Energy+Environmental Economics

Capacity and Flexibility Needs under Higher Renewables

Project Deliverable

October 1, 2015

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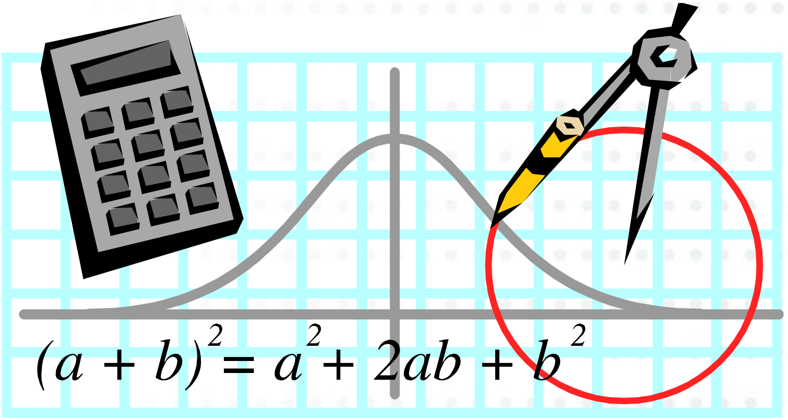
Defining today's planning problem

- **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

PGE currently utilizes a 12% PRM

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

$$PRM = \frac{Reliable\ December\ Capacity\ (MW)}{1 - in - 2\ year\ Peak\ Load\ (MW)} - 1$$

- 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

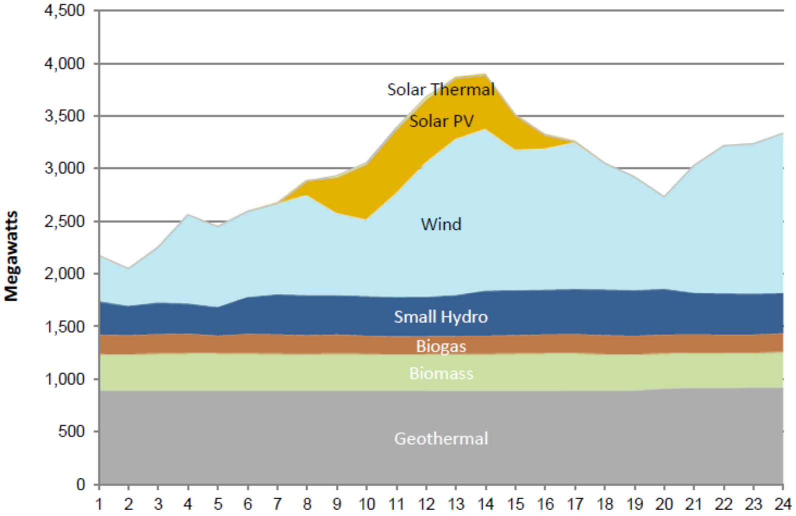
* PSE and Avista use NWPCC criterion of 5% probability of shortfall occurring any time in a given year
** SPP uses 1-day-in-10 years or 12% PRM system-wide

RECAP METHODOLOGY

E3's Renewable Energy Capacity Planning Model (RECAP)

- **E3 has developed an open-source model for evaluating <u>power system reliability</u> and <u>resource capacity value</u> 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

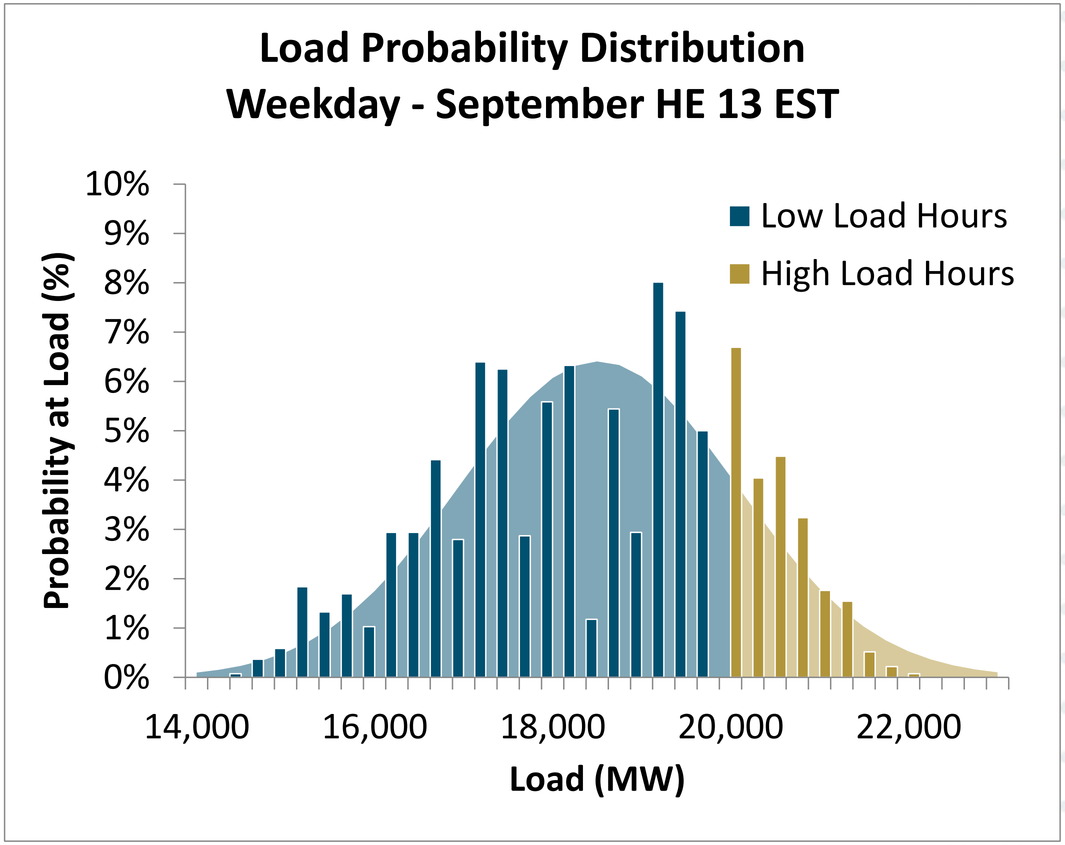


RECAP Model overview

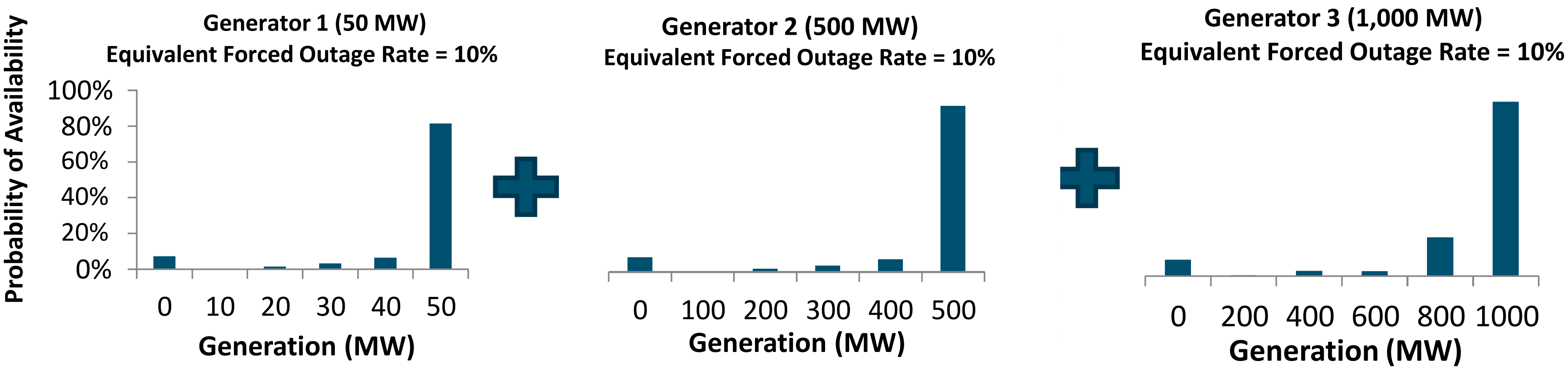
- **RECAP Model assesses reliability performance of a power system using the following metrics:**
  - **Loss of Load Probability (LOLP)**: probability of capacity shortfall in a given hour
  - **Loss of Load Expectation (LOLE)**: expected hours of capacity shortfall in a given year
  - **Expected Unserved 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**



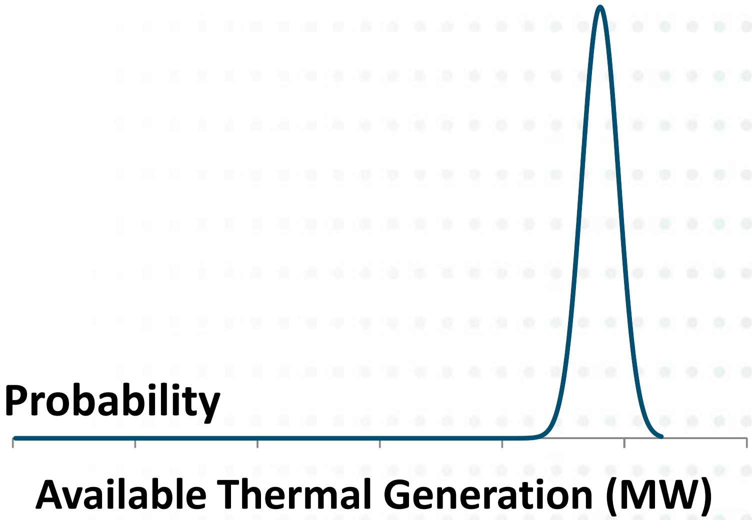
Step 2: Calculate available dispatchable generation



