Effective load carrying capacity

The peak reserve margin constraint attributes a certain amount of capacity to each resource that is assumed to be available for meeting the annual peak demand. For conventional (which are dispatchable) generation, this value is simply the rating of the unit, with some derating due to the forced outage rate of the plant. The situation is more complicated for variable generation (recall that the Midwest ISO is currently attributing only 8% of wind nameplate towards capacity – referred to as the “capacity credit” for wind.

The reason for this different treatment is that FOR of conventional generation tends to range between 2% and 20% (giving an availability between 80% and 98%), whereas wind energy is available at varying levels that average between 30% and 45% of the time depending on the quality of the wind resource at each particular site.

There is another issue why wind is considered to be less available than conventional generation. For conventional generation, the outage one plant is independent of the outage of another plant (except in certain cases related to cascading which we will not consider here). On the other hand, if the wind speed decreases significantly at windfarm A, then it is also very likely to decrease significantly at a nearby windfarm B. In other words, wind capacity experiences correlation between plants; conventional capacity does not (and this “geodiversity” is one reason why larger boundaries for control areas can be more effective than smaller boundaries).

An approach to account for low capacity factor and geodiversity is to set the capacity for variable generation equal to the amount of load that could be added without changing the risk of a shortage in generation capacity at peak load, as measured by loss of load expectation (LOLE) or loss of load probability (LOLP). This is referred to as the effective load carrying capability, or ELCC. This concept is illustrated in Fig. 7, which comes from an excellent and very recent paper [1].
In Fig. 7, we observe:

- The criterion indicated by the horizontal line is 1 day in 10 years or 0.1 day in 1 year is achieved for peak load less than or equal to 10000 MW.

- The addition of a certain block of new generation moves the LOLE function. If we required that the load remain the same, the LOLE would go down (get better) to about 0.09.

- Assume that we want to maintain the same LOLE value of 1 day in 10 years (or 0.1 day in one year). In this case, we may grow the load by 400 MW. This 400 MW load growth is called the ELCC of the additional generation.

- The ELCC of an additional block of generation will only be equal to the capacity of that additional block of generation if the additional block of generation is dispatchable and completely reliable.
When expanding wind capacity, an application should account for the impact of geodiversity (and also wind site quality, transmission availability and cost, and local siting costs) in selecting the next windfarm site within a region as the site which is least correlated with existing sites to ensure the highest ELCC for the next wind site.

Reference [1] provides a three-step method for computing ELCC, which depends on development of the capacity outage probability table (COPT). The description is lifted verbatim as follows:

1. “The COPT of the power system is used in conjunction with the hourly load time series to compute the hourly LOLPs without the presence of the wind plant. The annual LOLE is then calculated. The LOLE should meet the predetermined reliability target for that period. If it does not match, the loads can be adjusted, if desired, so that the target reliability level is achieved.

2. The time series for the wind plant power output is treated as negative load and is combined with the load time series, resulting in a load time series net of wind power. In the same manner as step 1, the LOLE is calculated. It will now be lower (and therefore better) than the target LOLE in the first step.

3. The load data is then increased by a constant across all hours using an iterative process, and the LOLE recalculated at each step until the target LOLE is reached. The increase in peak load (sum of) that achieves the reliability target is the ELCC or capacity value of the wind plant.”

We address several questions in what follows.

1. What is a capacity outage probability table (COPT)?
2. How to do the following: “The COPT of the power system is used in conjunction with the hourly load time series to compute the hourly LOLPs”?
3. How to compute the COPT?

Question 1: What is a capacity outage probability table (COPT)?
The capacity outage table is a table of generation outage states and their associated probabilities. A very simple COPT is provided below as Table 4 for a power system that has only one generation that may either be

- up, generating C (with capacity outage 0) at probability A, or
- down, generating 0 (with capacity outage C) at probability U.

Table 4

<table>
<thead>
<tr>
<th>Capacity Outage</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>A</td>
</tr>
<tr>
<td>C</td>
<td>U</td>
</tr>
</tbody>
</table>

If we had a power system comprised of two identical units, the COPT would appear as Table 5 below.

Table 5

<table>
<thead>
<tr>
<th>Capacity Outage</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>A^2</td>
</tr>
<tr>
<td>C</td>
<td>AU</td>
</tr>
<tr>
<td>C</td>
<td>UA</td>
</tr>
<tr>
<td>2C</td>
<td>U^2</td>
</tr>
</tbody>
</table>

Consider a system with two 3 MW units and one 5 MW unit, all of which have forced outage rates (FOR) of U=0.02. There is a procedure which will allow us to construct the COPT, and it results in Table 6 below.

