2019 Long-Term Reliability Assessment Data Form Instructions

The purpose of this document is to provide guidance on the completion of the data form for the 2019 Long-Term Reliability Assessment (2019LTRA). NERC collects data from the eight Regions on an Assessment Area-basis. While each Assessment Area adheres to various planning assumptions, methods, and terminology, NERC collaborates with representatives from all Regions, as well as the Energy Information Administration (EIA) through the Reliability Assessment Subcommittee (RAS) to develop this set of instructions to promote consistency for high-level data assumptions when developing reliability assessments. Please direct any questions regarding the content of these instructions to NERC Staff.

**Form A**

**Net Energy for Load**

**Actual Net Energy for Load:** The electric energy requirements of the system, which is defined as the system net generation plus energy received from others less energy delivered to others. It includes system losses but excludes energy required for the filling of reservoirs at pumped-storage plants. [Source: FERC-714]

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior Year Actual</td>
</tr>
<tr>
<td>Enter the actual Net Energy for Load in GWh for each month of the prior reporting year.</td>
</tr>
</tbody>
</table>

**Forecasted Net Energy for Load:** The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred from both transmission and distribution. [Source: FERC-714]

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reporting Year Forecast</td>
</tr>
<tr>
<td>Enter the Net Energy for Load forecast in GWh for each month of the current Reporting Year.</td>
</tr>
<tr>
<td>Year 1 Forecast</td>
</tr>
<tr>
<td>Enter the Net Energy for Load forecast in GWh for each month of Year 1.</td>
</tr>
<tr>
<td>Year 2-10 Forecast</td>
</tr>
<tr>
<td>Enter the Net Energy for Load forecast in GWh for Years 2-10.</td>
</tr>
</tbody>
</table>

**Peak Hour Demand**

**Actual Peak Hour Demand:** The largest electric power requirement (based on Net Energy for Load) during a specific period of time, usually integrated over one clock hour and expressed in megawatts (MW). Actual peak hour demand should be provided on an Assessment Area coincident basis (the sum of two or more demands on individual systems that occur during the same demand interval). [Source: FERC-714]

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior Year Actual</td>
</tr>
<tr>
<td>Enter the actual Peak Hour Demand for each month of the Prior Year.</td>
</tr>
<tr>
<td>Reporting Year Actual</td>
</tr>
<tr>
<td>Enter the actual Peak Hour Demand for January and February of the Reporting Year.</td>
</tr>
</tbody>
</table>

**Forecasted Peak Hour Demand (Total Internal Demand):** The projected sum of the net outputs of all generators within the system and the line flows into the system, less the line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Total Internal Demand should be reduced by indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, Stand-by Load under Contract, all non-controllable or non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs). Total Internal Demand should not be reduced by the projected impacts of Controllable and Dispatchable Demand Response programs.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reporting Year Forecast</td>
</tr>
<tr>
<td>Enter the Peak Hour Demand (Total Internal Demand) forecast for each month of the Reporting Year.</td>
</tr>
<tr>
<td>Year 1 Forecast</td>
</tr>
<tr>
<td>Enter the Peak Hour Demand (Total Internal Demand) forecast for each month of Year 1</td>
</tr>
<tr>
<td>Year 2 Forecast</td>
</tr>
<tr>
<td>Enter the Peak Hour Demand (Total Internal Demand) forecast for January and February of Year 2.</td>
</tr>
<tr>
<td>Year 2-10 Forecast</td>
</tr>
<tr>
<td>Enter the Peak Hour Demand (Total Internal Demand) forecast for each season for Years 2-10.</td>
</tr>
</tbody>
</table>
**Forecasted Net Internal Demand**: Total of all end-use customer demand and electric system losses within specified metered boundaries, reduced by the projected impacts of Controllable and Dispatchable Demand Response programs.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Automatically calculated by reducing Total Internal Demand by the projected impacts of Controllable and Dispatchable Demand Response programs.</td>
</tr>
</tbody>
</table>

**Demand-Side Management**

**Conservation**: a reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; or industrial processes. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit, and using occupancy sensors that turn off lights or appliances. [Source: DOE-EIA]

**Energy Efficiency**: refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption, often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems. [Source: DOE-EIA]

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter the combined impacts of energy efficiency and conservation programs that impact load growth beyond its natural or normal rate. Impacts should be reported on a cumulative basis, starting with the expected impacts in 2015. This data is being reported for informational purposes, as Total Internal Demand should already be reduced by the impacts of these programs.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Example 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy efficiency Program A introduced any time prior to the reporting period (with continued impacts on electricity usage) with an estimated 10 MW reduction per year should be reported as follows:</td>
</tr>
<tr>
<td>Year 1-S</td>
</tr>
<tr>
<td>Energy Efficiency and Conservation</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Example 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>In addition to Program A, energy efficiency Program B will be introduced in Year 5 with an estimate reduction of 100 MW in the Years 5-7, and a 50 MW reduction in Years 8-10 should be reported as follows:</td>
</tr>
<tr>
<td>Year 1-S</td>
</tr>
<tr>
<td>Energy Efficiency and Conservation</td>
</tr>
</tbody>
</table>
Controllable and Dispatchable Demand Response: The projected amount of unique MWs counted towards resource adequacy planning by an entity for activities or programs that are directly controlled or dispatched by a System Operator. These programs are designed to modify the amount of electricity used during the peak hour and may include any demand response called as part of an emergency operating procedure.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Program Total</strong> Enter, in megawatts, the projected amount of uniquely enrolled (i.e. installed, registered) Controllable and Dispatchable Demand Response programs. This should consider current participants registered in these programs, as well as the projected growth of these programs during the assessment period.</td>
</tr>
<tr>
<td><strong>Available</strong> Enter, in megawatts, the projected amount of expected response from Controllable and Dispatchable Demand Response programs when called to respond during the forecasted peak hour.</td>
</tr>
</tbody>
</table>

Example: An assessment area has 2,000MW registered in their on-peak demand response program. If this program has a limit of 50% that can be called at any time, the assessment area enters 2,000MW for Program Total and 1,000MW for Available.

