PROPOSED RULEMAKING

PENNSYLVANIA PUBLIC UTILITY COMMISSION

[52 PA. CODE CH. 57]

[L-0980136]

Annual Resource Report Filing Requirements

The Pennsylvania Public Utility Commission (Commission) on January 14, 1999, adopted a proposed rulemaking to amend annual resource report filing requirements appropriate within a competitive generation market. The contact persons are Carl Hisiro, Law Bureau, (717) 783-2812 and Blaine Loper, Bureau of CEEP, (717) 787-3810.

Executive Summary

Section 524(a) of 66 Pa.C.S. (relating to Public Utility Code) (code) requires electric utilities to submit to the Commission information concerning plans and projections for meeting future customer demand. The Commission's regulation under 52 Pa. Code § 57.141(a), promulgated under section 524(c) of the code, requires each jurisdictional electric utility to submit, on or before May 1 of each year, an Annual Resource Planning Report (ARPR) which contains information required under section 524(a) of the code.

In view of the enactment of 66 Pa.C.S. Chapter 28 (relating to Electricity Generation Customer Choice and Competition Act) (act), the Commission is proposing amendments to its existing reporting requirements which are appropriate within a competitive generation market. On September 3, 1998, the Commission issued an advance notice of proposed rulemaking to solicit comments from electric utilities, electric generation suppliers, power marketers and other interested parties. The notice was published in the *Pennsylvania Bulletin* on September 19, 1998 (28 Pa.B. 4724) with a 30-day comment period.

The proposed amendments reduce the reporting horizon for energy demand, connected peak load and number of customers from 20 to 5 years. Information regarding capital investments, energy costs, new generating facilities and expansions of existing facilities will no longer be required. These proposed amendments reflect the changes brought upon by competition in the electric generation segment of the industry.

Commissioners Present: John M. Quain, Chairperson; Robert K. Bloom, Vice Chairperson; David W. Rolka; Nora Mead Brownell; Aaron Wilson, Jr.

Public Meeting held
January 14, 1999

Proposed Rulemaking Order

By the Commission:

Section 524(a) of the code requires electric utilities to submit to the Commission information concerning plans and projections for meeting future customer demand. The Commission's regulation under 52 Pa. Code § 57.141(a), promulgated under section 524(c) of the code, requires each jurisdictional electric utility to submit, on or before May 1 of each year, an ARPR which contains information required under section 524(a) of the code.

In view of the enactment of Chapter 28 of the act, the Commission is proposing amendments to its existing reporting requirements which are appropriate within a competitive generation market. On September 3, 1998, the Commission issued an advance notice of proposed rulemaking to solicit comments from electric utilities, electric generation suppliers, power marketers and other interested parties. The notice was published in the *Pennsylvania Bulletin* on September 19, 1998 (28 Pa.B. 4724) with a 30-day comment period.

Comments were received from the Pennsylvania Electric Association (PEA), the Office of Consumer Advocate (OCA) and NorAm Energy Management, Inc. (NorAm) and reply comments from the Mid-Atlantic Power Supply Association (MAPSA). PEA also filed a response to MAPSA's reply comments. This order discusses the comments received and sets forth, in Annex A, proposed amendments to the regulations regarding electric utility resource planning.

General Comments

PEA submits that, although electric distribution companies (EDCs) can provide data regarding the amount of load they will serve over their transmission and distribution facilities, neither EDCs in their provider of last resort function nor electric generation suppliers (EGSs) can provide long-term forecasts of the amount of supply they will need to serve their customers. While PEA believes annual reports continue to be appropriate, it asserts that the Commission should monitor the matching of customer load with generating capacity at the power pool level. PEA submitted that any reporting requirements concerning the planning of generation resources should apply equally to the entire supply industry, and not just to the EDCs. PEA suggested that the Commission continue the existing summer and winter reliability meetings with representatives of the Pennsylvania-New Jersey-Maryland Interconnection, L.L.C. (PJM) and the East Central Area Reliability Coordination Agreement (ECAR) and explore other ways to obtain information from these entities, if necessary.

The OCA recommended that, given the move toward a competitive generation market, the Commission reduce the type and extent of the current reporting requirements to focus on reliability concerns and to move away from monitoring the economics of generation supply planning. The OCA suggested that, instead of a 20-year detailed look at forecasts, resource alternatives, energy efficiency, economic impacts and generation plans, the ARPR should include a more simple 3 to 5 year projection of an EGS's plans to procure the necessary generation resources to meet its contractual obligations. The OCA also recommended that, to the extent possible, these reporting requirements be coordinated with those of the appropriate Independent System Operator (ISO) or reliability organization to reduce any administrative burden.

NorAm submitted that the existing reporting requirements are not appropriate within a competitive generation market and should be eliminated. NorAm recommended that the Commission rely on the relevant PJM, North American Electric Reliability Council (NERC), ECAR and Mid-Atlantic Area Council (MAAC) reliability and capacity studies and reports to monitor reliability and generation reserve adequacy. NorAm suggested that, if the Commission determines that resource planning filing requirements should be maintained, the requirements should only apply to electric utilities and not to generation suppliers. If the Commission adopts reporting requirements for generation suppliers, NorAm believes that this information should be reported in the aggregate and on a confidential basis.

