NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2025 Long-Term Reliability Assessment

Data Form Instructions

Special Instructions and highlights:

- For off-shore wind, use prime mover code WS in Form B. See Appendix I for a list of all prime movers.
- Hybrid prime mover codes are IH (integrated hybrid) and CH (co-located hybrid).
- Balancing Authority Area and state/province are required fields for generators (Existing and Tier 1) on Form B.
- EIA-860 plant code is required for all generators in the US (Existing and Tier 1) on Form B.

The purpose of this document is to provide guidance on the completion of the data form for the *2025 Long-Term Reliability Assessment* (2025 LTRA). NERC collects data from the six Regions on an assessment area-basis. While each assessment area adheres to various planning assumptions, methods, and terminology, NERC collaborates with representatives from all Regions, as well as the Energy Information Administration (EIA) through the Reliability Assessment Subcommittee (RAS) to develop this set of instructions to promote consistency for high-level data assumptions when developing reliability assessments. Please direct any questions regarding the content of these instructions to NERC Staff.

Form A

Net Energy for Load (NEL) - Monthly

NEL – Prior Year Actual: The electric energy requirements of the system are 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 NEL in GWh for each month of the prior reporting year.

NEL – Reporting Year Forecast: The amount of energy required by the reported utility or group of utilities' retail customers in the system's service area plus the amount of energy supplied to full and partial requirements utilities (wholesale requirements customers) plus the amount of energy losses incurred from both transmission and distribution. Input for Year 1 Forecast as well. [Source: FERC-714]

Instructions	
NEL - Reporting Year Forecast	Enter the NEL forecast in GWh for each month of the current Reporting Year.
NEL - Year 1 Forecast	Enter the NEL forecast in GWh for each month of Year 1.

NEL – Annual

Instructions	
NEL - Year 2-10 Forecast	Enter the NEL forecast in GWh for Years 2-10.

Peak Hour Demand (PHD) - Monthly

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

Instructions	
PHD - Prior Year Actual	Enter the actual PHD for each month of the Prior Year.
PHD - Reporting Year Actual	Enter the actual PHD for January and February of the Reporting Year.

Forecasted PHD (Total Internal Demand): The projected sum of the net outputs of all generators within the system and the line flows into the system, less the line flows out of the system, in megawatts (MW). 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 PHD (Total Internal Demand) forecast for each month of the Reporting Year.
Year 1 Forecast	Enter the PHD (Total Internal Demand) forecast for each month of Year 1
Year 2 Forecast	Enter the PHD (Total Internal Demand) forecast for January and February of Year 2.

PHD – Seasonal

Instructions	
Year 2-10 Forecast	Enter the PHD (Total Internal Demand) forecast for each season for Years 2-10 in MW.

Demand-Side Management

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

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

Instructions
Enter the combined impacts of energy efficiency and conservation programs that impact load growth beyond its natural or normal rate, in MW. Impacts should be reported on a cumulative basis, starting with the expected impacts in 2025. 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:

	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	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 amount of unique MWs counted towards resource adequacy planning by an entity for activities or programs that are directly controlled or dispatched by a System Operator. These programs are designed to modify the amount of electricity used during the peak hour and may include any demand response called as part of an emergency operating procedure.

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

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

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

Other Demand Factors

Total Installed BTM Solar PV embedded in load forecast: Non-utility scale photovoltaic generation. Includes single-phase installed units that are considered “behind-the-meter”, “rooftop solar”, or part of a “building-integrated system” and embedded in the load forecast

Instructions
Report, in megawatts ac, the best estimation for the total amount of installed nameplate Solar PV. This field does not impact the Reserve Margin Calculations and is for information only.

BTM Solar PV On-Peak embedded in load forecast: Non-utility scale photovoltaic generation. Includes single-phase installed units that are considered “behind-the-meter”, “rooftop solar”, or part of a “building-integrated system” and embedded in the load forecast.

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

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 PHD for individual entities (LSEs, control areas, zones, etc.) within the Assessment Area, less the forecasted PHD for the entire Assessment Area. These values for each season and year will provide the difference between the non-coincident and coincident PHD 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 decimal, the Reference Margin Level for all seasons/years of the assessment period. If this data is not provided, NERC will apply a 15% Reference Margin Level for predominately thermal systems and 10% for predominately hydro systems.

