U.S. Department of Energy U.S. Energy Information Administration Form EIA-861 (2011)	***ANNUAL ELECTRIC POWER INDUSTRY REPORT INSTRUCTIONS***	**Form Approved** **OMB No. 1905-0129** **Approval Expires: 12/31/2013** **Burden: 9.0 hrs**

PURPOSE	Form EIA-861 collects information on the status of electric power industry participants involved in the generation, transmission, and distribution of electric energy in the United States, its territories, and Puerto Rico. The data from this form are used to accurately maintain the EIA list of electric utilities, to draw samples for other electric power surveys, and to provide input for the following EIA reports: *Electric Power Monthly*, *Monthly Energy Review, Electric Power Annual*, *Annual Energy Outlook, and Annual Energy Review*. 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 including: electric utilities, all DSM Program Managers (entities responsible for conducting or administering a DSM program), wholesale power marketers (registered with the Federal Energy Regulatory Commission), energy service providers (registered with the States), and electric power producers. Responses are collected at the business level (not at the holding company level).
RESPONSE DUE DATE	Submit the completed Form EIA-861 to the EIA by April 30, 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: EIA-861@eia.gov. • If you have registered with Single Sign-On, log on at https://signon.eia.gov/ssoserver/login • If you are having a technical problem with logging into e-file or using e-file contact the Help Desk for further information. Contact the Help Desk at: Email: CNEAFhelpcenter@eia.gov Phone: 202-586-9595 • If you need an alternate means of filing your response, contact the Help Desk. **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: Karen McDaniel (202) 586-4280 Stephen Scott (202) 586-5140 FAX Number: (202) 287-1938 Email: EIA-861@eia.gov

GENERAL INSTRUCTIONS

Submit the completed Form EIA-861 to the EIA by April 30, following the end of the calendar year.

1. Respondents, who also submit the Form EIA-826, “Monthly Electric Sales and Revenue Report with State Distributions," should coordinate the information submitted on the Form EIA-861, and Form EIA-826 to ensure consistency.

2. Complete the information at the top portion of the form with the name, telephone and FAX number, and 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 on the revenue on Schedule 3 and 4. Lines 4, 6 and 7 on Schedule 6A and line 3 on schedule 2C also contain one decimal point.

5. A state code can only be removed by highlighting the state and clicking on the **Remove Record** icon (Schedule 2C, 2D, 4A-D and 6D). The Remove Record icon is the last one in the icon row at the top (same row as the save and print button).

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 franchise 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 3, line 4 and 5, the number may 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).

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1. IDENTIFICATION

1. **Survey Contact:** Verify contact name, title, address, telephone number, fax number, and address.
2. **Supervisor of Contact Person for Survey:** Verify the contact's supervisor's name, title, address, telephone number, Fax number and address. **Supervisor contact must be different than the survey contact.**
3. **Report For:** Verify all information, including entity name, entity identification number, and reporting year for which data are being reported. These fields cannot be revised online. Contact EIA if corrections are needed.

If any of the above information is incorrect, revise the incorrect entry and provide the correct information. Provide any missing information.

Entity and Preparer Information

4. **Legal Name of Entity:** Enter the legal name of the entity for which this form is being prepared.
5. **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.).
6. **Preparer's Legal Name:** Enter the legal name of the company, which prepares this form, if different from the **Legal Name of Entity**.
7. **Current Address of Preparer's Office:** Enter the address to which 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 Regional Entity
FRCC .... Florida Reliability Coordinating Council
MRO................... Midwest Reliability Organization
NPCC................. Northeast Power Coordinating Council
RFC……………... Reliability*First* Corporation
SERC................. Southeastern Electric Reliability Council
SPP.................... Southwest Power Pool
WECC................ Western Electric Coordinating Council

For line 1a, 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
- Other

If your RTO or ISO does not appear on the list, select "Other" and explain in SCHEDULE 9. COMMENTS

2. For line 3, **Balancing Authority(s)**, enter the name of the balancing authority(s) responsible for your oversight. If your balancing authority is not on the list, use "Other" and list the authority in the Comments (Schedule 9).

