GTTF PERFORMANCE BASED ACCREDITATION RECOMMENDATIONS FOR CONVENTIONAL RESOURCES

SPP Generator Testing Task Force (GTTF)

December 2021
# REVISION HISTORY

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1 EXECUTIVE OVERVIEW

1.1 PURPOSE

The purpose of this document is to capture the SPP Generator Testing Task Force (GTTF) recommendations on developing a performance based accreditation method for conventional resources in the SPP Balancing Authority (BA) footprint. Conventional generation for the context of this document is defined as thermal generation (energy source of natural gas, petroleum, coal, nuclear, biomass, geothermal, or waste heat), pump storage hydro generation, and hydro generation with reservoir storage capability not subject to hourly river flow limitations similar to run-of-river hydro. The methodology recommendations in this document would be applied to the accreditation process outlined in the SPP Planning Criteria, which will then be applied to SPP’s Resource Adequacy process. The activities of the GTTF involved proposing revisions of the SPP generator testing requirements and practices as well as addressing the current accreditation practices applied to conventional generating facilities. Under the direction of the SPP Supply Adequacy Working Group (SAWG), the GTTF coordinated with SPP Planning, Markets, Operations staff and other SPP organizational groups to ensure effective collaboration of proposed methods and modifications to the current accreditation process.

1.2 CURRENT SPP ACCREDITATION PRACTICES

The SPP generator testing capability practices outlined in the SPP Planning Criteria are the foundation of accrediting conventional generation in SPP. The SPP Planning Criteria requires, at a minimum, these resources be tested once every five years to establish a net generating capability. The capability test result is then used as the accredited capacity of the resource in SPP Resource Adequacy as outlined in Attachment AA. Utilizing the net generating capability of the resource acknowledges the resource’s maximum output but does not consider the resource’s performance or contribution to reliability in comparison to the other resources in the SPP footprint. A change to the existing accreditation practices that considers performance or availability would more accurately quantify each resource’s contribution to reliability in the SPP BA and incentivize increased resource performance during the peak seasons.

1.3 METHODOLOGY PRINCIPLES, OBJECTIVES, AND IMPACTS

With the transformation to a more variable and energy limited resource fleet while aging thermal resources continue to retire, it is important to make sure all aspects of SPP’s processes consider the evolutionary changes as well, including the accreditation of resources applied to the Resource Adequacy process. Over the next 20+ years, the amount and utilization of conventional generation
will continue to change in the SPP BA footprint, which will require emphasis on increased reliance on the remaining conventional resources in order to maintain adequate balance of reliability, not only from a capacity planning standpoint but as well as under adverse operational conditions. The GTTF considered the following objectives and principles to create a method to measure reliability when discussing the proposal:

- Evolving needs due to the increase of variable and energy limited resources
- Incentivize adequate maintenance of resources in preparation for summer and winter seasons when resources are needed most
- Promote procurement of dependable, reliable, and effective resources
- Impact and modification of existing Resource Adequacy processes
- Impacts to Load Responsible Entities (LREs) when meeting the Resource Adequacy Requirement or Winter Season Obligation under Attachment AA

The Resource Adequacy areas of impact would include a reduction to the maximum amount of accredited capacity from conventional resources that can be utilized by LREs to meet the Resource Adequacy Requirement or Winter Season Obligation under Attachment AA as well as a modification to the Planning Reserve Margin (PRM) requirement outlined in SPP Planning Criteria. Through a high level conceptual analysis of performance based accreditation methodology impacts on other RTO or ISO resource adequacy processes across the North American continent, there is a trend of impacts attributed to the PRM compared to the maximum capacity of the conventional resources. The details of such impact analysis are not included in this document for the SPP region. As part of the proposed implementation, the GTTF recommends additional analysis be performed to further understand the impacts an adopted methodology would have on all resource adequacy processes and requirements. Additional discussions are needed to address how capacity shortfalls can be cured in a timely fashion. Examples could include generation interconnection and firm transmission service processes in relation to resource adequacy requirements.

1.4 GTTF RECOMMENDATIONS

This section outlines GTTF’s recommendations as part of the overall proposed performance based accreditation methodology. The GTTF proposes the items below be a package recommendation. If the direction on any recommendations below changes, then all accompanying recommendations would need to be re-addressed.

1. Deterministic method that utilizes an equation and historical outages to calculate an individual resource’s accredited capacity
2. Modified EFOF equation (EFOF') for the choice of method
3. Calculation be performed for the summer and winter seasons separately while excluding the “shoulder” seasons from the calculation
4. All hours of the applicable season to be considered in the calculation, with consideration to the EFOF equation
5. Most recent five years be included in the calculation where each year and season are calculated separately. The value from each year are averaged together with equal weighting.
6. Apply the same equation and method to all conventional resource types while calculating the accredited capacity of each resource independently
7. Primary data source and additional calculation recommendations
   a. NERC Generation Availability Data System (GADS) as the primary source of data for units that report to NERC
   b. SPP Staff to develop method of submitting NERC GADS equivalent data for units that do not report to NERC
   c. Exclude Outside of Management Control (OMC) events from the calculation
   d. Exclude planned and maintenance outages from the calculation
   e. Exclude planned unit derates from the calculation
8. For resources that have less than 5 years of commercial operation, assign forced outage values for years where data is not yet available. The assigned value would be phased out with available historical generating information year to year until 5 years of operation has been achieved
9. Any performance based capacity accreditation methodology to take effect no sooner than 5 years after annual data reporting requirements are implemented
10. Impact analysis on the Planning Reserve Margin and each LRE’s resource adequacy requirements upon completion of the 2021 SPP LOLE Study and 2022 Workbook submissions

1.5 ADDITIONAL CONSIDERATIONS

Below are considerations that were discussed at the GTTF but a recommendation has not been provided. The items listed below would need to be further discussed and developed before implementing the recommendations proposed by the GTTF.

1. Consideration of impact and timing attributed to the PRM and accreditation on how often the calculation is performed
2. Consistent method applied to all conventional resources for classifying and reporting outage types and cause codes
3. Determination of whether the submission of historical outage data will be a requirement for qualifying the resource under Attachment AA
4. Determination of the method applied to all resources, external and internal, that are qualified as Firm Capacity, Deliverable Capacity, or Firm Power under Attachment AA

5. Consideration and applicability of the method applied to resources external to SPP but fully or partially owned by the LRE

6. Consideration of the method applied to unit specific and slice of system bilateral capacity transactions for internal and external purchases and sales

7. Clarification of how the accredited and net generating capability values should be considered in day to day operations of the system and resource offers into the SPP Marketplace.

8. Consideration of the method applied to units registered in the SPP Marketplace but do not participate in Attachment AA submittal process

9. Quantified impact analysis of de-rates attributed to temperature or ambient-related losses in order to determine if any adjustments to the criteria need to be made for establishing capability ratings or accredited capacity of the resource

10. Consideration of the method applied to resources under FERC Order 2222

1.6 ACKNOWLEDGEMENTS

The GTTF would like to acknowledge the members of SPP and additional support from the Supply Adequacy Working Group (SAWG), Generator Outage Task Force (GOTF), among other working groups and task forces. The GTTF would also like to acknowledge and thank SPP Staff for their assistance in supporting the GTTF efforts.
2 INTRODUCTION AND BACKGROUND

2.1 CURRENT SPP ACCREDITATION PRACTICES

The current application of generation capability testing in the SPP planning criteria is the basis for accrediting conventional generation in SPP. Conventional generation for the context of this document is defined as thermal generation (energy source of natural gas, petroleum, coal, nuclear, biomass, geothermal, or waste heat), pump storage hydro generation, and hydro generation with reservoir storage capability (this does not include run-of-river hydro). The SPP Planning Criteria requires these resources to be tested for at least one hour in duration during the summer season, at ambient temperatures within 10 degrees of the ASHRAE specified design temperature for the resource location, once every five years. This test defines and verifies the net maximum capability of the resource, while taking into consideration any other limitations listed in the SPP Planning Criteria. Assuming no other availability limitations, the capability test result is then used as the accredited capacity of the resource in the SPP Resource Adequacy outlined in Attachment AA.

Utilizing the net generating capability of the resource acknowledges the resource’s maximum output but does not consider the resource’s performance or contribution to reliability in comparison to the other resources in the SPP footprint. As an example, two resources with equal net generating capability may have different failure rates depending on age, mechanical components, or physical make-up of the facility. The current method allocates all outages through the Planning Reserve Margin where each LRE is impacted equally. An improvement to the existing accreditation practices that considers performance or availability would more accurately quantify each resource’s contribution to reliability in the SPP BA and incentivize increased resource performance during the peak seasons.