MAPSA submitted that there is a fundamental distinction between EDCs and EGSs, including the EDC's responsibility of providing default provider-of-last-resort (PLR) service to retail customers. MAPSA averred that, until full competition develops, the EDCs continue to claim a unique status with respect to determining an EGS's costs of energy, capacity and transmission. MAPSA argued that EGSs need more, not less, information regarding the bases for allocating costs. MAPSA requested that any additional reporting requirements for EGSs be considered under two previous rulemaking dockets, namely the Electric Service Reliability rulemaking at Doc. No. L-00970120 and the Licensing Requirements for Electric Generation Suppliers rulemaking at Doc. No. L-00970124.

In its response to MAPSA's comments, PEA requests that the Commission strike MAPSA's comments, since they were filed nearly a month after the filing deadline as self-styled "reply comments" attempting to refute PEA's comments.

Specific Reporting Requirements

In its comments, PEA proposed revised reporting requirements for EDCs. PEA suggested that EDCs continue to be required to file information regarding historical and forecast energy demand, peak load and number of customers; cogeneration and independent power production facilities; scheduled imports and exports; and planned transmission line projects. PEA recommended that the forecast period be reduced from 20 years to 5 years. PEA also recommended the reporting of EGS information, including unregulated loads for the EDC's summer and winter peak periods. PEA further proposed reporting requirements for EGSs, which are identical to those contained in the Commission's licensing regulations in § 54.39.

The OCA submitted that a 3- to 5-year forecast may be appropriate in a restructured industry for the Commission to ensure reliability: a 3-year projection for EGSs serving retail load and a 5-year projection for PLRs. The OCA offered specific preliminary comments regarding each of the current reporting requirements.

As stated previously, NorAm does not believe that the existing reporting requirements are necessary and suggests that the Commission instead rely on reliability and capacity studies and reports prepared by regional reliability organizations.

MAPSA submitted that EDCs should be required to continue to report the same information at least until there is workable competition in the retail market.

Confidentiality Treatment

PEA believed that, if information regarding forecasts of sales of electricity supply by individual companies is required, it should be treated as confidential.

The OCA believed that, if the reporting requirements focus on reliability issues, the need for cost information in the ARPR will be minimized, which should not pose a confidentiality concern.

NorAm asserted that generation resource planning is commercially sensitive in a competitive environment and, if this information is required to be reported to the Commission by EGSs, it should be reported in the aggregate and on a confidential basis.

MAPSA did not take a position on this issue.

Forbearance Issue

Section 2809(e) of the code states, in part:

> The Commission may forbear from applying requirements of this part which it determines are unnecessary due to competition among electric generation suppliers.

66 Pa.C.S. § 2809(3).

PEA submitted that section 2809(e) of the code grants the Commission authority to decide which sections of the code will be applied to the electric supply segment of the industry, including the provision of supply by EDCs to meet their PLR requirements. PEA believed that the General Assembly has delegated discretion to the Commission to refrain from enforcing 66 Pa.C.S. § 524 in light of changes in the electric industry.

The OCA believed that the detailed information required by the existing regulations or section 524 of the code is unnecessary for the Commission to meet its responsibility to ensure the adequacy of capacity reserve margins. The OCA argued that, to the extent that an EDC or PLR can be considered an EGS, the Commission could forbear from applying the unnecessary portions of its regulations. The OCA submitted that meaningful reporting requirements, through regulation, must be in place for all EGSs before the Commission forbears from applying section 524 of the code.

While NorAm does not state so explicitly, the substance of its comments indicate that NorAm believed that the Commission can forbear from applying section 524 requirements of the code which it determines to be unnecessary due to competition in the generation market.

MAPSA argued that section 2809(e) of the code, which concerns the regulation of EGSs, does not apply to section 524 of the code, which refers to public utilities. MAPSA submitted that, even if section 2809(e) of the code could be interpreted to apply to section 524 of the code, the Commission must first determine that there exists "workable competition" among EGSs through a market monitoring process.

In its reply comments, PEA rejected MAPSA's argument that section 2809(e) of the code does not authorize the Commission to forbear from applying section 524 of the code to EDCs. PEA argued that EDCs function as electric suppliers to the extent that they serve as the PLR. Furthermore, PEA submitted that PLR service is an electric supply service evidenced by the fact that the Commission has opened PLR service to competition in many of the restructuring settlements approved to date. In response to MAPSA's position concerning the need for "workable competition" prior to forbearance, PEA stated that it is only asking the Commission to forbear from requiring EDCs to comply with the reporting requirements of section 524 of the code to the extent that those requirements relate to supplying electricity.