3. For line 4, **Operate Generating Plant(s)**, Check Yes to indicate that organization operated a generating plant(s) 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. **You must check at least one.**

   Generation from company owned plant. Owned power generation only.

   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 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."

   Bundled 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**, electric utility companies should enter the maximum hourly summer load (for 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, **Comments**. If adjustments cannot be made, furnish data as available and explain on Schedule 9, **Comments**. 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 nonfirm service. Note: Please identify on Schedule 9, **Comments**, the portion of purchased power obtained through tolling arrangements, and any 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 3-4). 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 3, 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 nonfirm customers. This entry should also correspond to the revenue from sales for resale reported in Schedule 3, line 3. Note: Please identify on Schedule 9, **Comments**, 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. GREEN PRICING

Green Pricing programs allow electricity customers the opportunity to purchase electricity generated from renewable resources and to pay for renewable energy development. Renewable resources include solar, wind, geothermal, hydroelectric power, and wood.

These programs are voluntary. Retail Customers pay an additional fee to purchase electricity generated from renewable sources. In addition, Renewable Energy Certificates (RECs), also known as green certificates, green tags, or tradable renewable certificates representing the environmental attributes of power produced from renewable energy projects may be purchased and incorporated into Green Pricing Programs when available renewable generation is insufficient to cover the requirements of the program for energy delivered in the reporting year.

Line1: Report the Total Green Pricing Revenue for customers in each customer class. Revenue should be reported in thousands of dollars to the nearest tenth (for example, $1,299 would be reported as 1.3 thousand dollars). Revenue should include revenue from the green pricing program <u>plus</u> the price of the electricity purchased.

Example: For 1000 kWh of electricity sales, if the normal price for electricity is $0.10 per kWh:

a) An entity sells Green Energy in blocks of $5.50 per 100 kWh block:
   Total cost = (1,000kWh x $0.10/kWh) + (($5.50/100kWh block) x (10 blocks of 100 kWh))
   = $100.00 + $55.00
   = $155.00
b) Alternatively, an Entity which sells Green Energy for a premium of $0.02 per kWh:
   Total cost = (1,000kWh x $0.10/kWh) + (($0.02/kWh) x (1,000kWh))
   = $100.00 + $20.00
   = $120.00

Line 2: Report the Total Green Pricing Sales, the total amount of megawatthours purchased by customers for each green pricing customer class (for example, 1,299 kWh would be reported as 1 MWh).

Line 3: Report the Total Green Pricing Customers, the number of customers who purchased green power for each customer class. The sales volumes and the number of customers should not exceed the values reported in Schedule 4, Parts A, B, or D.

Line 4: Report the revenue from RECs for each customer class in thousand of dollars to the nearest tenth. Enter only the amount associated with RECs as part of a Retail Green Pricing Program. This revenue must not exceed the Total Green Power Revenue reported in line 1 above.

Line 5: Report the sales from RECs in megawatthours for each customer class. This amount should not exceed the Total Green Pricing Sales reported in line 2 above,

The Total for each customer class will automatically sum for the electronic online e-file system.

SCHEDULE 2. PART D. NET METERING

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 any excess power it generates over its load requirement back to the electrical grid, typically at a rate equivalent to the retail price of electricity.

For net metering applications of 2 MW nameplate capacity or less, report the installed net metering capacity by State, customer class and technology. Report net metering data by sector and technology type for each state. Capacity should be reported in MW as AC load capable. Example: 8 kW should be 0.008 MW. Capacities should not exceed limits set up by each state. Please provide this capacity in MW, to the nearest 0.001 MW by technology. Do not report for net metering applications larger than 2 MW.

