U.S. Department of Energy U.S. Energy Information Administration Form EIA-411 (2011)	*COORDINATED BULK POWER SUPPLY AND DEMAND PROGRAM REPORT*	Form Approved OMB No. 1905-0129 Approval Expires: 12/31/2013 Burden: 17 hours

PURPOSE	Form EIA-411 collects information about regional electricity supply and demand projections for a ten-year advance period and information on the transmission system and supporting facilities. The data collected on this form appear in the U.S. Energy Information Administration (EIA) publication, *Electric Power Annual*. They are also used by the U.S. Department of Energy to monitor the current status and trends of the electric power industry and to evaluate the future of the industry.
REQUIRED RESPONDENTS	The Form EIA-411 is mandatory for those entities required to report. With the exception of Schedule 7, the form is to be completed by each of the Regional Entities of NERC. Each Regional Entity compiles the responses from data furnished by utilities and other members within their Region and provided to NERC. Where subregions exist, a subregional submittal is required. NERC then compiles and coordinates these data and provides them to the U.S. Energy Information Administration. Schedule 7 data for each Regional Entity will be provided by NERC from its Transmission Availability Data System database.
RESPONSE DUE DATE	Annual data, following the end of the calendar year, are due to the North American Electric Reliability Corporation by June 1st. After review, NERC will submit the completed Form EIA-411 to the EIA by July 15.
METHODS OF FILING RESPONSE	The North American Reliability Corporation (NERC) will oversee the methods of filing response of the data by the Regional Entities. NERC then submits the compiled report to EIA. Maps and power flow cases should be transmitted electronically using a secure file transfer process. Contact Orhan Yildiz at orhan.yildiz@eia.gov for instructions. If necessary, CD-ROM disks containing the data can also be mailed via overnight delivery to EIA at the following address: Orhan Yildiz, Survey Manager U.S. Energy Information Administration, Mail Stop EI-23 1000 Independence Avenue, S.W. Washington, DC. 20585-0690 Please retain a completed copy of this form for your files.
CONTACTS	**Data Questions:** For questions about the data requested on Form EIA-411, contact the Survey Manager: Orhan Yildiz Telephone Number: (202) 586-5410 FAX Number: (202) 287-1938 Email: orhan.yildiz@eia.gov

GENERAL INSTRUCTIONS

1. All forecast and projections should represent a ten-year outlook.
2. For schedules which require annual data, the "Actual" column represents the year prior to the reporting year. For example, for data submitted during 2011 (or, the 2011 reporting year), the "Actual" column should contain data for the year 2010; the "Year 1" column should contain data for the year 2011.
3. Provide transmission data for facilities 100kV and above, with the exception of AC circuit and transformer outages.

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1: IDENTIFICATION

1. **Survey Contact:** Verify contact name, title, telephone number, fax number, and email address.
2. **Supervisor of Contact Person for Survey:** Verify the contact's supervisor's name, title, telephone number, fax number and email address.
3. **Report For:** Verify the NERC Regional Entity and reporting party, whether it is a Regional Entity or subregion.

SCHEDULE 2, Part A and B: HISTORICAL AND PROJECTED PEAK DEMAND AND ENERGY

GENERAL INSTRUCTIONS

1. The reported peak demand for a Region or subregion should be:
   a. 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. For Regions or subregions that provide coincident peak demands, submit justification for providing a coincident value.
   b. 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.

The term "peak" is defined as:

- **Summer Peak Hour Demand:** The maximum load in megawatts during the period June through September. The summer peak period begins on June 1 and extends through September 30.
- **Winter Peak Hour Demand:** The maximum load in megawatts during the period December through February. The winter peak period begins on December 1 and extends through the end-of-February.
- **Peak Hour Demand:** The maximum load in megawatts during the specified reporting period.

The term "**Net Energy for Load**" is defined as:

- Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to other Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.

2. The fundamental test for determining the adequacy of the power system is to determine whether resources exceed demand while allowing sufficient margin to address 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. In some cases this can be done on a monthly interval during the peak season.

3. When providing a demand forecast to EIA the fundamental approach is to 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 that 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.

PART A: Enter monthly peak demand and Net Energy for Load for designated months as defined above.

Monthly peak demands should be reported based on Total Internal Demand (see definition on Schedule 3A and 3B, line 2.

PART B: Enter seasonal peak demand and Net Energy for Load for designated years as defined above. The summer peak demands will be the values entered on SCHEDULE 3, Part A, line 2 for the corresponding year, and the winter peak demands will be the values entered on SCHEDULE 3, Part B, line 2, for the corresponding year. Please Note: as of 2011, all forecasts and projections should represent a **ten**-year outlook.

SCHEDULE 3, PART A and B: HISTORICAL AND PROJECTED DEMAND, CAPACITY, TRANSACTIONS, AND RESERVE MARGINS

GENERAL INSTRUCTIONS

1. PART A should be filled out for the summer seasonal peak. PART B should be filled out for the winter seasonal peak.
2. Please Note: as of 2011, all forecasts and projections should represent a **ten**-year outlook.
3. Enter demand and capacity for the summer (PART A) and winter (PART B) peak periods of the designated years for the NERC Region or subregion. Peak demands reported should agree with the corresponding entries in SCHEDULE 2, Part B.
4. Where capacity values are entered, values should accumulate through the ten year projection period. For example, following the table below, in 2011 “0” was added; in 2012 “100” was added; in 2013 “0” was added; in 2014 “100” was added; in 2015 “100” was added. For the 2011 base-case, by 2015 “300” is planned to be added. The example years given would be correct for data submitted during 2012.

YEAR	Actual (2011)	Year 1 (2012)	Year 2 (2013)	Year 3 (2014)	Year 4 (2015)
Planned Capacity	0	100	100	200	300

5. For demand and capacity values, all numbers should be entered as MW in positive values – no negatives – up to one decimal place. (All subtractions will be shown on the respective line found in the form).
6. For hydroelectric capacity, explain in SCHEDULE 9, COMMENTS whether the projected year’s data are for an adverse water year, an average water year, or other.
7. For line 1**, Unrestricted Non-coincident Peak** Demand is the gross load of the region/sub-region, which includes New Conservation (Energy Efficiency) and Estimated Diversity; and excludes Additions for Non-member Loads and Stand-by Load Under Contract, as defined below.

    - For line 1a, **New Conservation (Energy Efficiency)**, enter the estimated impact of incremental passive energy efficiency programs. The increment represents the increase above the embedded amount from the base year. These impacts should be associated with programs to increase energy efficiency beyond its natural or normal growth. Report the expected capacity impacts (MW) during time of peak.