+ All other generators

for each month/hour/day-type

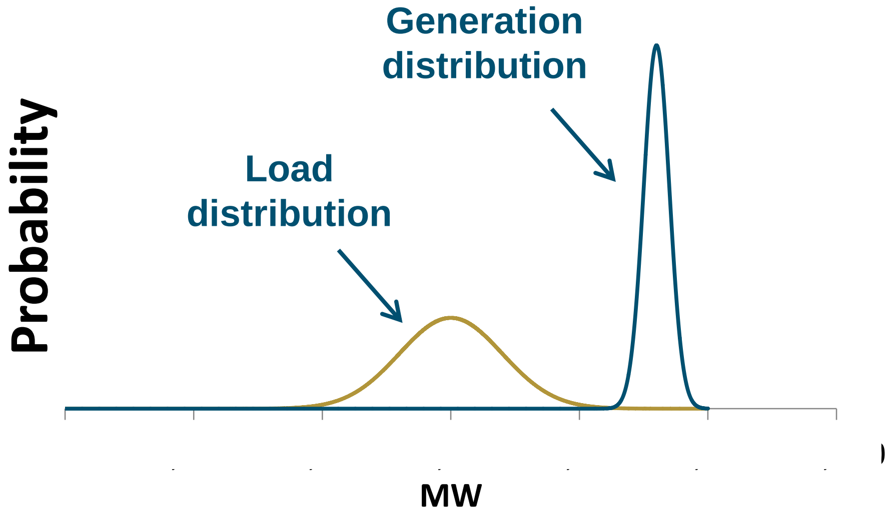
=

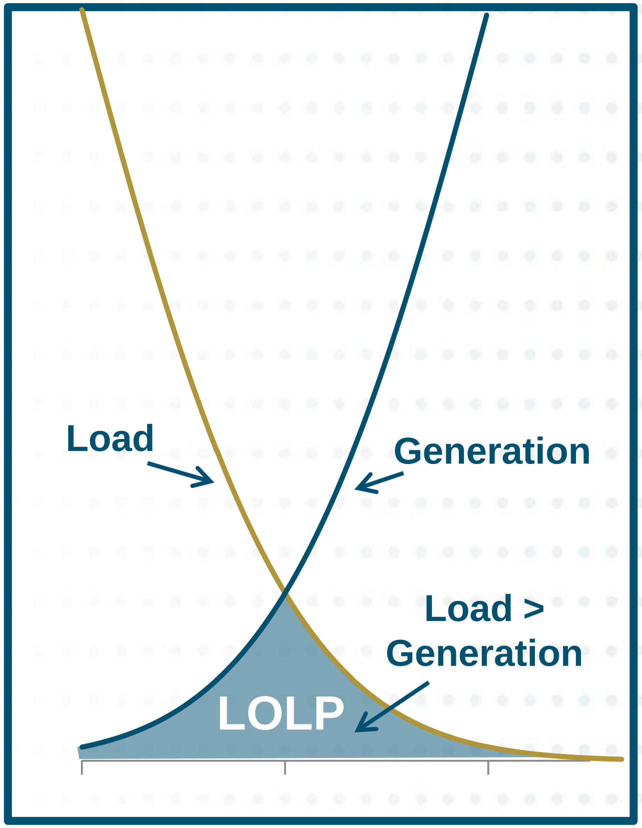


Step 3: Calculate LOLP

- 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

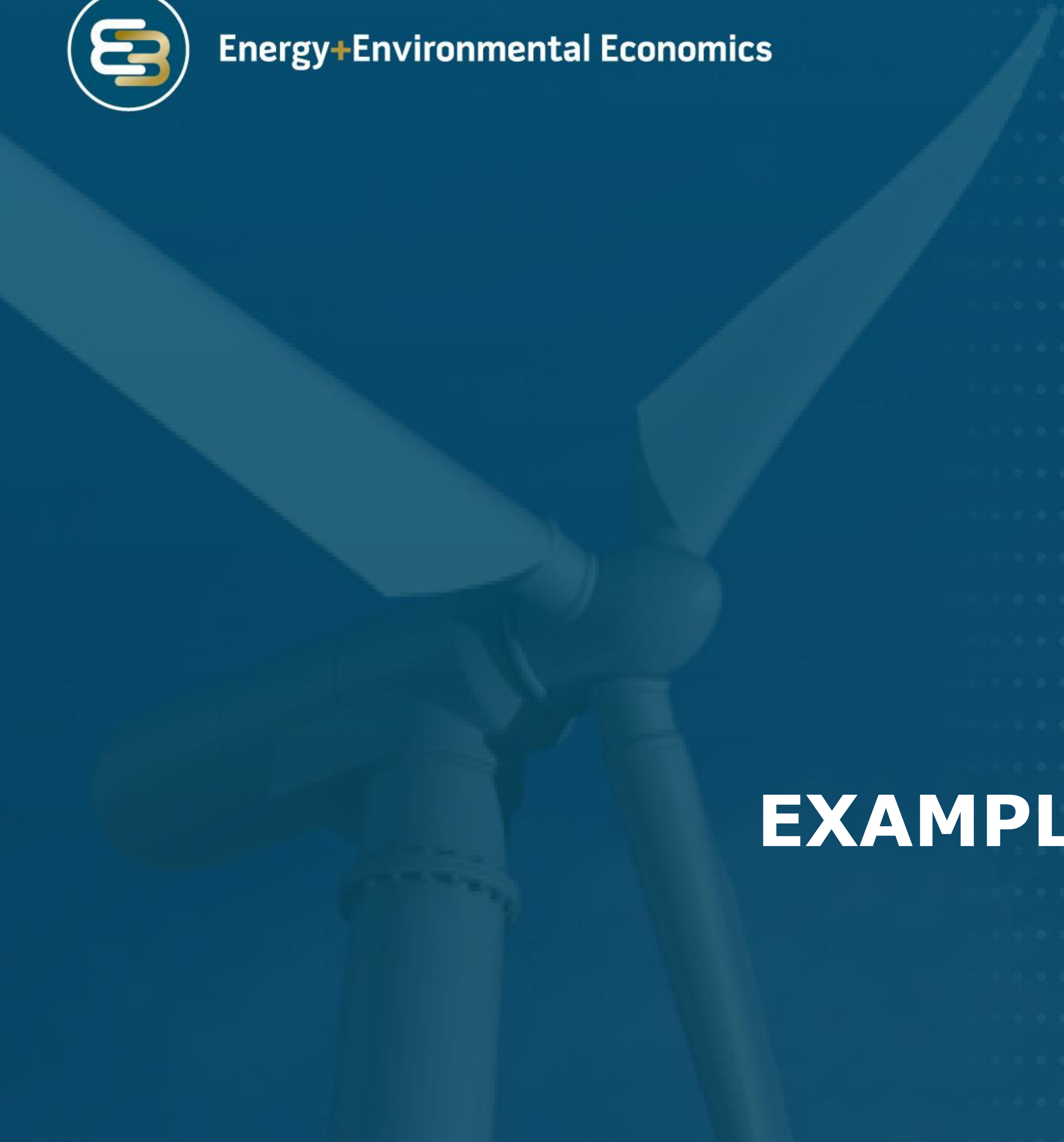
- LOLP is the probability of lost load in a given hour. LOLE is the annualized sum of LOLP across all hours (h) and simulated years (n)

$$LOLE \; = Average_n \left(\sum_{h=1}^{8760} \boldsymbol{LOLP_h} \right)$$

- 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*



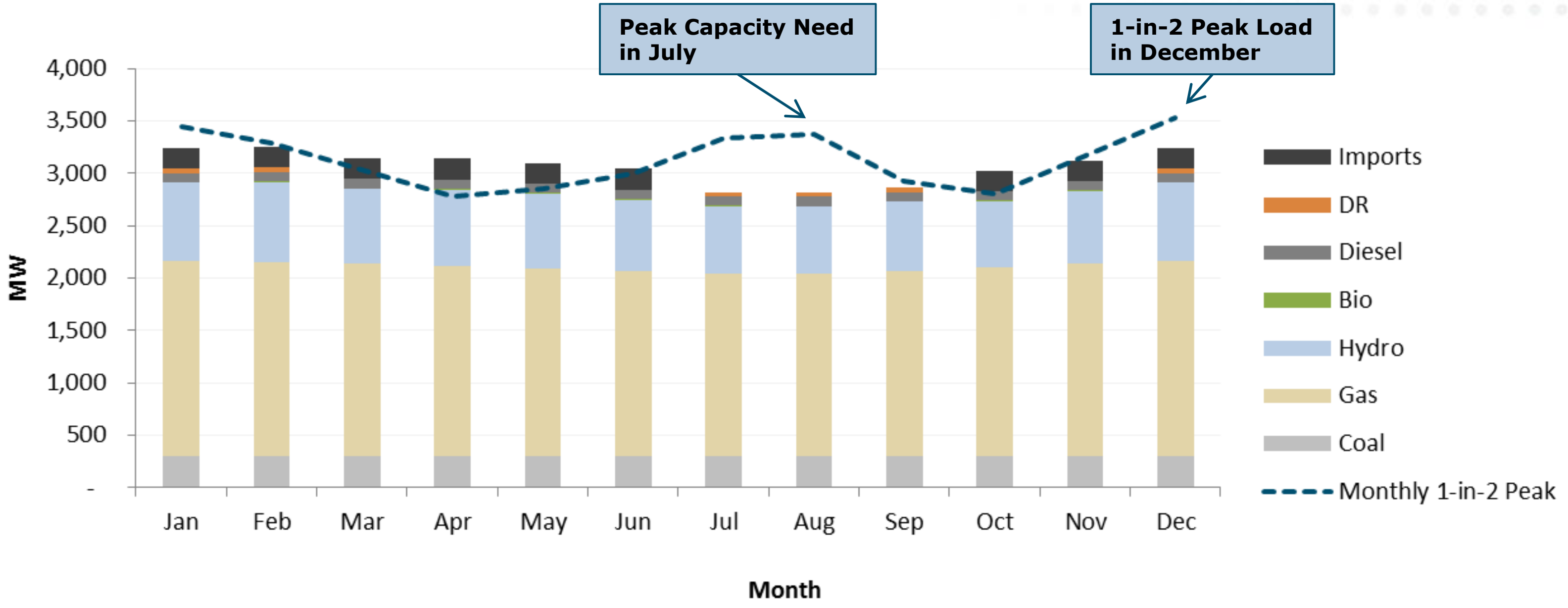
EXAMPLE RESULTS

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
  - 2008-2014 actual output for Biglow
  - 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 all but summer on-peak hours

