Energy+Environmental Economics

Capacity and Flexibility Needs under Higher Renewables

Portland General Electric IRP Public Meeting #3

August 13, 2015

Portland, Oregon

Arne Olson, Partner

Elaine Hart, Managing Consultant

Ana Mileva, Senior Consultant

E3's expertise has placed us at the nexus of planning, policy and markets

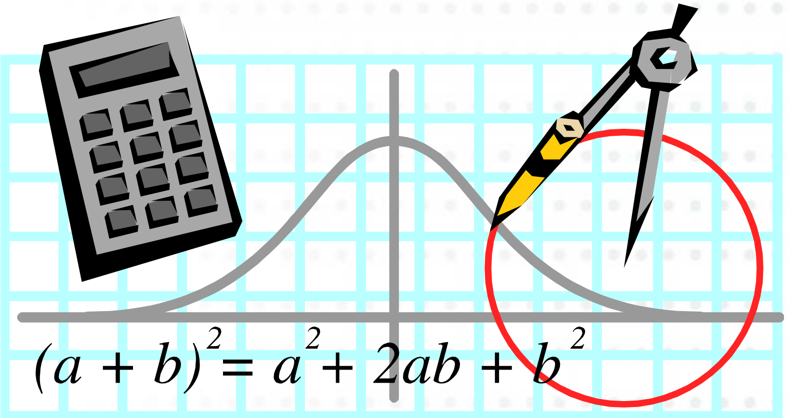
- San Francisco-based company with 40+ professionals
- Foremost North American consultancy in electricity sector economics, regulation, planning and technical analysis
- Consultant to many of the world's largest utilities and renewable developers
- Groundbreaking methods in capacity and flexibility assessment used by California agencies, CAISO, WECC, and many utilities and developers

Defining today's planning problem

- Introduction of variable renewables has shifted the planning paradigm
  - No longer sufficient to plan for adequate capacity
- Today's planning problem consists of two related questions:
  1. How many MW of <u>dispatchable</u> 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 makeup of the existing fleet of conventional and renewable resources?

Problem is stochastic in nature

- Load is variable and uncertain
  - Often characterized as “1-in-2” or “1-in-10”
  - Subject to forecast error



- Renewable output is variable and uncertain
- Conventional generation can also be stochastic
  - Hydro endowment varies from year to year
  - Generator forced outages are random
- Need robust stochastic modeling to better approximate the size, probability and duration of any shortfalls

E3 Approach

+ E3 has developed stochastic planning techniques to estimate capacity and flexibility needs under high renewables within a consistent analytical framework

  1. RECAP: Loss-of-Load Probability study completed first to ensure the system has sufficient "pure capacity" to meet a defined reliability standard. Also determines renewable resource capacity contribution.

  2. REFLEX: Stochastic production simulation study then estimates the value of flexible dispatch within a portfolio.

+ Analysis captures a wide distribution of system conditions through Monte Carlo draws of operating days from many years of load, wind, solar and hydro conditions

Energy+Environmental Economics

Planning Reserve Margin Investigation Using E3's Renewable Energy Capacity Planning Model

Arne Olson, Partner

PGE currently utilizes a 12% PRM

- In the past, PGE has used a 12% planning reserve margin (PRM) for establishing resource adequacy:

$$= \frac{(\quad)}{1 - \quad - 2 \quad (\quad)} - 1$$

  - Standard is based on a heuristic: 6% for operating reserves + 3% for more extreme weather + 3% for forced outages
    - This approach was adequate when most resources were dispatchable
  - PGE has a dual summer/winter peak, and in practice PGE uses two overlapping standards:
    - 12% PRM above summer peak, 12% PRM above winter peak
  - In the 2013 IRP, PGE signaled its intent to review its PRM in the 2016 IRP cycle

Current method needs updating

- December reliable capacity method may no longer be appropriate given fast-growing summer peak
- Current method does not lend itself well to developing a rigorous measure of the capacity contribution of dispatch-limited resources such as wind and solar
  - Current method is a deterministic analysis that focuses only on a single hour: the highest load hour of the year
  - Wind and solar output is stochastic: high sometimes, low at other times
  - These factors will be increasingly important as the renewable portfolio grows!

E3 investigated experience & methods in other jurisdictions

- E3 investigated reliability criteria, planning reserve margins, and PRM accounting methodologies for several utilities
  - Other utilities in the West and similarly-sized utilities throughout the country
- High-level findings:
  - No industry-standard method of determining acceptable reliability or PRM
  - No NERC or WECC requirements or standards
  - PRM accounting methodologies vary by utility
  - Planning Reserve Margins range from 12-20%

Planning criteria used by other utilities

	Peak Demand in 2021 (MW)	Planning Criterion	PRM	Peak Season
Puget Sound Energy	7,000 MW	LOLP: 5%*	16% (2023 - 2024)	Winter
Avista	Summer: 1,700 MW; Winter: 1,900 MW	LOLP: 5%*	22% (14% + operating reserves)	Both
PacifiCorp	10,876 MW	LOLE: 2.4 hrs/ year	13%	Summer
Arizona Public Service	9,071 MW	One Event in 10 Years	15%	Summer
Tuscon Electric Power	2,696 MW	PRM	15%	Summer
Public Service Co. of New Mexico	2,100 MW	LOLE: 2.4 hrs/ year	Greater of 13% or 250 MW	Summer
El Paso Electric	2,000 MW	PRM	15%	Summer
Cleco	3,000 MW	LOLE = 1-day-in-10 yrs.	14.8%	Summer
Kansas City Power & Light	483 MW	Share of SPP**	12%**	Summer
Oklahoma Gas & Electric	5,500 MW	Share of SPP**	12%**	Summer
South Carolina Electric & Gas	5,400 MW	24 to 2.4 days/10 yrs	14-20%	Both
Tampa Electric	4,200 MW	PRM	20%	Both
Interstate Power & Light	3,300 MW	PRM	7.3%	Summer
Florida Power and Light	24,000 MW	PRM	20%	Both
California ISO	52,000 MW	LOLE: 0.6 hours/year	15-17%	Summer

* PSE and Avista use NWPCC criterion of 5% probability of shortfall occurring any time in a given year

** SPP uses 1-day-in-10 years or 12% PRM system-wide

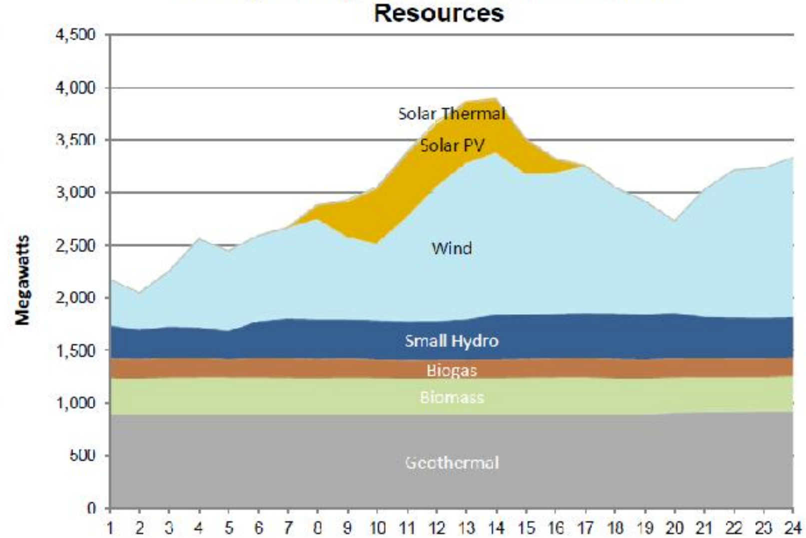
Energy+Environmental Economics

RECAP METHODOLOGY

E3's Renewable Energy Capacity Planning Model (RECAP)

- E3 has developed an open-source model for evaluating power system reliability and resource capacity value within high penetration renewable scenarios
- Based on extensive reliability modeling literature
- Used by a number of utilities and state agencies including CAISO, CPUC, CEC, SMUD, WECC, HECO, others

Hourly Average Breakdown of Renewable Resources

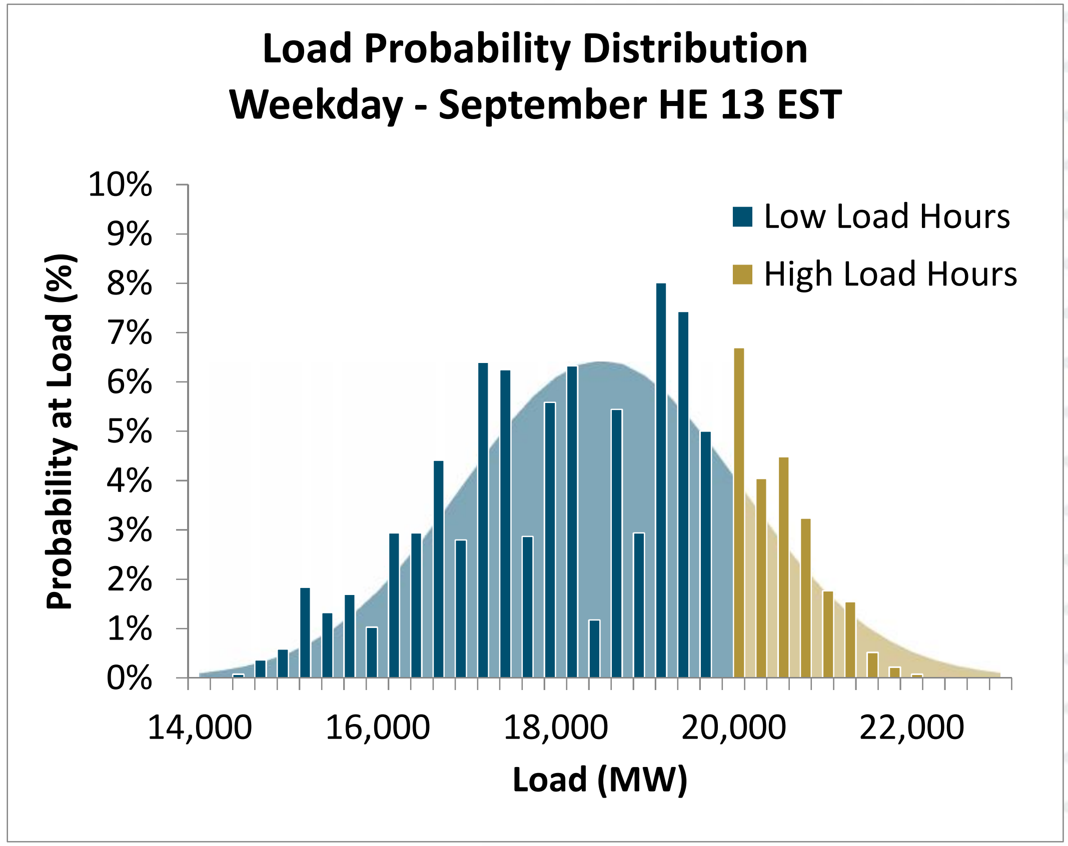


RECAP Model overview

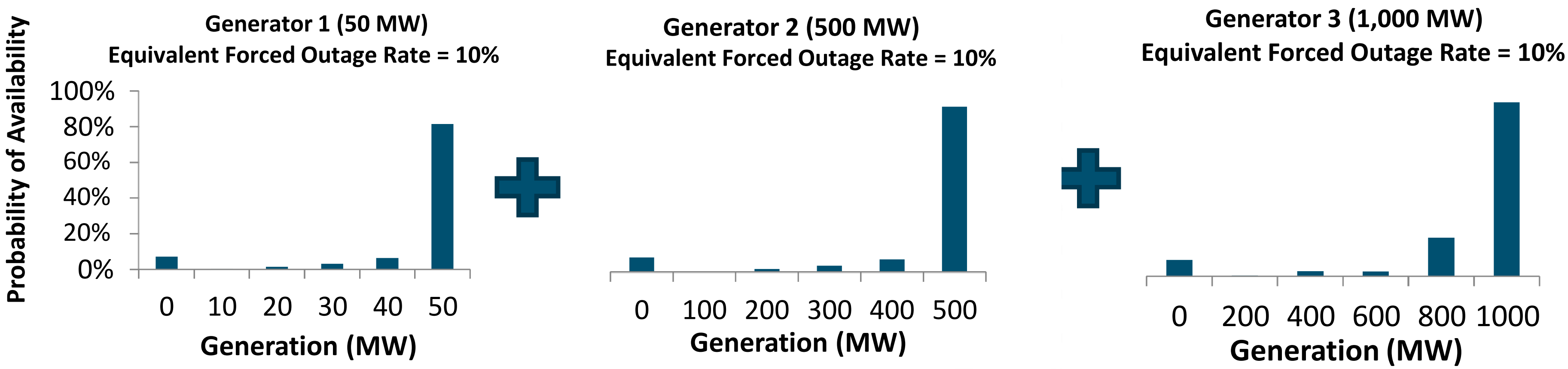
- RECAP Model assesses reliability performance of a power system using the following metrics:
  - Loss of Load Probability (LOLP): probability of capacity shortfall in a given hour
  - Loss of Load Expectation (LOLE): expected hours of capacity shortfall in a given year
  - Expected Unserved Energy (EUE): expected load not met due to capacity shortfall during a given year
- Four-step LOLE calculation:
  - Step 1: calculate hourly net load distributions
  - Step 2: calculate outage probability table for dispatchable capacity
  - Step 3: calculate probability that supply < net load in each time period
  - Step 4: sum across all hours of simulated years

Step 1: Create load distributions

- Create probability distribution of hourly load for each month / hour / weekday-weekend combination (12x24x2=576 total distributions)
- Source data: simulated load shapes for 33 weather years based on 2007-2012 loads
- Load shapes scaled to match monthly and seasonal 1-in-2 peak and energy forecasts provided by PGE