Example: An assessment area has 2,000MW registered in their on-peak demand response program. If this program has an historical performance of 95%, the assessment area enters 2,000MW for Program Total and 1,900MW for Available.

**Other Demand Factors**

**Total Installed DER/BTM Solar PV**: Non-utility scaled photovoltaic generation. Includes single-phase installed units that are considered “behind-the-meter”, “rooftop solar”, or part of a “building-integrated system”.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Report, in megawatts dc, the best estimation for the total amount of installed nameplate distributed generation. This field does not impact the Reserve Margin Calculations and is for information only.</td>
</tr>
</tbody>
</table>

**DER/BTM Solar PV On-Peak**: Non-utility scaled photovoltaic generation. Includes single-phase installed units that are considered “behind-the-meter”, “rooftop solar”, or part of a “building-integrated system”.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Report, in megawatts ac, the best estimation for the total amount of available distributed generation during the peak load hour. This data can include distributed generation that is reduced from the load forecast. That is, this value may represent the difference between Total Internal Demand and what Total Internal Demand would have been if there were no distributed generation. This should not include back-up generation that supports unserved peak load hour. Each Region/Assessment Area should document the method and approach used for calculation of this value. This field does not impact the Reserve Margin Calculations because impacts should already be captured in the load forecast (i.e., Total Internal Demand).</td>
</tr>
</tbody>
</table>

**Estimated Diversity**: the electric utility system’s load is made up of many individual loads that make demands upon the system usually at different times of the day, month, or season. The individual loads within the customer classes follow similar usage patterns, but these classes of service place different demands upon the facilities and the system grid. The service requirements of one electrical system can differ from another by time-of-day usage, facility usage, and/or demands placed upon the system grid. [Source: DOE-EIA]

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, in megawatts, the difference between the aggregation of forecasted Peak Hour Demand for individual entities (LSEs, control areas, zones, etc.) within the Assessment Area, less the forecasted Peak Hour Demand for the entire Assessment Area. These values for each season and year will provide the difference between the non-coincident and coincident Peak Hour Demand forecasts.</td>
</tr>
</tbody>
</table>

**Stand-by Load under Contract**: demand which is normally served by behind the meter generation which has a contract to provide power if the generator becomes unavailable.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
</table>
Enter, in megawatts, the expected demand at time of system peak required to provide power and energy (under a contract with a customer as a secondary source or backup for an outage of the customer’s primary source). Do not: (1) report the total (sum) of contracted stand-by load under contract; (2) separately report expected contract standby demand if it is already included in the forecasted peak data previously provided (if the load is reported as such the generation should also be reported).

Reference Margin Level: the assumptions of this metric vary by Assessment Area. Generally, the Reference Margin Level is typically based on load, generation, and transmission characteristics for each Assessment Area and, in some cases, the Reference Margin Level is a requirement implemented by the respective state(s), provincial authorities, ISO/RTO, or other regulatory bodies. If such a requirement exists, the respective Assessment Area generally adopts this requirement as the Reference Margin Level. In some cases, the Reference Margin Level will fluctuate over the duration of the assessment period, or may be different for the summer and winter seasons.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, as a decimal, the Reference Margin Level for all seasons/years of the assessment period. If this data is not provided, NERC will apply a 15 percent Reference Margin Level for predominately thermal systems and 10 percent for predominately hydro systems.</td>
</tr>
</tbody>
</table>
Form B
Generating Unit Information