2.2 GENERATOR TESTING TASK FORCE

The SPP Generator Testing Task Force (GTTF) was created in 2019 for developing annual and seasonal accredited net generating capacity testing requirements for generation in the SPP Balancing Authority. The activities of the GTTF were not limited to proposing revisions of the SPP generator testing requirements and practices but also addressing the current accreditation practices applied to conventional generating facilities. Under the direction of the SPP Supply Adequacy Working Group (SAWG), the GTTF coordinated with SPP Planning, Markets, and Operations staff as well as other SPP organizational groups to ensure effective collaboration of proposed methods and modifications to the current accreditation process. This document captures not only the recommended methodology changes but also attempts to reflect the other options extensively discussed at the GTTF.
2.3 METHODOLOGY PRINCIPLES AND OBJECTIVES

With the transformation to a more variable and energy limited resource fleet while aging thermal resources continue to retire, it is important to make sure that the resource accreditation in the Resource Adequacy process considers these changes. Changing resource mix. In the near future, the amount and utilization of conventional generation will continue to change in SPP’s Balancing Authority footprint, which will require emphasis on increased reliance on the remaining conventional resources in order to maintain adequate balance of reliability, not only from a capacity planning standpoint but as well as under adverse operational conditions. Grid conditions during previous summer and winter seasons in SPP further support the need to move towards a method that adequately measures a conventional resource’s contribution in times when the resource is needed most.

This document only addresses the GTTF efforts and recommendations related to the accreditation practices applied to conventional generating facilities. The GTTF proposes further investigation of the items listed in the Additional Considerations section, which the GTTF considers outside their scope of work, in order to complete the policy package of implementing performance based accreditation for conventional resources. The GTTF considered the following objectives and principles to creating a sustainable method when discussing the proposal.

- Evolving needs due to the increase of variable and energy limited resources
- Incentivize adequate maintenance of resources in preparation for summer and winter seasons when resources are needed most
- Promote procurement of dependable, reliable, and effective resources
- Possible impact and modification of not only existing Resource Adequacy processes but also SPP processes beyond Resource Adequacy
- Impacts to Load Responsible Entities (LREs) when meeting the Resource Adequacy Requirement or Winter Season Obligation under Attachment AA
3 ANALYSIS AND RECOMMENDATIONS

This section addresses GTTF’s recommendations as part of the overall proposed performance based accreditation methodology. This section will also address other options to the method components that were discussed in detail at the GTTF.

3.1 METHOD

**GTTF Recommendation: Deterministic method that utilizes an equation and historical outages to calculate an individual resource’s accredited capacity**

There are two predominantly used methods for determining a resource's accredited value based on historical performance. Both methods utilize historical outages that have occurred for the conventional resources over a specific timeframe, but one method is more complex over the other. The method used by most regions is the utilization of a forced outage rate or force outage factor equation through a deterministic analysis. The other method is Effective Load Carrying Capability, or commonly referred to as “ELCC”. ELCC studies are used mostly for variable or short term duration resources and require multiple probabilistic simulations against multiple weather years. Since forced outage rates of conventional resources are used as an input parameter for ELCC studies, instead of performing complex probabilistic studies to determine a conventional resource’s performance based accreditation, it is adequate to utilize a deterministic method for conventional resources that utilizes multiple historical years.

A deterministic approach provides more certainty from year to year when determining accreditation compared to the ELCC method for long duration dispatchable resources. Also, the utilization of such a method isolates the individual conventional resource performance from the other resources in SPP, whether it be from traditional or renewable type resources. Likewise, a proper and well-designed deterministic method places more ownership of the resource performance into the hands of the generator owner while allowing the entity to control the resource’s individual impacts as they align with the specific entity’s economic and investment decisions to meet their individual resource adequacy requirements.

3.2 EQUATION

**GTTF Recommendation: Modified EFOF equation (EFOF’)**
3.2.1 NARROWING THE EQUATIONS LIST

The GTTF extensively discussed a multitude of options for the equation used in the deterministic methodology. The majority of equations considered were sourced from NERC GADS Appendix F: Performance Indexes and Equations, which contains over 150 different equations. The GTTF began with equations that were focused on forced outages and derates, can be used for determining summer and winter values separately, and can accomplish the method’s principles and objectives. Initially proposed equations included the Demand Equivalent Forced Outage Rate (EFORd), Equivalent Availability Factor (EAF), Weighted Equivalent Forced Outage Rate (WEFOR), Equivalent Forced Outage Factor (EFOF), and a newly proposed question Net Generating Availability Factor (NGAF) which was very similar to the existing EFOF equation under NERC GADS Appendix F. Ultimately, the GTTF narrowed the scope of equations being considered to the EFORd, EFOF, and NGAF before requesting detailed calculations from SPP Staff for additional analysis.

EAF was dismissed because of the GTTF’s proposal to not include planned and maintenance outages in the calculation, while the WEFOR equation was dismissed due to its consistency with the EFOF and EFORd equations. Equations 1, 2, and 3 below represent the differences. See Appendix A for more equation details.

<table>
<thead>
<tr>
<th>Equation</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>( EFOF = \frac{FOH + EFDH}{PH} )</td>
</tr>
<tr>
<td>2</td>
<td>( EFORd = \frac{FOHd + EFDHd}{SH + FOHd} )</td>
</tr>
<tr>
<td>3</td>
<td>( NGAF = \frac{(NGC \times PH) - \sum EFE}{(NGC \times PH)} )</td>
</tr>
</tbody>
</table>

The most common equation used in the industry is EFORd, which takes into consideration forced outages and derates when the resource is needed most to serve load, i.e. “in demand”, where the EFOF and NGAF equations do not. One of the main differences between the EFORd and EFOF/NGAF equations is the utilization of hours when the resource is available but not operating to serve load or operating reserves. NERC GADS refers to these hours as “Reserve Shutdown” hours and typically driven by economic, environmental, or other commitment reasons. The EFORd equation does not consider these hours while the EFOF and NGAF methods give credit for these hours as Period Hours. Thus, the driver in terminology difference of “rate” focuses on how often the resource will fail based on how much the resource is utilized compared to “factor” which focuses on how often the resource was unavailable over a given time period. Resources that have low service hours, i.e. do not run that often, could show a lower EFOF or NGAF percentage than resources that run more often because of the equation is based on Period Hours instead of Service Hours.

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1 NERC GADS Appendix F: Performance Indexes and Equations
2 This decision was made so that SPP Staff would not be overwhelmed with the multitude of possibilities each equation and adjustment would bring to the assessment.
Hours, in which lower service hours could result in lower forced outage possibilities. However, since some resources have very few service hours, the EFORd equation would need to be modified to account for insufficient data. Other regions have adopted modification to the EFORd equation to account for such resources. The NGAF equation is a modification of the EFOF equation with a focus on energy over time instead of using durational hours as a component.

3.2.2 Analysis

SPP requested 2016 to 2020 historical NERC GADS information from entities internal to the SPP footprint in order to perform the GTTF requested analysis so that the GTTF could assess potential impacts to any modification of the method. The resources reporting GADS information are represented by fuel type in Table 1 and Table 2 below. A total of 56,278 MW of existing capacity was submitted by the entities, which is approximately 95% of the claimed accredited conventional capacity in the 2021 Resource Adequacy Attachment AA process.

Table 1: Net max capacity by size and fuel type for NERC GADS submitted data

<table>
<thead>
<tr>
<th>NET MAX CAPACITY BY SIZE AND FUEL TYPE</th>
<th>1-50</th>
<th>51-100</th>
<th>101-150</th>
<th>151-200</th>
<th>201-300</th>
<th>301-400</th>
<th>401-500</th>
<th>501-600</th>
<th>600+</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>173</td>
<td>456</td>
<td>504</td>
<td>936</td>
<td>1,750</td>
<td>2,758</td>
<td>5,344</td>
<td>9,210</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>1,113</td>
<td>598</td>
<td>1,383</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>Natural Gas and Other Gases</td>
<td>2,209</td>
<td>5,962</td>
<td>2,926</td>
<td>7,653</td>
<td>1,920</td>
<td>2,590</td>
<td>3,142</td>
<td>2,619</td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>1,980</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Petroleum</td>
<td>334</td>
<td>718</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 2: Number of resources by size and fuel type for NERC GADS submitted data

<table>
<thead>
<tr>
<th>NUMBER OF RESOURCES BY SIZE AND FUEL TYPE</th>
<th>1-50</th>
<th>51-100</th>
<th>101-150</th>
<th>151-200</th>
<th>201-300</th>
<th>301-400</th>
<th>401-500</th>
<th>501-600</th>
<th>600+</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>2</td>
<td>4</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>10</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>30</td>
<td>10</td>
<td>12</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas and Other Gases</td>
<td>79</td>
<td>83</td>
<td>25</td>
<td>46</td>
<td>8</td>
<td>8</td>
<td>7</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>1</td>
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<td></td>
<td></td>
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<td></td>
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<td>2</td>
<td></td>
</tr>
<tr>
<td>Petroleum</td>
<td>13</td>
<td>12</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
The submitted resource information was applied to each equation and are shown in Table 3 as an SPP weighted average percentage for each season utilizing the most recent five years of NERC GADS data. The results shown in Table 4 and Table 5 are the summer weighted average of the EFORd and the EFOF equations utilizing the most recent 5 years of data. The assumptions applied to the calculations are listed below.

