NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2012 Long-Term Reliability Assessment: Data From Instructions

General instructions for each schedule are included below. Reference the corresponding tab for data more granular instructions for each schedule

Schedule 1A & 1B: Historical and Projected Peak Demand and Energy – Monthly/Annual

The fundamental test for determining the adequacy of the power system is to determine whether resources exceed demand while allowing sufficient margin to address operating events (loss of generation for instance). This test requires that demand forecasts be provided and aggregated. While coincident demand determinations are preferable, this is not feasible given the number of entities reporting and the time available to build hourly models. Therefore peak demand forecasts will need to be aggregated at peak.

When providing a demand forecast, provide a normalized forecast. This is defined as a forecast which has been adjusted to reflect normal weather, and is expected on a 50% probability basis, i.e. a peak demand forecast level which has a 50% probably of being under or over achieved by the actual peak. This is also known as the 50/50 forecast. This forecast can then be used to test against more extreme conditions.

Schedule 1A and 1B are to be reported in total by each Regional Entity for all utilities, groups of utilities, such as subregional entities, Independent System Operators, or Regional Transmission Operators, within that Region. The reported peak demand for a Region or Subregion should be non-coincident, comprised of the sum of all peak demands for the various operating entities within a NERC Region or Subregion during the specified period. (Only file a coincident peak if the coincident and non-coincident values are equal.)

Schedule 2: Individual Unit Data

The purpose of this schedule is to identify individual units and portions of capacity resources that make up the total supply reported in Schedules 3A and 3B. Data may be submitted at the unit or plant level. Additionally, entries may be submitted at an aggregate level (i.e., reporting Transmission-Limited Resources in aggregate for a Region/subregion).

1 Existing capacity equals all expected on-peak values (Existing-Certain) plus all Existing-Other capacity plus all Existing-Inoperable capacity. This value equals the Net to Grid capacity (installed capacity). This is different than the total Existing nameplate values, though, in some cases, may be equal. For example, a wind plant expects 1 MW on-peak with a 9 MW derate. The total Net to Grid capacity equals 10 MW. Generally, the total nameplate value is also, 10 MW. Additionally, if a gas-fired plant has 100 MW nameplate capacity, but only expects 98 MW on-peak with a 2 MW derate (due to a seasonal rating or some other derate) then the total Net to Grid capacity equals 100 MW. However, if the derate of the same gas-fired plant (2 MW) was a permanent derate, and those 2 MW are now beyond the capability of the plant, than the Net to Grid Capacity equals 98 MW.

2 All reported resources are located physically within the Assessment Area (Region/subregion).

3 Each row of entry may represent a full unit, a portion of a unit, or an aggregated capacity value.

4 Negative values should only be used in the on-peak and derated columns for Future-Planned, Future-Other, or Conceptual retirements or scheduled outages.

5 Existing capacity is the sum of all existing generation connected to the electric system for the purpose of supplying electric load during the seasonal peak. Existing capacity does not include generation serving customers behind the meter.

6 Existing capacity is the amount (MW) currently in-service or “iron-in-the-ground” at the time of reporting. This value MUST remain constant throughout the 10-year reporting period. Any changes to Existing capacity (i.e., generator uprate, generator derate, retirement, adjustments in contracts, scheduled outages, et.) should be categorized as either Future-Planned, Future-Other, or Conceptual. In-service dates should not be entered anywhere on Schedule 2.

7 Mothballed capacity:
A. Capacity that may be brought back in-service during the period of assessment. Generally, this capacity may be brought back in-service within a short timeframe if needed. This capacity should be categorized as Existing-Other.
B. Capacity that may not be brought back in-service during the period of assessment. Generally, this capacity can be brought back in-service, but will require a longer lead time. This capacity should be categorized as Existing Inoperable.

8 Retirements:
A. To retire Existing-Certain capacity, enter a seperate line and select either Future-Planned or Conceptual (depending on the certainty of the retirement). Enter a NEGATIVE value in the Expected Summer and Winter On-Peak Capacity Columns (10 and 12).
B. To retire Existing-Other capacity, enter a seperate line and select either Future-Other or Conceptual (depending on the certainty of the retirement). Enter a NEGATIVE value in the Expected Summer and Winter On-Peak Capacity Columns (10 and 12).

9 Generation capacity reported as Energy Only (ENO) CANNOT be reported as an Existing-Certain resource unless deliverability is confirmed during peak demand and canot be curtailed.

GENERAL INSTRUCTIONS

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Schedule 3A & 3B: Demand & Capacity - Summer/Winter

Data for Schedule 3 should be entered on a cumulative basis through the assessment timeframe. Do not report incremental values for each year/month. Where capacity values are entered, values should accumulate through the assessment period.

For demand and capacity values, all numbers should be entered as MW in positive values up to one decimal place. Do not double count any capacity values in different line items, unless otherwise specified.

Schedule 5: Transmission Line Circuit Miles

Only the total existing transmission circuit miles (Line 1) need to be reported on this schedule. Lines 2-8 are automatically calculated and populated by data reported on Schedule 6A. The resulting values should be the net expected circuit miles for each category.

Schedule 6A: Projected Transmission Line Additions

Each Regional Entity must complete this schedule for all projected transmission line additions of 100kV for the 10-year period.

Each entry should have the same attributes over the entire reported line addition. For example, a reported line of 200-300kV should be the same voltage for the entirety of the specified line mileage. If line attributes change over a single project, the project must be reported on two separate lines.

When reporting circuit mile data, report only the net increase or decrease. For example, if a project results in a net loss of transmission mileage, report the circuit miles as a negative value.

Schedule 6B: Projected Transformer Additions

Each Regional Entity must complete this schedule for all projected transformer additions at 100 kV (Low-Side) and above for the 10-year period. Replacement transformers should be reported and noted in the Description/Status field.