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

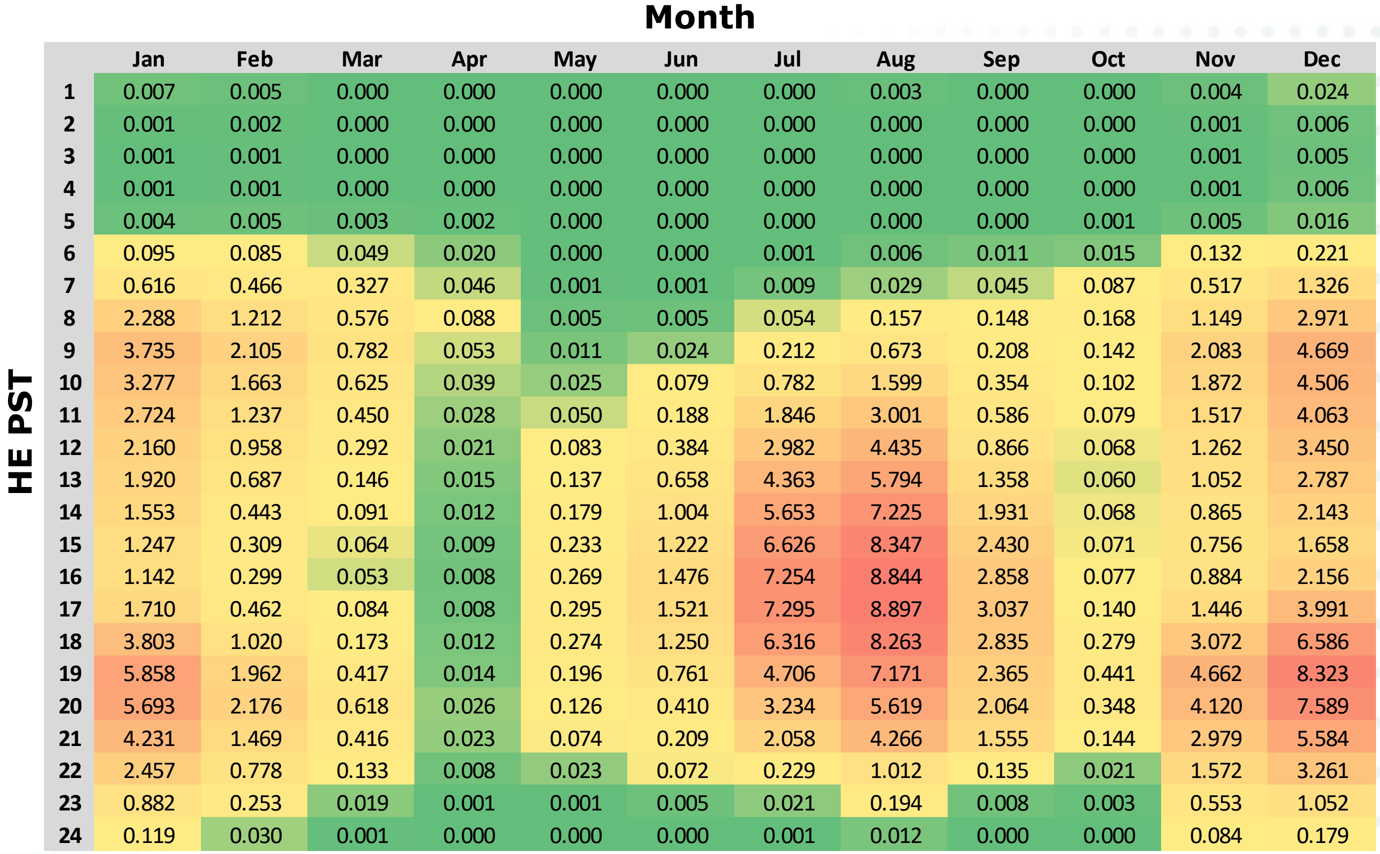


Peak Capacity Need in July

1-in-2 Peak Load in December

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

- Chart shows LOLP by month/hour timeslice
- Sum of time slices is test year LOLE: 332 hours per year before adding resources



Month

HE PST	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.007	0.005	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.004	0.024
2	0.001	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.006
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.005
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.006
5	0.004	0.005	0.003	0.002	0.000	0.000	0.000	0.000	0.000	0.001	0.005	0.016
6	0.095	0.085	0.049	0.020	0.000	0.000	0.001	0.006	0.011	0.015	0.132	0.221
7	0.616	0.466	0.327	0.046	0.001	0.001	0.009	0.029	0.045	0.087	0.517	1.326
8	2.288	1.212	0.576	0.088	0.005	0.005	0.054	0.157	0.148	0.168	1.149	2.971
9	3.735	2.105	0.782	0.053	0.011	0.024	0.212	0.673	0.208	0.142	2.083	4.669
10	3.277	1.663	0.625	0.039	0.025	0.079	0.782	1.599	0.354	0.102	1.872	4.506
11	2.724	1.237	0.450	0.028	0.050	0.188	1.846	3.001	0.586	0.079	1.517	4.063
12	2.160	0.958	0.292	0.021	0.083	0.384	2.982	4.435	0.866	0.068	1.262	3.450
13	1.920	0.687	0.146	0.015	0.137	0.658	4.363	5.794	1.358	0.060	1.052	2.787
14	1.553	0.443	0.091	0.012	0.179	1.004	5.653	7.225	1.931	0.068	0.865	2.143
15	1.247	0.309	0.064	0.009	0.233	1.222	6.626	8.347	2.430	0.071	0.756	1.658
16	1.142	0.299	0.053	0.008	0.269	1.476	7.254	8.844	2.858	0.077	0.884	2.156
17	1.710	0.462	0.084	0.008	0.295	1.521	7.295	8.897	3.037	0.140	1.446	3.991
18	3.803	1.020	0.173	0.012	0.274	1.250	6.316	8.263	2.835	0.279	3.072	6.586
19	5.858	1.962	0.417	0.014	0.196	0.761	4.706	7.171	2.365	0.441	4.662	8.323
20	5.693	2.176	0.618	0.026	0.126	0.410	3.234	5.619	2.064	0.348	4.120	7.589
21	4.231	1.469	0.416	0.023	0.074	0.209	2.058	4.266	1.555	0.144	2.979	5.584
22	2.457	0.778	0.133	0.008	0.023	0.072	0.229	1.012	0.135	0.021	1.572	3.261
23	0.882	0.253	0.019	0.001	0.001	0.005	0.021	0.194	0.008	0.003	0.553	1.052
24	0.119	0.030	0.001	0.000	0.000	0.000	0.001	0.012	0.000	0.000	0.084	0.179

PRM is 15.6% for 2021 test year

- **A 1-annual-event-in-10-years standard (LOLE=2.4) implies an annual capacity shortage of 918 MW in 2021**
- **Equivalent to a 15.6% PRM**
  - PRM calculations use average of summer and winter reliable capacity for thermal and hydro resources
  - Annual ELCC used for wind and solar

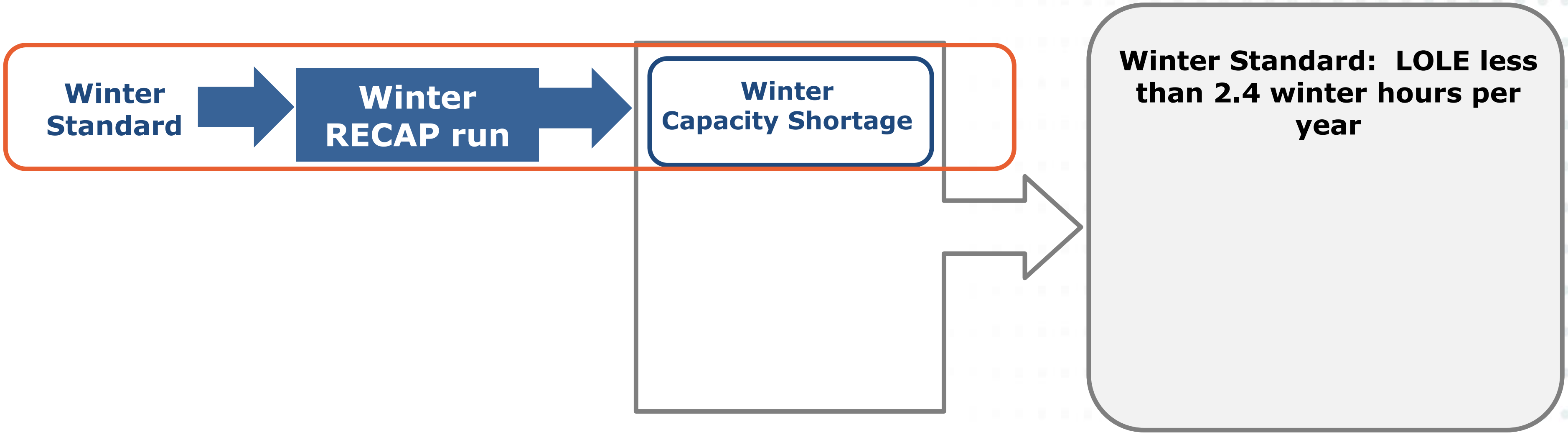
Unit	MW
Natural Gas	1,809
Colstrip	296
Hydro Projects	575
Mid-C Hydro Agreements	123
Other Contracts	9
DSG	85
DSM	41
Renewables	127
Imports	92
Total Available Dependable Capacity	**3,157**
1-in-2 Peak Load	3,525
Planning Reserve Margin	550
Total Dependable Capacity Needed	**4,075**
Dependable Capacity Shortage	**918**
PRM (%)	**15.6%**

