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Renewable Energy Flexibility (REFLEX) Results

California ISO Webinar

December 9, 2013

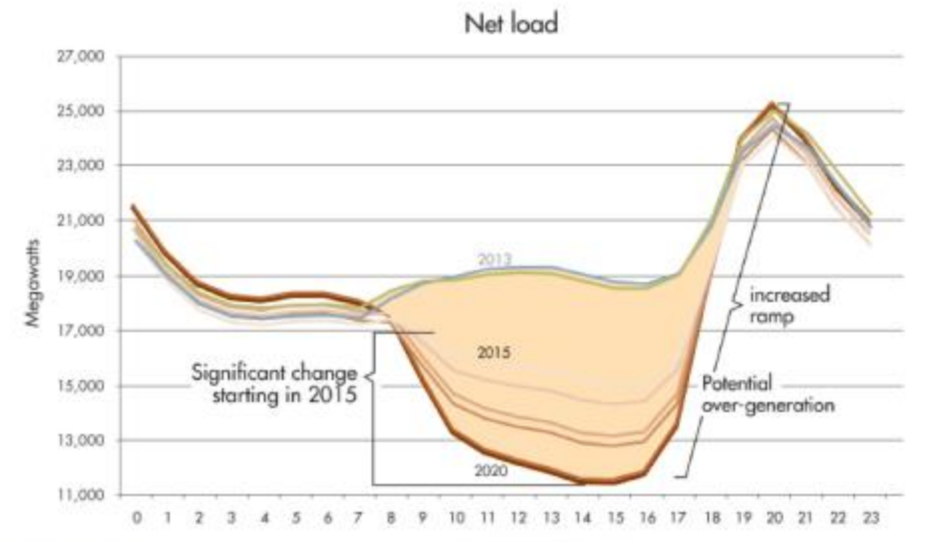
Agenda

1. Introduction: how to define and analyze the flexibility problem
2. Overview of E3's REFLEX model
3. Case Descriptions
4. Pure Capacity Need
5. 33% RPS Case Results
6. 40% Reduced Flexibility Case Results
7. Conclusions and Next Steps

INTRODUCTION

Defining the Problem

- **Introduction of variable renewables has shifted the capacity planning paradigm**



- **The new planning problem consists of two related questions:**

  1. How many MW of dispatchable resources are needed to (a) meet load, and (b) meet flexibility requirements on various time scales?

  2. What is the optimal mix of new resources, given the characteristics of the existing fleet of conventional and renewable resources?

Four Related Planning Challenges

1. Downward ramping capability

Thermal resources operating to serve loads at night must be ramped downward and potentially shut down to make room for a significant influx of solar energy after the sun rises.

2. Minimum generation flexibility

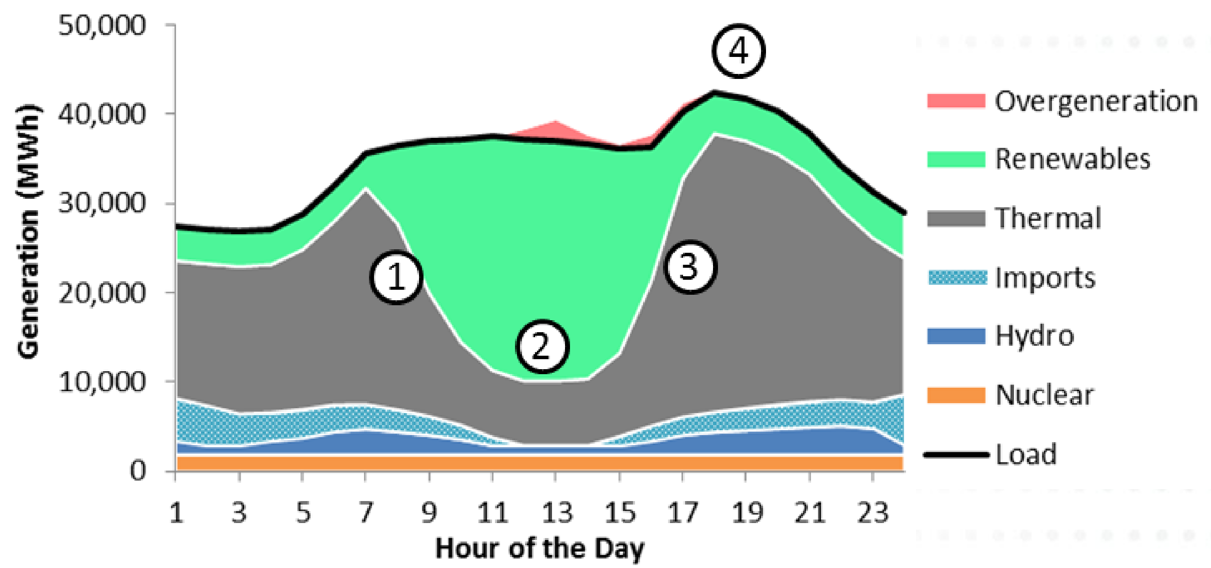
Overgeneration may occur during hours with high renewable production even if thermal resources and imports are reduced to their minimum levels. A system with more flexibility to reduce thermal generation will incur less overgeneration.

3. Upward ramping capability

Thermal resources must ramp quickly from minimum levels during daytime hours and new units may be required to start to meet high net peak demand occurring shortly after sundown.

4. Peaking capability

The system will need enough resources to meet the highest net-loads with sufficient reliability



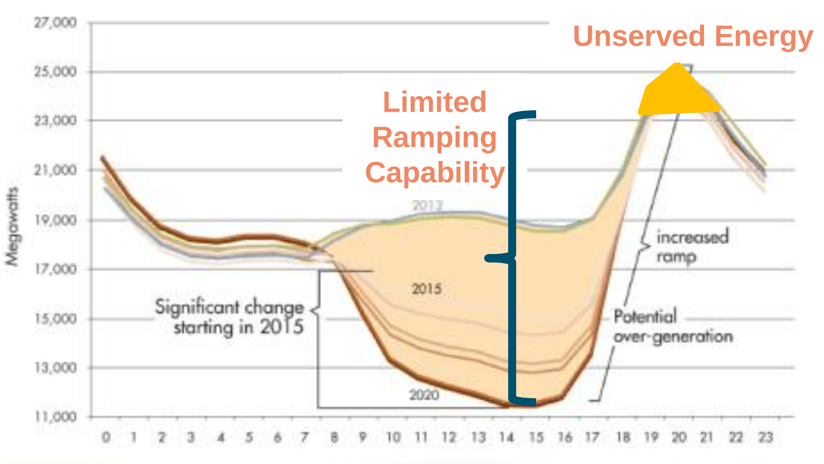
Many Resource Characteristics Can Help with Flexibility Needs

Characteristic	How it helps with system flexibility
Upward ramping capability on multiple time scales: • **1 minute, 5 minutes, 20 minutes, 1 hour, 3 hours, 5 hours**	Helps meet upward ramping demands
Downward ramping capability on multiple time scales: • **1 minute, 5 minutes, 20 minutes, 1 hour, 3 hours, 5 hours**	Helps meet downward ramping demands
Start time	Faster start times help meet upward ramping demands
Shut-down time	Faster shut-down times help avoid overgeneration
Minimum run times	Shorter minimum run times help avoid overgeneration
Minimum down times	Shorter minimum down times can help meet upward ramping needs
Minimum generation levels	Lower minimum generation levels can help meet upward ramping needs while avoiding overgeneration

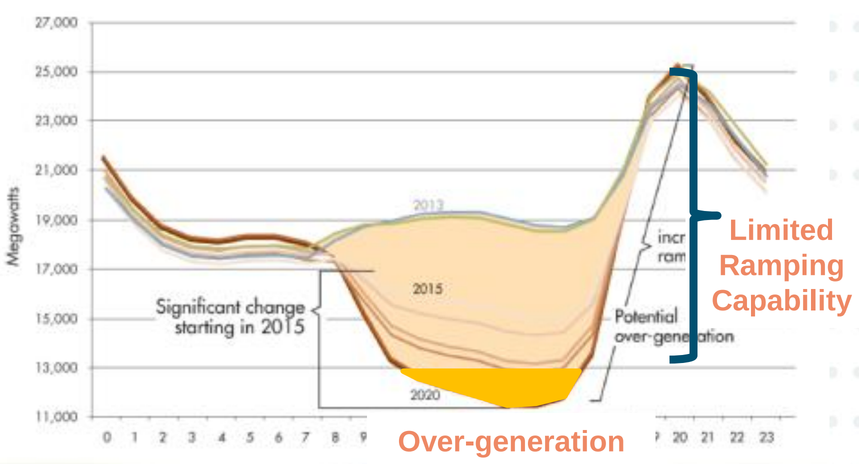
Relationship between flexibility violations

+ **Flexibility violations in each of the four types are <u>direct substitutes</u> for one another**
    - Upward ramping shortages can be solved using over-generation

Strategy to Minimize Downward Violations



Strategy to Minimize Upward Violations



Renewable Curtailment Will Be Necessary for Reliability

- **Scheduled curtailment <u>will be a necessary tool</u> for system operators as renewables increase up to and beyond 33% of load**
  - The benefit comes from relaxing the demands placed on dispatchable generation
    - Takes the foot off the gas. Taken to the extreme, renewable curtailment returns us to the “vintage” power system (i.e., the system without renewables).
  - Renewable dispatch is already being used to deal with renewable variability in other jurisdictions
    - Largely restricted to within-hour at present

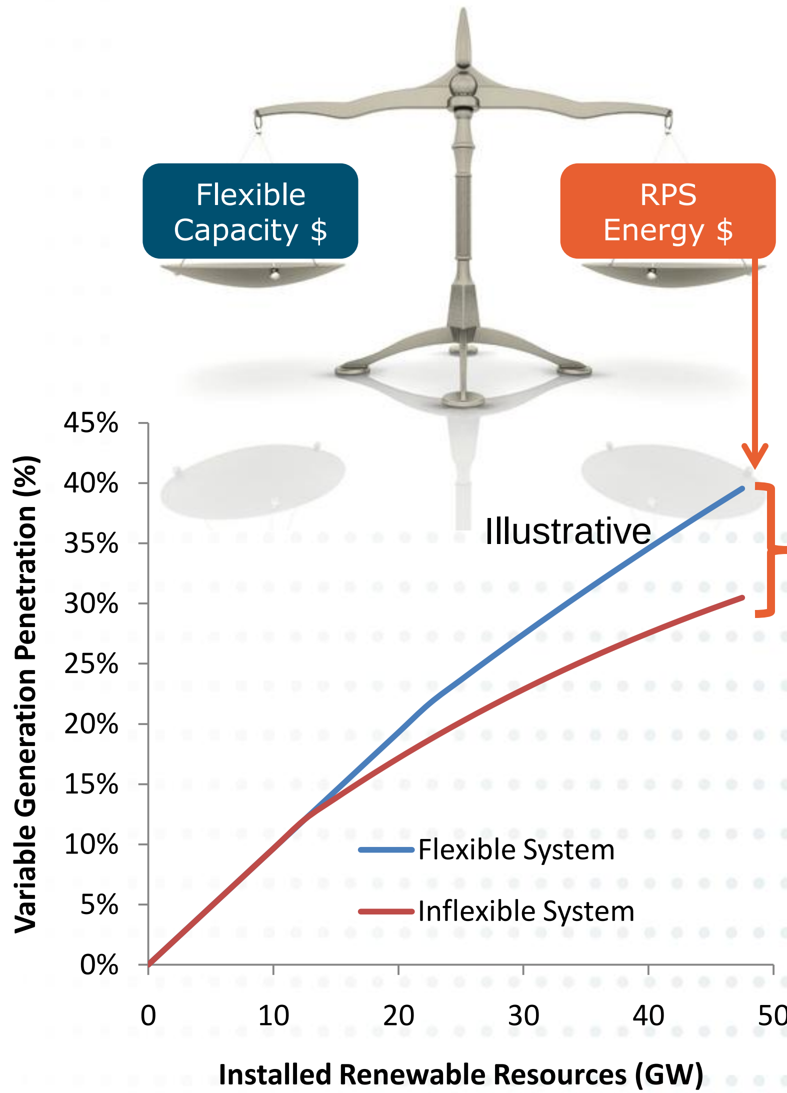
http://www.ieso.ca/imoweb/consult/consult_se91.asp

Renewable Curtailment is a Costly Reliability Strategy

- **Costs of curtailment include:**
  - Replacement cost of the renewable attribute
  - May also need to pay the curtailed generator
- **Policy question: How does the cost of renewable curtailment strategy compare to other strategies:**
  - New flexible generation
  - New DR programs
  - Market structure changes
  - Etc.

Implications for Flexibility Planning & Modeling

- **It may be difficult to derive a satisfactory flexible capacity "standard"**
  - The problem has too many dimensions
- **It is more helpful to think of the need for flexible capacity as <u>an economic problem</u>**
  - Use renewable curtailment as the "default" solution to maintain reliability
  - Value investments for their ability to reduce curtailment
- **Upward ramping shortages cannot be characterized without <u>accurately modeling downward violations</u>**



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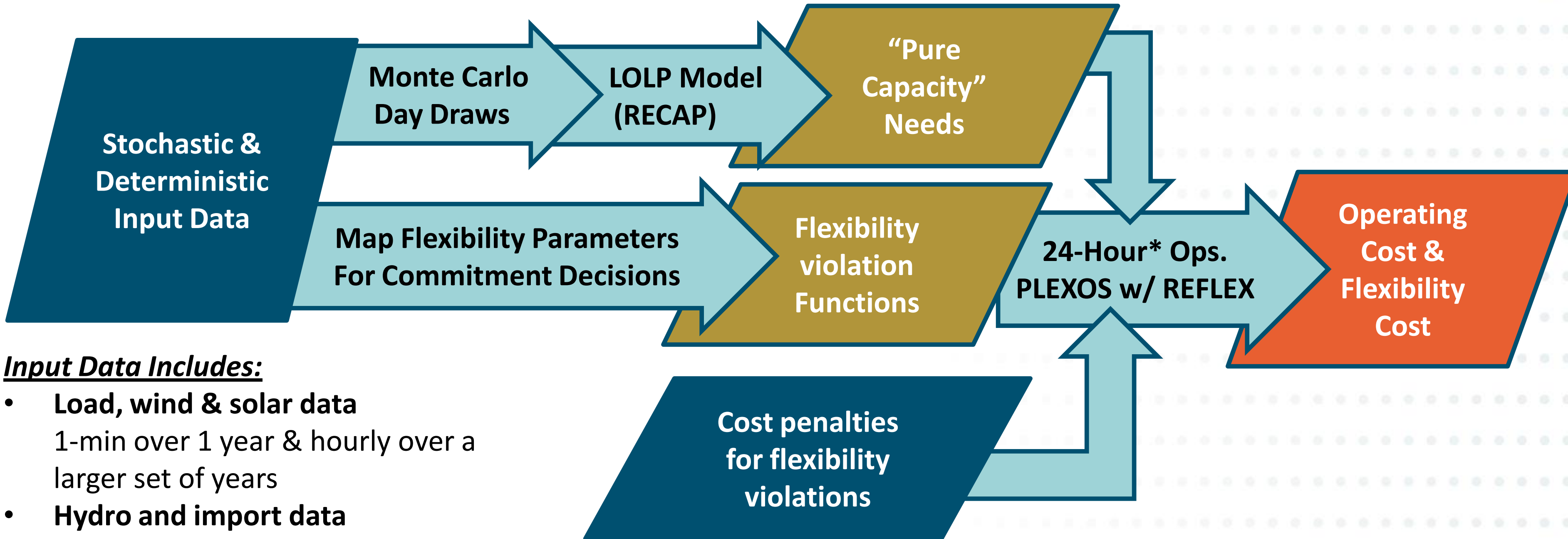
E3's RENEWABLE ENERGY FLEXIBILITY (REFLEX) MODEL

REFLEX: Stochastic Production Simulation Modeling

- **REFLEX answers critical questions about flexibility need through stochastic production simulation**
  - **Captures wide distribution of operating conditions** the system is likely to encounter through Monte Carlo analysis of a large sample of alternative load, wind, solar and hydro conditions
  - **Illuminates the significance of the operational challenges** by enabling calculation of likelihood, magnitude, duration & cost of flexibility violations
  - **Creates an economic framework** to guide choices between operational strategies and investments

Implemented as an add-on to Plexos for Power Systems

REFLEX Modeling Process



Input Data Includes:

- **Load, wind & solar data**
  1-min over 1 year & hourly over a larger set of years
- **Hydro and import data**
  (hourly over multiple years)
- **Conventional generator data**
  (Capacities, costs & outage schedules ***from deterministic case***)