Form B

Generating Unit Information

- For off-shore wind, use prime mover code WS. See Appendix I for a list of all prime movers.
- Hybrid prime mover codes are IH (integrated hybrid) and CH (co-located hybrid).
- Balancing authorities and states/provinces are required fields.
- EIA-860 plant code is required for all Tier 1 and Existing units in the US.

<table>
<tr><th colspan="2">Description/Instructions</th></tr>
<tr><td colspan="2">Form B should include all generating units over 1 MW located within the Assessment Area at the time of data collection. Data must be provided for each unit (with exceptions for wind, solar, or hydro units, which can be aggregated by plant). Energy Storage associated with another generation type should be reported as a separate technology. See Appendix I.</td></tr>
<tr><td>Status</td><td>Select one of the following options based on unit status at the time of reporting:
• Existing – in commercial operation
• Retired – permanently removed from commercial operation
• Mothballed – currently inactive or on standby, but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to Existing. If capacity contributions are desired to be shown in Prospective Reserve Margins, enter in Summer-Other and Winter-Other. Once a “mothballed” unit is confirmed to be capable for commercial operation, capacity contributions should be entered in Summer-Certain and Winter-Certain.
• Cancelled – planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
• Tier 1 – unit that meets <u>at least one</u> of the following guidelines (with consideration for an area’s planning processes)[1]:
▪ Construction complete (not in commercial operation)
▪ Under construction
▪ Signed/approved Interconnection Service Agreement (ISA)
▪ Signed/approved Power purchase agreement (PPA) has been approved
▪ Signed/approved Interconnection Construction Service Agreement (CSA)
▪ Signed/approved Wholesale Market Participant Agreement (WMPA)
▪ Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
• Tier 2 – unit that meets <u>at least one</u> of the following guidelines (with consideration for an area’s planning processes)[2]:
▪ Signed/approved Completion of a feasibility study</td></tr>
</table>

[1] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[2] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

	▪ Signed/approved Completion of a system impact study ▪ Signed/approved Completion of a facilities study ▪ Requested Interconnection Service Agreement ▪ Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs) • **Tier 3** – units in an interconnection queue that do not meet the Tier 2 requirement
Country	Select the country where the unit is physically located: • **CA** – Canada • **MX** – Mexico • **US** – United States
Region	The Regional Entity in which the generation unit resides.
Balancing Authority	Select the generating unit's balancing authority. If the unit has more than one balancing authority, provide details in the comments. Used for Existing and Tier 1 units.[3]
NERC Unit ID	Not Currently Used by NERC
Plant Code	**EIA-860 Plant Code should be used for all existing and tier 1 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)
Plant Name – 3	Assessment Area or Regional Entity Plant Name. (Optional)
Prime Mover	For combined cycle units, a prime mover code must be entered for each generator. EIA-860 Prime Mover should be used for all units. Separate category for hybrid Energy Storage systems added. **For run of river hydro, use HA.** See Appendix I.
Energy Source – 1	The energy source code for the fuel used in the largest quantity (Btus) to power the generator.[4] EIA-860 Predominant Energy Source should be used for all units. Separate category for hybrid Energy Storage systems added See Appendix I.
Energy Source – 2	The energy source code for the fuel used in the second largest quantity (Btus) to power the generator.[5] EIA-860 Second Most Predominant Energy Source to be used for all units. See Appendix I. For units with no secondary energy source, leave this field blank.
Generation Type	Automatically calculated, based on the Prime Mover and Energy Source – 1.
Initial Operating Month-Year	For existing units, provide only the year of the original effective date that the generator became operational (EIA operating year should be used for all units within the US). For planned units (Tier 1-3), enter the month, day, and year the unit is projected to become commercially operational. If a united meets the requirements for Tier1 – 3 and is delayed indefinitely, enter the date 9/9/9999.

[3] A description of each balancing authority can be found here: Real-time Operating Grid - U.S. Energy Information Administration (EIA).
[4] 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 Appendix I 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).
[5] 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).

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 U.S.
Nameplate Energy Capacity (MWh)	Enter nameplate energy output capacity (MWh) – applies to an energy storage device other than pumped storage or thermal storage. Includes battery, flywheel, compressed air, and any hybrid battery generators. If not known, enter UNK
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 U.S. 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 ac MW, rounded to the nearest tenth. EIA-860 summer capacity can be used for all units within the U.S. For Assessment Areas that test units on a seasonal basis, report the latest available net summer capacity.