GENERAL INSTRUCTIONS

Line	Term	Code	Definition	Instructions	Ref.
1	Actual - Peak Hour Demand	MDA	The highest hourly integrated (“60-minute net integrated peak”) Net Energy For Load within a reporting entity occurring within a given period. The integrated peak hour demand (MW) amount is derived by dividing Net Energy For Load (MWh) by 60 for a given hour.	Enter the actual monthly peak hour demands for designated months for the prior reporting year.	E
2	Actual - Net Energy for Load	MNLA	Net generation, plus energy received, less energy delivered through interchange. This includes losses but excluded energy required for storage at energy storage facilities.	Enter the actual monthly Net Energy For Load for designated months for the prior reporting year.	E
3	Reporting Year - Peak Hour Demand	MDF	The highest hourly integrated (“60-minute net integrated peak”) Net Energy For Load within a reporting entity occurring within a given period. The integrated peak hour demand (MW) amount is derived by dividing Net Energy For Load (MWh) by 60 for a given hour.	Enter the forecast monthly peak hour demands for designated months for the current reporting year.	E
4	Reporting Year - Net Energy for Load	MNLF	Net generation, plus energy received, less energy delivered through interchange. This includes losses but excluded energy required for storage at energy storage facilities.	Enter the forecast monthly Net Energy For Load for designated months for the current reporting year.	E
5	Next Year - Peak Hour Demand	MDS	The highest hourly integrated (“60-minute net integrated peak”) Net Energy For Load within a reporting entity occurring within a given period. The integrated peak hour demand (MW) amount is derived by dividing Net Energy For Load (MWh) by 60 for a given hour.	Enter the forecast monthly peak hour demands for designated months for next year.	E
6	Next Year - Net Energy for Load	MNLS	Net generation, plus energy received, less energy delivered through interchange. This includes losses but excluded energy required for storage at energy storage facilities.	Enter the forecast monthly Net Energy For Load for designated months for next year.	E
7	Summer - Peak Hour Demand (Total Internal Demand)	DS	The 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 includes adjustments for indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back). Adjustments for controllable demand response should not be included in this value.	Enter the forecast annual summer Net Internal Demand for the designated years. Actual Year, Reporting Year, and Next Year values are automatically calculated and should not be manually entered.	A, E
8	Winter - Peak Hour Demand (Total Internal Demand)	DW		Enter the forecast annual winter Net Internal Demand for the designated years. Reporting Year values are automatically calculated and should not be manually entered.	A, E
9	Net Energy For Load	NL	Net generation, plus energy received, less energy delivered through interchange. This includes losses but excluded energy required for storage at energy storage facilities.	Enter the forecast annual Net Energy For Load for the designated years. Actual Year, Reporting Year, and Next Year values are automatically calculated and should not be manually entered.	E

Line	Terms		Code	Definition/Description	Instructions
1	Entry Type		ENO	Energy Only Resources	Identify the type of entry for specific entry types listed.
			TL	Transmission-Limited Resources	
			SO	Schedules Outage - Maintenance	
			RE	Retirements	
2	Plant Code			EIA specified Plant Code	For US entities, enter the EIA assigned Plant Code. For other entities, enter a plant code that uniquely defines a plant. No entry is required for aggregated capacity.
3	Unit Code			EIA specified Unit Code	For US entities, enter the EIA assigned Unit Code. For other entities, enter a unit code that uniquely defines the unit. No entry is required for aggregated capacity.
4	Other Code			A reporting entity defined code.	If there is a code used by the reporting entity or other miscellaneous code for the unit, enter the other code. No entry is required for aggregated capacity.
5	Plant Name			The official or legal name of the power plant, if known.	Enter the official or legal name of the power plant. For Conceptual units, if the plant name is not known, enter a temporary or “place-holder” name (for example: WindGen-2). For aggregated capacity, describe the type aggregation (for example: for aggregated Demand Response resources, enter the Demand Response program name).

Line	Terms		Code	Definition/Description	Instructions
6	Prime Mover		ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)	Enter a Prime Mover code. For combined cycle units, a prime mover code must be entered for each generator.
			GT	Combustion (Gas) Turbine – Simple Cycle (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 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 that are in planning stage, for which specific generator details cannot be provided)	
			HY	Hydraulic Turbine (includes turbines associated with delivery of water by pipeline)	
			PS	Hydraulic Turbine – Reversible (pumped storage)	
			BT	Turbines Used in a Binary Cycle (such as used for geothermal applications)	
			PV	Photovoltaic	
			WT	Wind Turbine	
			CE	Compressed Air Energy Storage	
			FC	Fuel Cell	
			OT	Other	
			NA	Unknown at this time (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided).	

Line	Terms			Code	Definition/Description	Instructions
7 & 8	Primary/Secondary Energy Source	Fossil Fuels	Coal and Coal Synfuel	BIT	Anthracite Coal and Bituminous Coal	Enter the energy source code for the fuel used in the largest quantity (Btus) during the reporting year to power the generator. 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 the table of energy source codes below. 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). For secondary energy source, enter the energy sourrce code for the fuel used in the second largest quantity, based on the same assumptions in Line 7.
				LIG	Lignite Coal	
				SC	Coal Synfuel. Coal-based solid fuel that has been processed by a coal synfuel plant; and coal-based fuels such as briquettes, pellets, or extrusions, which are formed from fresh or recycled coal and binding materials	
				SUB	Subbituminous Coal	
				WC	Waste/Other Coal. Including anthracite culm, bituminous gob, fine coal, lignite waste, waste 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	
				RFO	Residual Fuel Oil. Including No. 5, No. 6 Fuel Oils, and Bunker C Fuel Oil	
				WO	Waste/Other Oil. Including Crude Oil, Liquid Butane, Liquid Propane, 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)	
				PG	Gaseous Propane	
		Renewable Fuels	Solid Renewable Fuels	AB	Agricultural Crop Byproducts/Straw/Energy Crops	
				MSW	Municipal Solid Waste	
				OBS	Other Biomass Solids, Specify in Comment Section	
				TDF	Tire-derived Fuels	
				WDS	Wood/Wood Waste Solids. Including paper pellets, railroad ties, utility poles, wood chips, bark, & 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. Includes red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids	

