Independent Statistics & Analysis U.S. Energy Information Administration	**FORM EIA-861 ANNUAL ELECTRIC POWER INDUSTRY REPORT INSTRUCTIONS**	**Approval: OMB No. 1905-0129** **Approval Expires: 3/31/2020** **Burden Hours: 12.75**

PURPOSE	Form EIA-861 collects information on the status of electric power industry participants involved in the generation, transmission, distribution, and sale of electric energy in the United States and its territories. The data from this form are made available in EIA publications and databases. The data collected on this form are used 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-861 is to be completed by electric power industry entities such as, but not limited to, electric utilities, all Demand Side Management (DSM) Program Managers (entities responsible for conducting or administering a DSM program), wholesale power marketers, energy service providers, electric power producers, transmission owners, transmission operators, and Third Party Owners of solar PV (TPO). Responses are collected at the operating company level (not at the holding company level).
RESPONSE DUE DATE	Submit the completed Form EIA-861 to the EIA by **May 16**, following the end of the calendar year.
METHODS OF FILING RESPONSE	Submit your data electronically using EIA's secure internet data collection system (e-file). This system uses security protocols to protect information against unauthorized access during transmission. • If you have not registered with EIA's Single Sign-On system, send an email requesting assistance to the Form EIA-861 mailbox. • If you have registered with Single Sign-On, log on at https://signon.eia.gov/ssoserver/login **Please retain a completed copy of this form for your files.**
CONTACTS	***Internet System Questions***: For questions related to e-file, see the help contact information immediately above. ***Data Questions:*** For questions about the data requested on Form EIA-861, contact the Survey Manager: Stephen Scott 202 586-5140 Email: Stephen.Scott@eia.gov FAX Number: 202-287-1938 Email: EIA-861@eia.gov

GENERAL INSTRUCTIONS

1. Respondents, who also submit the Form EIA-861M (Formerly EIA-826), “Monthly Electric Power Industry Report" should coordinate the information submitted on the Form EIA-861 and Form EIA-861M to ensure consistency.

2. For paper forms only, complete the information at the top portion of the form with the name, telephone and FAX number, and email address of the current contact person and the contact person’s supervisor.

3. Report peak demand in megawatts and energy values (e.g., generation and sales) in megawatthours, except where noted. One megawatthour equals 1,000 kilowatthours. To convert kilowatthours to megawatthours, divide by 1,000 and round to the nearest whole number. For example, sales of 5,245,790 kilowatthours should be reported as 5,246 megawatthours.

4. Report in whole numbers (i.e., no decimal points), except where explicitly instructed to report otherwise. For example: revenue of $8,459,688.42 should be reported as 8,460 (thousand dollars). There is one decimal place in the revenue on Schedules 2C and 4. Lines 2 and 4 on Schedule 6A and lines 3 and 4 on Schedule 6B also contain one decimal point.

5. For the on-line form only, a State Code can only be removed by highlighting the state and clicking on the **‘Remove record’** button**.** (Schedules 3A-C, 4A-D, 6A-D, 7A and 7B).

6. For number of customers, enter the average of the 12 close-of-month customer accounts.

   - All respondents having end-use customers, including retail power marketers selling power in deregulated, competitive state programs must use the average of the 12 close-of-month customer counts when reporting on Schedule 4, even if your company began business after the beginning of the reporting year, or ended business before the close of the year.

   - Count each meter as a separate customer in cases where commercial franchises or residential customer-buying groups have been aggregated under one buyer representative. The customer counts for public street and highway lighting should be one customer per community.

   - Please do not count each pole as a separate customer even if billing is by a flat rate per pole per month.

7. Use a minus sign for reporting negative numbers. Line 9 on Schedule 2B must be a negative number. On Schedule 2B, line 1 and Schedule 2C, lines 4 and 6, the number may be either positive or negative.

8. Where exact data are unavailable, report estimated data.

9. See the Glossary for terms used in this survey. The financial and accounting terms are consistent as outlined in the Uniform System of Accounts for Public Utilities and Licensees (U.S. of A.) (18 CFR Part 101).

Ownership Codes

Municipal Marketing Authority (A): Voted into existence by the residents of a municipality and given authority for creation by the state government. They are nonprofit organizations.

Behind the Meter (B): Entities that install, own, and/or operate a system (usually photovoltaic), and sell, under a long term power purchase agreement (PPA) or lease, all the production from the system to the homeowner or business with which there is a net metering agreement. **Third Party Owners (TPOs)** of PV solar installations use this ownership code.

Cooperative (C): Member-owned organizations.

Nonutility DSM Administrator (D): Only involved with Demand-Side Management activities.

Federal (F): Government agencies with the authority to deliver energy to end-use customers.

Community Choice Aggregation (G): Public agency that aggregates end user's electricity demand for a particular area and manages supply for those users.

Investor-Owned Utilities (I): Entities that are privately owned and provide a public service.

Municipal (M): Entities that are organized under authority of state statute to provide a public service to residents of that area.

Political Subdivision (P) (also called "public utility district"): Independent of city or county government and voted into existence by a majority of the residents of any given area for the specific purpose of providing utility service to the voters. State laws provide for the formation of such districts.

Independent Power Producer or Qualifying Facility (Q): Entities that own power plants and sell their power into the wholesale market.

Retail Power Marketer (R) or Energy Service Provider: Entities that market power to customers in restructured markets.

State (S): Entities that own or operate facilities or provide a public service.

Transmission (T): Entities that operate or own high voltage transmission wires that provide bulk power services.

Wholesale Power Marketer (W): Entities that buy and sell power in the wholesale market.

SCHEDULE 1: IDENTIFICATION

1. **Survey Contact:** Verify contact name, title, email address, telephone number, fax number.

2. **Supervisor of Contact Person for Survey:** Verify the contact's supervisor's name, title, address, telephone number, fax number and email address. **Supervisor contact must be different than the survey contact.**

If any of the above information is incorrect or missing, please send revisions to EIA-861@eia.gov.

Entity and Preparer Information

3. **Legal Name of Entity:** Enter the legal name of the entity for which this form is being prepared.