Summer/Winter Certain Capacity Category

Certain Capacity: For a generating unit's capacity to be included in this category and thus included in Anticipated Resources and the Anticipated Reserve Margin; the unit or portion of the unit must be commercially operable and meet at least one of the following requirements for the period of peak demand for each season/year for the assessment period:

- Unit must have a firm capability[6] and have a Power Purchase Agreement (PPA)[7] with firm transmission
- Unit must be classified as a Designated Network Resource[8]
- Where energy-only markets exist, unit must be a designated market resource eligible to bid into the market
- Report ES on hybrid systems as a separate technology unit. The nameplate/installed capacity should reflect the ES unit's design capability. Adjust the peak capacity reported based on sound engineering judgement or approved methodology.

Instructions	
Summer/Winter Certain – 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 demand 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,

[6] 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] (https://www.ferc.gov/sites/default/files/2020-06/form-714-instructions.doc).

[7] 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. (https://www.ferc.gov/industries-data/market-assessments/overview/glossary).

[8] 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: https://www.govinfo.gov/content/pkg/FR-1996-05-10/pdf/96-10694.pdf.

	transmission limitations, fuel limitations. All variable resources (wind, solar, hydro) must be derated. Thermal units should be derated for fuel availability if applicable. Report ES on hybrid systems as a separate technology unit. A unit's forced outage rate is generally not included as a derate. If a unit's forced outage rate is included as a derate, please indicate this in the comments and narrative response. 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. Existing-Other is a subset of Prospective Resources and Prospective Reserve Margins

Instructions	
Summer/Winter – 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, fuel availability. Include all derates as positive MW values. Other Capacity in Form B should not reflect reductions for Unconfirmed Retirements. Unconfirmed Retirements should be aggregated by fuel type and reported in Form C.

Location (State or Province) of Generator

Instructions	
State/Province	Select the two-letter state or Canadian province code where the generator is located. For generators in Mexico, select MX.

Form C

Capacity Transfers (Imports/Exports)

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

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

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. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s). The buyer(s) and seller(s) must coordinate and agree on how transactions are reported under this heading. This category is a subset of total Firm imports/exports.

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

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. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s).

Modeled and Coordinated Between Areas: Applicable for Assessment Areas that model potential transfers (imports/exports) and to eliminate potential double counting of capacity. The Assessment Areas affected have to align the purchase and sale. Although these transfers are assumed without a contract in place, there is reasonable expectation that these transfers can occur during the peak period.

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

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

Instructions
Enter, in megawatts, the amount of Expected transfers for each season and year. Reported transfers must be coordinated, reviewed, and vetted by neighboring Assessment Areas and corresponding Region(s).

Available On-Peak Reserves

Instructions	
Available Reserves During Peak - Prior Year Actual	Enter, in megawatts, the available reserves (spinning, non-spinning, and other reserves) that were available and deliverable during the Peak Demand Hour 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. This value for each season/year will reduce the area's total Existing-Certain capacity.

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 (not in the load forecast) – Additional Capacity contribution.

Instructions
Aggregate of generation on the customer's side of the retail meter that can be used as a capacity resource during the peak demand hour. (Exclude BTM generator units or aggregated capacity reported in Form B, if any)

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

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

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

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

Capacity Additions by Generation Type

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

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

Unconfirmed Capacity Retirements by Generation Type

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

- Reliability-must-run status and other issues may conflict with this proposed/requested retirement or conversion.

- Units that have announced or submitted a request for a generator deactivation, but have not received approval.
- Units expected to retire based on the result of a generator survey or analysis.

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

Form D

Planned Transmission Projects

Enter projects that are new construction or construction that is an upgrade to existing capacity. Do not enter line replacement projects that do not materially change transmission capacity. Projects with a line length of less than 10 circuit miles do not need to be reported.