Line	Terms			Code	Definition/Description	Instructions
7 & 8	Primary/Secondary Energy Source	All Other Energy Sources	Gaseous Renewable (Biomass)	LFG	Landfill Gas	Enter the energy source code for the fuel used in the largest quantity (Btus) during the reporting year to power the generator. 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 the table of energy source codes below. 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). For secondary energy source, enter the energy sourrce code for the fuel used in the second largest quantity, based on the same assumptions in Line 7.
				OBG	Other Biomass Gas. Includes digester gas, methane, and other biomass gasses. Specify in Comment Section.	
			All Other Renewable Fuels	SUN	Sun	
				WND	Wind	
				GEO	Geothermal	
				WAT	Water at a Conventional Hydroelectric Turbine	
				OS	Other Storage	
			All Other Energy Sources	PUR	Purchased Steam	
				WH	Waste heat not directly attributed to an energy source; should only be reported where the energy source for the waste heat is undetermined.	
				NUC	Nuclear Uranium, Plutonium, Thorium	
				OTH	Specify in Comment Section	
10	Supply Category			EC	Existing-Certain	Enter a supply category that is associated with this capacity. Refer to Schedule 3 for supply definitions.
				EO	Existing-Other	
				EI	Existing-Inoperable	
				FP	Future-Planned	
				FO	Future-Other	
				C	Conceptual	
11	Expected Summer On-Peak Capacity					Enter the expected summer on-peak capacity for the summer peak. See accompanying Schedule 2 Examples for entry guidelines.
12	Derated Summer On-Peak Capacity					Enter the derated summer on-peak capacity for the summer peak. See accompanying Schedule 2 Examples for entry guidelines.
13	Expected Winter On-Peak Capacity					Enter the expected winter on-peak capacity for the winter peak. See accompanying Schedule 2 Examples for entry guidelines.
14	Derated Winter On-Peak Capacity					Enter the derated winter on-peak capacity for the winter peak. See accompanying Schedule 2 Examples for entry guidelines.
15	Future/Conceptual In-Service Month					Enter a two-number numerical value for the expected in-service month of Future or Conceptual capacity. If no month is specified, it will be assumed a resource will be in-service for the peak of the specified in-service year.
16	Future/Conceptual In-Service Month					Enter a four-number numerical value for the expected in-service year of Future or Conceptual capacity.

Line	Term	Definition	Instructions	Ref.
1	Unrestricted Non-coincident Peak Demand	The gross load of the Assessment Area/Region/subregion, which includes New Conservation (Energy Efficiency) and Estimated Diversity; and excludes Additions for Non-member Loads and Stand-by Load Under Contract	Automatically calculated. Do not mannually enter.	A, B
1a	New Conservation (Energy Efficiency)	Conservation: This Demand-Side Management category represents the amount of consumer load reduction at the time of system peak due to utility programs that reduce consumer load during many hours of the year. Examples include utility rebate and shared savings activities for the installation of energy efficient appliances, lighting and electrical machinery, and weatherization materials. 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 reported in megawatthours), 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.	Enter the estimated impact of incremental passive energy efficiency programs. The increment represents the increase above the embedded amount from the base year and should be reported on a cumulative basis through the assessment timeframe. These impacts should be associated with programs to increase energy efficiency beyond its natural or normal growth. For energy efficiency, report the expected capacity impacts (MW) during time of peak which are the result from all energy efficiency measures and activities that reduce the load forecast.	A,B,C
1b	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. 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.	Enter the difference between the Assessment Areas's/Region's/subregion's peak and the sum of the peaks of the reporting entities (LSEs, control areas, zones, etc.)	A,B,C
1c	Additions for non-member load (load served by non-registered LSE's in a Region)	Load served by non-registered LSE's in a Region	Enter adjustments to account for the load of non-members, following the NERC Standard MOD-16 "data submittal requirements shall stipulate that each Load Serving Entity count its demand once and only once, on an aggregated and dispersed basis, in developing its actual and forecast customer demand values.	A,B,C
1d	Stand-by Load Under Contract (Normally served by behind the meter generation)	Demand which is normally served by behind the meter generation which has a contract to provide power if the generator becomes unavailable.	Enter 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 report the total (sum) of all contracted stand-by load. Additionally, do not separately report expected contract standby demand if it is already included in the forecasted peak data previously provided.	A
1e	Non-Controllable Demand-Side Demand Response	This should include all demand response that is not controlled by an area's balancing authority (not included in lines 2a-2d) but is used to lower Total Internal Demand. In general, this will include utility-level or load-serving entity-level programs designed to manage the peak demand forecast submitted to balancing authorities. Do not report the total (sum) of all demand response contracts—only the portion that is expected to perform during the peak.	Enter the expected amount of non-controllable and non-dispatchable demand response that is expected to reduce demand during the peak.	A,D

Line	Term	Definition	Instructions	Ref.
2	Total Internal Demand	For the Actual Year, the 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 includes adjustments for indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, all non-dispatchable demand response programs (such as Time-of-Use, Critical Peak Pricing, Real Time Pricing and System Peak Response Transmission Tariffs) and some dispatchable demand response (such as Demand Bidding and Buy-Back).	Enter the actual and forecast annual seasonal Total Internal Demand for the designated years. Adjustments for controllable demand response should not be included in this value. For the forecast years, enter the value which results using the equivalent assumptions as the Actual Year.	A,B
2a-2d	Supply-Side CCDR	Any Controllable Capacity Demand Response considered by the Assessment Area as a supply-side resource that is able to be economically dispatched and used year-round. Load must be under contract and included in demand projections.		
2a	Supply-Side Direct Control Load Management (Direct Load Control)	Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential or small commercial customers. DCLM as reported here does not include Interruptible Demand (line 2b).	Enter the MW value of customer demand that can be interrupted at the time of the seasonal peak load by direct control of a single operator by interrupting power supply to individual appliances or equipment on customer premises.	A,D,E
2b	Supply-Side Contractually Interruptible (Curtailable)	Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Contractually Interruptible Demand as reported here does not include Direct Control Load Management (line 2a).	Enter the MW value of customer demand that, in accordance with contractual arrangements, can be interrupted during the period of peak demand for the Region/subregion’s by direct control of the System Operator or by action of the customer at the direct request of the System Operator.	A,D,E
2c	Supply-Side Critical Peak-Pricing (CPP) with Control	A method of pricing electricity whereby "Time of Use Pricing" is in effect with the exception of certain "peak days" at which time electric prices may reflect the costs of generating and/or purchasing electricity at the wholesale level. In addition, this program is combined with a direct control device which automatically responds to a high price signal without customer intervention.	Enter the MW value of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the seasonal peak by direct control of the System Operator or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices.	A, D
2d	Supply-Side Load as a Capacity Resource	Aggregated Demand Response provided as a resource to reduce demand under direct control of the System Operator. These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from wholesale balancing authorities. Additionally, this capacity may be used to meet resource adequacy obligations when determining planning Reserve Margins.	Enter the MW value of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by a balancing authority.	A, D
3	Net Internal Demand	Total Internal Demand reduced by dispatchable and controllable Supply-Side Demand Response (lines 2a-2d).	Automatically calculated. Do not mannually enter.	A, D
3a-3d	Demand-Side CCDR	Any Controllable Capacity Demand Response considered by the Assessment Area as a demand-side resource that is used only in emergencies or to shave peak demand in capacity deficiency situations. Includes load under contract that is not included in demand projections.		
3a	Demand-Side Direct Control Load Management (Direct Load Control)	See definition for 2a. The same definition applies, but for Assessment Areas that count Demand Response as a load reduction.	Enter the MW value of customer demand that can be interrupted at the time of the seasonal peak load by direct control of a single operator by interrupting power supply to individual appliances or equipment on customer premises.	A,C,D