List of Assumptions:

- 2016 to 2020 NERC GADS data
- Included resources fully internal to SPP
- Include both forced derates and full forced outages in the FOH and EFDH calculations
  - Forced Outage Hours (FOH): Sum of all hours experienced during Forced Outages (U1,U2, & U3) + Startup Failures (SF)
  - Equivalent Forced Derated Hours (EFDH): Each individual Forced Derating (D1, D2, and D3) transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed.
- Each resource calculated independently
- Each season of each year calculated separately
- Equal weighting of the years for each season when averaged together for each resource
- Winter season considers hours December 1 to March 31; Summer season considers hours June 1 to September 30
- Excluded Outside of Plant Management Control (OMC) events as defined by NERC GADS Appendix K: Outside Management Control
  - Consistent application compared to other regions
- Utilized historical monthly Net Maximum Capacity reported through NERC GADS
  - If unit did not report value, used latest capability test result from 2021 Workbook submissions
- All hours of the season considered as Period Hours
  - If event was beyond season, then the duration was equalized to only the hours of the appropriate season. Example: If a Forced Outage Event lasts from 5/15 to 6/15

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3 NERC GADS Appendix K: Outside Management Control
(744 Hours), the duration was reduced to 336 hours to only consider June hours of the event

- For facilities that have been in commercial operation less than 5 years, only the most recent available data was used for the calculation

Table 3: Summer and winter SPP weighted average results for EFORd, EFOF, and NGAF

<table>
<thead>
<tr>
<th>Equation</th>
<th>Summer Season SPP Weighted Average</th>
<th>Winter Season SPP Weighted Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>EFORd</td>
<td>7.5%</td>
<td>11.2%</td>
</tr>
<tr>
<td>EFOF</td>
<td>5.7%</td>
<td>6.1%</td>
</tr>
<tr>
<td>NGAF</td>
<td>5.7%</td>
<td>6.1%</td>
</tr>
</tbody>
</table>

Table 4: Summer season weighted average EFORd results by size and fuel type

<table>
<thead>
<tr>
<th>EFORD WEIGHTED AVERAGE BY SIZE AND FUEL TYPE FOR THE SUMMER SEASON</th>
<th>1-50</th>
<th>51-100</th>
<th>101-150</th>
<th>151-200</th>
<th>201-300</th>
<th>301-400</th>
<th>401-500</th>
<th>501-600</th>
<th>600+</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>4.4%</td>
<td>0.9%</td>
<td>0.6%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas and Other Gases</td>
<td>8.1%</td>
<td>9.0%</td>
<td>8.4%</td>
<td>4.1%</td>
<td>3.1%</td>
<td>11.4%</td>
<td>15.0%</td>
<td>9.9%</td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.2%</td>
</tr>
<tr>
<td>Petroleum</td>
<td>11.6%</td>
<td>12.1%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 5: Summer season weighted average EFOF results by size and fuel type

<table>
<thead>
<tr>
<th>EFOF WEIGHTED AVERAGE BY SIZE AND FUEL TYPE FOR THE SUMMER SEASON</th>
<th>1-50</th>
<th>51-100</th>
<th>101-150</th>
<th>151-200</th>
<th>201-300</th>
<th>301-400</th>
<th>401-500</th>
<th>501-600</th>
<th>600+</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>5.6%</td>
<td>6.0%</td>
<td>4.8%</td>
<td>6.9%</td>
<td>4.8%</td>
<td>7.1%</td>
<td>5.6%</td>
<td>8.9%</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>3.6%</td>
<td>0.6%</td>
<td>0.4%</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>Natural Gas and Other Gases</td>
<td>4.4%</td>
<td>5.5%</td>
<td>4.2%</td>
<td>3.3%</td>
<td>2.7%</td>
<td>8.5%</td>
<td>10.2%</td>
<td>3.9%</td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>1.1%</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Petroleum</td>
<td>4.8%</td>
<td>1.3%</td>
<td></td>
<td></td>
<td></td>
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<td></td>
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</table>

After discussing the results, the GTTF discarded the NGAF equation from consideration since the analysis of EFOF compared to NGAF yielded the same overall results. Additional discussions continued at the GTTF that led to the proposed modifications to the EFOF and EFORd equations listed below. These modifications were to not only compare results to how other regions utilize the EFORd equation, but also isolate the effects of planned and maintenance outages from the EFOF equation since the period hours utilized in the EFOF equation defined under NERC GADS Appendix F awarded credit to the resource for taking the planned and maintenance outages during the specified timeframe.4

\[ EFOF' = \frac{FOH + EFDH}{PH'} \]

\[ PH' = PH - MOH - POH - EMDH - EPDH \]

Equation 5

For resources with at least 100 Service Hours per season:

\[ EFORd = \frac{FOHd + EFDHd}{SH + FOHd} \]

For resources less than 100 Service Hours per season:

\[ EFORd' = \frac{FOHd + EFDHd}{SH' + FOHd} \]

\[ SH' = \left[ \frac{\text{Actual Starts}}{\text{Attempted Starts}} \times \left( \frac{\text{Months of Operation}}{4} \times 100 - SH \right) \right] + SH \]

While it had been agreed that planned and maintenance outages should not count against a specific resource, this change ensures that planned and maintenance outages do not give additional credit to those resources.

---

4 While it had been agreed that planned and maintenance outages should not count against a specific resource, this change ensures that planned and maintenance outages do not give additional credit to those resources.
The weighted average results of the four equations for each season are shown in Table 6. The weighted average results by fuel type are shown in Table 7. As expected, the EFOF' showed an increase in outage factor after excluding the maintenance and planned outages from the total period hours and the EFORd' showed a reduction in overall outage rate percentage for resources with less than 100 service hours for each applicable season.

### Table 6: Summer and winter SPP weighted average results for EFORd, EFOF, EFORd', and EFOF'

<table>
<thead>
<tr>
<th>Equation</th>
<th>Summer Season SPP Weighted Average</th>
<th>Winter Season SPP Weighted Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>EFORd</td>
<td>7.5%</td>
<td>11.2%</td>
</tr>
<tr>
<td>EFORd'</td>
<td>7.1%</td>
<td>9.9%</td>
</tr>
<tr>
<td>EFOF</td>
<td>5.7%</td>
<td>6.1%</td>
</tr>
<tr>
<td>EFOF'</td>
<td>6.1%</td>
<td>6.7%</td>
</tr>
</tbody>
</table>

### Table 7: Summer season weighted average results for EFORd, EFOF, EFORd', EFOF' by size and fuel type

<table>
<thead>
<tr>
<th>Weighted Average by Technology and fuel type for the summer season</th>
<th>Max Capacity (MW)</th>
<th>EFORd</th>
<th>EFORd'</th>
<th>EFOF</th>
<th>EFOF'</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>21,131</td>
<td>8.0%</td>
<td>7.9%</td>
<td>7.2%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1,980</td>
<td>1.2%</td>
<td>1.2%</td>
<td>1.1%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Gas (0-100 MW)</td>
<td>7,189</td>
<td>9.0%</td>
<td>7.1%</td>
<td>5.2%</td>
<td>5.5%</td>
</tr>
<tr>
<td>Gas (101+ MW)</td>
<td>11,983</td>
<td>11.1%</td>
<td>10.9%</td>
<td>7.8%</td>
<td>8.9%</td>
</tr>
<tr>
<td>Combined Cycles</td>
<td>9,441</td>
<td>3.3%</td>
<td>3.1%</td>
<td>2.8%</td>
<td>2.9%</td>
</tr>
<tr>
<td>Petroleum</td>
<td>1,053</td>
<td>12.0%</td>
<td>3.0%</td>
<td>2.4%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Hydro</td>
<td>3,093</td>
<td>2.1%</td>
<td>1.9%</td>
<td>1.6%</td>
<td>1.7%</td>
</tr>
</tbody>
</table>

In representation of the four final equations, a unit specific analysis was conducted on seven different resources based on fuel, size, and technology. The information below in Table 8 is actual GADS data and represented as one season. For example, the values for Unit 1 below are from year
2020 for the timeframe of June 1 to September 30. The resource names were removed to maintain confidentiality.