<table>
<thead>
<tr>
<th>Description / Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Form B should include all generating units over 1 megawatt located within the Assessment Area at the time of data collection. Data must be provided for each unit (with exceptions for wind, solar, or hydro units, which can be aggregated by plant).</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Select one of the following options based on unit status at the time of reporting:</td>
</tr>
<tr>
<td>• <strong>Existing</strong> – in commercial operation</td>
</tr>
<tr>
<td>• <strong>Retired</strong> – permanently removed from commercial operation</td>
</tr>
<tr>
<td>• <strong>Mothballed</strong> – currently inactive or on standby, but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to “Existing” with capacity contributions entered in “Expected-Other”. Once a “mothballed” unit is confirmed to be capable for commercial operation, capacity contributions should be entered in “Expected-Certain”.</td>
</tr>
<tr>
<td>• <strong>Cancelled</strong> – planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.</td>
</tr>
<tr>
<td>• <strong>Tier 1</strong> – unit that meets at least one of the following guidelines (with consideration for an area’s planning processes)¹:</td>
</tr>
<tr>
<td>o Construction complete (not in commercial operation)</td>
</tr>
<tr>
<td>o Under construction</td>
</tr>
<tr>
<td>o Signed/approved Interconnection Service Agreement (ISA)</td>
</tr>
<tr>
<td>o Signed/approved Power purchase agreement (PPA) has been approved</td>
</tr>
<tr>
<td>o Signed/approved Interconnection Construction Service Agreement (CSA)</td>
</tr>
<tr>
<td>o Signed/approved Wholesale Market Participant Agreement (WMPA)</td>
</tr>
<tr>
<td>o Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)</td>
</tr>
<tr>
<td>• <strong>Tier 2</strong> – unit that meets at least one of the following guidelines (with consideration for an area’s planning processes)²:</td>
</tr>
<tr>
<td>o Signed/approved Completion of a feasibility study</td>
</tr>
<tr>
<td>o Signed/approved Completion of a system impact study</td>
</tr>
<tr>
<td>o Signed/approved Completion of a facilities study</td>
</tr>
<tr>
<td>o Requested Interconnection Service Agreement</td>
</tr>
<tr>
<td>o Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)</td>
</tr>
<tr>
<td>• <strong>Tier 3</strong> – units in an interconnection queue that do not meet the Tier 2 requirement</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Country</th>
</tr>
</thead>
<tbody>
<tr>
<td>Select the country where the unit is physically located:</td>
</tr>
<tr>
<td>• <strong>CA</strong> – Canada</td>
</tr>
<tr>
<td>• <strong>MX</strong> – Mexico</td>
</tr>
<tr>
<td>• <strong>US</strong> – United States</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Region</th>
</tr>
</thead>
<tbody>
<tr>
<td>The Regional Entity in which the generation unit resides.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NERC Unit ID</th>
</tr>
</thead>
<tbody>
<tr>
<td>NERC will assign a unique ID for all units.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Plant Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>EIA-860 Plant Code should be used for all US units.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Generator ID – 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>The unique generator identification commonly used by plant management. Generator identification can have a maximum of four characters. EIA-860 Generator ID should be used for all units within the US.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Generator ID – 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assessment area or Regional Entity Generator ID. (Optional)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Plant Name – 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>EIA-860 Plant Name should be used for all units within the US.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Plane Name – 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assessment area or Regional Entity Plant Name. (Optional)</td>
</tr>
</tbody>
</table>

¹ AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific) |
² AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
| Plant Name – 3 | Assessment Area or Regional Entity Plant Name. (Optional) |
| Prime Mover | For combined cycle units, a prime mover code must be entered for each generator. EIA-860 Prime Mover should be used for all units. See Appendix I. |
| Energy Source – 1 | The energy source code for the fuel used in the largest quantity (Btus) to power the generator. EIA-860 Predominant Energy Source should be used for all units. See Appendix I. |
| Energy Source – 2 | The energy source code for the fuel used in the second largest quantity (Btus) to power the generator. EIA-860 Second Most Predominant Energy Source to be used for all units. See Appendix I. For units with no secondary energy source, leave this field blank. |
| Generation Type | Automatically calculated, based on the Prime Mover and Energy Source – 1. |
| Initial Operating Month-Year | For existing units, provide only the year of the original effective date that the generator became operational (EIA operating year should be used for all units within the US). For planned units (Tier 1-3), enter the month and year the unit is projected to become commercially operational. |
| Confirmed Retirement Date | Only provide for units with formalized announced plans to retire; where applicable, the unit must have an approved generator deactivation request. For units that meet these requirements, enter the month and year of the unit’s confirmed retirement date. |
| Nameplate Capacity | The highest value on the nameplate in MW rounded to the nearest tenth as measured in alternating current (AC). EIA-860 nameplate capacity should be used for all units within the US. |
| Summer Capacity | Generator net summer capacity for the primary energy source; report in alternating current (AC) MW, rounded to the nearest tenth. EIA-860 summer capacity can be used for all units within the US. For Assessment Areas that test units on a seasonal basis, report the latest available net summer capacity. |
| Winter Capacity | Generator net winter capacity for the primary energy source; report in alternating current (AC) MW, rounded to the nearest tenth. EIA-860 summer capacity can be used for all units within the US. For Assessment Areas that test units on a seasonal basis, report the latest available net summer capacity. |

**Certain Capacity**

**Certain Capacity:** a subset of Anticipated Resources and the Anticipated Reserve Margin; included in this category are commercially operable generating units, or portions of generating units, that meet at least one of the following requirements when examining the period of peak demand for each season/year for the assessment period:

- Unit must have a firm capability² and have a Power Purchase Agreement (PPA)⁴ with firm transmission
- Unit must be classified as a Designated Network Resource⁷
- Where energy-only markets exist, unit must be a designated market resource eligible to bid into the market

| Instructions |
| Summer/Winter – Years 1-10 | For existing capacity, and capacity additions (Tier 1-3) that meet the requirements of Certain Capacity, provide the amount of capacity (in megawatts) projected to be available during the peak hour for the summer and winter of each year. Values for each season/year should be provided in the appropriate columns and reflect capacity adjustments for the following impacts: uprates, derates, confirmed retirements, transmission limitations, fuel limitations. All variable resources (wind, solar, hydro) must be derated. Thermal units should be derated for fuel availability if applicable. Capacity adjustments that are unavailable on a unit basis should be aggregated by fuel type and provided in Form C. Certain |

---

² For generators that are out of service for an extended period of time or on standby, report the energy sources based on the generator’s latest operating experience. Select appropriate energy source codes from Table 1 in these instructions. For generators driven by turbines using steam that is produced from waste heat or reject heat, report the original energy source used to produce the waste heat (reject heat).

⁴ Do not include a fuel used only for start-up or flame stabilization. For generators driven by turbines using steam that is produced from waste heat or reject heat, report the original energy source used to produce the waste heat (reject heat).