Line	Term	Definition	Instructions	Ref.
3b	Demand--Side Contractually Interruptible (Curtailable)	See definition for 2b. The same definition applies, but for Assessment Areas that count Demand Response as a load reduction.	Enter the MW value of customer demand that, in accordance with contractual arrangements, can be interrupted during the period of peak demand for the Region/subregion's by direct control of the System Operator or by action of the customer at the direct request of the System Operator.	A,C,D
3c	Demand-Side Critical Peak-Pricing (CPP) with Control	See definition for 2c. The same definition applies, but for Assessment Areas that count Demand Response as a load reduction.	Enter the MW value of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the seasonal peak by direct control of the System Operator or by action of the customer by responding to high prices of energy triggered by system contingencies or high wholesale market prices.	A,C,D
3d	Demand-Side Load as a Capacity Resource	See definition for 2d. The same definition applies, but for Assessment Areas that count Demand Response as a load reduction.	Enter the MW value of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by a balancing authority.	A,C,D
4	Total Controllable Demand Response	A sum of all controllable Demand Response (includes both Demand Response treated as a resource and as demand reduction).	Automatically calculated. Do not mannually enter.	A,C,D
4a	Demand Response used for Reserves - Spinning	Spinning Reserve: synchronized and ready to serve additional demand.	Enter the total MW value for demand-side resources that can displace generation deployed as operating reserves that are synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an electric grid event. Penalties are assessed for non-performance.	A,C,D
4b	Demand Response used for Reserves - Non-Spinning	Non-Spinning Reserve: not connected to the system but capable of serving demand within a specified timeframe.	Enter the total MW value of demand-side resources that can displace generation deployed as operating reserves that are not connected to the system but capable of serving demand within a specified time. Penalties are assessed for non-performance.	A,C,D
4c	Demand Response used for Regulation	Regulation Reserve: Reserve responsive to Automatic Generation Control (AGC), which is sufficient to provide normal regulating margin.	Enter the total MW value of demand-side resources that can be responsive to Automatic Generation Control (AGC) to provide a normal regulating margin.	A,C,D
4d	Demand Response used for Energy, Voluntary - Emergency	Short-notice program that provides payments to electric customers who reduce load during specific times during a system contingency. During these events, participants are expected, though not obligated, to either reduce energy consumption or transfer load to a qualifying on-site generator.	Enter the total MW value for demand-side resources that can be curtailed voluntarily when offered the opportunity to do so for compensation. Can occur as a result of system and/or local capacity constraints.	A,D

Line	Term	Definition	Instructions	Ref.
5	TOTAL INTERNAL CAPACITY	The internal capacity for the Assessment Area. Specifically, the sum of all existing generation connected to the electric system for the purpose of supplying electric load during the seasonal peak. Existing capacity does not include generation serving customers behind the meter. All seasonal rated capability during peak period, where full availability of primary fuel is assumed.	The reported value should include capacity of all generators physically located and interconnected in the reporting area or planned to be physically located and interconnected in the reporting area, including the full capacity of those generators wholly or partially owned by (or with entitlement rights held by) entities outside of the reporting area. Additionally, where load is considered a capacity resource, this capacity is also included.Automatically calculated. Do not mannually enter.	A
6a	Existing-Certain	Included in this category are generation resources available to operate and deliver power within or into the region during peak demand in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following: (1)contracted (or firm) or other similar resource confirmed able to serve load during peak demand in the assessment; (2)where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a Firm network resource; (3)Network Resource, as that term is used for FERC pro forma or other regulatory approved tariffs; (4)Energy-Only resources confirmed able to serve load during peak demand and will not be curtailed; (5)capacity resources that can not be sold elsewhere; (6)other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed during peak demand.	This value is automatically calculated and should not be manually entered, except for the actual value. For the actual value for the prior reporting year, enter the value that reflects the Existing, Certain capacity available during the period of peak demand. Only what exists on the day of reporting should be included in this category. Any additional changes to capacity (positive or negative) are considered to be Future or Conceptual. This value should be constant throughout the 10-year period.	A
6a1	Wind Expected On-Peak	The amount of existing wind capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6a2	Solar Expected On-Peak	The amount of existing solar capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6a3	Hydro Expected On-Peak	The amount of existing hydro capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6a4	Biomass Expected On-Peak	The amount of existing biomass capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6b	Existing-Other	Included in this category are generation resources that may be available to operate and deliver power within or into the region during peak demand in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in 6a, Existing, Certain. This category includes, but is not limited to the following: (1)a resource with non-Firm or other similar transmission arrangements; (2)Energy-Only resources that have been confirmed able to serve load for any reason during the reporting period, but may be curtailed for any reason; (3)mothballed generation (that may be returned to service during peak demand); (4)portions of variable generation not counted in the Existing-Certain category (e.g. wind, solar, etc.) that may not be available or derated during the peak; (5)hydro generation not counted as Existing, Certain or derated; (6)generation resources constrained for other reasons.	Automatically calculated. Do not mannually enter.	A
6b1	Wind Derate On-Peak	The amount of existing wind capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6b2	Solar Derate On-Peak	The amount of existing solar capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6b3	Hydro Derate On-Peak	The amount of existing hydro capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6b4	Biomass Derate On-Peak	The amount of existing biomass capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
6b5	Transmission-Limited Resources	The amount of transmission-limited generation resources that have known physical deliverability limitations to serve load that they are obligated to serve.	Automatically calculated. Do not mannually enter.	A