Table 8: Resource specific examples for EFORd, EFOF, EFORd’, and EFOF’

<table>
<thead>
<tr>
<th>VARIABLE</th>
<th>UNIT 1</th>
<th>UNIT 2</th>
<th>UNIT 3</th>
<th>UNIT 4</th>
<th>UNIT 5</th>
<th>UNIT 6</th>
<th>UNIT 7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit Type</td>
<td>Coal Steam Turbine</td>
<td>Natural Gas Turbine</td>
<td>Natural Gas Combined Cycle</td>
<td>Hydroelectric Turbine</td>
<td>Natural Gas Turbine</td>
<td>Petroleum Steam Turbine</td>
<td>Petroleum Steam Turbine</td>
</tr>
<tr>
<td>Net Max Capability</td>
<td>450 MW</td>
<td>175 MW</td>
<td>250 MW</td>
<td>50 MW</td>
<td>30 MW</td>
<td>70 MW</td>
<td>20 MW</td>
</tr>
<tr>
<td>FOH</td>
<td>239</td>
<td>102</td>
<td>96</td>
<td>31</td>
<td>144</td>
<td>4</td>
<td>487</td>
</tr>
<tr>
<td>EFDH</td>
<td>8.5</td>
<td>1</td>
<td>8</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>FO Events</td>
<td>6</td>
<td>3</td>
<td>7</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>7</td>
</tr>
<tr>
<td>Actual Starts</td>
<td>13</td>
<td>70</td>
<td>34</td>
<td>162</td>
<td>5</td>
<td>2</td>
<td>5</td>
</tr>
<tr>
<td>Attempted Starts</td>
<td>13</td>
<td>70</td>
<td>34</td>
<td>162</td>
<td>5</td>
<td>3</td>
<td>8</td>
</tr>
<tr>
<td>RS Hours</td>
<td>272</td>
<td>204</td>
<td>331</td>
<td>810</td>
<td>1387</td>
<td>2539</td>
<td>2139</td>
</tr>
<tr>
<td>Service Hours</td>
<td>2417</td>
<td>957</td>
<td>2501</td>
<td>697</td>
<td>25</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>SH Prime</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>100</td>
<td>67</td>
<td>62</td>
</tr>
<tr>
<td>Available Hours</td>
<td>2689</td>
<td>2817</td>
<td>2832</td>
<td>2363</td>
<td>1413</td>
<td>2547</td>
<td>2146</td>
</tr>
<tr>
<td>Sync Cond Hours</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>MOH + EMDH</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1371</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>POH + EPDH</td>
<td>1.4</td>
<td>50.4</td>
<td>0</td>
<td>534</td>
<td>0.7</td>
<td>376</td>
<td>271</td>
</tr>
<tr>
<td><strong>EFORd</strong></td>
<td>8.7%</td>
<td>4.9%</td>
<td>3.7%</td>
<td>2.3%</td>
<td>22.4%</td>
<td>20.1%</td>
<td>63.2%</td>
</tr>
<tr>
<td><strong>EFORd’</strong></td>
<td>8.7%</td>
<td>4.9%</td>
<td>3.7%</td>
<td>2.3%</td>
<td>6.7%</td>
<td>2.9%</td>
<td>17.4%</td>
</tr>
<tr>
<td><strong>EFOF</strong></td>
<td>8.4%</td>
<td>3.5%</td>
<td>3.5%</td>
<td>1.1%</td>
<td>5.0%</td>
<td>0.1%</td>
<td>16.5%</td>
</tr>
<tr>
<td><strong>EFOF’</strong></td>
<td>8.4%</td>
<td>3.6%</td>
<td>3.5%</td>
<td>1.3%</td>
<td>9.0%</td>
<td>0.2%</td>
<td>18.5%</td>
</tr>
</tbody>
</table>

3.2.3 **CONCLUSIONS**

As expected, the EFORd’ showed a reduction in forced outage rate due to the additional hours attributed in the calculation based on start efficiency and the EFOF’ resulted in a slight increase in
forced outage factor due to the reduction in period hours attributed to planned and maintenance outages and derates. There is very little difference between the EFOF and EFORd equations for resources with high service hours. As the service hours of a resource increase, it converges to more of a period hour representation of the season. The larger differences are highlighted in units with low service hours, which the majority of these resources are either behind the meter resources or are too expensive to run. The EFORd’ equations allows for these resources to attribute the reliability performance by starts due to the insufficient amount of service hours. Other regions have adopted modification to the EFORd equation to account for such resources. The EFOF’ equation does not give credit for taking planned and maintenance outages in the summer and winter seasons, which complements the GTTF recommendation to exclude planned and maintenance outages from the calculation. From some of the unit specific examples listed in Table 8, the EFOF’ and EFOF equations would still have the potential to underestimate the reliability of a resource and attribute its performance to availability instead when compared to the EFORd and EFORd’ equations. Unit 6 and 7 in the table above outlines this delineation when a resource failed to start but was available a large portion of the season. If the starts for these resource increased but failed to start during these incremental instances, the EFORd’ equation would take these situations into consideration with greater impact than the EFOF equation, where the EFOF equation has the potential to mask these situations. However, the EFORd equations are based solely on how often the unit is generating or the number of starts, which would bring additional modifications to the method to account for the infrequent use of some resources.

Upon review of the additional results and equations, the GTTF recommends the utilization of the EFOF’ equation for the reasons that the EFOF equation is less complex than the EFORd equation and the EFORd equation does not identify specific demand periods associated with historical events. This equation does, however, consider average demand factors over an identified time period. The GTTF recommends the EFOF’ over the EFOF in order to complement the GTTF recommendation to exclude planned and maintenance outages from the calculation.

3.2.4 APPLICATION TO THE NET GENERATING CAPABILITY

The Net Generating Capability is determined through a Capability Test in accordance with the SPP Planning Criteria at least once every five years. This test defines and verifies the net maximum capability of the resource, while taking into consideration any other limiting factor considerations outlined in the Planning Criteria. The EFOF’ results will be applied to the Net Generating Capability (NGC) of each resource through the equation 6 listed below. The newly adjusted accredited capacity would then be utilized in SPP’s Resource Adequacy calculations and process.

Equation 6

\[
\text{Accredited Capacity} = \text{NGC} \times (1 - \text{EFOF}')
\]
3.3 SEASONAL APPLICATION

**GTTF Recommendation:** *Calculation to be performed for the summer and winter seasons separately while excluding the “shoulder” seasons from the calculation*

In discussing the results of the analysis, the GTTF recommends the calculation be performed for each season separately. For some resources, seasonal variation can have an impact on a resource’s performance. Therefore, the GTTF felt it was necessary to still honor the seasonal impacts while adhering to the seasonal separation in Attachment AA.

For the context of this document, the shoulder months are defined as April 1 to May 30 and October 1 to November 30. In order to maintain consistency with timeframes outlined in Attachment AA of SPP Tariff, the GTTF recommends the shoulder seasons be excluded from the calculation so that the performance of a resource would be congruent with the current obligations and requirements. It was also mentioned there is currently no risk identified in the “shoulder” months but this assessment may need to be reconsidered if risk shifts as time progresses. Other regions include the shoulder seasons in their calculations, but they also calculate annual forced outage rates to apply to the net generating capability of a resource.

3.4 HOURS CONSIDERED

**GTTF Recommendation:** *All hours of the applicable season to be considered in the calculation, with consideration to the EFOF equation*

The GTTF discussed three main options for the hours considered in each season. They included all hours of the applicable season, top percentage of net load hours, tight supply hours. The tight supply hours is a method being recommended in the California ISO footprint through its current stakeholder discussions.  This method focuses on forced outages that occur during specific hours of the season when supply headroom is lowest. As an example, hours where high load, low variable energy resource output, and high level of conventional outages would be the main drivers. The GTTF discarded this method due to all conventional resources impacting each other’s accredited capacity and would also produce too much variability from year to year when procuring and planning for resource adequacy needs under Attachment AA.

The GTTF reached consensus on initially accepting the method for including all hours of the season but directed SPP Staff to further analyze the “top percentage of net load hours” method. Figure 1 and Figure 2 represent the hours considered for the top 5%, 10%, and 20% of net load hours across a 24 hour timespan for each season. Table 9 shows the results of each percentage for an EFOF method. The net load for this effort was defined as the SPP load less the impacts of solar and wind generation for each hour. The hours were defined on an SPP level and applied to

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5 [CAISO Resource Adequacy Enhancements](#)
each resource individually to derive an SPP weighted average value for each season. Forced outages and derates were only counted if they occurred on a historical top net load hour. Since this method breaks out the complexity of the season into a portion of hours, it can be applied to factor based equations such as EFOF. This method would not be recommended to be applied to rate based calculations such as EFORD.

Figure 1: Daily summary of summer top net load hours

Figure 2: Daily summary of winter top net load hours

Table 9: EFOF results at top 5%, 10%, and 20% net load hours

<table>
<thead>
<tr>
<th>Method</th>
<th>Summer Season SPP Weighted Average</th>
<th>Winter Season SPP Weighted Average</th>
</tr>
</thead>
</table>
Upon review of the additional analysis, the GTTF affirmed the recommended method of considering all hours within each applicable season. This method would be consistent with the timeframes outlined in Attachment AA of the SPP Tariff. Also, there is a possibility to have seasonal variation in the Net Generating Capability of a resource (based on a Capability Test) as well as seasonal performance of a resource based on temperature restrictions. Winter and summer seasons would be viewed as four consecutive months. Including all hours in the season would be simpler and produce more certainty compared to identifying outages that occur during a specific subset of hours within each applicable season and year. However, the GTTF understands the reliability and needs of the system could shift over time. Therefore, the GTTF would advise continued checks of the method over time to verify it is still suitable to meet the needs of the system.