⁵ The commitment of generation service to a customer under a contractual agreement to which the parties to the service anticipate no planned interruption (applies to generation and transmission). (Source: FERC-714) [http://www.ferc.gov/docs-filing/forms/form-714/form-714-instructions.doc](http://www.ferc.gov/docs-filing/forms/form-714/form-714-instructions.doc).

⁶ Power Purchase Agreement: Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner. [http://www.ferc.gov/market-oversight/guide/glossary.asp#P](http://www.ferc.gov/market-oversight/guide/glossary.asp#P).

⁷ Designated Network Resource: Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer’s Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a Commission-approved reserve sharing program. For more information see section 1432 of FERC Order 890: [http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf](http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf).
Capacity in Form B should not reflect reductions for Unconfirmed Retirements. Unconfirmed Retirements should be aggregated by fuel type and reported in Form C.

**Other Capacity**

**Other Capacity:** Included in this category are commercially operable generating units, or portions of generating units, that are expected to be available to serve load for the period of peak demand for each season/year of the assessment period, but do not meet the requirements of Existing-Certain. Existing-Other is a subset of Prospective Resources and Prospective Reserve Margins.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Years 1-10</strong> For existing capacity, and capacity additions (Tier 1-3) that do not meet at least one of the requirements of Certain Capacity, provide the amount of capacity, in megawatts, projected to be available during the peak hour for the summer and winter of each year. Values for each season/year should be provided in the appropriate columns and reflect capacity adjustments for the following impacts: uprates, derates, retirements, transmission limitations, fuel availability. Include all derates as positive MW values. Other Capacity in Form B should not reflect reductions for Unconfirmed Retirements. Unconfirmed Retirements should be aggregated by fuel type and reported in Form C.</td>
</tr>
</tbody>
</table>
Form C

Capacity Transfers (Imports/Exports)

**Firm Imports/Exports**: Electric power intended to meet the demand requirement of a utility's customers; the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption [NERC Glossary of Terms]. Firm transfers count towards the Anticipated resource category and corresponding reserve margin.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, in megawatts, the amount of capacity purchases or sales for which a firm contract has been signed. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s). Values should reflect Firm transfers in place for all seasons and years. Values should be equal to or greater than the aggregation of Full Responsibility Purchases and Owned Capacity/Entitlements Located Outside the Area.</td>
</tr>
</tbody>
</table>

**Firm Imports/Exports – Full Responsibility Purchases**: A firm contract for which the seller is contractually obligated to deliver power and energy to the purchaser with the same degree of reliability as provided to the seller’s own native load customers.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, in megawatts, the total of all Firm contracts for which the seller(s) is contractually obligated to deliver power and energy to the buyer(s) with the same degree of reliability as provided to the seller’s own native load customers. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s). The buyer(s) and seller(s) must coordinate and agree on how transactions are reported under this heading. This category is a subset of total Firm imports/exports.</td>
</tr>
</tbody>
</table>

**Firm Imports/Exports – Owned Capacity/Entitlement Located outside the Area**: A transfer in which owned capacity is located outside the reporting Region or subregion boundary. This category includes pseudo ties.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, in megawatts, the amount of externally owned capacity transfers or capacity entitlements located outside the Assessment Area footprint. This category is a subset of total Firm imports/exports. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s).</td>
</tr>
</tbody>
</table>

**Expected**: Projected transfers with a high expectation that a Firm contract will be executed. Expected transfers count towards the Prospective resource category and corresponding reserve margin.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, in megawatts, the amount of Expected transfers for each season and year. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s).</td>
</tr>
</tbody>
</table>

Available On-Peak Reserves

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prior Year Actual Enter, in megawatts, the available reserves (spinning, non-spinning, and other reserves) that were available and deliverable during the Peak Hour Demand during the prior summer and winter seasons.</td>
</tr>
</tbody>
</table>

Capacity Adjustments

**Scheduled Outages**: Capacity projected to be unavailable during the peak due to a scheduled outage.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enter, in megawatts, the aggregated amount of capacity projected to be unavailable due to a scheduled outage during the peak for all seasons/years of the assessment period. Do not include scheduled outages that are reflected by reducing Existing-Certain capacity on a unit-level-basis in Form B.</td>
</tr>
</tbody>
</table>

**Transmission Limitations**: Capacity projected to be unavailable due to transmission limitations caused by known physical deliverability limitations to serve load that the resources are obligated to serve. This value for each season/year will reduce the area’s total Existing-Certain capacity.

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
</table>
Enter, in megawatts, the aggregated amount of capacity projected to be unavailable due to a transmission limitations during the peak for all seasons/years of the assessment period. Do not include transmission limitations that are reflected by reducing Existing-Certain capacity on a unit-level-basis in Form B.

Other Capacity Adjustments – Addition: Other capacity adjustments to account for impacts not explicitly addressed in this form.

Instructions
Enter, in megawatts, the aggregated capacity adjustments to be added to Existing-Certain capacity. A comment must be provided to explain the use of these fields.

Other Capacity Adjustments – Reduction: Other capacity adjustments to account for impacts not explicitly addressed in this form.

Instructions
Enter, in megawatts, the aggregated capacity adjustments to be reduced from Existing-Certain capacity. A comment must be provided to explain the use of these fields. This field can be used to account for fleet-wide capacity adjustments, such as derates, transmission limitations, and fuel availability.

Capacity Additions by Generation Type
Aggregated Capacity Additions: capacity additions, aggregated by generation type.

