PG&E's Renewable Integration Model

March 4, 2010 Meeting with the CPUC Energy Division

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Model Overview: Model uses a variety of inputs to determine the integration needs and costs of variable generation

Inputs

- Installed variable generation
- Hourly profiles and intra-hour variability inputs for load & generation
- Forecast errors for load & generation
- Cost of conventional resources

Model

- Renewable Integration Model

Outputs

- Flexibility Requirements (Reg, load following, ramping)
- New resources to integrate variable generation
- Fixed and variable cost of integration

Hourly profiles & intra-hour variability parameters capture variability
Forecast errors capture forecast uncertainty
Conventional generation cost/emissions used to estimate integration cost

Outputs:
Flexibility requirements to manage variable generation

Model estimate amount of flexibility services needed:

- **Regulation (Reg Up/Down)**: resources that can increase or decrease output instantly to cover intra 5-minute variability and 5-minute ahead forecast error of load and resources
- **Load following:** resources to cover intra-hour variability and hour-ahead forecast error of load and resources
- **Day-ahead commitment**: resources to cover day-ahead forecast error of load and resources

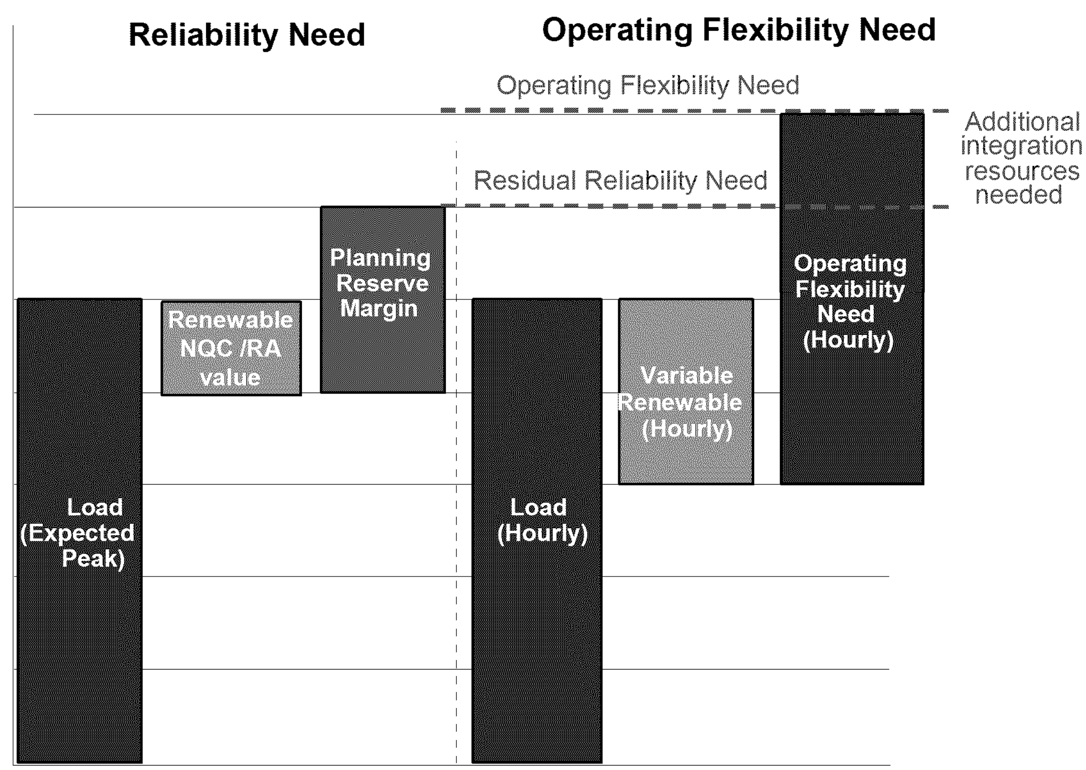
Flexibility services address load and generation variability and forecast errors

Intra 5-min variability	5-min forecast error	Intra-hour variability	Hour-ahead forecast error	Day-ahead forecast error
Regulation		Load-Following		Day-Ahead Commitment

Outputs:
Model estimates reliability and operating flexibility needs

System needs to satisfy both reliability and flexibility needs

- **Reliability Need** = Expected peak demand + the planning reserve margin – NQC of variable generation
- **Operating Flexibility Need** = hourly load + hourly flexibility services – hourly variable generation