Discussion

Recent changes in the electric industry require changes in the way the Commission regulates this industry. There are now EDCs which continue to be regulated and EGSs which compete for a share of the retail electricity market. Under a vertically integrated utility structure, the Commission promulgated the existing reporting requirements to provide long-term load forecast information and the utilities' plans to meet their legal obligation to serve customer load in a least cost manner. Now, as retail choice becomes a reality, the Commission must reevaluate our regulations to reflect the changes brought upon by competition in the electric generation segment of the industry.

We agree with PEA and the OCA that annual reporting of information should be continued, but in a more concise and direct manner. EDCs should continue to provide information relating to basic information, such as connected customer energy demand, seasonal peak load and number of customers. PEA has also suggested a continuation of reporting requirements regarding cogeneration and independent power production as well as scheduled imports and exports of energy and capacity.

We agree with the OCA that reporting of economic data relating to the planning of generation supply and the evaluation and integration of generating resources is unnecessary in a competitive generation market and that a focus on the reliability of the entire electric generation, transmission and distribution system continues to be necessary. We also agree with NorAm that the Commission should rely on such entities as PJM, MAAC, ECAR and NERC to provide regional assessments of the adequacy of generation resources to meet regional needs. These reliability organizations provide frequent evaluations of current and projected assessments of capacity and reserve margins for the reliability regions affecting consumers in this Commonwealth. It is noted that our regulations in § 57.196 require EGSs to maintain generating reserve capacity in compliance with the standards set forth by regional reliability organizations.

We accept the majority of PEA's recommendations for revising the reporting requirements of EDCs. Specifically, we propose to reduce the reporting horizon for energy demand, connected peak load and number of customers to 5 years. As provider-of-last-resort, the EDC will also continue to report its sources of supply necessary to serve customers who do not choose an alternate EGS and those customers served by an EGS which, for whatever reason, is unable to supply scheduled loads within the EDC's service territory. This information will continue to be helpful in determining the scope and extent of retail access in this Commonwealth and provide for some level of tracking the comparative impact of EGSs on the retail electricity market as well as highlighting potential problems with the provision of retail service by EGSs.

Information regarding capital investments and energy costs is no longer required. System cost data under § 57.146 had been required for the derivation of energy and capacity credits for qualifying facilities. System cost data refers to the actual and projected costs of "the utility's own generation." The EDC technically has no generation. Also, as the OCA points out, the PLR service is to be priced at "prevailing market price" and not at the EDC's own cost of generation, which has nothing to do with the generation which may be owned by an affiliated EGS. Thus, the reporting of the information is not necessary within a competitive generation market. Similarly, we propose to eliminate the requirement of an evaluation of the cost effectiveness of feasible supply-side and demand-side resource options under § 57.150.

Section 57.151 (relating to new generating facilities and expansions of existing facilities) has also been eliminated in the proposed rulemaking. While the OCA contended that this section is needed to assist the Commission in ensuring transmission system reliability, we find it is no longer relevant for the following reasons. This section, added in 1988, has never been used. The information required under this section relates mainly to siting issues, over which the Commission has no direct authority. The location of a generating facility and its connection to the grid must be approved by system reliability entities, such as MAAC. Furthermore, since electric generation has been deregulated, there is no need for this information.

We agree with the OCA that the regulations should be streamlined in terms of both the type and extent of reporting requirements and that the existing reporting formats are no longer applicable. Thus, we propose to eliminate the specific forms and schedules under § 57.152 to permit greater flexibility in the development of reporting formats without diminishing the effectiveness of the regulation. We also propose, consistent with the OCA's suggestion, to streamline the public reporting requirements under § 57.154.

With regard to the applicability of the reporting requirements to EGSs, as we discuss in the following, section 524 of the code applies only to public utilities, which are included in the definition of an EDC under section 2803 of the code. We do not, therefore, intend to apply the proposed reporting requirements to EGSs. In addition, this position is particularly relevant to these proposed revisions where we are removing generation-related reporting requirements and focusing instead on reliability-related reporting requirements.

On the forbearance issue, MAPSA argued that section 524 of the code refers to public utilities, while section 2809(e) of the code refers to EGSs and, thus, forbearance is not permitted in this case. This argument is seriously flawed since, except for Chapter 28, the entire code refers to public utilities. It would make absolutely no sense for the General Assembly to grant this Commission the authority to forbear from applying certain requirements of "this Part," obviously referring to 66 Pa.C.S. Part I, if it only referred to EGSs. MAPSA's argument is without merit.[1]

With regard to MAPSA's alternative position that forbearance should be postponed until there is "workable competition," section 2809(e) of the code simply gives the Commission the ability to forbear from enforcing any section of the code that is no longer necessary "due to competition among electric generation suppliers." Given that, as of January 2, 1999, over two-thirds of the retail market will be open to competing EGSs and the rest of the market will be open to competition by January 2, 2000, we believe this express qualification has been met.