Instructions
Enter, in megawatts, the aggregated capacity additions for each generation type and Tier. These fields should only be used for Assessment Areas with confidentiality restrictions that limit the reporting of capacity additions on a unit basis. A comment must be provided to explain the use of these fields.

Unconfirmed Capacity Retirements by Generation Type
Unconfirmed Retirements: Units that have been designated for retirement, but a formal notification to ISO, RTO, or regulatory bodies has not been provided. Also include units for which such notice has been made, but a reliability impact assessment, and potential designation as a reliability must run unit by the ISO or RTO, is pending. Examples include:

- Reliability-must-run status and other issues may conflict with this proposed/requested retirement or conversion.
- Units that have announced or submitted a request for a generator deactivation, but have not received approval.
- Units expected to retire based on the result of a generator survey or analysis.

Instructions
For capacity that meet the above requirements, provide the aggregated, cumulative amount of capacity that will retire for each season/year.
# Form D

## Planned Transmission Projects

<table>
<thead>
<tr>
<th>Description / Instructions</th>
<th>NERC Project ID</th>
<th>NERC will assign a unique ID for all projects</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project ID</td>
<td></td>
<td>Optional entry by Region/Assessment Area</td>
</tr>
<tr>
<td>Project Name</td>
<td></td>
<td>Enter the project name</td>
</tr>
<tr>
<td>Project Status</td>
<td>Under Construction</td>
<td>Construction of the line has begun</td>
</tr>
<tr>
<td></td>
<td>Planned</td>
<td>The line is included in a regional transmission plan</td>
</tr>
<tr>
<td></td>
<td>Conceptual</td>
<td>The line is in a project queue, but not included in a regional transmission plan</td>
</tr>
<tr>
<td></td>
<td>Planned (any of the following)</td>
<td>Permits have been approved to proceed</td>
</tr>
<tr>
<td></td>
<td>Design is complete</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Needed in order to meet a regulatory requirement</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Conceptual (any of the following)</td>
<td>A line projected in the transmission plan</td>
</tr>
<tr>
<td></td>
<td>A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Other projected lines that do not meet requirements of “Under Construction” or “Planned”</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Completed</td>
<td>A project reported in the prior year has been placed into service</td>
</tr>
<tr>
<td></td>
<td>Delayed - Load Growth</td>
<td>A project that has been delayed due to updated load growth projections</td>
</tr>
<tr>
<td></td>
<td>Delayed - Permitting Challenges</td>
<td>A project that has been delayed due to permitting challenges</td>
</tr>
<tr>
<td></td>
<td>Delayed - Siting Challenges</td>
<td>A project that has been delayed due to siting challenges</td>
</tr>
<tr>
<td></td>
<td>Delayed - Economics</td>
<td>A project that has been delayed due to economic impacts</td>
</tr>
<tr>
<td></td>
<td>Delayed - Other (Comment Required)</td>
<td>A project that has been delayed due to other reasons; an explanation must be provided in the comment field</td>
</tr>
<tr>
<td></td>
<td>Cancelled - Load Growth</td>
<td>A project that has been cancelled due to updated load growth projections</td>
</tr>
<tr>
<td></td>
<td>Cancelled - Permitting Challenges</td>
<td>A project that has been cancelled due to permitting challenges</td>
</tr>
<tr>
<td></td>
<td>Cancelled - Siting Challenges</td>
<td>A project that has been cancelled due to siting challenges</td>
</tr>
<tr>
<td></td>
<td>Cancelled - Economics</td>
<td>A project that has been cancelled due to economic impacts</td>
</tr>
<tr>
<td></td>
<td>Cancelled - Other (Comment Required)</td>
<td>A project that has been cancelled due to other reasons; an explanation must be provided in the comment field</td>
</tr>
<tr>
<td>Region</td>
<td></td>
<td>Regional Entity in which a majority of the line length is located.</td>
</tr>
<tr>
<td>Project Name</td>
<td></td>
<td>Name of project at the discretion of the assessment area.</td>
</tr>
<tr>
<td>Tie Line</td>
<td>Yes/No</td>
<td>A circuit connecting two Balancing Authority Areas or two separate systems. Specify whether the project is classified as a tie line.</td>
</tr>
<tr>
<td>Project Drivers (Primary and Secondary)</td>
<td>Reliability</td>
<td>Choose one or two of the predefined drivers for each line addition. While it is understood that one line could serve multiple functions (i.e. reliability and economics), please specify the principle consideration/driver for this addition. Do not write in other drivers in these fields; instead, select “Other” and include an explanation in the comment field.</td>
</tr>
<tr>
<td></td>
<td>Variable/Renewable Integration</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nuclear Integration</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Fossil-Fired Integration</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hydro Integration</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Economics/Congestion</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td></td>
</tr>
<tr>
<td>Terminal Origin</td>
<td></td>
<td>Provide the name of the point where the line originates</td>
</tr>
<tr>
<td>Terminal Origin State</td>
<td></td>
<td>Select the state where the line originates</td>
</tr>
<tr>
<td>Terminal Endpoint</td>
<td></td>
<td>Provide the name of the point where the line ends</td>
</tr>
<tr>
<td>Terminal Endpoint State</td>
<td></td>
<td>Select the state where the line ends</td>
</tr>
</tbody>
</table>

