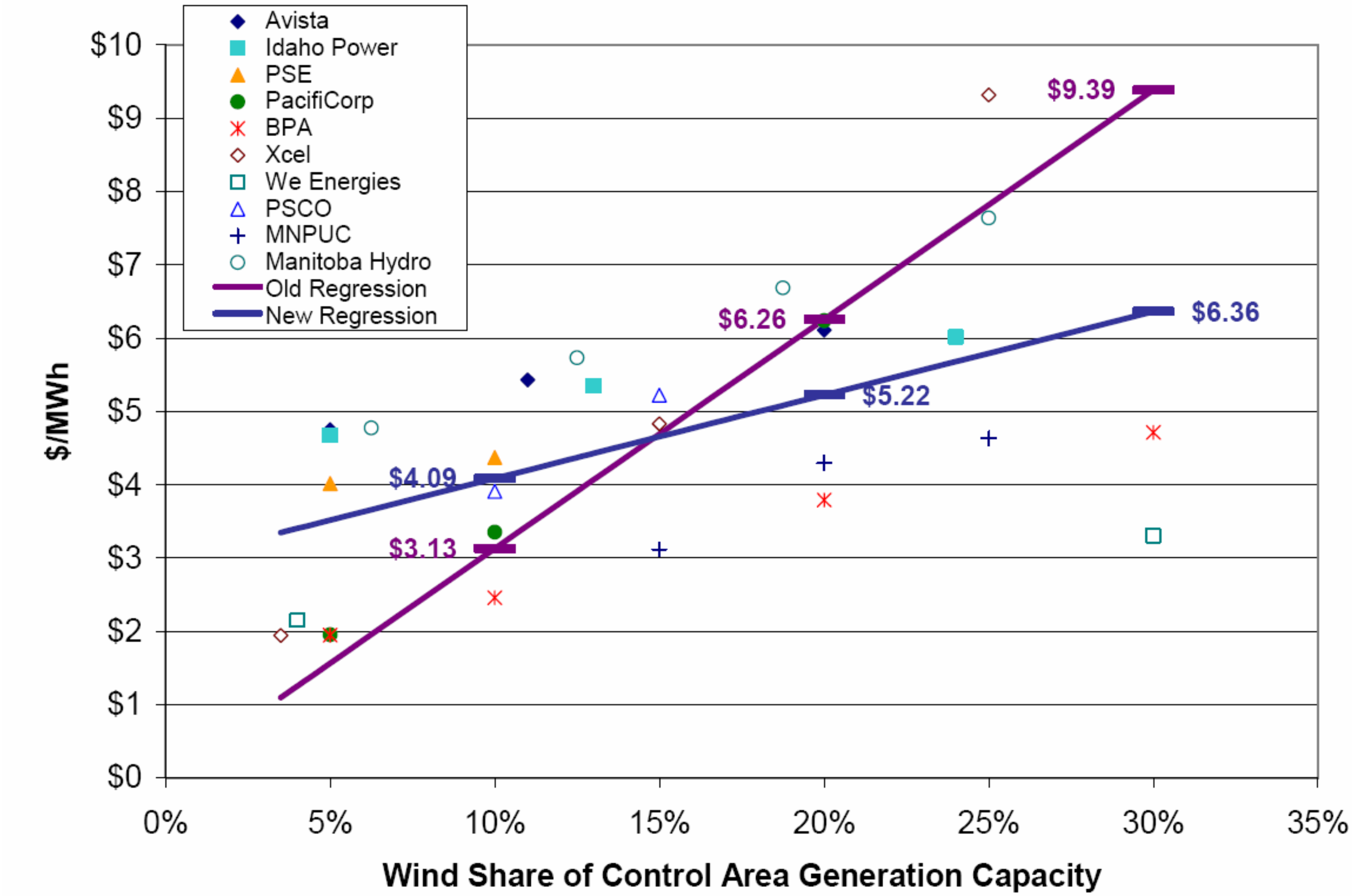
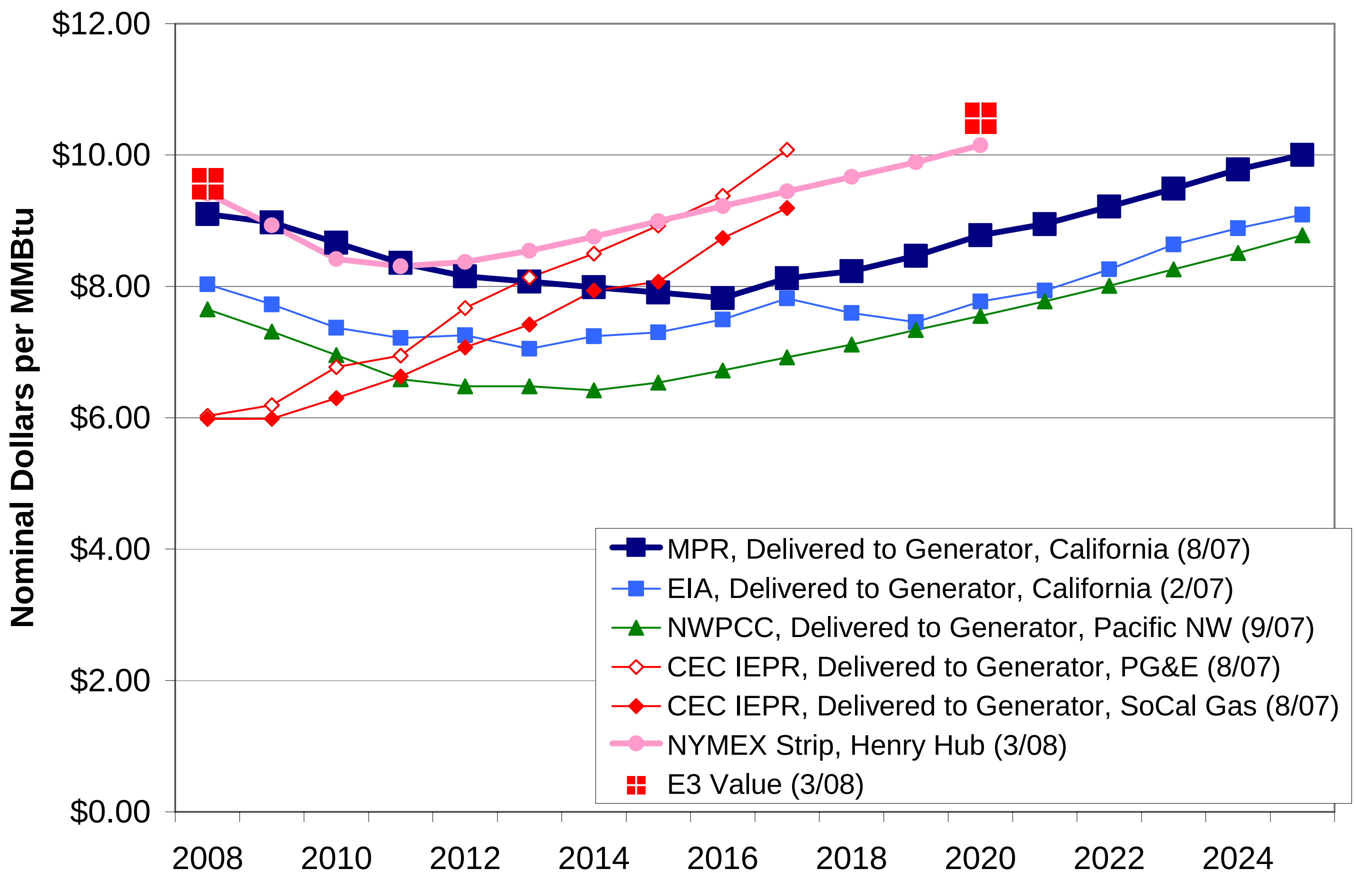
Change in Wind Integration Costs