### 3.5 NUMBER OF HISTORICAL YEARS

**GTTF Recommendation:** Most recent five years be included in the calculation where each year and season are calculated separately. The value from each year are averaged together with equal weighting

The GTTF recommends the most recent 5 historical years to be considered, at a minimum. As more years are considered in the calculation, stability of the forced outage rate becomes consistent from year to year when planning for generation to meet future RAR and Winter Season Obligation requirements. More available years also gives a greater sample size of data, which is why the GTTF is considering using the most recent 5 years of data instead of the most recent 2 or 3 years. The GTTF did consider more than 5 years attributed to the calculation but felt that 5 years was suitable for this method.

One additional modification proposed to the number of historical years included in the calculation was to exclude the worst performing year of the most recent five. The proposal included determining the forced outage rate of each resource for each season of each historical year separately and the worst performing year out of the 5 most recent years would be excluded by each individual season (i.e. worst summer value excluded and worst winter value excluded) where all years would be equally weighted. This proposal was discussed extensively at the GTTF and the task force requested staff perform calculations to compare the two methods. The SPP weighted average results are shown in Table 10 below.

| EFOF – Top 5% NLH | 5.8% | 7.1% |
| EFOF – Top 10% NLH | 5.7% | 6.9% |
| EFOF – Top 20% NLH | 5.8% | 6.6% |
Table 10: EFORd, EFOF, and NGAF results comparing best 4 out of 5 and 5 most recent years

<table>
<thead>
<tr>
<th>Equation and Method</th>
<th>Summer Season SPP Weighted Average</th>
<th>Winter Season SPP Weighted Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Most recent 5</td>
<td>Best 4 of 5</td>
</tr>
<tr>
<td>EFORd</td>
<td>7.5%</td>
<td>4.4%</td>
</tr>
<tr>
<td>EFOF</td>
<td>5.7%</td>
<td>3.1%</td>
</tr>
<tr>
<td>NGAF</td>
<td>5.7%</td>
<td>3.1%</td>
</tr>
</tbody>
</table>

Upon reviewing the results, the GTTF initially settled on the best 4 out of 5 years but also explored additional analysis to support their reasoning. Some GTTF members supported the best four out of five method because it would account outlier events that are not indicative of the actual performance of the resource. The anecdotal evidence would be an example of a transformer failure which is within Outside Management Control (OMC) but at no fault of maintenance management. This is a long lead time item which would leave the unit in forced outage for a long time. Using the best four out of five years, this event would not be included in the average. The end result would still be very representative of how the unit historically operates. Typically, this type of event should not happen very often at all, say once in 20-30 years. However, collecting historical data for 20 years would be too much burden. If units are continually having problems, only one of those years will be excluded and the average will still be very reflective of the unit’s historical forced outage rate. Eliminating the worst performing year also removes the subjectivity of determining how to throw out a “catastrophic event” if one were to occur in the future. The worst year will be determined on a seasonal basis to stay consistent with the seasonality direction. Events that occur in one season may not endure for an entire year. Availability and repairs are also evaluated on a more seasonal rather than annual basis. All historical years will be weighted equally to help equalize the impact of each year in the analysis. This method produces more certainty around forecasting accredited values of resources and is consistent with other ISO’S and RTO’s in the industry.

However, there were concerns that removing an entire season could be misrepresenting the resource’s actual performance. The intention of this method was to exclude one event in each season that rarely occur but are within the plant management’s control. The ensuing maintenance to alleviate the issue would fix the equipment of the resource and may not occur again for over 10 years. On the other hand, a resource may have multiple events occur within one season and get excluded from the calculation, which is not the intention of the method. Also, the lower amount of overall SPP weighted average outage rate translates to a method consistent with today’s accreditation practices. GTTF members proposed SPP Staff consider different ways to assess the data in comparing the two methods. Figure 3 through Figure 5 below represent the comparisons utilizing the EFOF method. As expected, the resources with higher EFOF for the most
recent five years received a much lower EFOF while shifting the weighted mean of the distribution to a lower value. The GTTF had additional discussions upon review of the additional analysis and reached consensus on recommending the most recent 5 years.

**Figure 3:** Summer count of resources comparing the most recent 5 and best 4 out of 5 years’ methods

**Figure 4:** Net maximum capacity impacts compared to weighted average EFOF
3.6 TECHNOLOGY TYPES

**GTTF Recommendation:** *Apply the same equation and method to all conventional resource types and calculate the accredited capacity of each resource independently*

The GTTF discussed considering the need to develop separate methods and equations applied to different conventional resources in the SPP footprint. This discussion included various topics such as, technology type, location, resource size, fuel type, how the resource is qualified under Attachment AA, how often the unit was dispatched or utilized, and transmission limitations within constrained areas. Consensus was reached at the GTTF to apply the same method to all conventional resources. The GTTF felt if there was a need to single out individual resource types based on the topics mentioned, then a modification could be made to the applied method and equation. This direction is also consistent with other regions applying a performance based accreditation method.

3.7 DATA SOURCE & OTHER CALCULATION ASSUMPTIONS

**GTTF Recommendation:** *Utilize NERC Generation Availability Data System (GADS) as the primary source of data for units that report to NERC.*

Two main data sources discussed at the GTTF for obtaining the historical outage information: NERC GADS and SPP Control Room Outage Window (CROW). NERC GADS provides multiple outage categories and codes for classifying the outages whereas CROW currently has a limited
number of cause codes and outage classifications. The GTTF coordinated with the Generator Outage Task Force (GOTF) on their plans for improving the CROW reporting requirements and information. However, the GTTF data needs for the performance based accreditation effort would exceed the GOTF’s scope of recommendations. Therefore, the GTTF recommends the use of NERC GADS data for units that report their outage information to NERC. NERC GADS data is also reported “after the fact”, which the generator owner has sufficient time to adequately classify the resource outage, compared to the real time reporting in CROW. GADS also has an established reporting parameters and procedures that are clearly outlined when identifying the type of outage based on repair type or the resource’s operational state.

**GTTF Recommendation: SPP Staff to develop method of submitting NERC GADS equivalent data for units that do not report to NERC.**

Units that do not currently report NERC GADS data will still be required to submit supplemental outage data to SPP. The LRE or Generator Owner will be responsible for submitting the appropriate information. The GTTF recommends SPP Staff develop a reporting process for units that do not report NERC GADS information while considering the tool’s compatibility with units that report NERC GADS information. This can be accomplished in many ways but the primary focus would be within the annual Resource Adequacy Workbook submission process.

**GTTF Recommendation: Exclude OMC events from the calculation**

Outside of Plant Management Control (OMC) events are defined as outages caused by forces outside of the plant’s or facility’s control. Some examples of these events include grid connection or substation failure, acts of nature such as ice storms, tornados, lightning, or hurricane, failure of supplier to fulfill contractual obligations, lack of fuel, and labor strikes. NERC has defined a list of cause codes related to this category in NERC GADS Appendix K: Outside Management Control⁶. The GTTF discussed the outages listed and if these outage should be considered as a decrement to a resource’s accredited capacity. When analyzing the 2016 to 2020 NERC GADS data, it was determined only 11% of the historical forced outages and derates were attributed to OMC events. The GTTF recommends the exclusion of these type of outages in the calculation. However, these outages will continue to be considered in the LOLE Study when establishing the Planning Reserve Margin for the region to where the entire region shares the impact of these events. This method is consistent with the method defined by other regions. The GTTF also had discussions regarding events that were outside of management control but not explicitly defined in NERC GADS Appendix K. An example of this type of situation could include but is not limited to long duration derates caused by maintenance outages declined by SPP. The GTTF feels that these type of events could be excluded from the calculation, but this topic will require further discussion before implementation.

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⁶ NERC GADS Appendix K: Outside Management Control
**GTTF Recommendation: Exclude Planned and Maintenance Outages from the calculation**

The GTTF recommends planned and maintenance outage not be considered in the calculation, i.e. a resource is not harmed or does not receive benefit for taking a planned or maintenance outage during the applicable season. If a resource requests to take a planned or maintenance outage, it has to be approved by the SPP BA. The GTTF decided to rely upon the ORWG’s, GOTF’s, and SPP Staff’s improvements to the Generation Assessment Process (GAP) in case planned or maintenance outages need to be taken during abnormal timeframes if the headroom is available for the outage to be taken in real time. The GAP assesses planned outages and allowable thresholds from an availability perspective up to two years in the future.