- For line 1b, **Estimated Diversity**, enter the difference between the region's/subregion's peak and the sum of the peaks of the reporting entities (LSEs, balancing area, zones, etc.). The electric utility system's load is made up of many individual loads that may make demands upon the system at different times of the day. Within a customer class, the individual loads may follow similar usage patterns, but these classes 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.
- For line 1c, **Additions for Non-member Loads**, enter adjustments to account for load of non-members, in accordance with the NERC Reliability Standard MOD-16 that "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."
- For line 1d, **Stand-by Load Under Contract**, 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.

6. For line 2, **Total Internal Demand**, enter 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. 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 incorporated in this value. These values should equal those as reported in SCHEDULE 2, Part B, Seasonal Peak Hour Demand for the corresponding years.

For Lines 2a-2d, do not double count demand response for different Demand Response categories. All capacity should be counted once and only once and categorized as one for the four types of dispatchable and controllable Demand Response. Only report demand response here if the Region/subregion accounts for demand response as a load-reducing resource.

- For line 2a, **Direct Control Load Management (Direct Load Control)**, enter the magnitude of customer demand that can be interrupted at the time of the seasonal peak load by direct control of a system operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential or small commercial customers. Direct Control Load Management (Direct Load Control) as reported here does not include Interruptible Demand (line 2b).
- For line 2b, **Contractually Interruptible Demand (Curtailable)**, enter the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Region or subregion's seasonal peak by direct control of the system operator or by action of the customer at the direct request of the system operator. 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).

- For line 2c, **Critical Peak Pricing (CPP) with Control**, enter the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Entity's 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.
- For line 2d, **Load as a Capacity Resource**, enter the magnitude of customer demand that, in accordance with contractual arrangements, is committed to pre-specified load reductions when called upon by a balancing authority. This demand response product is typically an aggregation of a variety of demand resources which must qualify to meet specific requirements aligned with traditional generating units (e.g., frequency response, responsive to AGC). These resources are not limited to being dispatched during system contingencies and may be subject to economic dispatch from balancing authorities. Additionally, this capacity may be used to meet resource adequacy obligations when determining planning reserve margins.

7. For line 3, **Net Internal Demand**, enter line 2, less line 2a, less line 2b, less 2c, less line 2d (Total Internal Demand, less Direct Control Load Management, Interruptible Demand, Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resources).

For lines 4a-4d, enter the amount of Demand Response that can be called upon for the following types of Demand Response categories. Double counting is permitted here. For example, if an entity has 100 MW of Direct Load Control Demand Response, all 100 MW can be used for Non-Spinning Reserves, and 50 MW can be used for Spinning Reserves, enter 100 on line 2a, 100 on line 4b, and 50 on line 4a.

8. For line 4a, **Demand Response used for Reserves - Spinning**, Enter demand-side resources which 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.
9. For line 4b, **Demand Response used for Reserves – Non-Spinning**, enter demand-side resources, which 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.
10. For line 4c, **Demand Response used for Regulation**, enter demand-side resources which can be responsive to Automatic Generation Control (AGC) to provide normal regulating margin.
11. For line 4d, **Demand Response used for Energy, Voluntary - Emergency**, enter demand-side resources, which curtail voluntarily when offered the opportunity to do so for compensation. Demand-side resources which curtail during system and/or local capacity constraints.

When determining categorization of supply resources, refer to the criteria listed within each supply category. Determine a supply resource's applicability to a category by assessing the criteria in each supply category in order of certainty (use logical progression). For example, first assess whether the resource falls into the Existing-Certain category. If the resource does not meet that criteria, assess the criteria of Existing-Other. If not, assess the criteria of Existing-Inoperable. If not, assess the criteria of Future-Planned. If not assess the criteria of Future-Other. If not, assess the criteria of Conceptual. A resource will qualify within a supply category if one or more of the listed criteria is true for that resource.

For supply definitions on this form, the criteria for each supply category is based on the "period of analysis", which refers to the reported seasonal peak, not the full year.

12. For line 5, **Total Internal Capacity**, is the internal capacity for the reporting area. (Defined as seasonal rated capability during peak period - where full availability of primary fuel, wind, and water 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. This value is the summation of all Existing and Future Capacity Additions (Line 6 + Line 7).
13. For Line 6 – 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. This value is automatically calculated by the summations of all Existing Capacity (Line 6a + Line 6b + Line 6c).
14. For line 6a, **Existing, Certain Capacity**, included in this category are generation resources available to operate and deliver power within or into the region during the period of analysis 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 the period of analysis 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 in the Federal Energy Regulatory Commission (FERC) *pro forma* or other regulatory approved tariffs.
    4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and are not subject to curtailment
    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 are not subject to curtailment during the period of analysis in the assessment

    Do not derate this value by unplanned or “forced” outages. For Actual-Year data, unplanned outages are to be reported on line 6c1.

    - For line 6a1, **Wind Expected On-Peak**, enter the amount of existing wind capacity that is expected to be available on the seasonal peak.
    - For line 6a2, **Solar Expected On-Peak**, enter the amount of existing solar capacity that is expected to be available on the seasonal peak.
    - For line 6a3, **Hydro Expected On-Peak**, enter the amount of existing hydro capacity that is expected to be available on the seasonal peak.
    - For line 6a4, **Biomass Expected On-Peak**, enter the amount of existing biomass capacity that is expected to be available on the seasonal peak.
    - For line 6a5, **Demand Response Expected On-Peak (Load Management Programs)**, The total amount of Demand Response capacity that is expected to be available on the seasonal peak. Values reported on this line are treated as a capacity resource and are held to the same criteria as an Existing, Certain resource. Do not double count Demand Response capacity here if already provided in lines 2a-2d. Only report Demand Response here if your Region/subregion counts Demand Response as a supply resource, and not a load-reducing resource.
15. For line 6b, **Existing, Other Capacity**, included in this category are generation resources that may be available to operate and deliver power within or into the region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for any reason. 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 various reason.
    3. Mothballed generation (that may be returned to service during the period of analysis)
    4. Portions of variable generation not counted in the Existing, Certain category (e.g.

wind, solar, etc.) that may not be available or de-rated during the period of analysis.

5. Hydro generation not counted as Existing, Certain or de-rated.
6. Generation resources constrained for other reasons.

Do not derate this value by unplanned or "forced" outages. For Actual-Year data, unplanned outages are to be reported on line 6c2.