Natural Gas Price Forecast

- NYMEX Henry Hub Plus Delivery to CA Generators



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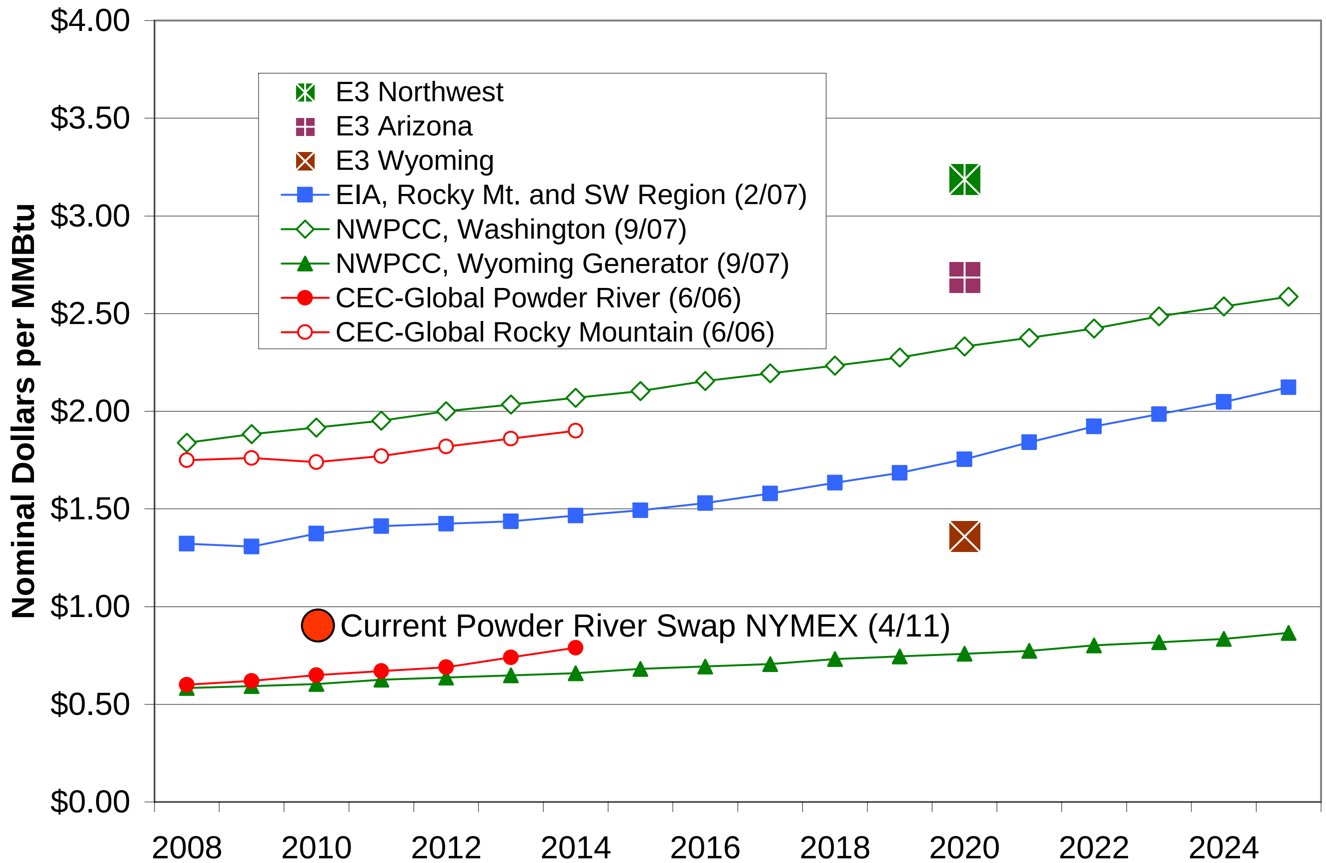
Coal Price Forecast

- Coal prices have also increased



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Generator Assignment

- Publicly available information used to map generators to LSEs
  - Utility-owned generation
  - Known long term contracts
- Stage 1 assignments posted for LSEs to review
- Updates incorporated into the Stage 2 model

Generator	Unit #	Location	Fuel Type	CA Owner	2008 LSE Share %	2020 Contract Status
Boardman	**1**	Boardman, OR	Coal	SDG&E	15.0%	**2018**
				Northern California Other	8.5%	**2013**
				Total CA	**24%**	
Four Corners	**4 & 5**	Fruitland, NM	Coal	SCE	48.0%	
				Total CA	**48.0%**	**Same**
Hoover		Boulder City, NV	Hydro	Southern California Other	34.1%	
				LADWP	15.4%	
				SCE	5.5%	
				Total CA	**55.0%**	**Same**
Intermountain Power Project	**1 & 2**	Delta, UT	Coal	LADWP	48.6%	
				Southern California Other	30.3%	
				Total CA	**78.9%**	**Same**
Navajo Generating Station	**1,2 & 3**	Page, AZ	Coal	LADWP	**21.2%**	**2019**
Palo Verde	**1,2 & 3**	Wintersburg, AZ	Nuclear	SCE	15.8%	
				Southern California Other	1.9%	
				LADWP	9.7%	
				Total CA	**27.4%**	**Same**
Reid Gardner	**4**	Moapa, NV	Coal	CA DWR	**67.8%**	**2013**
San Juan	**3**	San Juan, NM	Coal	Southern California Other	**41.8%**	**Same**
San Juan	**4**	San Juan, NM	Coal	Northern California Other	28.7%	
				Southern California Other	10.0%	
				Total CA	**38.8%**	**Same**
San Onofre	**2,3**	San Clemente, CA	Nuclear	SCE	75.0%	
				SDG&E	20.0%	
				Southern California Other	5.0%	
				Total CA	**100.0%**	**Same**
Diablo Canyon	**1,2**	San Louis Obispo, CA	Nuclear	PG&E	**100.0%**	**Same**
Bonaza	**1**	Utah	Coal	City of Riverside	**6.0%**	**2009**
Hunter	**2**	Utah	Coal	City of Riverside	**6.0%**	**2009**

Recent Changes in ARB Electricity Sector Emissions Inventory

- Stage 1 Model used Aug. 2007 ARB inventory as reference point for electricity sector GHG reductions
- Adopted (Nov. 2007) ARB inventory is significantly different
  - New 1990 level for electricity sector is 110.63 MMT CO2e (previously: 100.07 MMT CO2e)
  - 1990 to 2004 increase is now ~60% smaller
  - Most of the change is due to the change in the emissions factor for unspecified imports

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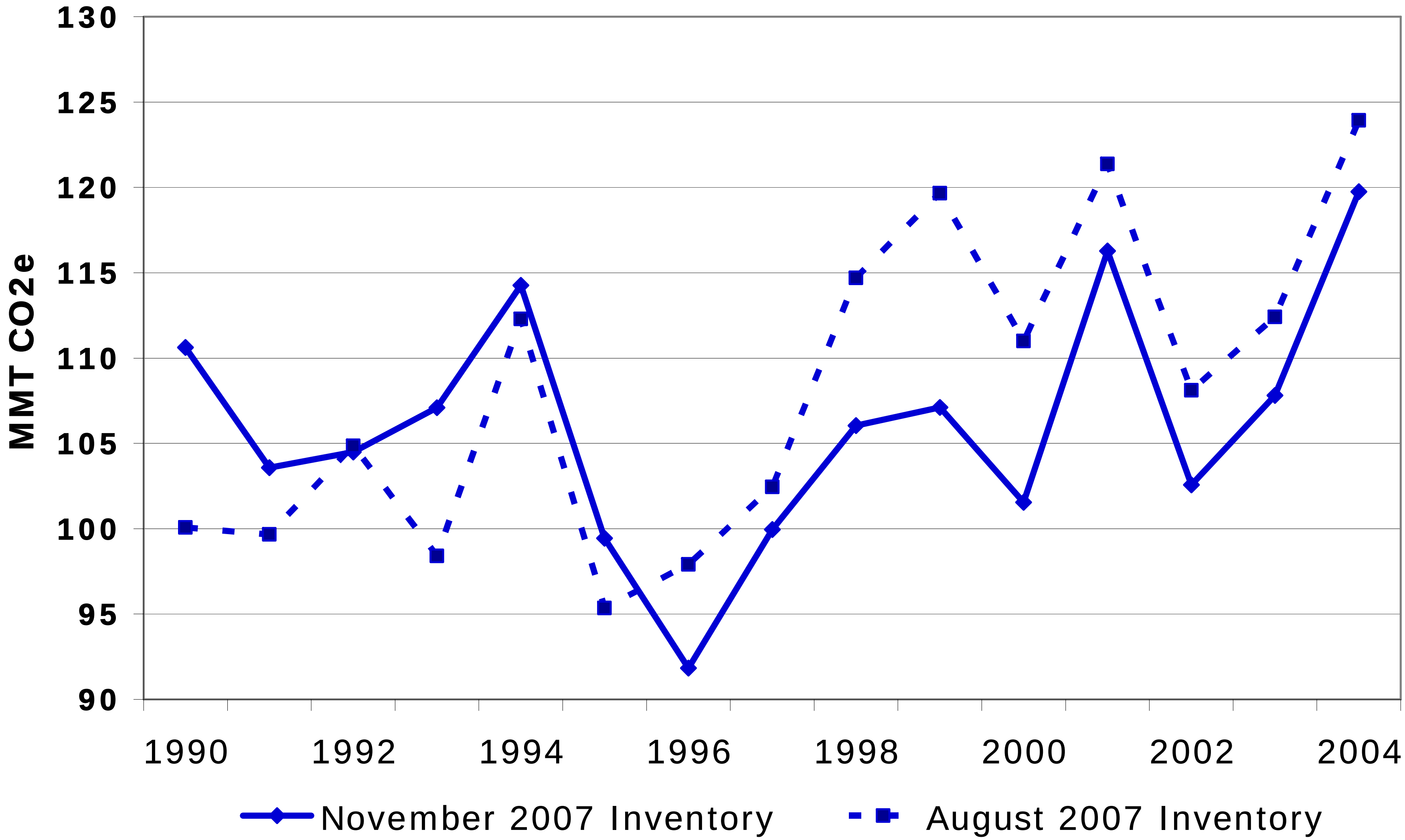
ARB Inventory of Electricity Sector Emissions