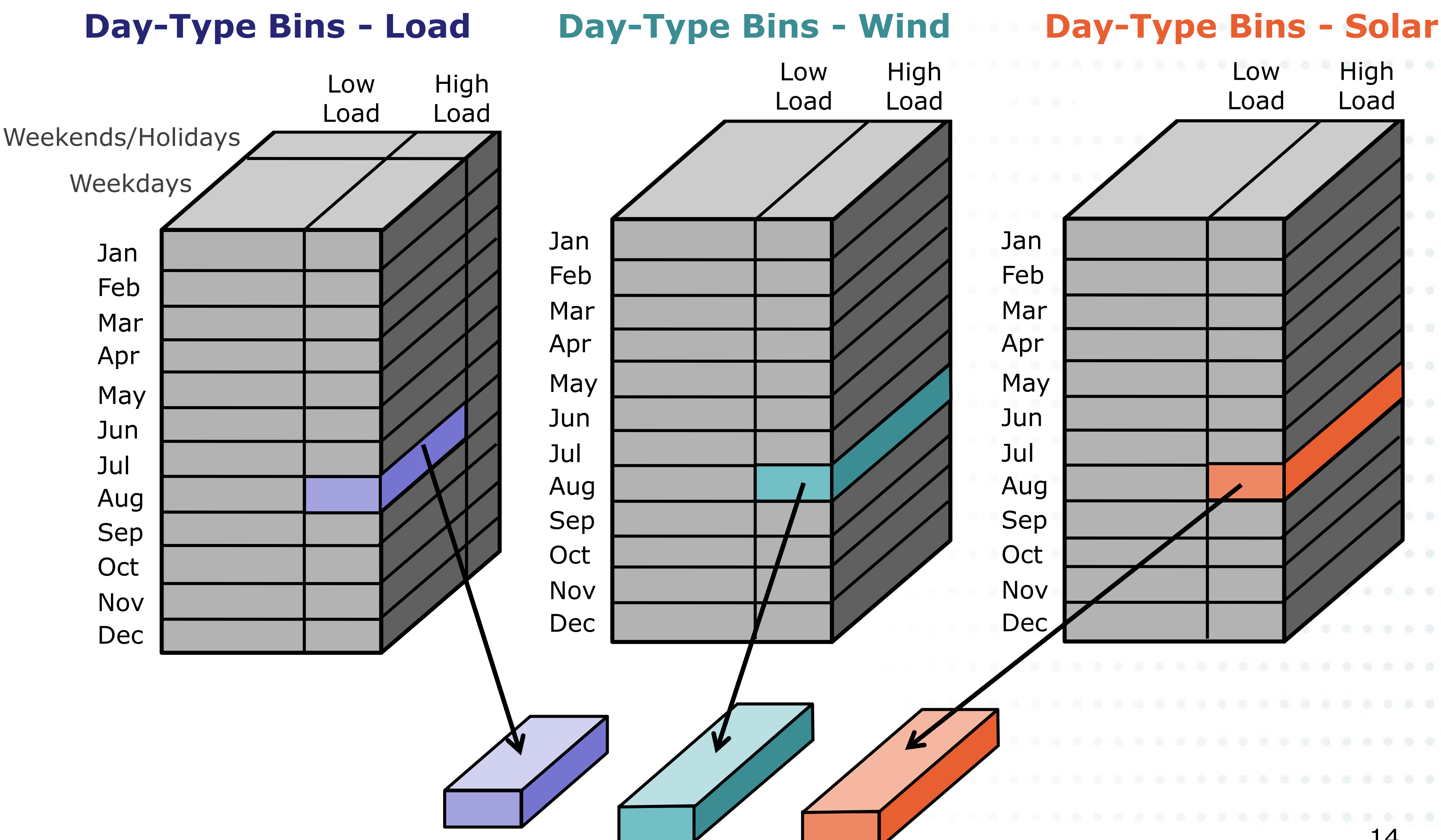
User-defined Cost per MWh for:

- Unserved Energy (USE)
- Reserve shortage
- Overgeneration
- Renewable Curtailment
- Upward Ramping shortage
- Downward Ramping shortage

*Optimization actually runs for 72 hour blocks. The first and third day are discarded to remove edge effects.

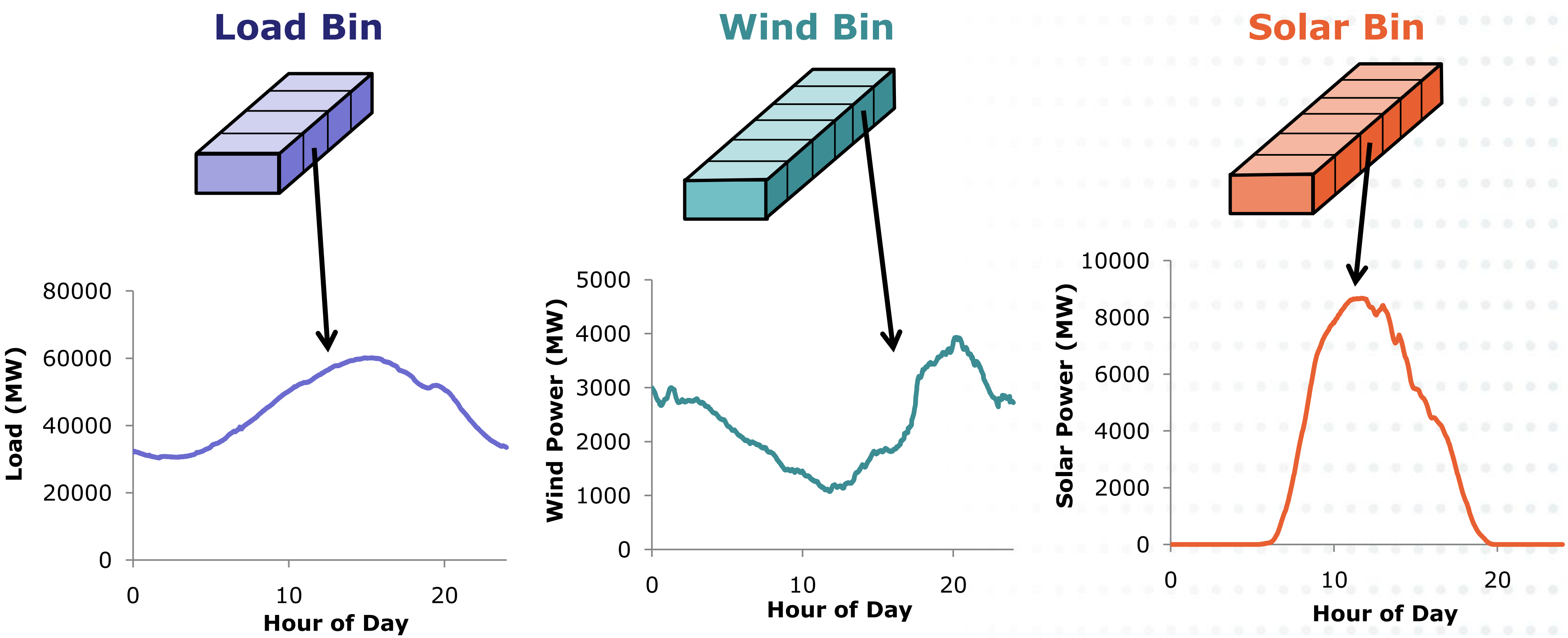
+ **Parallel calculation of conventional capacity needs & flexibility impact for use in 24-hour operations model**

Example Draw: High Load Weekday in August



Example Draw: High Load Weekday in August

+ **Within each bin, choose each (load, wind, and solar) daily profile randomly, and independent of other daily profiles**
  - 24 hours before and after each draw are included in the optimization



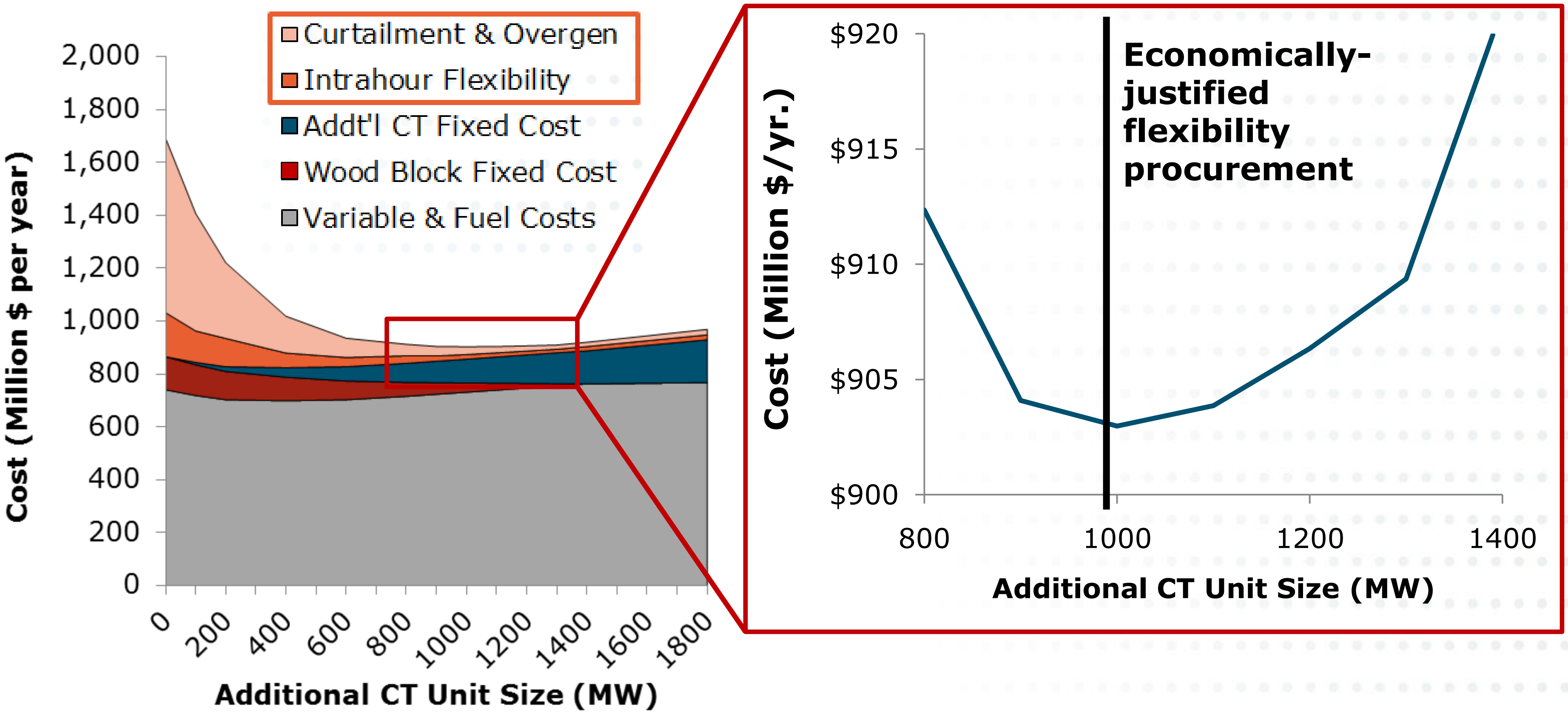
REFLEX extends conventional capacity planning

- **REFLEX extends conventional framework to include within-hour and downward flexibility violations**
- **Cost penalties provide a flexibility violation "loading order"**
- **Flexibility costs are calculated as the product of the expected flexibility violations and the penalty value**

	Hourly	**Within-hour**	**Regulation**
Upward	Unserved energy (EUE) **\$50,000/MWh**	Load following up (EUE_{WH}) **\$50,000/MWh**	Regulation up **\$1,100/MW**
Downward	Overgeneration (EOG) **\$250/MWh**	Load following down (EOG_{WH}) **\$300/MWh**	Regulation down **\$1,100/MW**

Optimal Flexibility Investment

- REFLEX provides an economic framework for determining optimal flexible capacity investments by trading off the cost of new resources against the value of avoided flexibility violations



Load Following Reserves in Deterministic Runs

+ Load following constraint imposed in each hour

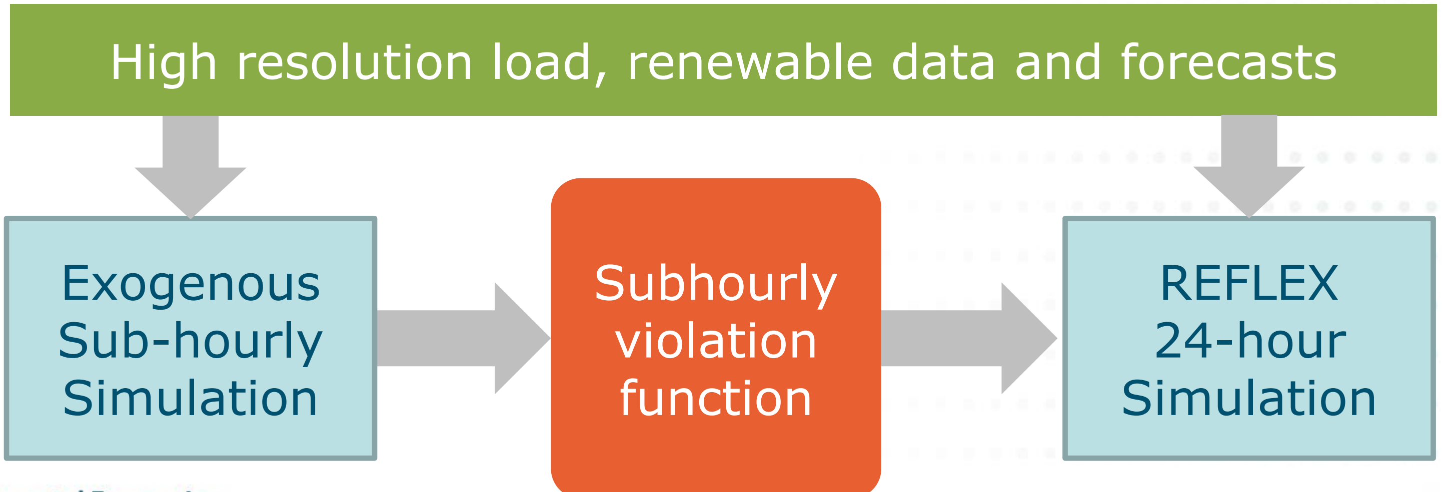
- Step 1 approach based on statistical analysis of deviations within the hourly time step
  - Ex: 95% of the time the net load falls within ±2,100MW of the hourly average → system is constrained to hold ±2,100MW of load following reserves

+ The issue is that we do not know if/how these MW constraint violations translate into real operational problems

- System operator is unlikely to shed firm load to maintain full load following stack
- Thus, how much investment should be motivated?

Load Following Reserves in REFLEX

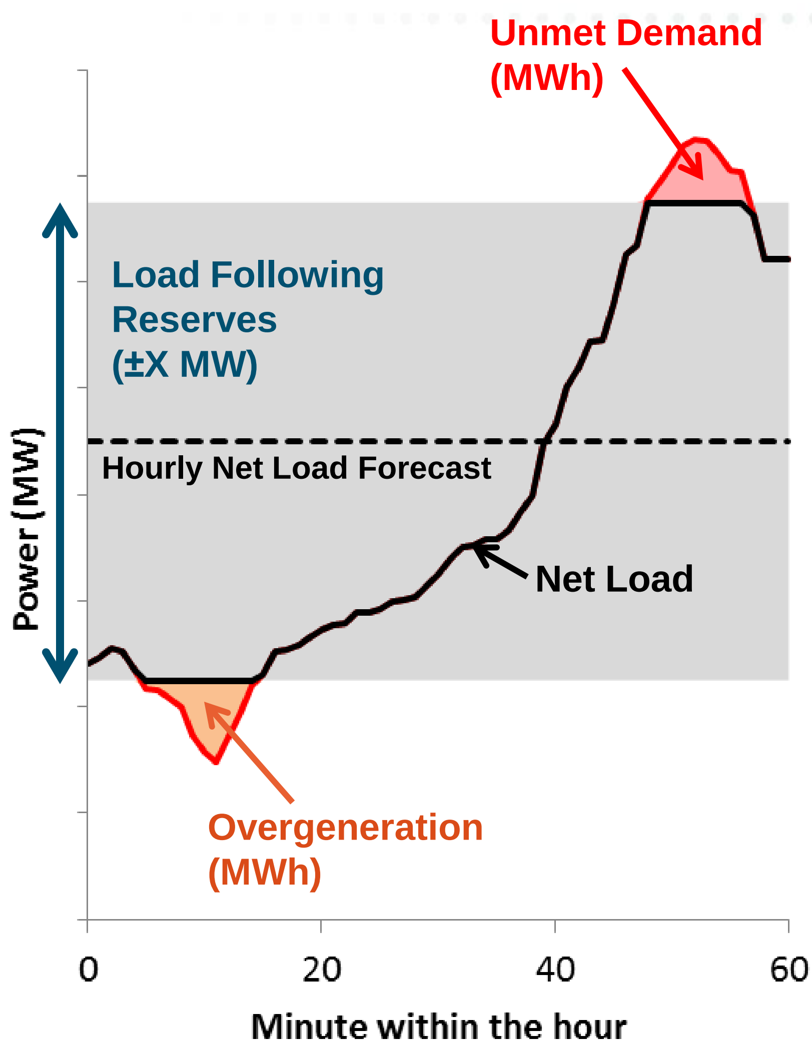
- **REFLEX replaces CAISO's "Step 1" approach with an exogenous, high resolution (1-minute) simulation of sub-hourly system behavior**
- **Provides expected violations (in MWh) as a function of:**
  - Load, wind and solar variability
  - Load, wind and solar forecast error
  - Level of load following reserves carried (in MW)
  - Speed of load following reserves carried (in MW/min.)