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



Winter Standard

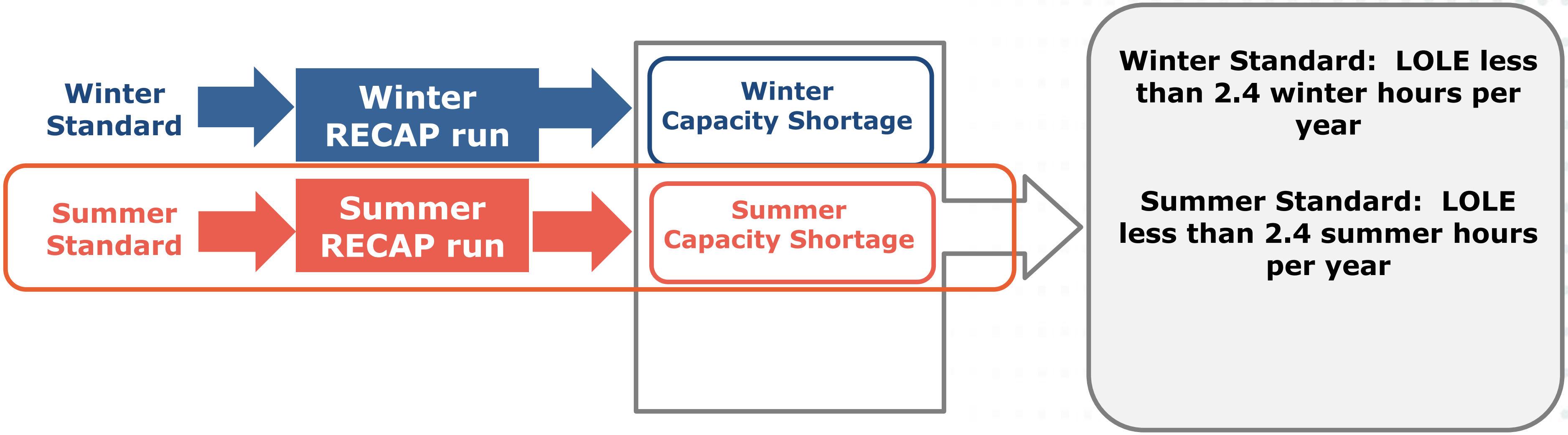
Winter RECAP run

Winter Capacity Shortage

Winter Standard: LOLE less than 2.4 winter hours per year

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



Winter Standard

Winter RECAP run

Winter Capacity Shortage

Summer Standard

Summer RECAP run

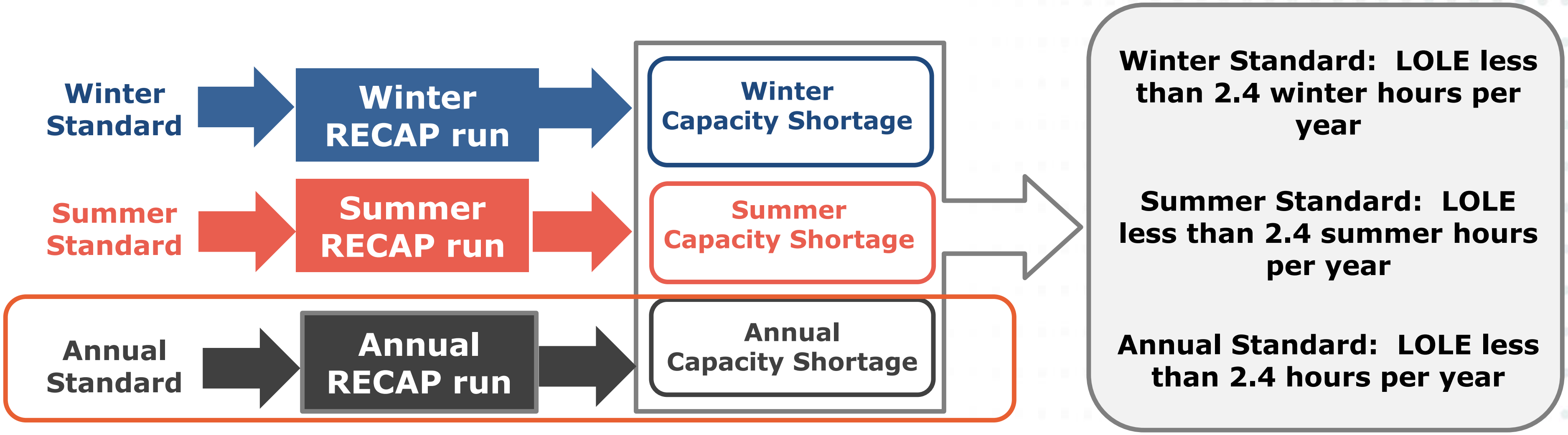
Summer Capacity Shortage

Winter Standard: LOLE less than 2.4 winter hours per year

Summer Standard: LOLE less than 2.4 summer hours per year

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)



Winter Standard → Winter RECAP run → Winter Capacity Shortage

Summer Standard → Summer RECAP run → Summer Capacity Shortage

Annual Standard → Annual RECAP run → Annual Capacity Shortage

Winter Standard: LOLE less than 2.4 winter hours per year

Summer Standard: LOLE less than 2.4 summer hours per year

Annual Standard: LOLE less than 2.4 hours per 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

Target PRM is 15.0% for Winter Test

- A 1-winter-event-in-10-years standard implies a winter capacity shortage of 687 MW in 2021
- Equivalent to a 15.0% PRM
- Winter standard is less conservative than annual standard

Unit	MW
Natural Gas	1,862
Colstrip	296
Hydro Projects	624
Mid-C Hydro Agreements	127
Other Contracts	9
DSG	85
DSM	41
Renewables	108
Imports	214
Total Available Dependable Capacity	**3,368**
1-in-2 Peak Load	3,525
Planning Reserve Margin	530
Total Dependable Capacity Needed	**4,055**
Dependable Capacity Shortage	**687**
PRM (%)	**15.0%**

Target PRM is 14.7% for Summer Test

- A 1-summer-event-in-10-years standard implies a summer capacity shortage of 884 MW in 2021
- Equivalent to a 14.7% PRM
- Summer standard is less conservative than annual standard
- Thermal reliable capacity lower in summer

Unit	MW
Natural Gas	1,756
Colstrip	296
Hydro Projects	526
Mid-C Hydro Agreements	119
Other Contracts	9
DSG	85
DSM	41
Renewables	138
Imports	20
Total Available Dependable Capacity	**2,989**
1-in-2 Peak Load	3,376
Planning Reserve Margin	498
Total Dependable Capacity Needed	**3,874**
Dependable Capacity Shortage	**884**
PRM (%)	**14.7%**

Target PRM is 15.6% for Annual Test

- **A 1-annual-event-in-10-years standard (LOLE=2.4) implies an annual capacity shortage of 918 MW in 2021**
- **Equivalent to a 15.6% PRM**
- **More conservative than winter + summer**
  - Winter + summer could result in 2 events in 10 yrs.

Unit	MW
Natural Gas	1,809
Colstrip	296
Hydro Projects	575
Mid-C Hydro Agreements	123
Other Contracts	9
DSG	85
DSM	41
Renewables	127
Imports	92
Total Available Dependable Capacity	**3,157**
1-in-2 Peak Load	3,525
Planning Reserve Margin	550
Total Dependable Capacity Needed	**4,075**
Dependable Capacity Shortage	**918**
PRM (%)	**15.6%**

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

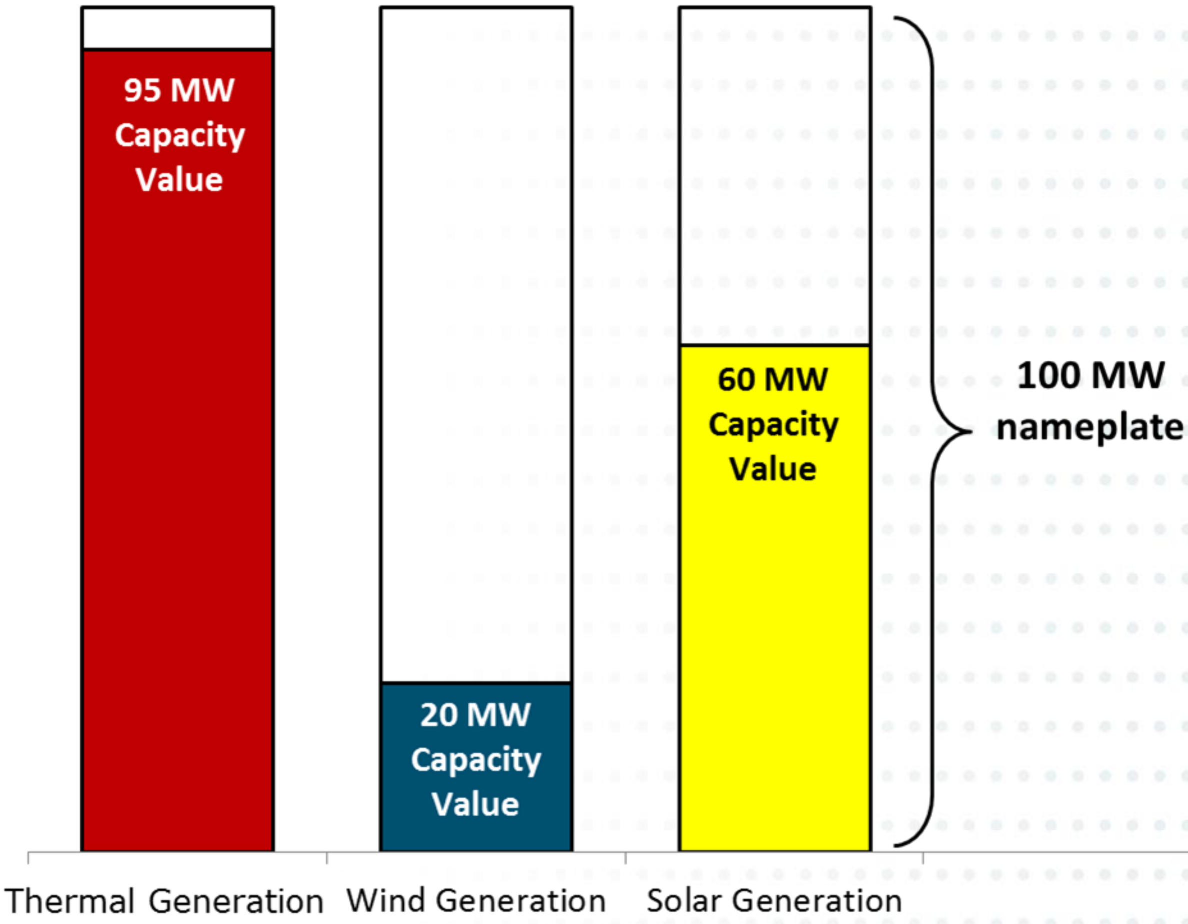
CAPACITY CONTRIBUTION OF DISPATCH-LIMITED RESOURCES

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**

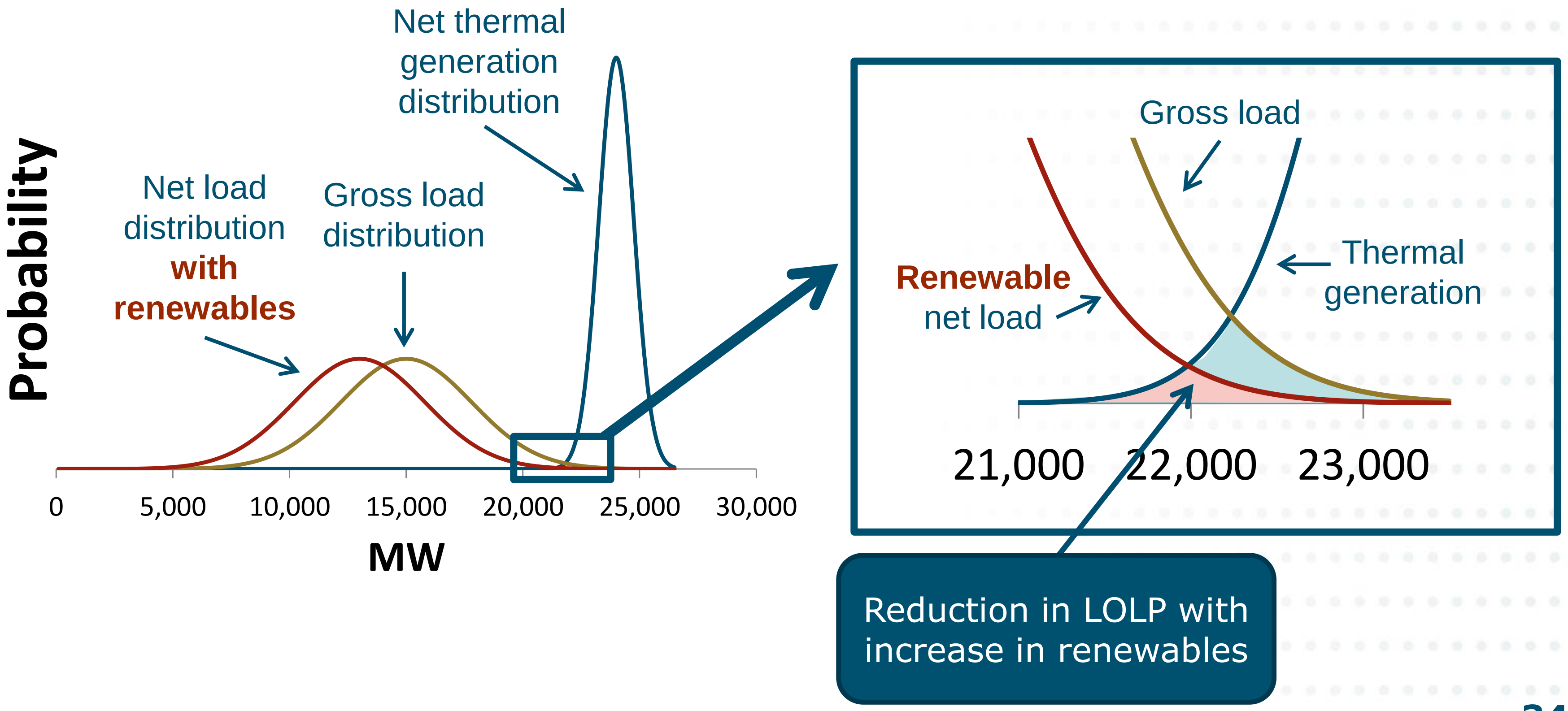
Illustrative Capacity Values

(not based on PGE system)