- For line 6b1, **Wind Derated On-Peak**, enter the amount of existing wind capacity that is expected to be unavailable on seasonal peak.
- For line 6b2, **Solar Derated On-Peak**, enter the amount of existing solar capacity that is expected to be unavailable on seasonal peak.
- For line 6b3, **Hydro Derated On-Pea**k, enter the amount of existing hydro capacity that is expected to be unavailable on seasonal peak.
- For line 6b4, **Biomass Derated On-Peak**, enter the amount of existing biomass capacity that is expected to be unavailable on seasonal peak.
- For line 6b5, **Load as a Capacity Resource Derated On-Peak (Load Management Programs)**, enter the amount of Load as a Capacity Resource that is expected to be unavailable on seasonal peak.
- For line 6b6, **Transmission-Limited Resources**, enter the amount of transmission-limited generation resources that have known physical deliverability limitations to serve load that they are obligated to serve.
- For line 6b7, **All Other Derates**, enter all other generation derates not reported in lines 6b1-6b6 that have known physical limitations during peak demand.
- For line 6b8, **Energy Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources 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. Energy Only resources are classified as energy-only resources by the FERC interconnection process.

16. For line 6c, **Existing, Inoperable Capacity**, included in this category are generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. 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 period of the assessment)
    2. Other existing but out-of-service generation (that can not be returned to service for the period of the assessment)
    3. This category does not include behind-the-meter generation or non-connected emergency generators.
    4. This category does not include partially dismantled units that are not forecasted to return to service

For Actual Year values, unplanned or "forced" outage capacity is to be considered as Existing, Inoperable Capacity. Report these values on lines 6c1 and 6c2.

- For line 6c1, Existing, Certain Capacity Forced Outage on Peak, enter the unplanned or "forced" outage of generators in MW, which were out-of-service due to ***any*** failures at the absolute peak.
- For line 6c2, Existing, Other Capacity Forced Outage on Peak, enter the unplanned or "forced" outage of generators in MW, which were out-of-service due to ***any*** failures at the absolute peak.

17. For line 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 milestones:
    1. Construction has started
    2. Regulatory permits (e.g. Site Permit, Construction Permit, Environmental Permit) being approved
    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
18. For line 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 the period of analysis 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 in FERC's pro forma or other regulatory approved tariffs.
    4. Energy-only resources confirmed able to serve load during the Reporting Period and will not be curtailed.
    5. Where applicable, included in an integrated resource plan under a regulatory framework that mandates resource adequacy requirements and an obligation to serve.

    For this value, only enter the Net Expected On-Peak Values of Future-Planned resources. Do not include derates.

    - For line 7a1, **Wind Expected On-Peak**, enter the amount planned wind capacity that is expected to be available on seasonal peak.
    - For line 7a2, **Wind Derate On-Peak**, enter the amount planned wind capacity that is expected to be unavailable on seasonal peak.
    - For line 7a3, **Solar Expected On-Peak**, enter the amount planned solar capacity that is expected to be available on seasonal peak.
    - For line 7a4, **Solar Derate On-Peak**, enter the amount planned solar capacity that is expected to be unavailable on seasonal peak.
    - For line 7a5, **Hydro Expected On-Peak**, enter the amount planned hydro capacity that is expected to be available on seasonal peak.
    - For line 7a6, **Hydro Derate On-Peak**, enter the amount planned hydro capacity that is expected to be unavailable on seasonal peak.
    - For line 7a7, **Biomass Expected On-Peak**, enter the amount planned biomass capacity that is expected to be available on seasonal peak.
    - For line 7a8, **Biomass Derate On-Peak**, enter the amount planned biomass capacity that is expected to be unavailable on seasonal peak.
    - For line 7a9, **Demand Response Expected On-Peak (Load Management Programs),** The total amount of Demand Response capacity that is expected to be available on seasonal peak. Values reported on this line are treated as a capacity resource and are held to the same criteria as a Future-Planned resource. Do not double count Demand Response capacity here if already provided in lines 2a-2d. Only report Demand Response here if your Region/subregion counts Demand Response as a supply resource.
    - For line 7a10, **Demand Response Derate On-Peak (Load Management Programs),** The total amount of Demand Response capacity that is expected to not be available on seasonal peak. Do not double count Demand Response capacity here if already provided in lines 2a-2d.
    - For line 7a11, **Transmission-Limited Resources,** enter amount of transmission-limited generation resources that have known physical deliverability limitations to serve load that they are obligated to serve. This value may represent a change

(+/-) in existing transmission-limited resources. The change in capacity is classified as Future-Planned.

- For line 7a12, **Scheduled Outage – Maintenance,** enter the amount of capacity reductions due to a generator outage that is scheduled well in advance and is of a predetermined duration. This scheduled outage is classified as Future-Planned capacity.
- For line 7a13, **All Other Derates**, enter all other generation derates not reported in lines above that have known physical limitations during peak demand.
- For line 7a14, **Energy Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources 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 above. Energy only resources are designated as such if they are not classified as a network resource. Energy Only resources are classified as energy-only resources by the FERC interconnection process.

19. For line 7b, **Future, Other**, included in this category are generation resources that do not qualify as Future, Planned and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment 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 period of analysis
    3. Variable generation not counted in the Future, Planned category or may not be available or is de-rated during the period of analysis
    4. Hydro generation not counted in the Future, Planned category or de-rated.

    Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position. The confidence factor for Future, Other resources should be entered on line 16a and only adjusts the expected on-peak values and not the derated values.

    - For line 7b1, **Wind Expected On-Peak**, enter the amount planned wind capacity that is expected to be available on seasonal peak.
    - For line 7b2, **Wind Derate On-Peak**, enter the amount proposed wind capacity that is expected to be unavailable on seasonal peak.
    - For line 7b3, **Solar Expected On-Peak**, enter the amount planned solar capacity that is expected to be available on seasonal peak.
    - For line 7b4, **Solar Derate On-Peak**, enter the amount proposed solar capacity that is expected to be unavailable on seasonal peak.
    - For line 7b5, **Hydro Expected On-Peak**, enter the amount planned hydro capacity that is expected to be available on seasonal peak.
    - For line 7b6, **Hydro Derate On-Peak**, enter the amount proposed hydro capacity that is expected to be unavailable on seasonal peak.
    - For line 7b7, **Biomass Expected On-Peak**, enter the amount planned biomass capacity that is expected to be available on seasonal peak.
    - For line 7b8, **Biomass Derate On-Peak**, enter the amount proposed biomass capacity that is expected to be unavailable on seasonal peak.
    - For line 7b9, **Energy Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.
    - For line 7b10, **Scheduled Outage – Maintenance,** enter the amount of capacity reductions due to a generator outage that is scheduled well in advance and is of a predetermined duration. This scheduled outage is classified as Future-Planned capacity.
    - For line 7b11, **All Other Derates**, enter all other generation derates not reported in lines above that have known physical limitations during peak demand.