Clearly, it was the intent of the General Assembly to give the Commission the authority to determine which requirements of the code we should refrain from applying within the context of the newly restructured electric industry. With the retail generation market now so irreversibly opened to competition, we have the authority, under section 2809(e) of the code, to forbear from applying any requirements of the code, including section 524 and existing regulations promulgated thereto, which we find no longer to be necessary because of that competition.

[1] Notwithstanding PEA's assertion that MAPSA's comments should be rejected outright, because they were untimely filed, we have taken MAPSA's comments into consideration. While we are equally concerned that parties may try to abuse the process by filing late comments in a rulemaking proceeding, as a practical matter, we would have to consider MAPSA's comments in any event before the proposed regulations are finalized. In any case, the timeliness of MAPSA's comments is a moot issue since we reject MAPSA's position on the forbearance issue.

Thus, we propose to amend our existing regulations, §§ 57.141—57.154, to reflect the changes taking place in the electric service industry. Accordingly, under sections 501, 1501, 1504 and 2809 of the Public Utility Code, 66 Pa.C.S. §§ 501, 1501, 1504 and 2809, and the Commonwealth Documents Law (45 P. S. § 1202 et. seq.) and the regulations promulgated thereunder in 1 Pa. Code §§ 7.1—7.4, we shall issue for comment proposed amendments to §§ 57.141—57.154; *Therefore*,

It Is Ordered that:

1. The proposed amendments to 52 Pa. Code §§ 57.141—57.154, to read as set forth in Annex A, are issued for comment.

2. The Secretary shall certify this order and Annex A and deposit them with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

3. Interested persons may submit an original and 15 copies of written comments to Secretary, Pennsylvania Public Utility Commission, P. O. Box 3265, Harrisburg, PA, 17105-3265, within 60 days from the date this order is published in the *Pennsylvania Bulletin*. A copy of written comments shall also be served upon the Commission's Bureau of Conservation, Economics and Energy Planning.

4. The Secretary shall submit this order and Annex A to the Office of Attorney General for approval as to legality.

5. The Secretary shall submit this order and Annex A to the Governor's Budget Office for review of fiscal impact.

6. The Secretary shall submit this order and Annex A for review by the designated standing committees of both Houses of the General Assembly, and for review and approval by the Independent Regulatory Review Commission.

7. A copy of this order and Annex A shall be served upon the Office of Consumer Advocate, the Office of Small Business Advocate, the Office of Trial Staff, all jurisdictional EDCs, all licensed EGSs, all parties of record and all Electric Competition Stakeholders.

JAMES J. MCNULTY,
Secretary

Fiscal Note: 57-203. No fiscal impact; (8) recommends adoption.

Annex A

TITLE 52. PUBLIC UTILITIES

PART I. PUBLIC UTILITY COMMISSION

Subpart C. FIXED SERVICE UTILITIES

CHAPTER 57. ELECTRIC SERVICE

Subchapter L. ANNUAL RESOURCE PLANNING REPORT

§ 57.141. General.

(a) **[A public utility] An electric distribution company (EDC), as defined in 66 Pa.C.S. § 2803 (relating to definitions),** shall submit to the Commission the Annual Resource Planning Report (ARPR) that contains the information prescribed in this subchapter. An original and **[seven] three** copies of the report shall be submitted on or before May 1, **[1995] 2000**, and May 1 of each succeeding year. One copy of the report shall also be submitted to the Office of Consumer Advocate (OCA) **[, the Pennsylvania Energy Office (PEO)]** and the Office of Small Business Advocate (OSBA). The name and telephone number of the persons having knowledge of the matters, and to whom inquiries should be addressed, shall be included.

* * * * *

(d) As a condition to receiving a copy of the ARPR, the OCA**[, PEO]** and OSBA shall be obligated to honor and treat as confidential those portions of the report designated by the utility as proprietary.

(1) If the Commission, OCA, **[PEO,]** OSBA or any person challenges the proprietary claim as frivolous or not otherwise justified, the Secretary's Bureau will issue, upon written request, a Secretarial letter directing the **[utility] EDC** file a petition for protective order under § 5.423 (relating to orders to limit availability of proprietary information) within 14 days.

* * * * *

§ 57.142. Forecast of energy **[resources, demands and reserves] demand, peak load and number of customers.**

(a) The Annual Resource Planning Report (ARPR) shall include a forecast of energy demand in megawatt-hours per calendar year**. [, annual system peak demand in megawatts and number of customers (year end) displayed by component parts, as shown in Form-IRP-ELEC 1A, Form-IRP-ELEC 1B and Form-IRP-ELEC 1C, respectively.**

(1) The data presented in Form-IRP-ELEC 1A, Form-IRP-ELEC 1B and Form-IRP-ELEC 1C shall consist of the following:

(i) The past 5 years actual historical data.

(ii) A 20-year forecast including the current year.

(2) The forecast shall include a minimum of three load growth scenarios: base, low and high. The base case is the growth scenario which is used by the utility as a basis for its resource planning.

(3) The load growth scenarios shall reflect the effects of existing and projected load modifications resulting from the utility's conservation and load management activities as defined in § 57.149 (relating to energy conservation and load management).