Exogenous Sub-hourly Simulation

+ Approach:

- If the system holds **X MW** of reserves, with resources that can ramp at **Y MW/min***, how much **unmet demand (MWh)** is there expected to be within the hour?
- Repeat for a wide range of load following levels, wind, solar, and load conditions (detailed on next slide)



***Ramping limits not shown at right for simplicity**

Steps for Building the Within-Hour Violation Function

1. **Select load following reserve level (in MW) and ramping ability (in MW/min.)**
2. **Conduct sub-hourly simulation for multiple hours to sample various load, wind, and solar conditions**
   - Used two years of load and weather-matched minutely data
3. **Track total unmet demand (sub-hourly unserved energy (EUE_{WH}) and overgen (EOG_{WH}) in MWh) in each hour**
4. **Select new reserve level and ramping ability and repeat**
   - Trace out full range from 0 to highest level that results in no shortages

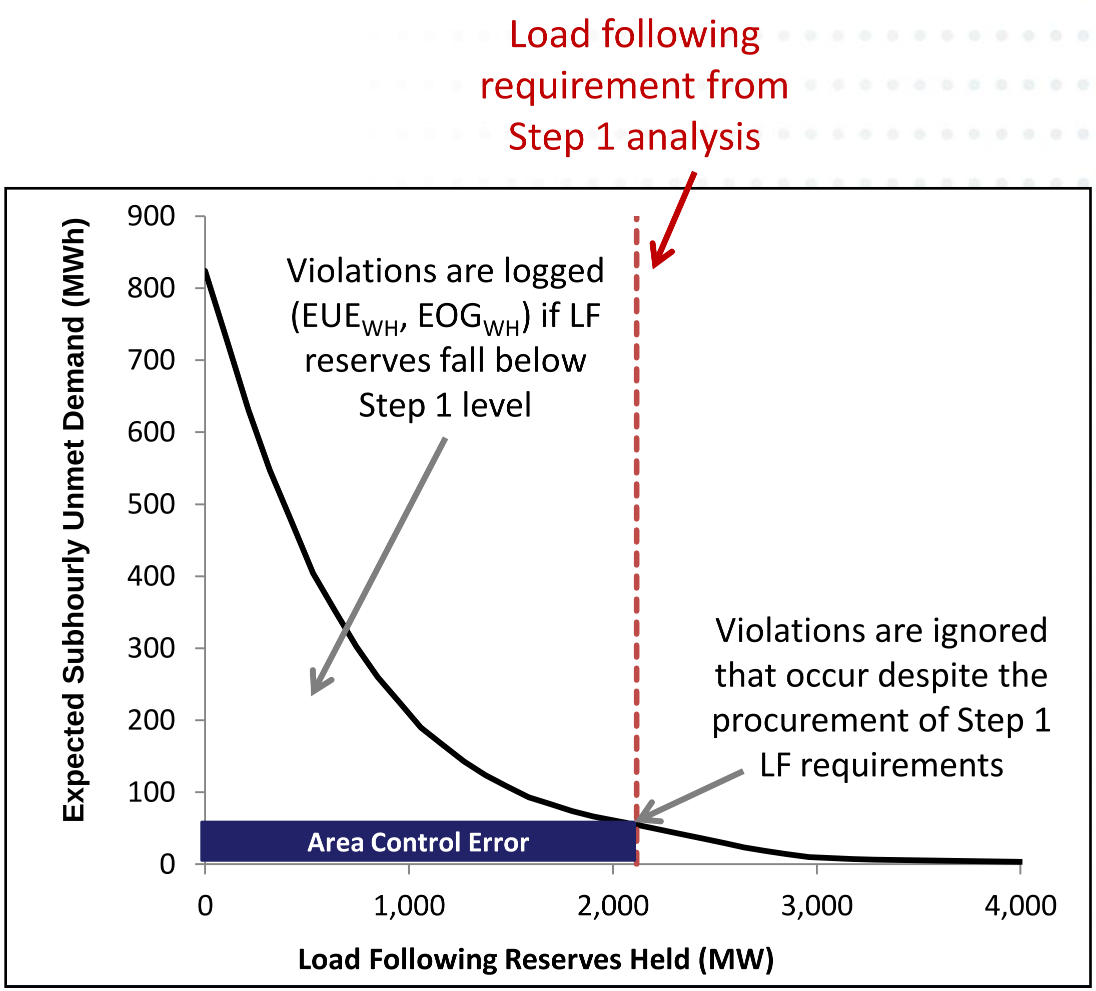
<u>Each simulation provides a point along two curves:</u>

$$EUE_{WH} = f(LF+(MW), LF+(MW/min), wind, solar, load)$$

$$EOG_{WH} = f(LF-(MW), LF-(MW/min), wind, solar, load)$$

Within-Hour Violation Function

- Separate curves generated for upward and downward directions
- Shape of curves changes with load, wind and solar forecast
- Cost penalties applied to violations
- Free pass on within-hour violations up to level that would occur at CAISO Step 1 Load Following requirement



(Example hour)

Deterministic vs. REFLEX Treatment of Within Hour Violations

Deterministic PLEXOS

- **Objective function**
  - Minimize production cost
- **Constraints**
  - Meet LF requirement
  - Meet Reg. requirement
  - Etc.

REFLEX

- **Objective function**
  - Minimize production cost + hourly flexibility costs + within-hour flexibility costs
- **Constraints**
  - Meet Reg. requirement
  - Etc.

- **Load Following moved from a MW constraint to part of the objective function**
- **Flexibility cost = EUE and EOG times cost penalties**

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CAISO 2012 LTPP CASES

REFLEX Cases

- **Today's results show 3 cases, each with system conditions progressively more constrained**
  - 33% Replicating TPP Case
  - 33% Reduced Flexibility Case
  - 40% Reduced Flexibility Case
- **A fourth, illustrative case demonstrates the need to include renewable curtailment as a solution**
- **Results are preliminary and indicative, not definitive**
  - Intended to illustrate the types of flexibility challenges California will face under high RPS and to beta-test a new methodology

REFLEX Case Details

	33% Case (Repl. TPP)	33% Reduced Flexibility	40% Reduced Flexibility
Renewable resources	2022 TPP	2022 TPP	2022 TPP & Additional in-state solar/wind
Dispatchable capacity	2022 TPP	Track 1 inflexible	Track 1 inflexible & 2,000 MW of gas gen. retired
Cost of renewable curtailment	$250/MWh	$250/MWh	$250/MWh

+ **Additional demonstration case is the same as 40% case but with very high curtailment cost**

Additional case comparisons

Violation Type	33% Case (Repl. TPP)	33% Reduced Flexibility	40% Reduced Flexibility
Renewable Penetration (%)	32%-33%	32%-33%	40%
Maximum instate solar production	13,320 MW		+5,320 MW
Maximum instate wind production	5,250 MW		+2,100 MW
Dispatchable Capacity (MW)			
CCGT	16,600 MW	-900 MW	-2,296 MW
GT	6,926 MW	-397 MW	-1,016 MW
ST	848 MW		
Storage (pumped and battery)	1,846 MW	-50 MW	-50 MW
DR	2,673 MW		
Inflexible Capacity (MW)			
Nuclear	2,240 MW		
CHP	3,744 MW		
Inflexible*	0 MW	+1,347 MW	+1,347 MW

- **Instate wind and solar scaled for 40% RPS**
- **Inflexible generation modeled by setting Pmin=Pmax and requiring each generator to either be on or be off for the entire three day commitment window**

Additional Key Input Assumptions

Assumptions	Input & notes
CA Conventional Generators	ISO deterministic case parameters; Monte Carlo outages
Nuclear	SONGS retired; Diablo as must-run
Conventional Hydro	Modeled as single statewide aggregate resource; max based on NQC; energy, min & ramp modeled stochastically based on historical data
Existing Pumped Hydro	Helms (3 units), Eastwood, & Hodges-Olivenhain dispatched by model with same parameters as deterministic case
Imports/Exports (ramping, minimum & maximum)	Ramping capability based on historical path flows (Min = 0, Max = 13,308)
Imports (heat rate)	Specified by month & hour based on ISO deterministic run (default = 10,000 Btu/kWh)
Local reliability (LCR) requirements	LA basin: 40% local (40/60 Rule) SDG&E: 25% local
Fuel & AB32 Permit Prices for 2022 Scenario	\$4.3/MMBtu, \$24/metric ton CO_2 (From ISO Case parameters)
Behind-the-meter PV	33% cases: 1,364 MW max production 40% cases: 1,910 MW max production Modeled as must-run (non-curtailable) resources

Multi-hour ramping constraints

- Hydro and import ramping constraints set by the 99th percentile of historical (2010-2012) hydro and net-intertie ramps
- Hydro has Pmin and daily energy budgets that vary by month

Hydro

Duration (hrs)	Max Ramp Up (MW)	Max Ramp Down (MW)
1	742	-775
2	1,143	-1,292
3	1,410	-1,704
4	1,618	-2,040
5	1,841	-2,304
6	2,067	-2,501
7	2,290	-2,690
8	2,484	-2,847
9	2,678	-2,956

Imports

Duration (hrs)	Max Ramp Up (MW)	Max Ramp Down (MW)
1	1,241	-1,206
2	1,890	-1,905
3	2,299	-2,384
4	2,610	-2,803
5	2,802	-3,089
6	2,992	-3,288
7	3,125	-3,402
8	3,220	-3,459
9	3,266	-3,462

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PURE CAPACITY NEED

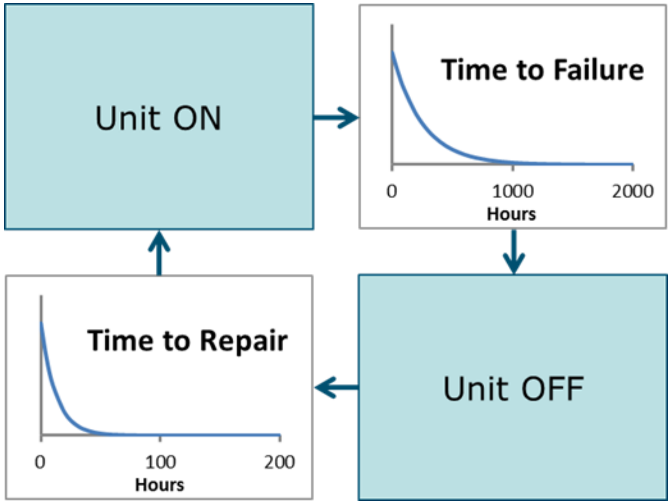
First Step: Determine Pure Capacity Need

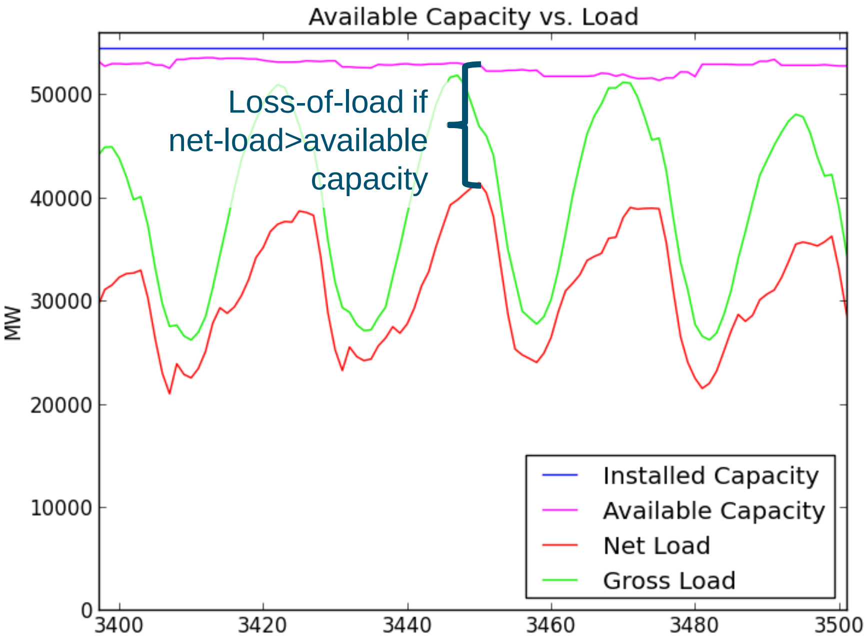
- **This step is necessary to isolate reliability issues related to *flexibility* from those related simply to *capacity***
- **Analysis is performed using E3's Renewable Energy Capacity Planning (RECAP) Model**
  - RECAP calculates standard reliability metrics such as LOLP, LOLE, LOLF, EUE, ELCC
- **If RECAP indicates pure capacity need, new resources would be added before the REFLEX step**

RECAP Modeling Methodology

- The time-sequential RECAP methodology uses the <u>same Monte Carlo draws</u> as REFLEX
- Over a <u>5,000 year simulation</u> the model tests if net-load and a 3% spinning reserve requirement exceeds the available resources
- By discarding operational detail, RECAP can <u>quickly assess</u>, with <u>high statistical confidence</u>, whether the cases have sufficient capacity, <u>independent of flexibility issues</u>

Markov Chain Forced Outage Model used in RECAP & REFLEX





Capacity Analysis Results

+ **RECAP analysis confirms that:**
  - All cases met a 15% PRM
  - All cases met a 1-in-10 loss of load frequency standard with 3% spinning reserves
+ **This step ensures that all reliability issues identified by REFLEX are related to flexibility, not capacity**

40% Reduced Flexibility Case Retirements

Retired Generator	Region	Capacity
Elk Hills CC1	PG&E_VLY	550
Gilroy1	PG&E_BAY	47.25
Gilroy2	PG&E_BAY	47.25
Gilroy3	PG&E_BAY	46.2
GrnlfPkr	PG&E_VLY	59.8
Lambie1	PG&E_VLY	48
VacaDxn	PG&E_VLY	42.04
Oakland1	PG&E_BAY	55
Oakland2	PG&E_BAY	55
Oakland3	PG&E_BAY	55
Lodi GT1	PG&E_VLY	22.7
Alameda1	PG&E_BAY	23.8
Alameda2	PG&E_BAY	24
SClaraGiaPk2	PG&E_BAY	24
Coalinga25D	PG&E_VLY	12.31
SClaraGiaPk3	PG&E_BAY	24
YbaCtyPk1	PG&E_VLY	46
Delta Energy CC1	PG&E_BAY	861

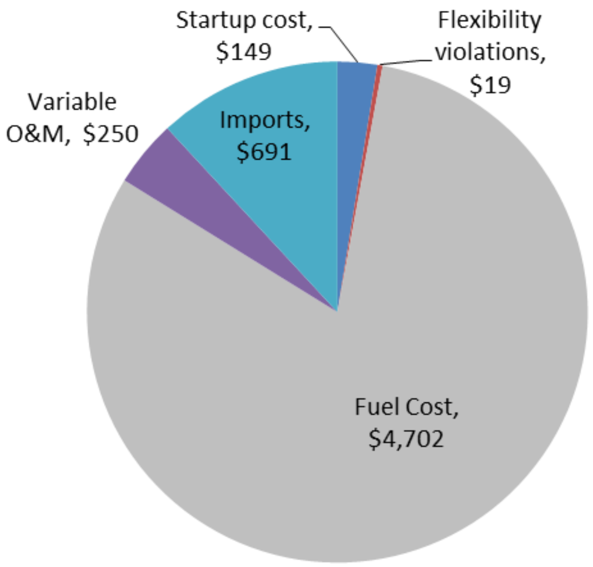
Violation Type	33% Case (Repl. TPP)	40% case with 2,000 MW removed
Loss of Load Frequency	0.03 events/year	0.07 events/year
Loss of Load Expectation	0.07 hr./year	0.14 hr./year
Expected Unserved Energy	100 MWh/year	240 MWh/year

33% CASE
(REPLICATING TPP)

Violations and production cost summary statistics

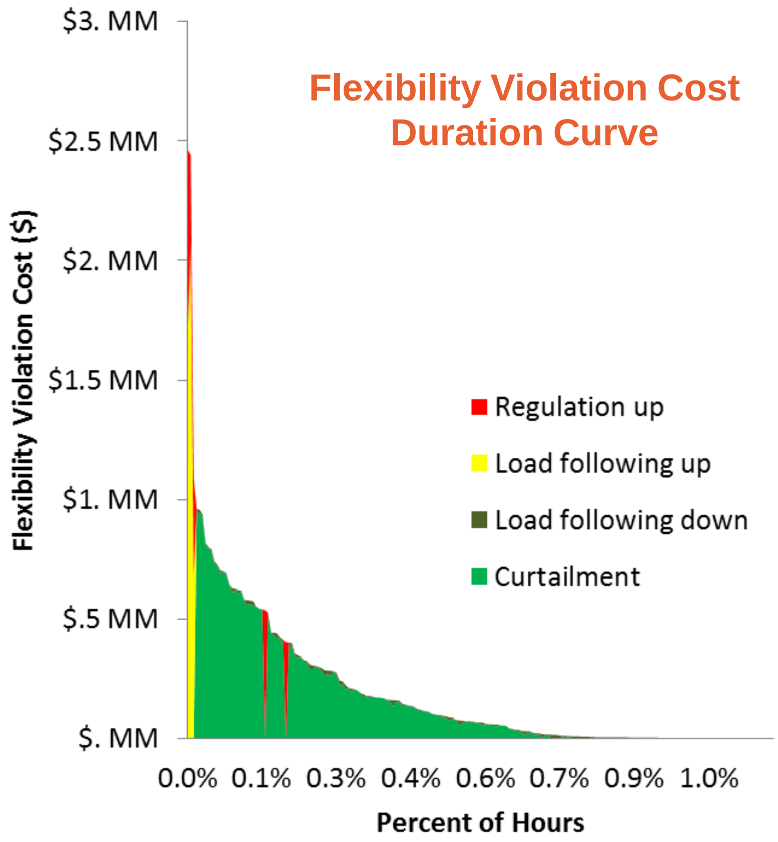
- Annual production cost of $5,800 MM/year
- Annual flexibility violation costs of $19 MM/year and startup costs of $149 MM/year

Violation Type	Expected Violations (MWh/yr)	Penalty ($/MWh)	Total Cost ($Millions)
Reg. Up	1,124	$1,100	$1.2
Reg. Down	0	$1,100	$0.0
EUE_{WH}	44	$50,000	$2.2
EOG_{WH}	1,908	$300	$0.6
EUE	0	$50,000	$0.0
EOG	61,372	$250	$15.3
Total			*$19.4*



