CHAPTER 216B

PUBLIC UTILITIES

216B.01 LEGISLATIVE FINDINGS.

It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers. Because municipal utilities are presently effectively regulated by the residents of the municipalities which own and operate them, and cooperative electric associations are presently effectively regulated and controlled by the membership under the provisions of chapter 308A, it is deemed unnecessary to subject such utilities to regulation under this chapter except as specifically provided herein.

History: *1974 c 429 s 1; 1978 c 795 s 1; 1989 c 356 s 8*

216B.013 [Renumbered 216B.8109]

216B.02 DEFINITIONS.

Subdivision 1. **Scope.** For the purposes of this chapter, the terms defined in this section have the meanings given them.

Subd. 1a. **Commission.** "Commission" means the Public Utilities Commission.

Subd. 1b. **Commissioner.** "Commissioner" means the commissioner of the Minnesota Department of Commerce.

Subd. 2. **Corporation.** "Corporation" means a private corporation, a public corporation, a municipality, an association, a cooperative whether incorporated or not, a joint stock association, a business trust, or any political subdivision or agency.

Subd. 2a. **Department.** "Department" means the Department of Commerce of the state of Minnesota.

Subd. 2b. **Municipality.** "Municipality" means any city however organized.

Subd. 3. **Person.** "Person" means a natural person, a partnership, or two or more persons having a joint or common interest, and a corporation as hereinbefore defined.

Subd. 3a. **Propane.** "Propane" means a gas made of primarily propane and butane, and stored in liquid form in pressurized tanks.

Subd. 3b. **Propane storage facility.** "Propane storage facility" means a facility designed to store or capable of storing propane in liquid form in pressurized tanks.

Subd. 4. **Public utility.** "Public utility" means persons, corporations, or other legal entities, their lessees, trustees, and receivers, now or hereafter operating, maintaining, or controlling in this state equipment or facilities for furnishing at retail natural, manufactured, or mixed gas or electric service to or for the public or engaged in the production and retail sale thereof but does not include (1) a municipality or a cooperative electric association, organized under the provisions of chapter 308A, producing or furnishing natural, manufactured, or mixed gas or electric service; (2) a retail seller of compressed natural gas used as a vehicular fuel which purchases the gas from a public utility; or (3) a retail seller of electricity used to recharge a battery that powers an electric vehicle, as defined in section 169.011, subdivision 26a, and that is not otherwise a public utility under this chapter. Except as otherwise provided, the provisions of this chapter shall not be applicable to any sale of natural, manufactured, or mixed gas or electricity by a public utility to another public utility for resale. In addition, the provisions of this chapter shall not apply to a public utility whose total natural gas business consists of supplying natural, manufactured, or mixed gas to not more than 650 customers within a city pursuant to a franchise granted by the city, provided a resolution of the city council requesting exemption from regulation is filed with the commission. The city council may rescind the resolution requesting exemption at any time, and, upon the filing of the rescinding resolution with the commission, the provisions of this chapter shall apply to the public utility. No person shall be deemed to be a public utility if it furnishes its services only to tenants or cooperative or condominium owners in buildings owned, leased, or operated by such person. No person shall be deemed to be a public utility if it furnishes service to occupants of a manufactured home or trailer park owned, leased, or operated by such person. No person shall be deemed to be a public utility if it produces or furnishes service to less than 25 persons.

Subd. 5. **Rate.** "Rate" means every compensation, charge, fare, toll, tariff, rental, and classification, or any of them, demanded, observed, charged, or collected by any public utility for any service and any rules, practices, or contracts affecting any such compensation, charge, fare, toll, rental, tariff, or classification.

Subd. 6. **Service.** "Service" means natural, manufactured, or mixed gas and electricity; the installation, removal, or repair of equipment or facilities for delivering or measuring such gas and electricity.

Subd. 6a. **Submetering.** "Submetering" means measuring, by a building's owner, through mechanical or electronic devices, the use of electricity by occupants in multiple-unit residential or commercial buildings to fairly apportion the entire electrical costs for the building among its occupants.

Subd. 6b. **Synthetic gas.** "Synthetic gas" means flammable gas created from (1) gaseous, liquid, or solid hydrocarbons, or (2) other organic or inorganic matter. Synthetic gas includes hydrogen or methane produced through processing, but does not include propane.

Subd. 7. [Renumbered subd 1a]

Subd. 8. [Renumbered subd 2a]

Subd. 9. [Renumbered subd 2b]

Subd. 10. **Transmission company.** "Transmission company" means persons, corporations, or other legal entities and their lessees, trustees, and receivers, engaged in the business of owning, operating, maintaining, or controlling in this state equipment or facilities for furnishing electric transmission service in Minnesota, but does not include public utilities, municipal electric utilities, municipal power agencies, cooperative electric associations, or generation and transmission cooperative power associations.

Subd. 11. **Data center.** "Data center" means a facility that is designed to have a load of 100 megawatts or more and whose primary purpose is the storage, management, and processing of digital data via the interconnection and operation of information technology and network telecommunications equipment, including all related facilities and infrastructure for backup electricity generation, power distribution, environmental control, cooling, and security.

Subd. 12. **Qualified large-scale data center.** "Qualified large-scale data center" has the meaning given in section 297A.68, subdivision 42, paragraph (e).

History: *1974 c 429 s 2; 1978 c 795 s 2; 1980 c 614 s 123; 1981 c 17 s 1; 1981 c 144 s 1; 1981 c 365 s 9; 1983 c 366 s 1,2; 1984 c 428 s 1; 1985 c 248 s 70; 1989 c 356 s 9; 1Sp2001 c 4 art 6 s 34-36; 2005 c 97 art 1 s 1; 2009 c 134 s 4; 2011 c 97 s 5; 1Sp2015 c 1 art 3 s 14-16; 1Sp2025 c 12 s 7,8*

216B.022 SUBMETERING IN SHARED-METERED RESIDENTIAL BUILDINGS.

Subdivision 1. **Definitions.** (a) For the purposes of this section and sections 216B.023 and 216B.024, the following terms have the meanings given.

(b) "Landlord" has the meaning given in section 504B.001, subdivision 7. Landlord includes a third-party billing agent.

(c) "Nonresidential building" means a building that is not a residential building.

(d) "Nonusage charges" means the total of the charges on the utility bill from a utility provider that represent all nonconsumption-based charges and fees, including but not limited to fixed-meter or service charges, taxes, surcharges, and other fees.

(e) "Shared-metered residential building" means a residential building with multiple separate residential dwelling units where the building's utility service is measured by fewer meters than the number of separate dwelling units in the building. Shared-metered residential building does not include a manufactured home park.

(f) "Submeter" means a meter that (1) is owned or installed by the landlord or by a third-party billing agent or other agent of the landlord, and (2) measures utility service consumed solely within an individual dwelling unit in the shared-metered residential building.

(g) "Tenant" means a person who is occupying a dwelling unit in a shared-metered residential building under a lease or contract, whether oral or written, that requires the payment of money or exchange of services. Tenant includes all other regular occupants of the subject dwelling unit.

(h) "Third-party billing agent" means a person or entity, other than the property owner, that performs one or more utility management services at a shared-metered residential building on behalf of a landlord, including but not limited to installing submeters, reading submeters, or handling utility billing or collections, or both.

(i) "Utility provider" means a public utility, a municipal utility, or a cooperative electric association providing utility service.

(j) "Utility service" means natural gas and electricity.

Subd. 2. **Submetering in shared-metered residential buildings.** (a) A landlord of a shared-metered residential building with installed submeters is subject to the commission's authority under this chapter.