Outputs:
Fixed & Variable Integration Costs, Carbon Emissions

- **Fixed Costs**
  - Fixed cost of resources needed beyond reliability need, reduced by the profits of energy sold in the marketplace
- **Variable Costs**
  - Fuel and operating costs of resources providing flexibility services
  - Includes: (1) start-up costs, (2) operational cost of running a less efficient unit, and (3) heat rate penalty for operating at a less than optimal point (for regulation only)
- **Carbon Emissions**
  - CO_2 emission volumes, in metric tons, based on the incremental fuel of resources providing flexibility services

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Sample inputs/outputs

March 3, 2010 meeting with

CAISO 33% RPS Integration Working Group

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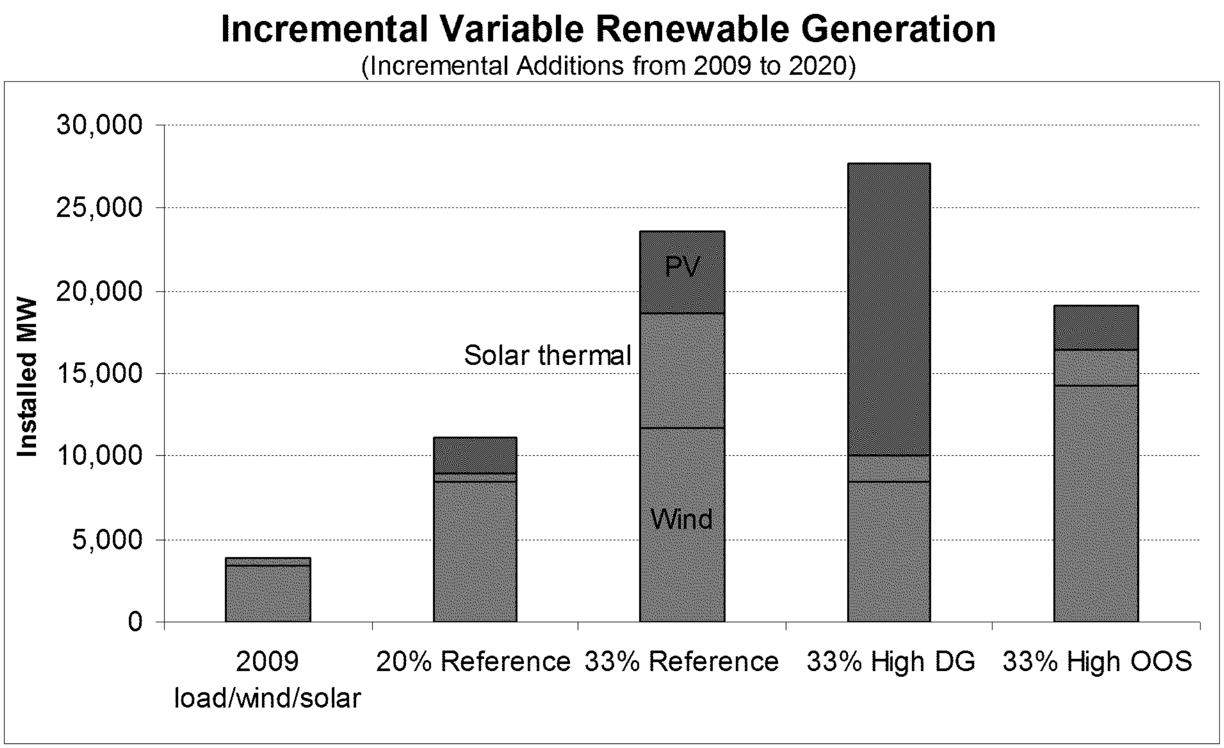
Inputs:
Variable generation installed capacity

Four 2020 high-load scenarios[1]

1. **20% Reference Case** blended renewable portfolio
2. **33% Reference Case** blended renewable portfolio
3. **33% High DG Case** high penetration of PV distributed generation (DG)
4. **33% High OOS Case** high Out Of State (OOS) imports, primarily wind