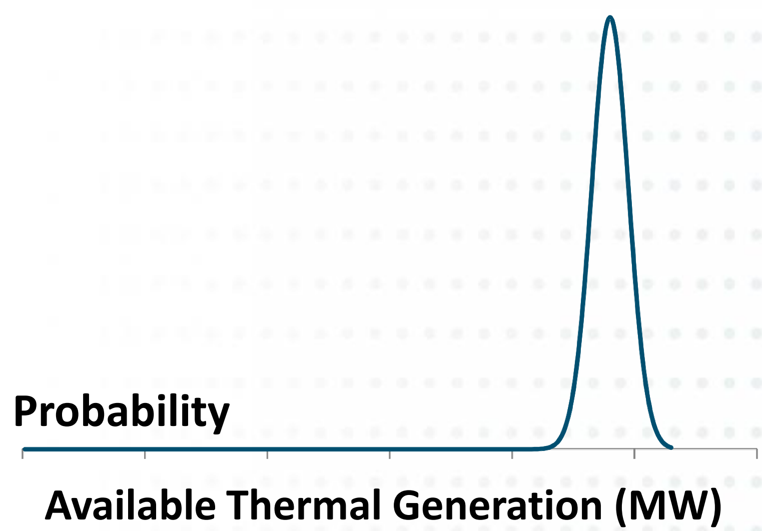


Step 2: Calculate available dispatchable generation



All other generators

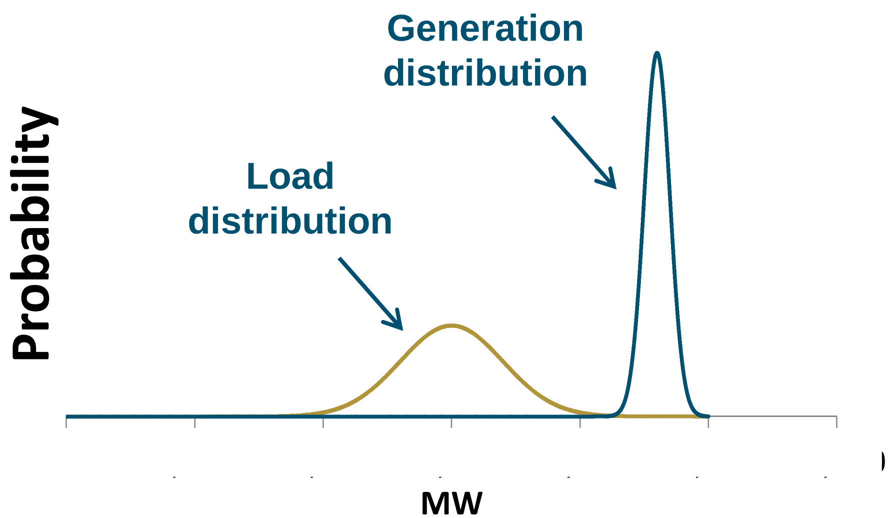
for each month / hour / day-type

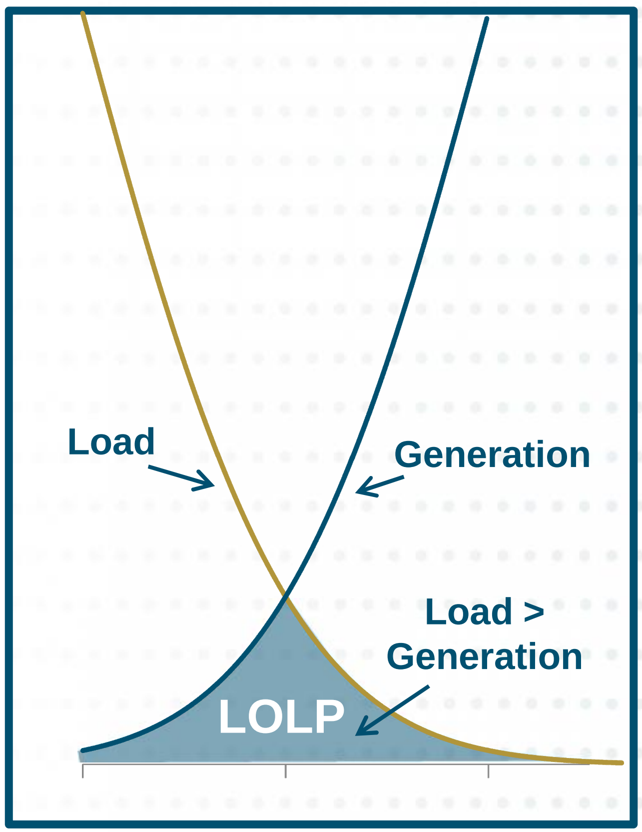


Step 3: Calculate LOLP

- Combination of load and resource distributions determines Loss-of-Load Probability for a given hour

- Load is most likely to exceed generation during hours with high load, high generator outages, or both





Step 4: Sum across all simulated years to get LOLE

- LOLP is the probability of lost load in a given hour. LOLE is the annualized sum of LOLP across all hours (h) and simulated years (n)

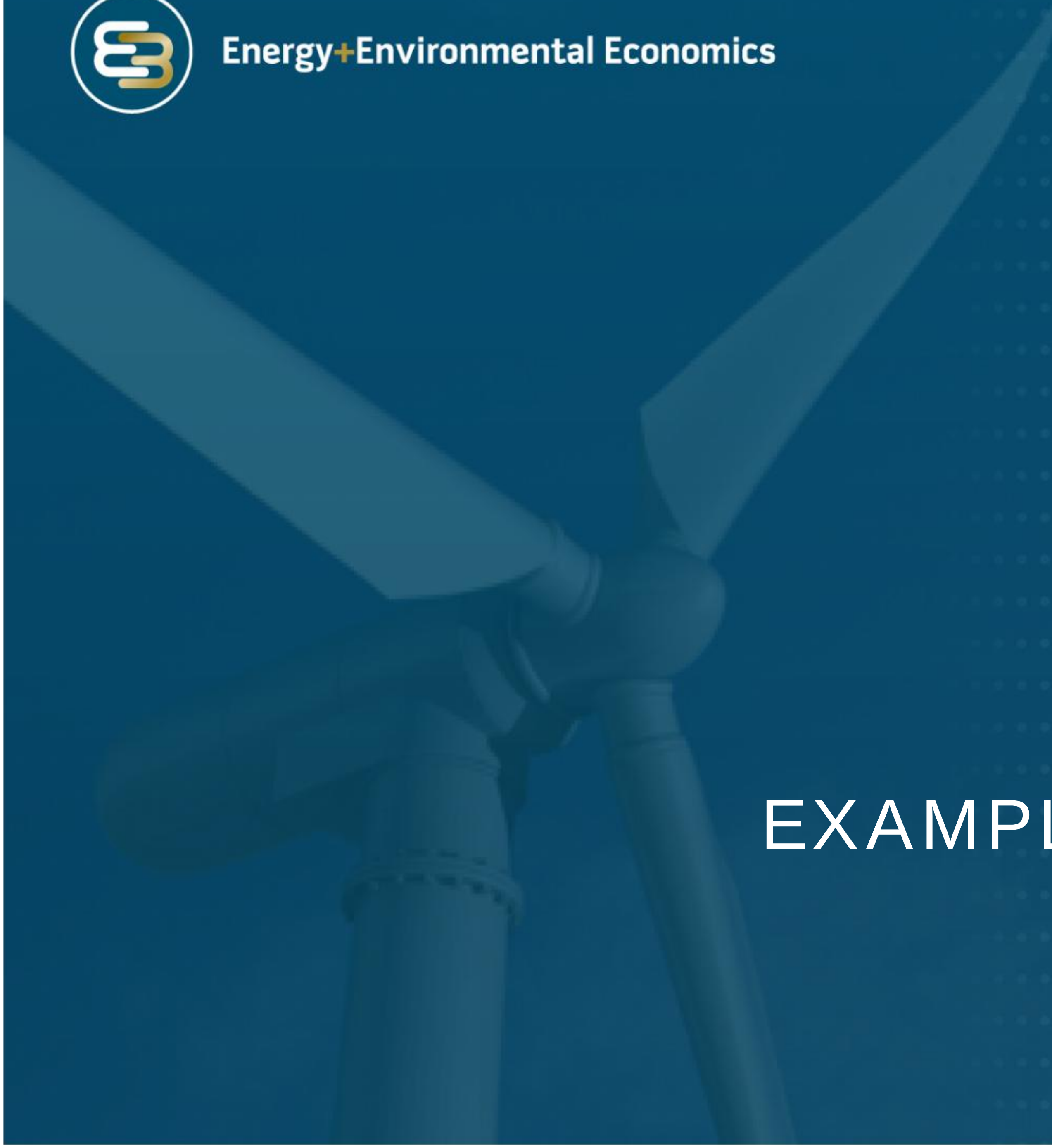
$$= \left(\quad \right)$$

- PGE has selected a LOLE standard of 24 hours in 10 years, or 2.4 hours/year
- PGE defines “loss of load” during a given hour as having available resources less than load plus 6% operating reserves
  - Regional emergency response may prevent actual load shedding even in the event of a shortfall

LOLE converted into Target PRM for planning and procurement

- LOLE is an accurate estimate of a system's reliability, however it can be cumbersome to use directly in planning and procurement
  - It is more convenient to convert result into a Target PRM to translate LOLE (hrs./yr.) into need (MW)
  - Target PRM defined as % increase above expected 1-in-2 peak load
- PRM should be interpreted as calculating the need for effective MW of capacity
  - PRM is not meant to be interpreted literally as MW available during single peak hour
  - PRM is a simplification of LOLE that can occur in any hour

Energy+Environmental Economics



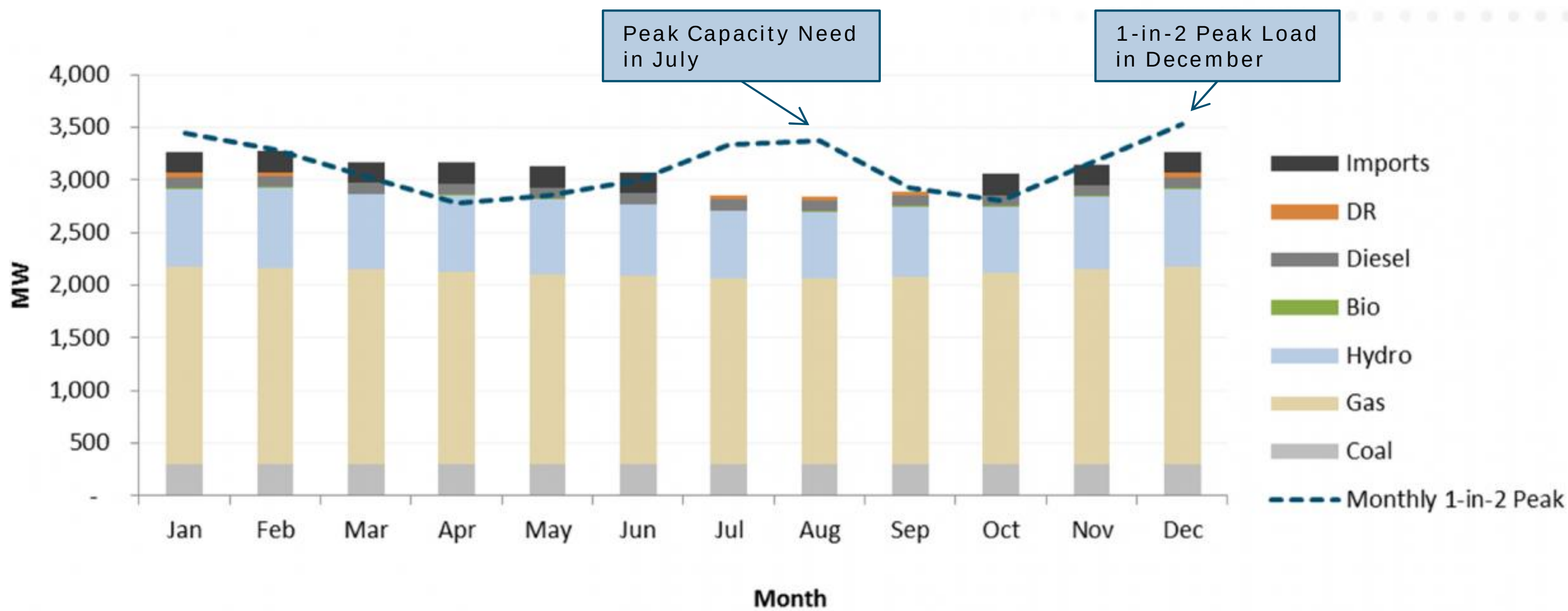
EXAMPLE RESULTS

Key inputs and assumptions for PGE system

- Thermal resources
  - Reliable capacities for each month, forced outage rates
- Hydro resources
  - Monthly dependable capacities for PGE units
  - Historical distribution of water availability for Mid-C contracts
- Renewables
  - 2004-2006 simulated production profiles for each wind site
  - 2006 simulated production profiles for distributed and utility clustered solar PV
- Market purchases
  - Up to 200 MW of imports are available to provide dependable capacity in non-summer months

PGE has higher capacity gap in summer than winter

- Load is higher in winter, with secondary peak in July / August
- Available resources lower in summer due to thermal de-rates, lower hydro output, and unavailability of imports



LOLP on PGE system is highest on summer afternoon, winter evening

- Chart shows hours of LOLP by month/hour timeslice
- Sum of time slices is test year LOLE: 334 hours per year before adding resources

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Preliminary PRM is 15.1% for 2021 test year

- A 1-annual-event-in-10-years standard (LOLE=2.4) implies an annual capacity shortage of 932 MW in 2021
- Equivalent to a 15.1% PRM
  - PRM calculations use average of summer and winter reliable capacity for thermal and hydro resources
  - Annual ELCC used for wind and solar

Unit	MW
Natural Gas	1,821
Colstrip	296
Hydro Projects	575
Mid-C Hydro Agreements	123
Other Contracts	9
DSM	142
Renewables	98
Imports	61
Total Available Dependable Capacity	**3,125**
1-in-2 Peak Load	3,525
Planning Reserve Margin	533
Total Dependable Capacity Needed	**4,058**
Dependable Capacity Shortage	**932**
PRM (%)	**15.1%**

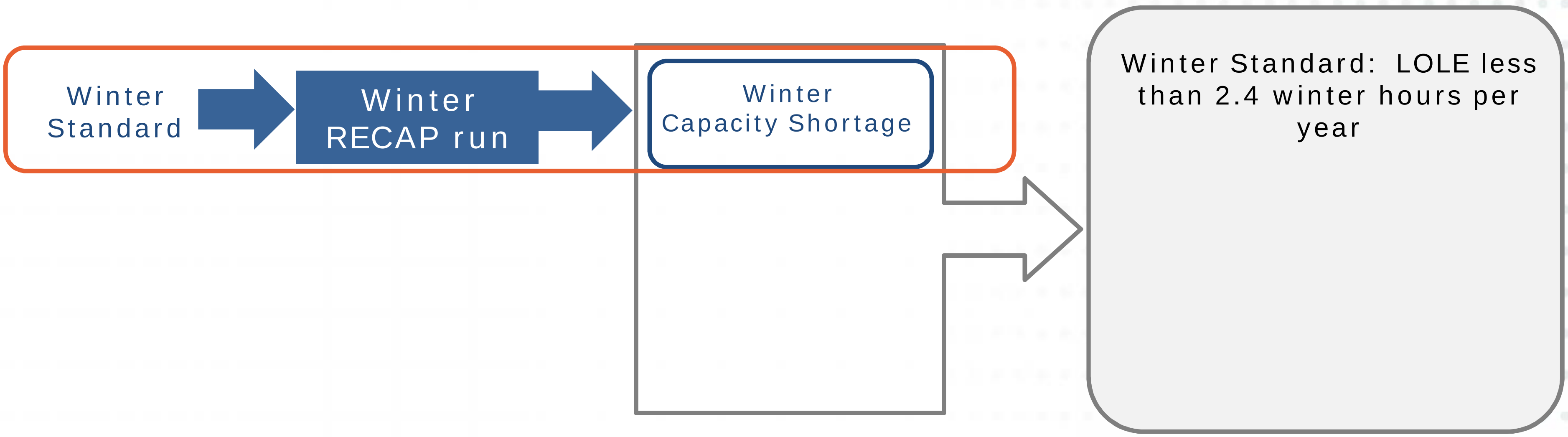
Preliminary results – do not cite

Seasonal LOLE

- PGE system is dual peaking, with non-zero LOLP in both summer and winter seasons
- E3 and PGE have developed a three-part test that ensures PGE system is resource adequate in both seasons while meeting annual LOLE target of 2.4 hours per/yr.
- PGE's system is defined to be resource adequate if it meets the following three loss-of-load standards:
  1. No more than one winter event in 10 years (2.4 winter hours);
  2. No more than one summer event in 10 years (2.4 summer hours); AND
  3. No more than one event in 10 years (2.4 anytime hours)