(b) On or after January 1, 2025, all submeters installed by a landlord to measure utility service must meet standards established by the American National Standards Institute.

(c) All submeters, regardless of when the submeter was installed, must accurately measure utility service.

Subd. 3. **Submetering in nonresidential buildings.** Nothing in this chapter grants the commission or a public utility the authority to limit the availability of submetering to a nonresidential building occupant when the building is served by a public utility's master meter which measures the total electric energy delivered to the building.

Subd. 4. **Inaccurate submeters.** (a) If a tenant notifies the landlord in writing that the tenant suspects the submeter is incorrectly registering the tenant's utility service and includes an explanation for the suspicion, the landlord must promptly investigate to determine whether the submeter is inaccurate. If the submeter is inaccurate, the landlord must either repair or replace the submeter or inform the tenant in writing why no corrective action is believed necessary.

(b) If the inaccurate submeter has resulted in an overcharge, the landlord must promptly refund the difference between what the tenant paid and what the tenant would have paid if the submeter had correctly registered the tenant's utility service.

(c) If the inaccurate submeter has resulted in an undercharge, the landlord may bill the tenant the difference between what the tenant paid and what the tenant would have paid if the submeter had correctly registered the tenant's utility service for a period not exceeding the previous six months. Any undercharge the landlord seeks to collect must be recovered in accordance with section 216B.023, subdivision 8.

(d) If a tenant has notified the landlord that the tenant suspects the tenant's submeter is incorrectly registering the tenant's utility service as provided in paragraph (a) and the landlord has failed within a reasonable time to check the submeter and provide the tenant with the results of a meter test demonstrating the submeter is accurate, the landlord is prohibited from recovering from the tenant any undercharge for the period between the date of the tenant's notification and the date the submeter was checked.

Subd. 5. **Submeter fees.** A landlord is prohibited from charging to or collecting from tenants any administrative, capital, or any other expenses associated with the installation, maintenance, repair, replacement, or reading of submeters, unless the expense is due to the tenant's willful, malicious, or negligent conduct. Nothing in this subdivision prevents the landlord from imposing a late payment charge, as provided under section 216B.023, subdivision 6, or an administrative billing charge, as provided under section 216B.023, subdivision 4.

History: *1983 c 366 s 3; 2024 c 107 s 1*

216B.023 SHARED-METERED RESIDENTIAL BUILDINGS; BILLING; CONSUMER PROTECTIONS.

Subdivision 1. **Billing requirements for submetered service.** (a) If utility service is submetered, utility bills provided by landlords to tenants must be based on actual submeter readings. If natural gas service is apportioned, landlords must comply with section 504B.216, subdivisions 5 and 6.

(b) Landlords are prohibited from billing submetered tenants or tenants whose natural gas service is apportioned less frequently than the landlord is billed by the utility. Landlords must include in the lease, or provide a written statement at the outset of the lease term, notice of when utility bills will be issued.

(c) Landlords must include the following information on each submetered utility service bill:

(1) the present and last preceding submeter readings;

(2) the date of the present reading;

(3) the rate at which the utility service is being billed, the amount of the service billed at the rate, and the rate at which the landlord is being billed by the utility provider for the utility service;

(4) the tenant's portion of taxes and surcharges;

(5) if any, the portion of any bill credit the landlord received from the utility provider that is credited to the tenant;

(6) any administrative billing charge, as provided in subdivision 4;

(7) the total amount of the bill; and

(8) the date by which payment is due; the date after which, if the bill is not paid, a late payment charge may be imposed; and the amount of the charge, if any, as provided in subdivision 6.

Subd. 2. **Separate billing for electricity.** (a) A landlord who bills a tenant separately from rent for electricity service (1) must not apportion the service; (2) must comply with this section, section 216B.022, and applicable provisions of section 504B.216; and (3) is subject to section 216B.024.

(b) A landlord who submeters electricity must:

(1) charge only for the electricity used in the tenant's unit, calculated by multiplying the kilowatt-hours used during the billing period, as measured by the submeter, by the rate charged to the landlord by the utility provider. A landlord must not charge a tenant for electricity consumed in common areas or in spaces used exclusively or primarily by the landlord;

(2) charge a tenant only for the tenant's pro rata share of nonusage charges, calculated by dividing the charges the landlord is billed by the utility provider equally among the number of units in the building; and

(3) deduct from a tenant's total bill the tenant's pro rata share of any bill credits or adjustments received by the landlord on the bill from the utility provider by dividing the credit or adjustment equally among the number of units in the building.

Subd. 3. **Separate billing for natural gas.** (a) A landlord who submeters natural gas service must bill tenants according to the methodology described in subdivision 2, paragraph (b), and comply with:

(1) subdivision 1, paragraph (c);

(2) section 216B.022; and

(3) applicable provisions of section 504B.216.

(b) A landlord who submeters or apportions natural gas service (1) must comply with subdivisions 4 to 8, and (2) is subject to section 216B.024.

Subd. 4. **Administrative billing charge.** A landlord who bills separately from rent for utility service may impose an administrative billing charge, as provided in section 504B.216, subdivision 8. No other fees or charges may be imposed on or collected from tenants for utility service, except as otherwise provided in subdivision 6 and section 216B.022, subdivision 5.

Subd. 5. **Billing errors.** (a) If a billing error occurs that has resulted in an overcharge, the landlord must promptly refund the difference between what the tenant paid and what the tenant would have paid but for the error.

(b) If a billing error has occurred that has resulted in an undercharge, the landlord may bill the tenant for the difference between what the tenant paid and what the tenant would have paid but for the billing error, for a period not exceeding six months. Any undercharge must be recovered in accordance with subdivision 8.

Subd. 6. **Late payment charge.** A late payment charge may be imposed as provided under section 504B.216, subdivision 9. No other fees or charges may be imposed on or collected from tenants for utility service, except as otherwise provided in subdivision 4 and section 216B.022, subdivision 5.

Subd. 7. **Payment plans.** A landlord must offer a payment plan for overdue utility service bills. The plan must be reasonable and take into account the tenant's financial circumstances and any extenuating circumstances that are voluntarily disclosed by the tenant. If the landlord and tenant cannot agree on a mutually acceptable payment plan, the landlord must inform the tenant of the right to seek assistance from the commission's consumer affairs office in resolving the dispute and provide the tenant the office's current telephone number and email address.

Subd. 8. **Undercharges.** A landlord must offer a payment plan to tenants who have been undercharged if no culpable conduct by the tenant or member of the tenant's household caused the undercharge. The agreement must cover a period equal to the time over which the undercharge occurred or a different time period that is mutually agreeable to the tenant and the landlord. No interest or delinquency fee may be charged as part of a payment plan under this subdivision.

History: *2024 c 107 s 2; 2025 c 20 s 182*

216B.024 SHARED-METERED RESIDENTIAL BUILDINGS; DISPUTE RESOLUTION.

A tenant disputing a bill or claiming a violation of section 216B.022 or 216B.023 must first attempt to resolve the dispute or claim with the landlord. If the tenant disagrees with the landlord's proposed resolution, the landlord must notify the tenant of the tenant's right to file a complaint with the commission's consumer affairs office and provide the tenant the office's current telephone number and email address. The consumer affairs office must follow the procedures set forth in section 216B.172, subdivision 2, and Minnesota Rules, part 7829.1600, and the procedures under section 216B.172, subdivisions 3 and 4, apply.

History: *2024 c 107 s 3*

MUNICIPALS, COOPERATIVES, DISTRIBUTION UTILITIES

216B.025 MUNICIPAL REGULATION OPTION.