Line	Term	Definition	Instructions	Ref.
6b6	All Other Derates	All other derates not reported in lines 6b1, 6b2, 6b3, 6b4 that are associated to specific generator limitations during peak demand.	Automatically calculated. Do not mannually enter.	A
6b7	Energy-Only	Capacity from generating resources that are designated as Energy-Only resources or have elected to be classified as Energy-Only resources by the FERC interconnection process and may include generating capacity that can be delivered within the area but may be recallable to another area. Do not include any wind, solar, biomass, or hydro capacity in this category--instead report this capacity on the associated derate in lines 6b1-6b4. Energy-Only resources are designated as such if they are not classified as a network resource.	Automatically calculated. Do not mannually enter.	A, F
6c	Unplanned Outages (Actual) / Current and Future Inoperable Resources	Included in this category are generation resources that are out-of-service and cannot be brought back into service to serve load during peak demand. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero (0). This includes ALL existing generation within a Region or subregion not included in line 6a, Existing, Certain or line 6b, Existing, Other, but is not limited to, the following: (1)mothballed generation (that can not be returned to service for the peak); (2)other existing but out-of-service generation (that can not be returned to service for the peak); (3)does not include behind-the-meter generation or non-connected emergency generators; (4)does not include partially dismantled units that are not forecasted to return to service.	Include aggregated Forced Outages for the actual year; include aggregated projected Inoperable resources through the remainder of the assessment period. This value may vary for future years.	A
6d	Total Supply-Side Demand Response	Total dispatchable and controllable capacity demand response.	Automatically calculated. Do not mannually enter.	A, D
7	FUTURE CAPACITY ADDITIONS	Included in this category are generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these criteria: (1)construction has started; (2)regulatory permits (site, construction,environmental, etc.) being approved. Permiting process has been started but permit is not necessarily in-hand (should be, regulatory processes have begun to obtain permits); (3)regulatory approval has been received to be in the rate base; (4)approved power purchase agreement; (5)approved and/or designated as a resource by a market operator. One of these criteria must be met before categorizing a supply resource as Future-Planned or Future-Other.	Automatically calculated. Do not mannually enter.	A
7a	Future, Planned	Included in this category are generation resources anticipated to be available to operate and deliver power within or into the region during peak demand in the assessment. This category includes, but is not limited to, the following: (1)contracted (or Firm) or other similar resource; (2)where organized markets exist, designated market resource that is eligible to bid into a market or has been designated as a Firm network resource; (3)Network Resource, as that term is used for FERC pro forma or other regulatory approved tariffs; (4)Energy-Only resources confirmed able to serve load during the peak and is not subject to curtailment; (5)where applicable, included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.	Automatically calculated. Do not mannually enter.	A
7a1	Wind Expected On-Peak	The amount of Future-Planned wind capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a2	Wind Derate On-Peak	The amount of Future-Planned wind capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a3	Solar Expected On-Peak	The amount of Future-Planned solar capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a4	Solar Derate On-Peak	The amount of Future-Planned solar capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A

Line	Term	Definition	Instructions	Ref.
7a5	Hydro Expected On-Peak	The amount of Future-Planned hydro capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a6	Hydro Derate On-Peak	The amount of Future-Planned hydro capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a7	Biomass Expected On-Peak	The amount of Future-Planned biomass capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a8	Biomass Derate On-Peak	The amount of Future-Planned biomass capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7a9	Transmission-Limited Resources	The amount of Future-Planned transmission-limited generation resources that have known physical deliverability limitations to serve load that they are obligated to serve. This value may represent a positive of negative change in existing transmission-limited resources.	Automatically calculated. Do not mannually enter.	A
7a10	Scheduled Outage - Maintenance	The amount Future-Planned capacity reduction due to a generator outage that is scheduled well in advance and is of a predetermined duration.	Automatically calculated. Do not mannually enter.	A
7a11	All Other Derates	All other derates not reported in lines 7a2, 7a4, 7a6, or 7a8, that are associated to specific generator limitations during peak demand.	Automatically calculated. Do not mannually enter.	A
7a12	Energy-Only	Capacity from generating resources that are designated as Energy-Only resources or have elected to be classified as Energy-Only resources by the FERC interconnection process and may include generating capacity that can be delivered within the area but may be recallable to another area. Do not include any wind, solar, biomass, or hydro capacity in this category--instead report this capacity on the associated derate in lines 7a2, 7a4, 7a6, or 7a8. Energy-Only resources are designated as such if they are not classified as a network resource.	Automatically calculated. Do not mannually enter.	A, F
7b	Future-Other	This category includes all generation resources that do not qualify as Future-Planned or Conceptual Energy-Only resources. This category includes, but is not limited to, generation resources during the peak that may: (1)be curtailed or interrupted at any time for any reason; (2)Energy-Only resources that may be able to serve load during the peak; (3)variable generation that may not be available or is derated during the peak; (4)hydro generation not counted in the Future-Planned category or derated.	Automatically calculated. Do not mannually enter.	A
7b1	Wind Expected On-Peak	The amount of Future-Other wind capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b2	Wind Derate On-Peak	The amount of Future-Other wind capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b3	Solar Expected On-Peak	The amount of Future-Other solar capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b4	Solar Derate On-Peak	The amount of Future-Other solar capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b5	Hydro Expected On-Peak	The amount of Future-Other hydro capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b6	Hydro Derate On-Peak	The amount of Future-Other hydro capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b7	Biomass Expected On-Peak	The amount of Future-Other biomass capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b8	Biomass Derate On-Peak	The amount of Future-Other biomass capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
7b9	Transmission-Limited Resources	The amount of Future-Other transmission-limited generation resources that have known physical deliverability limitations to serve load that they are obligated to serve. This value may represent a positive of negative change in existing transmission-limited resources.	Automatically calculated. Do not mannually enter.	A
7b10	Scheduled Outage - Maintenance	The amount Future-Other capacity reduction due to a generator outage that is scheduled well in advance and is of a predetermined duration.	Automatically calculated. Do not mannually enter.	A
7b11	All Other Derates	All other derates not reported in lines 7b2, 7b4, 7b6, or 7b8, that are associated to specific generator limitations during peak demand.	Automatically calculated. Do not mannually enter.	A