4. **Current Address of Entity's Principal Business Office:** Enter the complete address, excluding the legal name, of the entity's principal business office (i.e., headquarters, main office, etc.).

5. **Preparer's Legal Name:** Enter the legal name of the company that prepares this form, if different from the **Legal Name of Entity**.

6. **Current Address of Preparer's Office:** Enter the address to which correspondence regarding this form should be mailed, if different from the **Current Address of Entity's Principal Business Office**. Include an attention line, room number, building designation, etc. to facilitate the future handling and processing of the Form EIA-861.

SCHEDULE 2, PART A: GENERAL INFORMATION

1. For line 1, please check all of the Regional Entities within the North American Electric Reliability Corporation (NERC), in which your organization conducts operations.

   The Regional Entities are:

   - TRE (Texas Reliability Entity [ERCOT])
   - FRCC (Florida Reliability Coordinating Council)
   - MRO (Midwest Reliability Organization)
   - NPCC (Northeast Power Coordinating Council)
   - RFC (ReliabilityFirst Corporation)
   - SERC (SERC Reliability Corporation)
   - SPP (Southwest Power Pool, RE)
   - WECC (Western Electricity Coordinating Council)

2. For line 2, select the RTO or ISO from the list:

   - California ISO
   - Electric Reliability Council of Texas
   - Southwest Power Pool
   - Midwest ISO
   - PJM Interconnection
   - New York ISO
   - ISO New England
   - None

3. For line 4, **Operate Generating Plant(s)**, check 'Yes' to indicate that your organization operated at least one generating plant during the reporting period. Otherwise, check 'No.'

4. For line 5, **Activities**, check the appropriate activities the electric entity was engaged in during the reporting year. If your activity is not listed on line 5, include in Schedule 9. At least one activity must be provided.

   - **Generation from company owned plant.** Owned power generation.
   - **Transmission.** Owned or leased transmission lines.
   - **Buying transmission services on other electrical systems.** Types of services include borderline customers, transmission line rental, transmission capacity, transmission wheeling, and system operational services.
   - **Distribution using owned/leased electrical wires.** Power delivery to your own end-use customers over distribution facilities.
   - **Buying distribution on other electrical systems.** Types of support include customer billing, distribution system support charges for energy delivered, line maintenance, and/or equipment charges.
   - **Wholesale power marketing.** Wholesale transactions with other electric utilities, purchases from power producers, and transactions to export and/or import electricity to or from Canada or Mexico. Also includes electrical sales and purchases among Federal Energy Regulatory Commission (FERC) registered power marketers and similar participation in transactions with electric utilities.
   - **Retail power marketing.** Provision of electrical energy to end-use customers in areas where the customer has been given the legal right to select a power supplier other than the "traditional electric utility."
   - **Combined services.** Provision of electricity in combination with gas, water, cable, Internet, and/or telephone for a single price.

5. For line 6, **Highest Hourly Electrical Peak System Demand (MW)**, electric utility companies should enter the maximum hourly summer load (for the months of June through September) based on net energy for the system during the reporting year. Net energy for the system is the sum of energy an electric utility needs to satisfy their service area and includes full and partial wholesale requirements customers, and the losses experienced in delivery. The maximum hourly load is determined by the interval in which the 60-minute integrated demand is the greatest. If such data are unavailable, adjust available data to approximate a 60-minute demand interval and explain the adjustment on Schedule 9 (**Footnotes)**. If adjustments cannot be made, furnish data as available and explain on Schedule 9. For winter, enter the maximum hourly winter load (for months of January through March, and the previous December) based on the net energy for the system during the reporting year. Please note: These data elements should be provided in megawatts, to the nearest tenth.

6. For line 7, **Alternative-Fueled Vehicles**, check 'Yes' to indicate that your company owns/operates, or plans to own and operate, alternative-fueled vehicles; otherwise check 'No.' If "Yes," provide the name, title, FAX number, telephone number, and address of a contact person. Note: For the purpose of this question, an "alternative-fueled vehicle" is either designed or manufactured by an original equipment manufacturer or is a converted vehicle designed to operate in either dual-fuel, flexible-fuel, or dedicated modes on fuels other than gasoline or diesel. This does not include a conventional vehicle that is limited to operation on blended or reformulated gasoline fuels.

SCHEDULE 2, PART B: ENERGY SOURCES AND DISPOSITION

1. Enter the annual megawatthours (MWH) for all sources of electricity and disposition of electricity listed.

2. For line 1, **Net Generation**, enter the net generation (gross generation minus station use) from all respondent-owned plants. If a plant is jointly owned, enter only the reporting party's share of generation. Include generation used to replace system losses arising from wheeling transactions. Include net generation supplied as part of a tolling arrangement.

3. For line 2, **Purchases from Electricity Suppliers**, enter the total amount of energy purchased from electricity suppliers including: nonutility power producers and power marketers (reported separately in previous years), municipal departments and power agencies, cooperatives, investor-owned utilities, political subdivisions, state agencies and power pools, and marketing agencies of the United States Government and Canada; these agencies include Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), Western Area Power Administration (WAPA), Tennessee Valley Authority (TVA), United States Army Corps of Engineers, the United States Bureau of Reclamation, United States Bureau of Indian Affairs, International Boundary and Water Commission, Hydro-Quebec, etc. This entry includes requirements power, firm power, and all other non-firm service. Note: Please identify on Schedule 9, **Footnotes**, the portion of purchased power obtained through tolling arrangements and international purchases.

4. For line 3, **Exchanges Received (In)**, enter the amount of exchange energy received. Do not include power received through tolling arrangements.

5. For line 4, **Exchanges Delivered (Out)**, enter the amount of exchange energy delivered. Do not include power delivered as part of a tolling arrangement.

6. For line 5, **Exchanges (Net)**, enter the net amount of energy exchanged. Net exchange is the difference between the amount of exchange received and the amount of exchange delivered (lines 3 and4). This entry should not include wholesale energy purchased from or sold to regulated companies or unregulated companies for other systems.