- For line 7b12, **Energy Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources 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 above. Energy only resources are designated as such if they are not classified as a network resource. Energy Only resources are classified as energy-only resources by the FERC interconnection process.

20. For line 8, **Conceptual**, included in this category are 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. “Placeholder” generation for use in modeling.

    For this value, only enter the Net Expected On-Peak Value. Do not include derates or energy only.

    Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position. The confidence factor for Conceptual resources should be entered on line 16c and only adjusts the expected on-peak values and not the derated values.

    - For line 8a1, **Wind Expected On-Peak**, enter the amount planned wind capacity that is expected to be available on seasonal peak.
    - For line 8a2, **Wind Derate On-Peak**, enter the amount proposed wind capacity that is expected to be unavailable on seasonal peak.
    - For line 8a3, **Solar Expected On-Peak**, enter the amount planned solar capacity that is expected to be available on seasonal peak.
    - For line 8a4, **Solar Derate On-Peak**, enter the amount proposed solar capacity that is expected to be unavailable on seasonal peak.
    - For line 8a5, **Hydro Expected On-Peak**, enter the amount planned hydro capacity that is expected to be available on seasonal peak.
    - For line 8a6, **Hydro Derate On-Peak**, enter the amount proposed hydro capacity that is expected to be unavailable on seasonal peak.
    - For line 8a7, **Biomass Expected On-Peak**, enter the amount planned biomass capacity that is expected to be available on seasonal peak.
    - For line 8a8, **Biomass Derate On-Peak**, enter the amount proposed biomass capacity that is expected to be unavailable on seasonal peak.
    - For line 8a9, **Energy-Only**, enter the amount of generating resources that are designated as energy-only resources or have elected to be classified as energy only resources and may include generating capacity that can be delivered within the area but may be recallable to another area.

21. For line 9, **Anticipated Internal Capacity**, this value is automatically calculated by the summations of Existing, Certain and Future, Planned Capacity Additions (Line 6a + Line 7a)

NOTES FOR TRANSACTIONS:
Contracts for capacity are defined as an agreement between two or more parties for the Purchase (Import) and Sale (Export) of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a generating resource subject to a contract is located in one region and sold to another region, the region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside region. The importing region reports such capacity as an import, and ***does not*** report the capacity as a supply resource (in line 6, 7, or 8).

TRANSMISSION CAPACITY MUST BE AVAILABLE FOR ALL REPORTED IMPORT AND EXPORT TRANSACTIONS.

DO NOT INCLUDE TRANSMISSION SYSTEM LOSSES WHEN REPORTING IMPORTS AND EXPORTS TRANSACTIONS.

The following examples are provided to show how unit-specific transactions are handled between two or more reporting Regions or subregions for Imports and Exports:

1. Unit physically located in Area A that is fully owned by a company in Area B and not connected to the Area A network but instead has a direct and adequate transmission connect to the Area A.

   Solution: Show the unit completely in Area B with no transfers. All derating accounted for in Region or Province B.

2. Unit physically located in Area A that is half owned by a company in Area B.

   Solution: Show the unit completely in Area A with an export to Area B of half of the capacity. Area B would show an import of half of the capacity from Area A, as long as Area A & B can demonstrate adequate transmission capacity. Unit derating accounted for in Area A and export reduced by half of the derated amount.

3. Unit physically located in Area A that is fully owned by a company in Area B.

   Solution: Show the unit completely in Area A with an export to Area B of the full amount. Area B would show an import of the full amount of capacity from Area A, as long as Area A & B can demonstrate adequate transmission capacity. Unit derating should be accounted for in Area A and the import and export reduced by derated amounts in both Areas.

4. Unit physically located in Area A that is fully owned by a company in Area C and "wheeled" through Area B.

   Solution: Show the unit completely in Area A with an export to Area C of the full amount. Area B does not report either import or export. Area C would show an import of the full amount of capacity from Area A, as long as Areas A, B, and C can demonstrate adequate transmission capacity.

22. For line 10, **Capacity Transactions – Imports**, the sum of lines 10a through 10d.
23. For line 10a, **Firm**, enter the amount of capacity purchases for which a firm contract has been signed. These transactions will be associated with Existing Certain Capacity.
    - For line 10a1, **Full Responsibility Purchases** - 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.

- For line 10a2, **Owned Capacity/Entitlement Located Outside the Region/subregion** – 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.

24. For line 10b, **Non-firm**, enter the amount of capacity purchases for which a non-firm contract has been signed. This value should only be entered for the previous year actual data.
25. For line 10c, **Expected**, 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.
    - For line 10c1, **Full Responsibility Purchases** - 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.
    - For line 10c2, **Owned Capacity/Entitlement Located Outside the Region/subregion** - 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.
26. For line 10d, **Provisional**, enter the amount of capacity for which the transaction(s) is under study, but negotiations have not begun.
27. For line 11, **Capacity Transactions – Exports**, the sum of lines 11a through 11d.
28. For line 11a, **Firm**, enter the amount of capacity purchases for which a firm contract has been signed. These transactions will be associated with Existing Certain Capacity.
    - For line 11a1, **Full Responsibility Sales** - 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.
    - For line 11a2, **Owned Capacity/Entitlement Located Outside the Region/subregion** - Enter the amount of externally owned capacity or capacity entitlements that will move from the reporting Region or subregion to an outside Region or subregion. Values reported on this line represent a portion of Line 11a – Firm.
29. For line 11b, **Non-firm**, enter the amount of capacity purchases for which a non-firm contract has been signed. This value should only be entered for the previous year actual data.
30. For line 11c, **Expected**, 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.
    - For line 11c1, **Full Responsibility Sales** - 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.
    - For line 11c2, **Owned Capacity/Entitlement Located Outside the Region/subregion** - Enter the amount of externally owned capacity or capacity entitlements that will move from the reporting Region or subregion to an outside Region or subregion. Values reported on this line represent a portion of Line 11c – Expected.
31. For line 11d, **Provisional,** enter the amount of capacity for which the transaction(s) is under study, but negotiations have not begun.

NOTES FOR MARGIN CALCULATIONS:

Lines 12-15a are calculated automatically and represent the amount of capacity (generating supply and transactions) that will be counted towards margin calculations.