(4) A description of the methodology and assumptions used by the utility shall also be provided.]

(1) The data shall include the past year's actual historical data and a 5-year forecast including the current year.

(2) The data shall be displayed by the following component parts:

(i) Residential, commercial and industrial sectors.

(ii) Other demand, including public street and highway lighting, other sales to public authorities and sales to railroads and railways.

(iii) Sales for resale.

(iv) Total consumption, as the sum of subparagraphs (i)—(iii).

(v) System losses and company use.

(vi) Net energy for load, as (iv) minus (v).

(b) **[A forecast of peak resources, demands and reserves in megawatts for the 20-year period beginning with the current year (year zero), as indicated in Form-IRP-ELEC 2A and Form-IRP-ELEC 2B, shall be included. The data shall be provided for both summer and winter seasons, the latter being the winter of year 0-1, 1-2, 2-3 and the like.**

(c) Reporting utilities which are subsidiaries of a larger electric utility system operated on a coordinated system basis spanning the boundaries of this Commonwealth shall also file Form-IRP-ELEC 1A, Form-IRP-ELEC 2A and Form-IRP-ELEC 2B for the larger system.]

The ARPR shall include a forecast of connected peak load.

(1) The data shall include the past year's actual historical data and a 5-year forecast including the current year.

(2) The data shall be displayed by the following component parts:

(i) Peak loads for both summer and winter seasons, the latter being the winter following the summer of the past year.

(ii) The date and time of the summer and winter peak loads.

(iii) Annual peak load.

(iv) Annual load factor.

(c) The ARPR shall include a forecast of the number of connected customers.

(1) The data shall include the past year's actual historical data and a 5-year forecast including the current year.

(2) The data shall be displayed by the following component parts:

(i) Residential, commercial and industrial sectors.

(ii) Other, including public street and highway lighting, other sales to public authorities and sales to railroads and railways.

(iii) Total number of customers.

§ 57.143. Existing and planned generating capability.

(a) The Annual Resource Planning Report (ARPR) shall include a description of existing **and planned** generating capability **[in summary form as indicated in Form-IRP-ELEC 3] which is or will be allocated to serve connected load pursuant to the electric distribution company's (EDC's) provider-of-last-resort function in 66 Pa.C.S § 2807(e) (relating to duties of electric distribution companies).**

(1) The data **[presented in Form-IRP-ELEC 3]** shall include **station name and unit number, location, date installed or to be installed, unit type, primary fuel type and fuel transportation method, summer and winter net capability in megawatts,** changes in capability occurring during the past year **and percent ownership share.**

(2) **The data shall include those facilities which are owned in whole or in part by the reporting EDC either directly or indirectly, through a subsidiary or affiliate; or allocated to the EDC by an entity to serve the entity's load if the load is included in the EDC's forecast.** A jointly owned unit shall be designated as such and the **[utility's] EDC's** share of the unit shall be indicated.

(b) **[The ARPR shall include a description of future generating capability installations, changes and removals, for the 20-year period in summary form as indicated in Form-IRP-ELEC 4.**

(1) The data presented in Form-IRP-ELEC 4 shall include those facilities which are:

(i) Owned in whole or in part by the reporting utility either directly or indirectly, through a subsidiary.

(ii) Allocated to the utility by an entity to serve the entity's load if the load is included in the utility's forecast.

(2) A jointly owned unit shall be designated as such and the utility's share of the unit shall be indicated.

(3) A discussion of the potential for additional system capability achieved through productivity and longevity improvements to the existing system shall be provided.

(i) A summary tabulation of major capital additions and replacements, including environmental retrofits, which are necessary over the next 5 years to assure continued operation at current levels of performance, shall be provided for each coal-fired and base load generating station.

(ii) This discussion shall include economic analyses of major planned capital investments in base load generating stations which will result in either an increase in net dependable capacity or a continuation of operation beyond the plant's normal operating life. The analyses may be performed on an aggregate capital budget basis for each base load station being evaluated.

(iii) If a generating unit is scheduled to be removed from normal operation within the next 2 years, an economic analysis shall be provided which demonstrates that discontinuance of the unit from normal operation is more cost effective than continuing its operation, either with or without capital additions or operating improvements.]

The ARPR shall include a synopsis of major occurrences where electric generation suppliers (EGSs) were unable to supply scheduled loads within the EDC's service territory during the previous year. The synopsis shall include the EGS's name, the amount of energy and capacity involved in megawatt-hours and megawatts, respectively, the period of time involved and other pertinent information.

§ 57.144. Transmission line projection.

(a) The Annual Resource Planning Report (ARPR) shall contain a description of transmission lines, as defined in § 57.1 (relating to definitions), or any portions thereof for which construction or acquisition of right-of-way is scheduled to begin within the **[10]5**-year forecast period; and additions to or modifications of existing electric supply lines which will result in the creation of a transmission line, whether or not located entirely on existing rights-of-way, public roads or the property of the sole customer served by the line, for which construction or acquisition of right-of-way is scheduled to begin within the **[10] 5**-year forecast period.