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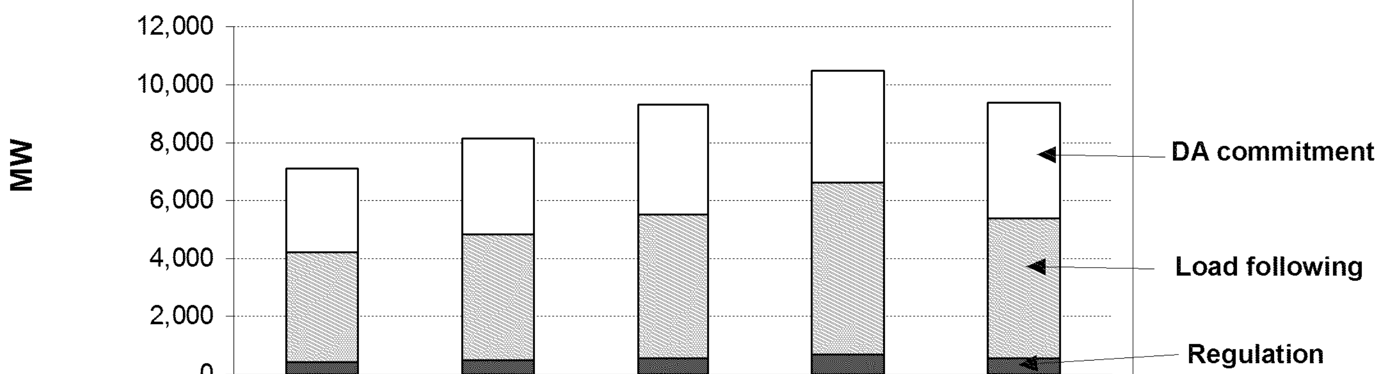
1/ All 33% scenarios include self-gen PV treated as PV supply to capture the integration requirement

Outputs:
Flexibility services projected

~2,000 to 3,500 MWs of incremental flexibility services are forecast to be required to integrate the 33% RPS scenarios