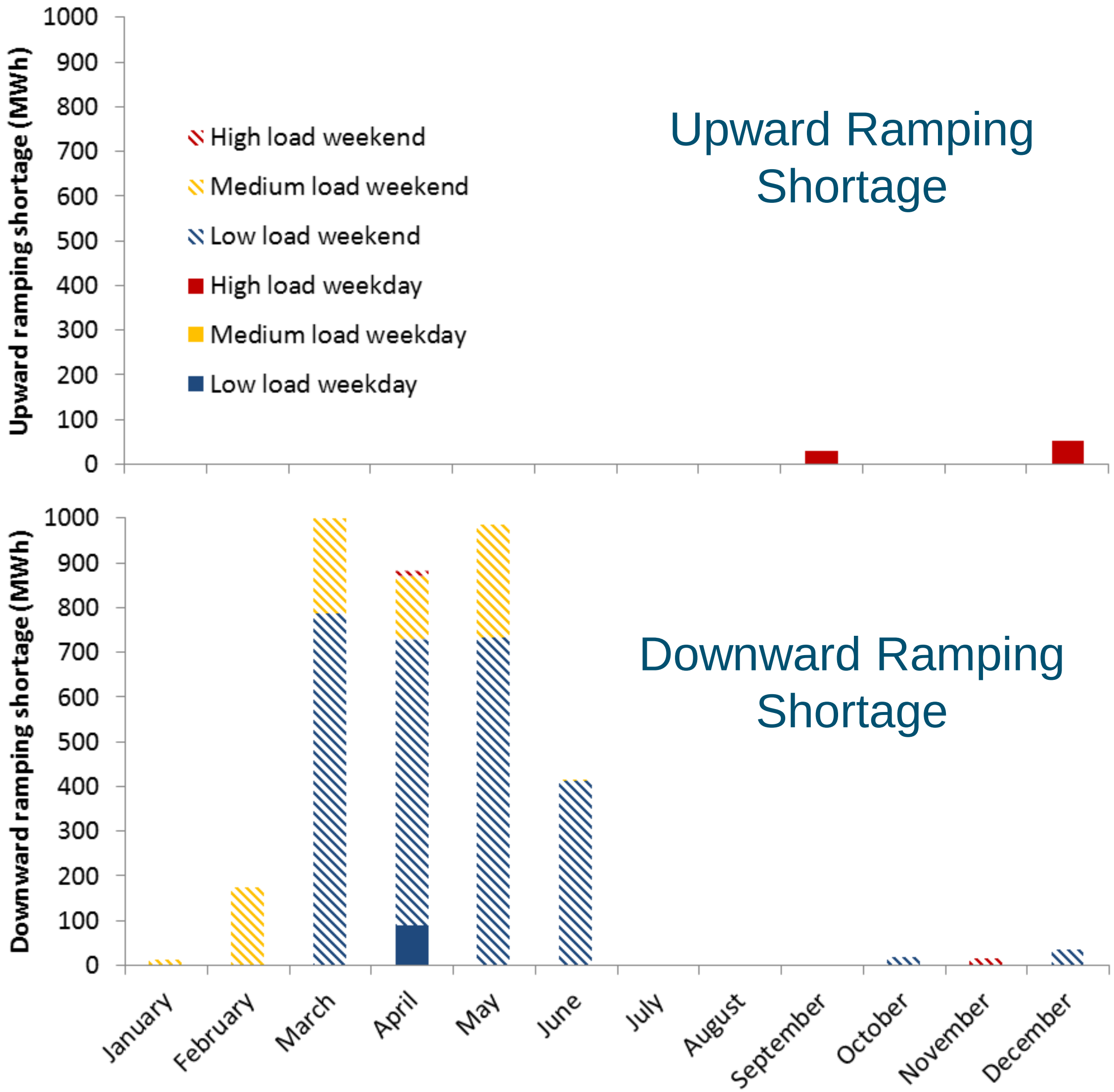
Interpreting flexibility violation costs

- **Expected flexibility violations of $19 MM/year concentrated in <1% of the hours**
- **Highest single hour violations are due to upward flexibility shortages but the majority of annual costs are from curtailment**
- **Additional work is needed to determine appropriate penalties to translate violations into costs**
  - What is the impact of violations of different magnitude?



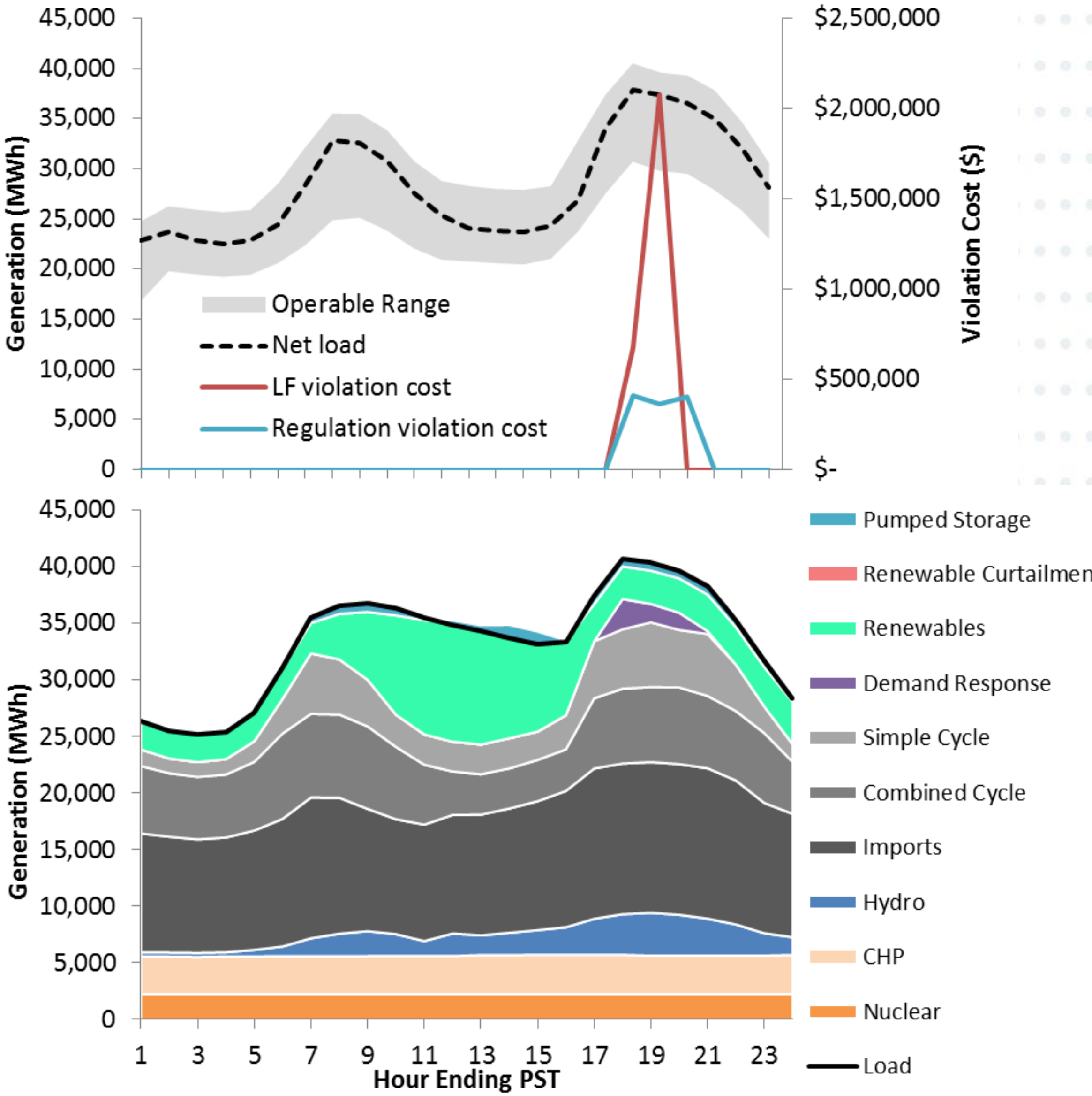
Flexibility violation patterns

- **Downward flexibility shortages are seen first on weekends during low-load, high-hydro**
- **Upward flexibility shortages first occur on high load weekdays in summer and winter months**



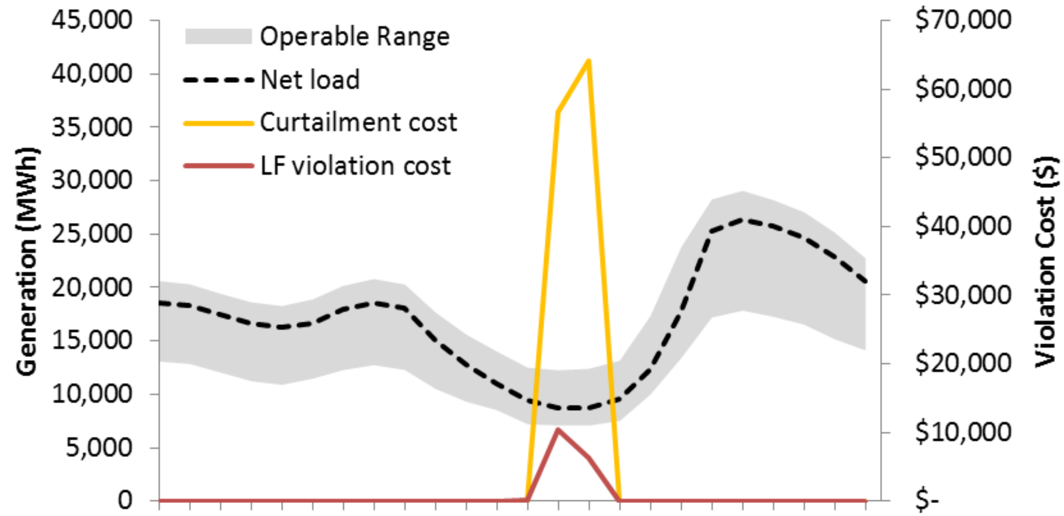
Day with greatest ramping shortage

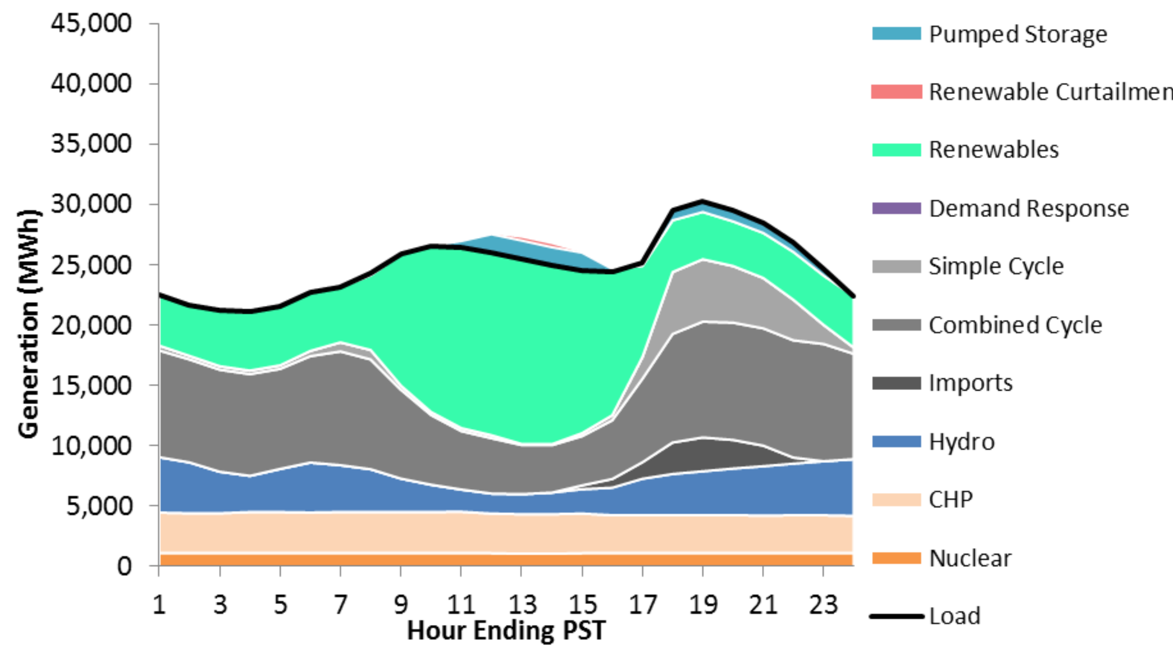
- December high-load weekday
- No capacity shortage (48,000 MW available)
- Demand response programs are used to assist with evening ramp



Day with maximum 3 hour ramp

- February medium load weekend
- Small amount of curtailment to avoid turning off CCGT's needed for evening ramp