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Stage 1 Revised Outputs

WECC Resource Additions to 2020

- Business As Usual Case – Nameplate MW

TEPPC 2008-2017 Additions	AB	AZ	BC	CA	CFE	CO	MT	NM	NV	NW	UT	WY	*WECC Total*
Bio											3		*3*
Coal	920	2,800				780	350				1,075	667	*6,592*
Gas	135	624		2,311	575	865	322	494	514	1,466			*7,306*
Geotherm									144		10		*154*
Hydro			935									3	*938*
Nuclear													*-*
Oil													*-*
Solar													*-*
Wind	60			375		75					100		*610*
TEPPC Total	***1,115***	***3,424***	***935***	***2,686***	***575***	***1,720***	***672***	***494***	***658***	***1,466***	***1,188***	***670***	***15,602***
E3 Renewable Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Biogas	-	33	50	-	-	59	5	18	-	88	21	2	*276*
Geothermal	-	-	185	1,577	-	-	-	-	-	-	-	-	*1,762*
Hydro - Small	100	-	469	-	-	-	25	-	-	112	65	12	*783*
Solar Thermal	-	3,557	-	863	-	-	-	-	-	-	-	-	*4,420*
Wind	1,920	1,352	1,231	4,293	-	2,032	44	779	-	3,049	68	88	*14,856*
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	*-*
E3 Total	***2,020***	***4,942***	***1,935***	***6,733***	***-***	***2,091***	***74***	***797***	***-***	***3,249***	***154***	***102***	***22,097***
E3 Conventional Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Gas CCCT (MW)	153	-	185	-	356	-	-	-	-	4,091	1,052	188	*6,024*
Gas CT (MW)	947	1,488	-	3,410	301	1,928	-	599	-	-	1,834	281	*10,787*
Total TEPPC and E3 Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***Grand Total***
Total Renewables	***2,080***	***4,942***	***2,870***	***7,108***	***-***	***2,166***	***74***	***797***	***144***	***3,249***	***267***	***105***	***23,802***
Total Conventional	***2,155***	***4,912***	***185***	***5,721***	***1,231***	***3,573***	***672***	***1,093***	***514***	***5,557***	***3,960***	***1,136***	***30,709***

Detail on CA 20% RPS Development

Sum of Quantity by Individual Resource (MW) - Selected For 20% RPS Case

Cluster Zone	Biogas	Geothermal	Hydro - Large	Hydro - Small	Solar Thermal	Wind	Biomass	*Grand Total*
Bay Delta				-		-		-
CA - Distributed	-						-	-
CFE						-		-
Geysers/Lake		-		-		-		-
Imperial		1,577			508	254		*2,339*
Mono/Inyo		-		-	-	-		-
NE NV						-		-
Northeast CA		-		-		-		-
Reno Area/Dixie Valley		-			-	-		-
Riverside					-	-		-
San Bernardino		-			-	-		-
San Diego				-	-	-		-
Santa Barbara						-		-
Tehachapi					355	4,039		*4,394*
Utah-Southern Idaho	-	-	-	-	-	-	-	-
Arizona-Southern Nevada	-				-	-	-	-
New Mexico	-	-			-	-	-	-
Wyoming	-			-		-	-	-
South Central Nevada	-	-		-	-	-	-	-
British Columbia	-	-	-	-		-	-	-
Colorado	-	-			-	-	-	-
Montana	-			-		-	-	-
Northwest	-	-	-	-		-	-	-
Alberta			-	-		-		-
Grand Total	***-***	***1,577***	***-***	***-***	***863***	***4,293***	***-***	***6,733***

WECC Resource Additions to 2020

- Aggressive Policy Case, 33% RPS in CA – Nameplate MW

TEPPC 2008-2017 Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Bio											3		*3*
Coal	920	2,800				780	350				1,075	667	*6,592*
Gas	135	624		2,311	575	865	322	494	514	1,466			*7,306*
Geotherm									144		10		*154*
Hydro			935									3	*938*
Nuclear													*-*
Oil													*-*
Solar													*-*
Wind	60			375		75					100		*610*
Total	*1,115*	*3,424*	*935*	*2,686*	*575*	*1,720*	*672*	*494*	*658*	*1,466*	*1,188*	*670*	*15,602*
E3 Renewable Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Biogas	-	33	50	-	-	59	5	18	-	88	21	2	*276*
Geothermal	-	-	185	2,479	-	-	-	-	-	-	-	-	*2,664*
Hydro - Small	100	-	469	5	-	-	25	-	-	112	65	12	*788*
Solar Thermal	-	3,557	-	1,342	-	-	-	-	-	-	-	-	*4,899*
Wind	1,920	1,352	1,231	7,122	-	2,032	44	779	-	3,049	68	88	*17,685*
Biomass	-	-	-	600	-	-	-	-	-	-	-	-	*600*
Total	*2,020*	*4,942*	*1,935*	***11,548***	-	*2,091*	*74*	*797*	-	*3,249*	*154*	*102*	*26,912*
E3 Conventional Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Gas CCCT (MW)	153	-	185	-	356	-	-	-	-	4,091	1,052	188	*6,024*
Gas CT (MW)	947	1,488	-	-	301	1,928	-	599	-	-	1,834	281	*7,378*
Total TEPPC and E3 Additions	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***Grand Total***
Total Renewables	***2,080***	***4,942***	***2,870***	***11,923***	***-***	***2,166***	***74***	***797***	***144***	***3,249***	***267***	***105***	***28,616***
Total Conventional	***2,155***	***4,912***	***185***	***2,311***	***1,231***	***3,573***	***672***	***1,093***	***514***	***5,557***	***3,960***	***1,136***	***27,300***

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Detail on CA 33% RPS Development

Sum of Quantity by Individual Resource (MW) - Selected For 33% RPS Case

Cluster Zone	**Biogas**	**Geothermal**	**Hydro - Large**	**Hydro - Small**	**Solar Thermal**	**Wind**	**Biomass**	***Grand Total***
Bay Delta				-		-		-
CA - Distributed	300						600	*900*
CFE						1,608		*1,608*
Geysers/Lake		538		-		157		*695*
Imperial		1,685			543	272		*2,500*
Mono/Inyo		-		-	-	-		-
NE NV						-		-
Northeast CA		255		3		742		*1,000*
Reno Area/Dixie Valley		-			-	-		-
Riverside					-	-		-
San Bernardino		-			-	-		-
San Diego				3	443	304		*750*
Santa Barbara						-		-
Tehachapi					355	4,039		*4,394*
Utah-Southern Idaho	-	-	-	-	-	-	-	-
Arizona-Southern Nevada	-				-	-	-	-
New Mexico	-	-			-	-	-	-
Wyoming	-			-		-	-	-
South Central Nevada	-	-		-	-	-	-	-
British Columbia	-	-	-	-		-	-	-
Colorado	-	-			-	-	-	-
Montana	-			-		-	-	-
Northwest	-	-	-	-		-	-	-
Alberta			-	-		-		-
Grand Total	***300***	***2,479***	***-***	***5***	***1,342***	***7,122***	***600***	***11,848***