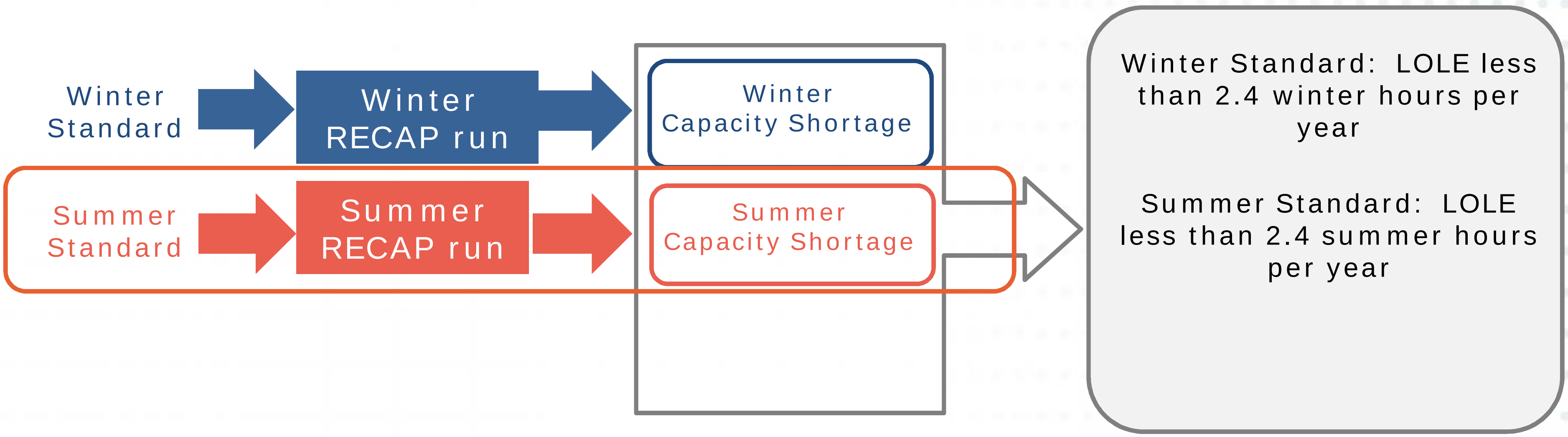
Independent seasonal and annual resource adequacy tests

- Winter need calculated using winter-only RECAP run
- Winter test intended to ensure no more than one winter loss-of-load event in 10 years



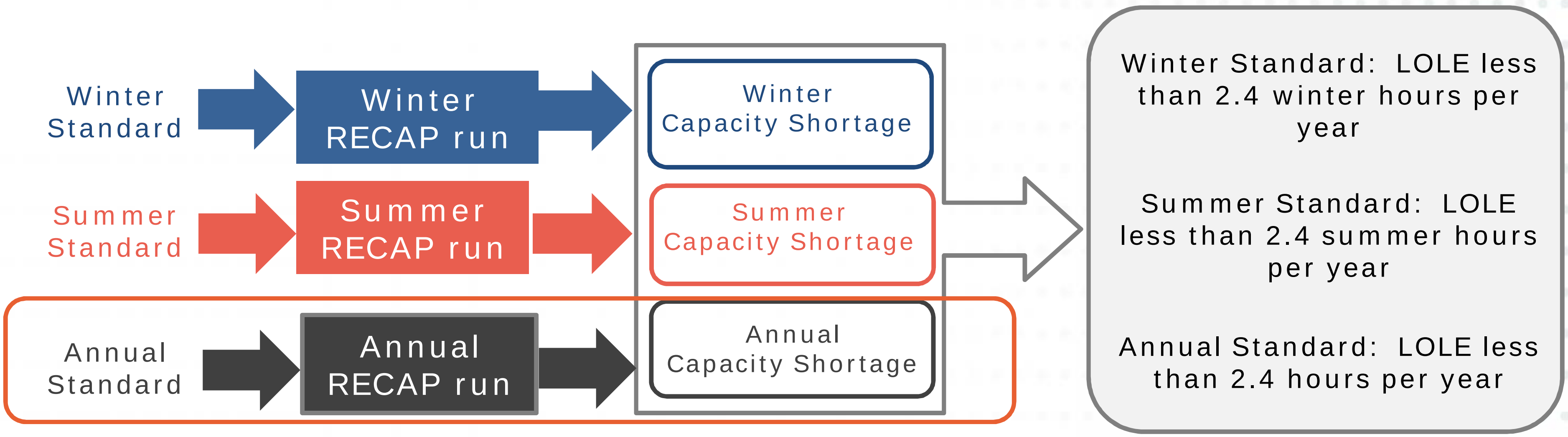
Independent seasonal and annual resource adequacy tests

+ Summer need calculated independently using summer-only RECAP run
+ Summer test intended to ensure no more than one summer loss-of-load event in 10 years



Independent seasonal and annual resource adequacy tests

- Annual need calculated independently using year-round RECAP run
- Annual test intended to ensure no more than one loss-of-load event in 10 years (any time of year)



Calculating Annual and Seasonal Planning Reserve Margins

- Annual, winter and summer capacity requirements can be translated into annual, winter and summer PRMs

- Definitions:
  - Winter PRM: Winter reliable MW divided by 1-in-2 winter peak load
  - Summer PRM: Summer reliable MW divided by 1-in-2 summer peak load
  - Annual PRM: Average of winter and summer reliable MW divided by 1-in-2 annual peak load

Preliminary Target PRM is 14.3% for Winter Test

- A 1-winter-event-in-10-years standard implies a winter capacity shortage of 630 MW in 2021
- Equivalent to a 14.3% PRM
- Winter standard is less conservative than annual standard

Unit	MW
Natural Gas	1,870
Colstrip	296
Hydro Projects	624
Mid-C Hydro Agreements	127
Other Contracts	9
DSM	142
Renewables	130
Imports	200
Total Available Dependable Capacity	**3,399**
1-in-2 Peak Load	3,525
Planning Reserve Margin	504
Total Dependable Capacity Needed	**4,029**
Dependable Capacity Shortage	**630**
PRM (%)	**14.3%**

Preliminary results – do not cite

Preliminary Target PRM is 14.6% for Summer Test

- A 1-summer-event-in-10-years standard implies a summer capacity shortage of 915 MW in 2021
- Equivalent to a 14.6% PRM
- Summer standard is less conservative than annual standard
- Thermal reliable capacity lower in summer

Unit	MW
Natural Gas	1,772
Colstrip	296
Hydro Projects	525
Mid-C Hydro Agreements	119
Other Contracts	9
DSM	142
Renewables	92
Imports	0
Total Available Dependable Capacity	**2,955**
1-in-2 Peak Load	3,376
Planning Reserve Margin	493
Total Dependable Capacity Needed	**3,869**
Dependable Capacity Shortage	**915**
PRM (%)	**14.6%**

Preliminary results – do not cite

Preliminary Target PRM is 15.1% for Annual Test

- A 1-annual-event-in-10-years standard (LOLE=2.4) implies an annual capacity shortage of 932 MW in 2021
- Equivalent to a 15.1% PRM
- More conservative than winter + summer
  - Winter + summer could result in 2 events in 10 yrs.

Unit	MW
Natural Gas	1,821
Colstrip	296
Hydro Projects	575
Mid-C Hydro Agreements	123
Other Contracts	9
DSM	142
Renewables	98
Imports	61
Total Available Dependable Capacity	**3,125**
1-in-2 Peak Load	3,525
Planning Reserve Margin	533
Total Dependable Capacity Needed	**4,058**
Dependable Capacity Shortage	**932**
PRM (%)	**15.1%**

Preliminary results – do not cite

Summary

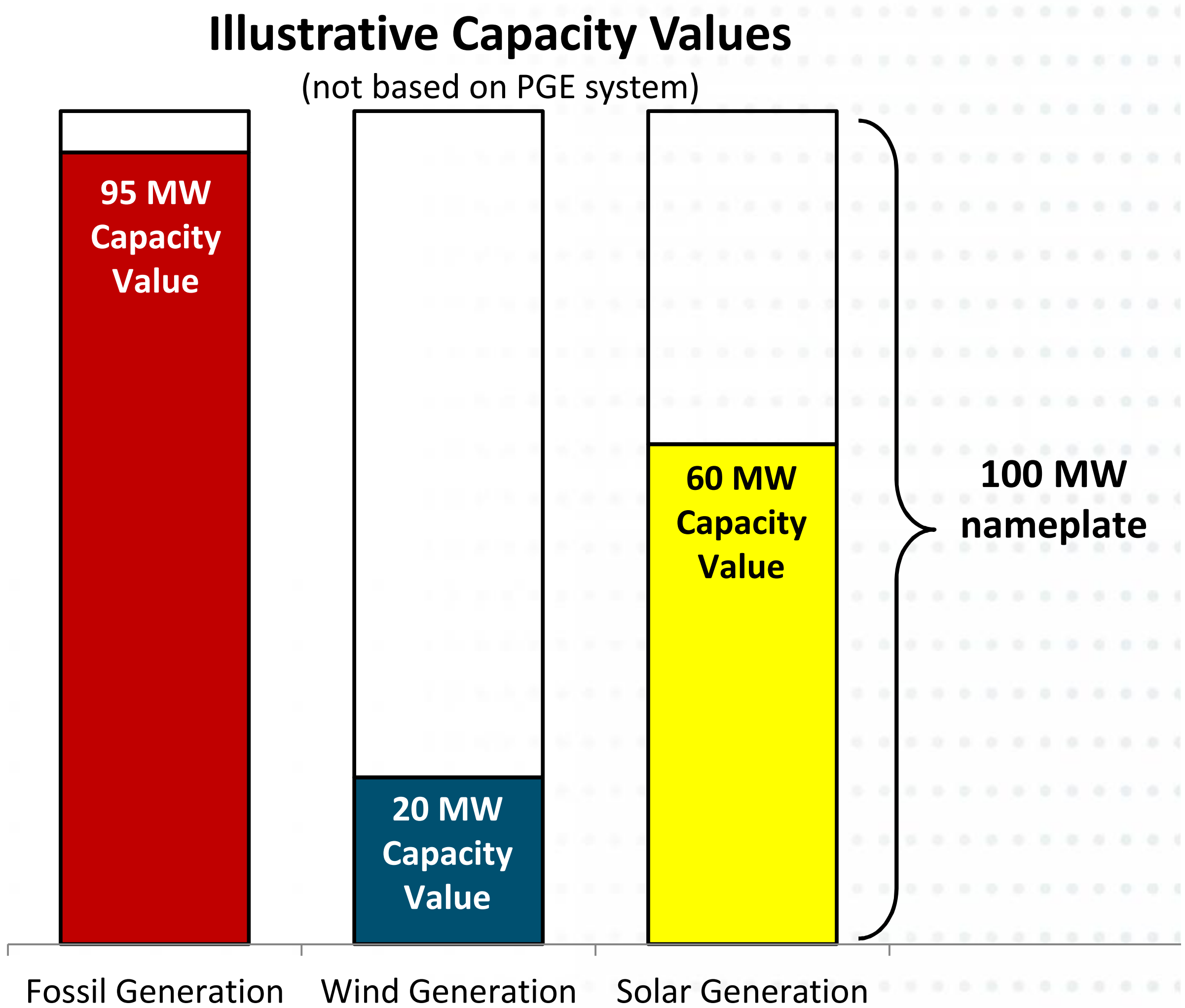
- PGE has selected a resource adequacy standard of 1-day-in-10 years
  - This is interpreted as 2.4 hours/year within the context of E3's RECAP model
- E3 and PGE have developed independent winter, summer, and annual capacity requirements based on 1-day-in-10 years
  1. No more than 2.4 winter hours of LOLE per year;
  2. No more than 2.4 summer hours of LOLE per year; AND
  3. No more than 2.4 hours of LOLE per year.
- These requirements are translated into annual, summer and winter PRMs