32. For line 12, **Existing, Certain and Net Firm Transactions** is calculated by the summation of Existing, Certain Capacity and the net of Firm Transactions
33. For line 13, **Anticipated Capacity Resources** is calculated by the summation of **Anticipated** Internal Capacity and the net of Firm and Expected Transactions. For the general public, this is the equivalent of “Planned Capacity Resources” on the older versions of this form.
34. For line 14, **Prospective Capacity Resources** is calculated by the summation of Anticipated Capacity Resources, Existing, Other Capacity, and the adjusted Future, Other Capacity (For this calculation, Future, Other resources are adjusted using the confidence factor reported on line 16a. This amount is automatically calculated in line 16b). All derates and outages are subtracted from this calculation.
35. For line 15, **Potential Capacity Resources** is calculated by the summation of Anticipated Capacity Resources, Existing, Other Capacity, Future, Other Capacity, Conceptual Capacity, and the net of Provisional Transactions. All derates and outages are subtracted from this calculation.
36. For line 15a, **Adjusted Potential Capacity Resources** is calculated by the summation of Prospective Capacity Resources, the adjusted Conceptual Capacity (For this calculation, Conceptual Resources are adjusted using the confidence factor reported on line 16c. This amount is automatically calculated in line 16d.) and the net of Provisional Transactions. All derates and outages are subtracted from this calculation.
37. For line 16a, **Confidence of Future, Other Resources** (line 7b), using reasonable judgment, enter a value between 0 and 100 that corresponds to the weight of emphasis placed on Future, Other additions for the given year. This factor only adjusts the expected on peak values.
38. For line 16b, **Net Future, Other Resources After Confidence Percentage Is Applied**, line 7b times line 16a.
39. For line 16c, **Confidence of Conceptual Resources** (line 8), using reasonable judgment, enter a value between 0 and 100 that corresponds to the weight of emphasis placed on Conceptual additions for the given year. This factor only adjusts the expected on peak values.
40. For line 16d, **Net Conceptual Resources After Confidence Percentage Is Applied**, line 8 times line 16c.
41. For line 17, **Target Reserve Margin**, enter a value between 0 and 100 that represents the expected target margin (%) set by the Region/subregion. If no value is entered, a reference margin level will be applied and it is assumed this value will remain constant throughout the reporting period.

NOTES FOR MARGINS:

Capacity margin (C) and reserve margins (R) calculations are computed by NERC and submitted on behalf of the Region or subregion.

42. For line 18**, Existing Certain and Net Firm Transactions**, take the difference between line 12 and line 3. Divide by line 3 for the reserve margin and divide by line 12 for the capacity margin.
43. For line 19, **Anticipated Capacity Resources**, take the difference between line 13 and line 3. Divide by line 3 for the reserve margin and divide by line 13 for the capacity margin.
44. For line 20, **Prospective Capacity Resources**, take the difference between line 14 and line 3. Divide by line 3 for the reserve margin and divide by line 14 for the capacity margin.
45. For line 21, **Total Potential Resources**, take the difference between line 15 and line 3. Divide by line 3 for the reserve margin and divide by line 15 for the capacity margin.
46. For line 22, **Adjusted Potential Resources**, take the difference between line 15a and line 3. Divide by line 3 for the reserve margin and divide by line 15a for the capacity margin.

NOTES FOR LINES 23, 24, AND 25:

This information comes from other EIA data collection (Form EIA-860 and Form EIA-861), and NERC is not obligated to supply this information. These categories are placed here for informational purposes so that the public will be aware of other capacity, which may need to be included in some analyses. The public can acquire this information from the EIA websites for the forms listed above.

SCHEDULE 5. BULK ELECTRIC TRANSMISSION SYSTEM MAPS

1. Each Regional Entity is to submit a map(s), in electronic format, showing the existing bulk electric transmission system 100 kV and above, including ties to all other Regional Entities, and the bulk electric transmission system additions projected for a ten-year period beginning with the year following the reporting year. The submission of Computer-Aided Design and/or Computer-Aided Design and Drafting (CAD/CADD) file types is also allowed.
2. Only major geographic features and State boundaries, bulk electric facilities, and the names of major metropolitan areas need be shown. The map scale to be used is left to the discretion of the Regional Entity or Reporting Party, but should be such as to allow convenient use of the map. Show the voltage level of all bulk electric transmission lines. The year of installation of all projected system additions may be shown at the option of the Regional Entity or Reporting Party.
3. The map requirement may be satisfied by either:
   - (a) A single map in electronic format showing the existing bulk electric transmission system as of January 1 of the reporting year and system additions for a ten-year period beginning with the reporting year; or
   - (b) Separate maps for a set of subregions that comprise the whole region.
4. For Line 1, enter the number of maps provided.
5. For Line 2, enter the requested map information in columns (a) through (d).

SCHEDULE 6 PART A & B: EXISTING AND PROJECTED TRANSMISSION CIRCUIT MILES AND CHARACTERISTICS OF PROJECTED TRANSMISSION ADDITIONS

PART A: Existing Transmission Circuit Miles

1. For the following lines, report transmission lines in WHOLE number circuit miles for the specified voltages:

Operative Voltage Range(kV)	Voltage Type	
100-120	AC	--
121-150	AC	--
151-199	AC	--
100-299	--	DC
200-299	AC	--
300-399	AC	DC
400-599	AC	DC
600+	AC	DC

2. All transmission lines must be classified into one of the following categories:

- **Existing**
    - o Energized line available for transmitting power
- **Under Construction**
    - o Construction of the line has begun
- **Planned (any of the following)**
    - o Permits have been approved to proceed
    - o Design is complete
    - o Needed in order to meet a regulatory requirement
- **Conceptual (any of the following)**
    - o A line projected in the transmission plan
    - o A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”
    - o Projected transmission lines that are not “Under Construction” or “Planned”

3. For line 1, report Existing transmission lines as of the last day in the prior reporting year. (For example, the 2011 Report Year, enter the amount of circuit miles existing as of 12/31/2010.)
4. For line 2, report Under Construction transmission lines as of the first day in the current reporting year. (For example, the 2011 Report Year, enter the amount of circuit miles existing as of 1/1/2011.)
5. For line 3, report Planned transmission lines to be completed within the first 5 years starting the first day in the current reporting year.
6. For line 4, report Conceptual transmission lines to be completed within the first 5 years starting the first day in the current reporting year.
7. For line 5, report Planned transmission lines to be completed within the second 5 years starting the first day of the 5th projection year.
8. For line 6, report Conceptual transmission lines to be completed within the second 5 years starting the first day of the 5th projection year.
9. For line 7, report the sum of all Existing, Under Construction, and Planned transmission line circuit miles for the ten year projection period.
10. For line 8, report the sum of all Existing, Under Construction, Planned, and Conceptual transmission line circuit miles for the ten year projection period.