### 3.8 NEW RESOURCES

**GTTF Recommendation: For new resources that have less than 5 years of commercial operation, utilize forced outage values for years where data is not yet available. The assigned value would be phased out with available historical generating information year to year until 5 years of operation has been achieved**

The GTTF briefly discussed the proposed method applied to new resources. Initial options included: applying a forced outage value or applying no derate to the Net Generating Capability of the resource for the years where the information is not available. Additional considerations included applying separate methods for the first two or three years of operation and then switching to the EFOF’ method. For resources that have less than 5 years of commercial operation, the GTTF recommends assigning forced outage values for years where data is not yet available. The assigned value would be phased out with available historical generating information year to year until 5 years of operation has been achieved. The entity may use design performance projections from the manufacturer as the assigned value. If the entity does not provide design performance projections, the assigned value applied would be a weighted class average based on fuel type and unit size calculated from other resources within the SPP footprint. SPP would need to calculate and publish these weighted class average values every time the calculation is performed. Table 11 below shows an example on how a new natural gas resource with a design performance projection of 3% EFOF’ would be applied within the first six years of commercial operation. The cells highlighted blue and with an asterisk (*) indicate the design performance projection of 3% while the cells not highlighted any color indicate the actual performance of the generating facility for each applicable operating year.
### Table 11: Example application for new conventional resources

<table>
<thead>
<tr>
<th>Operating Years</th>
<th>(Current Year – 1) EFOF’</th>
<th>(Current Year – 2) EFOF’</th>
<th>(Current Year – 3) EFOF’</th>
<th>(Current Year – 4) EFOF’</th>
<th>(Current Year – 5) EFOF’</th>
<th>Average EFOF’</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3.0%</td>
</tr>
<tr>
<td>1</td>
<td>4%</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3.2%</td>
</tr>
<tr>
<td>2</td>
<td>7%</td>
<td>4%</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>4.0%</td>
</tr>
<tr>
<td>3</td>
<td>1%</td>
<td>7%</td>
<td>4%</td>
<td>3%(*)</td>
<td>3%(*)</td>
<td>3.6%</td>
</tr>
<tr>
<td>4</td>
<td>3%</td>
<td>1%</td>
<td>7%</td>
<td>4%</td>
<td>3%(*)</td>
<td>3.6%</td>
</tr>
<tr>
<td>5</td>
<td>2%</td>
<td>3%</td>
<td>1%</td>
<td>7%</td>
<td>4%</td>
<td>3.4%</td>
</tr>
</tbody>
</table>

### 3.9 IMPLEMENTATION

**GTTF Recommendation:** *Any performance based capacity accreditation methodology to take effect no sooner than 5 years after annual data reporting requirements are implemented*

The GTTF had extensive discussions around the implementation considerations of a performance based accreditation. Areas of concern mentioned include allowing sufficient time for LREs to understand the future impacts for meeting resource adequacy requirements and allowing enough time for entities to begin recording outages for resources currently not required to report outages through NERC GADS or SPP CROW systems. Furthermore, the GTTF is concerned that the current 4-year backlog of generation interconnection studies requires entities to have at least 5 years to obtain new generation capacity. As discussed by the GTTF, implementing an enforcement mechanism without the opportunity to construct generation for curing capacity shortfalls reliability concerns may not be fully addressed. Additional options discussed included applying weighted average outage rate based on fuel type, technology and size, and allowing a “grace period” or phased-in approach within the implementation timeframe. The GTTF recommends that any performance based capacity accreditation methodology to take effect no sooner than 5 years after annual data reporting requirements are implemented. In this recommendation, the 5 year period would begin after the commencement of the data reporting process has been communicated to the LREs and Generator Owners. Additional discussions will be required on the timing or contingent events which initiate such communication. This requirement allows sufficient time for entities to adjust for the implementation of any method and enough time for entities to begin recording outages for resources that are currently not required to report outages through NERC GADS or SPP CROW systems.
4 ADDITIONAL CONSIDERATIONS

Below are considerations that were discussed at the GTTF but recommendations have not been provided. The items listed below would need to be further discussed and developed before implementing the recommendations proposed by the GTTF.

1. Consideration of impact and timing attributed to the PRM and accreditation on how often the calculation is performed

2. Consistent method applied to all conventional resources for classifying and reporting outage types and cause codes

3. Determination of whether the submission of historical outage data will be a requirement for qualifying the resource under Attachment AA

4. Determination of the method applied to all resources, external and internal, that are qualified as Firm Capacity, Deliverable Capacity, or Firm Power under Attachment AA

5. Consideration and applicability of the method applied to resources external to SPP but fully or partially owned by the LRE

6. Consideration of the method applied to unit specific and slice of system bilateral capacity transactions for internal and external purchases and sales

7. Clarification of how the accredited and net generating capability values should be considered in day to day operations of the system and resource offers into the SPP Marketplace.

8. Consideration of the method applied to units registered in the SPP Marketplace but do not participate in Attachment AA submittal process

9. Quantified impact analysis of derates attributed to temperature or ambient-related losses in order to determine if any adjustments to the criteria need to be made for establishing capability ratings or accredited capacity of the resource

10. Consideration of the method applied to resources under FERC Order 2222

11. Consideration of impact on SPP’s maintenance outage scheduling under recommended methodology
5 IMPACTS TO THE RESOURCE ADEQUACY PROCESS

At a minimum, the methodology recommendations in this document would be applied to the accreditation process outlined in the SPP Planning Criteria, which will then be applied to SPP’s Resource Adequacy process. The areas of impact would include a reduction to the maximum amount of accredited capacity from conventional resources that can be utilized by LREs to meet the Resource Adequacy Requirement or Winter Season Obligation under Attachment AA in conjunction with a modification to the Planning Reserve Margin (PRM) requirement outlined in SPP Planning Criteria.

Through a high level conceptual analysis of performance based accreditation methodology impacts on other RTO or ISO resource adequacy processes across the North American continent, there is a trend of impacts attributed to the PRM compared to the maximum capacity of the conventional resources. Multiple regions define the net maximum capability of a resource as the Installed Capacity (ICAP) and the derated amount of accredited capacity due to historical performance as the Unforced Capacity (UCAP), while each region considers their own modification to the method when determining the UCAP amount.

When a region determines their PRM requirement, the ICAP amount is used in a probabilistic Loss of Load Expectation (LOLE) analysis while modeling historical forced and planned outages and derates. (An LOLE Study is typically used to determine the minimum PRM of a region.) Upon completion of the LOLE analysis, a minimum “ICAP PRM” required at a specific reliability metric is calculated using the net generating capability of the conventional resources. Then, a calculation to determine the UCAP of each resource is performed external of the LOLE simulation process. Lastly, a “UCAP PRM” is calculated by replacing the ICAP value with the UCAP value of resources. Typically, when the total amount of accredited capacity is reduced, the PRM requirement takes into consideration the reduction as well. For example, if a system contains 1,000 MW of demand and the ICAP PRM requirement is 15%, the minimum required installed capacity is 1,150 MW (1000 MW + (1000 MW x 15%)). When performing the calculation to a UCAP PRM, it is first determined that the UCAP value is 95% of the ICAP. This reduction is applied to the minimum installed capacity needed bringing the minimum UCAP to 1,092 MW and the UCAP PRM to 9.25% [(1,092 – 1,000)/1,000]. The new UCAP PRM is the amount load serving entities would plan to meet for resource adequacy requirements.

The details of such impact analysis are not included in this document. As part of the proposed implementation, the GTTF recommends additional analysis be performed to further understand the impacts a final method would have on not only the accredited capacity of resources, the SPP

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7 SPP currently calculates the PRM using this referenced “ICAP” methodology, but does not currently determine a “UCAP” PRM value.
PRM, but as well as each LRE’s impact to meeting Attachment AA requirements upon completion of the 2021 SPP LOLE Study.
6 APPENDIX A: DETAILED DESCRIPTION OF EQUATIONS

The items below list the variables associated with the equations outlined in this recommendations document. For additional information, reference NERC GADS Appendix F: Performance Indexes and Equations.