Line	Term	Definition	Instructions	Ref.
7b12	Energy-Only	Capacity from generating resources that are designated as Energy-Only resources or have elected to be classified as Energy-Only resources by the FERC interconnection process and may include generating capacity that can be delivered within the area but may be recallable to another area. Do not include any wind, solar, biomass, or hydro capacity in this category--instead report this capacity on the associated derate in lines 7b2, 7b4, 7b6, or 7b8. Energy-Only resources are designated as such if they are not classified as a network resource.	Automatically calculated. Do not mannually enter.	A, F
8	Conceptual	This category includes generation resources that are not in a prior listed category, but have been identified and/or announced on a resource planning basis through one or more of the following sources: (1)corporate announcement; (2)entered into or is in the early stages of an approval process; (3)is in a generator interconnection (or other) queue for study; (4)“place-holder” generation for use in modeling.	Automatically calculated. Do not mannually enter.	A
8a1	Wind Expected On-Peak	The amount of Conceptual wind capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a2	Wind Derate On-Peak	The amount of Conceptual wind capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a3	Solar Expected On-Peak	The amount of Conceptual solar capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a4	Solar Derate On-Peak	The amount of Conceptual solar capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a5	Hydro Expected On-Peak	The amount of Conceptual hydro capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a6	Hydro Derate On-Peak	The amount of Conceptual hydro capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a7	Biomass Expected On-Peak	The amount of Conceptual biomass capacity that is expected to be available on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a8	Biomass Derate On-Peak	The amount of Conceptual biomass capacity that is expected to be unavailable on seasonal peak.	Automatically calculated. Do not mannually enter.	A
8a9	All Other Derates	All other derates not reported in lines 8a2, 8a4, 8a6, or 8a8, that are associated to specific generator limitations during peak demand.	Automatically calculated. Do not mannually enter.	A
8a10	Energy-Only	Capacity from generating resources that are designated as Energy-Only resources or have elected to be classified as Energy-Only resources by the FERC interconnection process and may include generating capacity that can be delivered within the area but may be recallable to another area. Do not include any wind, solar, biomass, or hydro capacity in this category. Instead, report this capacity on the associated derate in lines 8a2, 8a4, 8a6, or 8a8. Energy-Only resources are designated as such if they are not classified as a network resource.	Automatically calculated. Do not mannually enter.	A, F
9	ANTICIPATED INTERNAL CAPACITY	This value is automatically calculated by the summations of Existing-Certain and Future-Planned Capacity Additions (Line 6a + 6d+ Line 7a)	Automatically calculated. Do not mannually enter.	A
10	CAPACITY TRANSACTIONS - IMPORTS	The sum of lines 10a through 10d.	Automatically calculated. Do not mannually enter.	A
10a	Firm	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.	Enter the amount of capacity purchases for which a Firm contract has been signed. These transactions will be associated with Existing Certain Capacity. (Note: The sum of 10a1 and 10a2 must be <= 10a)	A, E

Line	Term	Definition	Instructions	Ref.
10a1	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.	Enter the total of all purchases 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. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 10a – Firm.	A
10a2	Owned Capacity/Entitlement Located Outside the Region/Subregion	A transfer in which owned capacity is externally located physically outside the reporting Region or subregion boundary.	Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 10a – Firm.	A
10b	Non-firm	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.	Enter the amount of capacity purchases for which a non-Firm contract has been signed. This value should only be entered in the actual column.	A, E
10c	Expected	A Firm contract has a reasonable expectation to be implemented.	Enter the amount of capacity for which a contract has not been executed, but in negotiation, projected, or other. These transactions will be associated with Planned Capacity Additions. (Note: The sum of 10c1 and 10c2 must be <= 10c)	A
10c1	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.	Enter the total of all purchases 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. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 10c – Expected.	A
10c2	Owned Capacity/Entitlement Located Outside the Region/Subregion	A transfer in which owned capacity is externally located physically outside the reporting Region or subregion boundary.	Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 10c - Expected.	A
11	CAPACITY TRANSACTIONS - EXPORTS	The sum of lines 11a through 11d.	Automatically calculated. Do not mannually enter.	A

Line	Term	Definition	Instructions	Ref.
11a	Firm	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.	Enter the amount of capacity purchases for which a Firm contract has been signed. These transactions will be associated with Existing Certain Capacity. (Note: The sum of 11a1 and 11a2 must be <= 11a)	A, E
11a1	Full-Responsibility Sales	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.	Enter the total of all purchases 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. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 11a – Firm.	A
11a2	Owned Capacity/Entitlement Located Outside the Region/Subregion	A transfer in which owned capacity is externally located physically outside the reporting Region or subregion boundary.	Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 11a – Firm.	A
11b	Non-firm	Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.	Enter the amount of capacity purchases for which a non-Firm contract has been signed. This value should only be entered in the actual column.	A, E
11c	Expected	A Firm contract has a reasonable expectation to be implemented.	Enter the amount of capacity for which a contract has not been executed, but in negotiation, projected, or other. These transactions will be associated with Planned Capacity Additions. (Note: The sum of 11c1 and 11c2 must be <= 11c)	A
11c1	Full-Responsibility Sales	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.	Enter the total of all purchases 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. Each purchaser and seller must agree on which of their transactions are reported under this heading. Values reported on this line represent a portion of Line 11c – Expected.	A
11c2	Owned Capacity/Entitlement Located Outside the Region/Subregion	A transfer in which owned capacity is externally located physically outside the reporting Region or subregion boundary.	Enter the amount of externally owned capacity or capacity entitlements that will move from an outside Region or subregion to the reporting Region or subregion. Values reported on this line represent a portion of Line 11c - Expected.	A