A municipality may elect to become subject to regulation by the commission pursuant to sections 216B.10 and 216B.11. An election for regulation may be effected by resolution of the governing body requesting regulation and filed with the commission.

History: *1981 c 142 s 1*

216B.026 COOPERATIVE ELECTRIC ASSOCIATION; ELECTION ON REGULATION.

Subdivision 1. **Election.** A cooperative electric association may elect to become subject to rate regulation by the commission pursuant to sections 216B.03 to 216B.23. The election shall be approved by a majority of members or stockholders voting by mail ballot initiated by petition of not less than five percent of the members or stockholders of the association, as determined by membership figures submitted by the association to the Rural Electric Administration for the month in which the petition was submitted.

Subd. 2. **Petition contents; verification.** The petition form shall be prescribed by the department and sample forms shall be available from the department and electric cooperative associations. Petitions shall include a uniform statement that petition signers are requesting a balloting of the association membership on the question of regulation of electric rates of the association by the commission. The department shall, upon receipt, transmit the prescribed form of petition to the appropriate association for validation of petition signatures in accordance with agreed procedures between the association and the department. When the association rejects any signature on a petition as invalid, it shall provide the department with a written statement as to the reason the cooperative deems the signature invalid. The department may challenge the association's decisions on the validity of signatures and may appeal to the commission for a resolution of the issue through informal proceedings before the commission after notice to all parties.

Subd. 3. **Voting for members.** Whenever a vote or petition of members or stockholders of an association is submitted pursuant to this section, the spouse of the member or stockholder may sign the petition and vote on behalf of the member or stockholder unless the member or stockholder has notified the association in writing otherwise. Such a notification by a member or stockholder shall be provided to the association and to the department for those petition matters pursuant to this section.

Subd. 4. **Election procedure; effect.** If the department determines that the petition meets the percent requirement of subdivision 1, a balloting of members on the question of regulation of electric rates by the commission shall be supervised by the department. The ballot to be used for the election shall be approved by the board of directors of the association and the department. In the event of a dispute on balloting procedures, the dispute shall be resolved through informal proceedings before the commission after notice to all parties. The association shall mail ballots to the association's members who shall return the ballots to the department. The department shall keep the ballots sealed until a date agreed upon by the department and the board of directors. On this date, representatives of the department and the association shall count the ballots. If a majority of the association's members or spouses who vote, elect to become subject to rate regulation by the commission, the election shall be effective 30 days after certified copies of the resolutions approving the election are filed with the commission. These provisions also apply to associations that wish to be deregulated. Any cooperative that is regulated by the commission, pursuant to sections 216B.03 to 216B.23 may follow the procedures set forth above. Any association subject to regulation of rates by the commission shall be exempt from the provisions of sections 216B.48, 216B.49, 216B.50, and 216B.51.

Subd. 5. **Member due process.** Section 216B.027, granting rights to stockholders, applies to the exercise of stockholders' rights regardless of whether a referendum has been held as required by section 216B.027, subdivision 7. Notwithstanding section 216B.027, subdivision 6, a cooperative shall pay the costs of including stockholders' positions on issues as provided under section 216B.027, subdivision 6. This subdivision applies only to elections that require no less than one percent of members to initiate pursuant to subdivision 1.

History: *1981 c 144 s 2; 2000 c 292 s 1-3; 2011 c 97 s 6*

216B.027 COOPERATIVE ELECTRIC ASSOCIATION STOCKHOLDER RIGHTS.

Subdivision 1. **Intent.** It is the intent of this section to specify those rights which shall be extended to stockholders of cooperative electric associations. The guarantee of these rights, as specified herein, is intended to further the active participation of stockholders in any and all matters pertaining to the prudent operation of their organization.

Subd. 2. **Scope.** Cooperative associations organized under chapter 308A for the purpose of providing rural electrification at retail to ultimate consumers shall comply with the provisions of this section in addition to other applicable provisions of chapter 308A and other applicable state and federal laws.

Subd. 3. **Business records.** The provisions of section 302A.461 and any amendments or successor requirements to it shall apply to every wholesale or retail cooperative electric association. The rights granted to wholesale and retail electric cooperative stockholders in this section shall apply also to the spouse of the stockholder. In addition to the requirements of section 302A.461, a wholesale or retail electric cooperative shall maintain records of all proceedings of meetings of stockholders and directors during the previous three-year period including the vote of each director on roll call votes. Roll call votes are required on actions which directly establish service charge and rate schedules. Roll call voting is also required on any matter upon the request of one or more directors. Every duly elected director of a retail cooperative electric association shall have the right to inspect under section 302A.461, in person and at any reasonable time, the business records required by this subdivision and maintained by the wholesale cooperative electric association from which it purchases the majority of its electric requirements.

Subd. 4. **Open meeting; notice.** Meetings of the board of directors of any retail cooperative electric association must be open to the stockholders of the cooperative and the stockholders' spouses. Stockholders must be given notice of all regularly scheduled meetings except those of an emergency nature. Duly elected directors of retail cooperative associations must be given notice, through their retail cooperative associations, of all meetings of the board of directors of the wholesale cooperative association, except those of an emergency nature, from which the retail cooperative purchases the majority of its electric requirements. Portions of meetings relating to labor negotiations, current litigation, personnel matters, and nonpayment of customer accounts are excluded from the provisions of this subdivision.

Subd. 5. **Petitions; voting.** Notwithstanding the provisions of sections 308A.611 and 308A.615, upon receipt of a written petition concerning governance matters signed by at least 500 stockholders or five percent of the stockholders, whichever is less, of a retail cooperative electric association, the matter in the petition must be presented to the stockholders of the cooperative for a vote at the next annual meeting. Petitions must be received by the cooperative electric association 60 days prior to the scheduled annual meeting. For purposes of this section, "governance matters" means matters properly contained in the articles of incorporation or bylaws by adopting, amending, or repealing bylaws or the articles of incorporation.

Subd. 6. **Equal time; petitioner.** Whenever the directors of a retail cooperative electric association provide information to stockholders to influence their vote on a matter to be decided by a vote of the stockholders pursuant to a successful petition submitted under the provisions of subdivision 5 or section

216B.026, subdivision 4, the directors shall provide the organizers of the petition or person presenting the petition the opportunity to include their position on the matter to the stockholders in a substantially similar mode and range of distribution. The organizers of the petition shall pay the costs of such inclusion.

Subd. 7. **Optional referendum.** No cooperative shall be bound by the provisions of this section unless adoption has been approved at referendum using the petition and election procedures in section 216B.026. Within 60 days of May 19, 1983, the board of directors of each cooperative electric association shall notify the stockholders of the provisions of this section and shall explain the process for ratification by petition and election as provided in this subdivision.

History: *1983 c 162 s 1; 1989 c 144 art 2 s 3; 1989 c 356 s 10*

216B.029 STANDARDS FOR DISTRIBUTION UTILITIES.

Subdivision 1. **Standards.** (a) The commission and each cooperative electric association and municipal utility shall adopt standards for safety, reliability, and service quality for distribution utilities. Standards for cooperative electric associations and municipal utilities should be as consistent as possible with the commission standards.

(b) Reliability standards must be based on the system average interruption frequency index, system average interruption duration index, and customer average interruption duration index measurement indices. Service quality standards must specify, if technically and administratively feasible:

(1) average call center response time;

(2) customer disconnection rate;

(3) meter-reading frequency;

(4) complaint resolution response time;

(5) service extension request response time;

(6) recording of service and circuit interrupter data;

(7) summary reporting;

(8) historical reliability performance reporting;

(9) notices of interruptions of bulk power supply facilities and other interruptions of power; and

(10) customer complaints.