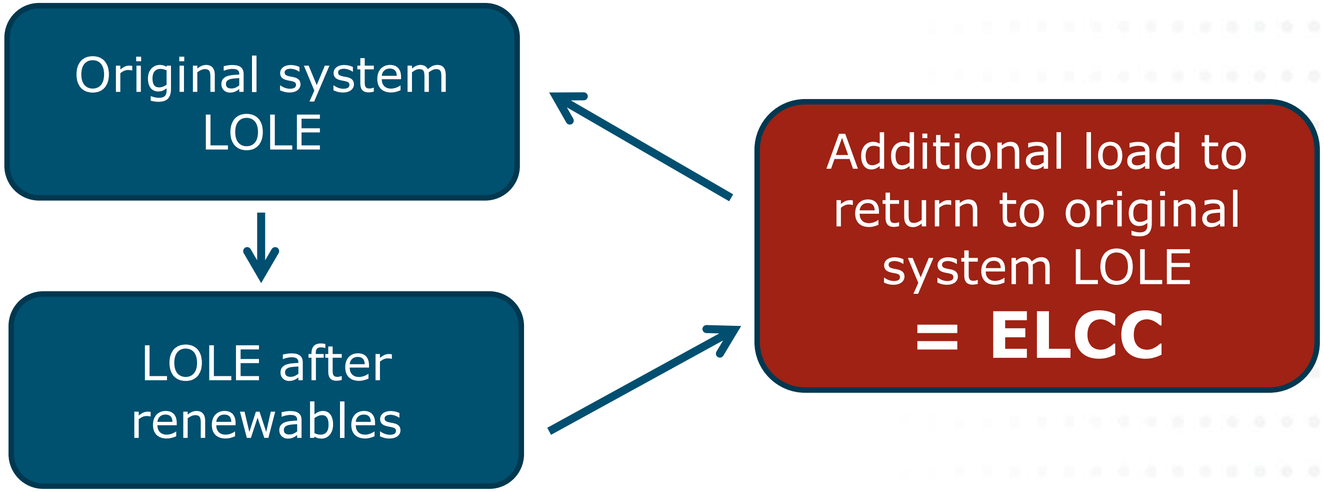
Renewables subtracted from load in LOLP calculations

- 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)



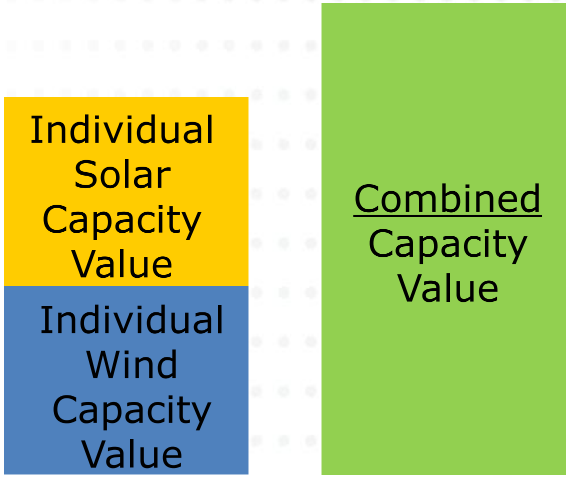
Original system LOLE

LOLE after renewables

Additional load to return to original system LOLE

= ELCC

Capacity value in applications



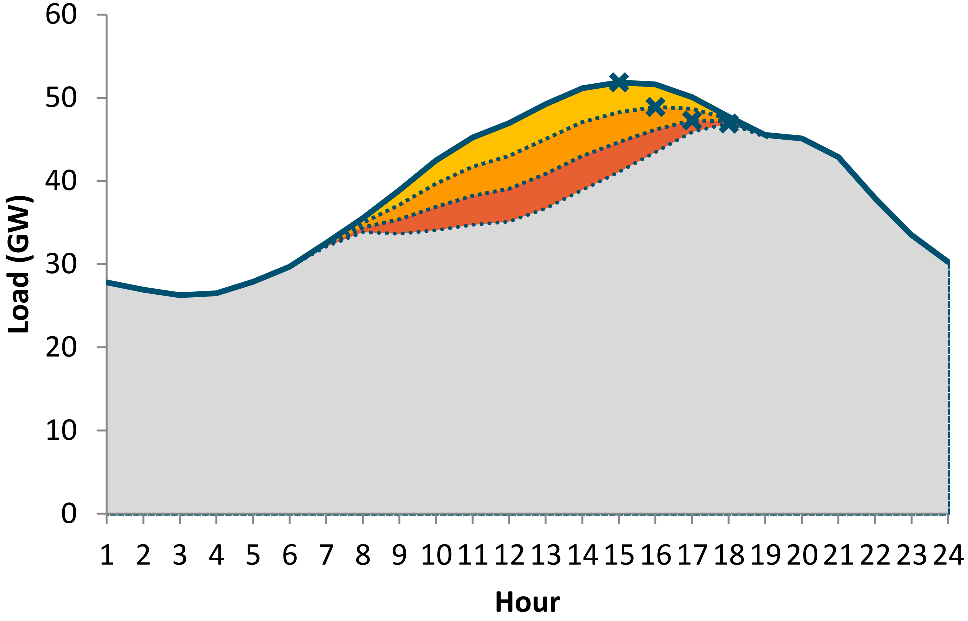
- **The portfolio capacity value is the most relevant calculation to consider in resource planning**
  - Due to the complementarity of different resources the portfolio value will be higher than the sum of each individual resource measured alone
  - It is sometimes necessary to attribute the capacity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

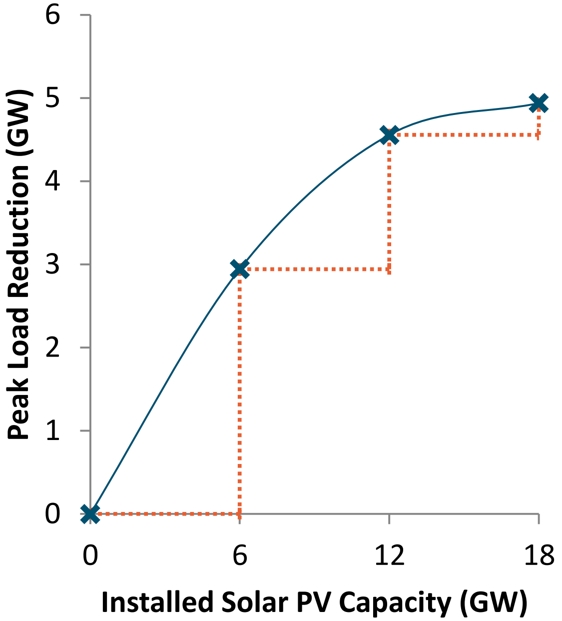
Factors that affect the capacity value of variable generation

- **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

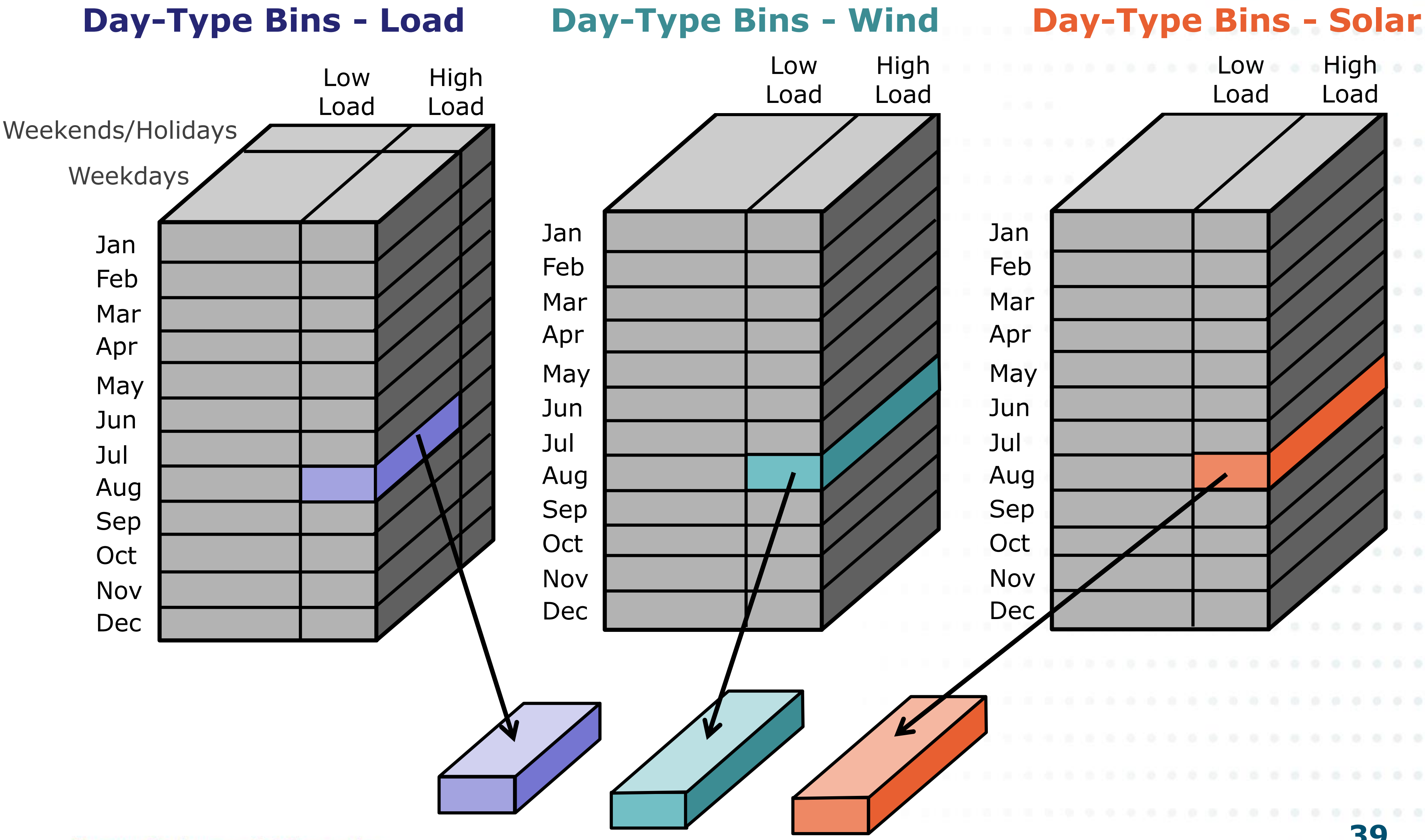
Marginal capacity value declines as penetration increases