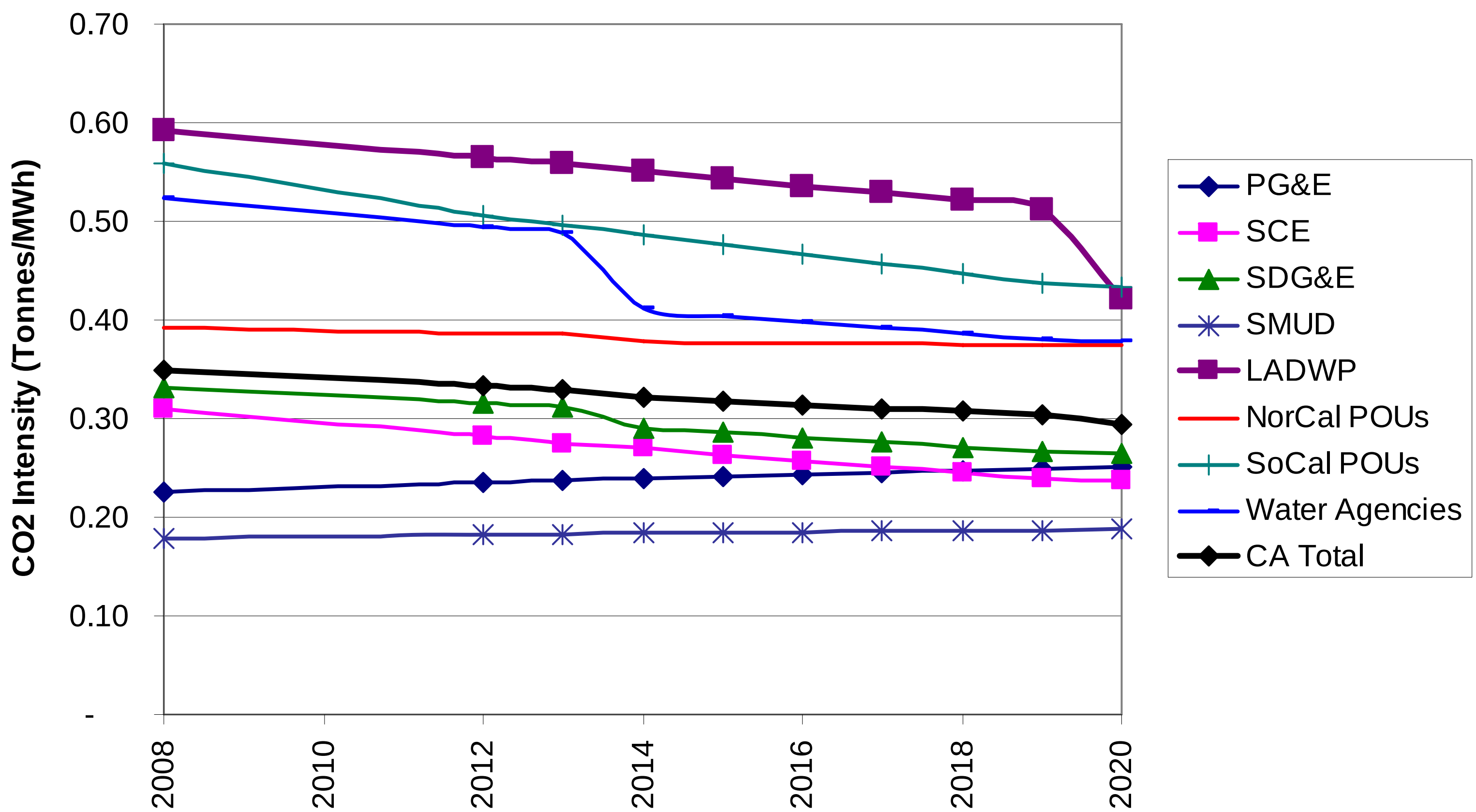
2020 BAU Reference Comparison

Policies	Stage 1 BAU	Revised BAU
Energy Efficiency (EE)	Assume 23,000 GWh EE embedded in CEC load forecast	Assume 16,450 GWh EE embedded in CEC load forecast
Rooftop solar PV	1,091 MW nameplate of rooftop PV installed	847 MW nameplate of rooftop PV installed
Demand Response	5% demand response	5% demand response
Combined heat and power (CHP)	No explicit assumption	292 MW nameplate behind-the-meter CHP No new large (>5MW) CHP
Renewable Energy	20% RPS (7,404 MW)	20% RPS (6,733 MW)
2008 Emissions	109.4 M MMTCO2e	109.6 MMT CO2e
2020 Emissions	112.5 MMTCO2e	107.1 MMTCO2e

2020 Aggressive Reference Comparison

Policies	**Stage 1 Aggressive Policy**	**Revised Aggressive Policy**
Energy Efficiency	100% of economic energy efficiency potential achieved	‘High goals’ EE scenario based on CPUC Goals Update Study, March 08
Rooftop solar PV	3,000 MW of rooftop PV	3,000 MW of rooftop PV
Demand Response	5% demand response	5% of demand response
Combined heat and power (CHP)	No explicit assumption	1,574 MW nameplate small CHP (< 5 MW) 2,804 MW nameplate larger CHP (>5 MW)
Renewable Energy	33% RPS (16,119 MW)	33% RPS (12,847 MW)
2020 Emissions	83.6 MMTCO2e	85.6 MMT CO2e

Emissions Intensity by LSE



Scenario: 20% RPS, ‘mid’ goals for energy efficiency, no carbon market

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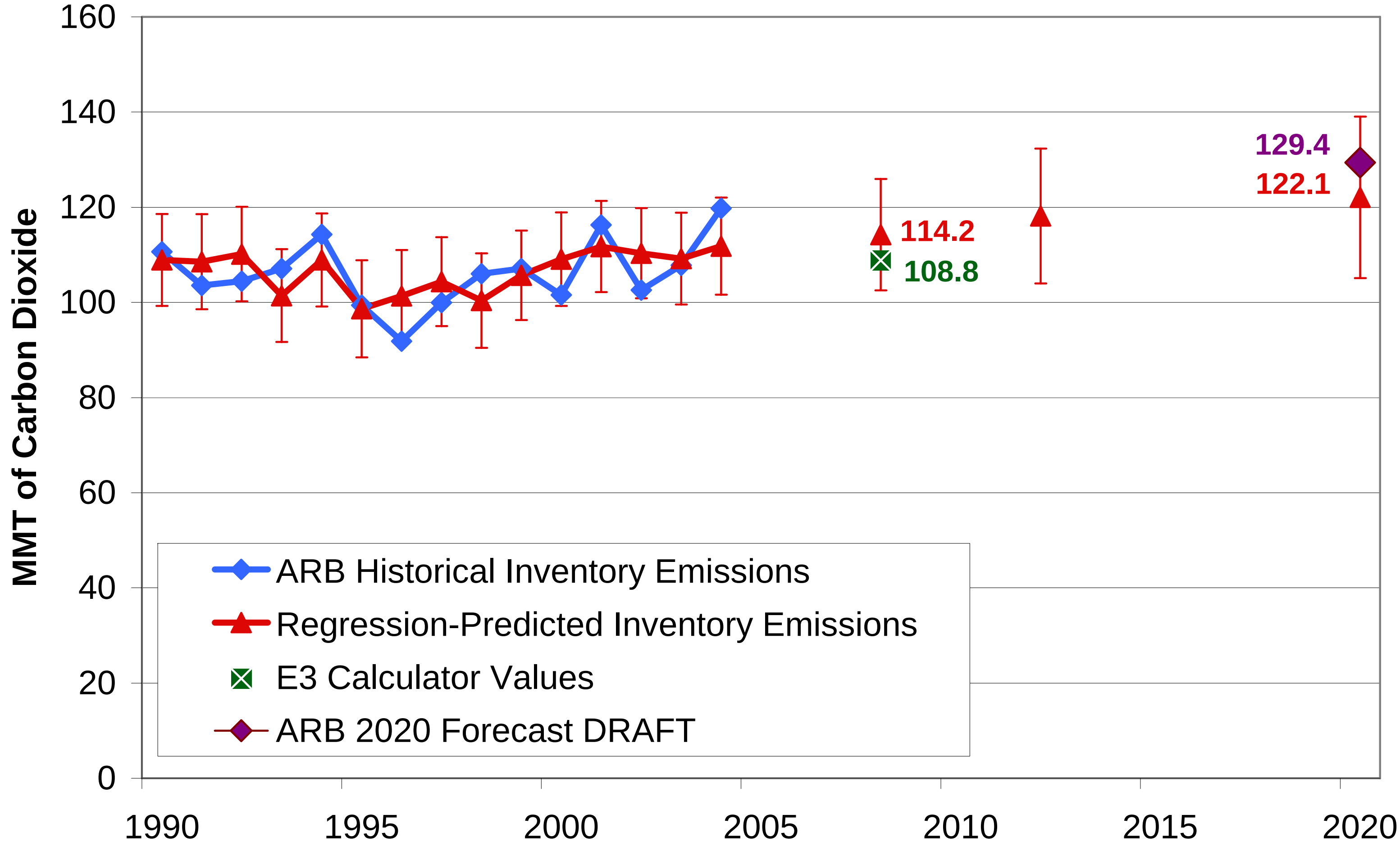
Key Data Uncertainties & Shortcomings