7. For line 6, **Wheeled Received (In)**, enter the total amount of energy entering your system from other systems for transmission through your system (wheeling) for delivery to other systems. Do not report as Wheeled Received, energy purchased or exchanged for consumption within your system, which was wheeled to you by others.

8. For line 7, **Wheeled Delivered (Out)**, enter the total amount of energy leaving your system that was transmitted through your system for delivery to other systems. If Wheeling Delivered is not precisely known, please estimate based on your system's known percentage of losses for wheeling transactions.

9. For line 8, **Wheeled (Net)**, enter the difference between the amount of energy entering your system for transmission through your system and the amount of energy leaving your system (line 6 minus line 7). Wheeled net represents the energy losses on your system associated with the wheeling of energy for other systems.

10. For line 9, **Transmission by Others, Losses**, enter the amount of energy losses associated with the wheeling of electricity provided to your system by other utilities. Transmission by Others, Losses should always be expressed as a **negative** value.

11. For line 11**, Sales to Ultimate Customers**, enter the amount of electricity sold to customers purchasing electricity for their own use and not for resale. This entry should correspond to the revenue from sales to

ultimate customers reported on Schedule 2 Part C, line 1, and should be equal to the total megawatthours reported on Schedule 4, Parts A, B and D, when summed for all reported states.

12. For line 12, **Sales for Resale**, enter the amount of electricity sold for resale purposes. This entry should include sales for resale to power marketers (reported separately in previous years), full and partial requirements customers, firm power customers, and non-firm customers. This entry should also correspond to the revenue from sales for resale reported in Schedule 2 Part C, line 3. Note: Please identify on Schedule 9, the portion of sales for resale power sold through tolling arrangements and any international sales.

13. For line 13, **Energy Furnished without Charge**, enter the amount of electricity furnished by the electric utility without charge, such as to a municipality under a franchise agreement or for public street and highway lighting. This entry does not include data entered in line 14.

14. For line 14, **Energy Consumed by Respondent without Charge**, enter the amount of electricity used by the electric utility in its electric and other departments without charge. This entry does not include data entered in line 13.

15. For line 15, **Total Energy Losses**, enter the total amount of electricity lost from transmission, distribution, and/or unaccounted for. This is the difference between line 10, "**Total Sources**," and the sum of lines 11, 12, 13, and 14. Total Energy Losses should always be expressed as a positive value.

SCHEDULE 2, PART C: ELECTRIC OPERATING REVENUE

1. All electric operating revenue data should be rounded to the nearest tenth and reported in thousand dollars; for example, revenue of $8,461,688.42 should be reported as 8,461.7 (thousand dollars).

2. For line 1, **Electric Operating Revenue from Sales to Ultimate Customers**, enter the amount of revenue from sales of electricity to those customers purchasing electricity for their own use and not for resale. Revenue reported on Schedule 4C, for delivery service (and all other charges) should **not** be reported on Schedule 2C, line 1, but should be reported in Schedule 2C, line 2, **Revenue from Unbundled (Delivery) Customers**. Revenue entered on line 1 is gross revenue and includes the revenue from state and local income taxes, energy or demand charges, customer service charges, environmental surcharges, franchise fees, fuel adjustments and other miscellaneous charges applied to end-use customers during normal billing operations. Revenue entered on line 1should not include deferred charges, credits, or other adjustments, such as fuel or revenue from purchased power, from previous reporting periods which are included in Schedule 2C, line 4, **Electric Credits/ Other Adjustments**. Revenue entered on line 1 should correspond to electricity sales reported in Schedule 2B, line 11. (Revenue entered on line 1 should also be the same total revenue reported on Schedule 4, column e (**Total**) for Parts A, B, and D, when summed for all reported states). Revenue entered on line 1 should include all unbilled revenue resulting from power sold during the reporting period.

3. For line 2**, Revenue from Unbundled (Delivery) Customers**, enter the amount of revenue from unbundled customers who purchase their electricity from a supplier other than the electric utility that distributes power to their premises. This electric operating revenue does not include the charges for electric energy but does include the revenue required to cover power delivery. Revenue entered on line 2 should be the same total revenue reported on Schedule 4C, column e, when summed for all states.

4. For line 3, **Electric Operating Revenue from Sales for Resale**, enter the amount of revenue from sales of electricity sold for resale purposes. This entry should include revenue from sales for resale to wholesale or retail power marketers, full and partial requirements customers (firm), and to no

requirements (non-firm) customers. This entry should also correspond to the sales for resale reported in Schedule 2B, line 12.

5. For line 4, **Electric Credits/Other Adjustments**, enter the amount of deferred revenue, which corresponds to Account 449.1 of the Uniform System of Accounts including revenue not applied to end-use or resale customers during the normal billing cycle. Funds included in this entry consist of refunds to customers resulting from rate commission rulings delayed beyond the reporting year in which the funds were originally collected. Also, include revenue distributions to customers from rate stabilization funds where the distribution occurred during the current reporting year but the funds were collected during previous reporting years.

6. For line 5, **Revenue from Transmission,** enter the amount of revenue derived from the transmission of electricity for others (wheeling).

7. For line 6, **Other Electric Operating Revenue**, enter the amount of revenue received from electric activities other than selling electricity. This may include revenue from selling or servicing electric appliances, revenue from the sale of water and water power for irrigation, domestic, industrial or hydroelectric operations, revenue from electric plants leased to others, revenue from the sale of steam, but not including sales made by a steam heating department or transfers of steam under joint facility operations, revenue from interdepartmental rents or sale of electric property, revenue from late fees, penalties or reconnections, and revenue from interest.

SCHEDULE 3, PART A: DISTRIBUTION SYSTEM INFORMATION

For purposes of this schedule, a distribution circuit is any circuit with a voltage of 35kV or below that serves end use customers directly or through step-down transformers or substations. Circuits that are operated in a closed-looped manner, i.e. not operated radially, are called 'networked'. Networks serve key downtown or metropolitan customers. Networks also provide sub-transmission supply to other distribution circuits through step-down transformers or substations. During outages to one or more network circuits, the customers are automatically served by other network circuits with no interruption. For network primary systems, the circuit count includes all circuits that supply the network. Where a circuit with a voltage of 35 kV or below is a source for lower voltage circuits through step-down transformers or substations, the circuits at the higher voltage and the lower voltage are included in the circuit count. Report this schedule if you own distribution lines.