- **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





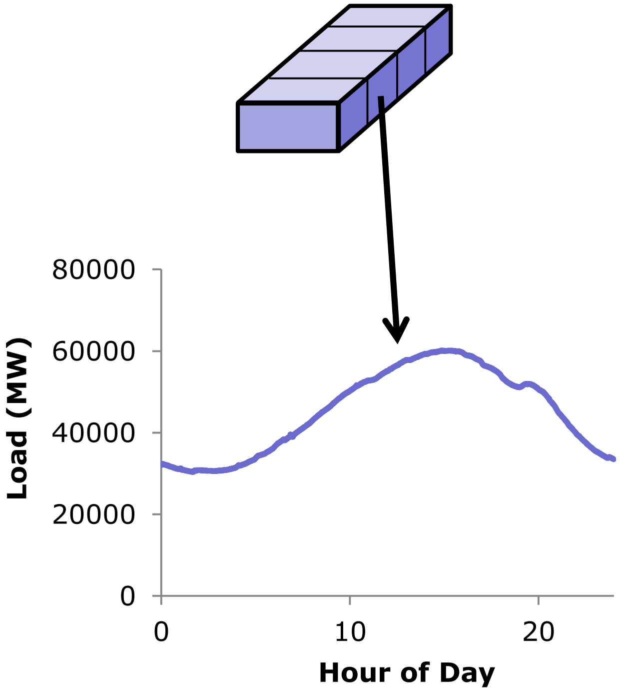
Example Draw: High Load Weekday in August



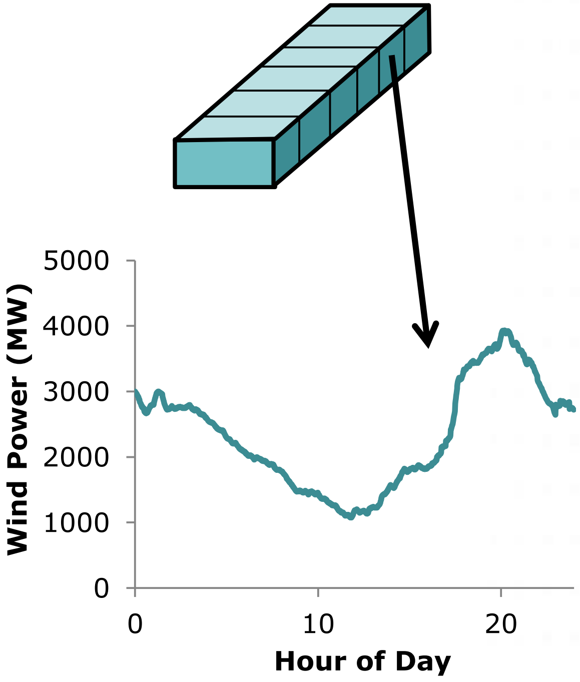
Example Draw:
High Load Weekday in August

- Within each bin, choose each (load, wind, and solar) daily profile randomly, and independent of other daily profiles

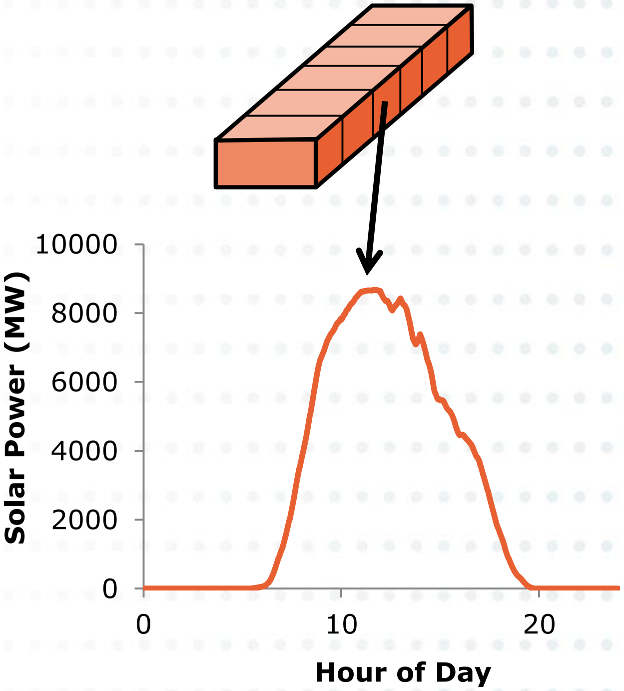
Load Bin



Wind Bin



Solar Bin

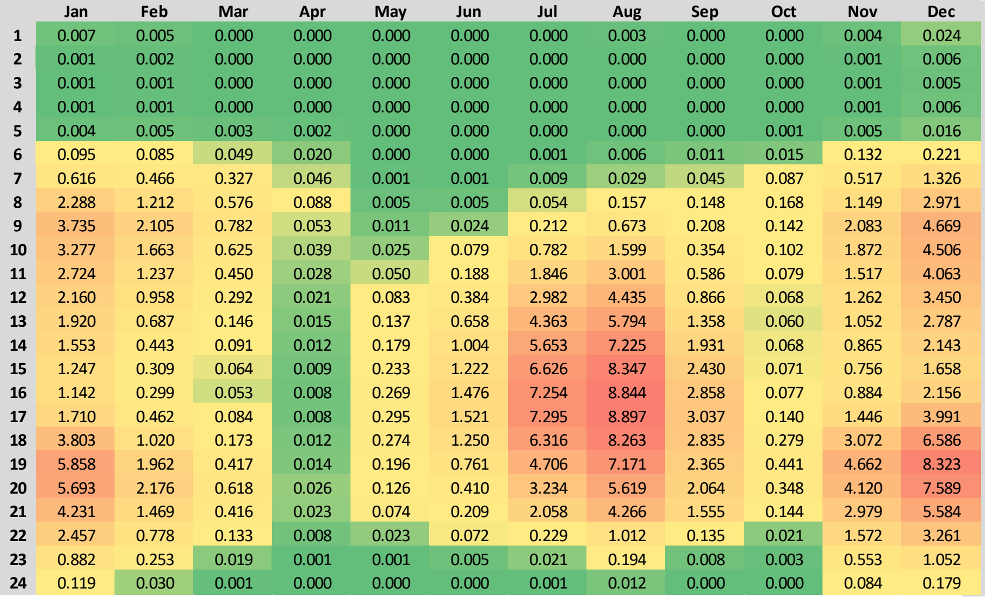


Gorge wind has low output during hours with high LOLP

Coincidence of high renewable output and high system LOLE affects resource ELCC

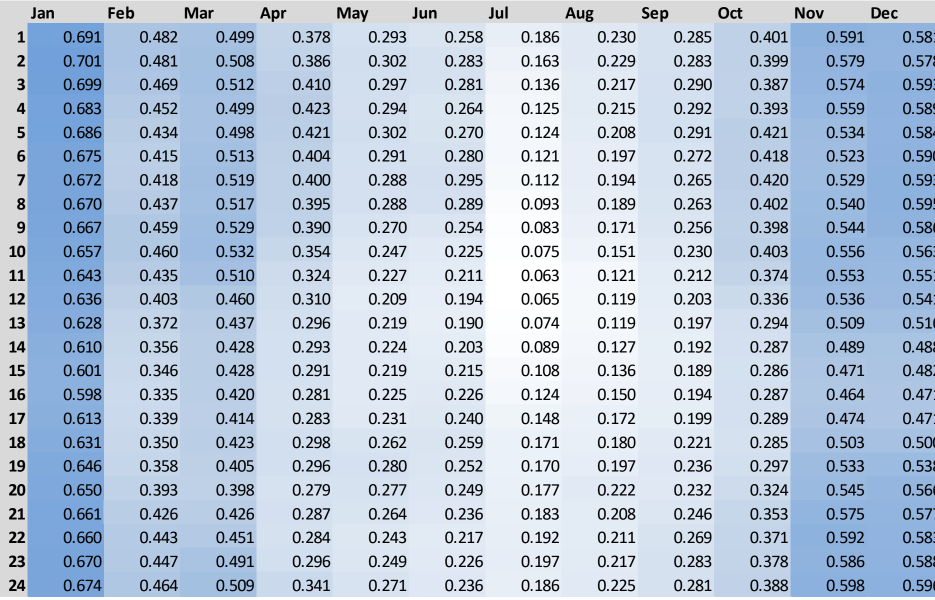
- System LOLE is concentrated in summer afternoon hours
- Sample Gorge wind site has relative low output on summer afternoons, resulting in low ELCC

System LOLE



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.007	0.005	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.004	0.024
2	0.001	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.006
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.005
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.006
5	0.004	0.005	0.003	0.002	0.000	0.000	0.000	0.000	0.000	0.001	0.005	0.016
6	0.095	0.085	0.049	0.020	0.000	0.000	0.001	0.006	0.011	0.015	0.132	0.221
7	0.616	0.466	0.327	0.046	0.001	0.001	0.009	0.029	0.045	0.087	0.517	1.326
8	2.288	1.212	0.576	0.088	0.005	0.005	0.054	0.157	0.148	0.168	1.149	2.971
9	3.735	2.105	0.782	0.053	0.011	0.024	0.212	0.673	0.208	0.142	2.083	4.669
10	3.277	1.663	0.625	0.039	0.025	0.079	0.782	1.599	0.354	0.102	1.872	4.506
11	2.724	1.237	0.450	0.028	0.050	0.188	1.846	3.001	0.586	0.079	1.517	4.063
12	2.160	0.958	0.292	0.021	0.083	0.384	2.982	4.435	0.866	0.068	1.262	3.450
13	1.920	0.687	0.146	0.015	0.137	0.658	4.363	5.794	1.358	0.060	1.052	2.787
14	1.553	0.443	0.091	0.012	0.179	1.004	5.653	7.225	1.931	0.068	0.865	2.143
15	1.247	0.309	0.064	0.009	0.233	1.222	6.626	8.347	2.430	0.071	0.756	1.658
16	1.142	0.299	0.053	0.008	0.269	1.476	7.254	8.844	2.858	0.077	0.884	2.156
17	1.710	0.462	0.084	0.008	0.295	1.521	7.295	8.897	3.037	0.140	1.446	3.991
18	3.803	1.020	0.173	0.012	0.274	1.250	6.316	8.263	2.835	0.279	3.072	6.586
19	5.858	1.962	0.417	0.014	0.196	0.761	4.706	7.171	2.365	0.441	4.662	8.323
20	5.693	2.176	0.618	0.026	0.126	0.410	3.234	5.619	2.064	0.348	4.120	7.589
21	4.231	1.469	0.416	0.023	0.074	0.209	2.058	4.266	1.555	0.144	2.979	5.584
22	2.457	0.778	0.133	0.008	0.023	0.072	0.229	1.012	0.135	0.021	1.572	3.261
23	0.882	0.253	0.019	0.001	0.001	0.005	0.021	0.194	0.008	0.003	0.553	1.052
24	0.119	0.030	0.001	0.000	0.000	0.000	0.001	0.012	0.000	0.000	0.084	0.179