- Energy efficiency costs
- Uncertainty regarding the amount of embedded energy efficiency in the CEC's load forecast
- Assignment of generators to LSEs based on ownership or long-term contracts

Do the emissions results make sense?

- To see how the model's 2008 emissions results compare to the ARB electricity sector emissions inventory trend, E3 performed a simple regression analysis:
  - Key predictors of historical emissions are load and in-state hydro
  - To match the current modeling of unspecified imports, E3 recast historical inventory with constant emissions factor
  - Exercise is imprecise because inventory values are themselves uncertain
- E3 model's 2008 emissions level falls within the 95% confidence interval of the 2008 regression analysis forecast (based on ARB inventory 1990 – 2004)

Historical vs. Predicted Electricity Sector Emissions



Stage 2 Approach

Stage 2 Functionality

- Maintains ‘Stage 1’ Functionality, with additions
- Ability to model ‘Energy Deliverer’ policy options
- Ability to change generator ownership shares & contracts with LSEs in the model
- Added sensitivity analysis ‘record’ feature
- Added supply curve output

Energy Deliverer Framework

- Energy deliverer, multi-sector cap and trade
- California-only carbon price
- Hybrid model structure (regulation & market)
  - CO2 market
    - Input market clearing price of GHG emission permits
      - No ‘electricity-sector’ emissions cap, just multi-sector
      - Electricity sector is assumed to be a ‘price-taker’ for emission permits
    - Adjust allocation, auction and offsets controls
  - Regulatory requirements
    - Input LSE policy requirements (RPS, EE)
- **Model does NOT determine the CO2 market price!**
- The model determines CO2 quantity in the <u>electricity</u> sector based on an assumed market clearing price

Building Scenarios in the Model

- Set RPS and energy efficiency targets
- Set market price for GHG emission permits
- Set assumptions to apply to out-of-state coal contracts
- Choose whether permits will be auctioned or administratively allocated
  - If allocated, choose basis for allocation: updating output-based or historic emissions-based
- Choose whether auction revenues will be recycled to LSEs in the electricity sector
  - If recycled, choose basis for revenue reallocation: updating sales-based or historic emissions-based
- Choose whether to allow carbon ‘offsets’
  - If offsets are allowed: pick price and % allowable for several types of offsets

'Mock-up' of CO2 Market Control Panel

Market Clearing Price for Emissions Permits	2012	2013	2014	2015	2016	2017	2018	2019	2020
Market clearing price for permits ($/MMTCO2e)	$ 30.00	$ 37.50	$ 45.00	$ 52.50	$ 60.00	$ 67.50	$ 75.00	$ 82.50	$ 90.00

Administrative allocation	2012	2013	2014	2015	2016	2017	2018	2019	2020
Quantity of permits administratively allocated (MMT CO2e)	106.5	95.4	83.4	72.6	62.0	51.4	40.9	28.7	18.3
Percent of permits administratively allocated	100%	90%	80%	70%	60%	50%	40%	30%	20%
Percent of permits auctioned to energy deliverers	0%	10%	20%	30%	40%	50%	60%	70%	80%
Basis of allocation									
Energy Output (updated yearly)	50%	60%	70%	80%	90%	100%	100%	100%	100%
Historic 2008 emissions	50%	40%	30%	20%	10%	0%	0%	0%	0%

Exclude non-fossil GWh from sales-based allocations

CO2 Markets and Prices									
Offsets Price ($/tonne CO2e)	2012	2013	2014	2015	2016	2017	2018	2019	2020
California offsets	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00
Regional offsets	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00	$ 10.00
International offsets	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Maximum % of emissions requirement that can be met with offsets									
California offsets	10%	10%	10%	10%	10%	10%	10%	10%	10%
Regional offsets	5%	5%	5%	5%	5%	5%	5%	5%	5%
International offsets	5%	5%	5%	5%	5%	5%	5%	5%	5%

Auction Revenue Redistribution to LSEs	2012	2013	2014	2015	2016	2017	2018	2019	2020
Percent of auction revenue returned to LSEs	100%	100%	100%	100%	100%	100%	100%	100%	100%
Method for Returning Revenues									
Return based on LSE Sales (updated yearly)	50%	50%	50%	50%	50%	50%	50%	50%	50%
Return based on 2008 emissions	50%	50%	50%	50%	50%	50%	50%	50%	50%

Options on Coal Contracts

Choices for Modeling Out-of-State Coal Contracts

- **Default option A1:** LSEs hold coal contracts until the expiration date, regardless of the carbon price.
  - **Alternative scenario A2:** LSEs break coal contracts if the carbon price becomes too expensive.
- **Default option B1:** After coal contract expires, LSEs are prevented from contracting with coal plants, even if it is economic
  - **Alternative scenario B2:** After contract expires, LSEs can buy coal power with short-term contracts, if it is economic

Generator Costs and Electricity Price

	Specified	Unspecified
In-State	VOM + Fuel cost + Generator CO2 price	MCP + Generator CO2 price (or choose VOM + Fuel cost)
Outside CA	VOM + Fuel cost + Generator CO2 price	MCP + CO2 price at the deemed emissions intensity for imports

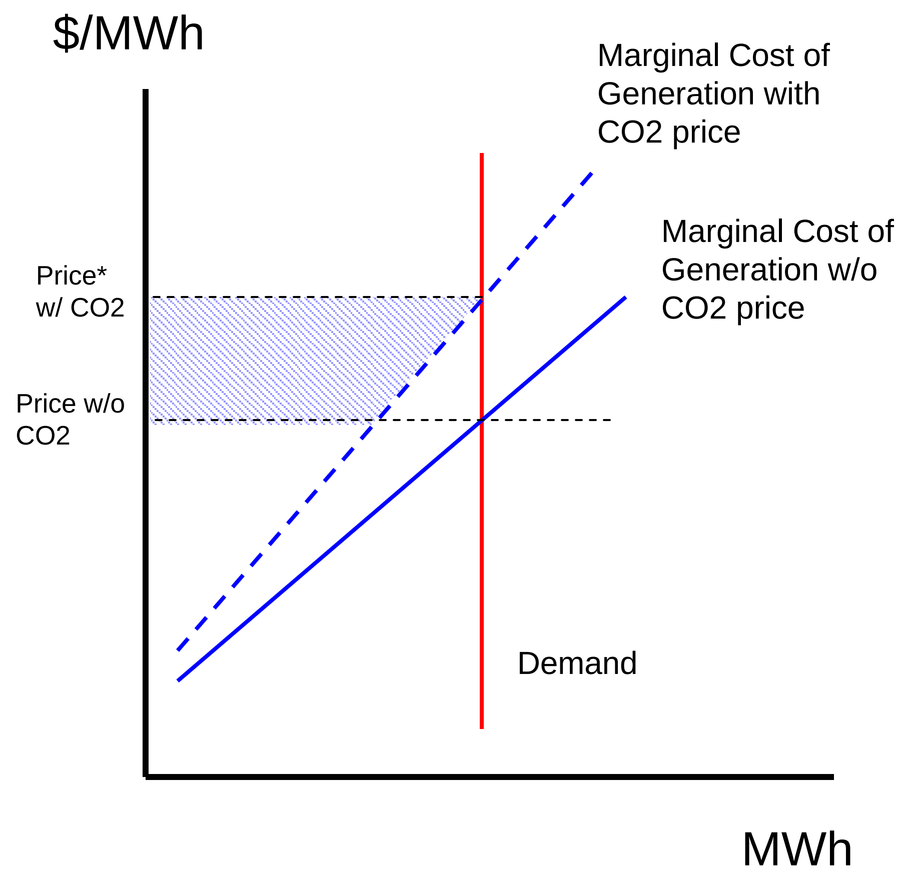
VOM = Variable Costs plus Operation and Maintenance Costs