PART B: Characteristics of Projected Transmission Line Additions

1. This SCHEDULE must be completed by each Regional Entity for all transmission line additions at 100 kV and above projected for the ten-year period beginning with the first day of the current reporting year.
2. For transmission classified as Conceptual, the assumptions used during the transmission planning process and in the planning models are to be reported in this schedule.
3. For line 1, Project Name, enter the project name
4. For line 2, Project Status, enter the level of certainty defined by the following criteria:
   - **Under Construction**
     - Construction of the line has begun
   - **Planned (any of the following)**
     - Permits have been approved to proceed
     - Design is complete
     - Needed in order to meet a regulatory requirement
   - **Conceptual (any of the following)**
     - A line projected in the transmission plan
     - A line that is required to meet a NERC TPL Standard or powerflow model and cannot be categorized as “Under Construction” or “Planned”
     - Projected transmission lines that are not “Under Construction” or “Planned”

5. For line 3, **Tie line**, specify whether this addition interconnects Balancing Authorities (YES/NO).
6. For line 4a & 4b, **Primary** and **Secondary Driver**, specify drivers from the following list:
   - Reliability
   - Generation integration
     - Variable/Renewable (identify by source or combination of sources)
     - Nuclear
     - Fossil-Fired (identify by source or combination of sources)
     - Hydro
   - Congestion Relief
   - Other (please specify in Schedule 9, Comments)

7. For line 5, **Terminal Location (From)**, enter the name of the beginning terminal point of the line.
8. For line 6, **Terminal Location (To)**, enter the name of the ending terminal point of the line.
9. For line 7, **Company Name**, enter the company name.
10. For line 8, **EIA Company Code**, identify each organization by the six-character code assigned by EIA.
11. For line 9, **Type of Organization**, identify the type of organization that best represents the line owner including the following types of utilities – Investor-owned (I), Municipality (M), Cooperative (C), State-owned (S), Federally-owned (F), or other (O).
12. For line 10, **Percent Ownership**, if the transmission line will be jointly-owned, enter the percentages owned by each transmission owner.
13. For line 11, Circuit **Line Length**, enter the number of circuit line miles between the beginning and ending terminal points of the line.
14. For line 12, **Line Type**, select physical location of the line conductor – overhead (OH), underground (UG), or submarine (SM).
15. For line 13, **Voltage Type**, select voltage as alternating current (AC) or direct current (DC).
16. For line 14, **Voltage Operating**, enter the voltage at which the line will be normally operated in kilovolts (kV).
17. For line 15, **Voltage Design**, enter the voltage at which the line is designed to operate in kilovolts (kV).
18. For line 16, **Conductor Size**, enter the size of the line conductor in thousands of circular mils (MCM).

19. For line 17, **Conductor Material Type**, enter the line conductor material type – aluminum, ACCR, ACSR, copper, superconductor, or other.
20. For line 18, **Bundling Arrangement**, enter the bundling arrangement/configuration of the line conductors – single, double, triple, quadruple, or other.
21. For line 19, **Circuits per Structure Present,** enter the current number of three-phase circuits on the structures of the line.
22. For line 20, **Circuits per Structure Ultimate**, enter the ultimate number of three-phase circuits that the structures of the line are designed to accommodate.
23. For line 21, **Pole/Tower Type**, identify the predominant pole/tower material for the line – wood, concrete, steel, combination, composite material, or other. Also include the type of structure – single pole, H-frame structure, tower, underground, or other.
24. For line 22, **Capacity Rating**, enter the normal load-carrying capacity of the line in millions of volt-amperes (MVA).
25. For line 23, **Original In-Service Date**, enter the originally projected date the line was to be energized under the control of the system operator.
26. For line 24, **Expected In-Service Date**, enter the currently projected date the line will be energized under the control of the system operator.
27. For line 25, **Line Delayed**, enter “Y” if the line has been delayed and “N” if it has not.
28. For line 26, **Cause of Delay**, if the line has been delayed, enter the cause.

SCHEDULE 7. ANNUAL DATA ON TRANSMISSION LINE OUTAGES FOR EHV LINES, GENERAL INSTRUCTIONS FOR PARTS A, B, C, and D

Outages are defined below for purposes of reporting on this schedule and are intended to be consistent with the instructions and definitions in the NERC Transmission Availability Data System (TADS) Data Reporting Instruction Manual and TADS Definitions (Appendix 7 of the Instructions) at http://www.nerc.com/page.php?cid=4|62 An **Element** includes certain specified voltage classes of AC Circuits, DC Circuits, and Transformers. An **In-Service State** means an Element that is energized and connected at all its terminals to the system.

Outages that occur on intertie lines between regions are to be reported only once by one or the other of the reporting regions. Outages on lines that cross international borders must be reported.

Automatic Outages

An **Automatic Outage** is an outage which results from the automatic operation of a switching device, causing an Element to change from an In-Service State to a not In-Service State. A successful AC single-pole (phase) reclosing event is not an Automatic Outage. If practices are different from this, please note in SCHEDULE 9 Comments.

- A **Sustained Outage** is an Automatic Outage with an Outage Duration of a minute or greater.
- A **Momentary Outage** is an Automatic Outage with an Outage Duration of less than one (1) minute. Momentary outages <u>should not be included</u>.

An **Event** is a transmission incident that results in the Automatic Outage (Sustained or Momentary) of one or more Elements.

Non-Automatic Outages

A **Non-Automatic Outage** is an outage which results from the manual operation (including supervisory control) of a switching device, causing an Element to change from an In-Service State to a not In-Service State. If practices are different from this, please note in SCHEDULE 9 Comments.

- A **Planned Outage** is a Non-Automatic Outage with advance notice for the purpose of maintenance, construction, inspection, testing, or planned activities by third parties that may be deferred. Outages of Elements of 30 minutes or less in duration resulting from switching steps or sequences that are performed in preparation for or restoration from an outage of another Element are not reportable.
- An **Operational Outage** is a Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred.