Volt/VAR Optimization (VVO) is a process used by electric distribution companies to actively manage voltage levels and reactive power on distribution circuits in order to reduce energy losses and improve reliability and power quality. VVO is typically achieved through the use of real-time information and controls that activate capacitor banks, voltage regulators, and transformer load tap changers - and in some cases, distributed generation to adjust voltage and VAR levels on the primary and secondary distribution circuits.

1. On line 1 enter the Total Number of Distribution Circuits.

2. On line 2 enter the Total Number of Distribution Circuits that employ voltage/VAR optimization (VVO).

SCHEDULE 3, PART B: DISTRIBUTION SYSTEM RELIABILITY INFORMATION - IEEE

If your entity calculates system average interruption duration index (SAIDI) and/or system average interruption frequency index (SAIFI) answer yes to question 1. If you determine Major Event Days in accordance with the IEEE standard, answer 'yes' to question 2 and complete Part B, otherwise answer 'no' to question 2 and complete Part C. If your entity does not calculate SAIDI and SAIFI answer 'no' to question 1 and go to Schedule 4A.

For lines 3 through 6 complete all that you calculate.

Example 1, if you include all outage data in your SAIDI/SAIFI calculations, fill out the fields under the subtitle 'Including Major Events'.

Example 2, if you do the calculations to find out which outages are major events or Major Event Days, exclude major events or Major Event Days from the data and use the limited remaining data to calculate SAIDI and SAIFI, complete the area under the subtitle 'Excluding Major Events'.

1. The **system average interruption frequency index, or SAIFI**, indicates how often the average customer experiences a sustained interruption (of over 5 minutes) over a predefined period of time. In this schedule report annual SAIFI, or the SAIFI resulting from all interruptions in the reporting year. SAIFI is calculated as the sum over the year of total number of customers that experienced an interruption of more than 5 minutes, divided by the total number of customers.

2. SAIFI = [Sum of total number of customers interrupted over the year] / [Total number of customers served]

3. The **system average interruption duration index, or SAIDI**, indicates the total duration of interruption for the average customer over a predefined period of time. In this schedule report annual SAIDI, or the SAIDI resulting from all interruptions in the reporting year. SAIDI is calculated as the sum over the year of all customers interrupted for more than 5 minutes times the number of minutes they experienced an interruption, divided by total number of customers.

4. SAIDI = [Sum of customer minutes interrupted over the year] / [Total number of customers served]

5. On lines 3 through 6 report the values that you calculate.

    a. Report the Annual Distribution SAIDI Including Major Event Days on line 3,
    b. Report the Annual Distribution SAIDI Excluding Major Event Days on line 3,
    c. Report both the Annual Distribution SAIDI Including Major Event Days excluding events where the reliability event was initiated from loss of supply (e.g. resulted from an event on the distribution system, not from the high-voltage system) the Annual Distribution SAIDI Excluding Major Event Days excluding events where the reliability event was initiated from loss of supply on line 4.
    d. Report the Annual Distribution SAIFI Including Major Event Days on line 5,
    e. Report the Annual Distribution SAIFI Excluding t Major Event Days on line 5,
    f. Report both the Annual Distribution SAIFI Including and Excluding Major Event Days excluding events where the reliability event was initiated from loss of supply on line 6.

6. On line 7, enter the **Total number of customers used to calculate SAIDI and SAIFI**, as reported on this schedule. A customer is defined as a metered electrical service point for which an active bill account is established at a specific location (e.g., premise). *(IEEE 1366-2003 pg. 2)*

7. On line 8, **indicate the voltage at which you distinguish the distribution system from the supply system**.

8. On line 9, indicate whether your company has an outage management system that detects loss of load or customer outages. Answer "yes", even if you also receive outage information manually via other methods.

SCHEDULE 3, PART C: DISTRIBUTION SYSTEM RELIABILITY

INFORMATION – OTHER

SAIDI and SAIFI calculations via other methods, calculated by state

1. On lines 10 through 11 report the values that you calculate.

   a. Report the Annual Distribution SAIDI Including major events on line 10,
   b. Report the Annual Distribution SAIDI Excluding major events on line 10,
   c. Report the Annual Distribution SAIFI Including major events on line 11,
   d. Report the Annual Distribution SAIFI Excluding major events on line 11.

2. On line 12, enter the total number of customers used to calculate SAIDI and SAIFI, as reported on this schedule.

3. On lines 13, indicate whether your utility includes inactive accounts in its definition of customers used to determine SAIDI and SAIFI.

4. On line 14, indicate how your utility defines momentary outages, i.e., less than how many minutes. Outages can be classified as either momentary or sustained. Momentary outages are not included in determining SAIDI and SAIFI.

5. On line 15, report the voltage that you use to distinguish the distribution system from the supply system.

6. On line 16, indicate whether your company has an outage management system that detects loss of load or customer outages. Answer "yes", even if you also receive outage information manually via other methods.

SCHEDULE 4, PART A: SALES TO ULTIMATE CUSTOMERS.
FULL SERVICE – ENERGY AND DELIVERY SERVICE (BUNDLED)

The table below should be used as a guide for the classification of your end-use customers; pay close attention to how your consumers should be organized based on our four Sectors: Residential, Commercial, Industrial, and Transportation. Please note that data for the Transportation Sector (see definitions) has replaced the "Other" Sector on all parts of Schedule 4. Non-Transportation customers previously reported under "Other," including street and highway lighting, should now be included in the Commercial Sector. Irrigation customers should be reported in the Industrial Sector.