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 power flow 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
New/Upgrade	New/Upgrade	Indicate if project is new construction or an upgrade to existing capacity.
Region		Regional Entity in which a majority of the line length is located.
Project Name		Name of project at the discretion of the assessment area.
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 Variable/Renewable Integration Nuclear Integration Fossil-Fired Integration Hydro Integration Economics/Congestion Other	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.
Terminal Origin		Provide the name of the point where the line originates
Terminal Endpoint		Provide the name of the point 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 all projects within the U.S.
Entity Type	I – Investor-owned M – Municipality C – Cooperative S – State-owned F – Federally-owned O – Other	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.
Ownership (%)		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%.
Line Length (Circuit Miles)		Enter circuit line miles (not linear miles) between the terminal origin and end points. Projects with a line length of less than 10 circuit miles should not be included.
Line Type	OH – Overhead UG – Underground SM – Submarine	Select the predominant physical location of the line conductor.
Voltage Type		Select alternating or direct current (AC/DC)
Operating Voltage Class (kV)		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.
Voltage Design (kV)		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).
Circuits Per Structure Present / Ultimate	1 Three-Phase Circuit	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.
	2 Three-Phase Circuits	
	3 Three-Phase Circuits	
Capacity Rating (MVA)		Enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).
Original In-Service Date		For delayed projects, enter the month, day, and year that the line was scheduled to be energized under the control of the system operator. This cell is required for delayed lines only.
Expected In-Service Date		Enter month, day, and year that the line will be energized under the control of the system operator. This field is required for all projects. If a date is not currently known, please state unknown and provide a comment. Use of any dates prior to 2025 requires explanation in the Cause of Delay / Other Comments field.
Cause of Delay / Other Comments		Describe any information available regarding the reasons for the delay. Provide any other important information regarding the project.

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	Under Construction
	Planned
	Conceptual
	Completed (Provide Actual In-Service Date as Comment)
	Delayed (Comment Required)
	Cancelled (Comment Required)
Project Name	Enter the project name
Voltage – Low-Side (kV)	Enter the transformer's low-side voltage
Voltage – High-Side (kV)	Enter the transformer's high-side voltage
Original In-Service Date	For delayed transformer projects, enter the month, day, and year that the transformer was scheduled to be energized under the control of the system operator. This cell is required for delayed transformer projects only.
Expected In-Service Date	Enter the month, day, and year that the transformer is projected to be energized under the control of the system operator. If a date is not currently known, please state unknown and provide a comment. Use of any dates prior to 2025 requires explanation in the Description/Status field.
Description/Status	Provide a brief description/status on the transformer addition.

Summary Tables

The summary tables include basic formulas that are intended to provide data submitters with critical metrics, including demand and Demand-Side Management, Capacity, Capacity Transfers, Resource Categories, Reserve Margin Excess and Shortfall, and Planning Reserve Margins. Important information and clarification on each category is provided below. Data submitters should refrain from modifying these formulas and contact NERC staff with any questions.

Demand/Demand-Side Management

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

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 **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.

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**.

Reference Margin Level Excess/Shortfall

Existing-Certain and Net Firm Transfers Shortfall

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

Anticipated Resources Shortfall

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

Prospective Resources Shortfall

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

Planning Reserve Margins

Planning Reserve Margins: the primary metric used to measure resource adequacy, defined as the difference in resources (Anticipated or Prospective) and Net Internal Demand, divided by Net Internal Demand, shown as a percentile.

$$\text{Anticipated Reserve Margin} = \frac{(\text{Anticipated Resources} - \text{Net Internal Demand})}{\text{Net Internal Demand}}$$

$$\text{Prospective Reserve Margin} = \frac{(\text{Prospective Resources} - \text{Net Internal Demand})}{\text{Net Internal Demand}}$$

Fuel Type Capacities (Existing/Tier 1/Tier 2/Tier 3)

Fuel type capacities are calculated based on the summer and winter certain capacity

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)
IH	Integrated Hybrid
CH	Co-Located Hybrid

*Use HA for all Run of River Hydro applications.

**Use HY for all Conventional Hydro applications.

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		AB	Agricultural By-Products
		MSW	Municipal Solid Waste

Fuel Type		Code	Fuel Description
	Solid Renewable Fuels	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)
		HS	Hybrid - Solar and Battery
		HW	Hybrid - Wind and Battery
		HG	Hybrid - Natural Gas and Battery
		HO	Hybrid - Other and Battery
Energy Storage	Battery	BA	Battery Storage