Automatic Outage Causes

- **Weather, excluding lightning,** covers all outages in which severe weather conditions (snow, extreme temperature, rain, tornado, hurricane, ice, high winds, etc.) are the primary cause of the outage, with the exception of lightning. This includes flying debris caused by wind.
- **Lightning**
- **Environmental,** includes environmental conditions such as earth movement (earthquake, subsidence, earth slide), flood, geomagnetic storm, or avalanche.
- **Foreign Interference,** includes objects such as aircraft, machinery, vehicles, kites, events where animal movement or nesting impacts electrical operations, flying debris not caused by wind, and falling conductors from one line into another.
- **Contamination,** covers outages caused by bird droppings, dust, corrosion, salt spray, industrial pollution, smog, or ash.
- **Fire,** includes outages caused by fire or smoke.
- **Vandalism, Terrorism, or Malicious Acts,** includes intentional activity such as gunshots, removed bolts, or bombs.
- **Failed AC Substation Equipment,** includes equipment inside the substation fence, but excludes protection system equipment.
- **Failed AC/DC Terminal Equipment,** includes equipment inside the terminal fence, including power-line carrier filters, AC filters, reactors and capacitors, transformers, DC valves, smoothing reactors, and DC filters. This excludes protection system equipment.
- **Failed Protection System Equipment,** includes any relay and/or control misoperations except those that are caused by incorrect relay or control settings that do not coordinate with other protective devices (these should be categorized as Human Error)
- **Failed AC Circuit Equipment,** includes overhead or underground equipment outside the substation fence.
- **Failed DC Circuit Equipment,** includes equipment outside the terminal fence.
- **Human Error,** covers any incorrect action traceable to employees and/or contractors for companies operating, maintaining, and/or providing assistance to the utility. This includes any human failure or interpretation of standard industry practices and guidelines that cause an outage.
- **Power System Condition,** include instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations.
- **Vegetation**, includes outages initiated by vegetation in the proximity of transmission facilities. Reporting definition will be consistent with the NERC template and vegetation management criteria.
- **Unknown**, any unknown causes should be reported in this category.
- **Other**, includes outages for which the cause is known; however, the cause is not included in the above list.

Non-Automatic, Operational Outage Causes

- **Emergency,** includes outages taken to avoid risk to human life, damage to equipment, damage to property, or similar threatening consequences
- **System Voltage Limit Mitigation,** covers outages taken to maintain the voltage on the transmission system within desired levels (i.e., voltage control).
- **System Operating Limit Mitigation,** (excluding voltage limit mitigation) covers outages

taken to keep the transmission system within System Operating Limits, including facility ratings, transient stability ratings, and voltage stability ratings covering MW, MVar, Amperes, Frequency, or Volts.

- **Other Operational Outage**, includes all other causes, including human error.

Non-Automatic, Planned Outage Causes

- **Maintenance and Construction** covers any planned outage associated with maintenance and construction of electric facilities, including testing.
- **Third Party Requests,** covers outages taken at the request of a third party such as highway department, Coast Guard, etc.
- **Other Planned Outage**, includes all other causes, including human error.

<u>PART A: Annual Data on AC Transmission Line Outages</u>

1. All transmission line outages involving Extra High Voltage (EHV) **AC Circuit Elements** of 200 kV and above are to be aggregated by each Regional Entity and reported on this schedule.
2. For the appropriate outage type (Automatic; Non-Automatic, Planned; or Non-Automatic, Operational), enter the following:
   - **Number of Outages** (lines 2, 5, and 8), report the total number of outages that occurred in the reporting period for each voltage class.
   - **Number of Circuit-Hours Out of Service** (lines 3, 6, and 9), report the total circuit-hours out of service for all of the outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was not in an In-Service State during the reporting period.
   - **Outage Cause** (lines 4, 7, and 10), report the number of outages by the pertinent cause code, as listed above. For Automatic Outages, report the number of outages for both the **Initiating Cause** and the **Sustained Cause**. For the Sustained Cause, use the Cause Code that describes the cause that contributed to the longest duration of the outage.

<u>PART B: Annual Data on DC Transmission Line Outages</u>

3. All transmission line outages involving Extra High Voltage (EHV) **DC Circuit Elements** of ±100 kV and above are to be aggregated by each Regional Entity and reported on this schedule.
4. For the appropriate outage type (Automatic; Non-Automatic, Planned; or Non-Automatic, Operational), enter the following:
   - **Number of Outages** (lines 2, 5, and 8), report the total number of outages that occurred in the reporting period for each voltage class.
   - **Number of Circuit-Hours Out of Service** (lines 3, 6, and 9), report the total circuit-hours out of service for all of the outages for each voltage class during the year. This is the sum across all circuits of the number of hours each circuit was not in an In-Service State during the reporting period.
   - **Outage Cause** (lines 4, 7, and 10), report the number of outages by the pertinent cause code, as listed above. For Automatic outages, report the number of outages for both the **Initiating Cause** and the **Sustained Cause**. For the Sustained Cause, use the Cause Code that describes the cause that contributed to the longest duration of the outage.

<u>PART C: Annual Data on Transformer Outages</u>

5. All transformer outages involving **Transformer Elements** with a <u>low-side voltage</u> of ≥200 kV are to be aggregated by each Regional Entity and reported on this schedule.
6. For the appropriate outage type (Automatic; Non-Automatic, Planned; or Non-Automatic, Operational), enter the following:
   - **Number of Outages** (lines 2, 5, and 8), report the total number of outages that occurred in the reporting period for each voltage class based on the <u>high-side voltage</u> of the

transformer.

- **Number of Transformer-Hours Out of Service** (lines 3, 6, and 9), report the total transformer-hours out of service for all of the outages for each voltage class (by high-side voltage) during the year. This is the sum across all transformers of the number of hours each transformer was not in an In-Service State during the reporting period.
- **Outage Cause** (lines 4, 7, and 10), report the number of outages by the pertinent cause code, as listed above. For Automatic outages, report the number of outages for both the **Initiating Cause** and the **Sustained Cause**. For the Sustained Cause, use the Cause Code that describes the cause that contributed to the longest duration of the outage.

PART D: Element Inventory and Event Summary

The **Element** inventory data collected on Part D can be used to normalize the outage data collected on Parts A, B, and C. The Event summary data can be used to compare with outage totals collected on Parts A, B, and C.