Enter the reporting year revenue (thousands of dollars, to the nearest tenth), megawatthours, and number of customers for sales of electricity to ultimate customers by state, balancing authority, and customer class

category for whom your company provides both energy and delivery service. Power marketers providing both energy and delivery service should report on Part D. Note: For sales to customer groups using brokers or aggregators, continue to count each customer separately. For instance, count a group of franchised commercial establishments aggregated through a single broker as separate customers (as reported in prior years). Using the drop down menus, enter the 2-letter U.S. Postal Service abbreviation for the state and the balancing authority in which the electric sales occurred. Select the check box to indicate whether your rates are decoupled. If you select 'Yes," indicate whether the revenue adjustment is automatic or requires a rate making proceeding. Entities completing this Schedule are also required to complete Schedule 6 Part D, Advanced Metering.

The **residential sector** includes private households and apartment buildings where energy is consumed primarily for: • space heating • water heating • air conditioning • lighting • refrigeration • cooking • clothes drying	The **commercial sector** includes nonmanufacturing business establishments such as: • hotels • motels, • restaurants • wholesale businesses • retail stores • health, social, and educational institutions • public street and highway lighting • municipalities • divisions or agencies of states and federal governments under special contracts or agreements, and other utility departments, as defined by the pertinent regulatory agency and/or electric utility
The **industrial sector** includes: • manufacturing • construction • mining • agriculture (irrigation), • fishing • forestry establishments	The **transportation sector** includes: • railroads and railways (The fuel source of propulsion must be electrical like a metro system which exists in large cities. Please count number of systems not meters.)

SCHEDULE 4, PART B: SALES TO ULTIMATE CUSTOMERS ENERGY–ONLY SERVICE (WITHOUT DELIVERY SERVICE)

Enter the reporting year revenue (thousands of dollars, to the nearest tenth), megawatthours, and number of customers for sales of electricity to ultimate customers by state, by balancing authority, and customer class category for which your company provides only the energy consumed, where another electric utility provides delivery services, including, for example, billing, administrative support, and line maintenance.

SCHEDULE 4, PART C: SALES TO ULTIMATE CUSTOMERS DELIVERY–ONLY SERVICE (AND ALL OTHER CHARGES)

Enter the reporting year revenue (thousand dollars, to the nearest tenth), megawatthours delivered, and number of customers for sales of electricity to ultimate customers in your service territory by state by balancing authority and customer class category for which your company provides only billing and related energy delivery services, where another company supplies the energy. Entities completing this Schedule are also required to complete Schedule 6 Part D, Advanced Metering and Customer Communications.

SCHEDULE 4, PART D: SALES TO ULTIMATE CUSTOMERS. BUNDLED SERVICE (ENERGY SERVICE PROVIDERS AND POWER MARKETERS)

Note: typically, the only entities that report on Schedule D are Texas Energy Service Providers. Any other entity that believes it should report on Schedule D should first contact EIA.

Enter the reporting period revenue (thousands of dollars, to the nearest tenth), megawatthours, and number of customers for sales of electricity to ultimate customers by state, by balancing authority, and customer class category for whom your company provided both energy and delivery service. For public street and highway lighting, count all poles in a community as one customer. Note: For sales to customer groups using brokers or aggregators, continue to count each customer separately. For instance, count a group of franchised commercial establishments aggregated through a single broker as separate customers (as reported in prior years). Enter the two-letter U.S. Postal Service abbreviation (if not preprinted) for the state in which the electric sales occur. (Note: Texas Energy Service Providers (ESPs) should include delivery revenues.)

Common Instructions: SCHEDULE 4. PARTS A, B, C, AND D

1. For the on-line form, when adding a new state and/or balancing authority, the state **must** be entered first, from the drop down menu and then the balancing authority must also be selected from the drop down menu. All new states or balancing authorities must be added to Schedule 4 before they can be added to a subsequent schedule.

2. For column a, **Residential,** enter the revenue, megawatthours, and number of customers for electric energy supplied for residential (household) purposes. For the residential class, do not duplicate the customer accounts due to multiple metering for special services (e.g., water heating, etc.).

3. For column b, **Commercial**, enter the revenue, megawatthours, and number of customers for electric energy supplied for commercial purposes.

4. For column c, **Industrial**, enter the revenue, megawatthours, and number of customers for electric energy supplied for industrial purposes.

5. For column d, **Transportation**, enter the revenue, megawatthours, and number of customers for electric energy supplied for transportation purposes.

SCHEDULE 5: MERGERS AND/OR ACQUISITIONS

If a merger or acquisition has occurred during the reporting period, report those newly-acquired corporate entities whose operations are now included in this report.

SCHEDULE 6: DEMAND-SIDE MANAGEMENT AND SMART GRID INFORMATION

Demand-side management (DSM) programs, both energy efficiency programs and demand response programs, are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Schedule 6 is divided into four parts:

- Part A, Energy Efficiency Programs,
- Part B, Demand Response Programs,
- Part C, Dynamic Pricing Programs,
- Part D, Advanced Metering and Customer Communications

SCHEDULE 6, PART A: Energy Efficiency Programs

The reporting entity depends on who has oversight and decision-making authority over the program:

You should report for programs your company administers or if your company contracts another company to provide DSM to your customers and your company is responsible for decision making relative to that program.

You should not report for programs that are run by another entity (nonutility DSM Administrator; see further discussion immediately below) that is typically selected by an authority that provides oversight to the program. The nonutility DSM Program Administrator will provide the results of the program in this section, and your company should not do so, except as noted below:

Nonutility DSM Administrators: These are entities selected by a government organization to contract for and administer energy efficiency portfolios within a specific geographic region and or market. Administrators are typically selected by a public service commission or a non-profit or state government agency as determined by legislation.

EIA currently collects these data from the following program administrators:

- Sustainable Energy Trust Fund (DC)
- Efficiency Maine Trust
- Energy Trust of Oregon
- Focus on Energy (Wisconsin)
- NYSERDA
- Cape Light Compact
- Hawaii Energy Efficiency Program
- Delaware Sustainable Energy Utility
- NJ Clean Energy Program
- Vermont Energy Investment Corporation

If your nonutility DSM Administrator is listed above, you do not report in Schedule 6A. **If your Nonutility DSM Administrator is not listed above, you will have to report new energy efficiency activities for your customers, in Schedule 6A.** If you have a nonutility DSM Administrator not listed above, you may request that they be added for the next reporting year by entering that request in the comment section of the form. If your nonutility DSM administrator reports for you indicate your DSM administrator by selecting them from the drop down list on question?