(c) Minimum performance standards developed under this section must treat similarly situated distribution systems similarly and recognize differing characteristics of system design and hardware.

(d) Electric distribution utilities shall comply with all applicable governmental and industry standards required for the safety, design, construction, and operation of electric distribution facilities, including section 326B.35.

Subd. 2. **Definitions.** For the purpose of this section, the terms defined in this subdivision have the meanings given them.

(a) The "system average interruption frequency index" is the average number of interruptions per customer per year. It is determined by dividing the total annual number of customer interruptions by the average number of customers served during the year.

(b) The "system average interruption duration index" is the average customer-minutes of interruption per customer. It is determined by dividing the annual sum of customer-minutes of interruption by the average number of customers served during the year.

(c) The "customer average interruption duration index" is the average customer-minutes of interruption per customer interruption. It approximates the average length of time required to complete service restoration. It is determined by dividing the annual sum of all customer-minutes of interruption durations by the annual number of customer interruptions.

History: *2001 c 212 art 6 s 1; 2007 c 140 art 5 s 32; art 13 s 4*

RATES, STANDARDS, AND PRACTICES

216B.03 REASONABLE RATE.

Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer. For rate-making purposes a public utility may treat two or more municipalities served by it as a single class wherever the populations are comparable in size or the conditions of service are similar.

History: *1974 c 429 s 3; 1983 c 179 s 4; 1987 c 312 art 1 s 10 subd 1*

216B.04 STANDARD OF SERVICE.

Every public utility shall furnish safe, adequate, efficient, and reasonable service; provided that service shall be deemed adequate if made so within 90 days after a person requests service. Upon application by a public utility, and for good cause shown, the commission may extend the period for not to exceed another 90 days.

History: *1974 c 429 s 4*

216B.045 REGULATION OF INTRASTATE NATURAL GAS PIPELINE.

Subdivision 1. **Definition of intrastate pipeline.** For the purposes of this section "intrastate pipeline" means a pipeline wholly within the state of Minnesota which transports or delivers natural gas received from another person at a point inside or at the border of the state, which is delivered at a point within the state to another, provided that all the natural gas is consumed within the state. An intrastate pipeline does not include a pipeline owned or operated by a public utility, unless a public utility files a petition requesting that a pipeline or a portion of a pipeline be classified as an intrastate pipeline and the commission approves the petition.

Subd. 2. **Reasonable rate.** Every rate and contract relating to the sale or transportation of natural gas through an intrastate pipeline shall be just and reasonable. No owner or operator of an intrastate pipeline shall provide intrastate pipeline services in a manner which unreasonably discriminates among customers receiving like or contemporaneous services.

Subd. 3. **Transportation rate; discrimination.** Every owner or operator of an intrastate pipeline shall offer intrastate pipeline transportation services by contract on an open access, nondiscriminatory basis. To the extent the intrastate pipeline has available capacity, the owner or operator of the intrastate pipeline must provide firm and interruptible transportation on behalf of any customer. If physical facilities are needed to establish service to a customer, the customer may provide those facilities or the owner or operator of the intrastate pipeline may provide the facilities for a reasonable and compensatory charge.

Subd. 4. **Contract; commission approval.** No contract establishing the rates, terms, and conditions of service and facilities to be provided by intrastate pipelines is effective until it is filed with and approved by the commission. The commission has the authority to approve the contracts and to regulate the types and quality of services to be provided through intrastate pipelines. The approval of a contract for an intrastate pipeline to provide service to a public utility does not constitute a determination by the commission that the prices actually paid by the public utility under that contract are reasonable or prudent nor does approval constitute a determination that purchases of gas made or deliveries of gas taken by the public utility under that contract are reasonable or prudent.

Subd. 5. **Complaint.** Any customer of an intrastate pipeline, any person seeking to become a customer of an intrastate pipeline, the department, or the commission on its own motion, may bring a complaint regarding the rates, contracts, terms, conditions, and types of service provided or proposed to be provided through an intrastate pipeline, including a complaint that a service which can reasonably be demanded is not offered by the owner or operator of the intrastate pipeline. If a complaint involves the question of whether or not an intrastate pipeline has capacity available, the commission shall after hearing make a determination of the available capacity but shall not impair the owner or operator of the intrastate pipeline contractual obligation to provide firm transportation service. If a complaint concerns the use of available capacity by one or more customers of an intrastate pipeline, the commission shall after hearing determine the reasonable use of the available capacity by the customers. The commission shall not require an owner or operator of an intrastate pipeline to expand its available capacity but may require the owner or operator to maintain a reasonable quality of service. The commission may dismiss any complaint without a hearing if in its opinion a hearing is not in the public interest. Complaints brought under this subdivision shall be governed by section 216B.17.

Subd. 6. **Records; reports; inspections; cost assessments.** Sections 216B.10, subdivisions 1 and 4, 216B.12, 216B.13, and 216B.62, subdivisions 2, 4, and 6, shall apply to owners and operators of intrastate pipelines.

Subd. 7. **Natural gas emergency.** The commission may declare a natural gas supply emergency if it finds that a severe natural gas shortage endangering the health or safety of the citizens of the state exists or is imminent in the state. If the commission declares that a natural gas supply emergency exists, it may for the duration of the emergency order the suspension of any contract providing for the sale and transportation of natural gas through an intrastate pipeline, and may for the duration of the emergency order an owner or operator of the intrastate pipeline to furnish such transportation services as are required by the public interest. The owner or operator of the intrastate pipeline shall be compensated for its services furnished under an emergency order issued under this section, and the commission shall determine the just and reasonable compensation for the services required to be provided during the emergency.

History: *1987 c 9 s 1; 1990 c 370 s 1; 1992 c 478 s 1*

216B.05 FILING SCHEDULES, RULES, AND SERVICE AGREEMENTS.

Subdivision 1. **Public rate filing.** Every public utility shall file with the commission schedules showing all rates, tolls, tariffs, and charges which it has established and which are in force at the time for any service performed by it within the state, or for any service in connection therewith or performed by any public utility controlled or operated by it.

Subd. 2. **Schedule and rules filing.** Every public utility shall file with and as a part of the filings under subdivision 1, all rules that, in the judgment of the commission, in any manner affect the service or product, or the rates charged or to be charged for any service or product, as well as any contracts, agreements, or arrangements relating to the service or product or the rates to be charged for any service or product to which the schedule is applicable as the commission may by general or special order direct; provided that contracts and agreements for electric service must be filed as required by subdivision 2a.

Subd. 2a. **Electric service contract.** A contract for electric service entered into between a public utility and one of its customers, in which the public utility and the customer agree to customer-specific rates, terms, or service conditions not already contained in the approved schedules, tariffs, or rules of the utility, must be filed for approval by the commission pursuant to the commission's rules of practice. Contracts between public utilities and customers that are necessitated by specific statutes in this chapter must be filed for approval under those statutes and any rules adopted by the commission pursuant to those statutes.

Subd. 3. **Public inspection.** Every public utility shall keep copies of the filings under subdivisions 1, 2, and 2a open to public inspection under rules as the commission may prescribe.

History: *1974 c 429 s 5; 1985 c 248 s 70; 1997 c 191 art 1 s 1*

216B.06 RECEIVING DIFFERENT COMPENSATION.

No public utility shall directly or indirectly, by any device whatsoever, or in any manner, charge, demand, collect, or receive from any person a greater or less compensation for any service rendered or to be rendered by the utility than that prescribed in the schedules of rates of the public utility applicable thereto when filed in the manner provided in Laws 1974, chapter 429, nor shall any person knowingly receive or accept any service from a public utility for a compensation greater or less than that prescribed in the schedules, provided that all rates being charged and collected by a public utility upon January 1, 1975, may be continued until schedules are filed.