1. For line 1, report in accordance with the applicable voltage class indicated..
2. For line 2, an AC Circuit is a set of overhead or underground three-phase conductors that are bound by AC substations. Radial circuits are AC Circuits.
3. For line 2a, enter the **Number of Overhead AC Circuits** in each voltage class.
4. For line 2b, enter the **Number of Underground AC Circuits** in each voltage class.
5. For line 3, an AC Circuit Mile is one mile of a set of three-phase AC conductors in an Overhead or Underground AC Circuit
6. For line 3a, enter the **Number of Overhead AC Circuit Miles** in each voltage class.
7. For line 3b, enter the **Number of Underground AC Circuit Miles** in each voltage class.
8. For line 4, enter the **Number of Multi-Circuit Structure Miles** in each voltage class. A Multi-Circuit Structure Mile is a one-mile linear distance of sequential structures carrying multiple Overhead AC Circuits. (Note: this definition is *not* the same as the industry term “structure mile.” A Transmission Owner’s Multi-Circuit Structure Miles will generally be less than its structure miles since not all structures contain multiple circuits.)
9. For line 5, report in accordance with the applicable voltage class indicated.
10. For line 6, a DC circuit is one pole of an overhead or underground line which is bound by an AC/DC Terminal on each end.
11. For line 6a enter the **Number of Overhead DC Circuits** in each voltage class.
12. For line 6b, enter the **Number of Underground DC Circuits** in each voltage class.
13. For line 7, a DC Circuit Mile is one mile of one pole of a DC Circuit.
14. For line 7a, enter the **Number of Overhead DC Circuit Miles** in each voltage class.
15. For line 7b, enter the **Number of Underground DC Circuit Miles** in each voltage class.
16. For line 8, report in accordance with the applicable voltage class indicated based on the high-side voltage of the Transformer. Note: To be reported on this form, the Transformer must have a low-side voltage ≥200 kV.
17. For line 9, enter the **Number of Transformers** in each voltage class. A Transformer is a bank of three single-phase transformers or a single three-phase transformer. A Transformer is bounded by its associated switching or interrupting devices.
18. For line 10, enter the total annual **Number of Events** associated with the outages reported on Schedules 7A, 7B, and 7C.

SCHEDULE 8. BULK TRANSMISSION FACILITY POWER FLOW CASES

1. Each Regional Entity is to coordinate the collection of data on basic electrical data and power flow information on prospective new bulk transmission facilities of 100 kV and above (including lines, transformers, HVDC terminal facilities, phase shifters, and static VAR compensators) that have been approved for construction and are scheduled to be energized over the next two years.
2. If the prospective bulk transmission facilities are represented in the respondent’s current FERC Form 715 submission, please provide a copy of an annual peak load power flow case

submitted which represents a period of at least two years into the future and complete (see Instructions 6 through 13).

3. If the facilities are not represented in the respondent's current FERC Form 715 submission, please submit a power flow case(s) representing the prospective facilities. The respondent may submit a single annual peak load power flow case that includes all prospective facilities to be energized in the next two years. Alternatively, the respondent may provide a copy of any annual peak load power flow case that includes the new facility for the year it is to be energized. If more than one facility is to be energized in a given year, it is acceptable to provide a single annual peak load power flow case that includes all the new facilities added in that year. The power flow shall be in the same format as used for the respondent's FERC Form 715 filing.
4. For each power flow case that is provided in response to Items 2 and 3 above, please identify on SCHEDULE 8 all prospective facilities that are not currently in service and the projected in-service date of those facilities. Complete one page for each new power flow case. In each case, identify only the new facility by type and list bus numbers and names that the new facility is connected with electrically.
5. The EIA expects that in nearly all cases the power flow format will be one of the following:
    - The Raw Data File format of the PTI (Power Technologies, Inc.) PSS/E power flow program;
    - The Card Deck Image format of the Philadelphia Electric power flow program;
    - The Card Deck format of the WSCC power flow program;
    - The Raw Data File format of the General Electric (formerly Electric Power Consultant, Inc. or EPC), or the PSLF power flow program; or
    - The IEEE Common Format for Exchange of Solved Power Flows.

    Respondents submitting their own cases must supply the input data to the solved base cases and associated ACSII output data on compact disk in the format associated with the power flow program used by the respondents in the course of their transmission studies, as described above.
6. For Line 1, enter the case name.
7. For Line 2, enter the year studied in this power flow case.
8. For Line 3, enter the case number assigned by respondent.
9. For Line 4, column a, enter the name and type (e.g. line transformer, etc.) of a prospective facility included on the power flow case.
10. For Line 4, column b, enter the projected in-service date of the proposed facility. Please provide month and year (e.g., 12-2004).
11. For Line 4, column c and d, enter the number and name respectively of each bus to which the facility is connected. Use one line for each bus.
12. Repeat Instructions 9 through 12 for each prospective facility.

SCHEDULE 9. COMMENTS

Identify each comment by the appropriate schedule, part, line number, column identifier and page number. Use additional sheets, as required. (Any comment referencing sensitive information will be considered sensitive.)

U.S. Department of Energy U.S. Energy Information Administration Form EIA-411 (2011)	*COORDINATED BULK POWER SUPPLY AND DEMAND PROGRAM REPORT*	Form Approved OMB No. 1905-0129 Approval Expires: 12/31/2013 Burden: 17 hours

GLOSSARY	The glossary for this form is available online at the following URL: http://www.eia.gov/glossary/index.html For NERC definitions, see www.nerc.com, or this EIA copy at: http://www.eia.gov/cneaf/electricity/page/eia411/nerc_glossary_2009.pdf
SANCTIONS	The timely submission of Form EIA-411 by those required to report is requested under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. Failure to respond may result in a penalty of not more than $2,750 per day for each civil violation, or a fine of not more than $5,000 per day for each criminal violation. The government may bring a civil action to prohibit reporting violations, which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. **Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**
REPORTING BURDEN	Public reporting burden for this collection of information is estimated to be 120 hours per response for the Regional Entities and NERC, and 16 hours per response for the members within each council, including the time of reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. **The weighted average burden for the Form EIA-411 is 17 hours.** The burden includes not only the hours needed by the Regional Entities and NERC, but also for the members within each council. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the U.S. Energy Information Administration, Statistics and Methods Group, EI-70, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585-0670; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. A person is not required to respond to the collection of information unless the form displays a valid OMB number.
PROVISIONS REGARDING THE CONFIDENTIALITY OF INFORMATION	The information contained on SCHEDULE 5, Bulk Electric Transmission System Maps, SCHEDULES 7A, 7B, and 7C, Annual Data on AC and DC Transmission Line and Transformer Outages, and SCHEDULE 8, Bulk Transmission Facility Power Flow Cases, will be protected and not disclosed to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905. All other information reported on Form EIA-411 are considered public information and may be publicly released in company identifiable form. The Federal Energy Administration Act requires the EIA to provide company-specific data to other Federal agencies when requested for official use. The information reported on this form may also be made available, upon request, to another component of the Department of Energy (DOE) to any Committee of Congress, the Government Accountability Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order. The information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes. Disclosure limitation procedures are applied to the protected statistical data published from SCHEDULES 5, 7, and 8, on Form EIA-411 to ensure that the risk of disclosure of identifiable information is very small.