If you are a Nonutility DSM Administrator listed above, please provide a list of electric utilities for whom you provide DSM products and services, either as an attachment to this form or if submitting electronically, in the comment section.

The DSM information **should**:

1) Reflect only new reporting year activities that are undertaken specifically in response to company-administered programs, including activities implemented by third parties under contract to the company;

2) Account for the complete range of DSM programs, including energy efficiency and demand response; and

3) Represent the energy and demand savings at the **customer meter** (i.e., transmission and distribution or reserve requirement savings should be excluded). Also, energy and demand savings should be reported as adjusted gross savings. **Adjusted Gross Savings** is the change in energy consumption and or demand that results directly from program-related actions taken by participants in an efficiency program regardless of why they participated. The effects that building demolition, equipment degradation, and program attrition can have on the life and savings of the efficiency measure can be included to the extent that they are easily estimated from prior similar programs or experience.

The DSM information **should exclude**, to the extent possible, energy and demand savings that are not attributable to DSM program activities. Non-program related effects include changes in energy and demand attributable to:

1) Government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage;

2) Natural operations of the marketplace (e.g., reductions in customer energy usage due to higher prices); and,

3) Weather and business-cycle fluctuations.

Power supply cooperatives, municipal joint action agencies, and Federal Power Marketing Administrations should coordinate the reporting of DSM information with their power purchasing utilities to avoid double counting the effects and costs of DSM programs. Distribution companies should weigh the benefits of taking credit for their programs by reporting this information under their utility identification versus the convenience of having their program directors report this information in aggregate. EIA would prefer the distribution company to report the data whenever possible.

Energy efficiency measures consist of installations of more efficient devices or implementing more efficient processes that exceed current standards. An energy efficiency resource must achieve a long term continuous reduction in demand for electricity and be available without a requirement of notice or dispatch from the grid operator.

Examples are replacing light bulbs with more efficient technology or replacing older HVAC systems with high efficiency systems that exceed current codes and standards.

This part of the schedule collects information on the energy and demand savings of a portfolio of Energy Efficiency Programs implemented, and measures installed, by major customer sector within a state and balancing authority. It is divided into five subparts:

- Reporting Year Incremental Annual Savings
- Incremental Life Cycle Savings
- Reporting Year Incremental Costs
- Incremental Life Cycle Costs
- Weighted Average Life for Portfolio (Years)

1. **Incremental Annual Savings – Reporting Year** are those changes in energy use (measured in megawatthours) and peak load (reduction in load at the time of the annual system peak hour, measured in megawatts) caused in the current reporting year by

    - new participants in DSM programs that operated in the previous reporting year, and
    - participants in new DSM programs that operated for the first time in the current reporting year.

    A "New program" is a program for which the reporting year is the first year the program achieved savings, regardless of when program development and expenditures began.

    Annualize all Estimates: Reporting Year Incremental Annual Savings should be annualized, i.e., they should be reported as if the participants were in the program starting on Jan 1 of the reporting year and continued in the program for a full year.

    Incremental Savings - **Life Cycle** are the estimated total changes in energy use and peak load for incremental programs and participants over the life of the programs. DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible, consider the useful life of efficiency by accounting for building demolition, equipment degradation, and program attrition.

    A "Life cycle" means the number of years the program is planned to exist, and includes all future anticipated savings as well as reporting year savings. The mean life of a program is measured based on the number of years that savings are expected to be achieved independent of the number of years of expenditures for any measure. Please note that **Life Cycle Savings** should be provided if **Reporting Year Annual Savings** are reported

    - Incremental life-cycle energy savings (megawatt-hours): report as the lump sum total savings projected for the life cycle of the incremental programs and participants. For example, if a project has an anticipated life of 10 years with savings in each year of 10,000 MWH, report the total of 100,000 MWH.
    - Incremental life cycle peak demand saving (megawatts): report the average of the annual peak demand savings for the life cycle of the incremental programs and participants. For example, if a program has a four-year life with the following pattern of demand reductions – Year 1: 10 MW, Year 2: 20 MW, Year 3: 20 MW, Year 4: 10 MW – report the average of 15 MW.

2. For Part A, please report for both **"**Reporting Year Incremental Annual Savings" and "Incremental Life Cycle Savings" under the appropriate customer sector: Residential, Commercial, Industrial, and Transportation: for Energy Efficiency,

a. On Lines 1 and 3, enter the aggregate Energy Savings (megawatthours) and

b. On Lines 2 and 4, the Peak Demand Savings (megawatts to one decimal point).

3. **Costs for energy efficiency programs** should be broken down into two categories, customer incentives and all other costs. Customer incentives are the total financial value provided to a customer for program participation, whether, for example, cash payment, or lowered tariff rates relative to non-participants, in-kind services (e.g. design work), or other benefits directly provided to the customer for their program participation. Reporting Year Incremental costs should include all costs for the programs for years prior to the incremental year if these costs were incurred as part of the startup of the program. Incremental life cycle costs should include all anticipated costs of the program including the Reporting Year Incremental Costs and all future costs.

   Please note that **Reporting Year Incremental Costs** should be provided if **Reporting Year Incremental Annual Savings** are reported. In some cases **Reporting Year Incremental Costs and Incremental Life Cycle Costs** may be the same, due to most energy efficiency expenditures being incurred in the first year for participants. See the 861 FAQ site for more details.

   a. For lines 5 through 8 report costs in thousands of dollars for each state, each balancing authority, and for each sector.

   b. For example, if a program has a life cycle of 10 years and if $10,000 was incurred prior to the incremental year of a program for startup costs and the average cost of the program for the next ten years is $5,000/year, the reporting year incremental costs would be $15,000 and the incremental life cycle costs would be $60,000**.** Note in this example the length in years of the program (10 years based on the number of years of savings) is one less year than the years of expenditures (11 years). The number of years of program savings is used to determine the life of the program.