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(e) The ARPR shall include an estimate of change in import and export capability or change in system transmission constraints which will result from any planned transmission change identified in subsection (a).

§ 57.145. Cogeneration and **[small] independent** power production.

The Annual Resource Planning Report (ARPR) shall include a description of each existing and planned cogeneration**[, small power production]** and independent power production facility, from which the **[utility] electric distribution company (EDC)** will purchase energy or capacity, or both**[, as indicated in Form-IRP-ELEC 5].** Projects shall be grouped by status and subtotals shall be provided.

(1) The data **[presented in Form-IRP-ELEC 5]** shall include the amount of energy in kilowatt-hours from each facility during the past calendar year, or the expected amount of energy to be purchased from the facility, and the contract capacity in kilowatts, if applicable.

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(3) If an entity has requested anonymity, the **[utility] EDC** does not have to name it, but shall only provide the facility's characteristics.

§ 57.146. **[System cost data] (Reserved).**

[(a) The Annual Resource Planning Report (ARPR) shall include the utility's actual energy costs for the previous year and a forecast of energy costs for the 10-year period, based on the utility's preferred resource plan, as indicated in Form-IRP-ELEC 6. These costs shall include the costs of fuel, variable operation and maintenance expenses, and other costs associated with the utility's own generation. These costs shall be stated on a mills per kilowatt-hour basis, during daily peak and off-peak periods, for each season: the summer season being June through September and the winter season being December through March. Other months shall be grouped together for the current calendar year and each of the next 10 years. Levelized projected energy costs shall also be provided for the 10-year period as stated in § 57.34(b)(2)(iii) (relating to purchases from qualifying facilities). In support of these cost estimates, each utility shall provide the following:

(1) A brief description of the methodology used to estimate the energy costs.

(2) The average cost of fuel in cents per mmbtu during the past year by plant and fuel type; for example: nuclear, coal, oil and gas, and the current projection of the inflation rate for each fuel type and the general inflation rate.

(3) The projected source and average cost of electric energy supply for each year of the 10-year period by fuel type.

(4) The variable operations and maintenance expense.

(5) Other relevant factors.

(b) For each planned capacity addition provided under § 57.143 (relating to existing and planned generating capability), the ARPR shall include the following:

(1) The estimated total cost at completion in current (actual) and constant (corrected for inflation) dollars.

(2) The amount currently expended, if applicable.

(3) The expected annual expenditures to completion in current (actual) and constant (adjusted for inflation) dollars.

(4) The projected life of the plant.

(5) The levelized fixed charge rate, including rate of return, depreciation, and taxes, and its calculation.

(6) The expected annual net generation.

(7) The fixed and variable operations and maintenance expense.

(8) Estimated energy cost, including costs of fuel, variable operations and maintenance expenses, and other costs associated with the facility's generation in $/KWH for 10 years.

(9) Estimated capacity cost, including the total estimated cost of construction, in current dollars adjusted by the levelized fixed charge rate, and the estimated levelized fixed operations and maintenance cost over the life of the facility in $/KWH for 10 years.

(c) A distribution utility which obtains its requirements for electric energy and capacity from another electric utility shall file the rates at which it currently purchases the energy and capacity instead of the data required under subsection (a) and (b).]

§ 57.147. **[Forecast of generating capability and generation distribution] Scheduled imports and exports.**

(a) The Annual Resource Planning Report (ARPR) shall include a forecast of **[generating capability distribution] scheduled imports and exports** in megawatts**[, as indicated in Form-IRP-ELEC 7A and Form-IRP-ELEC 7B].**

(1) Actual data for the past **[5 years] year** and estimated data for the ensuing **[20] 5** years shall be provided.

(2) The data shall be provided for both summer and winter seasons, the latter being the winter **[of year 0-1, 1-2, 2-3 and the like] following the summer of the past year.**

(3) **[Total capability shall include the sum total of the generating capability described in § 57.143 (relating to existing and planned generating capability).**

(4) Net transactions, scheduled imports less scheduled exports, shall include purchases from and sales to other electric utilities and systems, including utility subsidiaries, public utilities, municipal systems, electric cooperatives and cogeneration and small power production facilities.

(5) Total resources, the sum total capability and net transactions, shall correspond with total resources in Form-IRP-ELEC 2A and Form-IRP-ELEC 2B.

(6)] A breakdown of scheduled imports and exports shall be provided**[, as indicated in Form-IRP-ELEC 7B, for the 20-year period] including the name and type of each participating entity.**

(b) The ARPR shall include a forecast of **[generation distribution in gigawatt-hours, as indicated in Form-IRP-ELEC 8A and Form-IRP-ELEC 8B] scheduled imports and exports in megawatt-hours.**

(1) Actual data for the past **[5 calendar years] year** and estimated data for the ensuing **[20] 5** years shall be provided.