Energy+Environmental Economics

CAPACITY CONTRIBUTION OF DISPATCH-LIMITED RESOURCES

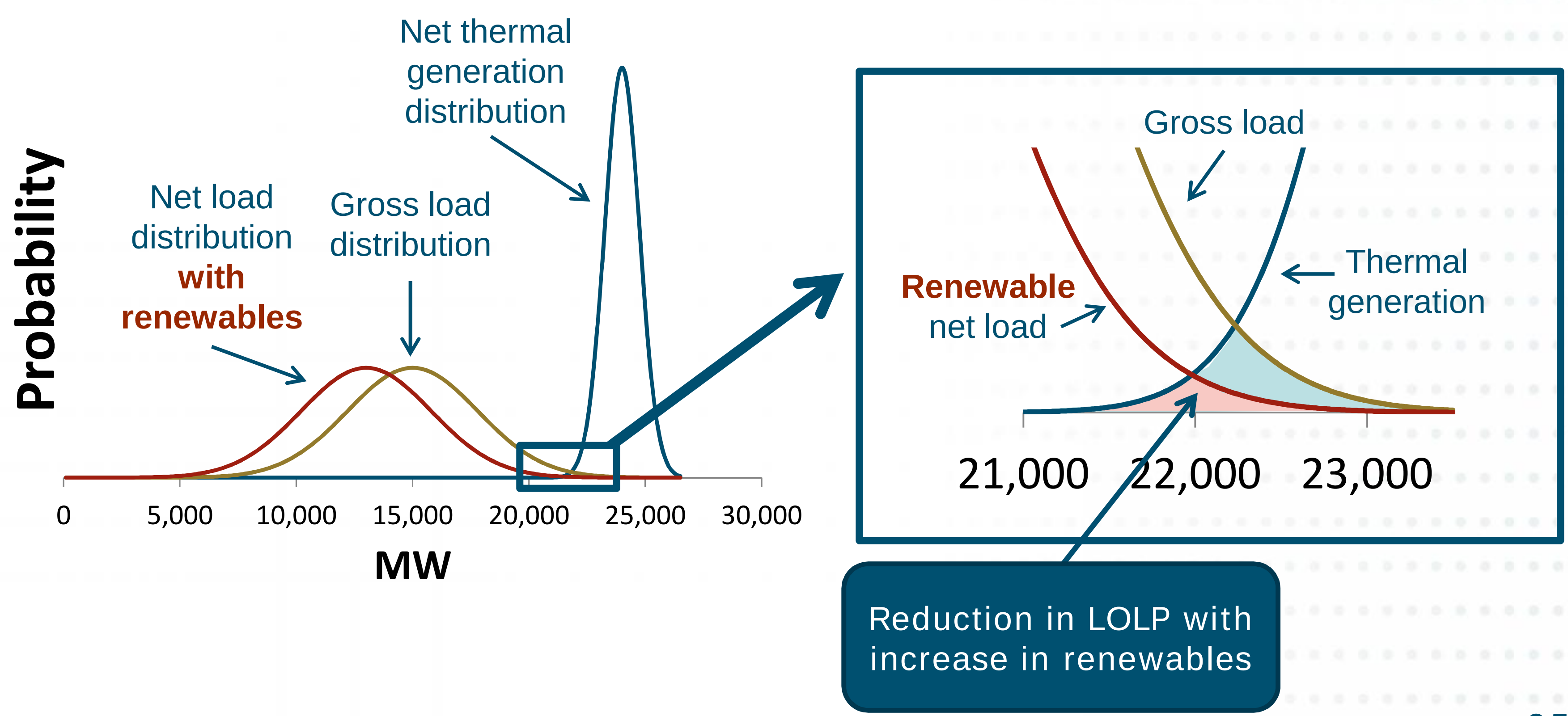
Renewable resources can contribute to system reliability

- No resource is perfectly available to help reduce LOLP
- By convention, dispatchable resources rated at nameplate and forced outages factored into PRM
- Non-dispatchable resources assigned "effective capacity" rating



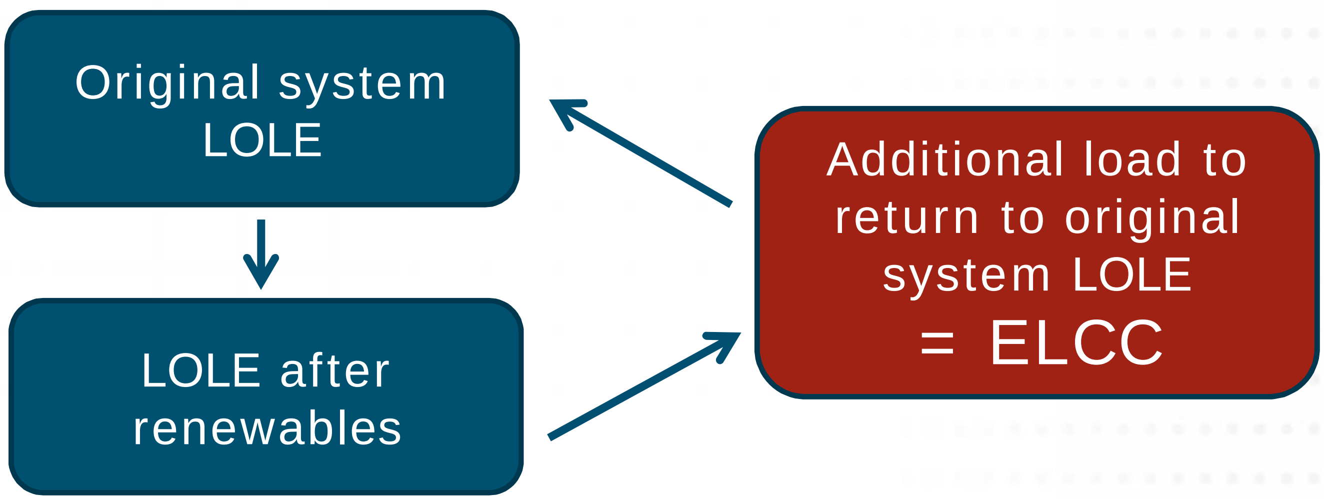
Renewables subtracted from load in LOLP calculations

- Renewable production is subtracted from gross load to yield "net load", which is always lower
- LOLP decreases in every hour



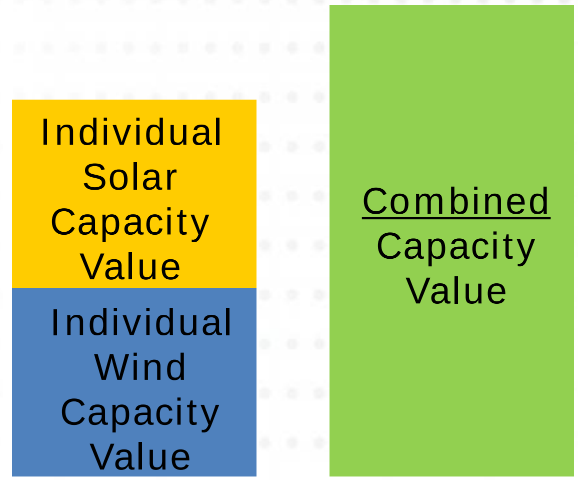
Calculating ELCC

- Since LOLE has decreased with the addition of renewables, adding pure load will return the system to the original LOLE
- The amount of load that can be added to the system is the Effective Load-Carrying Capability (ELCC)



Capacity value in applications

- The portfolio capacity value is the most relevant calculation to consider in resource planning
  - Due to the complementarity of different resources the portfolio value will be higher than the sum of each individual resource measured alone



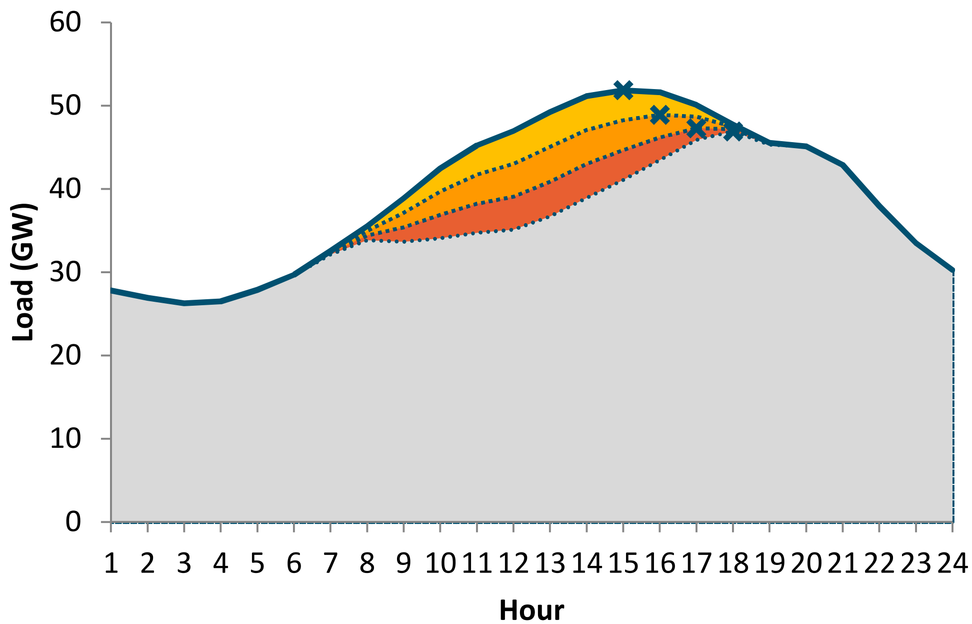
  - It is sometimes necessary to attribute the capacity value of the portfolio to individual resources
    - There are many options, but no standard or rigorous way to do this
- The marginal capacity value, given the existing portfolio, is more appropriate for use in procurement
  - This value will change over time as the portfolio changes

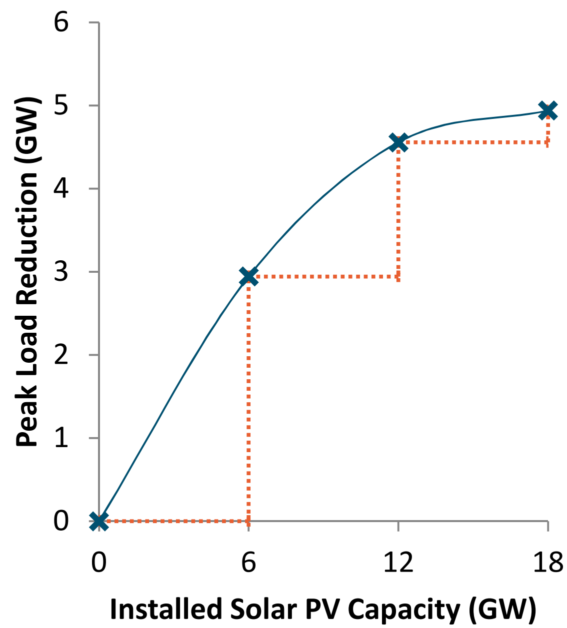
Factors that affect the capacity value of variable generation

- **Coincidence with load**
  - Locations with better resources and better correlation with high load periods will have higher ELCC values
- **Coincidence with existing variable generation**
  - Common resource types show diminishing marginal returns; each additional plant has less value than the previous one
- **Production variability**
  - Statistically, the possibility of low production during a peak load event reduces the value of a resource
- **Location**
  - T&D losses are affected by resource size and location

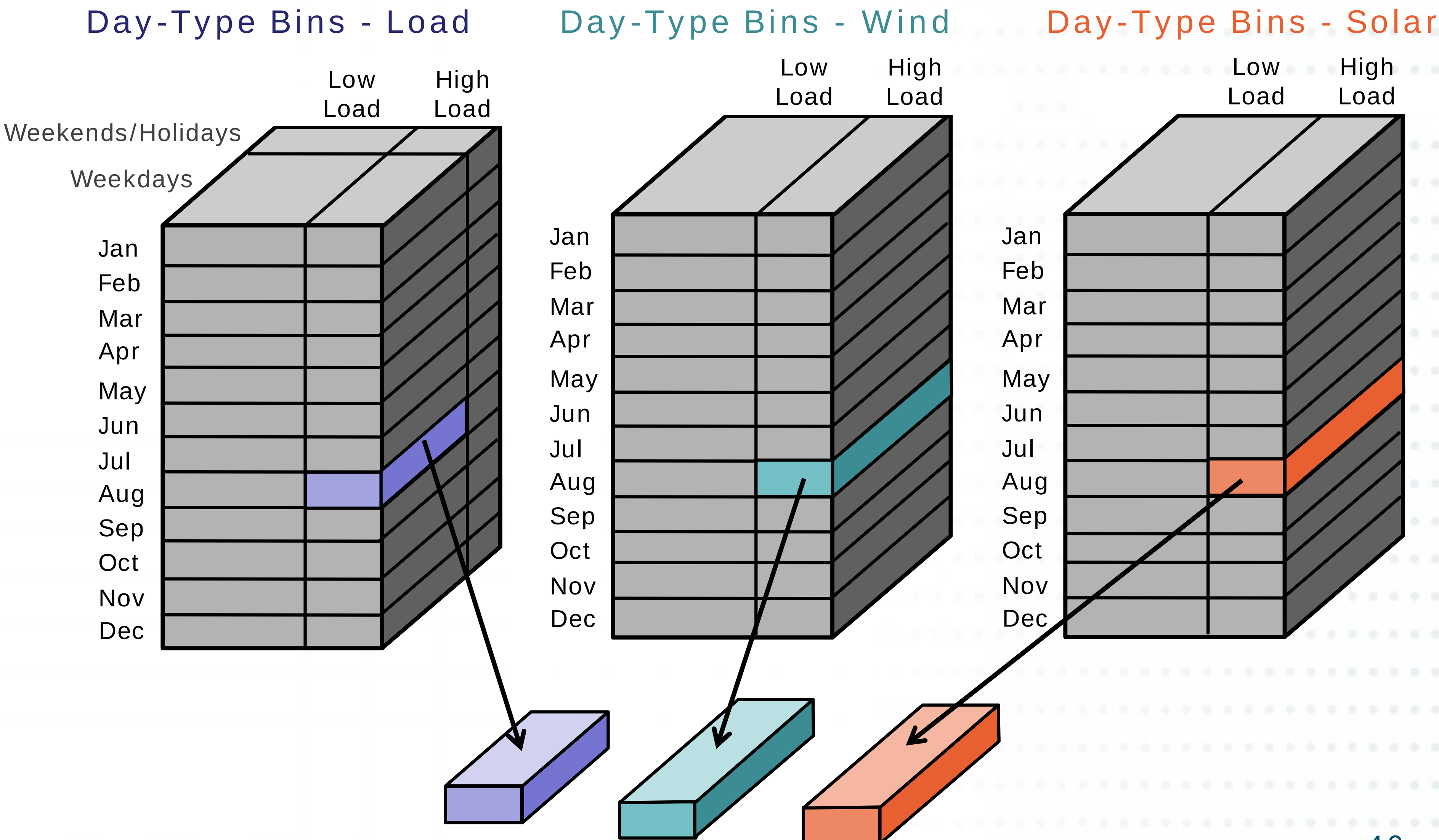
Marginal capacity value declines as penetration increases

+ A resource's contribution towards reliability depends on the other resources on the system
+ The diminishing marginal peak load impact of solar PV is illustrative of this concept
  - While the first increment of solar PV has a relatively large impact on peak, it also shifts the "net peak" to a later hour in the in day
  - This shift reduces the coincidence of the solar profile and the net peak such that additional solar resources have a smaller impact on the net peak