Total Operational Flexibility Services -Summer

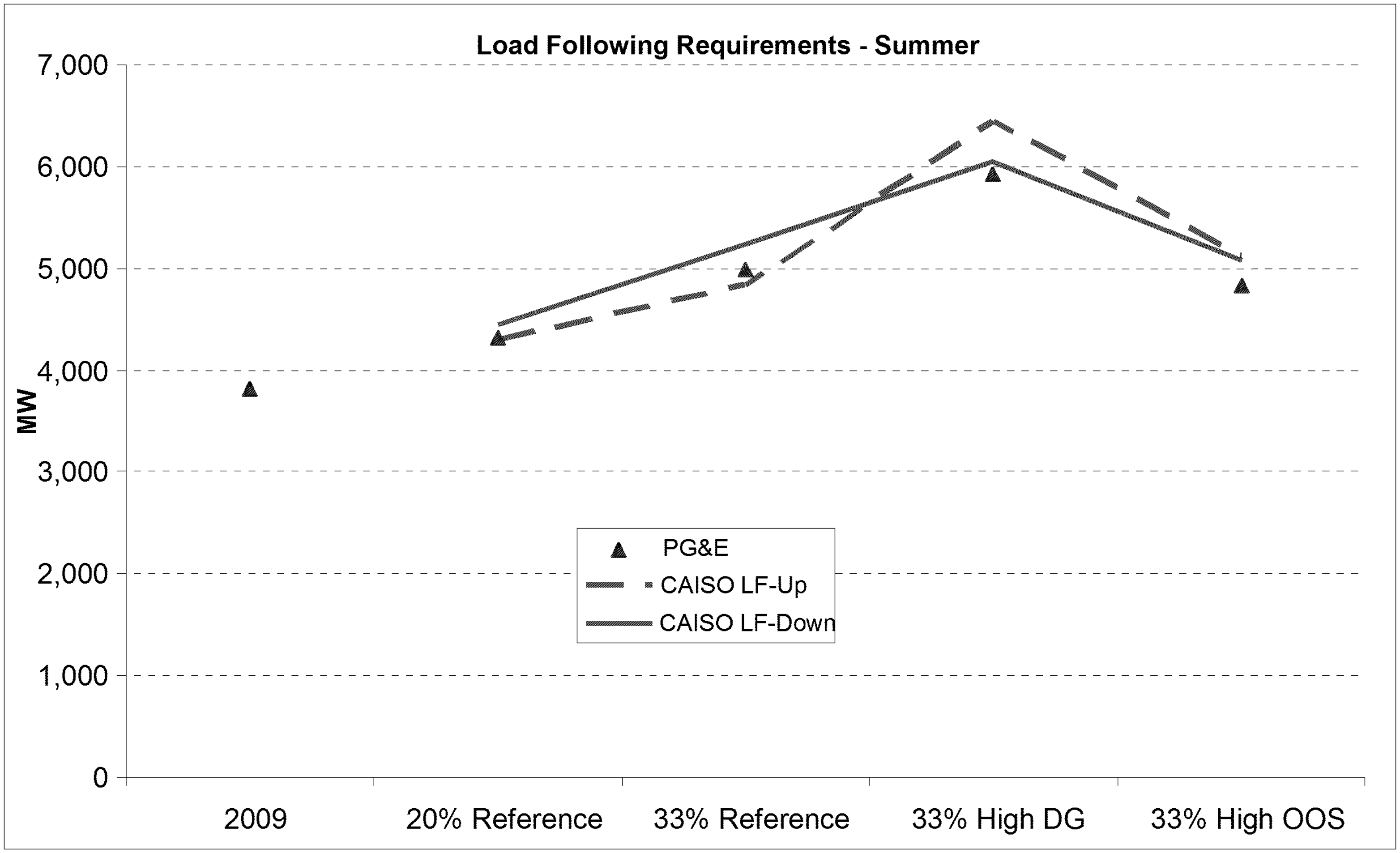


	2009	20% Reference	33% Reference	33% High DG	33% High OOS
DA Commitment	2,856	3,337	3,792	3,876	4,037
Load Following	3,818	4,334	4,995	5,920	4,832
Reg-Up/Down	419	474	555	690	528

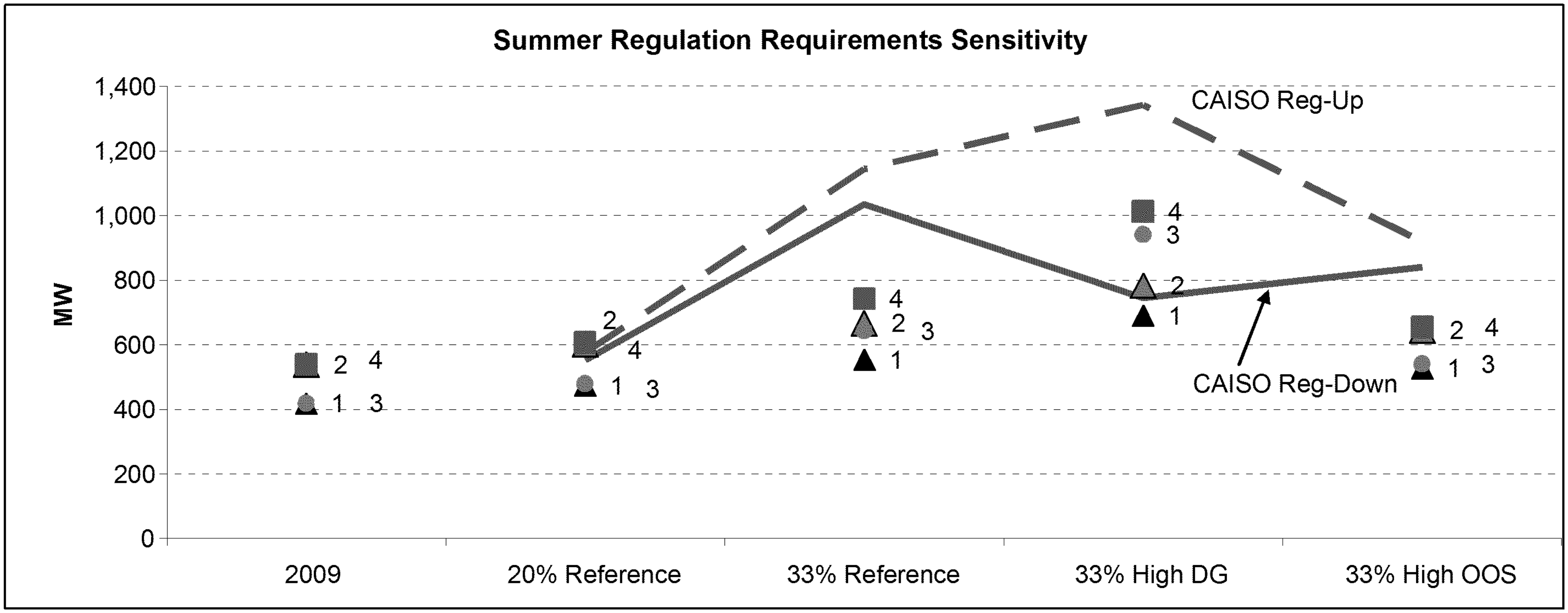
Key Take-Away:

Not surprisingly scenarios with higher intermittent renewable penetration have greater flexibility requirements

Outputs:
Load following estimates compare well with CAISO's



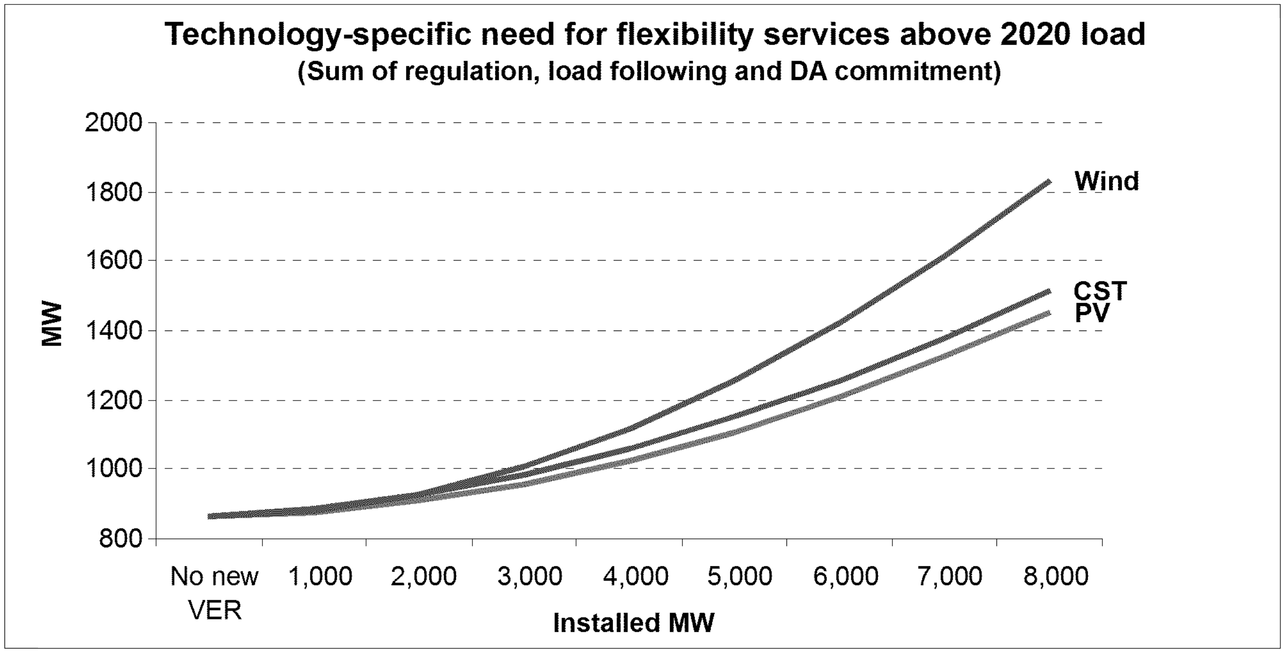
Outputs:
Sensitivity of Reg-Up/Down to variability/error inputs



	5-min load variability	CST and PV 5-min error	2009	20% Reference	33% Reference	33% High DG	33% High OOS
	MW of load	% of installed MW					
Case 1	65 MW	0.70%	419	474	555	690	528
Case2	130 MW	0.70%	539	602	667	783	645
Case 3	65 MW	1.40%	419	479	643	941	540
Case 4	130 MW	1.40%	539	606	742	1,011	655
CAISO Reg-Up				577	1,144	1,341	918
CAISO Reg-Down				552	1,034	744	839

Key Take-Away: Use higher solar forecast error or increase coverage of solar forecasts deviations by increasing the number of standard deviations used by model.