---

2018 Long-Term Reliability Assessment – Data Form Instructions 10
<table>
<thead>
<tr>
<th>Company Name</th>
<th>Enter the company that owns the majority of the transmission line.</th>
</tr>
</thead>
<tbody>
<tr>
<td>EIA Company Code</td>
<td>Identify each organization by the six-character code assigned by EIA. Required for all projects within the U.S.</td>
</tr>
<tr>
<td>Entity Type</td>
<td>Select the type of organization that best represents the line owner. If there is more than one organization, select the type of entity that has the highest stake of ownership. List each of the owners in the comments section with corresponding percentage of ownership.</td>
</tr>
<tr>
<td>Ownership (%)</td>
<td>For jointly-owned projects, enter the percentages owned by the entity with the highest stake of ownership. List each of the owners in the comments section with corresponding percentage of ownership. If the line is not jointly-owned, enter 100 percent.</td>
</tr>
<tr>
<td>Line Type</td>
<td>Select the predominant physical location of the line conductor.</td>
</tr>
<tr>
<td>Voltage Type</td>
<td>Select alternating or direct current (AC/DC)</td>
</tr>
<tr>
<td>Line Length (Circuit Miles)</td>
<td>Enter circuit line miles (not linear miles) between the terminal origin and end points. Projects with a line length of less than 1 circuit mile should not be included.</td>
</tr>
<tr>
<td>Operating Voltage (kV)</td>
<td>For new lines, select the voltage class that the line is designed to operate. For existing lines that are being upgraded to a higher operating voltage class, enter the voltage class that the line will operate at after the upgrade.</td>
</tr>
<tr>
<td>Voltage Design (kV)</td>
<td>For new lines, manually enter the exact voltage the line is designed to operate. For existing lines that are being upgraded to a higher operating voltage class, enter the current voltage (prior to the upgrade).</td>
</tr>
<tr>
<td>Upgraded Voltage Design (kV)</td>
<td>Only required for existing lines that are being upgraded to a higher operating voltage class. Enter the exact voltage the line will operate at following the upgrade.</td>
</tr>
<tr>
<td>Circuits Per Structure Present / Ultimate</td>
<td>The line structures are projected to utilize a one (1) to three (3) three-phase circuit, once operational. For new projects, enter the number of three-phase circuits expected to be used on each tower. For the ultimate field, enter the total number of three-phase circuits that the tower is capable of accommodating.</td>
</tr>
<tr>
<td>Capacity Rating (MVA)</td>
<td>Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).</td>
</tr>
<tr>
<td>Original In-Service Month</td>
<td>For delayed projects, select the original month the line was scheduled to be energized under the control of the system operator. This cell is required for delayed lines only.</td>
</tr>
<tr>
<td>Original In-Service Year</td>
<td>For delayed projects, select the original year the line was scheduled to be energized under the control of the system operator. This cell is required for delayed lines only.</td>
</tr>
<tr>
<td>Expected In-Service Month</td>
<td>Select the expected month the line will be energized under the control of the system operator. This field is required for all projects.</td>
</tr>
<tr>
<td>Expected In-Service Year</td>
<td>Select the expected year the line will be energized under the control of the system operator. This field is required for all projects.</td>
</tr>
<tr>
<td>Cause of Delay / Other Comments</td>
<td>Describe any information available regarding the reasons for the delay. Provide any other important information regarding the project.</td>
</tr>
</tbody>
</table>
Form E
Projected Transformer Additions

<table>
<thead>
<tr>
<th>Instructions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Respondent must complete this schedule for all projected transformer additions within the Assessment Area at 100 kV (Low-Side) and above for the 10-year period. Replacement transformers should be reported and noted in the Description/Status field.</td>
</tr>
</tbody>
</table>

| Project ID | To be provided by NERC staff for tracking purposes. |
| Status |
| Under Construction |
| Planned |
| Conceptual |
| Completed (Provide Actual In-Service Date as Comment) |
| Delayed (Comment Required) |
| Cancelled (Comment Required) |

| Project Name | Enter the project name |
| Voltage – Low-Side (kV) | Enter the transformer’s low-side voltage |
| Voltage – High-Side (kV) | Enter the transformer’s high-side voltage |

| Expected In-Service Month | The projected month the transformer will be energized under the control of the system operator. Select the appropriate month from the drop-down list. |
| Expected In-Service Year | The projected year the transformer will be energized under the control of the system operator. Select the appropriate year from the drop-down list. |

| Description/Status | Provide a brief description/status on the transformer addition. |
Summary Tables
The summary tables include basic formulas that are intended to provide data submitters with critical metrics, including demand and Demand-Side Management, Capacity, Capacity Transfers, Resource Categories, Reserve Margin Excess and Shortfall, and Planning Reserve Margins. Important information and clarification on each category is provided below. Data submitters should refrain from modifying these formulas and contact NERC staff with any questions.

Demand/Demand-Side Management
- Energy efficiency, conservation, behind-the-meter generation, and distributed generation are assumed to be already embedded in the load forecast.
- The difference between Total Internal Demand and Net Internal Demand is the amount Controllable and Dispatchable Demand Response expected to be available at the time of peak for each season and year.

Capacity
Existing-Certain
- Adds on-peak capacity, as reported for Certain-Summer and Certain-Winter in Form B for units with a status of Existing and Mothballed.
- Adds Behind the Meter Generation – Capacity, as reported for each season and year, on an aggregated basis in Form C.
- Adds Other Capacity Adjustments – Additions, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Other Capacity Adjustments – Reductions, as reported for each season and year, on an aggregated basis in Form C.
- Accounts for Confirmed Retirements, as reported for Certain-Summer and Certain-Winter in Form B by unit.
- Subtracts Unconfirmed Retirements, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Scheduled Outages, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Transmission Limitations, as reported for each season and year, on an aggregated basis in Form C.