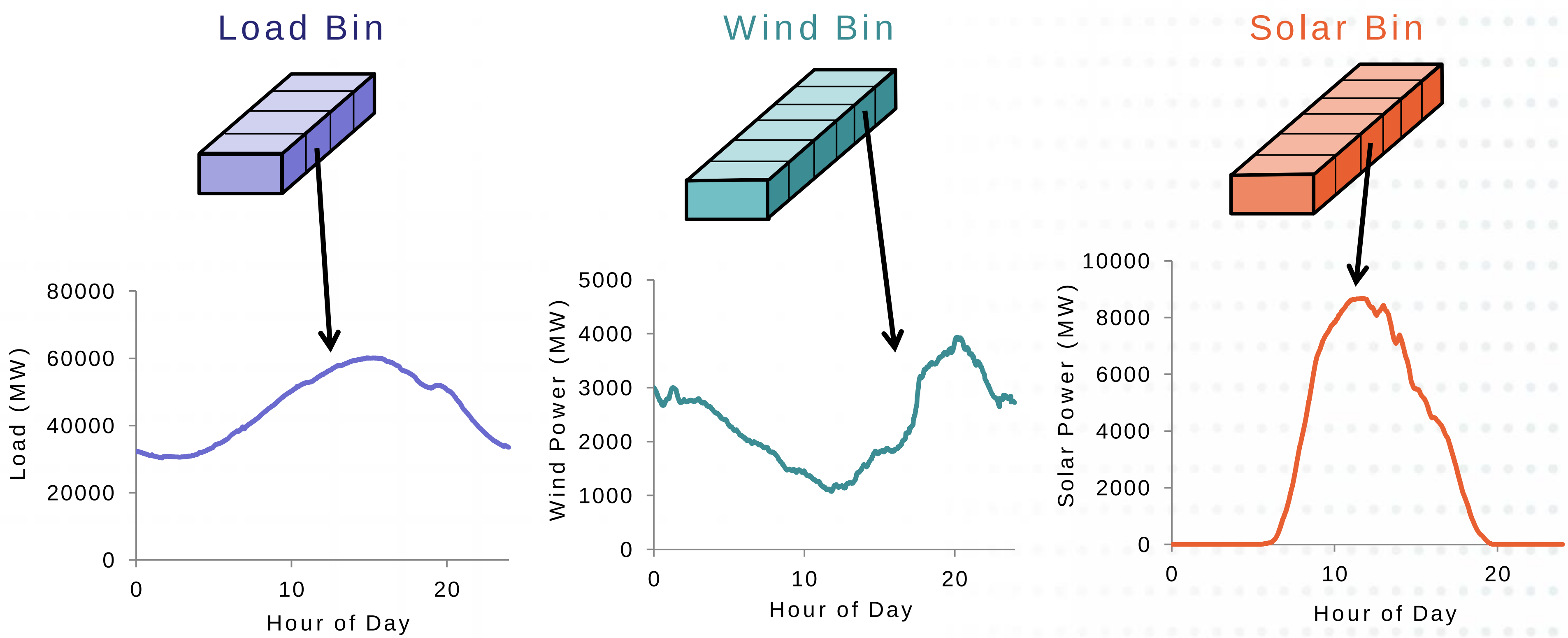


Example Draw: High Load Weekday in August



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



Gorge wind has low output during hours with high LOLP

- Coincidence of high renewable output and high system LOLE results in a higher ELCC
  - System LOLE is concentrated in summer afternoon hours
  - Sample Gorge wind site has relative low output on summer afternoons, resulting in low ELCC

System LOLE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Average Normalized Wind Output Sample Wind Site 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.691	0.482	0.499	0.378	0.293	0.258	0.186	0.230	0.285	0.401	0.591	0.58
2	0.701	0.481	0.508	0.386	0.302	0.283	0.163	0.229	0.283	0.399	0.579	0.57
3	0.699	0.469	0.512	0.410	0.297	0.281	0.136	0.217	0.290	0.387	0.574	0.59
4	0.683	0.452	0.499	0.423	0.294	0.264	0.125	0.215	0.292	0.393	0.559	0.58
5	0.686	0.434	0.498	0.421	0.302	0.270	0.124	0.208	0.291	0.421	0.534	0.58
6	0.675	0.415	0.513	0.404	0.291	0.280	0.121	0.197	0.272	0.418	0.523	0.59
7	0.672	0.418	0.519	0.400	0.288	0.295	0.112	0.194	0.265	0.420	0.529	0.59
8	0.670	0.437	0.517	0.395	0.288	0.289	0.093	0.189	0.263	0.402	0.540	0.59
9	0.667	0.459	0.529	0.390	0.270	0.254	0.083	0.171	0.256	0.398	0.544	0.58
10	0.657	0.460	0.532	0.354	0.247	0.225	0.075	0.151	0.230	0.403	0.556	0.56
11	0.643	0.435	0.510	0.324	0.227	0.211	0.063	0.121	0.212	0.374	0.553	0.55
12	0.636	0.403	0.460	0.310	0.209	0.194	0.065	0.119	0.203	0.336	0.536	0.54
13	0.628	0.372	0.437	0.296	0.219	0.190	0.074	0.119	0.197	0.294	0.509	0.51
14	0.610	0.356	0.428	0.293	0.224	0.203	0.089	0.127	0.192	0.287	0.489	0.48
15	0.601	0.346	0.428	0.291	0.219	0.215	0.108	0.136	0.189	0.286	0.471	0.48
16	0.598	0.335	0.420	0.281	0.225	0.226	0.124	0.150	0.194	0.287	0.464	0.47
17	0.613	0.339	0.414	0.283	0.231	0.240	0.148	0.172	0.199	0.289	0.474	0.47
18	0.631	0.350	0.423	0.298	0.262	0.259	0.171	0.180	0.221	0.285	0.503	0.50
19	0.646	0.358	0.405	0.296	0.280	0.252	0.170	0.197	0.236	0.297	0.533	0.53
20	0.650	0.393	0.398	0.279	0.277	0.249	0.177	0.222	0.232	0.324	0.545	0.56
21	0.661	0.426	0.426	0.287	0.264	0.236	0.183	0.208	0.246	0.353	0.575	0.57
22	0.660	0.443	0.451	0.284	0.243	0.217	0.192	0.211	0.269	0.371	0.592	0.58
23	0.670	0.447	0.491	0.296	0.249	0.226	0.197	0.217	0.283	0.378	0.586	0.58
24	0.674	0.464	0.509	0.341	0.271	0.236	0.186	0.225	0.281	0.388	0.598	0.59

Montana wind output is higher during hours with high LOLP

Coincidence of high renewable output and high system LOLE results in a higher ELCC

- System LOLE is concentrated in summer afternoon hours
- Sample Montana wind site has higher relative output on summer afternoons, resulting in higher ELCC

System LOLE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Average Normalized Wind Output
Sample Wind Site 2

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.755	0.563	0.577	0.454	0.406	0.444	0.313	0.300	0.429	0.456	0.657	0.760
2	0.769	0.573	0.586	0.421	0.390	0.446	0.315	0.296	0.415	0.482	0.657	0.770
3	0.761	0.589	0.580	0.408	0.360	0.413	0.301	0.282	0.420	0.490	0.661	0.774
4	0.755	0.597	0.570	0.423	0.342	0.390	0.277	0.258	0.421	0.487	0.664	0.768
5	0.767	0.598	0.563	0.426	0.348	0.359	0.269	0.255	0.412	0.501	0.660	0.750
6	0.769	0.595	0.534	0.434	0.363	0.333	0.243	0.289	0.436	0.493	0.649	0.752
7	0.771	0.595	0.527	0.430	0.368	0.310	0.248	0.291	0.438	0.482	0.646	0.773
8	0.774	0.593	0.524	0.420	0.369	0.286	0.235	0.263	0.434	0.496	0.647	0.789
9	0.773	0.603	0.524	0.371	0.364	0.297	0.203	0.243	0.407	0.505	0.656	0.800
10	0.787	0.612	0.515	0.355	0.372	0.308	0.213	0.247	0.362	0.500	0.669	0.810
11	0.785	0.609	0.510	0.373	0.390	0.345	0.260	0.281	0.382	0.480	0.664	0.804
12	0.762	0.617	0.559	0.405	0.414	0.382	0.309	0.325	0.427	0.498	0.666	0.787
13	0.748	0.633	0.585	0.450	0.439	0.415	0.340	0.346	0.461	0.531	0.668	0.767
14	0.755	0.639	0.598	0.476	0.468	0.456	0.381	0.362	0.485	0.552	0.661	0.768
15	0.753	0.640	0.600	0.474	0.465	0.487	0.392	0.369	0.504	0.559	0.671	0.759
16	0.729	0.642	0.599	0.474	0.482	0.506	0.419	0.385	0.506	0.550	0.683	0.748
17	0.719	0.648	0.585	0.457	0.492	0.506	0.403	0.376	0.483	0.531	0.683	0.735
18	0.715	0.652	0.588	0.456	0.498	0.502	0.363	0.356	0.445	0.523	0.677	0.745
19	0.730	0.640	0.583	0.430	0.493	0.482	0.342	0.313	0.437	0.508	0.677	0.745
20	0.733	0.653	0.582	0.424	0.443	0.486	0.304	0.345	0.430	0.504	0.676	0.733
21	0.750	0.633	0.595	0.448	0.422	0.457	0.285	0.354	0.439	0.510	0.673	0.732
22	0.748	0.613	0.587	0.461	0.409	0.426	0.296	0.304	0.456	0.494	0.666	0.740
23	0.745	0.594	0.560	0.445	0.407	0.419	0.316	0.312	0.467	0.464	0.661	0.729
24	0.760	0.567	0.555	0.427	0.408	0.426	0.305	0.318	0.447	0.445	0.665	0.733

Solar output is high during summer peak hours

- Coincidence of high renewable output and high system LOLE results in a higher ELCC
  - System LOLE is concentrated in summer afternoon hours
  - Solar PV has high output on summer afternoons, resulting in high ELCC

System LOLE

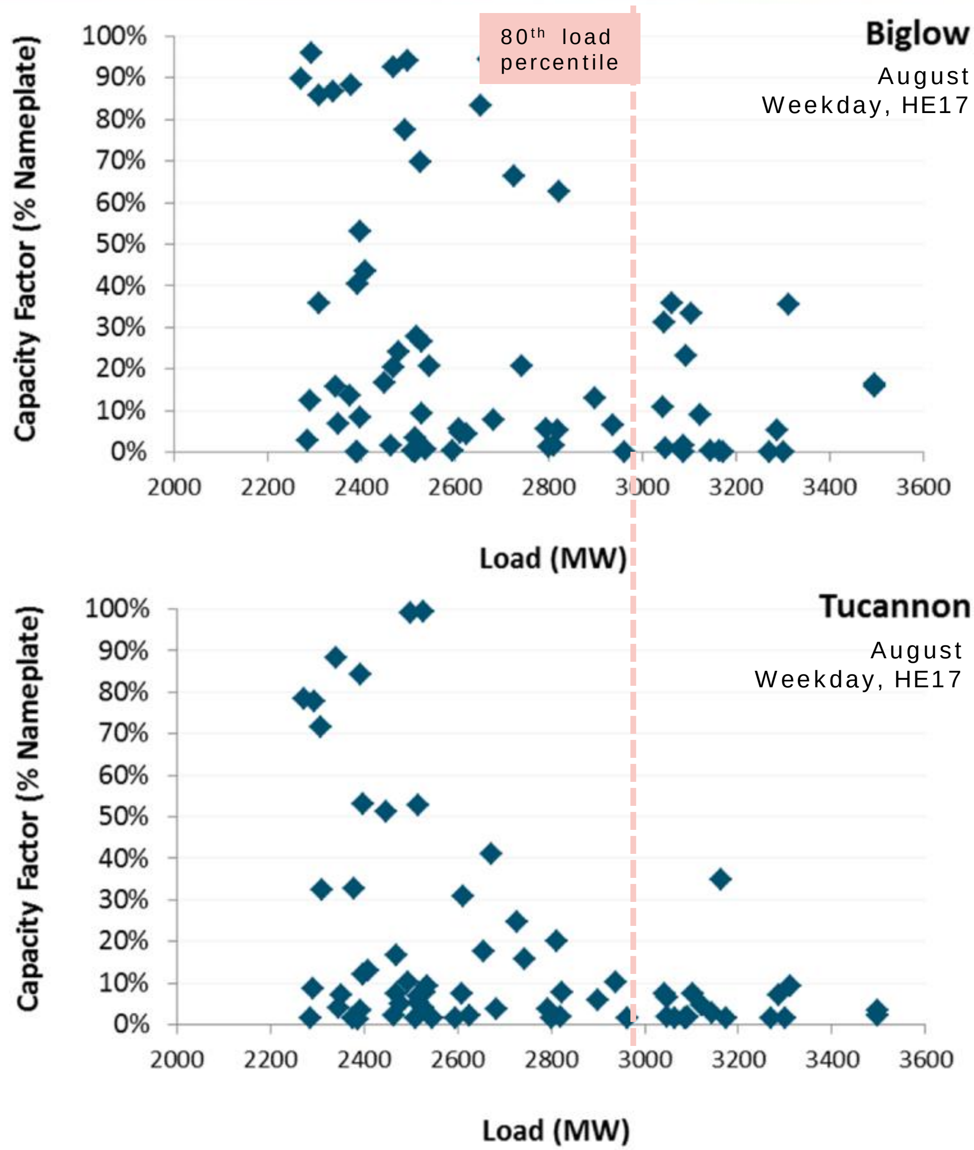
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Average Normalized Solar Output Sample Site

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
7	0.000	0.000	0.000	0.009	0.087	0.118	0.091	0.016	0.000	0.000	0.000	0.000
8	0.000	0.000	0.018	0.170	0.261	0.257	0.272	0.203	0.141	0.013	0.000	0.000
9	0.003	0.077	0.211	0.344	0.438	0.423	0.467	0.432	0.415	0.271	0.076	0.003
10	0.280	0.416	0.401	0.478	0.578	0.568	0.629	0.608	0.584	0.509	0.349	0.280
11	0.425	0.551	0.487	0.602	0.664	0.644	0.723	0.707	0.685	0.617	0.430	0.441
12	0.383	0.593	0.557	0.660	0.701	0.707	0.773	0.766	0.756	0.669	0.426	0.443
13	0.385	0.586	0.568	0.678	0.722	0.735	0.791	0.809	0.768	0.678	0.423	0.472
14	0.382	0.571	0.539	0.699	0.708	0.734	0.788	0.807	0.772	0.669	0.367	0.467
15	0.358	0.541	0.526	0.658	0.660	0.686	0.753	0.770	0.739	0.615	0.306	0.449
16	0.331	0.475	0.487	0.587	0.587	0.628	0.696	0.710	0.672	0.571	0.247	0.393
17	0.238	0.387	0.402	0.493	0.526	0.546	0.604	0.636	0.561	0.415	0.124	0.218
18	0.059	0.208	0.257	0.358	0.404	0.440	0.464	0.479	0.374	0.154	0.006	0.001
19	0.000	0.005	0.074	0.180	0.232	0.271	0.297	0.269	0.120	0.001	0.000	0.000
20	0.000	0.000	0.000	0.021	0.072	0.113	0.113	0.056	0.001	0.000	0.000	0.000
21	0.000	0.000	0.000	0.000	0.001	0.004	0.003	0.000	0.000	0.000	0.000	0.000
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Gorge wind is negatively correlated with load during summer peak hours