Line	Term	Definition	Instructions	Ref.
12	EXISTING, CERTAIN CAPACITY & NET Firm TRANSACTIONS	The summation of Existing, Certain Capacity and the net of Firm Transactions.	Automatically calculated. Do not mannually enter.	A
13	ANTICIPATED CAPACITY RESOURCES	The summation of Anticipated Internal Capacity and the net of Firm and Expected Transactions.	Automatically calculated. Do not mannually enter.	A
14	PROSPECTIVE CAPACITY RESOURCES	The summation of Anticipated Capacity Resources, Existing-Other, Future-Other capacity and the net of Firm and Expected Transactions. All derates and outages are subtracted from this calculation.	Automatically calculated. Do not mannually enter.	A
15	TOTAL POTENTIAL CAPACITY RESOURCES	The summation of Anticipated Capacity Resources, Existing-Other, Future-Other, and Conceptual capacity, and the net of Firm, Expected, and Provisional Transactions. All derates and outages are subtracted from this calculation.	Automatically calculated. Do not mannually enter.	A
16	ADJUSTED POTENTIAL CAPACITY RESOURCES	The summation of Anticipated Capacity Resources, Existing-Other, Future-Other, and Conceptual capacity, and the net of Firm, Expected, and Provisional Transactions. All derates and outages are subtracted from this calculation. A confidence factor adjusts Future-Other and Conceptual resources.	Automatically calculated. Do not mannually enter.	A
16a	Confidence of Future, Other (7b)	Based on reasonable judgment, enter a percentage of total Future-Other capacity that has a reasonable expectation to be in-service. The confidence factor only adjusts the net expected on-peak value.	Using best judgement, enter a value between 0 and 100 (ex.: 0 = 0%; 33 = 33% ; 100 = 100%). This value will correspond to the weight of emphasis placed on the Future-Other additions for the given year. If no adjustments are made by the Region/Subregion, 100(%) must be entered for this line.	A
16b	Net Future-Other Resources After Confidence Percentage Is Applied		Automatically calculated. Do not mannually enter.	A
16c	Confidence of Conceptual (8), using reasonable judgment	Based on reasonable judgment, enter a percentage of total Conceptual capacity that has a reasonable expectation to be in-service. The confidence factor only adjusts the net expected on-peak value.	Enter a value between 0 and 100 (ex.: 0 = 0%; 33 = 33% ; 100 = 100%). This value will correspond to the weight of emphasis placed on the Conceptual additions for the given year. If no adjustments are made by the Region/Subregion, 100(%) must be entered for this line.	A
16d	Net Conceptual Resources After Confidence Percentage Is Applied		Automatically calculated. Do not mannually enter.	A
17	Region/Subregion Target Reserve Margin	This value can represent Regional/subregional reserve margin requirements, targets, or guidelines. This value may be an enforceable requirement by a regulatory authority. This value be a requirement as a result of a subregional adequacy study.	Enter a value between 0 and 100 that represents the expected target margin (%) for the Region/subregion. If no value is entered, the NERC Reference Margin Level will be applied and assumed to remain constant throughout the reporting period.	A
19	Anticipated Capacity Resources Reserve Margin	The difference between Anticipated Capacity Resources and Net Internal Demand, divided by Total Internal Demand	Automatically calculated. Do not mannually enter.	A

Line	Term	Definition	Instructions	Ref.
20	Prospective Capacity Resources Reserve Margin	The difference between Prospective Capacity Resources and Net Internal Demand, divided by Total Internal Demand	Automatically calculated. Do not mannually enter.	A
21	Total Potential Resources Reserve Margin	The difference between Total Potential Resources and Net Internal Demand, divided by Total Internal Demand	Automatically calculated. Do not mannually enter.	A
22	Adjusted Potential Resources Reserve Margin	The difference between Adjusted Potential Resources and Net Internal Demand, divided by Total Internal Demand	Automatically calculated. Do not mannually enter.	A
23	Total Baseline Installed Capacity	Total Existing installed (nameplate) capacity for the prior actual reporting year.	Automatically calculated. Do not mannually enter.	A
24	Distributed or Other Capacity (Behind the Meter) < 1 MW	Form EIA-411	Enter the amount of capacity that comprises distributed generators that have less than 1 MW of capacity.	A
25	Distributed or Other Capacity (Behind the Meter) >= 1 MW	Form EIA-411	Enter the amount of capacity that comprises of distributed generators.	A
26	Capacity Total from EIA-860	Form EIA-411	Enter the total amount of seasonal capacity for all generators reported on Form EIA-860 Schedule 3, as provided by EIA. U.S. only.	A

Line	Term	Definition	Instructions	Ref.
1	Existing as of the last day of the prior reporting year	N/A	Report only Existing (commercially in-service and in control of the operator) transmission lines as of the last day of the prior reporting year in whole number circuit miles for the specified voltages.	A

Line	Term (s)	Code	Definition 1	Definition 2	Instructions
1	Transmission Status (Choose One)		Under Construction	Construction of the line has begun	Choose one of the predefined transmission categories.
			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	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”	
				Projected transmission lines that are not “Under Construction” or “Planned”	
			Planned Retirement	Any lines that will be tatken out of service during the assessment period.	Project retirements should include a negative value for circuit miles.
			Planned Upgrade	Projects that involve upgrades to existing transmission lines.	Projects that involve re-lining with the same voltage should have a zero-value for circuit miles. Projects that involve re-lining with higher or lower voltages should be entered on two lines: Line 1: The first line should include a negative circuit mile value for the old line. Line 2: The second line should include the same information, except that the circuit miles should be positive.
2 & 3	Primary Driver and Secondary Drivers (Choose One for Each)		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.
			Variable/Renewable		
			Nuclear Integration		
			Fossil-Fired		
			Hydro Integration		
			Economics / Congestion		
			Other		
4	Tie Line		Yes/No	A tie line connects two or more systems.	Specify whether the project is classified as a tie line across two or more systems.
5	Merchant Line		Yes/No		Specify whether the project is classified as a merchant line.
6	Project Name			Reporting entity defined project name	Enter the project name associated with this addition.
7	Terminal From Location			Beginning terminal point	Enter the name of the beginning terminal point of the line.
8	Terminal To Location			Ending terminal point	Enter the name of the ending terminal point of the line.
9	Company Name			The name of the company	Enter the company that owns the majority of the transmission line.
10	EIA Company Code				Identify each organization by the six-character code assigned by EIA. Required for all projects within the U.S.