Report the number of net metering customers by customer class. They should not exceed the values in Schedule 4 Parts A and C. <u>If you are unable to utilize the e-file system which creates the totals automatically</u>; then provide the Totals for net metering megawatt hours, installed net metering capacity and customers by State, customer class and technology. Complete all lines for Schedule 2, Part D.

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

SCHEDULE 3. 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 4, Part C, for delivery service (and all other charges) should **not** be reported on Schedule 3, line 1, but should be reported in Schedule 3, line 2, **Revenue from Unbundled (Delivery) Customers**. This entry 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. This entry should 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 3, line 4, **Electric Credits/ Other Adjustments**. This entry should correspond to electricity sales reported in Schedule 2, Part B, line 11. (This entry should also be the same total revenue reported on Schedule 4, column e, Parts A and B, when summed for all reported States). This entry 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.

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 nonrequirements (nonfirm) customers. This entry should also correspond to the sales for resale reported in Schedule 2, Part B, 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 4. PART A. SALES TO ULTIMATE CUSTOMERS.
FULL SERVICE – ENERGY AND DELIVERY SERVICE (BUNDLED)

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 (thousand dollars, to the nearest tenth), megawatthours, and number of customers for sales of electricity to ultimate customers by State 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). Enter the 2-letter U.S. Postal Service abbreviation for the State in which the electric sales occurred.

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

Enter the reporting year revenue (thousand dollars, to the nearest tenth), megawatthours, and number of customers for sales of electricity to ultimate customers by State and customer class category for whom 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 and customer class category for whom your company provides only billing and related energy delivery services, where another company supplies the energy.

SCHEDULE 4. PART D. SALES TO ULTIMATE CUSTOMERS. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS, OR ANY POWER MARKETER THAT PROVIDES “BUNDLED SERVICE”

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

Enter the reporting period revenue (thousand dollars, to the nearest tenth), megawatthours, and number of customers for sales of electricity to ultimate customers by State 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 Retail Energy Providers (REPs) should include delivery revenues.)

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

1. 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.).

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

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

4. 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 INFORMATION

Demand-side management (DSM) 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, **Actual Effects,** Part B, **Annual Costs,** Part C, **Supplemental Information** and Part D, **Advanced Metering.** SCHEDULE 6 is to be completed by DSM program managers (entities responsible for conducting or administering a DSM program). In previous years, companies with sales to ultimate customers **or** sales for resale which were less than 150,000 megawatthours were required to complete only the **INCREMENTAL EFFECTS** portion of Part A and annual cost to achieve in Part B, line 13, **Total Cost. For this reporting year and forward, all companies including those non-utility DSM Program Managers are required to complete the entire schedule.**

The DSM information provided should: 1) reflect only 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 load management; and 3) represent the energy and load effects at the customer meter (i.e., transmission and distribution or reserve requirement savings should be excluded). The DSM information should exclude, to the extent possible, energy and load effects that are not attributable to DSM program activities.

Non-program related effects include changes in energy and load attributable to: 1) non-participants (e.g., customers known as free-riders, who would adopt program-recommended actions even without the program); 2) government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage; 3) natural operations of the marketplace (e.g., reductions in customer energy usage due to higher prices); and 4) 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. Utilities that have their DSM activities reported on Schedule 6 of another company should name that company in the space provided on line 2 of the schedule and proceed to Schedule 6, Part D.

SCHEDULE 6. PART A. ACTUAL EFFECTS

This part of the Schedule collects information on the energy and load effects of DSM programs implemented, and measures installed, for each program category by major customer sector within a State. It is divided into two subparts, **Incremental Effects** and **Annual Effects**.

1. Incremental Effects: The changes in energy use (measured in megawatthours) and peak load (measured in megawatts) caused in the current reporting year by new participants in existing DSM programs and all participants in your new DSM programs (that is programs begun during the current reporting year). Reported Incremental Effects should be annualized.