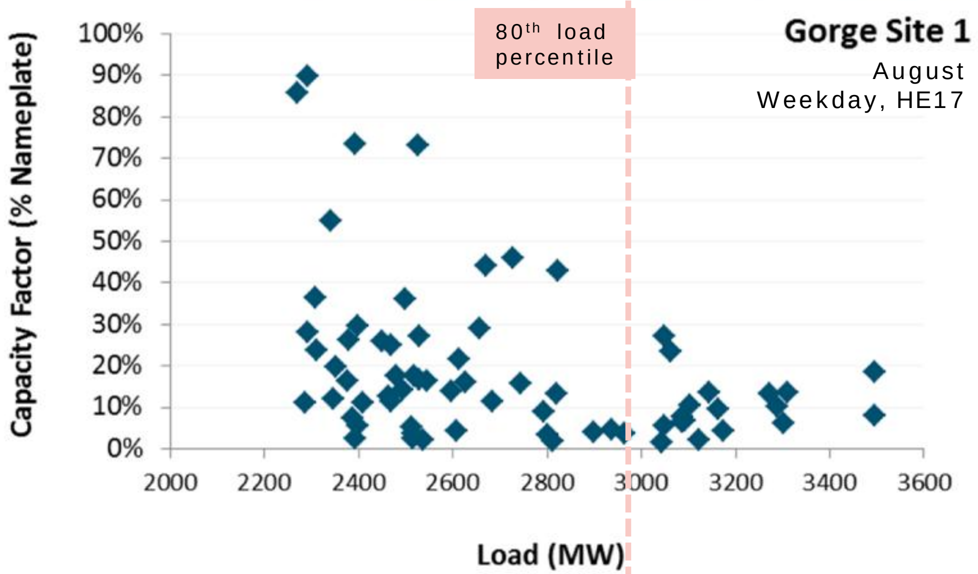
- Correlation between load and renewable output may exist even within each month-hour-day type
  - E.g. decrease in wind output in high load hours, as both are correlated to high temperatures
- To capture these correlations, fractions of gross load are binned separately
  - 80th load percentile used
- Additional data on renewable output would improve accuracy of ELCC estimates

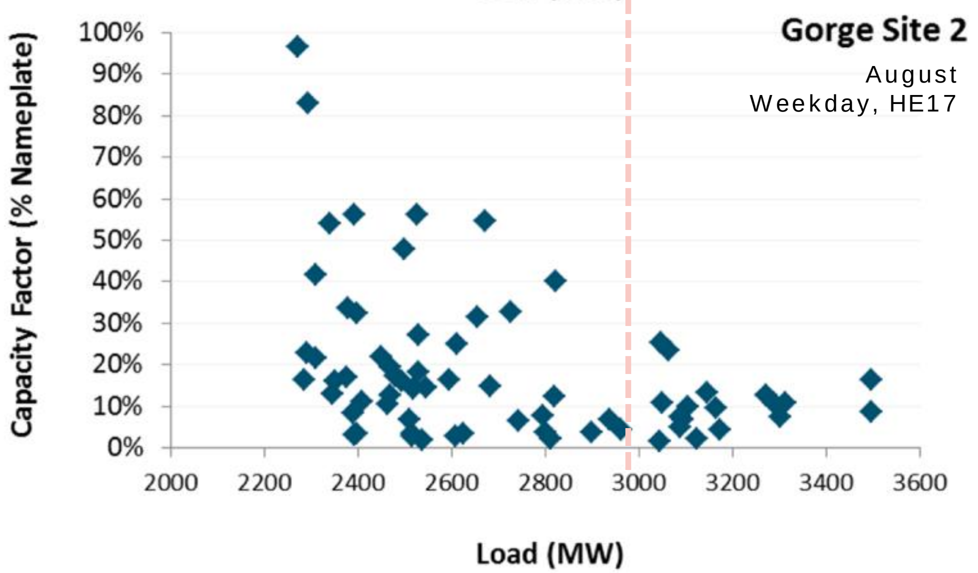


Preliminary results – do not cite

Gorge wind is negatively correlated with load during summer peak hours

- Correlation between load and renewable output may exist even within each month-hour-day type
  - E.g. decrease in wind output in high load hours, as both are correlated to high temperatures
- To capture these correlations, fractions of gross load are binned separately
  - 80th load percentile used
- Additional data on renewable output would improve accuracy of ELCC estimates





Preliminary results – do not cite

Preliminary ELCC for PGE's current renewable portfolio is 11.4%

	Winter	Summer	Annual
Nameplate rating MW	861	861	861
Portfolio ELCC (MW)	130	92	98
Portfolio ELCC (% of nameplate MW)	15.1%	10.7%	11.4%

Preliminary results – do not cite

- PGE portfolio currently has 861 MW of renewables
  - Most is wind capacity
  - Total energy penetration equal to 12.6% of 2021 load
- ELCC value calculated for the entire existing portfolio
  - Incorporates correlations and diversity among resources
  - No attribution of portfolio value to individual resources

Preliminary marginal ELCC of incremental resources

- Marginal ELCC measures the additional ELCC provided by adding new resources to the portfolio
- Sample portfolio includes two Gorge sites and PV
  - The Gorge sites add little diversity to the existing portfolio and have relatively low ELCCs
  - Incremental PV resource has higher ELCC due to its high summer capacity factors

Resource	Nameplate Rating (MW)	Annual ELCC
Incremental Wind Sites	665 MW	68 MW (10%)
Incremental Solar Sites	142 MW	66 MW (46%)
Total Incremental Portfolio	807 MW	138 MW (17%)

Preliminary results – do not cite

Preliminary marginal ELCC of incremental resources by season

- Gorge wind resources have higher ELCC in winter than in the summer
- Solar PV has high summer value due to coincidence of output with peak needs, but very low winter value due to nighttime peak loads
- Portfolio effects result in similar total incremental ELCC for all three tests

Resource	Nameplate Rating (MW)	Winter ELCC	Summer ELCC
Incremental Wind Sites	665 MW	129 MW (19%)	61 MW (9%)
Incremental Solar Sites	142 MW	14 MW (10%)	77 MW (55%)
Total Incremental Portfolio	807 MW	147 MW (18%)	140 MW (17%)

Preliminary results – do not cite

Flexibility Assessment Using E3's Renewable Energy Flexibility Model

Elaine Hart, Managing Consultant

Background

- Introduction of variable renewables has shifted the capacity planning paradigm
- PGE has been directed by the Oregon PUC to provide an "Evaluation of new analytical tools for optimizing flexible resource mix to integrate load and variable resources"

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

Flexibility Planning Challenges

1. **Downward ramping capability**

   Thermal & hydro resources operating to serve loads at night must be ramped downward and potentially shut down to make room for an 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**

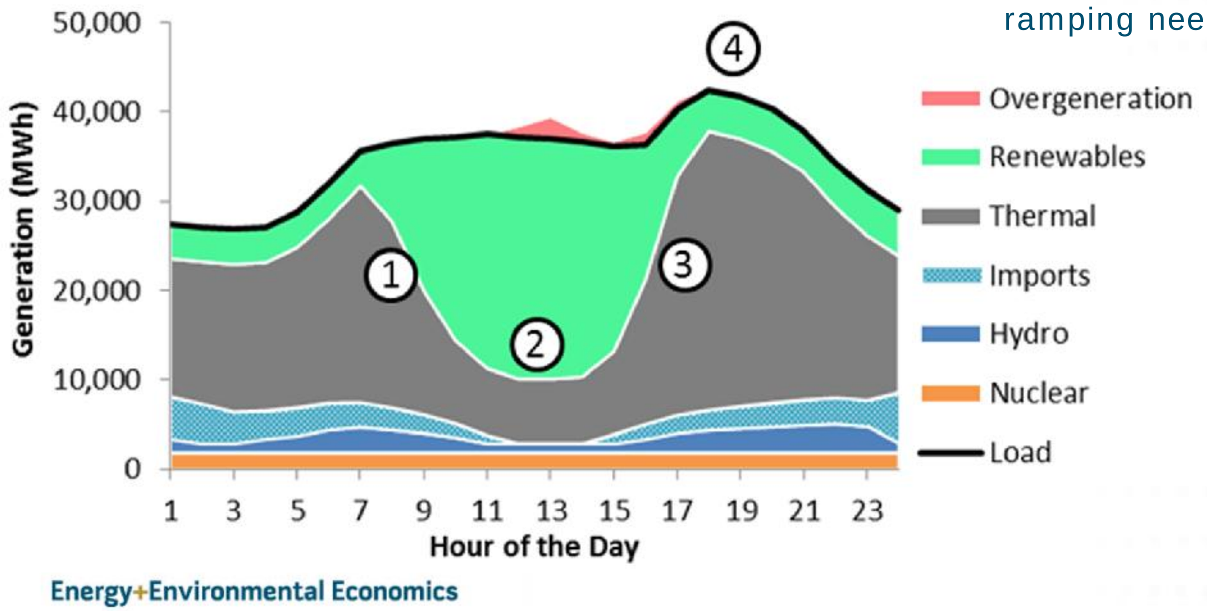
   Thermal & hydro resources must ramp up quickly and new units may be required to start up to meet a high net peak demand that occurs shortly after sundown.

4. **Peaking capability**

   The system will need enough resources to meet the highest peak loads with sufficient reliability.

5. **Sub-hourly flexibility (not shown in chart)**

   Flexible capacity needed to meet sub-hourly ramping needs.



There are a number of potential flexibility constraints that can become binding at various times and on various systems.

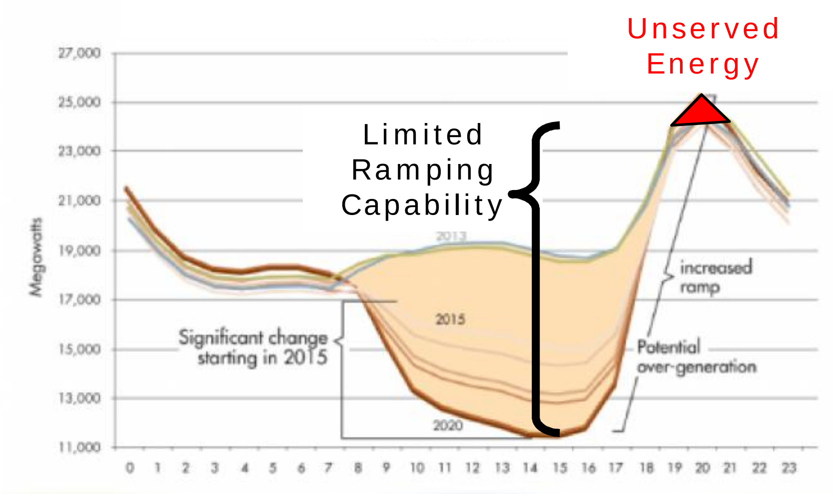
Many Resource Characteristics Can Be Important for Flexibility

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
Minimum generation levels	Lower minimum generation levels can help meet upward ramping needs while avoiding overgeneration
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
Number of starts	If starts are limited under air permits, units are less available to meet ramping needs

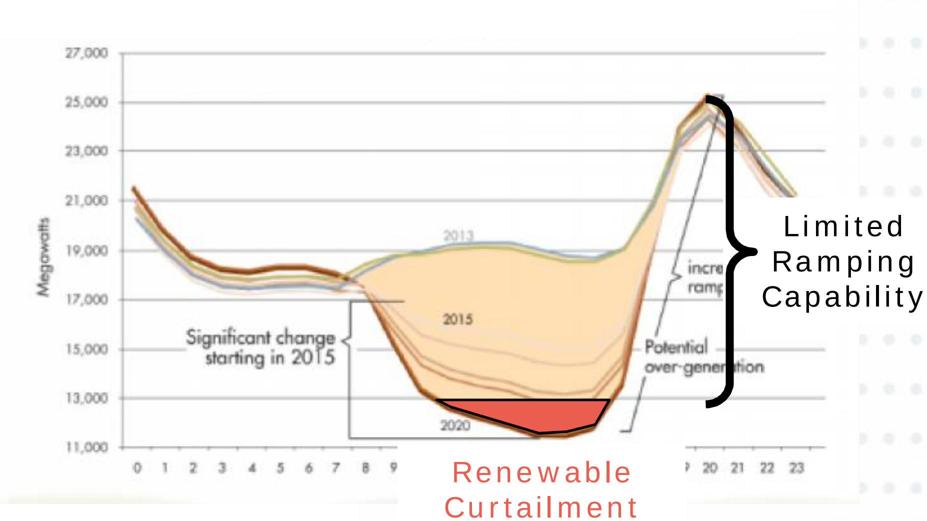
Flexibility and Economics

- Renewable integration can be framed as an economic operating decision
- Flexibility violations in upward and downward directions are substitutes for one another
  - Upward ramping shortages can be solved using renewable curtailment

Strategy to Minimize Downward Violations

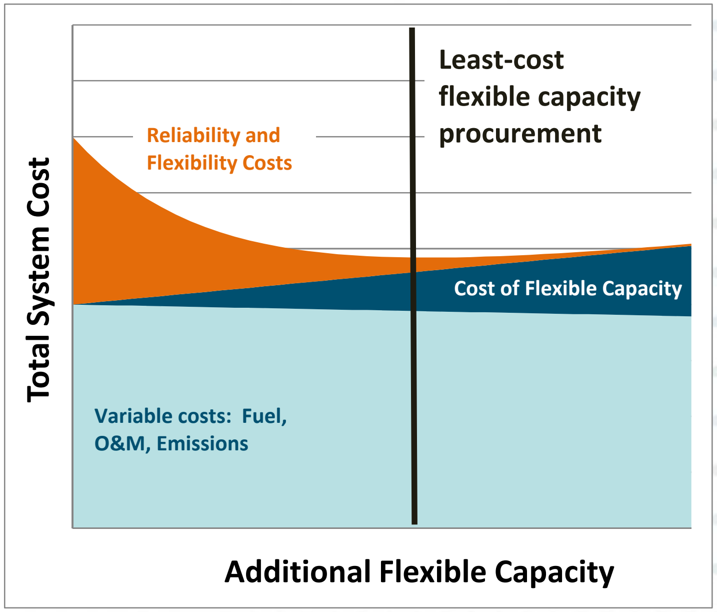


Strategy to Minimize Upward Violations



Cost-Effective Flexibility Investment

- Curtailment can be difficult if relied on as a long-term grid flexibility solution
  - Must compensate curtailed generator
    - Requires systems in place to calculate generator lost revenue
  - Must replace renewable energy
    - Replacement energy may itself be subject to curtailment
- Investment in flexibility reduces frequency and duration of flexibility violation events
  - Reduces dispatch cost
  - Improves compliance with NERC operating standards
  - Improves compliance with policy

