2015 Long-Term Reliability Assessment

Data Form Instructions

Version 1

The purpose of this document is to provide guidance on the completion of the data form for the *2015 Long-Term Reliability Assessment* (2015LTRA). 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 Data Working Group (RADWG) 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]

Instructions	
Prior Year Actual	Enter the actual Net Energy for Load for each for each month of the prior reporting year.

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 in the transmission and distribution. [Source: FERC-714]

Instructions	
Reporting Year Forecast	Enter the Net Energy for Load forecast for each month of the current Reporting Year.
Year 1 Forecast	Enter the Net Energy for Load forecast for each month of Year 1.
Year 2-10 Forecast	Enter the Net Energy for Load forecast for Years 2-10.

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 a coincident basis (the sum of two or more demands on individual systems that occur during the same demand interval). [Source: FERC-714]

Instructions	
Prior Year Actual	Enter the actual Peak Hour Demand for each month of the Prior Year.
Reporting Year Actual	Enter the actual Peak Hour Demand for January and February of the Reporting Year.

Forecasted Peak Hour Demand (Total Internal Demand): The projected sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered 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.

Instructions	
Reporting Year Forecast	Enter the Peak Hour Demand (Total Internal Demand) forecast for each month of the Reporting Year.
Year 1 Forecast	Enter the Peak Hour Demand (Total Internal Demand) forecast for each month of Year 1
Year 2 Forecast	Enter the Peak Hour Demand (Total Internal Demand) forecast for January and February of Year 2.
Year 2-10 Forecast	Enter the Peak Hour Demand (Total Internal Demand) forecast for each season for Years 2-10.

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.

Instructions
Automatically calculated by reducing Total Internal Demand by the projected impacts of Controllable and Dispatchable Demand Response programs.

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; industrial processes; or vehicle transportation. 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, using occupancy sensors that turn off lights or appliances, and car-pooling. [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]

Instructions
Enter the combined impacts of new 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.

Example 1

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:

	2015-S	2016-S	2017-S	2018-S	2019-S	2020-S	2021-S	2022-S	2023-S	2024-S
Energy Efficiency and Conservation	10	20	30	40	50	60	70	80	90	100

Example 2

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:

	Year 1-S	Year 2-S	Year 3-S	Year 4-S	Year 5-S	Year 6-S	Year 7-S	Year 8-S	Year 9-S	Year 10-S
Energy Efficiency and Conservation	10	20	30	40	150	260	370	430	490	550

Controllable and Dispatchable Demand Response: The projected impact of any activities or programs that are directly controlled or dispatched by the System Operator or Load-Serving Entity to influence the amount electricity used during the peak hour.

Instructions	
Program Total	Enter, in megawatts, the projected amount of 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.
Available	Enter, in megawatts, the projected impacts of Controllable and Dispatchable Demand Response programs. This should consider the projected quantity of reduced electrical consumption during the forecasted Peak Hour Demand.

Other Demand Factors

Behind the Meter Generation: a generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail load with electric energy. [Source: NERC Project 2010-17 Definition of Bulk Electric System (Phase 2)]

Instructions
Report, in megawatts, the total amount of behind the meter generation that has been excluded from the load forecast. This data is being reported for informational purposes, as Total Internal Demand should already reflect the reduced impacts of these programs. This should also include and "behind the fence" generation.

Distributed Generation: Generation that is located close to the particular load that it is intended to serve. General, but non-exclusive, characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less). [Source: DOE-EIA]

Instructions
Report, in megawatts, the best estimation for the total amount of distributed generation that is embedded in the load forecast.

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]

Instructions
Enter, in megawatts, the difference between the aggregation of forecasted Peak Hour Demands 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.

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.

Instructions
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.

Instructions
Enter, as a percent, 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.

Form B
Generating Unit Information

Description / Instructions	
Form B should include all generating units over 1 megawatt located within the Assessment Area at the time of data collection. Data must be provide for each unit (with exceptions for wind, solar, or hydro units, which can be aggregated by plant).	
Status	Select one of the following options based on unit status at the time of reporting: • **Existing** – capable of commercial operation • **Retired** – the unit has been taken out of commercial operation • **Mothballed** – capable of commercial operation but currently inactive or on standby • **Cancelled** – planned unit previously reported as either Tier 1, 2, or 3 has been cancelled • **Tier 1** – planned units that must have a confirmed primary fuel source and meet at least one of the following requirements: o Construction is underway or complete (not in commercial operation) o A Power purchase agreement (PPA) has been approved o The resource has been designated or approved by a market operator and an Interconnection Service Agreement (ISA) has been executed and signed. o The resource has been specifically included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement o The resource has been identified by a load-serving entity (LSE) to meet the obligation to serve load • **Tier 2** – planned units that do not meet the requirements of Tier 1, but have a confirmed primary fuel source and meet at least one of the following requirements: o All regulatory approvals, including those for inclusion in the rate base have been requested o A power purchase agreement (PPA) or Generation Interconnection has been requested • **Tier 3** – conceptual units that do not meet the requirements of Tier 2 with a fuel type that is unknown, report the primary fuel type as "Other."
Country	Select the country where the unit is physically located: • **CA** – Canada • **MX** – Mexico • **US** – United States
NERC Unit ID	NERC will assign a unique ID for all units.
Plant Code	EIA-860 Plant Code should be used for all US units.
Generator ID – 1	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.
Generator ID – 2	Assessment area or Regional Entity Generator ID. (Optional)
Plant Name – 1	EIA-860 Plant Name should be used for all units within the US.
Plane Name – 2	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.[1] EIA-860 Predominant Energy Source should be used for all units. See Appendix I.
Energy Source – 2	The energy source code for the energy source used in the second largest quantity (Btus) to power the generator.[2] 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),