Please leave blanks, not zeros, if the questions do not apply. For example, your company operates industrial programs but does not expect any incremental effects in the current reporting year, the field would have a value of zero. However, if your company does not operate any industrial programs, then the field should be left blank.

2. Annual Effects: The total changes in energy use (measured in megawatthours) and peak load (measured in megawatts) caused in the current reporting year by all participants in all of your DSM programs. This includes new and existing participants in existing programs (those implemented prior to the current reporting year that were in place during prior reporting year), all participants in new programs (those implemented during current reporting year), and participants in programs terminated since 1992 (those effects continue even though the programs have been discontinued). DSM programs have a useful life, and the net effects of these programs will diminish over time. To the extent possible, the Annual Effects should consider the useful life of efficiency and load control measures by accounting for building demolition, equipment degradation, and program attrition. The effects of new participants in existing programs and all participants in new programs should be based on their start-up dates (i.e., if participants enter a program in July, only the effects from July to December are to be reported). If start-up dates are unknown and cannot be reasonably estimated, the effects can be annualized (i.e., assume the participants were initiated into the program on January 1). **Please note that Annual Effects are not a summation of 12 monthly peaks, but are the total DSM program effects of all programs and all participants for the current reporting year.**

3. For Part A, under the appropriate customer sector: Residential, Commercial, Industrial, and Transportation, enter the aggregate Energy Effects (megawatthours, to one decimal point, if possible) and Actual Peak Reduction (megawatts to one decimal point, if possible) attributable to Energy Efficiency and Load Management programs. For Load Management also enter the Potential Peak Reduction (megawatts to one decimal point, if possible) attributable to each customer sector. Please leave blanks, not zeros, if the questions do not apply. For example, your company operates industrial programs but does not expect any incremental effects in the current reporting year, the field would have a value of zero. However, if your company does not operate any industrial programs, then the field should be left blank.

SCHEDULE 6. PART B. ANNUAL COSTS

This part of the schedule collects information on actual DSM program costs in the current reporting year. Program costs consist of the cash expenditures, reported in thousands of dollars, incurred by the company. Costs should reflect the total cash expenditures for the year, reported in thousands of dollars that flow out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occurred. For example, the cash expenditures to purchase 1,000 load control devices for installation in customers' homes could be incurred a year in advance of the actual load savings that result from operation of the devices.

Annual Costs: For each State enter for each sector your actual Direct Costs, Incentive Payments, and Indirect Costs, incurred in the current reporting year.
Direct Costs are those costs that are directly attributable to a particular DSM program (e.g., Energy Efficiency or Load Management).

Incentives are the total financial value provided to a customer for program participation, whether cash payment, in-kind services (e.g. design work), or other benefits directly provided customer for their program participation.

Indirect Costs may include other costs that have not been included in any program category, but could be meaningfully identified with operating the company’s DSM programs (e.g., Administrative, Marketing, Monitoring & Evaluation, Company-Earned Incentives, Other).

Report Energy Efficiency and Load Management Costs separately. The Total Cost row, line 13 and the Total column (e) will be summed automatically for respondents that file electronically through the e-file system. Provide the actual costs breakdown in thousand dollars.

SCHEDULE 6. PART C. SUPPLEMENTAL INFORMATION

1. Please indicate, by checking "Yes" or "No" on line 14, whether DSM program changes, tracking procedures, evaluations, or reporting methods have affected the data reported on this schedule (since 1992).

2. Please indicate, by checking "Yes" or "No" on line 15, whether your company currently operates any incentive-based demand response programs, i.e., direct load control, interruptible programs, demand bidding/buyback, emergency demand response, capacity market programs, and ancillary service market programs. If the answer is "Yes," enter the number of participating customers, by state and class, on line 16.

3. Please indicate, by checking "Yes" or "No" on line 17, whether your company currently operates any time-based rate programs, e.g., real-time pricing, critical peak pricing, variable peak pricing and time-of-use rates administered through a tariff. If the answer is "Yes," enter the number of participating customers, by state and class, on line 18.