(2) **[Total net generation shall include the sum total of electric energy produced by the generating units owned in whole or in part by the reporting utility either directly or indirectly, through a subsidiary, less pumping energy, if applicable.**

(3) Net energy imports or exports shall include purchases from, and sales to, other electric utilities and systems, including utility subsidiaries, public utilities, municipal systems, electric cooperatives and cogeneration and small power production facilities.

(4) Total energy for load, the sum of total net generation and net energy imports or exports, shall agree with the corresponding totals in Form-IRP-ELEC 1A.

(5)] A breakdown of projected imports and exports shall be provided**[, as indicated in Form-IRP-ELEC 8B, for the 20-year period] including the name and type of each participating entity.**

§ 57.148. Demand, resource and energy data.

The Annual Resource Planning Report (ARPR) shall include a summary of demand, resource and energy data for the past year**[, as indicated in Form-IRP-ELEC 9].**

* * * * *

(2) **[Peak load data shall include native and internal load only.**

(3) The report shall identify capacity, which was unavailable at the time of peak and provide a breakdown of capacity not available.]

The report shall provide peak day purchases and sales of the electric distribution company in megawatts and calendar year purchases and sales in megawatt-hours.

(3) The report shall identify each electric generation supplier's peak day unregulated load in megawatts and calendar year sales in megawatt-hours.

§ 57.149. Energy conservation and load management.

[(a) Except as required by subsection (c), the] The Annual Resource Planning Report (ARPR) shall include a detailed description of conservation and load management programs implemented or operational during the past calendar year and all programs which are proposed to be implemented within 1 year following the filing of this report.

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(3) **[The program description shall conform to the information requirements of Form-IRP-ELEC 10A.**

(4) A summary of all programs shall be provided, as indicated on Form-IRP-ELEC 10B.

(5) For each program with an annual utility expenditure of more than $100,000 or more than 0.1% of total annual revenue, whichever is less, excepting informational, educational or research and development programs, the utility shall submit a cost-benefit analysis using the common evaluation methodology set forth in § 57.153 (relating to evaluation methodology), as indicated on Form-IRP-ELEC 10C and Form-IRP-ELEC 10D.

(6) The Commission, through its Bureau of Conservation, Economics and Energy Planning, may issue a list of specific conservation and load management programs which shall be considered for implementation by each designated utility. The utility shall provide information documenting the consideration of these and other conservation and load management options and supporting the utility's decision of whether or not to implement the options.

(b) The ARPR shall include a forecast of the potential for promoting and ensuring the full utilization of practical and economical energy conservation and load management, within the utility's service territory, for the 20-year period, as indicated in Form-IRP-ELEC 10E.

(1) The data presented in Form-IRP-ELEC 10E shall include general conservation of electric energy, load shifting from peak to off-peak periods and peak load reductions, which have the potential for occurring through utility efforts, absent the effects of price elasticity market-induced conservation and building and appliance efficiency standards.

(2) A discussion of how the existing and planned utility programs provided by subsection (a) do or do not adequately attain the utility's potential for general electric energy conservation, load shifting and peak load reductions shall be provided.

(c) The ARPR shall include a summary description of the utility's most recent approved Demand Side Management Program Plan.]

The program description shall include actual or anticipated results and a breakdown of monetary and personnel resources.

§ 57.150. **[Evaluation and integration of resources] (Reserved).**

[(a) The ARPR shall include an evaluation of the cost effectiveness of feasible supply-side and demand-side resource options. A detailed description of the methodology and assumptions used by the utility also shall be included.

(b) A comparison of the overall potential revenue requirement impacts of feasible supply-side and demand-side resource options shall be included.

The revenue requirement impacts shall be stated in total dollars and in cents per kilowatt-hour generated, saved or purchased or in dollars per kilowatt installed, reduced, shifted or contracted for, where appropriate.

(c) A detailed narrative explaining the decision-making process used by the utility in the integration of supply-side and demand-side resource options to derive the preferred, least-cost resource mix to meet customer demand, shall be included.

(1) The narrative shall discuss and set forth the preferred resource mix developed for the base case load growth scenario. The narrative shall discuss what modifications to that resource plan would be necessary if either of the other load growth scenarios were to occur.

(2) Alternative plans developed for the base case load growth scenario shall be identified, including the year by year resource modifications for each plan. A comparison of the cost to the utility and its ratepayers of its preferred plan to meet customer demand and alternative plans considered for the 20-year period, as indicated in Form-IRP-ELEC 11, shall be provided. The cost shall be stated in total annual dollars and in cents per kilowatt-hour sold.

(3) A discussion of system reliability and the uncertainties and risks associated with the resource options, and how they have been incorporated into the decision-making process, shall be provided. If the utility's preferred resource mix is not the least-cost resource mix, the utility shall document why the least-cost resource mix was not chosen.]

§ 57.151. **[New generating facilities and expansions of existing facilities] (Reserved).**

[The Annual Resource Planning Report (ARPR) shall include the following information for new public utility generating facilities and expansions of existing generating facilities, for which the site and the type of facility and fuel have been selected:

(1) A general description of the planned facility which includes the following items:

(i) The facility name.