Average Normalized Wind Output Sample Wind Site 1



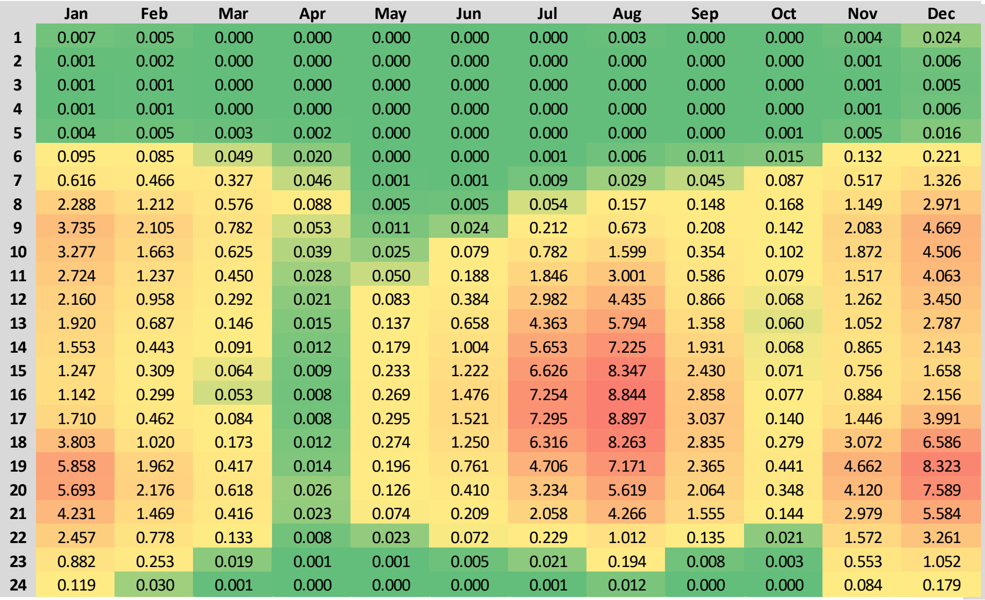
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.691	0.482	0.499	0.378	0.293	0.258	0.186	0.230	0.285	0.401	0.591	0.58
2	0.701	0.481	0.508	0.386	0.302	0.283	0.163	0.229	0.283	0.399	0.579	0.57
3	0.699	0.469	0.512	0.410	0.297	0.281	0.136	0.217	0.290	0.387	0.574	0.59
4	0.683	0.452	0.499	0.423	0.294	0.264	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 affects resource ELCC

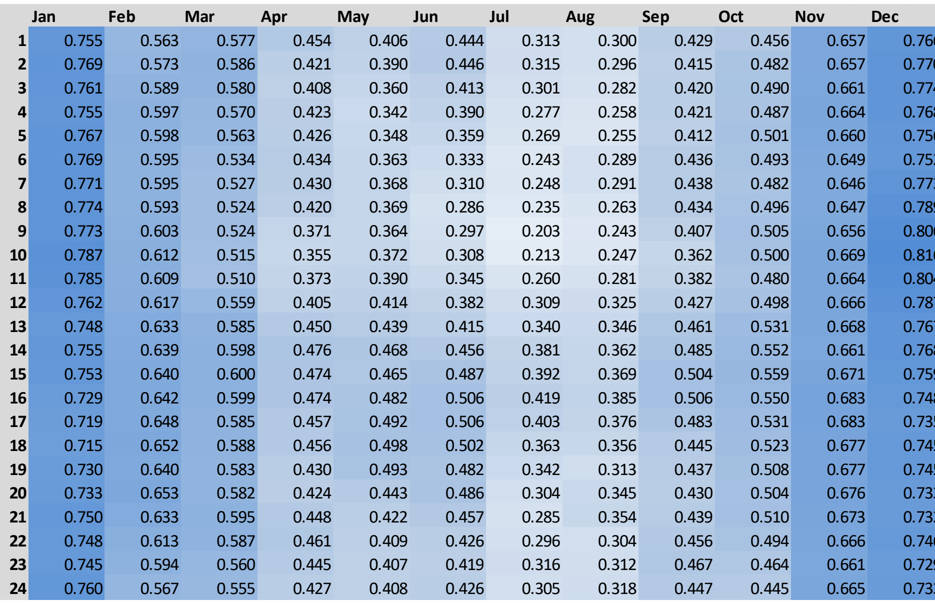
- System LOLE is concentrated in summer afternoon hours
- Sample Montana wind site has higher relative output on summer afternoons, resulting in higher ELCC

System LOLE



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.007	0.005	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.004	0.024
2	0.001	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.006
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.005
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.006
5	0.004	0.005	0.003	0.002	0.000	0.000	0.000	0.000	0.000	0.001	0.005	0.016
6	0.095	0.085	0.049	0.020	0.000	0.000	0.001	0.006	0.011	0.015	0.132	0.221
7	0.616	0.466	0.327	0.046	0.001	0.001	0.009	0.029	0.045	0.087	0.517	1.326
8	2.288	1.212	0.576	0.088	0.005	0.005	0.054	0.157	0.148	0.168	1.149	2.971
9	3.735	2.105	0.782	0.053	0.011	0.024	0.212	0.673	0.208	0.142	2.083	4.669
10	3.277	1.663	0.625	0.039	0.025	0.079	0.782	1.599	0.354	0.102	1.872	4.506
11	2.724	1.237	0.450	0.028	0.050	0.188	1.846	3.001	0.586	0.079	1.517	4.063
12	2.160	0.958	0.292	0.021	0.083	0.384	2.982	4.435	0.866	0.068	1.262	3.450
13	1.920	0.687	0.146	0.015	0.137	0.658	4.363	5.794	1.358	0.060	1.052	2.787
14	1.553	0.443	0.091	0.012	0.179	1.004	5.653	7.225	1.931	0.068	0.865	2.143
15	1.247	0.309	0.064	0.009	0.233	1.222	6.626	8.347	2.430	0.071	0.756	1.658
16	1.142	0.299	0.053	0.008	0.269	1.476	7.254	8.844	2.858	0.077	0.884	2.156
17	1.710	0.462	0.084	0.008	0.295	1.521	7.295	8.897	3.037	0.140	1.446	3.991
18	3.803	1.020	0.173	0.012	0.274	1.250	6.316	8.263	2.835	0.279	3.072	6.586
19	5.858	1.962	0.417	0.014	0.196	0.761	4.706	7.171	2.365	0.441	4.662	8.323
20	5.693	2.176	0.618	0.026	0.126	0.410	3.234	5.619	2.064	0.348	4.120	7.589
21	4.231	1.469	0.416	0.023	0.074	0.209	2.058	4.266	1.555	0.144	2.979	5.584
22	2.457	0.778	0.133	0.008	0.023	0.072	0.229	1.012	0.135	0.021	1.572	3.261
23	0.882	0.253	0.019	0.001	0.001	0.005	0.021	0.194	0.008	0.003	0.553	1.052
24	0.119	0.030	0.001	0.000	0.000	0.000	0.001	0.012	0.000	0.000	0.084	0.179

Average Normalized Wind Output
Sample Wind Site 2



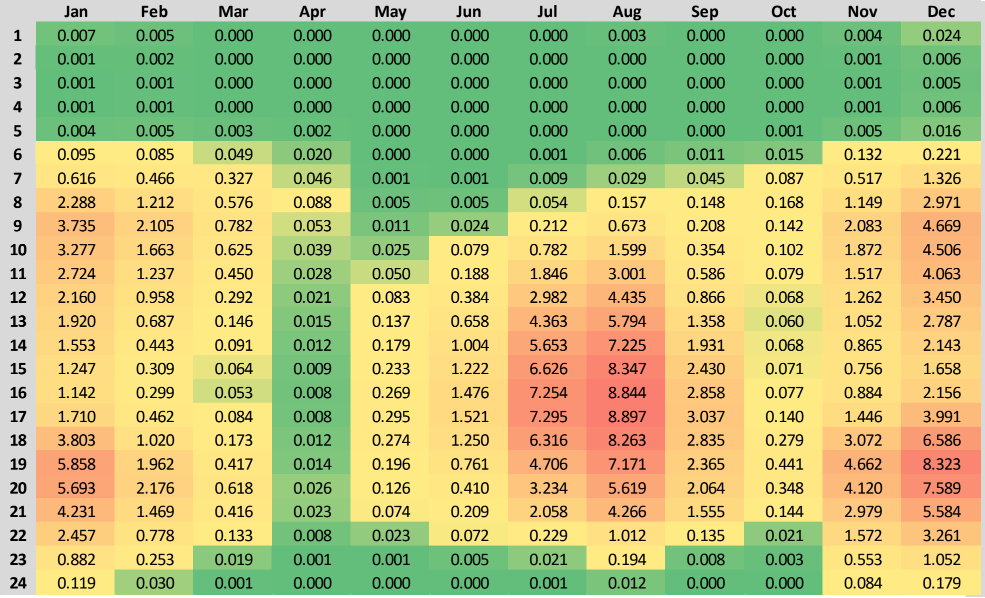
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.755	0.563	0.577	0.454	0.406	0.444	0.313	0.300	0.429	0.456	0.657	0.76
2	0.769	0.573	0.586	0.421	0.390	0.446	0.315	0.296	0.415	0.482	0.657	0.77
3	0.761	0.589	0.580	0.408	0.360	0.413	0.301	0.282	0.420	0.490	0.661	0.77
4	0.755	0.597	0.570	0.423	0.342	0.390	0.277	0.258	0.421	0.487	0.664	0.76
5	0.767	0.598	0.563	0.426	0.348	0.359	0.269	0.255	0.412	0.501	0.660	0.75
6	0.769	0.595	0.534	0.434	0.363	0.333	0.243	0.289	0.436	0.493	0.649	0.75
7	0.771	0.595	0.527	0.430	0.368	0.310	0.248	0.291	0.438	0.482	0.646	0.77
8	0.774	0.593	0.524	0.420	0.369	0.286	0.235	0.263	0.434	0.496	0.647	0.78
9	0.773	0.603	0.524	0.371	0.364	0.297	0.203	0.243	0.407	0.505	0.656	0.80
10	0.787	0.612	0.515	0.355	0.372	0.308	0.213	0.247	0.362	0.500	0.669	0.81
11	0.785	0.609	0.510	0.373	0.390	0.345	0.260	0.281	0.382	0.480	0.664	0.80
12	0.762	0.617	0.559	0.405	0.414	0.382	0.309	0.325	0.427	0.498	0.666	0.78
13	0.748	0.633	0.585	0.450	0.439	0.415	0.340	0.346	0.461	0.531	0.668	0.76
14	0.755	0.639	0.598	0.476	0.468	0.456	0.381	0.362	0.485	0.552	0.661	0.76
15	0.753	0.640	0.600	0.474	0.465	0.487	0.392	0.369	0.504	0.559	0.671	0.75
16	0.729	0.642	0.599	0.474	0.482	0.506	0.419	0.385	0.506	0.550	0.683	0.74
17	0.719	0.648	0.585	0.457	0.492	0.506	0.403	0.376	0.483	0.531	0.683	0.73
18	0.715	0.652	0.588	0.456	0.498	0.502	0.363	0.356	0.445	0.523	0.677	0.74
19	0.730	0.640	0.583	0.430	0.493	0.482	0.342	0.313	0.437	0.508	0.677	0.74
20	0.733	0.653	0.582	0.424	0.443	0.486	0.304	0.345	0.430	0.504	0.676	0.73
21	0.750	0.633	0.595	0.448	0.422	0.457	0.285	0.354	0.439	0.510	0.673	0.73
22	0.748	0.613	0.587	0.461	0.409	0.426	0.296	0.304	0.456	0.494	0.666	0.74
23	0.745	0.594	0.560	0.445	0.407	0.419	0.316	0.312	0.467	0.464	0.661	0.72
24	0.760	0.567	0.555	0.427	0.408	0.426	0.305	0.318	0.447	0.445	0.665	0.73