[1] 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).

[2] 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).

	enter the month and year the unit is projected to become 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: 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 capability[3] and have a Power Purchase Agreement (PPA)[4] with firm transmission must be in effect for the unit
- Unit must be classified as a Designated Network Resource[5]
- 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. Capacity adjustments that are unavailable on a unit basis should be aggregated by fuel type and provided in Form C. Certain 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.

Instructions	
Years 1-10	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. 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.

[3] 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).

[4] 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).

[5] 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.

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].

Instructions
Enter, in megawatts, the amount of capacity purchases or sales for which a firm contract has been signed. Values should reflect Firm transfers in place for all seasons/years that have confirmed purchases/sales from another Assessment Area. Values should be equal to or greater than the aggregation of Full Responsibility Purchases, Owned Capacity/Entitlements Located Outside the Area, and Modeled Transfers. For the Reporting Year, use the projected Firm value reported for the seasonal assessment.

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.

Instructions
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. 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.

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.

Instructions
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.

Modeled: Applicable for Assessment Areas that model potential transfers (imports/exports) to eliminate potential double counting of capacity. Because of delivery options, the Assessment Area does not attempt to align the purchase and sale of contracts. Instead, conservative transfer limits are applied on associated transfer paths and modeled between subregions. Although these transfers are assumed without a contract in place, Firm transmission is maintained by the importing or exporting entities, and modeling of the existing transmission, including transfer capability, has been executed to verify these transfers can occur during the peak.

Instructions
Enter, in megawatts, the amount of modeled transfers between subregions within the Assessment Area. This category is a subset of total Firm imports/exports and can only be used with Assessment Areas with defined subregions.

Expected: Projected transfers with a high expectation that a Firm contract will be executed.

Instructions
Enter, in megawatts, the amount of projected transfers with a high expectation that a Firm contract will be executed. These transfers will be counted towards the Prospective resource category.

Available On-Peak Reserves

Instructions	
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.

Capacity Adjustments

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

Instructions
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.

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.

Instructions
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.

Behind the Meter Generation – Capacity: a generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail load with electric energy. [Source: NERC Project 2010-17 Definition of Bulk Electric System (Phase 2)]

Instructions
Enter, in megawatts, the aggregated amount of behind the meter generation that is obligated to serve load. This category of behind the meter generation will be counted as Existing-Certain capacity. This should also include and "behind the fence" generation. To avoid double-counting, do not include behind-the-meter generation that has been provided 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.

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: includes units that have been earmarked for retirement. Examples include:

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

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

Description / Instructions		
NERC Project ID		NERC will assign a unique ID for all projects
Project ID		Optional entry by Region/Assessment Area
Project Name		Enter the project name
Project Status	Under Construction	Construction of the line has begun
	Planned	The line is included in a regional transmission plan
	Conceptual	The line is in a project queue, but not included in a regional transmission plan
	Planned (any of the following)	Permits have been approved to proceed
		Design is complete
		Needed in order to meet a regulatory requirement
	Conceptual (any of the following)	A line projected in the transmission plan
		A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”
		Other projected lines that do not meet requirements of “Under Construction” or “Planned”
	Completed	A project reported in the prior year has been placed into service
	Delayed - Load Growth	A project that has been delayed due to updated load growth projections
	Delayed - Permitting Challenges	A project that has been delayed due to permitting challenges
	Delayed - Siting Challenges	A project that has been delayed due to siting challenges
	Delayed - Economics	A project that has been delayed due to economic impacts
	Delayed - Other (Comment Required)	A project that has been delayed due to other reasons; an explanation must be provided in the comment field
	Cancelled - Load Growth	A project that has been cancelled due to updated load growth projections
	Cancelled - Permitting Challenges	A project that has been cancelled due to permitting challenges
	Cancelled - Siting Challenges	A project that has been cancelled due to siting challenges
	Cancelled - Economics	A project that has been cancelled due to economic impacts
	Cancelled - Other (Comment Required)	A project that has been cancelled due to other reasons; an explanation must be provided in the comment field
Tie Line	Yes/No	A circuit connecting two Balancing Authority Areas or two separate systems. Specify whether the project is classified as a tie line.
Project Drivers (Primary and Secondary)	Reliability	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.
	Variable/Renewable Integration	
	Nuclear Integration	
	Fossil-Fired Integration	
	Hydro Integration	
	Economics/Congestion	
	Other	
Terminal Origin		Provide the name of the point where the line originates
Terminal Origin State		Select the state where the line originates
Terminal Endpoint		Provide the name of the point where the line ends
Terminal Endpoint State		Select the state where the line ends
Company Name		Enter the company that owns the majority of the transmission line.
EIA Company Code		Identify each organization by the six-character code assigned by EIA. Required for