(ii) The number of units.

(iii) The unit type.

(iv) The primary and secondary fuel types.

(v) The summer and winter generating capability.

(vi) The site acreage.

(vii) The estimated capital investment for land, land improvements, buildings and equipment.

(viii) The estimated month and year of construction commencement, completion and commencement of service.

(ix) The type and cost of necessary air and water pollution abatement methods and equipment.

(2) Estimates of applicable capital and intangible costs for the various components of the facility as in the Federal Energy Regulatory Commission Uniform System of Electric Plant Accounts.

(3) A discussion of the proposed and alternative sites for the construction and operation of the planned facilities.

(i) For each site, maps of suitable detail shall be provided which show the following:

(A) The proposed facility.

(B) Major population centers and geographic boundaries.

(C) Major transportation routes and utility corridors.

(D) Major institutions, parks and recreational areas.

(E) Major bodies of water.

(F) Topographic contours.

(G) Individual residential, commercial and industrial buildings and installations.

(ii) A brief discussion of the methodology used in the utility's site selection process, including steps taken to insure public involvement in the siting process, shall be provided.

(iii) A general discussion of the advantages and disadvantages of each site, including technical, financial, environmental and social considerations, and an estimate of the effect of each site on annual capital and operating costs, shall be provided.

(4) A discussion of the proposed and alternative types of facilities and fuels considered.

(i) A brief discussion of the methodology used in the utility's facility selection process shall be provided.

(ii) A general discussion of the advantages and disadvantages of each facility type and fuel, including technical, financial, environmental and social considerations, and an estimate of the effect of each facility type and fuel on annual capital and operating costs, shall be provided.]

§ 57.152. Formats.

In preparing the Annual Resource Planning Report required by this subchapter, each **[public utility] electric distribution company** shall use the current forms and schedules specified by the Bureau of Conservation, Economics and Energy Planning**. [, which shall include the following:**

(1) Form-IRP-ELEC 1A—Historical and Forecast Energy Demand (MWH); Form-IRP-ELEC 1B—Historical and Forecast Peak Demand (MW); Form-IRP-ELEC 1C—Historical and Forecast Number of Customers (Year End).

(2) Form-IRP-ELEC 2A—Estimated Peak Resources, Demands and Reserves for the 10-year Period (MW); Form-IRP-ELEC 2B—Estimated Peak Demands, Resources and Reserves for the 10-20 Year Period (MW).

(3) Form-IRP-ELEC 3—Existing Generating Capability (as of January 1—Current Year).

(4) Form-IRP-ELEC 4—Future Changes and Removals to Existing Generating Capability for the 20-Year Period.

(5) Form-IRP-ELEC 5—Cogeneration and Small Power Production Facilities.

(6) Form-IRP-ELEC 6—System Cost Data.

(7) Form-IRP-ELEC 7A—Distribution of Net Generating Capability by Fuel Type for the 20-Year Period (MW); Form-IRP-ELEC 7B—Scheduled Imports and Exports (MW).

(8) Form-IRP-ELEC 8A—Distribution of Net Generation by Fuel Type for the 20-Year Period (GWH); Form-IRP-ELEC 8B—Scheduled Imports and Exports (MWH).

(9) Form-IRP-ELEC 9—Summary of Demands, Resources and Energy for the Past Year.

(10) Form-IRP-ELEC 10A—Conservation and Load Management Program Description; Form-IRP-ELEC 10B—Conservation and Load Management Program Summary; Form-IRP-ELEC 10C—Conservation and Load Management Program Cost-Benefit Analysis Inputs; Form-IRP-ELEC 10D—Conservation and Load Management Program Cost-Benefit Analysis Results; Form-IRP-ELEC 10E—Assessment of Conservation and Load Management Potential for the 20-Year Period.

(11) Form-IRP-ELEC 11—Comparison of Costs of Preferred Resource Plan with Alternative Plans.]

§ 57.153. **[Evaluation methodology] (Reserved).**

[A public utility shall utilize cost-benefit methodologies as prescribed by the Bureau of Conservation, Economics and Energy Planning to evaluate the costs and benefits of conservation and load management programs, and demand-side management programs. The cost-benefit methodologies shall be utilized by the utility during the next program year after they are prescribed.]

§ 57.154. Public information and distribution.

The Annual Resource Planning Report shall be accompanied by a summary which is suitable for public distribution. **[Utilities] Electric distribution companies** shall maintain copies of the summary open to public inspection during normal business hours.

[(1) The summary shall include a 2-year implementation plan specifying activities scheduled for the acquisition and development of the least-cost resources delineated in this report, which are to take place during the ensuing 2 years.

(2) Informal sessions may be scheduled by the Bureau of Conservation, Economics and Energy Planning for reviewing the 2-year implementation plans and providing an opportunity for interested parties to participate in the review process.]

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