### 6.1 VARIABLES

<table>
<thead>
<tr>
<th>Variable Description</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Service Hours – SH – SH</td>
<td>Sum of all unit Service Hours</td>
</tr>
<tr>
<td>Synchronous Condensing Hours – Sync Cond Hours</td>
<td>Sum of all hours the unit is in the synchronous condensing mode. The units are considered to be in non-generating service operation</td>
</tr>
<tr>
<td>Pumping Hours</td>
<td>Sum of all hours the pumped storage unit is in pumping mode. The units are considered to be in non-generating service operation.</td>
</tr>
<tr>
<td>Reserve Shutdown Hours – RSH</td>
<td>Sum of all hours the unit is available but not committed for Service Hours</td>
</tr>
<tr>
<td>Available Hours - AH - AH</td>
<td>Sum of all Service Hours (SH) + Reserve Shutdown Hours (RSH) + Pumping Hours + Synchronous Condensing Hours</td>
</tr>
<tr>
<td>Period Hours – PH – PH</td>
<td>Number of hours in the period being reported that the unit was in the active state.</td>
</tr>
<tr>
<td>Forced Outage Hours - FOH - FOH</td>
<td>Sum of all hours experienced during Forced Outages (U1, U2, and U3) + Startup Failures (SF). (see Appendix B for more details)</td>
</tr>
<tr>
<td>Maintenance Outage Hours - MOH - MOH</td>
<td>Sum of all hours experienced during Maintenance Outages (MO) + Maintenance Outage Extensions (ME) of any Maintenance Outages (MO) (see Appendix B for more details)</td>
</tr>
</tbody>
</table>

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8 NERC GADS Appendix F: Performance Indexes and Equations
<table>
<thead>
<tr>
<th>Description</th>
<th>Formula/Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned Outage Hours – POH</td>
<td>Sum of all hours experienced during Planned Outages (PO) + Planned Outage Extensions (PE) of any Planned Outages (PO) (see Appendix B for more details)</td>
</tr>
<tr>
<td>Equivalent Forced Derated Hours – EFDH</td>
<td>Each individual Forced Derating (D1, D2, and D3) transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. <em>NOTE: Includes Forced Deratings (D1, D2, and D3) during Reserve Shutdowns (RS).</em></td>
</tr>
<tr>
<td>Equivalent Maintenance Derated Hours – EMDH</td>
<td>Each individual Maintenance Derating (D4, DM of D4) is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. <em>NOTE: Includes Maintenance Deratings (D4) during Reserve Shutdowns (RS).</em></td>
</tr>
<tr>
<td>Equivalent Planned Derated Hours – EPDH</td>
<td>Each individual Planned Derating (PD, DP of PD) is transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of reduction (MW) and dividing by the Net Maximum Capacity (NMC). These equivalent hour(s) are then summed. <em>NOTE: Includes Planned Deratings (PD) during Reserve Shutdowns (RS)</em></td>
</tr>
<tr>
<td>Average forced outage deration – r</td>
<td><em>(FOH) / Number of FO occurrences</em></td>
</tr>
<tr>
<td>Average demand time – D</td>
<td><em>(SH) / Number of unit actual starts</em></td>
</tr>
<tr>
<td>Average Reserve Shutdown time – T</td>
<td><em>(RSH) / Number of unit attempted starts</em></td>
</tr>
<tr>
<td>Equivalent Forced Energy – EFE</td>
<td>Sum of all energy for the unit when on forced outage or forced derate</td>
</tr>
<tr>
<td>--------------------------------</td>
<td>---------------------------------------------------------------------</td>
</tr>
</tbody>
</table>

## 6.2 EQUATIONS

### Equivalent Forced Outage Rate demand – EFORd

\[
EFORd = \frac{FOHd + EFDHd}{SH + FOHd} \times 100%
\]

\[
FOHd = f \times FOH
\]

\[
EFDHd = fp \times EFDH
\]

\[
fp = \frac{SH}{AH}
\]

\[
f = \frac{\left(\frac{1}{T} + \frac{1}{T}\right)}{\left(\frac{1}{T} + \frac{1}{T} + \frac{1}{D}\right)}
\]

### Equivalent Forced Outage Rate demand Prime – EFORd’

For resources with at least 100 Service Hours per season:

\[
EFORd = \frac{FOHd + EFDHd}{SH + FOHd}
\]

For resources less than 100 Service Hours per season:

\[
EFORd' = \frac{FOHd + EFDHd}{SH' + FOHd}
\]

\[
SH' = \left[\left(\frac{Actual\ Starts}{Attempted\ Starts}\right) \times \left(\frac{\text{Months\ of\ Operation}}{4}\right) + 100 - \text{SH}\right] + \text{SH}
\]

### Equivalent Forced Outage Factor – EFOF

\[
EFOF = \frac{FOH + EFDH}{PH}
\]

### Equivalent Forced Outage Factor Prime – EFOF’

\[
EFOF' = \frac{FOH + EFDH}{PH'}
\]

\[
PH' = PH - MOH - POH - EMDH - EPDH
\]
Net Generating Availability Factor (NGAF)

\[
\text{NGAF} = \frac{(NGC \times PH) - \sum EFE}{(NGC \times PH)}
\]

6.3 ADDITIONAL ASSUMPTIONS

Additional assumptions attributed to special cases were applied to the EFORd and EFORd‘ equations in the order listed below:

1) \( f = 1 \) for units with less than 1 reserve shutdown hours
2) \( f = 1 \) when (service hours + synchronous condensing hours) = 0
3) \( f = 0 \) when \( (1/r + 1/T + 1/D) = 0 \)
4) \( 1/r = 0 \) when the number of forced outage occurrences = 0 or forced outage hours = 0
5) \( 1/T = 0 \) when reserve shutdown hours = 0 or the number of unit attempted starts = 0
6) \( 1/D = 0 \) when the number of unit actual starts = 0 or (service hours + synchronous condensing hours) = 0
7) \( fp = 0 \) when (service hours + reserve shutdown hours + synchronous condensing hours) = 0
8) \( \text{EFORd} = 0 \) when \((\text{service hours} + \text{synchronous condensing hours}) + (f \times \text{forced outage hours})\) = 0
The categories and diagram below in Figure 6 outline the types of events reported in NERC GADS and their definitions. For additional information please see the NERC GADS Data Reporting Instructions Manual.\(^9\) \(\text{(Note: All information below is sourced from the NERC GADS Data Reporting Instructions Manual)}\)

\(\text{Figure 6: NERC GADS outage classifications}\)

### 7.1 PLANNED OUTAGE – PO

An outage that is scheduled well in advance and is of a predetermined duration, can last for several weeks, and occurs only once or twice a year. Typically, these events are specifically listed in the plant budget. Turbine and boiler overhauls or inspections, testing, and nuclear refueling are typical planned outages. For a planned outage, all of the specific individual maintenance and operational tasks to be performed are determined in advance and are referred to as the "original scope of

\(^9\) [NERC GADS Data Reporting Instructions Manual](#)
"The general task of repairing turbines, boilers, pumps, etc. is not considered a work scope because it does not define the individual tasks to be performed. For example, if a general task such as repair boiler is considered the work scope, it is impossible to conclude that any boiler work falls outside of the original scope of work. Discovery work and re-work which render the unit out of service beyond the estimated PO end date are not considered part of the original scope of work. A planned extension may be used only in instances where the original scope of work requires more time to complete than the estimated time. For example, if an inspection that is in the original scope of work for the planned outage takes longer than scheduled, the extra time should be coded as an extension (PE). However, if damage found during the inspection results in an extension of the outage, the extra time required to make repairs should be coded as a forced outage.

7.2 MAINTENANCE OUTAGE – MO

An outage that can be deferred beyond the end of the next weekend (defined as Sunday at 2400 hours or as Sunday turns into Monday), but requires that the unit be removed from service, another outage state, or Reserve Shutdown state before the next Planned Outage (PO). Characteristically, a MO can occur any time during the year, has a flexible start date, may or may not have a predetermined duration, and is usually much shorter than a PO. Discovery work and re-work which render the unit out of service beyond the estimated MO end date are not considered part of the original scope of work. A maintenance extension may be used only in instances where the original scope of work requires more time to complete than the estimated time. For example, if an inspection that is in the original scope of work for the outage takes longer than scheduled, the extra time should be coded as an extension (ME). If the damage found during the inspection is of a nature that the unit could be put back on-line and be operational past the end of the upcoming weekend, the work could be considered MO. If the inspection reveals damage that prevents the unit from operating past the upcoming weekend, the extended work time should be Forced Outage (U1).

There are cases when there are equipment issues and a unit could theoretically run past the next weekend, but the unit would not be run because of high risk for unit damage. If the risk is too high to run the unit, management is unwilling to run the unit, running the unit violates sound engineering practice or running the unit would invalidate your insurance, the outage is forced not maintenance. Examples are DC emergency equipment out of service or one ground on the generator.

Note: If an outage occurs before Friday at 2400 hours (or before Friday turns into Saturday), the above definition applies. But if the outage occurs after Friday at 2400 hours and before Sunday at 2400 hours (the 48 hours of Saturday and Sunday), the MO will only apply if the outage can be delayed past the next, not current, weekend. If the outage cannot be deferred, the outage shall be a forced event.
7.3 PLANNED OUTAGE EXTENSION – PE

GADS defines a planned outage extension as an extension of a Planned Outage (PO) beyond its estimated completion date. This means that at the start of the PO, the outage had an estimated duration (time period) for the work and a date set for the unit to return to service. All work during the PO is scheduled (part of the original scope of work) and all repair times are determined before the outage started. For more information, see PE rules and regulations in NERC GADS Data Reporting and Instructions Manual.