Solar output is high during summer peak hours

+ Coincidence of high renewable output and high system LOLE affects resource 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	0.007	0.005	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.004	0.024
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16	1.142	0.299	0.053	0.008	0.269	1.476	7.254	8.844	2.858	0.077	0.884	2.156
17	1.710	0.462	0.084	0.008	0.295	1.521	7.295	8.897	3.037	0.140	1.446	3.991
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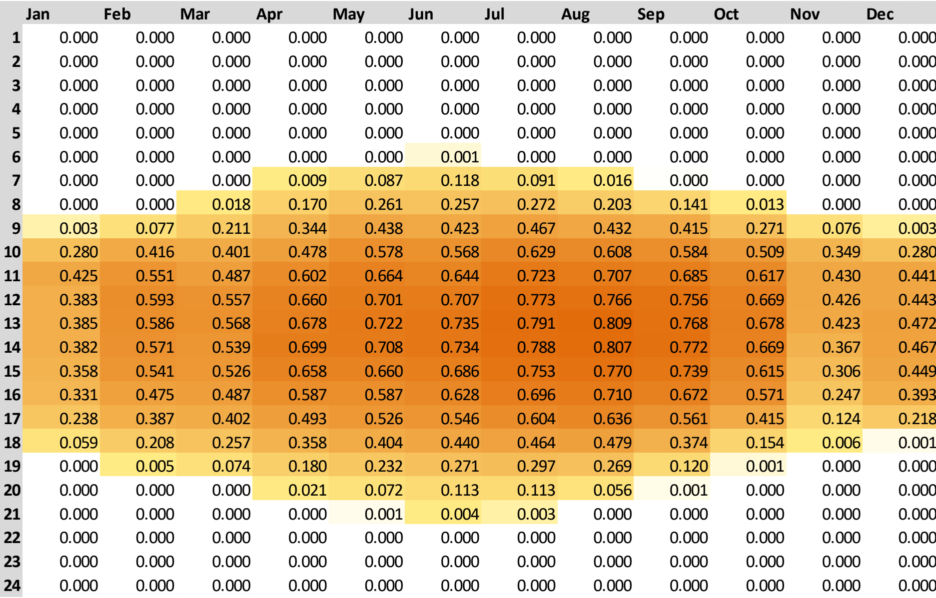
21	4.231	1.469	0.416	0.023	0.074	0.209	2.058	4.266	1.555	0.144	2.979	5.584
22	2.457	0.778	0.133	0.008	0.023	0.072	0.229	1.012	0.135	0.021	1.572	3.261
23	0.882	0.253	0.019	0.001	0.001	0.005	0.021	0.194	0.008	0.003	0.553	1.052
24	0.119	0.030	0.001	0.000	0.000	0.000	0.001	0.012	0.000	0.000	0.084	0.179

Average Normalized Solar Output Sample Site

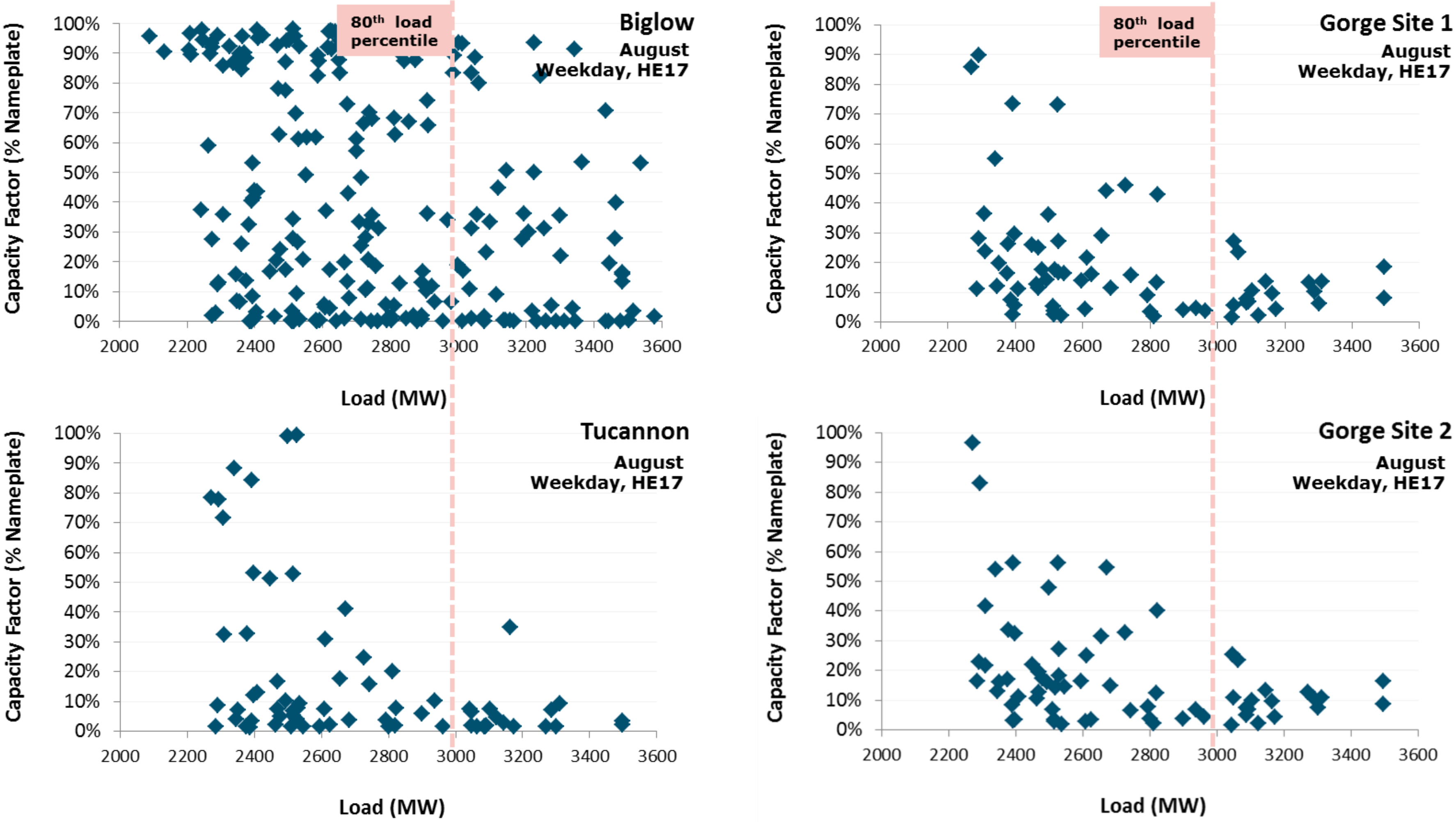


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.000	0.000	0.000	0.000	0.000	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**

Gorge wind is negatively correlated with load during summer peak hours



Preliminary ELCC for PGE's current renewable portfolio is 14.1%

	Winter	Summer	Annual
Nameplate rating MW	902	902	902
Portfolio ELCC (MW)	108	138	127
Portfolio ELCC (% of nameplate MW)	12.0%	15.3%	14.1%

- **PGE portfolio currently has 902 MW of renewables**
  - Most is wind capacity
- **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 Gorge Wind	609 MW	65 MW (11%)
Incremental Solar	168 MW	68 MW (41%)
Total Incremental Portfolio	777 MW	141 MW (18%)

Preliminary marginal ELCC of incremental resources

- Montana wind has capacity factor and higher ELCC than the Gorge sites
- The Montana wind site exhibits strong portfolio effects with solar PV

Resource	Nameplate Rating (MW)	Annual ELCC
Incremental Montana Wind	445 MW	91 MW (20%)
Incremental Solar	168 MW	68 MW (41%)
Total Incremental Portfolio	613 MW	171 (28%)

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 portfolio ELCC for all three tests

Resource	Nameplate Rating (MW)	Winter ELCC	Summer ELCC
Incremental Gorge Wind	609 MW	112 MW (18%)	55 MW (9%)
Incremental Solar	168 MW	12 MW (7%)	91 MW (54%)
Total Incremental Portfolio	777 MW	127 MW (16%)	148 MW (19%)

Preliminary marginal ELCC of incremental resources by season

- **Montana wind resources have higher ELCC than the Gorge sites in both the winter and the summer**
- **Positive portfolio effects with solar PV result in similar incremental portfolio ELCC in winter and summer**

Resource	**Nameplate Rating (MW)**	**Winter ELCC**	**Summer ELCC**
Incremental Montana Wind	445 MW	192 MW (43%)	74 MW (17%)
Incremental Solar	168 MW	12 MW (7%)	91 MW (54%)
Total Incremental Portfolio	613 MW	208 MW (34%)	166 MW (27%)

Thank You!

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