Table 6

<table>
<thead>
<tr>
<th>Capacity outage state k</th>
<th>Capacity outage, C_k</th>
<th>Probability</th>
</tr>
</thead>
</table>
Table 6 tells us that over a given time interval, the probability that the system will have a capacity outage:

- of 0 MW is 0.941192;
- of 3 MW is 0.038416;
- of 5 MW is 0.019208;
- of 6 MW is 0.000392;
- of 8 MW is 0.000784;
- of 11 MW is 0.000008.

The procedure for obtaining the COPT is easily extended to consider any number of units with any forced outage rates, identical or not. But before considering that procedure, let’s answer the second question.

**Question 2:** How to do the following: “The COPT of the power system is used in conjunction with the hourly load time series to compute the hourly LOLPs”?

To answer this question, we recognize that we will have loss of load if the load exceeds the generation capacity.

The generation capacity will be the installed capacity, call it $IC$, less the capacity that is outaged, call it $C_k$ (corresponding to capacity outage state $k$). Thus, we see loss of load if

$$d > IC - C_k$$  (11)
So we would like to obtain \( \Pr(d > IC - C_k) \).

We can view this another way, by observing the criterion for loss of load is
\[
C_k > IC - d
\]
and so we desire \( \Pr(C_k > IC - d) \).

In our above example, we observe that our capacity is 11 MW. Let’s assume that the load is 5 MW. Then we may obtain
\[
\begin{align*}
\Pr(C_k > 11 - 5) &= \Pr(C_k > 6) \\
&= \Pr(C_k = 8) + \Pr(C_k = 11) \\
&= 0.000784 + 0.000008 \\
&= 0.000792
\end{align*}
\]

We can formalize what we have done.

Denote the capacity outage as a random variable \( Y \). Observe that the probabilities given by the COPT characterize a probability mass function (which is the discrete version of a probability density function), and we will define it as \( f_Y(y) \), as indicated in Fig. 8 below.

We can then define a cumulative probability function \( F_Y(y) \) according to:
\[
F_Y(y) = P(Y > y) = \sum_{y_j > y} f_Y(y_j) = 1 - \sum_{y_j \leq y} f_Y(y_j)
\]
Adding a column to our COPT for $F_Y(y)$ results in Table 7.

<table>
<thead>
<tr>
<th>Capacity outage state $k$</th>
<th>Capacity outage, $C_k$</th>
<th>Probability $f_Y(y)$</th>
<th>Cumulative probability $F_Y(y)$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>0.941192</td>
<td>0.0588</td>
</tr>
<tr>
<td>2</td>
<td>3</td>
<td>0.038416</td>
<td>0.0204</td>
</tr>
<tr>
<td>3</td>
<td>5</td>
<td>0.019208</td>
<td>0.0012</td>
</tr>
<tr>
<td>4</td>
<td>6</td>
<td>0.000392</td>
<td>0.000792</td>
</tr>
<tr>
<td>5</td>
<td>8</td>
<td>0.000784</td>
<td>0.000008</td>
</tr>
<tr>
<td>6</td>
<td>11</td>
<td>0.000008</td>
<td>0</td>
</tr>
</tbody>
</table>

We plot $F_Y(y)$ in Fig. 9 below, but not to scale.

![Fig. 9](image-url)
Once we have Table 7, given a certain load $d$, we may compute the LOLP, i.e., the probability of interrupting load, during the desired time interval, as the probability that the capacity outage exceeds $IC-d$, which is just $F_Y(y=IC-d)$, that is,

$$LOLP(d) = F_Y(y=IC-d)$$

Thus, recalling $IC=11$, and with a load of 5 MW, we obtain $LOLP(5) = F_Y(y=6)=0.000792$.

We make a couple of comments about use of $F_Y(y)$:

1. Consider what $IC-d$ really is. It is the difference between the installed capacity and the load. This is actually the reserve, and so we are actually computing, for a given load $d$, $Pr(Y>\text{Reserve})=F_Y(y=\text{Reserve})$.

2. In computations, one needs to decide how to handle points of discontinuity. For example, referring to Fig. 9, should $F_Y(3)$ be 0.0588 or 0.0204? This is asking, when we have a load of 8, implying a reserve of 11-8=3,
   - Should LOLP be 0.0588?
   - Or should LOLP be 0.0204?
   The key to answering this question is to recall the definition of $F_Y(y)$, which is
   $$F_Y(y) = P(Y > y) = \sum_{y_j > y} f_Y(y_j)$$

That is, $F_Y(y)$ gives the probability of having an outage that is greater than $y$. The probability of 0.0588 is the accumulated probabilities of all outage situations, since all of them will cause outage capacity

- greater than 0,
- greater than 1,
- greater than 2,
- greater than 2.9
- greater than 2.99999999999
Now, as long as we have reserve of 3, we will not lose load, and so 0.0588 should not be the LOLP.

On the other hand, the probability of 0.0204 is the accumulated probabilities of all outage situations resulting in outage capacity greater than 3. If we have reserves of only 3, all of these situations will result in load interruption, and therefore 0.0204 gives the proper LOLP when reserves are 3, i.e., when IC-d=3.