Outputs:
Incremental flexibility services by technology



		Amounts of Flexibility Services Needed, % of installed capacity			
		Regulation	Load following	DA commitment	Total
Average for 8000 MW addition	Wind	0.5%	4%	7%	12%
	Solar thermal	0.7%	6%	2%	8%
	PV	0.7%	5%	2%	7%
Last 1000 MW increment	Wind	0.8%	8%	13%	22%
	Solar thermal	1.3%	9%	3%	14%
	PV	1.2%	9%	3%	13%

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Integration costs

[work in progress]

Outputs:
Integration cost by scenario

33% RPS integration cost projected range: $20 - $40/MWh

- Previous E3 estimate: $7.5/MWh
- Integration cost is sensitive to:
  - natural gas price
  - NQC value of variable energy resource (VER)
  - forecast errors
- The majority of integration costs is due to fixed cost of new generation to provide incremental flexibility services

	20% Reference	33% Reference	33% High DG	33% High OOS
Average integration costs per MWh of new VER				
Fixed cost	5	23	32	14
Variable cost	2	4	6	3
Total	7	27	39	18
Average CO2 emissions per MWh of new VER				
lb/MWh	13	22	40	21

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Appendix

Inputs:
Variability and forecast errors

Season	5-min Forecast Error St. Dev (MW)	INTRA 5-min Variability St. Dev (MW)	HA Forecast Error St. Dev. (MW)	INTRA-Hour Variability St. Dev. (MW)	DA Forecast Error St. Dev. (MW)
			2020 Load		
SPRING	138	55	823	472	1,000
SUMMER	138	65	1,232	618	1,155
FALL	138	56	941	512	1,354
WINTER	138	62	873	519	607

Season	5-min Forecast Error St. Dev (% of CAP)	INTRA 5-min Variability St. Dev (% of CAP)	HA Forecast Error St. Dev. (% of CAP)	INTRA-Hour Variability St. Dev. (% of CAP)	DA Forecast Error St. Dev (% of CAP)
			Existing Wind		
SPRING	1.0%	0.2%	9.0%	1.3%	10.2%
SUMMER	0.8%	0.2%	8.0%	1.1%	6.0%
FALL	0.8%	0.3%	8.0%	1.0%	10.4%
WINTER	0.7%	0.2%	7.0%	0.9%	7.1%
			New Wind		
SPRING	1.0%	0.2%	9.0%	1.3%	10.2%
SUMMER	0.8%	0.2%	8.0%	1.1%	6.0%
FALL	0.8%	0.3%	8.0%	1.0%	10.4%
WINTER	0.7%	0.2%	7.0%	0.9%	7.1%
			Solar Thermal		
SPRING	1.6%	1.0%	5.6%	7.8%	8.7%
SUMMER	0.7%	0.6%	4.1%	6.3%	2.5%
FALL	1.2%	0.8%	4.7%	7.4%	5.5%
WINTER	1.3%	0.8%	5.4%	6.9%	8.3%
			PV		
SPRING	1.6%	1.0%	5.6%	7.8%	8.7%
SUMMER	0.7%	0.6%	4.1%	6.3%	2.5%
FALL	1.2%	0.8%	4.7%	7.4%	5.5%
WINTER	1.3%	0.8%	5.4%	6.9%	8.3%

Inputs: Other key inputs and assumptions

Statewide
- Statewide load and variable generation resources equal to those used by CAISO's 33% RPS integration study

Load Assumptions
- CEC's adopted 2009 IEPR base forecast
- 2005 hourly load profile scaled to 2020 levels
- CAISO load forecast error parameters based on 2006 operation scaled to 2020 based on projected load growth

Resource Assumptions
- Installed wind/solar amounts equal to those used by CAISO study's working group
- NQCs for wind/solar based on recent RA D. 09-06-028
- Existing wind/solar hourly and minute by minute profiles based on 2005 generation
- New wind/solar profiles based on NREL 2005 simulated profiles
- Wind forecast error parameters based on CAISO's past operating experience
- Solar forecast error parameters based on clearness index (5-minute error and variability), and persistence approach hour-ahead and day-ahead errors

Other
- Planning Reserve Margin (PRM): 15%
- Forward gas prices ~ $8.45/mmbtu in 2020 (nominal)
- CT net fixed cost ~ $160/kW-yr in 2020 (nominal)

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