Generator CO2 = generator cost for emissions permit

MCP = Market Clearing Price for electricity

Market Clearing Price including Carbon

- Including CO2 in the wholesale market increases the MCP
- Has distributional impacts on energy deliverers and LSEs



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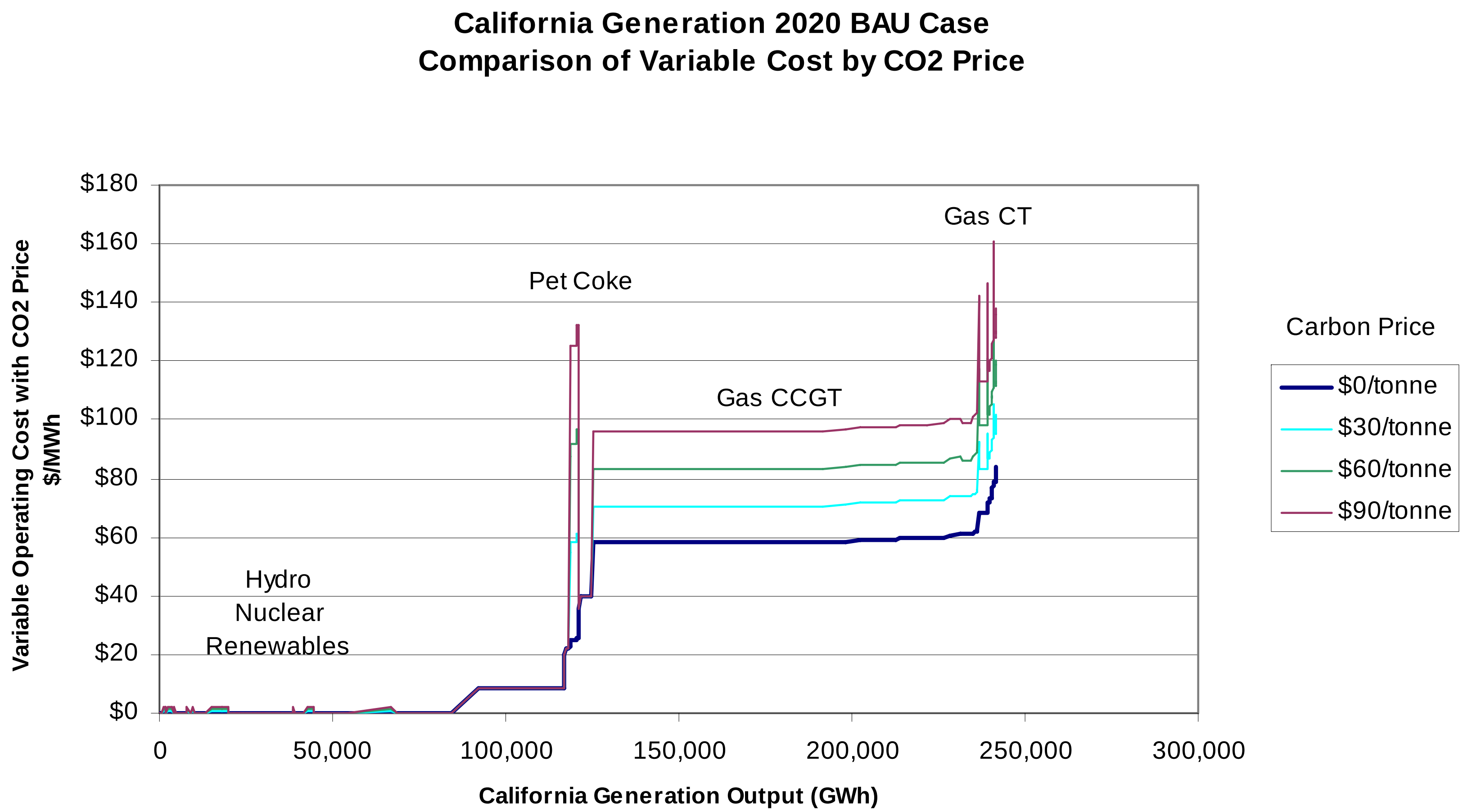
Implications of GHG Cap and Trade for California's Electricity Sector

Possible Impacts of a California GHG Market on the Electricity Sector

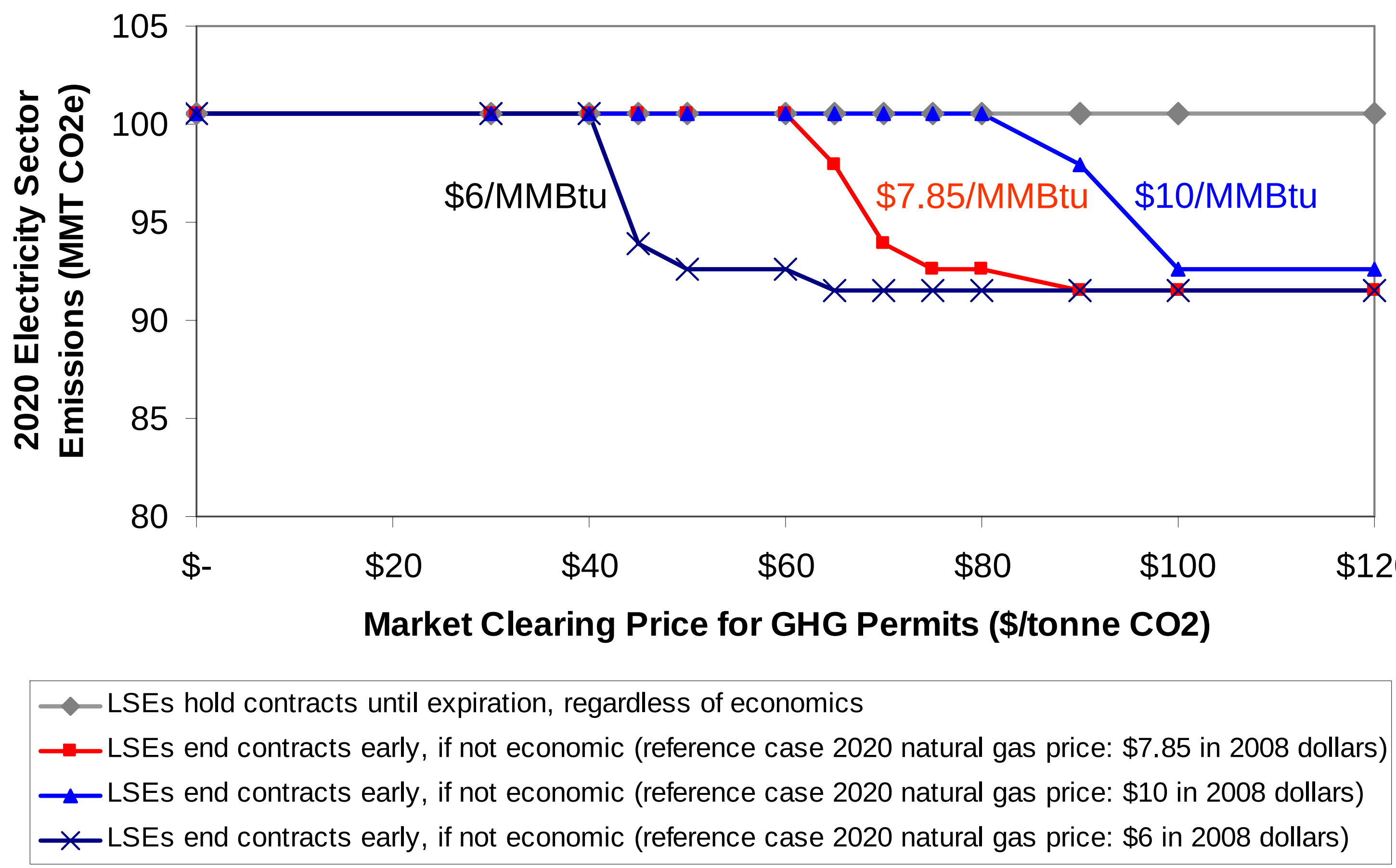
- Change in operation of existing plants
  - Cost of CO_2 could change the relative economics of natural gas and coal
- Reduction of emissions intensity of imports
  - Increase in low-carbon specified imports and/or reduction in high-carbon specified imports
- New capital investment
  - Cost of CO_2 could make all-in costs of low-carbon resources look relatively less than fossil-fuel resources
- Technology innovation (not directly modeled)
  - A higher market price for power and a CO_2 price could drive new technology innovation, resulting in new sources of emission reductions
- Distributional impacts
  - Distributional impacts due to emission allocation policy choices and impacts due to impact of CO_2 market on electricity prices