Existing-Other
- Includes on-peak capacity, as reported for Other-Summer and Other-Winter in Form B by unit.
- Includes Behind the Meter Generation – Capacity, as reported for each season and year, on an aggregated basis in Form C.
- Adds Other Capacity Adjustments – Additions, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Other Capacity Adjustments – Reductions, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Confirmed Retirements, as reported for Certain-Summer and Certain-Winter in Form B by unit.
- Subtracts Confirmed Retirements, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Unconfirmed Retirements, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Scheduled Outages, as reported for each season and year, on an aggregated basis in Form C.
- Subtracts Transmission Limitations, as reported for each season and year, on an aggregated basis in Form C.

Planned-Tier 1
- Includes on-peak capacity, as reported for Certain-Summer and Certain-Winter in Form B for units with a status of Tier 1.
- Includes Tier 1 capacity additions, as reported for each season and year, as aggregated fuel-type in Form C.

Planned-Tier 2
- Includes on-peak capacity, as reported for Certain-Summer and Certain-Winter in Form B for units with a status of Tier 2.
- Includes Tier 2 capacity additions, as reported for each season and year, as aggregated fuel-type in Form C.

Planned-Tier 3
- Includes on-peak capacity, as reported for Certain-Summer and Certain-Winter in Form B for units with a status of Tier 3.
- Includes Tier 3 capacity additions, as reported for each season and year, as aggregated fuel-type in Form C.
Resource Categories

Existing-Certain and Net Firm Transfers
• Includes Existing-Certain capacity and Net Firm Capacity Transfers

Anticipated Resources
• Includes Existing-Certain and Net Firm Transfers, plus Tier 1 planned capacity additions

Prospective Resources
• Includes Anticipated Resources, plus Existing-Other capacity, plus Tier 2 planned capacity additions, minus Unconfirmed Retirements.

Note: the Adjusted-Potential Resources and corresponding Reserve Margin has been removed. Tier 3 capacity additions will be collected for informational purposes. If the Prospective Reserve Margin for an Assessment Area falls below the Reference Margin Level during the assessment period, additional analysis will be performed by NERC staff to determine how much Tier 3 capacity additions will be needed to maintain the Reference Margin Level.

Reference Margin Level Excess/Shortfall

Existing-Certain and Net Firm Transfers Shortfall
• Shortfall: provides a negative value, in megawatts, for each season and year for how much capacity is needed to maintain the Reference Margin Level, beyond what already projected for Existing-Certain and Net Firm Transfers.

Anticipated Resources Shortfall
• Shortfall: provides a negative value, in megawatts, for each season and year for how much capacity is needed to maintain the Reference Margin Level, beyond what already projected for Anticipated Resources.

Prospective Resources Shortfall
• Shortfall: provides a negative value, in megawatts, for each season and year for how much capacity is needed to maintain the Reference Margin Level, beyond what already projected for Prospective Resources.

Note: the Adjusted-Potential Resources and corresponding Reserve Margin was removed in the 2015LTRA. Tier 3 capacity additions will continue to be collected for informational purposes. If the Prospective Reserve Margin for an Assessment Area fall below the Reference Margin Level during the assessment period, additional analysis will be performed by NERC staff to determine how many Tier 3 capacity additions will be needed to maintain the Reference Margin Level.
# Appendix I: EIA-860 Prime Mover and Energy Source Codes

## Prime Mover Codes

<table>
<thead>
<tr>
<th>Code</th>
<th>Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>BA</td>
<td>Energy Storage, Battery</td>
</tr>
<tr>
<td>CE</td>
<td>Energy Storage, Compressed Air</td>
</tr>
<tr>
<td>CP</td>
<td>Energy Storage, Concentrated Solar Power</td>
</tr>
<tr>
<td>FW</td>
<td>Energy Storage, Flywheel</td>
</tr>
<tr>
<td>PS</td>
<td>Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)</td>
</tr>
<tr>
<td>ES</td>
<td>Energy Storage, Other (specify in comments section)</td>
</tr>
<tr>
<td>ST</td>
<td>Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)</td>
</tr>
<tr>
<td>GT</td>
<td>Combustion (Gas) Turbine (includes jet engine design)</td>
</tr>
<tr>
<td>IC</td>
<td>Internal Combustion Engine (diesel, piston, reciprocating)</td>
</tr>
<tr>
<td>CA</td>
<td>Combined Cycle Steam Part</td>
</tr>
<tr>
<td>CT</td>
<td>Combined Cycle Combustion Turbine Part (type of coal or solid must be reported as energy source for integrated coal gasification)</td>
</tr>
<tr>
<td>CS</td>
<td>Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)</td>
</tr>
<tr>
<td>CC</td>
<td>Combined Cycle Total Unit (use only for plants/generators in planning stages, for which specific generator details cannot be provided)</td>
</tr>
<tr>
<td>HA*</td>
<td>Hydrokinetic, Axial Flow Turbine</td>
</tr>
<tr>
<td>HB</td>
<td>Hydrokinetic, Wave Buoy</td>
</tr>
<tr>
<td>HK</td>
<td>Hydrokinetic, Other (specify in comments section)</td>
</tr>
<tr>
<td>HY**</td>
<td>Hydroelectric Turbine (includes turbines associated with delivery of water by pipeline)</td>
</tr>
<tr>
<td>BT</td>
<td>Turbines Used in a Binary Cycle (including those used for geothermal applications)</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
</tr>
<tr>
<td>WT</td>
<td>Wind Turbine, Onshore</td>
</tr>
<tr>
<td>WS</td>
<td>Wind Turbine, Offshore</td>
</tr>
<tr>
<td>FC</td>
<td>Fuel Cell</td>
</tr>
<tr>
<td>OT</td>
<td>Other/Unknown (specify in comments section)</td>
</tr>
</tbody>
</table>

*Use HA for all Run of River Hydro applications.