4. **Weighted Average Life for Portfolio (Years)** – Please use the Excel spreadsheet (press the 'Calculate' button to call up the template) to determine the weighted average life of your portfolio of EE programs or measure - by state, balancing authority, and sector on 6A, line 10. Weighted Average Life for portfolio of Energy Efficiency activities or measures should include all measures that are reporting in lines 1 through 4. On the spreadsheet enter your program or measure number, the total life cycle savings in MWH for each incremental program and its associated life in years. The life in years should be estimated as the mean life of the measure. Once all your programs have been entered the spreadsheet will return the weighted average life for the portfolio. This spreadsheet should be used for each state balancing authority, and sector. These averages may be used to estimate the economic value of the energy efficiency portfolio in total and is a key metric to the economic comparison of energy efficiency activities and other options.

SCHEDULE 6, PART B: DEMAND RESPONSE PROGRAMS

Demand Response Programs are procedures that encourage a temporary reduction in demand for electricity at certain times in response to a signal from the grid operator or market conditions. Examples are the dimming of lights, turning on backup generators or shutting down industrial processes. Demand Response program reporting should be broken down by state, balancing authority, and customer class.

Potential peak demand savings refers to the total demand savings that could occur at the time of the system peak hour assuming all demand response is called.

Actual peak demand savings is demand reduction actually achieved by demand response activities and is measured at the time of the company's annual system peak hour.

1. On line 1 enter the number of customers participating in the Demand Response programs.
2. On line 2 enter the energy savings in MWH by customer sector.
3. On line 3 enter the potential peak demand savings in MWs for demand response programs.
4. On line 4 enter the actual peak demand savings in MWs for demand response programs.
5. On line 5 enter the total customer incentives in thousands of dollars.
6. On line 6 enter all other costs to run the Demand Response program; these are in thousands of dollars.
7. On line 7 enter the number of grid-enabled water heaters (as defined in 10 CFR Part 430) that you added to your program this year. A grid interactive water heater is an electric storage water heater that is capable of being controlled remotely by a third party (usually an electricity service provider) that provides the third party the ability to control the operation of the unit by storing thermal energy during off-peak times. DOE's Office of Energy Efficiency and Renewable Energy is in the process of issuing a final rule for efficiency standards for residential water heaters. Once those standards are finalized, EIA will, if necessary, adjust the definition above to be in accordance with the minimum efficiency standards for grid-enabled water heaters.

SCHEDULE 6, PART C: DYNAMIC PRICING PROGRAMS

Dynamic pricing programs (also known as time-based rate programs) are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Report those customers that are enrolled in the program and are billed accordingly whether or not they are active participants. For each state, balancing authority, and customer sector, report the number of customers enrolled in dynamic pricing programs.

Time of Use Prices (TOU) is a program in which customers pay different prices at different times of the day. On-peak prices are higher and off-peak prices are lower than a "standard" rate. Price schedule is fixed and predefined, based on season, day of week, and time of day.

Real Time Pricing (RTP) is a program of rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.

Variable Peak Pricing (VPP) is a program in which a form of TOU pricing allows customers to purchase their generation supply at prices set on a daily basis with varying on-peak and constant off-peak rates. Under the VPP program, the on-peak price for each weekday becomes available the previous day (typically late afternoon) and the customer is billed for actual consumption during the billing cycle at these prices.

Critical Peak Pricing (CPP) is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by imposing a pre-specified high rate or price for a limited number of days or hours. Very high "critical peak" prices are assessed for certain hours on event days (often limited to 10-15 per year). Prices can be 3-10 times as much during these few hours. Typically, CPP is combined with a TOU rate, but not always.

Critical Peak Rebate (CPR) is a program in which rate and/or price structure is designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies, by providing a rebate to the customer on a limited number of days and for a limited number of hours, at the request of the energy provider. Under this structure the energy provider can call event days (often limited to 10-15 per year) and provide a rebate typically several times the average price for certain hours in the day. The rebate is

based on the actual customer usage compared to its baseline to determine the amount of the demand reduction each hour.

1. On line 1, enter the number of customers participating in dynamic pricing programs, by customer class.
2. On line 2, for each customer sector indicate if customers in this sector are participating in Time-of-Use Pricing.
3. On line 3, for each customer sector indicate if customers in this sector are participating in Real Time Pricing.
4. On line 4, for each customer sector indicate if customers in this sector are participating in Variable Peak Pricing
5. On line 5, for each customer sector indicate if customers in this sector are participating in Critical Peak Pricing.
6. On line 6, for each customer sector indicate if customers in this sector are participating in Critical Peak Rebate.

SCHEDULE 6, PART D: ADVANCED METERING

Entities providing data on Schedule 4 Part A and/or C are required to complete Schedule 6 Part D.

Standard Electric Meters (non AMI/AMR meters) are electromechanical or solid state meters measuring aggregated kWh where data are manually retrieved over monthly billing cycles for billing purposes only. Standard meters may also include functions to measure time-of-use and/or demand with data manually retrieved over monthly billing cycles.

Automated Meter Reading (AMR): Meters that collect data for billing purposes only and transmit this data **one way**, usually from the customer to the distribution utility. Aggregated monthly kWh data captured on these meters may be retrieved by a variety of methods including drive-by vans with short-distance remote reading capabilities and communication over a fixed network such as a cellular network. Enter the state and balancing authority and report the total number of AMR meters by sector.

Advanced Metering Infrastructure (AMI): Meters that measure and record usage data at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in **two-way** communication capable of recording and transmitting instantaneous data.

Installed AMI with home area network (HAN) gateway enabled should be reported as a subset of AMI (see number 4 above). In this case, a HAN consists of software and hardware components residing within an AMI meter that permits the meter to communicate with devices within a customer's premises.