Operational changes of CA generation with carbon prices



CO2 price does not change the economic dispatch order in California (much)

Change in imports of out-of-state fossil generation with different natural gas and carbon prices



Scenario: 20% RPS, 'Mid goals' of EE

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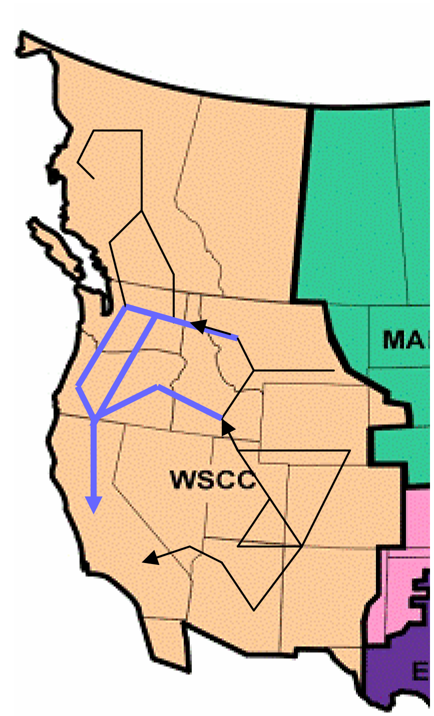
Emissions intensity of imports

- Large hydroelectric capacity in the Northwest
  - provides potential for long-term storage of hydropower
- Active trading with more carbon-intensive generation in the West and Southwest
- Potential for Northwest to sell low carbon electricity to California made possible by past high carbon purchases for domestic load
- California emissions reporting requirements seek to prevent such 'green-washing'

Research on potential for 'shuffling' done by:

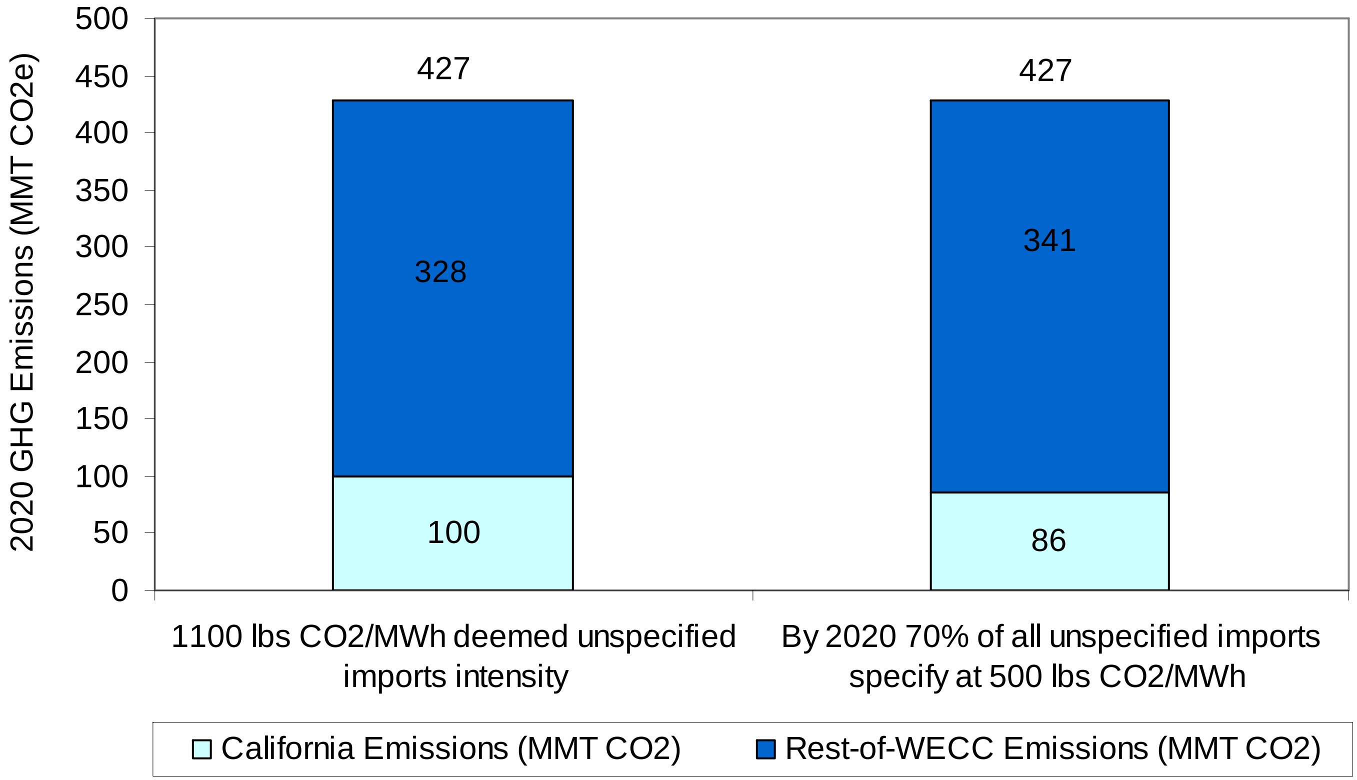
- Yihsu Chen, Andrew Liu, Benjamin Hobbs, "Economic and Emissions Implications of Load-based, Source-based and First-seller Emissions Trading Programs under California AB32", March 2008.

http://faculty.ucmerced.edu/ychen/Power_0326.pdf



Hypothetical ‘Shuffling’ Example

Example: 70% of previously unspecified imports is specified at 500 lbs CO2/MWh by 2020