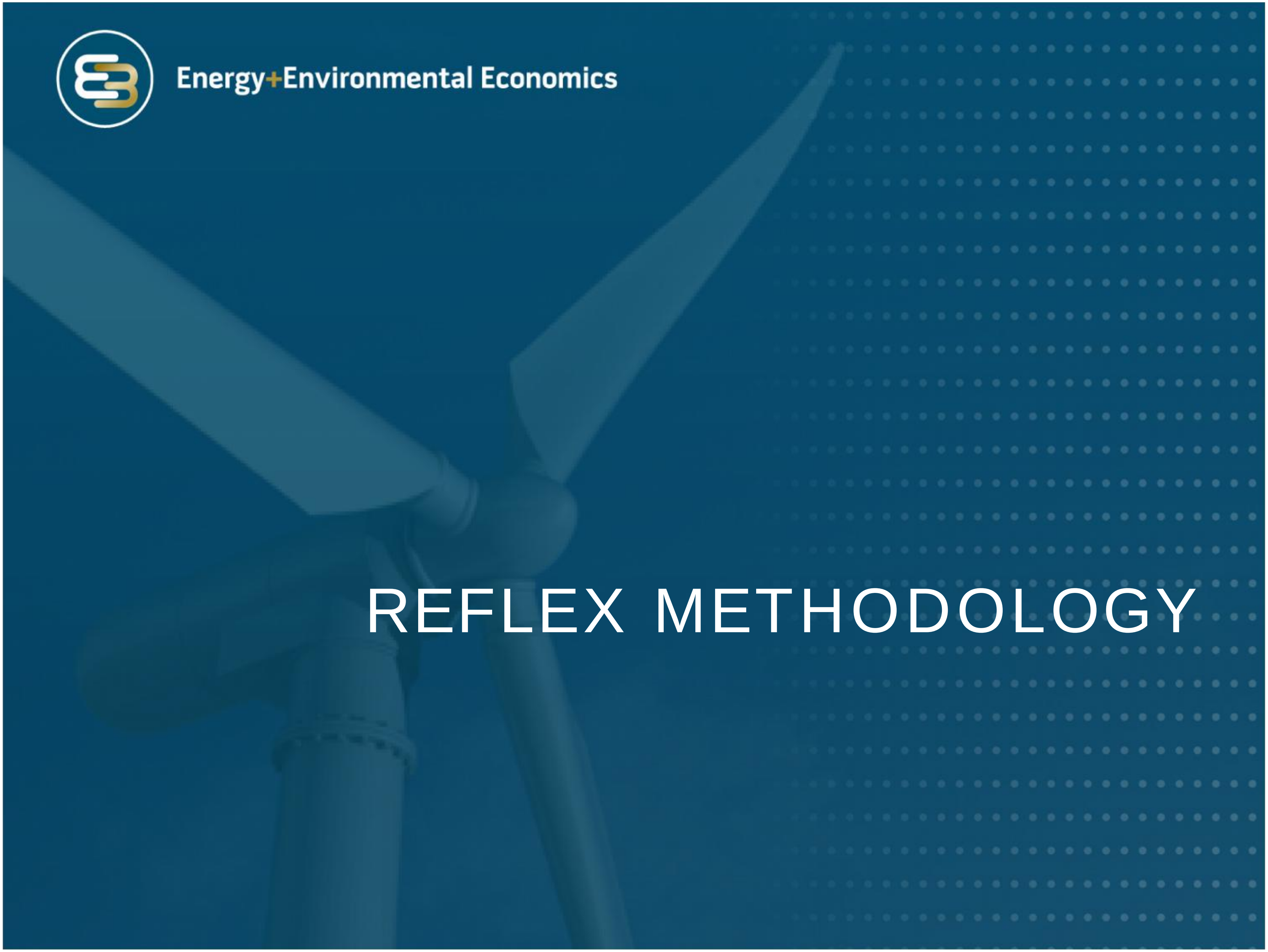


<u>Analysis question:</u>
When does investment in grid flexibility become cost-effective relative to default solution of renewable curtailment?

Scope of this project

- Estimate expected flexibility violations
  - REFLEX: Adapted production simulation methodology designed to assess system flexibility
- Identify and assess candidate portfolios of flexibility solutions
  - Renewable portfolio diversity
  - Energy storage
  - Peaking thermal resources

Energy+Environmental Economics



REFLEX METHODOLOGY

Renewable Energy Flexibility (REFLEX) Model

- REFLEX answers critical questions about flexibility need through adapted production simulation
  - Captures wide distribution of operating conditions through Monte Carlo draws of operating days
  - Illuminates the significance of the operational challenges by calculating the likelihood, magnitude, duration & cost of flexibility violations
  - Assesses the benefits and costs of investment to avoid flexibility violations

Available as standalone model or add-on to Plexos for Power Systems

REFLEX Has Features of Reliability and Production Simulation Models

LOLP Model

- Reliability/Resource Adequacy
- E.g., RECAP, GE-MARS, SERVM
- Determines quantity of resources needed to meet load reliably by calculating metrics such as loss-of-load probability (LOLP)
- Must consider a broad range of stochastic variables such as load, wind, solar, hydro and generator outages in order to get robust probabilities

Production Simulation

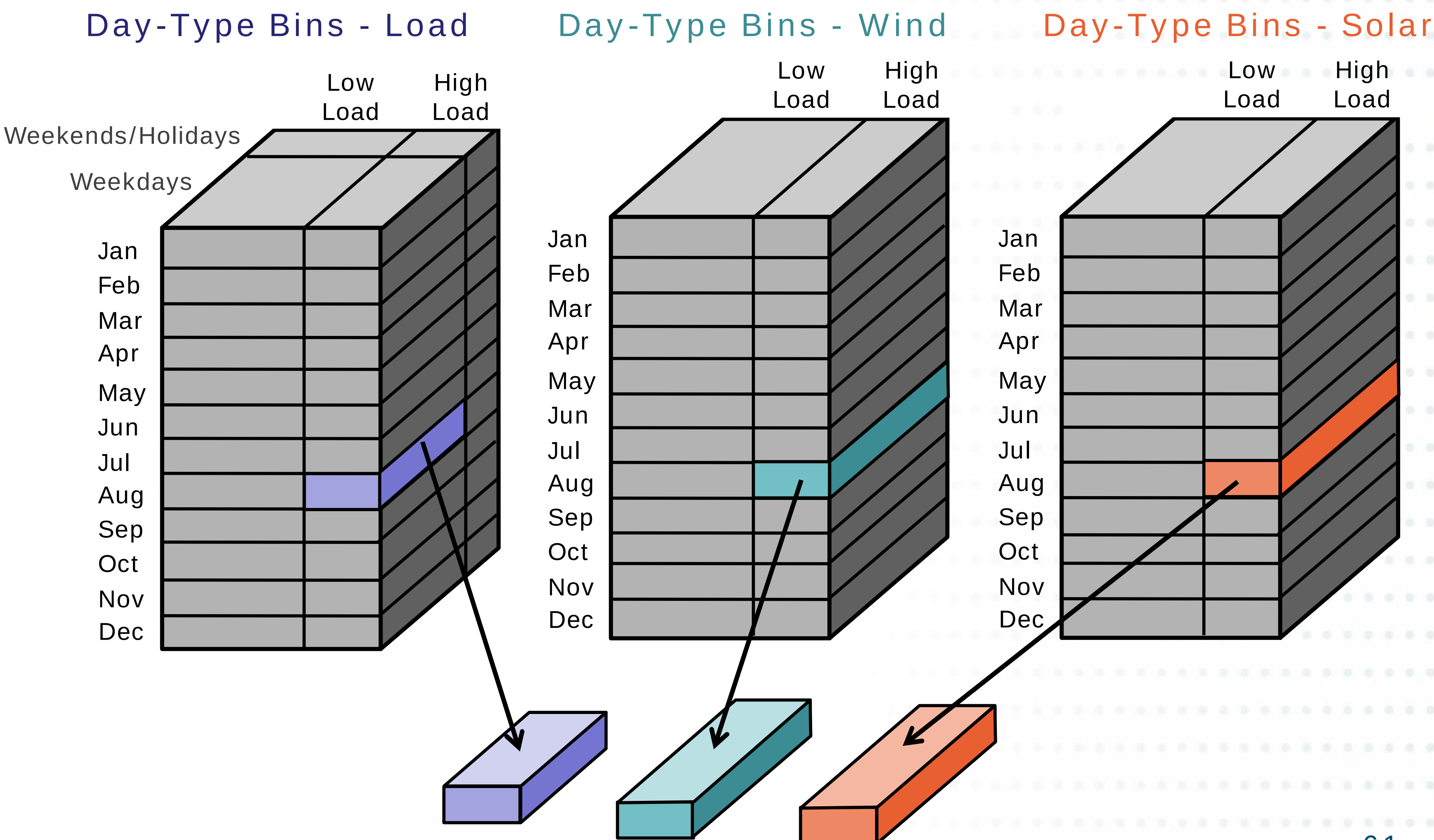
- Production simulation
- E.g., GridView, PLEXOS
- Calculates least-cost dispatch subject to generation and transmission constraints
- Used to estimate operational requirements and transmission flows
- Computation time typically allows only a single, deterministic case

REFLEX addresses the long-term uncertainties of an LOLP model with the operational detail of production simulation

Flexibility Metrics

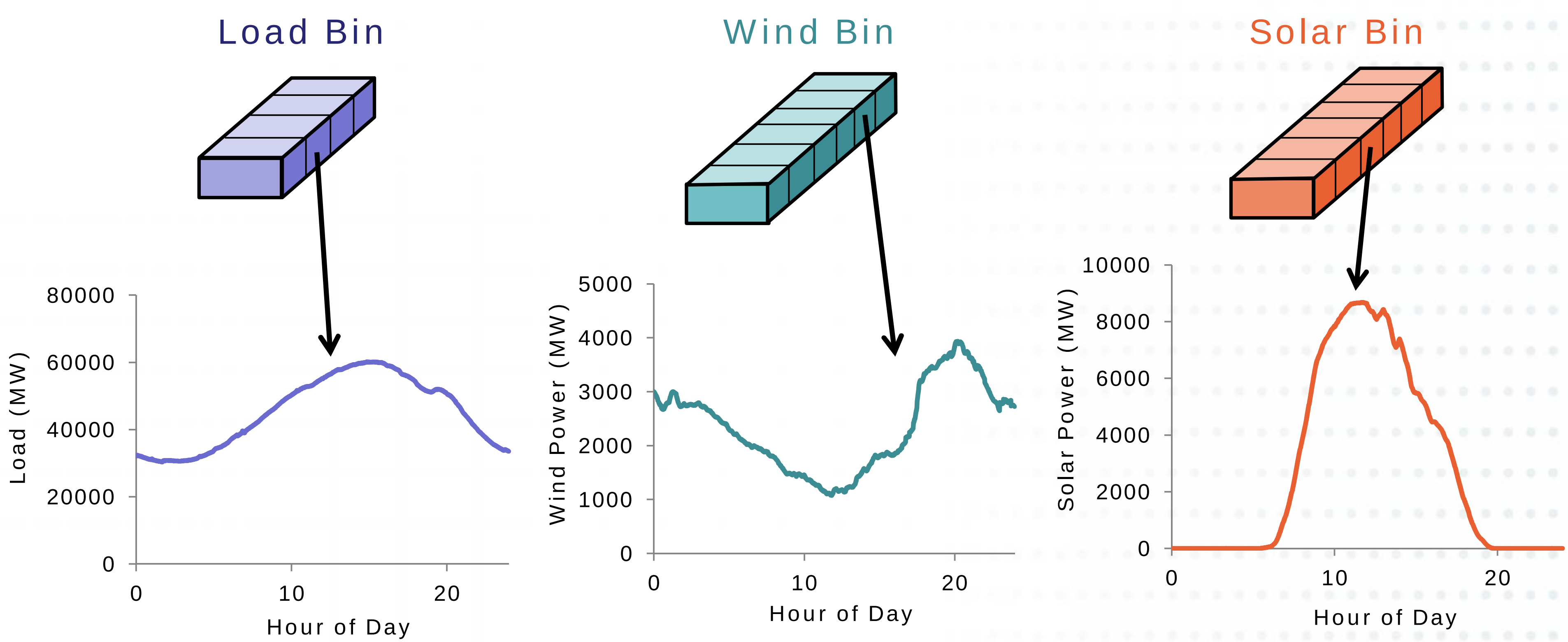
- Flexibility violations occur when the power system cannot meet all changes in net load over all time scales
- REFLEX reports two categories of flexibility violations:
  - EUE: Expected Unserved Energy
  - EOG: Expected Overgeneration, aka renewable curtailment
    - Hourly and within-hour timescales
- Economic parameters are also required:
  - VUE: Value of Unserved Energy
    - $2,000–50,000/MWh based on value of lost load
  - VOG: Value of Overgeneration
    - $30-150/MWh based on replacement cost of renewable energy
- REFLEX also reports production costs & CO_2 emissions

Stochastic Sampling of Load, Wind, and Solar



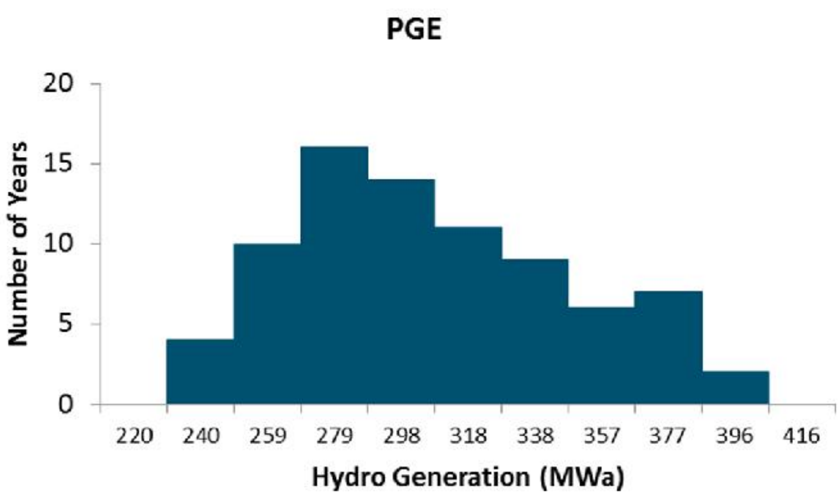
Example Draw: High Load Weekday in August