7.4 MAINTENANCE OUTAGE EXTENSION – ME

GADS defines a maintenance outage extension as an extension of a maintenance outage (MO) beyond its estimated completion date. This means that at the start of an MO, the outage had an estimated duration (time period) for the work and a date set for the unit to return to service. All work during the MO is scheduled (part of the original scope of work) and all repair times are determined before the outage started. For more information, see PE rules and regulations in NERC GADS Data Reporting and Instructions Manual.

7.5 STARTUP FAILURE – SF

This is an outage that results when a unit is unable to synchronize within a specified startup time following an outage or reserve shutdown. The startup period for each unit is determined by the operating company. It is unique for each unit, and depends on the condition of the unit at the time of startup (cold, warm, and hot). A typical unit startup occurs in three phases: warm up, synchronization, and ramp up. NERC defines a startup period to begin with the command to start and end when the unit is synchronized. An SF begins when a problem preventing the unit from synchronizing occurs. The SF ends when the unit is synchronized, another SF occurs, or the unit enters another permissible state. Problems encountered during ramp up that force the unit offline are considered outages not SF events.

7.6 IMMEDIATE UNPLANNED (FORCED) OUTAGE – U1

This is an outage that requires immediate removal of a unit from service, another outage state, or a reserve shutdown state. This type of outage usually results from automatic control system trips or operator-initiated manual trips of the unit in response to unit alarms but can also occur while the unit is offline.

There is a need by a number of the NERC Planning Committee working groups and subcommittees to collect the various types of trips experienced by generating units. They are most interested in automatic grid separation trips caused by many things, including transmission. In
order to maintain the historical meanings of the existing component trip codes 82 and 83, GADS created the two amplification codes T1 and T2 to be used for complete, 100% unit trips:

- T1 – Tripped/shutdown grid separation --- automatic. A full outage that suddenly trips the unit from some loading to zero loading without operator initiation. This is an unexpected grid separation event where the unit is in normal operation when the mechanical, electrical, or hydraulic control or protective systems automatically trip the generating unit(s). This trip is not when the unit is manually tripped, or when the unit operator assisted to lower loadings and then the unit automatically tripped. The unit must be in service (breakers closed) before a grid separation trip event is accepted by GADS. No other unit outage condition can precede this event.

- T2 – Tripped/shutdown grid separation --- manual. The unit is quickly removed from service with operator assistance. This type of outage includes operator-initiated trips in response to unit alarms. If the cause of the trip is not known, then you can use amplification code 84 but it must be changed to the appropriate amplification code (T1 or T2) before the end of the year to be acceptable by GADS.
  
  - 84 - Unknown – investigation underway (change this code once failure mechanism is determined) If the U1 is not a trip but the result of a change of state (from planned outage to U1, for example), then the amplification code can be any other amplification code if the operating company chooses to report it. In other words, the amplification code under such conditions is voluntary. Starting January 1, 2011, the need to report T1, T2 or 84 amplification codes became mandatory to pass GADS edits. For a complete list of the amplification codes see Appendix J of the GADS Data Reporting Instructions.

7.7 DELAYED UNPLANNED (FORCED) OUTAGE – U2

This is an outage that does not require immediate removal of a unit from the in-service state, instead requiring removal within six hours. This type of outage can only occur while the unit is in service.

7.8 POSTPONED UNPLANNED (FORCED) OUTAGE – U3

This is an outage that can be postponed beyond six hours but requires that a unit be removed from the in-service state before the end of the next weekend (Sunday at 2400 or before Sunday turns into Monday). This type of outage can only occur while the unit is in service.
7.9 PLANNED DERATING – PD

This is a derating that is scheduled well in advance and is of a predetermined duration. Periodic deratings for tests, such as weekly turbine valve tests, should not be reported as PD’s. Report deratings of these types as Maintenance Deratings (D4). On combined cycle and co-generation units always account for the loss of waste heat input to the HRSG whenever a gas turbine goes on planned outage by adding a concurrent planned derate to the steam turbine. Be sure to use the same start/end dates/times and the same cause code as the planned outage and specify in the description that this is a concurrent planned derate due to the outage on the appropriate gas turbine.

7.10 MAINTENANCE DERATING – D4

This is a derating that can be deferred beyond the end of the next weekend (Sunday at 2400 or before Sunday turns into Monday) but requires a reduction in capacity before the next Planned Outage (PO). A D4 can have a flexible start date and may or may not have a predetermined duration. On combined cycle and co-generation units always account for the loss of waste heat input to the HRSG whenever a gas turbine goes on maintenance outage by adding a concurrent maintenance derate to the steam turbine. Be sure to use the same start/end dates/times and the same cause code as the maintenance outage and specify in the description that this is a concurrent maintenance derate due to the outage on the appropriate gas turbine.

Note: If a derate occurs before Friday at 2400 hours (or before Friday turns into Saturday), the above definition applies. But if the derating occurs after Friday at 2400 hours and before Sunday at 2400 hours (the 48 hours of Saturday and Sunday), the D4 will only apply if the derating can be delayed passed the next, not current, weekend. If the derating cannot be deferred, the derating shall be a forced derating event.

7.11 PLANNED DERATING EXTENSION – DP

GADS defines a planned derating extension as an extension of a planned derate beyond its estimated completion date. This means that at the start of the PD, the derate had an estimated duration (time period) for the work and a date set for the unit to return to service. All work during the PD is scheduled (part of the original scope of work) and all repair times are determined before the outage started. Use a DP only in instances where the scope of work requires more time to complete than originally scheduled. Do not use a DP in instances when unexpected problems or delays outside the scope of work are encountered that render the unit incapable of full load beyond the estimated end date of the PD. The DP must start at the same time (month/day/hour/minute) that the PD ended.
7.12 MAINTENANCE DERATING EXTENSION – DM

If a maintenance derating (D4) continues beyond its estimated completion date, then it is considered maintenance derate extension (DM). This means that at the start of the D4 event, the derate has an estimated work time and a set date for the unit for returning to service. All work during the D4 is scheduled (part of the original scope of work) and all repair times are determined before the outage started. Use a DM only in instances where the scope of work requires more time to complete than originally scheduled. Do not use a DM in those instances where unexpected problems or delays outside the scope of work are encountered which render the unit incapable of full load beyond the estimated end date of the D4. The DM must start at the same time (month/day/hour/minute) that the D4 ended.

7.13 IMMEDIATE UNPLANNED (FORCED) DERATING – D1

This is a derating that requires an immediate reduction in capacity. On combined cycle and co-generation units always account for the loss of waste heat input to the HRSG whenever a gas turbine goes on forced outage or a startup failure by adding an appropriate concurrent derate (D1, D2, or D3) to the steam turbine. Be sure to use the same start/end dates/times and the same cause code as the as the forced outage or startup failure and specify in the description that this is a concurrent derate due to the forced outage or startup failure on the appropriate gas turbine.

7.14 DELAYED UNPLANNED (FORCED) DERATING – D2

This is a derating that does not require an immediate reduction in capacity, but rather within six hours. On combined cycle and co-generation units always account for the loss of waste heat input to the HRSG whenever a gas turbine goes on forced outage or a startup failure by adding an appropriate concurrent derate (D1, D2, or D3) to the steam turbine. Be sure to use the same start/end dates/times and the same cause code as the as the forced outage or startup failure and specify in the description that this is a concurrent derate due to the forced outage or startup failure on the appropriate gas turbine.

7.15 POSTPONED UNPLANNED (FORCED) DERATING – D3

This is a derating that can be postponed beyond six hours but requires a reduction in capacity before the end of the next weekend. On combined cycle and co-generation units always account for the loss of waste heat input to the HRSG whenever a gas turbine goes on forced outage or a startup failure by adding an appropriate concurrent derate (D1, D2, or D3) to the steam turbine. Be sure to use the same start/end dates/times and the same cause code as the as the forced outage or startup failure and specify in the description that this is a concurrent derate due to the forced outage or startup failure on the appropriate gas turbine.
8 APPENDIX C: STAFF RECOMMENDATIONS

SPP would like have a record of the staff recommendations made and presented as part of the overall proposed performance based accreditation methodology. Staff believes the recommendations below are consistent with reliability concerns expressed during GTTF discussions and are addressed as additional options to the body of this document. These recommendations reflect the staff opinions for constructing a performance based accreditation methodology:

1. Adopt the modified EFORd equation (EFORd’)
2. The calculation be performed for the summer and winter seasons separately while including the “shoulder” seasons (Two 6-month seasons)
3. Any performance based capacity accreditation methodology to take effect no later than summer 2025.
   a. By May 1, 2022, SPP Staff to implement recommendation for GO’s that are not subject to NERC, to submit NERC GADS equivalent data.
   b. For resources that do not submit NERC GADS data, the most recent three years of data will be included in the calculation at a minimum until five year of data is available.
   c. For resources that do submit NERC GADs data, the most recent five years of data will be included in the calculation.