Energy Served through AMI (MWH) should be entered in megawatthours for customers served and should not be greater than the combined total sales reported on Schedule 4 Part A and/or C

Direct Load Control: A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

1. Enter the state and balancing authority and on line 1 enter the number of AMR meters, by customer class.
2. On line 2 enter the number of AMI meters, by customer class.
3. On line 3 enter the number of AMI meters with home area network (HAN) gateway enabled, by customer class.
4. On line 4 enter the number of standard (non-AMR/AMI) meters, by customer class.
5. Line 5 auto-sums the total number of meters (All Types), by customer class.
6. On line 6 enter the energy served (megawatthours) through AMI meters, by customer class.
7. On line 7 enter the number of customers able to access daily energy usage through a web portal or other electronic means.
8. On line 8 enter the number of customers with direct load control, by customer class. Please note that EIA is asking for customers and not meters, so the reported number shall not exceed what was stated on 4A and 4C combined.

SCHEDULE 7, PART A: NET METERING PROGRAMS

Net Metering tariff arrangements permit a facility, typically generating electricity from a renewable resource (using a meter that reads inflows and outflows of electricity) to sell excess power generated over its load requirement back to the electrical grid, typically but not necessarily at a rate equivalent to the retail price of electricity.

Virtual Net Metering: A billing arrangement that allows multiple energy customers to receive net metering credit from a shared onsite or remote renewable energy system as if it was located behind the customer's own meter. Generally but not always virtual net metering programs have two primary business partners. One is the solar developer or operator, that sells a fraction (or all) of the system (usually measured in capacity or shares) to the ultimate customer(s) and an electric distribution company that bills the customer(s) for its energy use and provides a credit on the customer's bill for the generation allocated to its share of the resource. In some cases the distribution company serves in both of these roles.

There is a new question for reporting the capacity of solar PV, select either AC or DC for the units.

Capacity for wind and other technologies should be reported in MW as AC load capable. For all net metering applications, report the installed net metering capacity by state, balancing authority, customer class and technology. All of which should be reported to the nearest 0.001 MW. Example: 8 kW should be 0.008 MW.

Report the number of net metering installations/customers that are actively enrolled in a net metering program as of December 31st of the data year. Customer count/ installation by technology should not exceed the values in Schedule 4 Parts A and C, combined. For each program technology type and sector, if you complete installed capacity or number of installations/customers then you will need to complete both lines of data.

For PV solar installations also report the number of virtual net metered customers and the capacity of virtual net metering programs both for programs from resources that are less than one MW and resources that are 1 MW or greater. All three programs, net metering, virtual net metering below 1 MW and virtual net metering above 1 MW should be mutually exclusive, meaning all three are added together to get the total. For example if you report

capacity in net metering you would not report that capacity for the same installation in virtual net metering. If the installation is not part of a net- metering or virtual net metering agreement, the installation if under 1 MW would be reported in Schedule 7B Non-net metered Distributed Generators.

For virtual net metering, the capacity should be reported based on which customer class/sector has the virtual net metering agreement, not the physical location of the generator(s).

In addition, report the amount of known storage associated with the PV net metering installations, **if available**.

If the data is available, enter the amount of electric energy sold back to the utility **(MWh)** through the net metering application.

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SCHEDULE 7, PART B: NON NET-METERED DISTRIBUTED GENERATORS

Dispersed generator data is no longer collected on the EIA-861.

Schedule 7, Part B is intended to collect information about generators that are NOT reported on Form EIA-860, "Annual Electric Generator Report." Plants with a capacity of 1 MW or greater which ARE grid-connected, meet the threshold criteria for reporting on the Form EIA-860 and as such, **need not** be reported on Schedule 7B of Form EIA-861. **Also Schedule 7B is intended to collect information about generators that are NOT reported in Schedule 7A (Net Metering)**. Therefore, if the generator data has been reported in Schedule 7A, DO NOT include it under Schedule 7B, but include generators other than those that are net metered.

This schedule now collects information from distribution companies by **sector** (residential, industrial, commercial and transportation) on generators of less than 1 megawatt (1000 kilowatts) installed at or near a customer's site, or other sites within the system. Provide actual data if available, otherwise provide best estimates.

NUMBER AND CAPACITY

1. For line 1, **Number of generators**, provide the number of distributed generators in the area served by your distribution system, by state, by balancing authority. **(Less than 1 megawatt)**

2. For line 2, **Total combined capacity**, provide the nameplate capacity (to the nearest thousandths) **for all generators with less than 1 megawatt** that reported on line 1.

3. For line 3, capacity that consists of **backup-only units**, provide the total nameplate capacity of generators that are used **only** for emergency backup service.

4. For Line 4, capacity owned by respondent, provide the total nameplate capacity listed in line 2 that the respondent owns.

CAPACITY BY TECHNOLOGY AND SECTOR

For each of the technologies listed in lines 5 through 13, provide the capacity and **sector**. The total of lines 5 through 13 (line 14) should equal the total combined capacity in line 2.

Storage should be included if available.

Direct Connected is for installations that are not located at an ultimate customer's site but are in front of the meter and/or connected directly to a distribution system.

SCHEDULE 8: SERVICE TERRITORY INFORMATION

Please verify the names of the counties, parishes, etc. (provided by EIA in a drop-down menu), by state, where your utility-owned distribution system's electrical equipment is located. The information may have been reported by the respondent last year or the result of independent research by the EIA staff processing the Form EIA-861. If the information is incorrect, please provide the correct information in Schedule 9.

SCHEDULE 9: FOOTNOTES

This schedule provides additional space for comments. For clarification purposes, identify schedule, part, line number and column (if applicable) for each comment.

GLOSSARY	The glossary for this form is available online at the following URL: http://www.eia.gov/glossary/index.html
SANCTIONS	The timely submission of Form EIA-861 by those required to report is mandatory 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 average 10.97 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. 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, Office of Survey Development and Statistical Integration, EI-21 Forrestal Building, 1000 Independence Avenue SW, 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.
DISCLOSURE OF INFORMATION	The following information reported on this survey 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 Department of Energy (DOE) regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905: • All information associated with the “Survey Preparer” and the “Survey Preparer’s Supervisor” on Schedule 1. All other information reported on Form EIA-861 is public information and may be publicly released in company identifiable form.