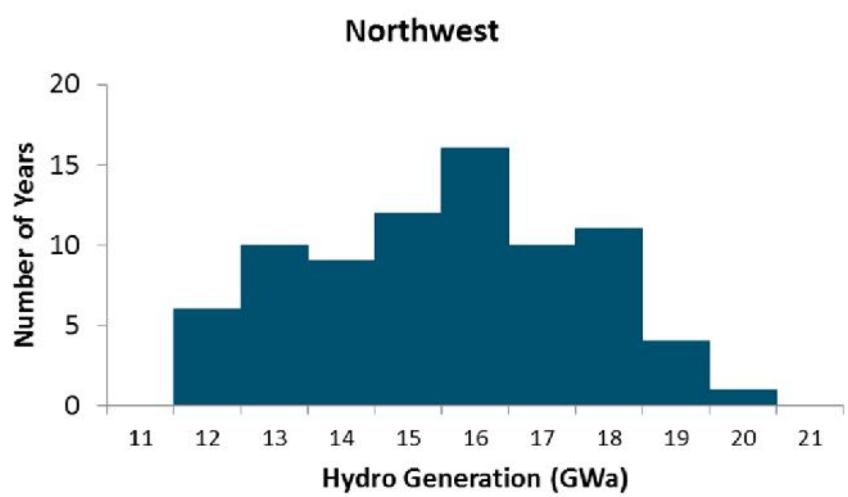
- Within each bin, choose each (load, wind, and solar) daily profile randomly, and independent of other daily profiles
  - 24 hour spin-up and spin-down periods included in the optimization



Stochastic Sampling of Hydro Conditions

- Traditional production simulation analysis typically relies on a single year of hydro conditions
- REFLEX samples energy budgets from a wide range of historical hydro conditions (1928-2008)
  - Northwest Power and Conservation Council (NWPCC) simulated monthly output data by plant for 1928-2008 hydro conditions
  - NWPCC data used to supplement PGE data to characterize full range of historical hydro conditions





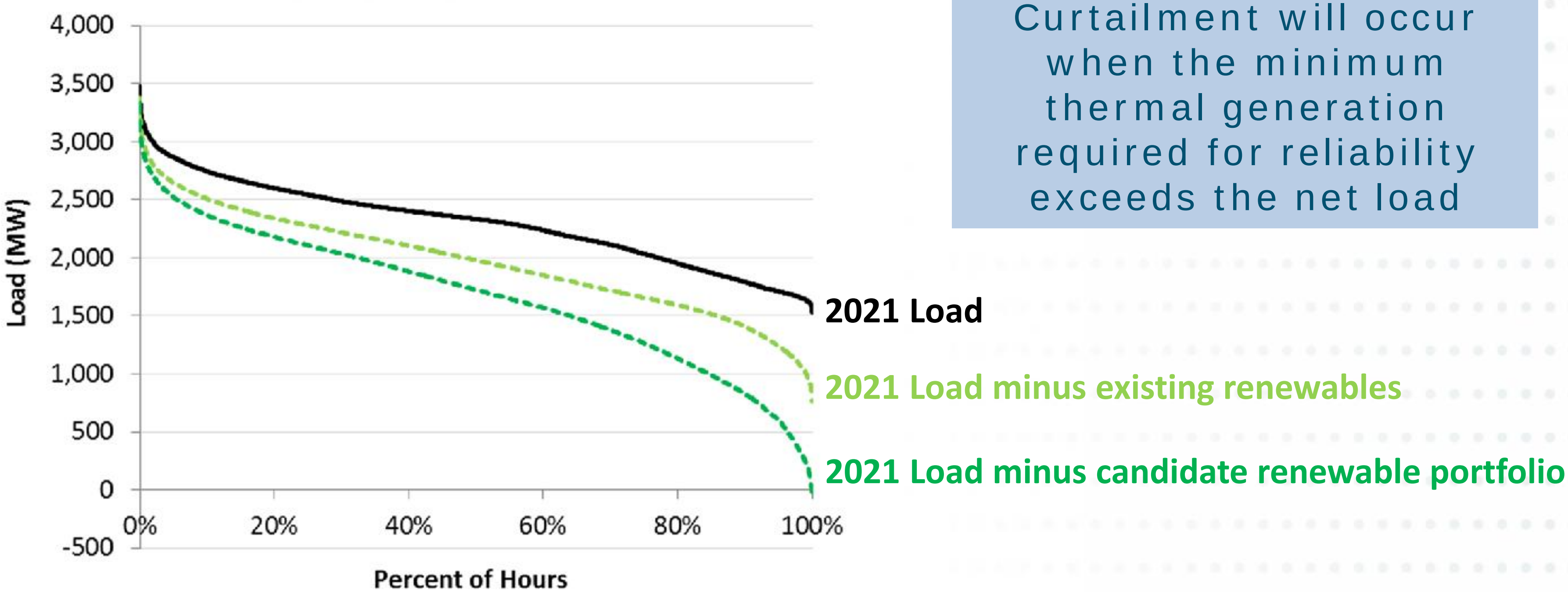
Source: Northwest Power Council

Energy+Environmental Economics

FLEXIBILITY CHALLENGES IN THE PGE SYSTEM

Minimum Generation Challenges

+ Low net load conditions
  - May increase cycling of thermal plants
  - May require renewable curtailment to ensure system reliability



Curtailment will occur when the minimum thermal generation required for reliability exceeds the net load

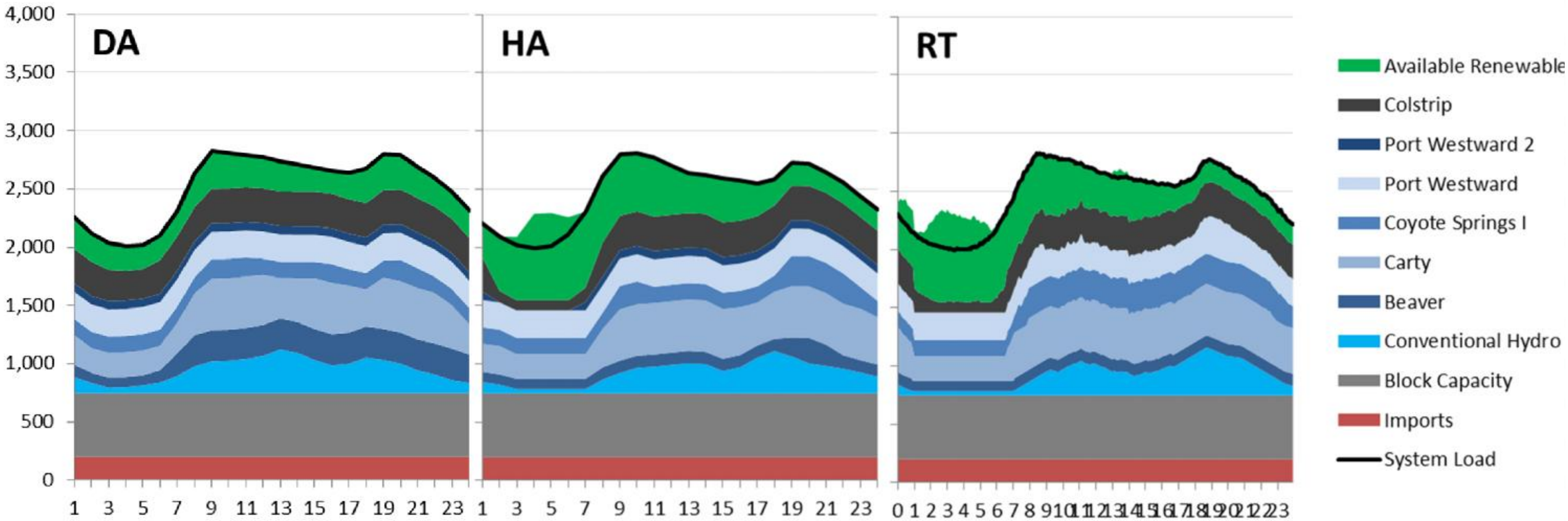
Ramping Challenges

- Continued wind development increases the tails of ramping distributions
  - Existing renewables increase magnitude of most extreme ramp events by factor of 1.3 – 1.5 relative to no renewables
  - Candidate portfolios increase magnitude of extreme ramp events by factor of ~2.5 relative to no renewables

Hourly Ramp Percentiles (MW)	0.1%	1.0%	10.0%	90.0%	99.0%	99.9%
2021 Load Ramps	-487	-239	-141	145	310	373
2021 Net Load Ramps - Existing Renewables	-723	-291	-156	156	333	479
2021 Net Load Ramps - Candidate Renewable Portfolio	-1,274	-425	-176	176	390	915

Example scheduling and dispatch – Existing renewables

- REFLEX models real-time (5-minute) dispatch and day-ahead and hour-ahead unit commitment based on imperfect forecasts
- Example dispatch shown below meets all 2021 capacity needs with entirely inflexible “Block Capacity” resource
- Early morning day-ahead wind forecast error drives curtailment
- Real-time fluctuations managed primarily with gas



Curtailment patterns at higher wind & solar penetrations

Average renewable curtailment by month-hour in 2021

Hour of Day

Existing Renewables

Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	55	75	93	110	116	86	36	8	1	-	-	-	-	-	-	-	0	-	-	-	-	-	2	24
2	23	47	68	73	63	46	19	4	0	-	-	-	-	-	0	0	-	0	-	-	-	-	1	10
3	82	110	116	113	98	62	28	8	3	-	-	-	-	0	1	1	0	1	0	-	-	-	8	34
4	123	148	163	152	108	49	16	8	1	0	-	0	0	1	2	3	2	1	0	1	-	-	8	73
5	121	158	157	155	137	82	27	7	4	1	-	-	-	2	-	0	1	1	-	0	-	-	5	43
6	129	178	207	222	198	151	68	17	4	1	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6	50
7	74	132	166	181	185	158	102	35	10	3	0	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	6	53
8	51	79	108	126	123	97	72	40	12	0	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	22
9	63	82	112	130	133	101	40	25	11	3	1	0	1	1	0	1	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	20	65
10	109	131	155	170	137	77	21	7	3	1	-	-	-	-	-	0	-	-	-	[illegible]	[illegible]	3	12	48
11	61	76	95	102	81	56	31	9	2	0	-	-	1	1	1	2	2	0	-	-	[illegible]	-	2	21
12	32	66	92	102	100	79	43	14	2	-	-	-	-	-	0	1	1	-	-	-	[illegible]	-	0	4

Candidate Portfolio

Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	207	261	284	306	300	262	179	90	55	37	31	23	23	24	27	29	31	21	4	3	4	8	36	113
2	87	127	157	150	142	137	97	48	27	14	15	15	22	25	24	22	10	7	[illegible]	[illegible]	[illegible]	[illegible]	12	48
3	247	283	281	274	263	214	120	56	32	30	26	28	26	28	29	31	25	19	[illegible]	[illegible]	[illegible]	[illegible]	79	161
4	303	373	406	402	365	268	140	97	89	76	79	93	107	112	114	113	91	77	[illegible]	[illegible]	[illegible]	[illegible]	110	214
5	236	265	263	270	260	221	147	83	69	65	33	23	24	31	17	23	24	27	27	38	36	37	78	155
6	254	301	308	320	300	272	136	93	61	48	37	34	32	27	22	24	26	24	22	23	24	28	53	131
7	89	115	136	147	149	123	81	33	14	4	-	-	-	-	-	0	1	1	2	6	12	18	34	96
8	91	114	137	149	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3	4	3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	6	24	55
9	127	140	154	170	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	31	26	23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	18	40	96	153
10	178	207	238	260	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	3	4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8	19	41	81
11	145	176	198	197	173	142	108	66	47	34	16	19	24	20	21	21	17	9	1	5	7	22	47	82
12	118	175	209	224	233	207	155	81	32	18	15	11	14	18	23	23	20	12	6	9	12	14	23	34

Exacerbates nighttime curtailment

Introduces daytime curtailment

Completed Work and Next Steps

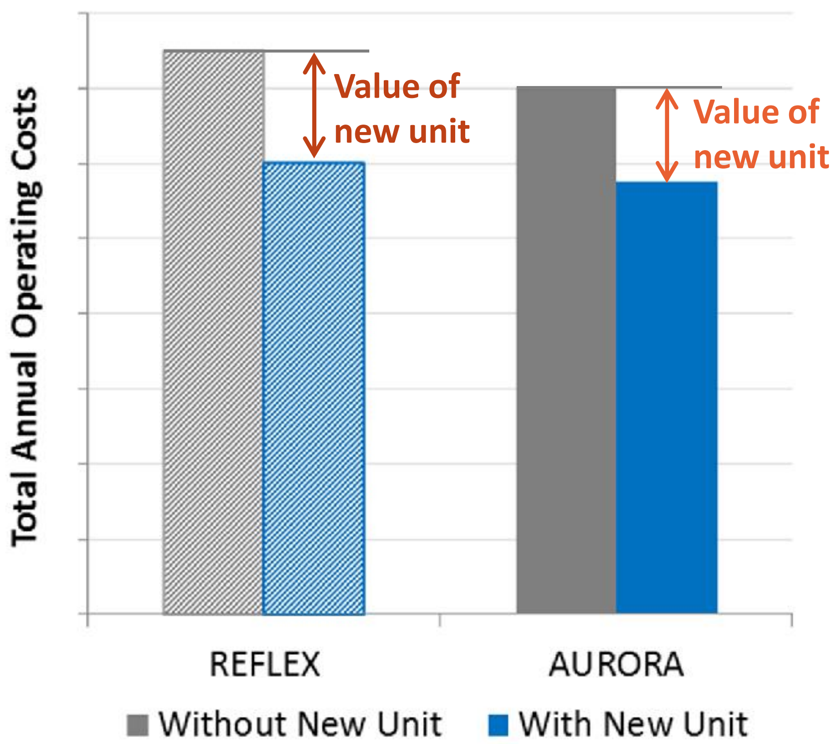
- Develop REFLEX cases for several renewable portfolios
  - ✓ PGE loads and resources
  - ✓ PGE hydro conditions
  - ✓ Colstrip dispatch behavior
  - ✓ On-peak/off-peak import treatment
- Quantify flexibility challenges
  - ✓ Simulate dispatch and quantify curtailment with inflexible “Block Capacity”
- Assess flexibility solutions
  - ❑ Simulate dispatch and quantify curtailment with candidate resources

Incorporation into PGE IRP process

- Metrics from REFLEX can be used to supplement outputs from AURORA
  - Example: REFLEX models constraints related to starts and stops that are not well resolved by planning models
  - A unit that can quickly and cheaply start and stop might provide additional value not captured by AURORA
- E3 will test candidate resources in REFLEX in parallel to PGE's AURORA modeling

Example (not to scale below):

Value adder in AURORA =
[Unit value in REFLEX w/ all constraints] –
[Unit value in REFLEX w/o flexibility constraints]



Energy+Environmental Economics

Thank You!

Energy and Environmental Economics, Inc. (E3)
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
Tel 415-391-5100
Web http://www.ethree.com

Arne Olson, Partner (arne@ethree.com)
Elaine Hart, Managing Consultant (elaine.hart@ethree.com)
Ana Mileva, Senior Consultant (ana.mileva@ethree.com)