<table>
<tr><td colspan="2"></td><td>all projects within the U.S.</td></tr>
<tr><td rowspan="6">Entity Type</td><td>I – Investor-owned</td><td rowspan="6">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>M – Municipality</td></tr>
<tr><td>C – Cooperative</td></tr>
<tr><td>S – State-owned</td></tr>
<tr><td>F – Federally-owned</td></tr>
<tr><td>O – Other</td></tr>
<tr><td colspan="2">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 rowspan="3">Line Type</td><td>OH – Overhead</td><td rowspan="3">Select the predominant physical location of the line conductor.</td></tr>
<tr><td>UG – Underground</td></tr>
<tr><td>SM – Submarine</td></tr>
<tr><td colspan="2">Voltage Type</td><td>Select alternating or direct current (AC/DC)</td></tr>
<tr><td colspan="2">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 miles should not be included.</td></tr>
<tr><td colspan="2">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 colspan="2">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 colspan="2">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 rowspan="3">Circuits Per Structure Present / Ultimate</td><td>1 Three-Phase Circuit</td><td rowspan="3">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>2 Three-Phase Circuits</td></tr>
<tr><td>3 Three-Phase Circuits</td></tr>
<tr><td colspan="2">Capacity Rating (MVA)</td><td>Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).</td></tr>
<tr><td colspan="2">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 colspan="2">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 colspan="2">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 colspan="2">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 colspan="2">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>
</table>

Form E

Projected Transformer Additions

Instructions		
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.		
Project ID	To be provided by NERC staff for tracking purposes.	
Status	Planned	
	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 and conservation, behind the meter generation, and distributed generation is 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 Excess/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 Form Transfers**.
- Excess: provides a positive value, in megawatts, for each season and year for how much capacity is available to meet the Reference Margin Level, beyond what already projected for **Existing-Certain and Net Form Transfers**.

Anticipated Resources Excess/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**.
- Excess: provides a positive value, in megawatts, for each season and year for how much capacity is available to meet the Reference Margin Level, beyond what already projected for **Anticipated Resources**.

Prospective Resources Excess/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**.
- Excess: provides a positive value, in megawatts, for each season and year for how much capacity is available to meet the Reference Margin Level, beyond what already projected for **Prospective Resources**.

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.

Appendix I: EIA-860 Prime Mover and Energy Source Codes

Prime Mover Codes

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

Energy Source Codes

Fuel Type		Code	Fuel Description
Fossil Fuels	Coal	ANT	Anthracite Coal
		BIT	Bituminous Coal
		LIG	Lignite Coal
		SGC	Coal-Derived Synthesis Gas
		SUB	Subbituminous Coal
		WC	Waste/Other Coal (including anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
		RC	Refined Coal
	Petroleum Products	DFO	Distillate Fuel Oil. Including Diesel, No. 1, No. 2, and No. 4 Fuel Oils
		JF	Jet Fuel
		KER	Kerosene
		PC	Petroleum Coke
		PG	Gaseous Propane
		RFO	Residual Fuel Oil (including No. 5, and No. 6 fuel oils, and bunker C fuel oil)
		SGP	Synthesis Gas from Petroleum Coke
		WO	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)
	Natural Gas and Other Gases	BFG	Blast Furnace Gas
		NG	Natural Gas
		OG	Other Gas (specify in comments section)
Renewable Fuels	Solid Renewable Fuels	AB	Agricultural By-Products
		MSW	Municipal Solid Waste
		OBS	Other Biomass Solids (specify in comment section)
		WDS	Wood/Wood Waste Solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)
	Liquid Renewable (Biomass) Fuels	OBL	Other Biomass Liquids (specify in comment section)
		SLW	Sludge Waste
		BLQ	Black Liquor
		WDL	Wood Waste Liquids excluding Black Liquor (including red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
	Gaseous Renewable (Biomass Fuel)	LFG	Landfill Gas
		OBG	Other Biomass Gas (including digester gas, methane, and other biomass gases; specify in comments section)
	All Other Renewable Fuels	SUN	Solar
		WND	Wind
		GEO	Geothermal
		WAT	Water at a Conventional; Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology
All Other Fuels	All Other Energy Sources	WAT	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
		NUC	Nuclear (including Uranium, Plutonium, and Thorium)
		PUR	Purchased Steam
		WH	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.)
		TDF	Tire-derived Fuels
		MWH	Electricity used for energy storage
		OTH	Other (specify in comment section)
		UKN	Unknown (specify in comment section)