Line	Term (s)	Code	Definition 1	Definition 2	Instructions
11	Type of Entity	I	Investor-owned		Identify the type of organization that best represents the line owner. If there is more than one organization, select the primary and list the seceondary owners in the comments section.
		M	Municipality		
		C	Cooperative		
		S	State-owned		
		F	Federally-owned		
		O	Other		
12	Percent Ownership				If the transmission line will be jointly-owned, enter the percentages owned by each individual respondent. If the line is not joingly-owned, enter 100 percent.
13	Line Length in Circuit Miles				Enter miles between beginning and ending terminal points of the line. Enter Circuit Line Miles and not linear miles. Line Length is used to populate Schedule 5. Enter negative value for future retirements.
14	Line Type	OH	Overhead		Select the predominant physical location of the line conductor.
		UG	Underground		
		SM	Submarine		
15	Voltage Type	AC/DC	Alternating or Direct Current		Select voltage type.
16	Voltage Operating	100-120			Enter the voltage at which the line is normally operated in kilovolts (kV). Operating Voltage is used to populate Schedule 5. A non-predefined voltage entry WILL NOTbe populated in Schedule 5.
		121-150			
		151-199			
		200-299			
		300-399			
		400-599			
		600+			
17	Voltage Design				Enter the voltage at which the line was designed to operate in kilovolts (kV).
18	Conductor Size				Enter the size of the line conductor in thousands of circular mils (MCM).
19	Conductor Material Type	AL	Aluminum		Enter the line conductor material type. If the conductor type is not included in the drop-down list, please select "Other" and include the actual conductor material type in the comments section.
		ACCR	Aluminum Conductor Composite Reinforced		
		ACSR	Aluminium Conductor Steel Reinforced		
		CU	Copper		
		OT	Other		
20	Bundling Arrangement	1	Single		Enter the bundling arrangement/configuration of the line conductors.
		2	Double		
		3	Tripple		
		4	Quadruple		
		OT	Other		

Line	Term (s)	Code	Definition 1	Definition 2	Instructions
21	Circuits Per Structure Present	1	1 Three-Phase Circuit	The line structures are projected to utilize a single three-phase circuit, once operational.	Enter the number of three-phase circuits expected to be used on the structures of the line. A line of entry must be used for each three-phase circuit.
		2	2 Three-Phase Circuits	The line structures are projected to utilize 2 three-phase circuit, once operational.	
		3	3 Three-Phase Circuits	The line structures are projected to utilize 3 three-phase circuit, once operational.	
22	Circuits Per Structure Ultimate	1	1 Three-Phase Circuit	The line structures are projected to be capabile of utilizing only a single three-phase circuit, once operational.	Enter the total number of three-phase circuits that the structures of the line will be capable of accomodating.
		2	2 Three-Phase Circuits	The line structures are projected to be capabile of utilizing up to 2 three-phase circuit, once operational.	
		3	3 Three-Phase Circuits	The line structures are projected to be capabile of utilizing up to 3 three-phase circuit, once operational.	
23	Pole/Tower Material	W	Wood		Identify the predominant pole/tower material for the line. For underground lines, select "Other."
		C	Concrete		
		S	Steel		
		B	Combination		
		P	Composite Materials		
		O	Other		
24	Pole/Tower Structure Type	P	Single pole		Identify the predominant structure type.
		H	H-Frame		
		T	Tower		
		U	Underground		
		O	Other		
25	Capacity Rating	MVA			Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).
26	Original In-Service Month	MM			Enter the month/year the line was originally scheduled to be energized under the control of the system operator. This date should be consistent with the date when this project first appeared on this form. This cell must be complete if the project is delayed. If a line is not delayed, enter the same values for original in-service dates and expected in-service dates.
27	Original In-Service Year	YYYY			
28	Expected In-Service Month	MM			Enter the most recent projection for the month/year the line will be energized under the control of the system operator. This cell must be filled-in for ALL projects. If a line is not delayed, enter the same values for original in-service dates and expected in-service dates.
29	Expected In-Service Year	YYYY			

Line	Term (s)	Code Definition 1	Definition 2	Instructions
30	Line Delayed	Yes/No		Identify if this line has been delayed. A line is considered delayed if the expected in-service date is later than the original in-service date. For this form, deferment is considered a delay.
31	Cause of Delay	No Longer Needed		If "Yes" was selected for a project in Column 30, a selection must be made from the defined causes, or enter a custom cause if not provided. Describe any information available regarding the cause(s) of the delay in the comments section.
		Siting/Permitting		
		Construction		
		Rescheduled		
32	Comments			Enter any necessary comments or project descriptions. Comments are required for lines that are delayed.

Line	Term	Instructions	Ref.
1	Transformer Project Name	Enter the name of the project.	A
2	High-Side Voltage (kV)	Enter High-Side Voltage	A
3	Low-Side Voltage (kV)	Enter Low-Side Voltage.	A
4	Expected In-Service Date (MM-YYYY)	Enter the projected date the transformer will be energized under the control of the system operator.	A
5	Description/Status	Provide a brief description/status on the projected transformer addition.	A

Ref. Code	Reference Title	Link
A	Reliability Assessment Guidebook	http://www.nerc.com/filez/ragtf.html
B	2007 Load Forecasting Working Group Recommendations Report	http://www.nerc.com/docs/pc/lfwg/NERC_Load_Forecasting_Survey_LFWG_Report_111907.pdf
C	EIA Glossary	http://205.254.135.7/tools/glossary/
D	2010 RIS Recommendations: Demand Response Application in Reserve Margin Calculations	http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf
E	NERC Glosssary	http://www.nerc.com/files/Glossary_12Feb08.pdf
F	FERC Guidance	http://www.ferc.gov/industries/electric/indus-act/reliability/orders/2003-2009.asp