History: *1974 c 429 s 6; 1978 c 795 s 3*

216B.07 RATE PREFERENCE PROHIBITED.

No public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage.

History: *1974 c 429 s 7*

216B.075 METER READING; CUSTOMER SCHEDULING NEEDS.

Notwithstanding any other provision of rule or policy to the contrary, every public utility providing natural gas or electricity at retail shall make a reasonable effort to obtain readings at least once every 18 months from nonaccessible meters. Readings shall be obtained at times that meet the needs of customer schedules. Utilities shall make a reasonable effort to provide evening and Saturday or Sunday meter reading service at no extra charge to a customer whose work or other schedule makes a business hour reading of meters a hardship. Utilities may refuse to read a customer's meter during nondaylight hours if such activity could threaten the safety of the utility meter-reading employee.

A utility may also allow a customer to self-read the customer's meter for periods of time not to exceed 18 months, provided that the customer is reminded periodically of the potentially serious financial consequences of errors in self-reading.

A utility may terminate service to a customer who refuses to allow a utility company employee access to a nonaccessible meter for a period of 18 months or more.

History: *1983 c 176 s 1*

COMMISSION RESPONSIBILITIES

216B.08 DUTIES OF COMMISSION.

The commission is hereby vested with the powers, rights, functions, and jurisdiction to regulate in accordance with the provisions of Laws 1974, chapter 429 every public utility as defined herein. The exercise of such powers, rights, functions, and jurisdiction is prescribed as a duty of the commission. The commission is authorized to make rules in furtherance of the purposes of Laws 1974, chapter 429.

History: *1974 c 429 s 8; 1985 c 248 s 70*

216B.09 STANDARDS; CLASSIFICATIONS; RULES; PRACTICES.

Subdivision 1. **Commission authority, generally.** The commission, on its own motion or upon complaint and after reasonable notice and hearing, may ascertain and fix just and reasonable standards, classifications, rules, or practices to be observed and followed by any or all public utilities with respect to the service to be furnished.

Subd. 2. **Electric service, rules, measurement standards, grounding.** The commission, on its own motion or upon complaint and after reasonable notice and hearing, may ascertain and fix adequate and reasonable standards for the measurement of the quantity, quality, pressure, initial voltage, or other condition pertaining to the supply of the service; prescribe reasonable rules for the examination and testing of the service and for the measurement thereof; establish or approve reasonable rules, specifications, and standards to secure the accuracy of all meters, instruments, and equipment used for the measurement of any service of any public utility. In this subdivision, service standards or requirements governing any current or voltage originating from the practice of grounding of electrical systems apply to cooperative associations and municipal utilities providing or furnishing retail electric service to agricultural customers.

Subd. 3. **Filings.** Any standards, classifications, rules, or practices now or hereafter observed or followed by any public utility may be filed by it with the commission, and the same shall continue in force until amended by the public utility or until changed by the commission as herein provided.

The commission may require the filing of all rates, including rates charged to and by public utilities.

Subd. 4. **Appearance before federal agency.** The commission is empowered to appear before the Federal Energy Regulatory Commission to offer evidence and to seek appropriate relief in any case in which the rates charged consumers within the state of Minnesota may be affected.

History: *1974 c 429 s 9; 1985 c 248 s 70; 1993 c 327 s 3*

RESIDENTIAL PROTECTIONS; DISCONNECTION

216B.091 MONTHLY REPORTS.

(a) Each public utility must report the following data on residential customers to the commission monthly, in a format determined by the commission:

(1) number of customers;

(2) number and total amount of accounts past due;

(3) average customer past due amount;

(4) total revenue received from the low-income home energy assistance program and other sources contributing to the bills of low-income persons;

(5) average monthly bill;

(6) total sales revenue;

(7) total write-offs due to uncollectible bills;

(8) number of disconnection notices mailed;

(9) number of accounts disconnected for nonpayment;

(10) number of accounts reconnected to service; and

(11) number of accounts that remain disconnected, grouped by the duration of disconnection, as follows:

(i) 1-30 days;

(ii) 31-60 days; and

(iii) more than 60 days.

(b) Monthly reports for October through April must also include the following data:

(1) number of cold weather protection requests;

(2) number of payment arrangement requests received and granted;

(3) number of right to appeal notices mailed to customers;

(4) number of reconnect request appeals withdrawn;

(5) number of occupied heat-affected accounts disconnected for 24 hours or more for electric and natural gas service separately;

(6) number of occupied non-heat-affected accounts disconnected for 24 hours or more for electric and gas service separately;

(7) number of customers granted cold weather rule protection;

(8) number of customers disconnected who did not request cold weather rule protection; and

(9) number of customers disconnected who requested cold weather rule protection.

(c) The data reported under paragraphs (a) and (b) is presumed to be accurate upon submission and must be made available through the commission's electronic filing system. A monthly report must be filed with the commission no later than 45 days after the last day of the month for which data is reported.

History: *2007 c 57 art 2 s 11; 2008 c 162 s 1*

216B.095 [Repealed, 2007 c 57 art 2 s 42,43]

216B.0951 PROPANE PREPURCHASE PROGRAM.

Subdivision 1. **Establishment.** The commissioner of commerce shall operate, or contract to operate, a propane fuel prepurchase fuel program. The commissioner may contract at any time of the year to purchase the lesser of one-third of the liquid propane fuel consumed by low-income home energy assistance program recipients during the previous heating season or the amount that can be purchased with available funds. The propane fuel prepurchase program must be available statewide through each local agency that administers the energy assistance program. The commissioner may decide to limit or not engage in prepurchasing if the commissioner finds that there is a reasonable likelihood that prepurchasing will not provide fuel-cost savings.

Subd. 2. **Hedge account.** The commissioner may establish a hedge account with realized program savings due to prepurchasing. The account must be used to compensate program recipients an amount up to the difference in cost for fuel provided to the recipient if winter-delivered fuel prices are lower than the prepurchase or summer-fill price. No more than ten percent of the aggregate prepurchase program savings may be used to establish the hedge account.

Subd. 3. **Report.** The Department of Commerce shall issue a report by June 30, 2008, made available electronically on its website and in print upon request, that contains the following information:

(1) the cost per gallon of prepurchased fuel;

(2) the total gallons of fuel prepurchased;

(3) the average cost of propane each month between October and the following April;

(4) the number of energy assistance program households receiving prepurchased fuel; and

(5) the average savings accruing or benefit increase provided to energy assistance households.

History: *2007 c 57 art 2 s 12*

216B.096 COLD WEATHER RULE; PUBLIC UTILITY.

Subdivision 1. **Scope.** This section applies only to residential customers of a utility.

Subd. 2. **Definitions.** (a) The terms used in this section have the meanings given them in this subdivision.

(b) "Cold weather period" means the period from October 1 through April 30 of the following year.

(c) "Customer" means a residential customer of a utility.

(d) "Disconnection" means the involuntary loss of utility heating service as a result of a physical act by a utility to discontinue service. Disconnection includes installation of a service or load limiter or any device that limits or interrupts utility service in any way.

(e) "Household income" means the combined income, as defined in section 290A.03, subdivision 3, of all residents of the customer's household, computed on an annual basis. Household income does not include any amount received for energy assistance.

(f) "Reasonably timely payment" means payment within five working days of agreed-upon due dates.

(g) "Reconnection" means the restoration of utility heating service after it has been disconnected.