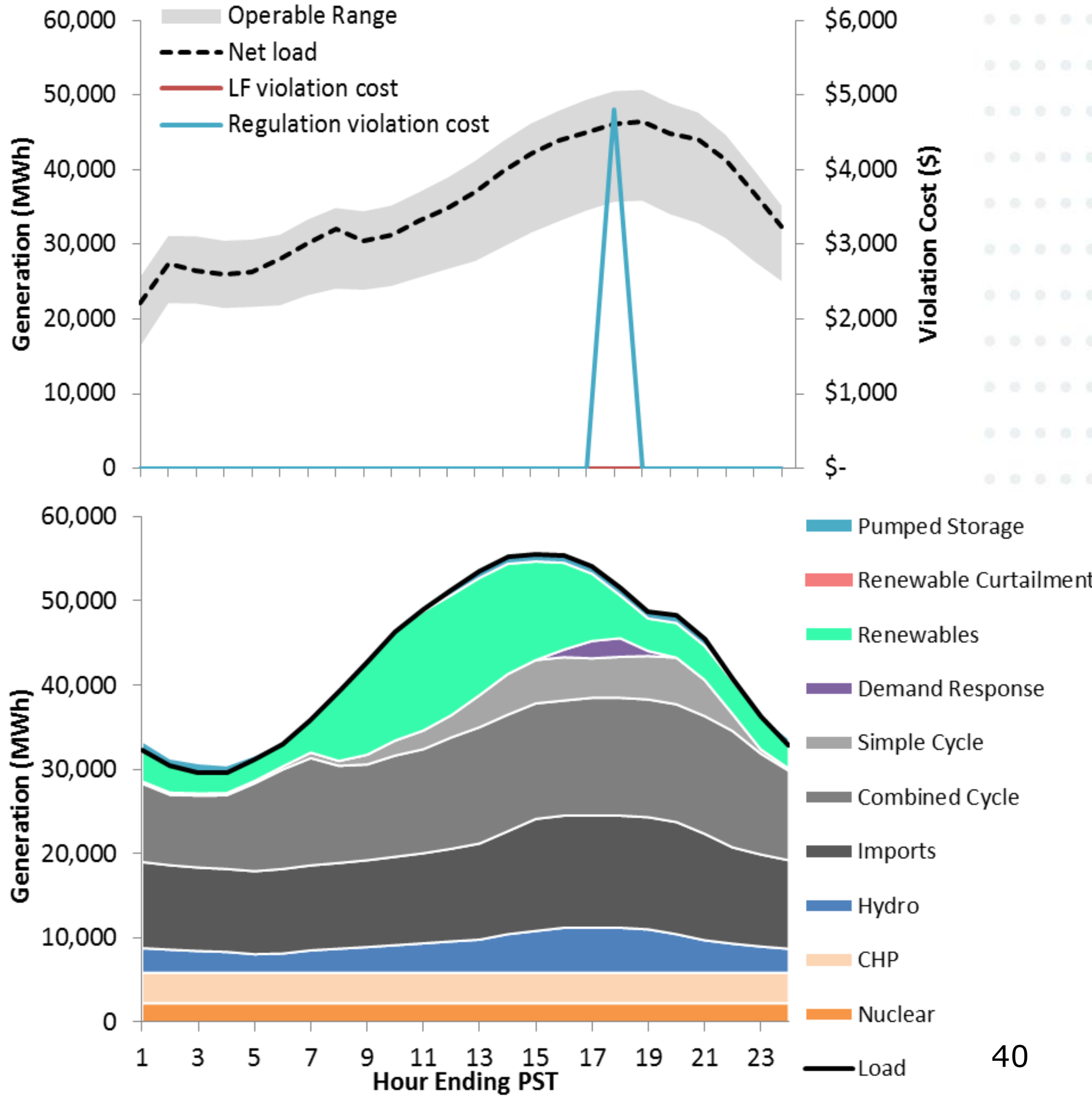




Day 548

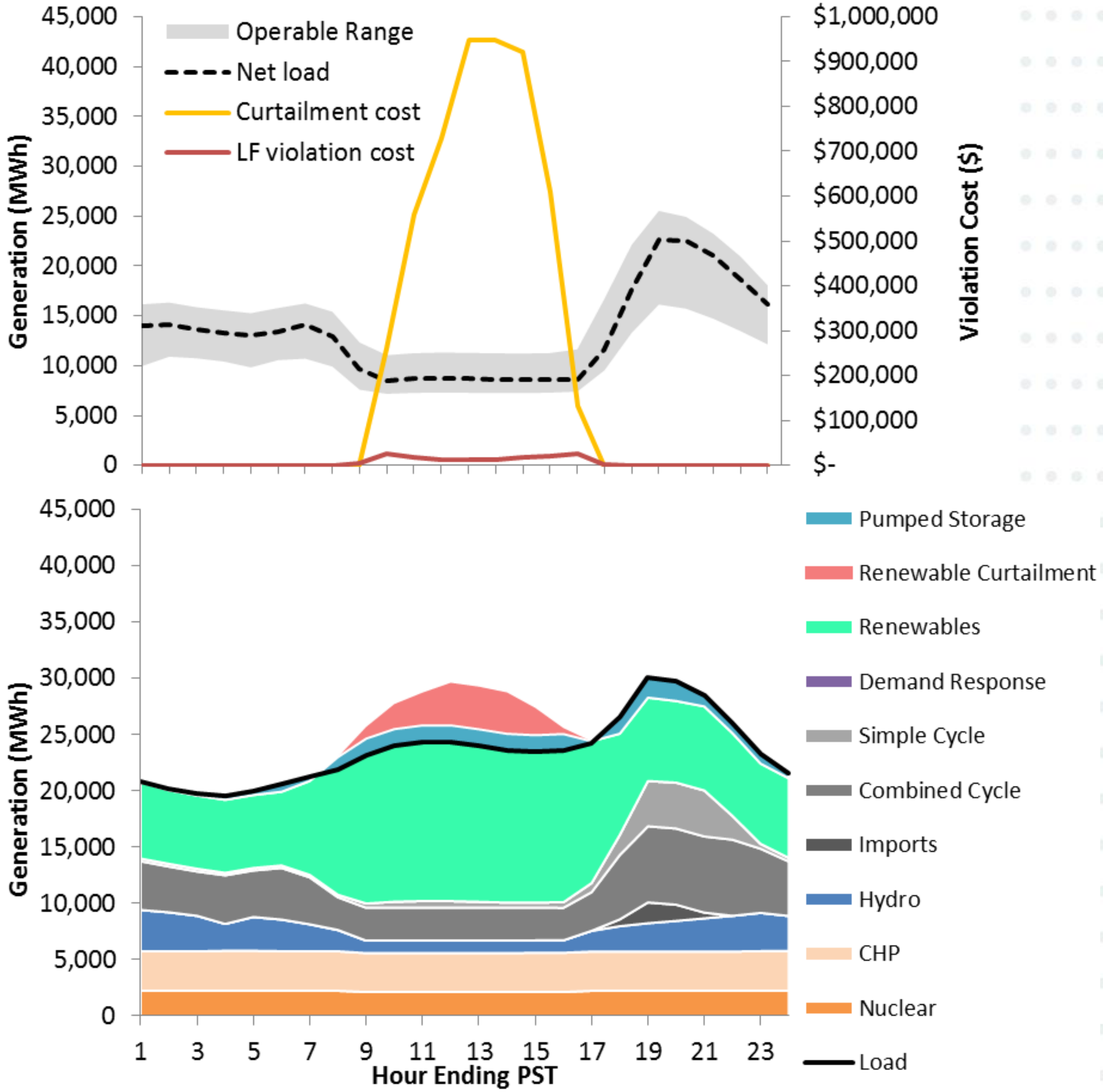
Day with highest net load

- August high-load weekday
- Shortage of regulation



Day with highest curtailment

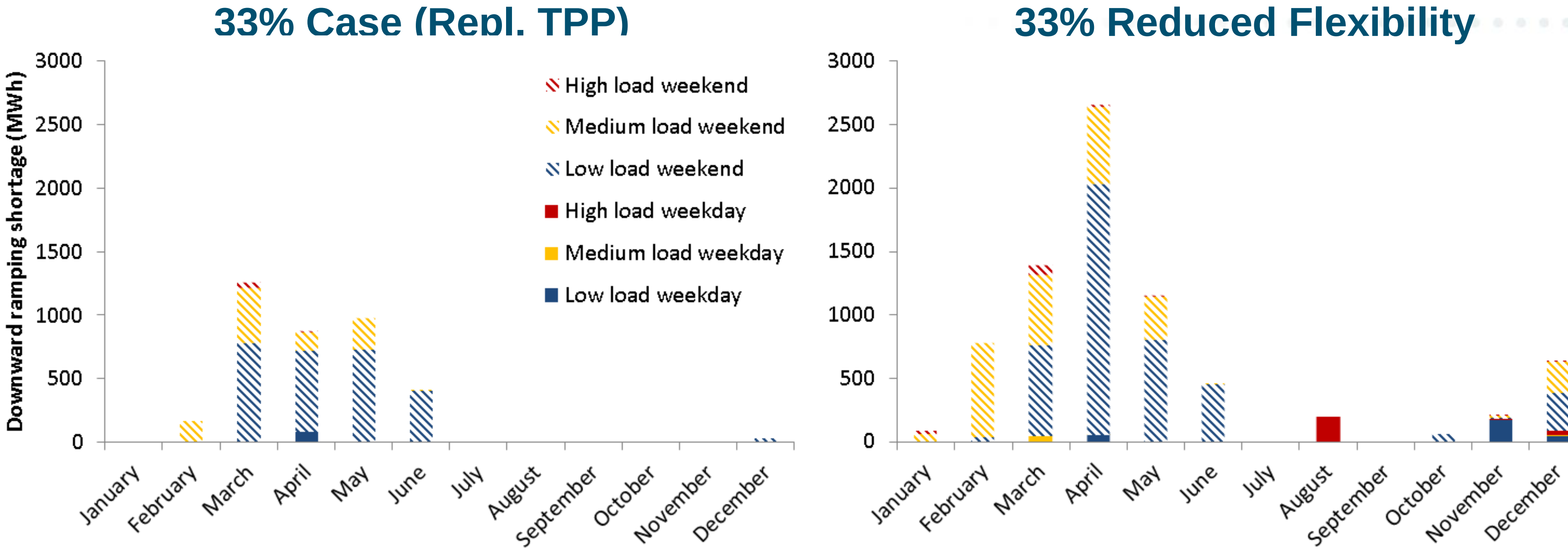
- April low-load weekend
- 20,000 MWh of renewable curtailment across 8 hours



Day 574

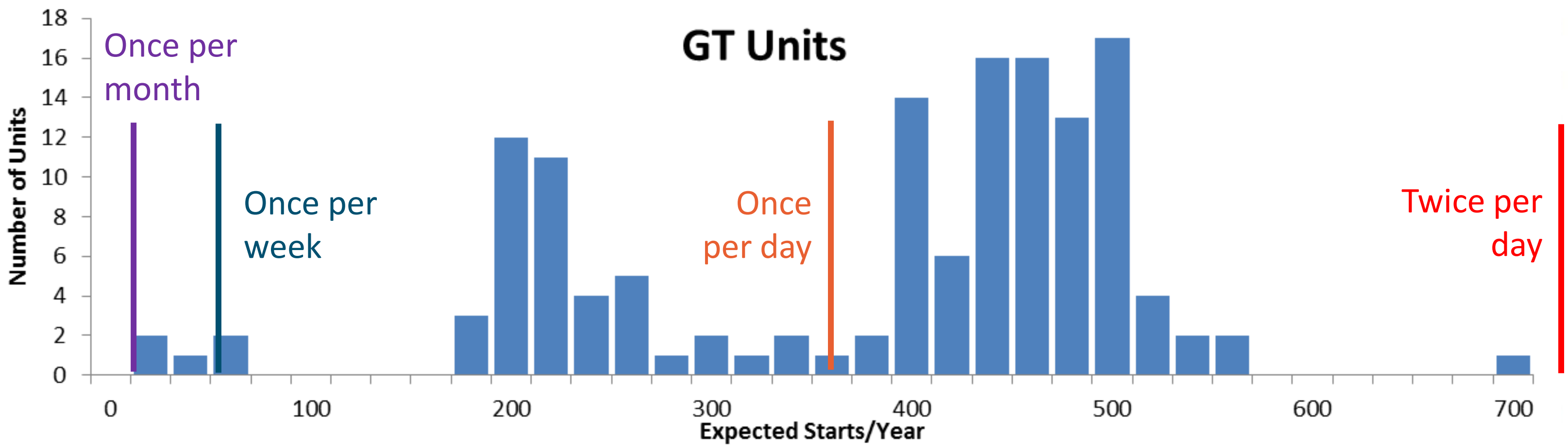
Comparison to 33% Reduced Flexibility Case

+ **Noticeable increase in flexibility violations if Track 1 capacity is not flexible**
+ **Additional upward violations in December**



Startup behavior

- Start-up costs not included in optimization, inclusion should reduce number of starts, but at the expense of additional flexibility violations
- Two thirds of all GT units average more than one start each day



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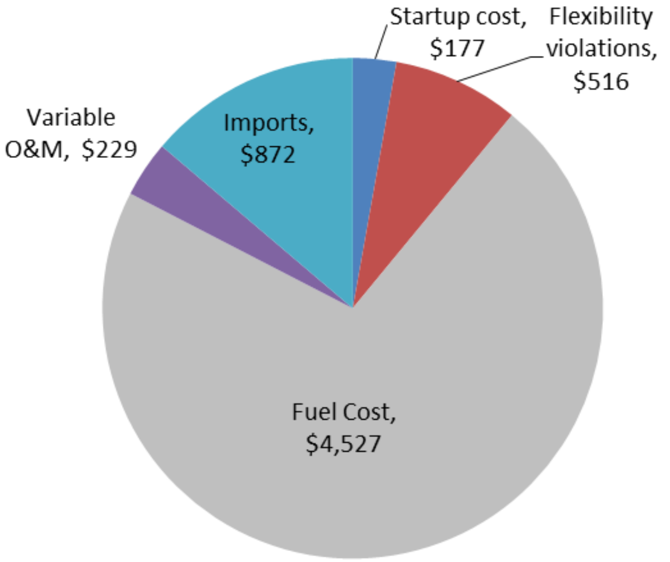
40% REDUCED FLEXIBILITY CASE

Violations and production cost summary statistics

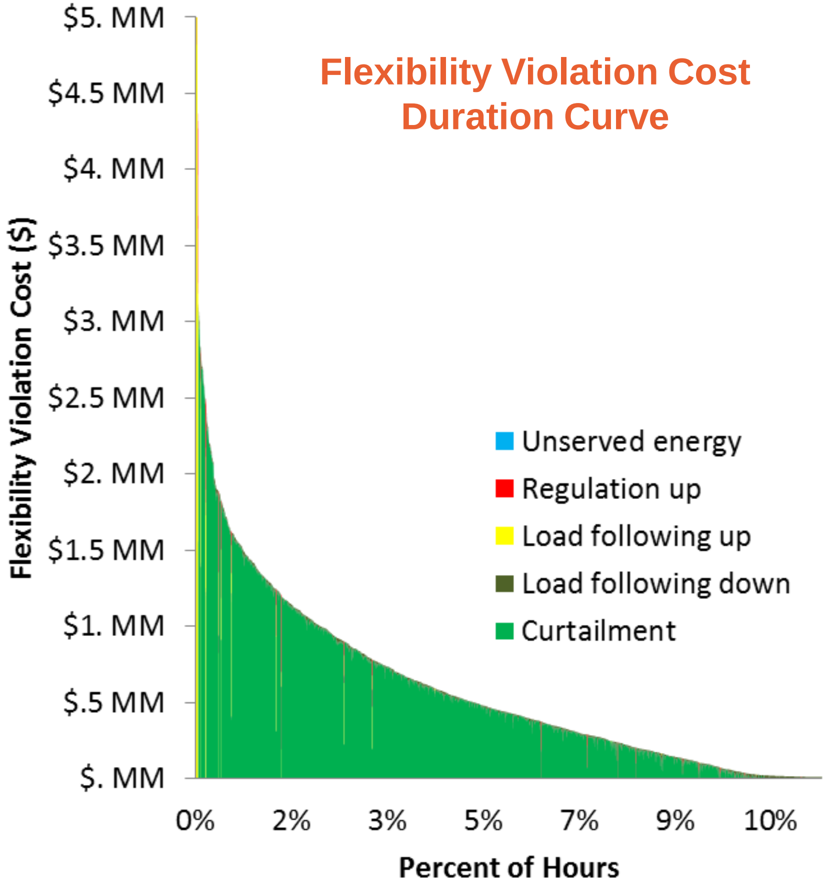
+ **Production cost is $6,322 MM/year, up from $5,800 MM/year in the TPP case**
  - Cause is increase in startup costs and flexibility violations
+ **Flexibility costs increase to $516 MM**

Violation Type	Expected Violations (MWh/yr)	Penalty ($/MWh)	Total Cost ($Millions)
Reg. Up	5,307	$1,100	$5.8
Reg. Down	0	$1,100	$0.0
EUE_{WH}	533	$50,000	$26.7
EOG_{WH}	47,377	$300	$14.2
EUE	309	$50,000	$15.5
EOG	1,816,577	$250	$454.1
Total			*$516.3*



Flexibility violation costs in 40% Reduced Flexibility Case

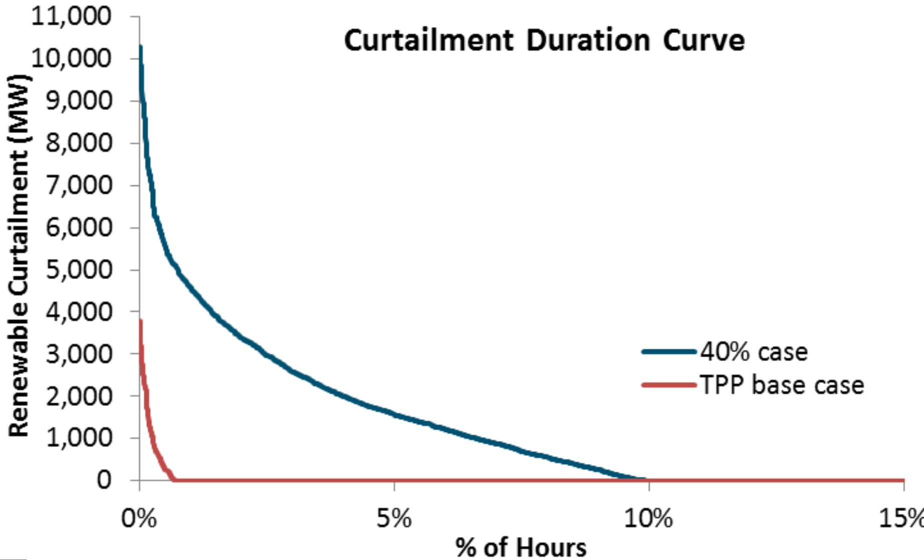
- **Expected flexibility violations of $516 MM/year are significant**
  - Given the frequency and magnitude of violations, new flexible capacity may be cost effective
- **Highest single hour violations are due to upward shortages but the majority of annual costs come from curtailment**
  - Some curtailment is to avoid more expensive upward ramping shortages

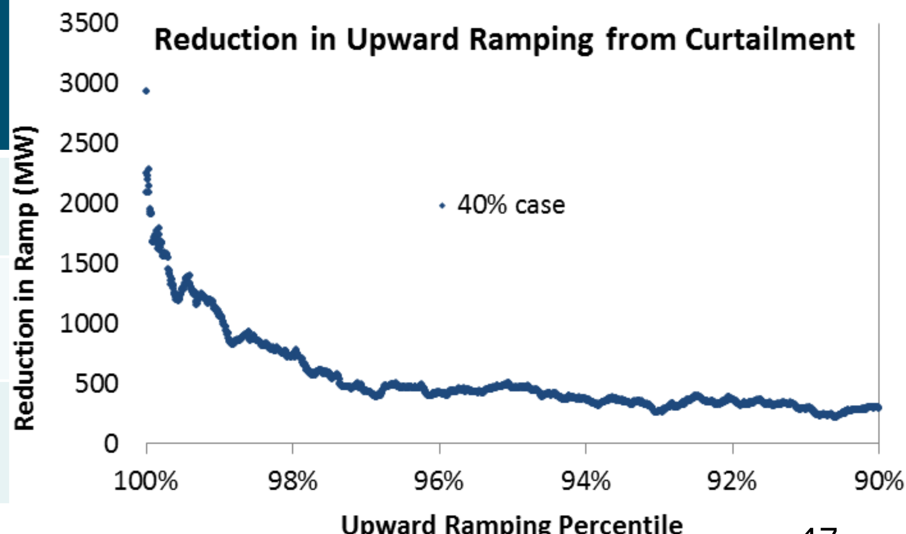


Curtailment in 40% Reduced Flexibility Case

+ **Renewable curtailment is seen both due to excess energy and ramping shortages**
+ **Daytime curtailment in every month outside July-September**
+ **Night-time curtailment in December**

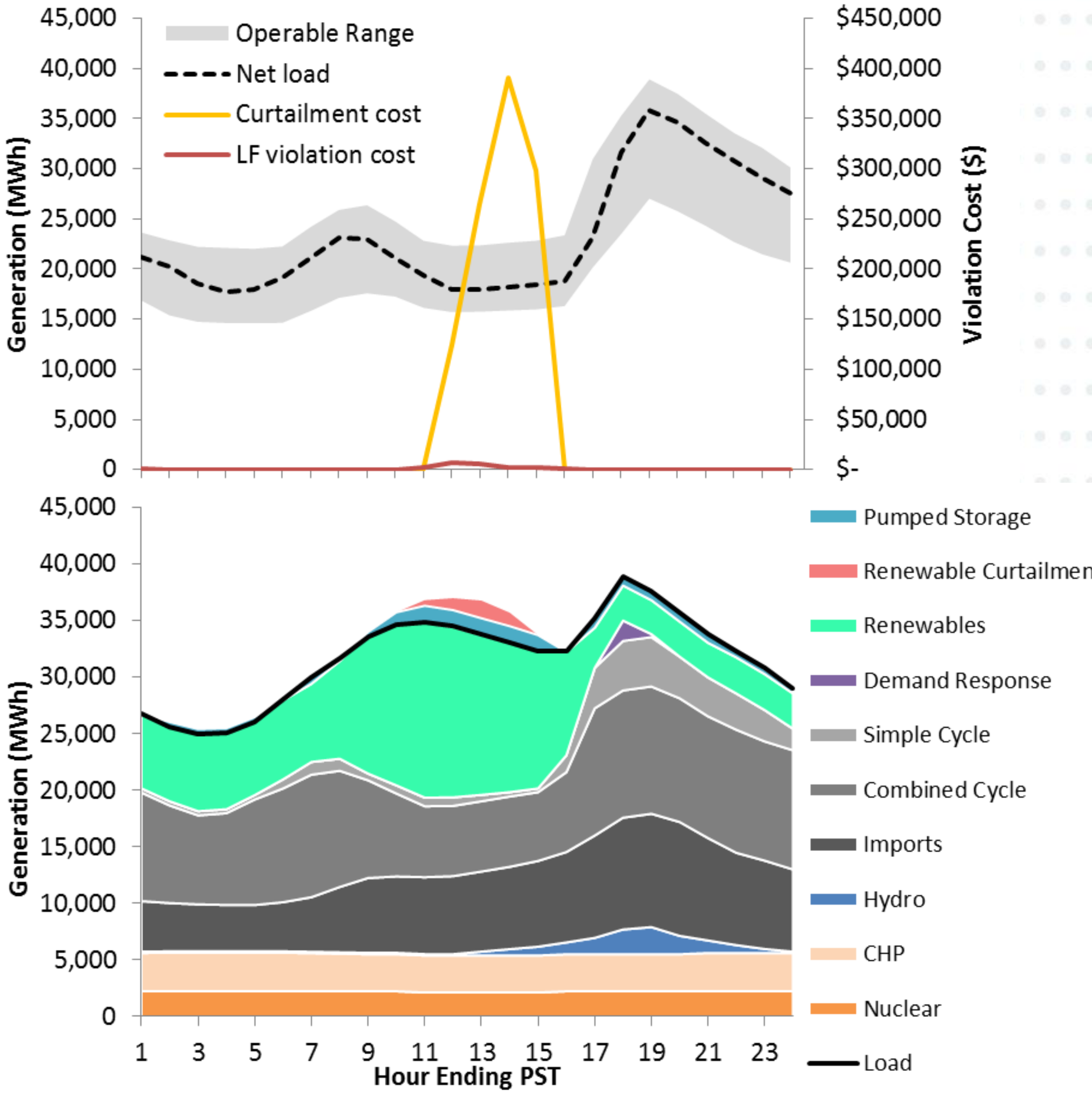
	33% Case	40% Reduced Flex.
Curtailed Energy	6 GWh	1,140 GWh
Percent of renewables curtailed	0.01%	1.3%
Percent of hours with curtailment	0.7%	10%