SCHEDULE 6. PART D. ADVANCED METERING

This schedule should only include customers from Schedule 4 Part A or Part C.

Standard (Electric) 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 report the total number of AMR meters by sector. The number of AMR meters may be equal to but not exceed the number of customers on Schedule 4.

Advanced Metering Infrastructure (AMI): Meters that measure and record usage data at a minimum, in hourly intervals, and provide usage data to both consumers and energy companies at least once daily. 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.

Enter the state and report the total number of AMI meters by sector.

For AMI meters that are only being used as AMR, report meters as AMR.

Energy Served Through AMI (MWh) should be entered in megawatthours for customers served.

SCHEDULE 7. DISTRIBUTED AND DISPERSED GENERATION

This schedule collects information from distribution companies on industrial and commercial generators of less than 1 megawatt (1000 kilowatts) installed at or near a customer's site, or other sites within the system. Provide all of the requested information for grid connected/synchronized distributed generators in column a, and for dispersed generators that are not grid connected/synchronized in column b. Also provide the data on all industrial and commercial dispersed generators in the Total column. Provide actual data if available, otherwise provide best estimates, and indicate the nature of the data by checking the appropriate box on the form.

Schedule 7 is intended to collect information about generators on the systems that are NOT reported on Form EIA-860, "Annual Electric Generator Report." Plants with capacity of 1 MW or greater which ARE grid-connected, meet the threshold criteria for reporting on the 860 and as such, **need not** be reported on Schedule 7 of the EIA-861. Residential applications should not be reported.

SCHEDULE 7. PART A. NUMBER AND CAPACITY

1. For line 1, Number of generators, provide in column (a), the number of distributed generators in the area served by your distribution system. **(Less than 1 megawatt)** In column (b), provide the number of dispersed generators. **(Total and less than 1 megawatt)** If you are unable to provide the breakout, please explain in Schedule 9, Comments. **The total number of dispersed generators must be greater than or equal to the number of dispersed generators less than 1 MW.**

2. For line 2, Total combined capacity, columns (a) and (b), provide the nameplate capacity (to the nearest tenth) **for all generators with less than 1 megawatt** that reported on line 1. For column (b), also provide the sum of the capacity for all generators. **The total capacity must be greater than or equal to the capacity less than 1 MW.**

3. For line 3, columns (a) and (b), 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, columns (a) and (b), capacity owned by respondent, provide the total nameplate capacity listed in line 2 that the respondent owns.

5. For Line 5, columns (a) and (b), Nature of data reported, provide actual data if available, otherwise provide best estimates, and indicate the nature of the data by checking the appropriate box on the form.

6. For Line 6, columns (a) and (b), State, provide the 2-letter U.S. Postal Service abbreviation for the State in which the generators are located.

SCHEDULE 7. PART B, CAPACITY BY GENERATING TYPE AND TECHNOLOGY

For each of the technologies listed in columns (a) and (b), lines 1 through 8, provide the capacity. The total of lines 1 through 8 (line 9) should equal the total combined capacity in line 2 in each column, (a, < 1MW) and (b - Total).

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

Please verify the EIA provided names of the counties, parishes, etc. (dropdown menu), by State, where your utility-owned distribution system's electrical equipment are 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. COMMENTS

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

U.S. Department of Energy U.S. Energy Information Administration Form EIA-861 (2011)	***ANNUAL ELECTRIC POWER INDUSTRY REPORT INSTRUCTIONS***	**Form Approved** **OMB No. 1905-0129** **Approval Expires: 12/31/2013** **Burden: 9.0 hrs**

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 9.0 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, 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 CONFIDENTIALITY OF INFORMATION	Information reported on Form EIA-861 will be treated as non-sensitive and may be publicly released in identifiable form. In addition to the use of the information by EIA for statistical purposes, the information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.