(h) "Summary of rights and responsibilities" means a commission-approved notice that contains, at a minimum, the following:

(1) an explanation of the provisions of subdivision 5;

(2) an explanation of no-cost and low-cost methods to reduce the consumption of energy;

(3) a third-party notice;

(4) ways to avoid disconnection;

(5) information regarding payment agreements;

(6) an explanation of the customer's right to appeal a determination of income by the utility and the right to appeal if the utility and the customer cannot arrive at a mutually acceptable payment agreement; and

(7) a list of names and telephone numbers for county and local energy assistance and weatherization providers in each county served by the utility.

(i) "Third-party notice" means a commission-approved notice containing, at a minimum, the following information:

(1) a statement that the utility will send a copy of any future notice of proposed disconnection of utility heating service to a third party designated by the residential customer;

(2) instructions on how to request this service; and

(3) a statement that the residential customer should contact the person the customer intends to designate as the third-party contact before providing the utility with the party's name.

(j) "Utility" means a public utility as defined in section 216B.02, and a cooperative electric association electing to be a public utility under section 216B.026. Utility also means a municipally owned gas or electric utility for nonresident consumers of the municipally owned utility and a cooperative electric association when a complaint in connection with utility heating service during the cold weather period is filed under section 216B.17, subdivision 6 or 6a.

(k) "Utility heating service" means natural gas or electricity used as a primary heating source, including electricity service necessary to operate gas heating equipment, for the customer's primary residence.

(l) "Working days" means Mondays through Fridays, excluding legal holidays. The day of receipt of a personally served notice and the day of mailing of a notice shall not be counted in calculating working days.

Subd. 3. **Utility obligations before cold weather period.** Each year, between August 15 and October 1, each utility must provide all customers, personally, by first class mail, or electronically for those requesting electronic billing, a summary of rights and responsibilities. The summary must also be provided to all new residential customers when service is initiated.

Subd. 4. **Notice before disconnection during cold weather period.** Before disconnecting utility heating service during the cold weather period, a utility must provide, personally or by first class mail, a commission-approved notice to a customer, in easy-to-understand language, that contains, at a minimum, the date of the scheduled disconnection, the amount due, and a summary of rights and responsibilities.

Subd. 5. **Cold weather rule.** (a) During the cold weather period, a utility may not disconnect and must reconnect utility heating service of a customer whose household income is at or below 50 percent of the state median income if the customer enters into and makes reasonably timely payments under a mutually acceptable payment agreement with the utility that is based on the financial resources and circumstances of the household; provided that, a utility may not require a customer to pay more than ten percent of the household income toward current and past utility bills for utility heating service.

(b) A utility may accept more than ten percent of the household income as the payment arrangement amount if agreed to by the customer.

(c) The customer or a designated third party may request a modification of the terms of a payment agreement previously entered into if the customer's financial circumstances have changed or the customer is unable to make reasonably timely payments.

(d) The payment agreement terminates at the expiration of the cold weather period unless a longer period is mutually agreed to by the customer and the utility.

(e) Each utility shall use reasonable efforts to restore service within 24 hours of an accepted payment agreement, taking into consideration customer availability, employee availability, and construction-related activity.

Subd. 6. **Verification of income.** (a) In verifying a customer's household income, a utility may:

(1) accept the signed statement of a customer that the customer is income eligible;

(2) obtain income verification from a local energy assistance provider or a government agency;

(3) consider one or more of the following:

(i) the most recent income tax return filed by members of the customer's household;

(ii) for each employed member of the customer's household, paycheck stubs for the last two months or a written statement from the employer reporting wages earned during the preceding two months;

(iii) documentation that the customer receives a pension from the Department of Human Services, the Social Security Administration, the Veteran's Administration, or other pension provider;

(iv) a letter showing the customer's dismissal from a job or other documentation of unemployment; or

(v) other documentation that supports the customer's declaration of income eligibility.

(b) A customer who receives energy assistance benefits under any federal, state, or county government programs in which eligibility is defined as household income at or below 50 percent of state median income is deemed to be automatically eligible for protection under this section and no other verification of income may be required.

Subd. 7. **Prohibitions and requirements.** (a) This subdivision applies during the cold weather period.

(b) A utility may not charge a deposit or delinquency charge to a customer who has entered into a payment agreement or a customer who has appealed to the commission under subdivision 8.

(c) A utility may not disconnect service during the following periods:

(1) during the pendency of any appeal under subdivision 8;

(2) earlier than ten working days after a utility has deposited in first class mail, or seven working days after a utility has personally served, the notice required under subdivision 4 to a customer in an occupied dwelling;

(3) earlier than ten working days after the utility has deposited in first class mail the notice required under subdivision 4 to the recorded billing address of the customer, if the utility has reasonably determined from an on-site inspection that the dwelling is unoccupied;

(4) on a Friday, unless the utility makes personal contact with, and offers a payment agreement consistent with this section to the customer;

(5) on a Saturday, Sunday, holiday, or the day before a holiday;

(6) when utility offices are closed;

(7) when no utility personnel are available to resolve disputes, enter into payment agreements, accept payments, and reconnect service; or

(8) when commission offices are closed.

(d) A utility may not discontinue service until the utility investigates whether the dwelling is actually occupied. At a minimum, the investigation must include one visit by the utility to the dwelling during normal working hours. If no contact is made and there is reason to believe that the dwelling is occupied, the utility must attempt a second contact during nonbusiness hours. If personal contact is made, the utility representative must provide notice required under subdivision 4 and, if the utility representative is not authorized to enter into a payment agreement, the telephone number the customer can call to establish a payment agreement.

(e) Each utility must reconnect utility service if, following disconnection, the dwelling is found to be occupied and the customer agrees to enter into a payment agreement or appeals to the commission because the customer and the utility are unable to agree on a payment agreement.

Subd. 8. **Disputes; customer appeals.** (a) A utility must provide the customer and any designated third party with a commission-approved written notice of the right to appeal:

(1) a utility determination that the customer's household income is more than 50 percent of state median household income; or

(2) when the utility and customer are unable to agree on the establishment or modification of a payment agreement.

(b) A customer's appeal must be filed with the commission no later than seven working days after the customer's receipt of a personally served appeal notice, or within ten working days after the utility has deposited a first class mail appeal notice.

(c) The commission must determine all customer appeals on an informal basis, within 20 working days of receipt of a customer's written appeal. In making its determination, the commission must consider one or more of the factors in subdivision 6.

(d) Notwithstanding any other law, following an appeals decision adverse to the customer, a utility may not disconnect utility heating service for seven working days after the utility has personally served a disconnection notice, or for ten working days after the utility has deposited a first class mail notice. The notice must contain, in easy-to-understand language, the date on or after which disconnection will occur, the reason for disconnection, and ways to avoid disconnection.

Subd. 9. **Cooperative and municipal disputes.** Complaints in connection with utility heating service during the cold weather period filed against a municipal or a cooperative electric association with the commission under section 216B.17, subdivision 6 or 6a, are governed by section 216B.097.

Subd. 10. **Customers above 50 percent of state median income.** During the cold weather period, a customer whose household income is above 50 percent of state median income:

(1) has the right to a payment agreement that takes into consideration the customer's financial circumstances and any other extenuating circumstances of the household; and

(2) may not be disconnected and must be reconnected if the customer makes timely payments under a payment agreement accepted by a utility.

Subdivision 7, paragraph (b), does not apply to customers whose household income is above 50 percent of state median income.