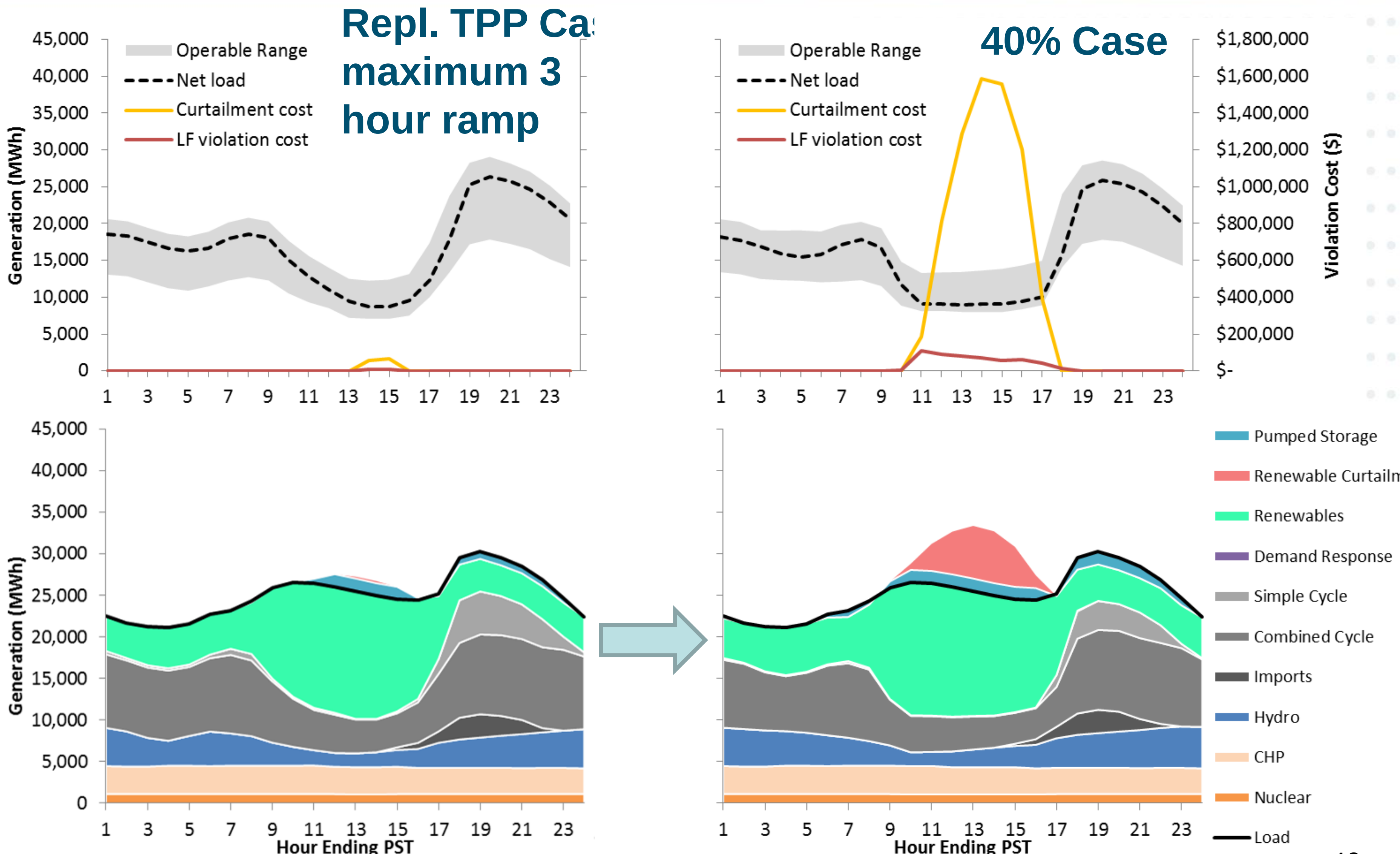


New day with maximum 3 hour ramp

- December high-load weekend
- To avoid ramping shortages model curtails $1 MM
- DR is used for ramping, indicating no additional resources were available

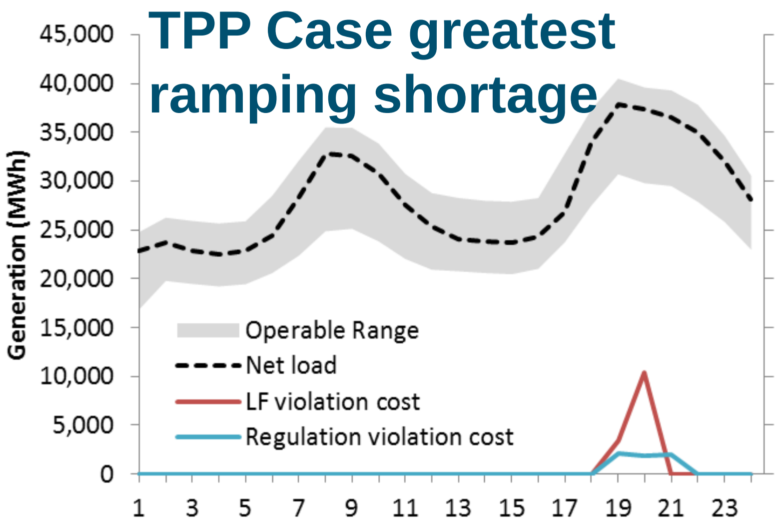


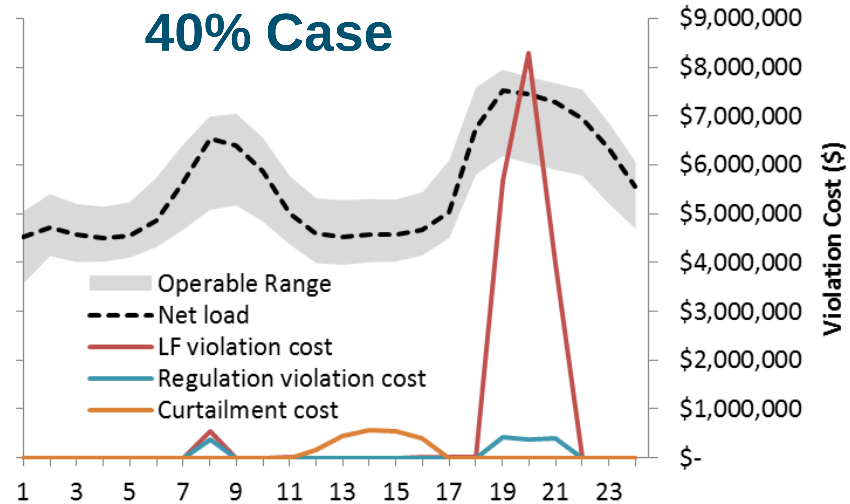
Comparison between days with large 3 hour ramps

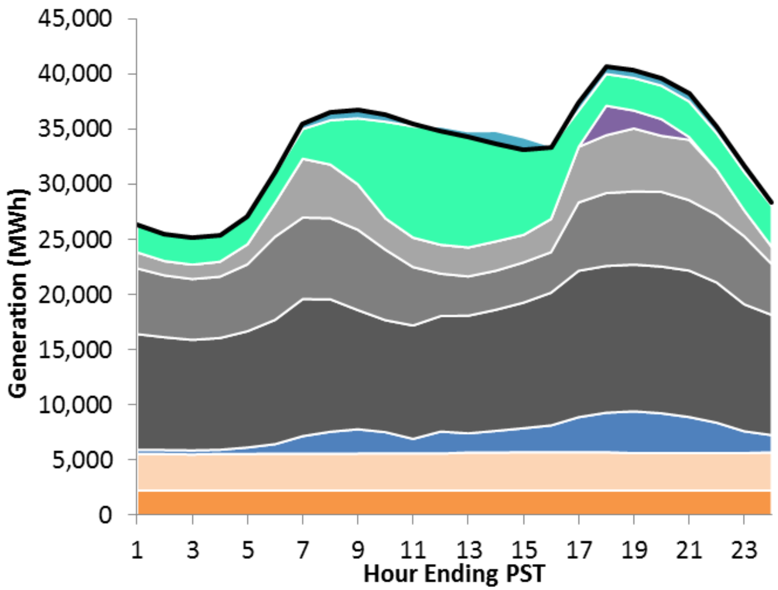


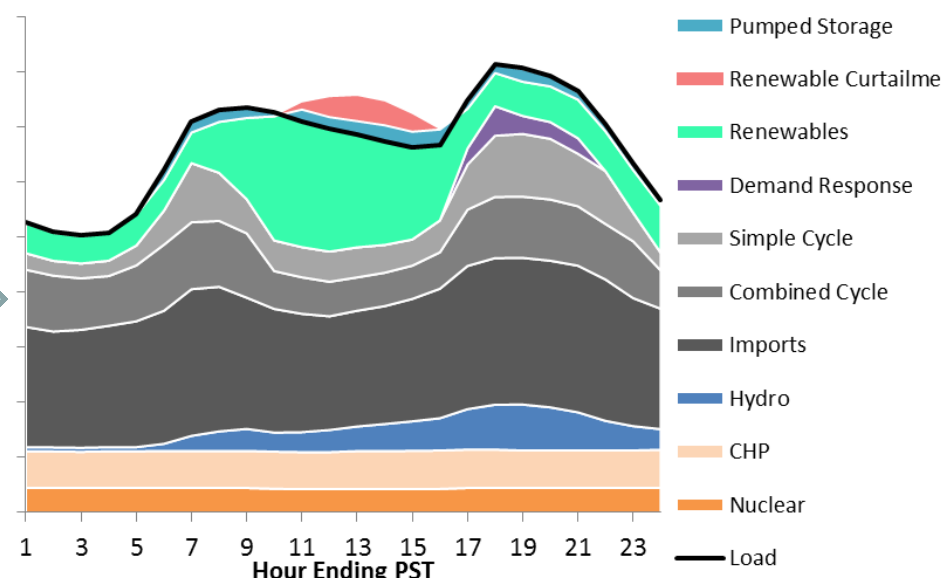
Day 548 February medium load weekend

Comparison between days ramping shortages









Day 511 December high-load weekday

Demand response usage

- **Demand response usage in the Repl. TPP case is primarily in summer**
- **In the 40% Reduced Flexibility case, DR is used extensively for meeting evening net-load ramps**
  - Some DR programs show over 80 calls/year
- **Enforcing frequency and energy limits within independent draws is difficult but can be done**
  - Result will likely be greater pre-curtailment of renewables to reduce the need for ramping capability

33% Case (Repl. TPP) MWh Demand Response

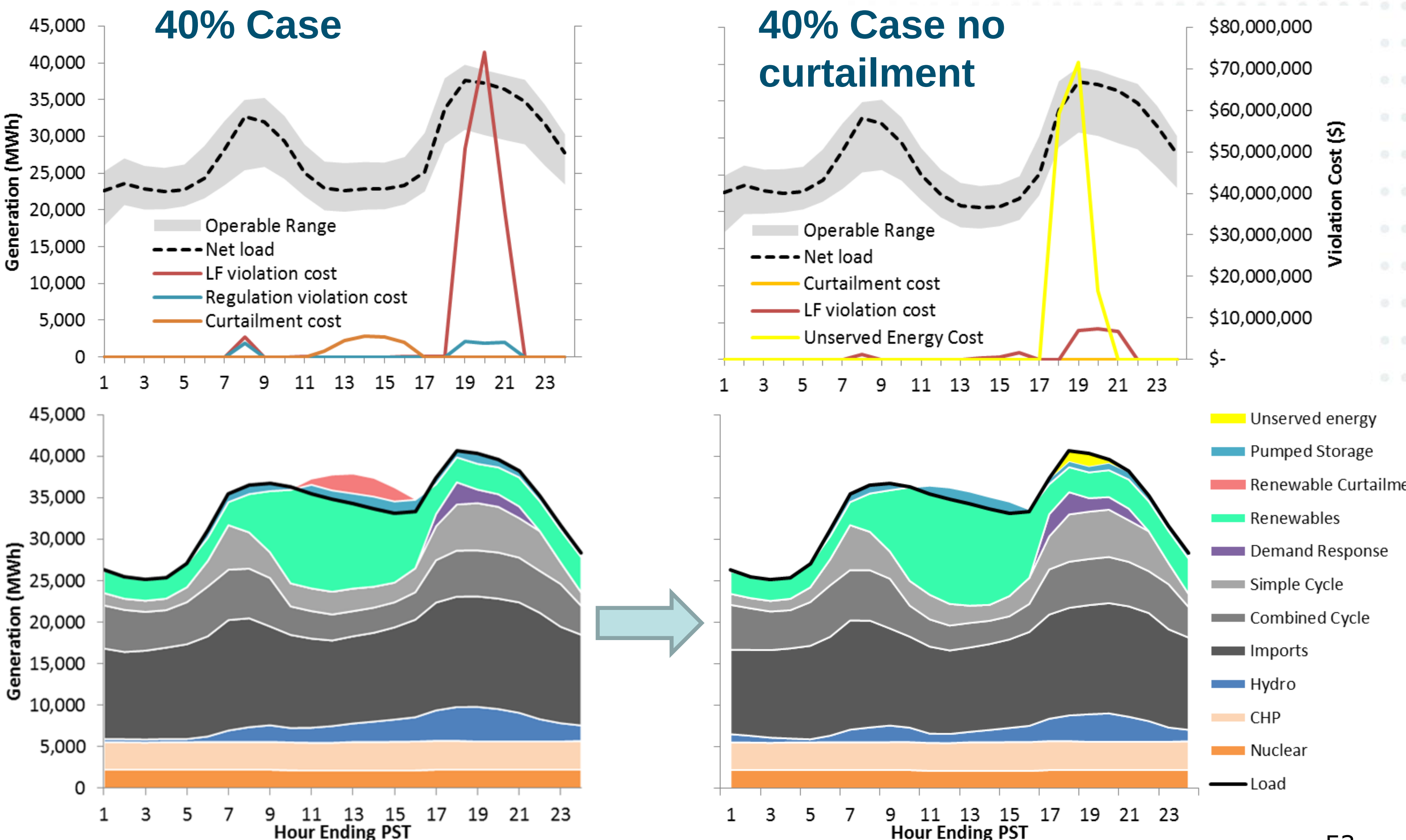
Hour Ending PST	January	February	March	April	May	June	July	August	September	October	November	December
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-								-	-	-
7	-	-								-	-	-
8	-	-								-	-	-
9	-	-								-	-	-
10	-	-								-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	1,576	-	-	-
16	-	-	-	-	-	-	-	902	3,884	-	-	-
17	-	-	-	-	-	-	-	2,057	4,400	-	-	-
18	302	-	-	-	189	-	-	2,209	4,000	-	4,152	7,533
19	-	-	342	-	-	-	-	592	2,803	-	1,200	4,820
20	-	-	-	-	-	-	-	-	923	-	-	1,516
21	-	-	-	-	-	-	-	-	-	-	-	255
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

40% Reduced Flexibility MWh Demand Response

Hour Ending PST	January	February	March	April	May	June	July	August	September	October	November	December
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-								-	-	-
5	-	-								-	-	-
6	-	-								-	-	-
7	-	-								-	-	-
8	-	-								-	-	-
9	-	-								-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	1,610	-	-	-
16	-	-	-	-	-	-	-	1,040	3,465	-	-	-
17	27,156	2,854	1,571	877	-	66	-	2,673	6,296	37,241	59,867	61,169
18	92,646	69,454	88,278	34,985	13,416	7,927	3,235	3,296	26,803	77,835	104,994	127,131
19	59,297	55,562	88,974	66,585	35,821	22,721	7,822	2,322	16,236	42,287	59,184	78,022
20	48,632	40,588	79,764	49,645	30,068	25,644	3,640	1,516	10,234	21,270	38,410	64,036
21	28,242	23,108	37,601	17,844	9,999	9,850	2,808	838	2,195	1,056	25,267	48,672
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