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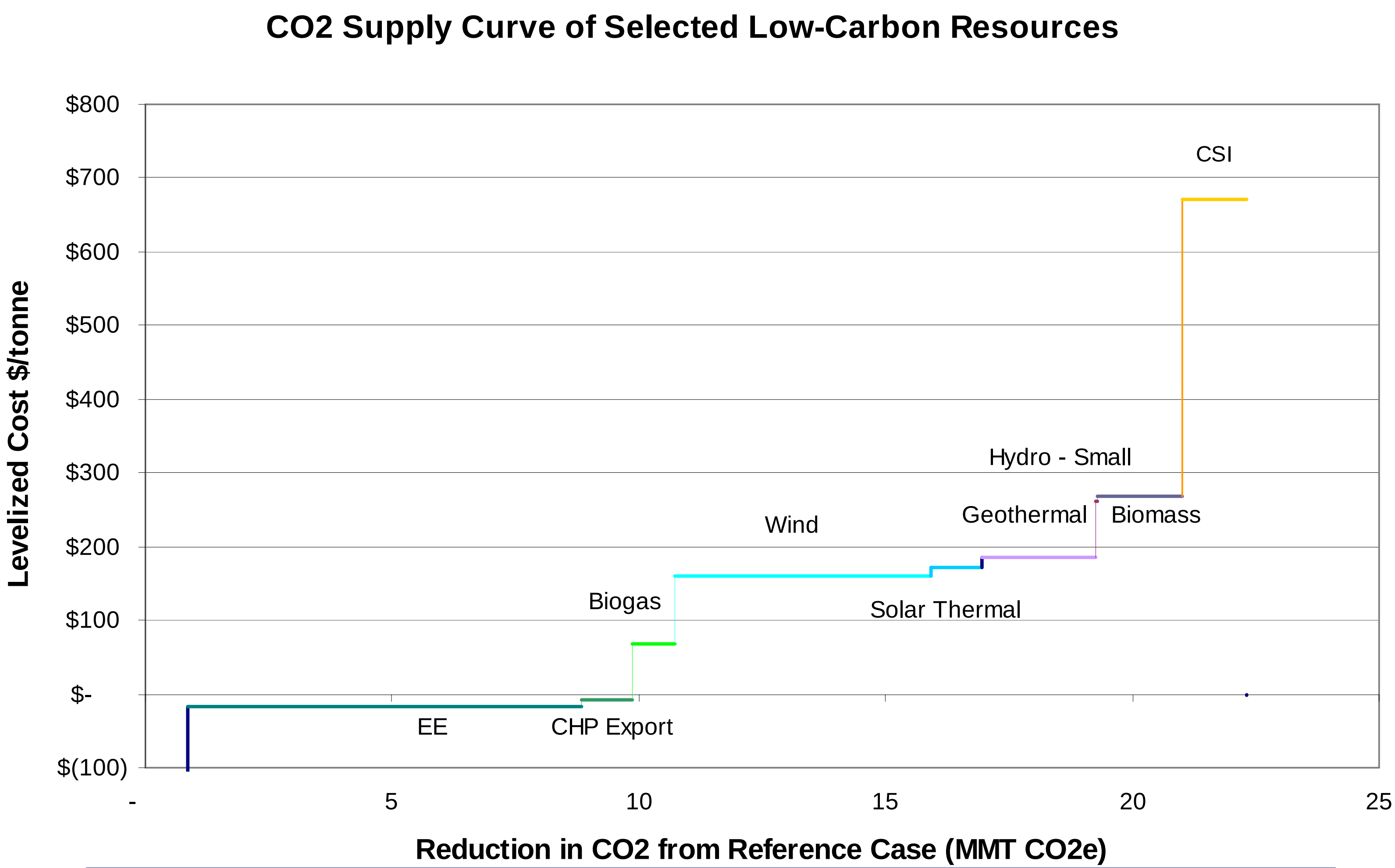
Implied carbon price for new low-carbon capital investment



CO2 price must be in the $150/tonne range to induce investment in renewable energy beyond the RPS

How is $150/tonne calculated?

Back of the envelope example

$$CO_2 \text{ \$/tonne} = \Delta \text{ cost} / \Delta CO_2$$
$$= (\text{cost}_{clean} - \text{cost}_{gas}) / (CO_{2gas} - CO_{2clean})$$

Δ cost = $60/MWh between market price and least cost renewable

cost_{clean} = $120/MWh (all-in cost of least-cost renewables)

cost_{gas} = $60/MWh (market price of CCGT generation @ $8/MMBtu)

Δ CO_2 = 0.4 tonne/MWh based on efficiency of a CCGT

CO_{2clean} = 0 tonne/MWh

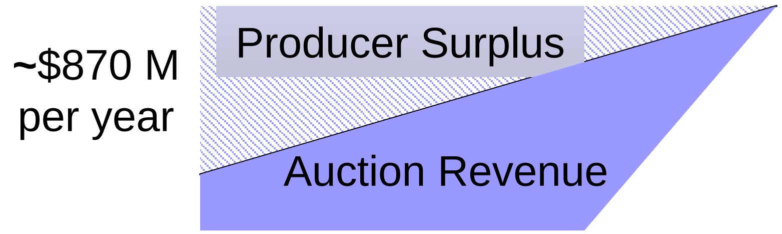
CO_{2gas} = 0.4 tonne/MWh (8000 Btu/kWh heat rate, 117 lbs/MMBtu)

$/tonne CO_2 = $60/MWh / 0.4 tonne/MWh
= $150/tonne

* Actual calculation is more complex, and includes difference in capacity value as well

Profits for Clean Generation through MCP

- MCP with CO2 leads to increased profits for producers and importers with low carbon generation
- At $30/t CO2: State pays approximately $870 million to producers due to higher market clearing price for power
- Assumes utility-owned generation and long-term contracts do not capture the windfall since they are compensated at cost for CO2

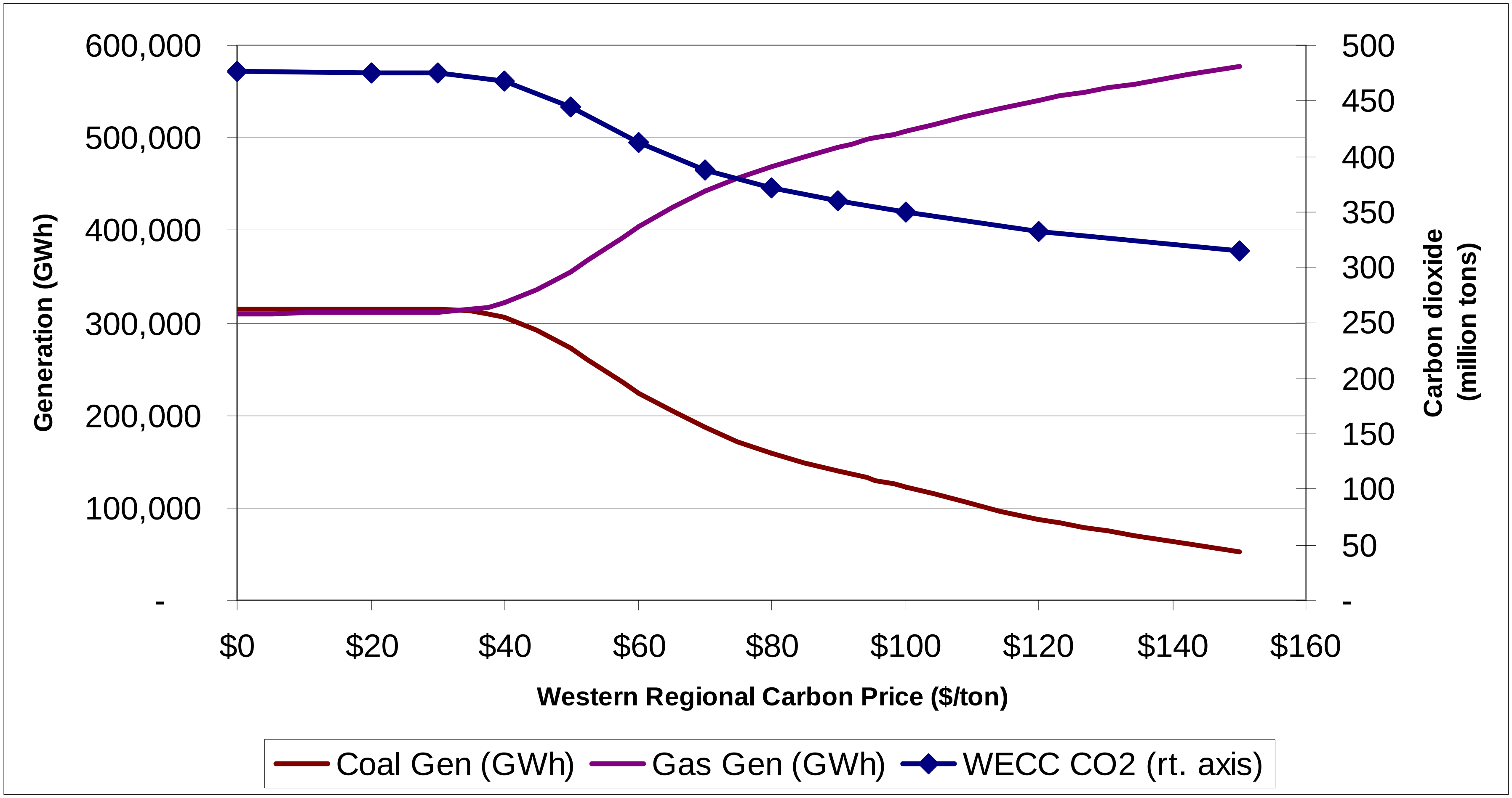


Preliminary analysis affected significantly by contract assignment assumptions

Regional Carbon Price Scenario

- Regional scenario limits contract shuffling
- PLEXOS analysis of a regional carbon price on WECC-wide dispatch
  - Driven by coal - natural gas price spread
  - Fuel prices vary by location in WECC
    - Gas: $9.50 - $10.50/MMBtu
    - Coal: $0.80 - $2.00/MMBtu

WECC-wide carbon price: Impact on existing generator dispatch



Thank You

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