Subd. 11. **Reporting.** Annually on October 15, a utility must electronically file with the commission a report, in a format specified by the commission, specifying the number of utility heating service customers whose service is disconnected or remains disconnected for nonpayment as of September 15 and October 1. If customers remain disconnected on October 1, a utility must file a report each week between October 15 and the end of the cold weather period specifying:

(1) the number of utility heating service customers that are or remain disconnected from service for nonpayment; and

(2) the number of utility heating service customers that are reconnected to service each week. The utility may discontinue weekly reporting if the number of utility heating service customers that are or remain disconnected reaches zero before the end of the cold weather period.

The data reported under this subdivision are presumed to be accurate upon submission and must be made available through the commission's electronic filing system.

History: *2007 c 57 art 2 s 13,43; 2008 c 162 s 2,3; 2011 c 97 s 7; 1Sp2021 c 4 art 8 s 9,10; 2023 c 60 art 12 s 10*

216B.097 COLD WEATHER RULE; COOPERATIVE OR MUNICIPAL UTILITY.

Subdivision 1. **Application; notice to residential customer.** (a) A municipal utility or a cooperative electric association must not disconnect and must reconnect the utility service of a residential customer during the period between October 1 and April 30 if the disconnection affects the primary heat source for the residential unit and all of the following conditions are met:

(1) The household income of the customer is at or below 50 percent of the state median household income. A municipal utility or cooperative electric association utility may (i) verify income on forms it provides or (ii) obtain verification of income from the local energy assistance provider. A customer is deemed to meet the income requirements of this clause if the customer receives any form of public assistance,

including energy assistance, that uses an income eligibility threshold set at or below 50 percent of the state median household income.

(2) A customer enters into and makes reasonably timely payments under a payment agreement that considers the financial resources of the household.

(3) A customer receives referrals to energy assistance, weatherization, conservation, or other programs likely to reduce the customer's energy bills.

(b) A municipal utility or a cooperative electric association must, between August 15 and October 1 each year, notify all residential customers of the provisions of this section.

Subd. 2. **Notice to residential customer facing disconnection.** (a) Before disconnecting service to a residential customer during the period between October 1 and April 30, a municipal utility or cooperative electric association must provide the following information to a customer:

(1) a notice of proposed disconnection;

(2) a statement explaining the customer's rights and responsibilities;

(3) a list of local energy assistance providers;

(4) forms on which to declare inability to pay; and

(5) a statement explaining available time payment plans and other opportunities to secure continued utility service.

(b) At the same time that notice is given under paragraph (a), the utility must also give written or electronic notice of the proposed disconnection to the local energy assistance provider and the department.

Subd. 3. **Restrictions if disconnection necessary.** (a) If a residential customer must be involuntarily disconnected remotely using advanced metering infrastructure or physically at the property being disconnected between October 1 and April 30 for failure to comply with subdivision 1, the disconnection must not occur:

(1) on a Friday, unless the customer declines to enter into a payment agreement offered that day in person or via personal contact by telephone by a municipal utility or cooperative electric association;

(2) on a weekend, holiday, or the day before a holiday;

(3) when utility offices are closed; or

(4) after the close of business on a day when disconnection is permitted, unless a field representative of a municipal utility or cooperative electric association who is authorized to enter into a payment agreement, accept payment, and continue service, offers a payment agreement to the customer.

Further, the disconnection must not occur until at least 30 days after the notice required in subdivision 2 has been mailed to the customer or 15 days after the notice has been personally delivered to the customer.

(b) The customer must not be disconnected until the utility attempts to confirm whether the residential unit is actually occupied, which the utility may accomplish by:

(1) visiting the residential unit; or

(2) examining energy usage data obtained through advanced metering infrastructure to determine whether there is energy usage over at least a 24-hour period that indicates occupancy.

(c) A utility may not disconnect a residential customer who is in compliance with section 216B.098, subdivision 5.

(d) If, prior to disconnection, a customer appeals a notice of involuntary disconnection, as provided by the utility's established appeal procedure, the utility must not disconnect until the appeal is resolved.

(e) For the purposes of this section, "advanced metering infrastructure" means an integrated system of smart meters, communication networks, and data management systems that enables two-way communication between a utility and its customers.

Subd. 4. **Application to service limiters.** For the purposes of this section, "disconnection" includes a service or load limiter or any device that limits or interrupts electric service in any way.

Subd. 5. **Cost recovery.** A municipal utility or cooperative electric association may recover the reasonable costs of disconnecting and reconnecting a residential customer, based on the costs of providing notice to the customer and other entities and whether the process was accomplished physically at the property being disconnected or reconnected or remotely using advanced metering infrastructure.

History: *1991 c 235 art 2 s 1; 2001 c 212 art 4 s 2; 1Sp2003 c 11 art 3 s 2; 2007 c 57 art 2 s 14,15; 1Sp2021 c 4 art 8 s 11-14*

216B.0975 DISCONNECTION DURING EXTREME HEAT CONDITIONS.

A utility may not effect an involuntary disconnection of residential services in affected counties when an excessive heat watch, heat advisory, or excessive heat warning issued by the National Weather Service is in effect. For purposes of this section, "utility" means a public utility providing electric service, municipal utility, or cooperative electric association.

History: *1Sp2003 c 11 art 3 s 3*

216B.0976 NOTICE OF UTILITY DISCONNECTION.

Subdivision 1. **Notice required.** Notwithstanding section 13.685 or any other law or administrative rule to the contrary, a public utility, cooperative electric association, or municipal utility must provide notice to a statutory city or home rule charter city, and to the department, as prescribed by this section, of disconnection of a customer's gas or electric service. Upon written request from a city or the department, on October 1 and November 1 of each year, or the next business day if that date falls on a Saturday or Sunday, a report must be made available to the city or the department of the address of properties currently disconnected and the date of the disconnection. Upon written request from a city or the department, between October 1 and April 30, daily reports must be made available of the address and date of any newly disconnected properties.

A city provided notice under this section must provide the information on disconnection to the police and fire departments of the city within three business days of receipt of the notice.

For the purpose of this section, "disconnection" means a cessation of services initiated by the public utility, cooperative electric association, or municipal utility that affects the primary heat source of a residence and service is not reconnected within 24 hours.

Subd. 2. **Data.** Data on customers that are provided under subdivision 1 are private data on individuals or nonpublic data, as defined in section 13.02.

History: *2008 c 253 s 2; 1Sp2021 c 4 art 8 s 15*

216B.098 RESIDENTIAL CUSTOMER PROTECTIONS.

Subdivision 1. **Applicability.** The provisions of this section apply to residential customers of public utilities, municipal utilities, and cooperative electric associations. Each municipal utility and cooperative electric association may establish terms and conditions for the plans and agreements required under subdivisions 2 and 3.

Subd. 2. **Budget billing plans.** A utility shall offer a customer a budget billing plan for payment of charges for service, including adequate notice to customers prior to changing budget payment amounts. Municipal utilities having 3,000 or fewer customers are exempt from this requirement. Municipal utilities having more than 3,000 customers shall implement this requirement before July 1, 2003.

Subd. 3. **Payment agreements.** A utility shall offer a payment agreement for the payment of arrears. Payment agreements must consider a customer's financial circumstances and any extenuating circumstances of the household. No additional service deposit may be charged as a consideration to continue service to a customer who has entered and is reasonably on time under an accepted payment agreement.

Subd. 4. **Undercharges.** (a) A utility shall offer a payment agreement to customers who have been undercharged if no culpable conduct by the customer or resident of the customer's household caused the undercharge. The agreement must cover a period equal to the time over which the undercharge occurred or a different time period that is mutually agreeable to the customer and the utility, except that the duration of a payment agreement offered by a utility to a customer whose household income is at or below 50 percent of state median household income must consider the financial circumstances of the customer's household.

(b) No interest or delinquency fee may be charged as part of an undercharge agreement under this subdivision.