40% NO CURTAILMENT CASE

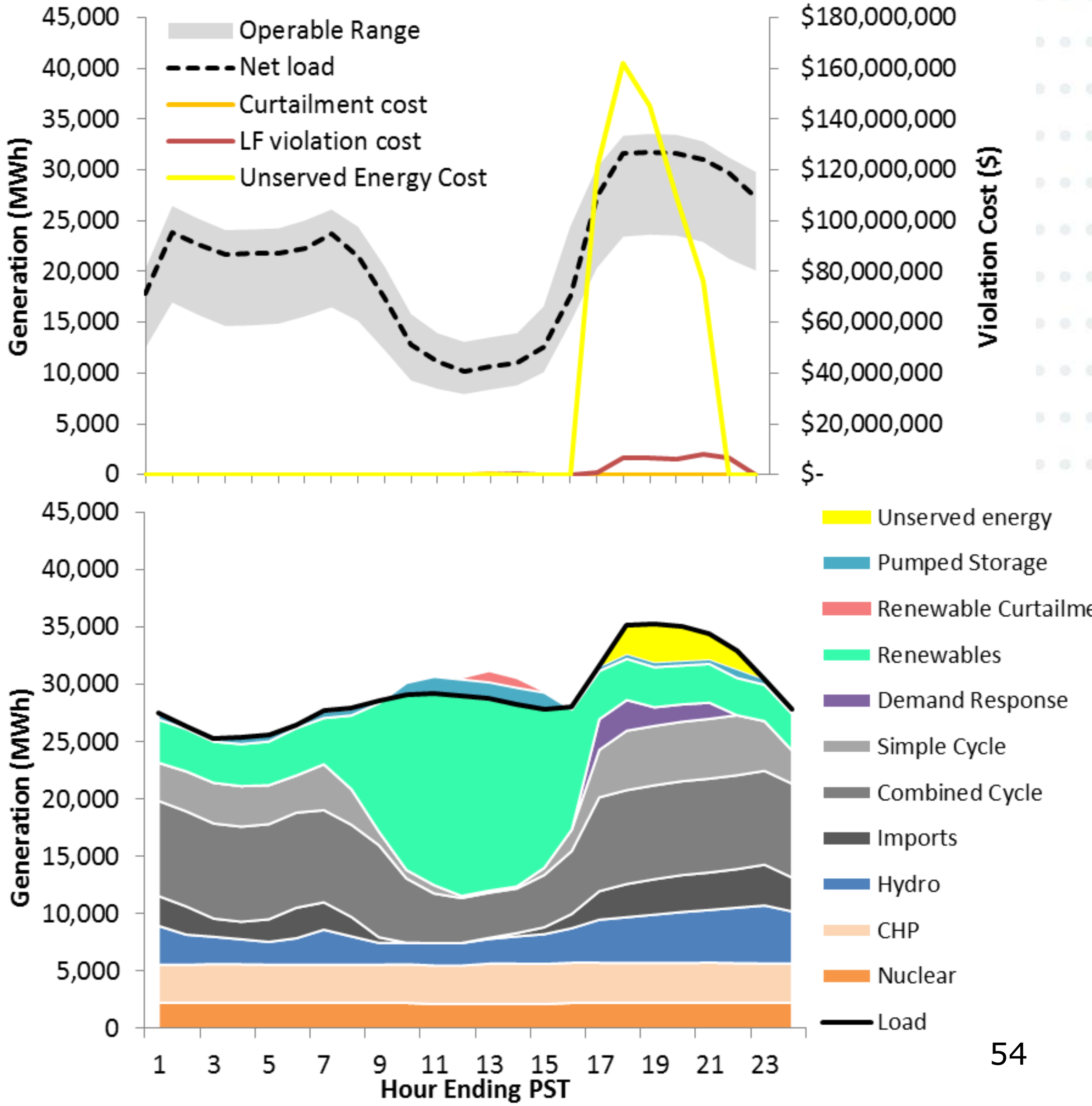
Comparison between days ramping shortages



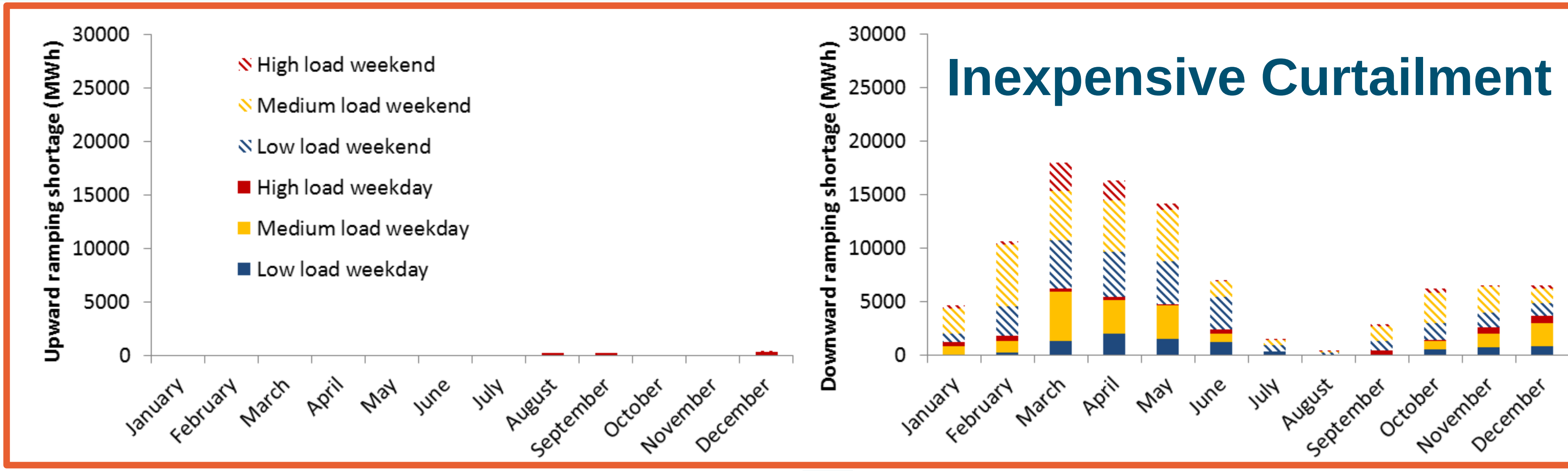
Day 511 December high-load weekday

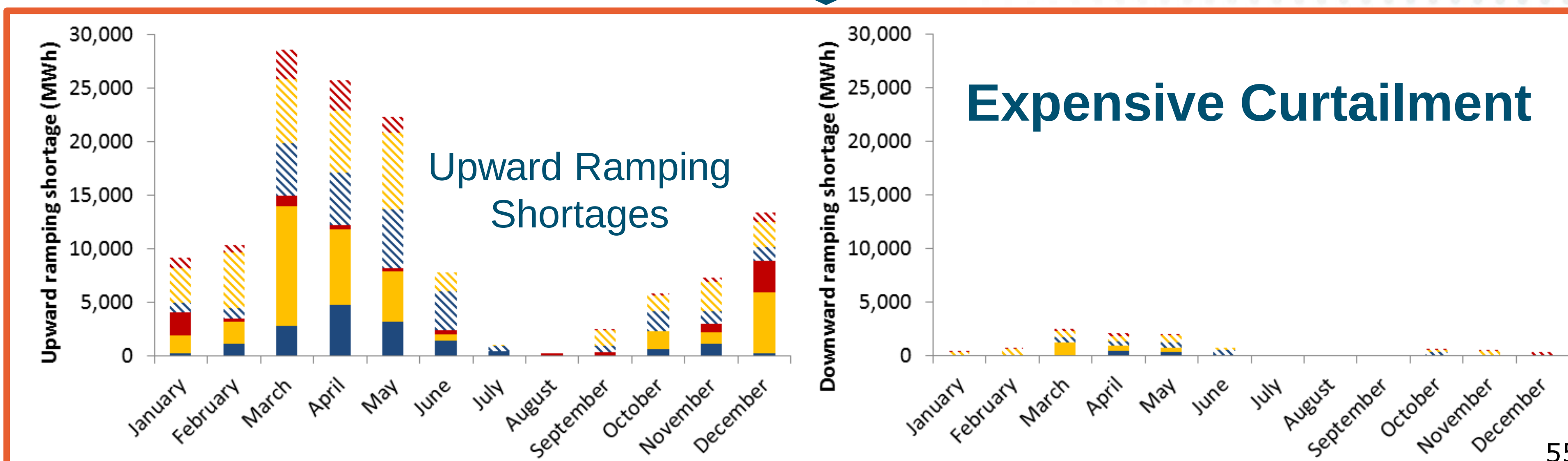
Unserved energy in 40% case with high cost curtailment

- December medium-load weekend
- Imports and thermal capacity are backed down to minimum
- Large amount of unserved energy results when system is unable to ramp capacity



Expensive Curtailment Changes Downward Violations to Upward





Flexibility Costs under No Curtailment Case

- **Flexibility costs increase dramatically if curtailment is not allowed due to significant amounts of unserved energy**
- **Still unable to avoid all renewable curtailment!**

Violation Type	40% Reduced Flexibility Case	40% No Curtailment Case
Downward violation costs ($MM)	**468**	**365**
Regulation down	0	0
Sub-hourly overgen	14	1
Hourly overgen (curtailment)	454	165
Dump energy	0	198
Upward violation costs ($MM)	**48**	**9,092**
Regulation up	6	467
Sub-hourly unserved energy	27	3,347
Hourly unserved energy	15	5,279
Total ($MM)	**516**	**9,457**

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CONCLUSIONS AND NEXT STEPS

Flexibility cost comparison

- **Emerging system-wide flexibility issues indicated at 33%**
- **Need to ensure sufficient flexible capacity strongly indicated above 33%**
- **Results are preliminary and based on limited draws**

Violation Type	33% Case	33% Reduced Flexibility Case	40% Reduced Flexibility Case
Downward violation costs ($MM)	**16**	**16**	**468**
Regulation down	0	0	0
Sub-hourly overgen	1	1	14
Hourly overgen (curtailment)	15	15	454
Dump energy	0	0	0
Upward violation costs ($MM)	**3**	**12**	**48**
Regulation up	1	11	6
Sub-hourly unserved energy	2	1	27
Hourly unserved energy	0	0	15
Total ($MM)	**19**	**29**	**516**

Marginal renewable curtailment

- **Marginal curtailment is the proportion of the next MWh of resource that would be curtailed due to flexibility issues**
  - Marginal curtailment increases significantly between 33% and 40% RPS
- **Solar has high marginal curtailment because most of the over-generation is during day-time hours**
- **Results indicate the value of procuring a diverse portfolio of renewables**

Marginal Curtailment	33% Case (Repl. TPP)	40% Reduced Flexibility
In-state solar	2.3%	29.5%
In-state wind	1.0%	9.9%
Baseload	0.7%	10.0%

Next Steps

- **Develop new base case with higher renewables**
  - Include 5,400 MW of NEM PV systems, additional renewables for SONGS replacement and likely effect of overprocurement – ***base case may be closer to 40%!***
  - Test RPS levels between 33% and 40% to see where flexibility constraints start to bind
- **Test robustness of system to changes in thermal fleet**
  - Develop specific retirement scenarios and identify the extent of any flexibility issues
  - Identify thresholds where flexibility constraints start to bind
- **Develop zonal models: SP26, NP26**
  - Flexibility issues may show up first in Southern California due to higher renewable penetration
- **Investigate the costs of sub-hourly ramping shortages**

Next Steps (Cont.)

- **Test sensitivity to key input parameters**
  - Exports: determine reasonable level of exports to allow
  - Exports: test changes to intertie ramping constraints
  - Integration duties for out-of-state resources
- **EIM: test addition of PacifiCorp loads and resources**
- **Test how results change with alternative resource builds above 33%**
  - Investigate “crossover point” where integration costs become significant enough to change the relative economics among solar PV, wind, CSP and geothermal/biomass
- **Begin investigating the implications of making renewables dispatchable**
  - Policy issues, regulatory structures, market mechanisms, etc.
  - Technical issues: how fast can renewables ramp?

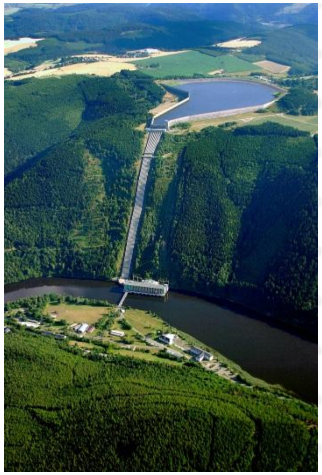
Next Steps (Cont.)

- **Investigate impediments to utilizing full flexibility of existing resources (e.g., self-scheduling)**
- **Develop better generator operating data**
  - REFLEX modeling requires very detailed data on each unit's capabilities:
    - Start-up costs and start times (hot and cold)
    - Number of starts allowed by air permits (by year and month)
    - Pmin and Pmin-to-Pmax ramp rates (some ramp rates in database appear to be from 0-to-Pmax)
    - Minimum generation needed for reliability in load pockets
- **Investigate appropriate convergence criteria under different conditions to determine how many draws are needed**
  - Develop smart sampling techniques to allow more draws if necessary

Next Steps (Cont.): Investigate Potential Solutions

- **Increased regional coordination**
  - Make best use of latent flexibility in current system
- **Renewable resource diversity**
  - Reduces overgeneration and need for flexible resources

- **Flexible loads**
  - Shifting loads from one time period to another, sometimes on short notice
- **Flexible generation**
  - Need generation that is fast ramping, starts quickly, and has min. gen. flexibility



- **Energy storage**
  - Deep-draw (diurnal) storage is important

Energy+Environmental Economics

Thank You!

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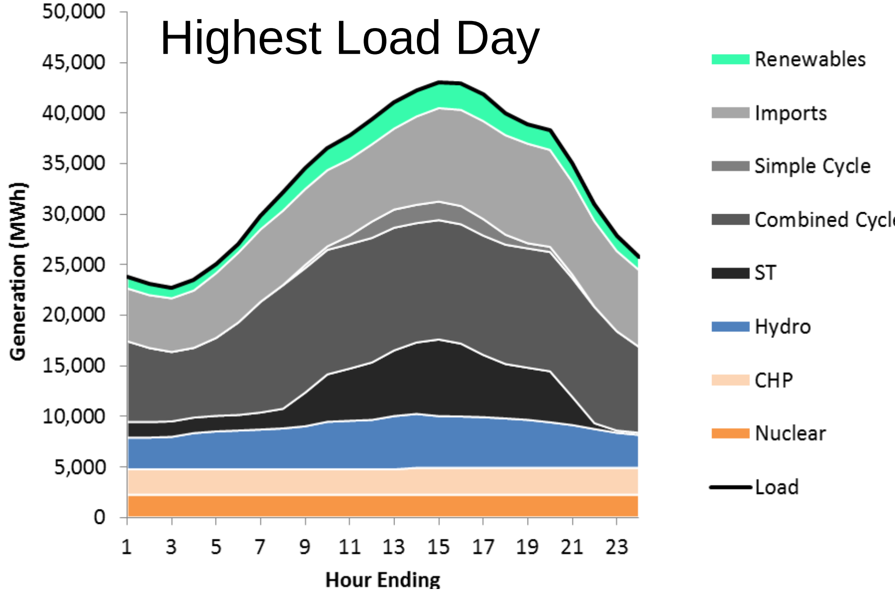
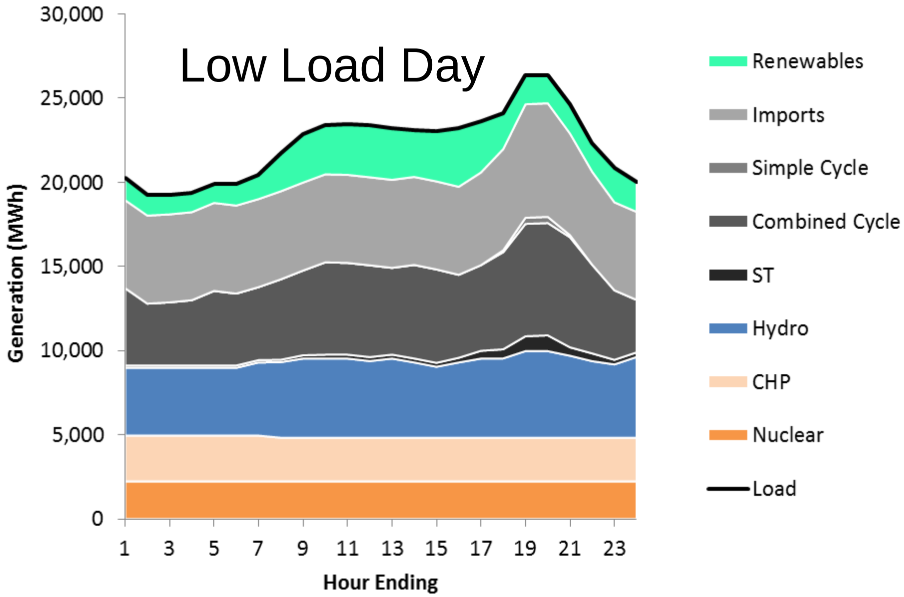
EXTRA SLIDES

2012 Test Case

- RECAP model showed no capacity shortages or system level over-generation after 5,000 years of draws
- REFLEX runs had no capacity, flexibility, or over-generation violations over 1 year of draws