Conclusion here is that at points of discontinuities, we should use the lower probability for the LOLP.

We are now prepared to answer our second question, which we repeat here for convenience:

How to do the following? The COPT of the power system is used in conjunction with the hourly load time series to compute the hourly LOLPs.

Consider that we have 8760 hours of load data, of which Table 8 below represents 10 hours of that record.

<table>
<thead>
<tr>
<th>Time</th>
<th>$d$ (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.0</td>
</tr>
<tr>
<td>2</td>
<td>4.5</td>
</tr>
<tr>
<td>3</td>
<td>5.0</td>
</tr>
<tr>
<td>4</td>
<td>5.5</td>
</tr>
<tr>
<td>5</td>
<td>6.0</td>
</tr>
<tr>
<td>6</td>
<td>7.0</td>
</tr>
<tr>
<td>7</td>
<td>8.0</td>
</tr>
<tr>
<td>8</td>
<td>9.0</td>
</tr>
<tr>
<td>9</td>
<td>8.5</td>
</tr>
<tr>
<td>10</td>
<td>7.5</td>
</tr>
<tr>
<td>…</td>
<td>…</td>
</tr>
</tbody>
</table>
Now we can use Fig. 9, repeated here for convenience, to obtain LOLP for each of these load levels, as given in Table 9.

![Fig. 9](image-url)

### Table 9

<table>
<thead>
<tr>
<th>Time</th>
<th>$d$ (MW)</th>
<th>$y=IC-d$</th>
<th>$\text{LOLP}(d)=F_Y(y=IC-d)=\Pr(Y&gt;IC-d)$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.0</td>
<td>7.0</td>
<td>0.0000792</td>
</tr>
<tr>
<td>2</td>
<td>4.5</td>
<td>6.5</td>
<td>0.0000792</td>
</tr>
<tr>
<td>3</td>
<td>5.0</td>
<td>6.0</td>
<td>0.0000792</td>
</tr>
<tr>
<td>4</td>
<td>5.5</td>
<td>5.5</td>
<td>0.0012</td>
</tr>
<tr>
<td>5</td>
<td>6.0</td>
<td>5.0</td>
<td>0.0012</td>
</tr>
<tr>
<td>6</td>
<td>7.0</td>
<td>4.0</td>
<td>0.0204</td>
</tr>
<tr>
<td>7</td>
<td>8.0</td>
<td>3.0</td>
<td>0.0204</td>
</tr>
<tr>
<td>8</td>
<td>9.0</td>
<td>2.0</td>
<td>0.0588</td>
</tr>
<tr>
<td>9</td>
<td>8.5</td>
<td>2.5</td>
<td>0.0588</td>
</tr>
<tr>
<td>10</td>
<td>7.5</td>
<td>3.5</td>
<td>0.0204</td>
</tr>
<tr>
<td>...</td>
<td>...</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Now we can obtain the LOLE as the expected amount of time during the year that load will be interrupted. This will be

\[
LOLE = \sum_{t=1}^{8760} LOLP(d(t)) \times \Delta T(t)
\]  

(16)

In this case, \(\Delta T(t)=1\)hr, and so our LOLE expression is

\[
LOLE = \sum_{t=1}^{8760} LOLP(d(t))
\]  

(17)

For our 10 hour period given in Table 9, the contribution to LOLE is 0.1814 hrs, which is 10.884 minutes. If our 10 hours is representative of the rest of the year, then it means our annual LOLE would be

\[
(8760/10) \times 10.884/60 = 158.91
\]

That is, our annual LOLE would be 159 hours, or 6.625 days. This would be significantly above our 0.1 day in 10 years!

There are three reasons why we are getting such a high LOLE for this example. The first two reasons are specific to this particular example, and understanding them just provides you with some context in which to see more deeply into these kinds of calculations. The third reason is an important one that, if you do not know, will cause you to make a significant error.

1. Our assumption that these 10 hours are representative of the rest of the year is not a very good one, since inspection of the loading increase in these hours suggests that they are daytime hours. Nighttime hours, assuming the same on-line installed capacity, would have significantly more reserves available.

2. We have 5 hours where reserves do not cover an N-1 loss for at least one unit (hours 6, 7, 8, 9, 10); these hours give an order of magnitude higher LOLP than that of the hour with the next highest LOLP.

3. The values used for U and A within this procedure to characterize generator probabilities are too high. The reason for this is that we
have used the forced outage rate (U=FOR) and the availability (A) here. These long-run (or steady-state) probabilities indicate the percentage of time in a year the unit will be in the associated state. This is different than the probability that the unit will fail in the next hour given it is operating at the beginning of the hour. This latter probability is called the outage replacement rate (ORR).

Here we will not consider the nuance of ORR.