**Use HY For all Conventional Hydro applications.
## Energy Source Codes

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Code</th>
<th>Fuel Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>ANT</td>
<td>Anthracite Coal</td>
</tr>
<tr>
<td></td>
<td>BIT</td>
<td>Bituminous Coal</td>
</tr>
<tr>
<td></td>
<td>LIG</td>
<td>Lignite Coal</td>
</tr>
<tr>
<td></td>
<td>SGC</td>
<td>Coal-Derived Synthesis Gas</td>
</tr>
<tr>
<td></td>
<td>SUB</td>
<td>Subbituminous Coal</td>
</tr>
<tr>
<td></td>
<td>WC</td>
<td>Waste/Other Coal (including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)</td>
</tr>
<tr>
<td></td>
<td>RC</td>
<td>Refined Coal</td>
</tr>
<tr>
<td>Fossil Fuels</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Petroleum Products</td>
<td>DFO</td>
<td>Distillate Fuel Oil. Including Diesel, No. 1, No. 2, and No. 4 Fuel Oils</td>
</tr>
<tr>
<td></td>
<td>JF</td>
<td>Jet Fuel</td>
</tr>
<tr>
<td></td>
<td>KER</td>
<td>Kerosene</td>
</tr>
<tr>
<td></td>
<td>PC</td>
<td>Petroleum Coke</td>
</tr>
<tr>
<td></td>
<td>PG</td>
<td>Gaseous Propane</td>
</tr>
<tr>
<td></td>
<td>RFO</td>
<td>Residual Fuel Oil (including No. 5, and No. 6 fuel oils, and bunker C fuel oil)</td>
</tr>
<tr>
<td></td>
<td>SGP</td>
<td>Synthesis Gas from Petroleum Coke</td>
</tr>
<tr>
<td></td>
<td>WO</td>
<td>Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)</td>
</tr>
<tr>
<td>Natural Gas and Other Gases</td>
<td>BFG</td>
<td>Blast Furnace Gas</td>
</tr>
<tr>
<td></td>
<td>NG</td>
<td>Natural Gas</td>
</tr>
<tr>
<td></td>
<td>OG</td>
<td>Other Gas (specify in comments section)</td>
</tr>
<tr>
<td>Solid Renewable Fuels</td>
<td>AB</td>
<td>Agricultural By-Products</td>
</tr>
<tr>
<td></td>
<td>MSW</td>
<td>Municipal Solid Waste</td>
</tr>
<tr>
<td></td>
<td>OBS</td>
<td>Other Biomass Solids (specify in comment section)</td>
</tr>
<tr>
<td></td>
<td>WDS</td>
<td>Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)</td>
</tr>
<tr>
<td>Renewable Fuels</td>
<td>OBL</td>
<td>Other Biomass Liquids (specify in comment section)</td>
</tr>
<tr>
<td>Liquid Renewable (Biomass) Fuels</td>
<td>SLW</td>
<td>Sludge Waste</td>
</tr>
<tr>
<td></td>
<td>BLQ</td>
<td>Black Liquor</td>
</tr>
<tr>
<td></td>
<td>WDL</td>
<td>Wood Waste Liquids excluding Black Liquor (including red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)</td>
</tr>
<tr>
<td>Gaseous Renewable (Biomass Fuel)</td>
<td>LFG</td>
<td>Landfill Gas</td>
</tr>
<tr>
<td>All Other Renewable Fuels</td>
<td>OBG</td>
<td>Other Biomass Gas (including digester gas, methane, and other biomass gases; specify in comments section)</td>
</tr>
<tr>
<td>All Other Energy Sources</td>
<td>SUN</td>
<td>Solar</td>
</tr>
<tr>
<td></td>
<td>WND</td>
<td>Wind</td>
</tr>
<tr>
<td></td>
<td>GEO</td>
<td>Geothermal</td>
</tr>
<tr>
<td></td>
<td>WAT</td>
<td>Water at a Conventional; Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology</td>
</tr>
<tr>
<td></td>
<td>NUC</td>
<td>Nuclear (including Uranium, Plutonium, and Thorium)</td>
</tr>
<tr>
<td></td>
<td>PUR</td>
<td>Purchased Steam</td>
</tr>
<tr>
<td></td>
<td>WH</td>
<td>Waste heat not directly attributed to a fuel source (WH should only be reported where the fuel source for the waste heat is undetermined, and for combined cycle steam turbines that do not have supplemental firing.)</td>
</tr>
<tr>
<td></td>
<td>TDF</td>
<td>Tire-derived Fuels</td>
</tr>
<tr>
<td></td>
<td>MWH</td>
<td>Electricity used for energy storage</td>
</tr>
<tr>
<td></td>
<td>OTH</td>
<td>Other (specify in comment section)</td>
</tr>
<tr>
<td></td>
<td>UKN</td>
<td>Unknown (specify in comment section)</td>
</tr>
</tbody>
</table>