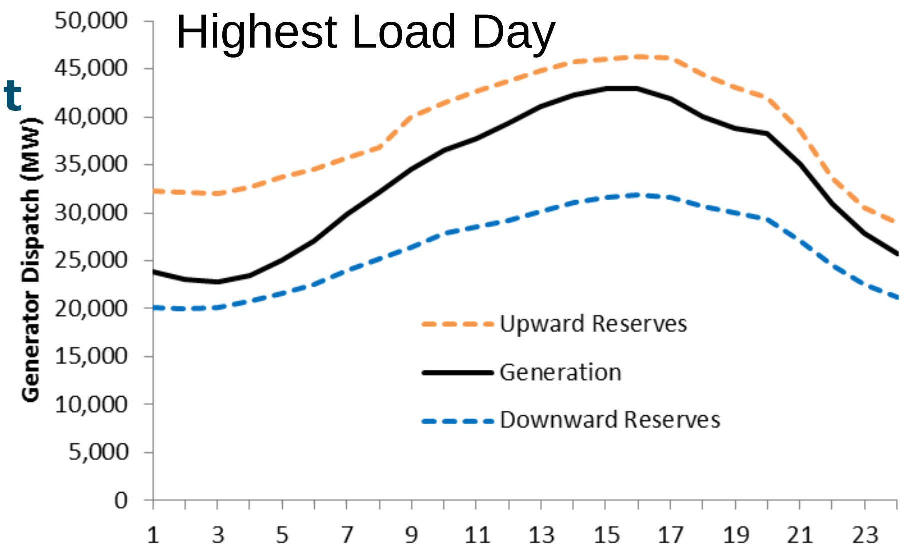


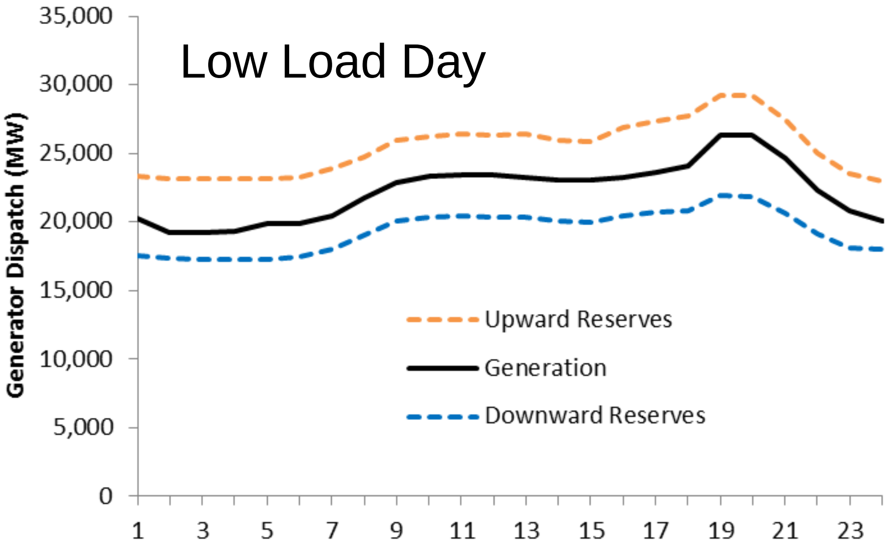


Load Following in 2012 test case

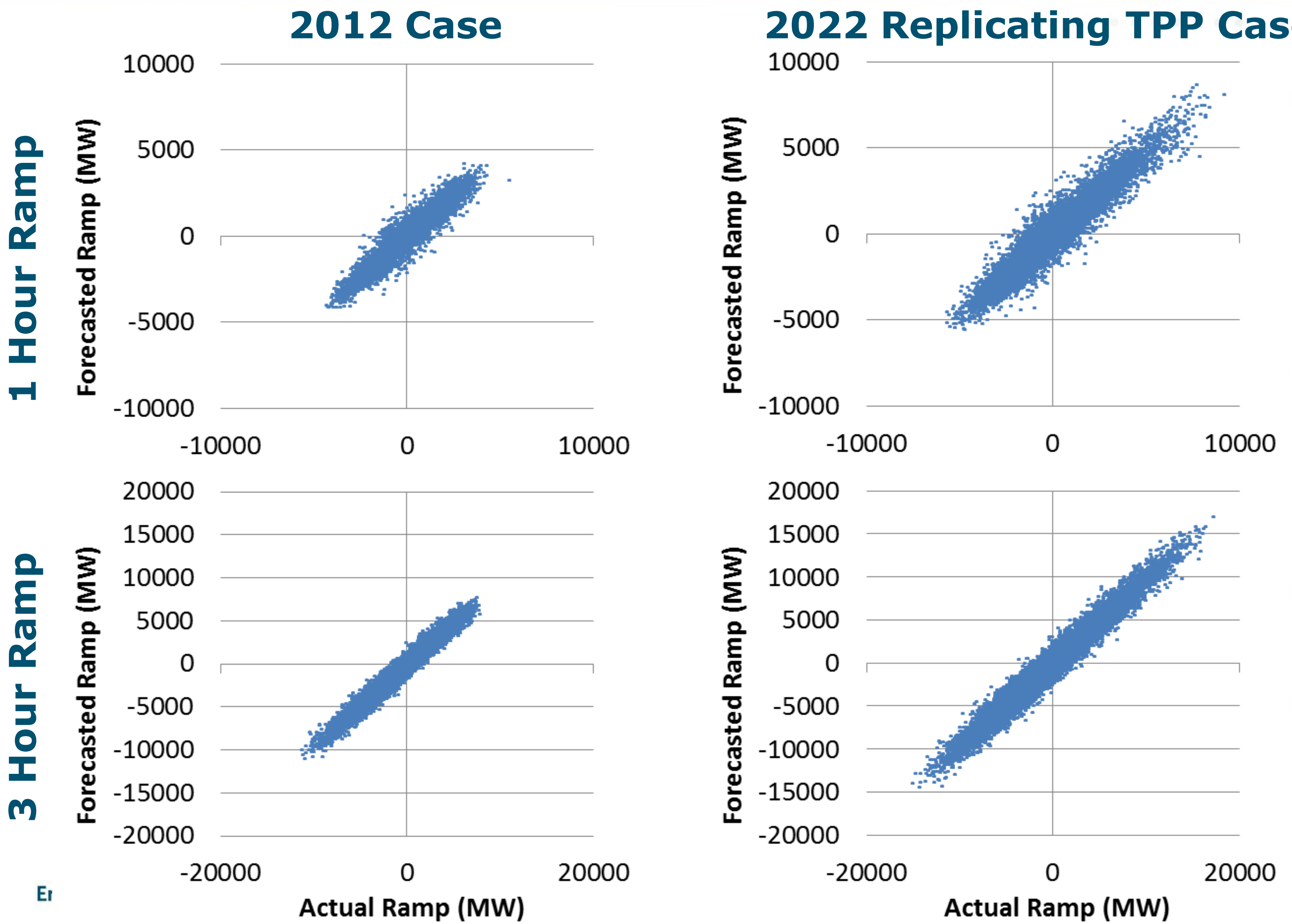
- **REFLEX reserve provision results are reasonable compared to current practice**

	Upward		Downward	
	% of Load	MW	% of Load	MW
minimum	7%	1,150	6%	1,972
average	20%	5,231	15%	3,660



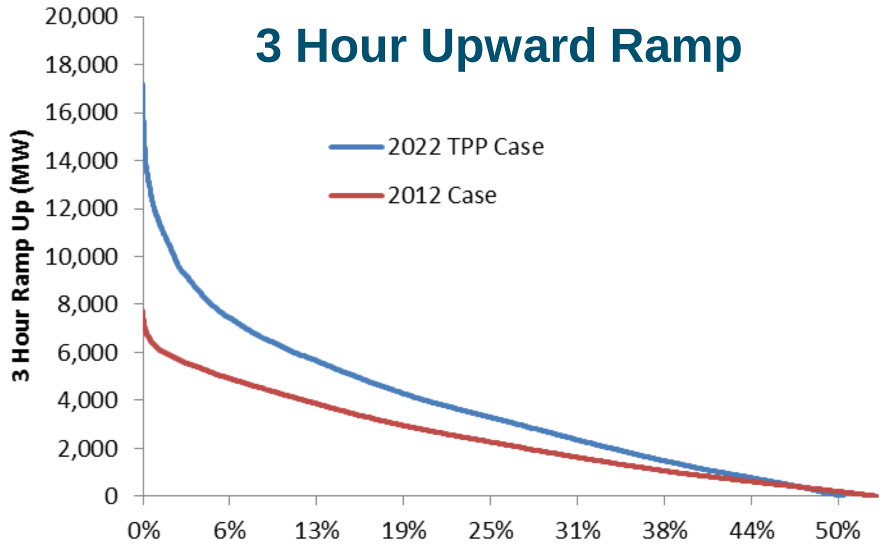


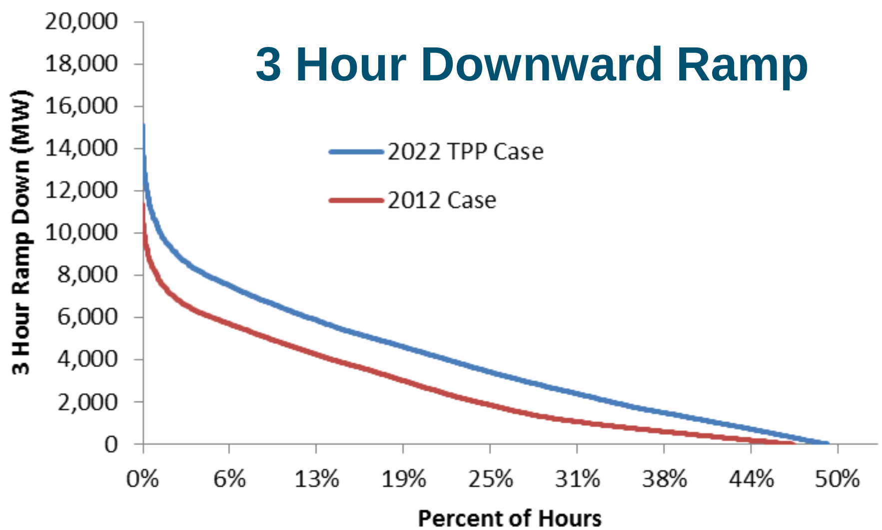
Net Load Ramps Increase Between 2012 and 2022



Ramp duration curves

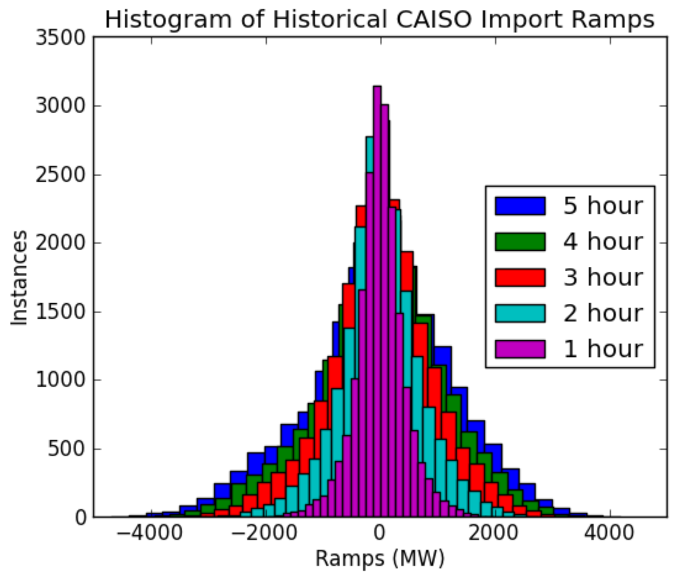
- **Significant increases multi-hour ramping needs due to renewable penetration and load growth**
  - Maximum upward 3 hour upward ramp expected to double between 2012 and 2022

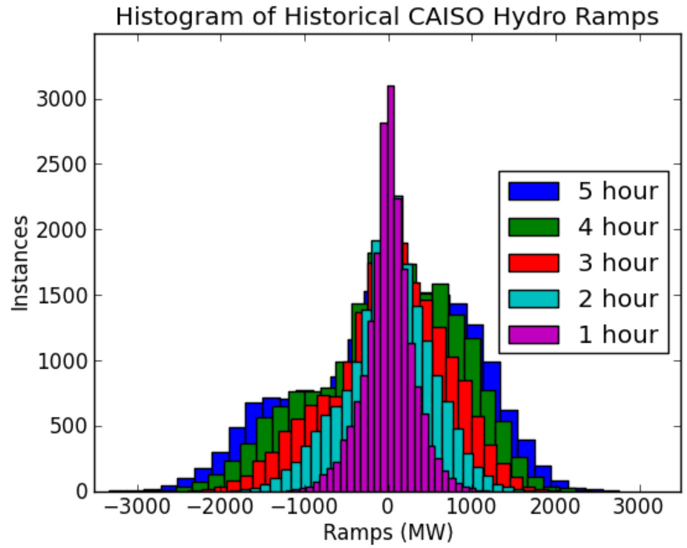




Hydro and import ramping capability

- Hydro and imports are adjusted by unit commitment and dispatch engine
- Subject to multi-hour ramping constraints developed from historical record
- Min and max values to further bound the range of values

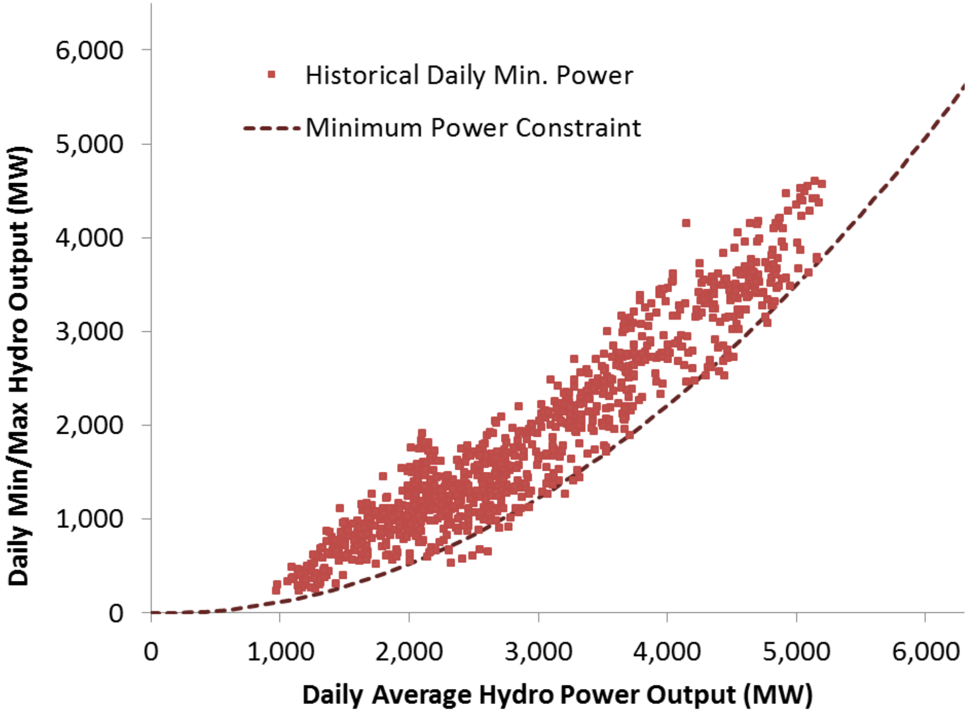




Hydro and import minimum and maximum capacity

+ **Max values hydro capacity based on NQC**
+ **Maximum imports based on SCIT tool**
+ **Min hydro is stochastic based on historical record**
+ **Min imports set at 0 MW due to uncertain export capability in 2022**

Daily hydro minimum capacity as a function of daily average hydro



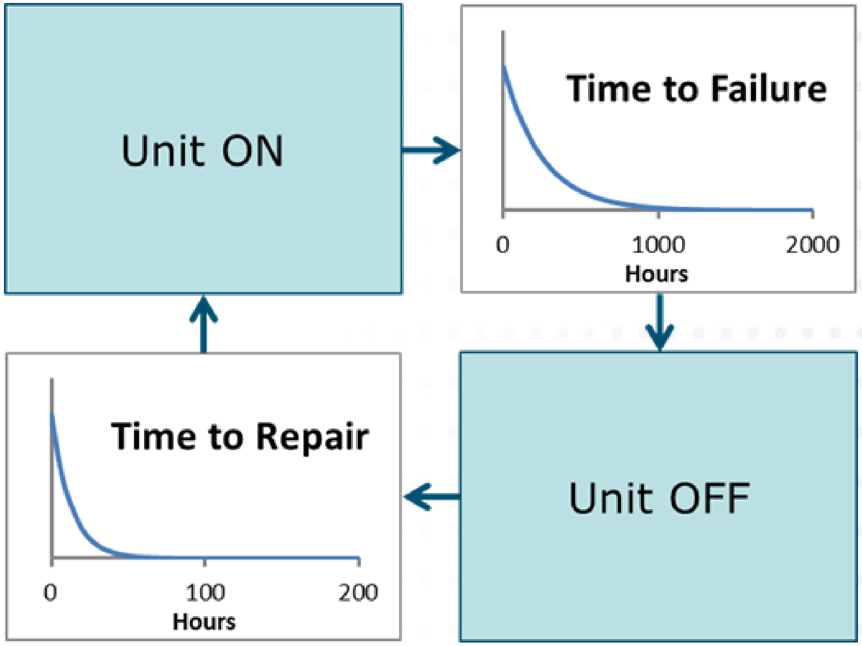
Incorporating Forecast Error

- **REFLEX makes unit commitment decisions at specified intervals**
  - Day-ahead, 4 hour-ahead, 1 hour-ahead
- **Load following demand curves account for both forecast error and net load variability**
  - Forecast error incorporated through choice on capacity (MW) axis
  - Sub-interval variability incorporated through choice on ramp rate (MW/min.) axis
- **If forecast error is reduced, the load following demand curve reduces the need for resources**

Forced outage and Maintenance

- Forced outages are modeled using mean time to failure and mean time to repair and assuming exponential distributions
- Maintenance is allocated after an initial model runs identify unconstrained months

Markov Chain
Forced Outage Model



Stochastic Input Data

Data Type	Stochastic	Time Slice	Source
Weather years	Variable & Uncertain	Daily 1950-2012	California Energy Commission
Loads	Variable & Uncertain	Hourly 1950-2012	Regression based on weather data, shapes trained based on 2004-2012
Wind Profiles	Variable & Uncertain	Hourly 2004-2006	NREL Western Wind Dataset
Solar PV Profiles	Variable & Uncertain	Hourly 1998-2009	NREL Solar Anywhere and SAM
Solar Thermal Profiles	Variable & Uncertain	Hourly 1998-2005	NREL Solar Anywhere and SAM
Hydro Energy	Variable	Monthly 1970-2011	EIA hydro production datasets
Hydro minimum capacity	Variable	Monthly 1970-2011	CAISO & EIA hydro production data