(c) If a customer inquiry or complaint results in the utility's discovery of the undercharge, the utility may bill for undercharges incurred after the date of the inquiry or complaint only if the utility began investigating the inquiry or complaint within a reasonable time after when it was made.

Subd. 5. **Medically necessary equipment.** (a) A utility shall reconnect or continue service to a customer's residence where a medical emergency exists or where medical equipment requiring electricity necessary to sustain life is in use, provided that the utility receives written certification, or initial certification by telephone and written certification within five business days, that failure to reconnect or continue service will impair or threaten the health or safety of a resident of the customer's household.

(b) Certification of the necessity for service is required. Certification may be provided by:

(1) a licensed medical doctor;

(2) a licensed physician assistant;

(3) an advanced practice registered nurse, as defined in section 148.171; or

(4) a registered nurse, but only to the extent of verifying the current diagnosis or prescriptions made by a licensed medical doctor for the customer or member of the customer's household.

(c) Except as provided in paragraph (d), a certification may not extend beyond six months from the date of written certification.

(d) If a utility determines that a longer certification is appropriate given a particular customer's circumstances, the utility may, at its sole discretion, extend the duration of a certification for up to 12 months.

(e) A certification may be renewed, provided that the renewal complies with this subdivision. A certification may be renewed by the same or another medical professional who meets the qualifications of paragraph (b).

(f) A customer whose account is in arrears must contact and enter into a payment agreement with the utility. The payment agreement must consider a customer's financial circumstances and any extenuating circumstances of the household. The payment agreement may, at the discretion of the utility, contain a provision by which the utility forgives all or a portion of the amount in which the account is in arrears, which, if implemented, extinguishes individual liability for the amount forgiven.

Subd. 6. **Commission authority.** (a) In addition to any other authority, the commission has the authority to resolve customer complaints against a public utility or a landlord of a shared-metered residential building, whether or not the complaint involves a violation of this chapter. The commission may delegate this authority to commission staff as it deems appropriate.

(b) The commission has the authority to levy a penalty of not less than $100 and not more than $1,000 for each violation of section 216B.022, 216B.023, or 216B.024 with respect to complaints filed by tenants. Nothing in this chapter limits the right of a tenant to seek or obtain judicial remedies.

(c) For the purposes of this subdivision:

(1) "landlord" has the meaning given in section 216B.022, subdivision 1, paragraph (b);

(2) "public utility" has the meaning given in section 216B.02, subdivision 4; and

(3) "shared-metered residential building" has the meaning given in section 216B.022, subdivision 1, paragraph (e).

Subd. 7. **Social Security number and individual taxpayer identification number.** If a utility requires a new customer to provide a Social Security number on an application for utility service, the utility must accept an individual taxpayer identification number in lieu of a Social Security number. The utility application must indicate that the utility accepts an individual taxpayer identification number.

History: *2001 c 212 art 4 s 3; 2002 c 379 art 1 s 54; 2007 c 57 art 2 s 16; 2008 c 162 s 4; 2014 c 254 s 2; 2024 c 107 s 4; 2024 c 126 art 6 s 5; 2024 c 127 art 42 s 5*

216B.0991 DEFINITIONS.

Subdivision 1. **Scope.** For the purposes of sections 216B.0991 to 216B.0995, the terms defined in this section have the meanings given them.

Subd. 2. **Customer.** "Customer" means a person who has an established relationship with a propane distributor and whose propane system meets the safety guidelines established by the propane distributor for residential heating service.

Subd. 3. **LIHEAP.** "LIHEAP" means the low-income home energy assistance program.

Subd. 4. **Propane distributor.** "Propane distributor" means a person who sells propane at retail to customers as their primary residential heat source; propane distributors are not public utilities.

Subd. 5. **Residential heating service.** "Residential heating service" means the provision of the primary source of heat for the interior of a residential structure.

History: *2014 c 254 s 3*

216B.0992 PRICE AND FEE DISCLOSURE.

A propane distributor must provide a document listing the current per-gallon price of propane and all additional charges, fees, and discounts that pertain to residential heating service. The document must be:

(1) made available to the general public upon request; and

(2) provided to new customers before residential heating service is initiated.

History: *2014 c 254 s 4*

216B.0993 BUDGET PAYMENT PLAN.

(a) A propane distributor who offers customers a budget payment plan must make that same plan available to all customers, including those who participate in the LIHEAP program.

(b) A budget payment plan must equalize a customer's estimated annual propane bill by dividing it into equal monthly payments. Any budget plan started after the propane distributor's traditional budget plan start date will be divided by the remaining months in the budget plan year. Any positive balance remaining at the end of a year may, at the customer's discretion, be provided to the customer as a cash payment or carried over as a credit on the customer's bill for the next year.

(c) A propane distributor must notify a customer on a budget payment plan of a price or fee change that may affect the monthly amount due under the budget payment plan by more than 20 percent.

(d) A propane distributor may alter or terminate the plan if a customer has failed to pay two monthly payments during the period of the budget payment plan. In lieu of the requirements of this section, the parties may enter into a mutually agreeable plan.

History: *2014 c 254 s 5*

216B.0994 PROPANE PURCHASE CONTRACTS.

A propane distributor is prohibited from adding any service, distribution, transportation, or similar fees to customer billings for those customers who have entered into a contract for prepurchasing or capitated pricing of propane for the period of the contract provided that:

(1) the customer has met all obligations of that contract; and

(2) the propane distributor can receive product from its contracted supply points and a force majeure has not been declared by the propane distributor's supplier.

History: *2014 c 254 s 6*

216B.0995 TERMS OF SALE.

Subdivision 1. **Cash sales.** A propane distributor with an available supply of propane must not refuse to sell propane to a customer who:

(1) pays the distributor's established price upon delivery in cash, by certified or cashier's check, or by commercial money order or its equivalent; or

(2) receives energy assistance from LIHEAP or a governmental or private agency that has funds available to pay for a delivery.

Subd. 2. **LIHEAP participation; delivery.** A propane distributor who accepts LIHEAP payments must, upon request, make available to its customers information regarding LIHEAP, including income eligibility and contact information for organizations accepting LIHEAP applications.

Subd. 3. **Third-party credit disclosure.** A propane distributor must not make known the names of past or present delinquent customers to other propane distributors, except in the course of a routine credit check performed when a prospective customer applies for credit privileges.

History: *2014 c 254 s 7*

ACCOUNTING, MERCURY COSTS, DEPRECIATION

216B.10 ACCOUNTING.

Subdivision 1. **System of accounts.** The commission shall establish a system of accounts to be kept by public utilities subject to its jurisdiction. A public utility which maintains its accounts in accordance with the system of accounts prescribed by a federal agency or authority shall be deemed to be in compliance with the system of accounts prescribed by the commission. Where optional accounting is prescribed by a federal agency or authority, the commission may prescribe which option is to be followed.

Subd. 2. **Other business of public utility.** Every public utility engaged directly or indirectly in any other business than that of the production, transmission or furnishing of natural gas or electric service shall, if required by the commission, keep and render separately to the commission in like manner and form the accounts of all the other business, in which case all the provisions of Laws 1974, chapter 429 shall apply to the books, accounts, papers, and records of the other business.

Subd. 3. **Manner and form.** Every public utility is required to keep and render its books, accounts, papers, and records accurately and faithfully in the manner and form prescribed by the commission, and to comply with all directions of the commission relating to these books, accounts, papers, and records.

Subd. 4. **Reports.** The commission may require any public utility to file annual reports in the form and content, having regard for the provisions of this section, as the commission may require, and special reports concerning any matter about which the commission is authorized to inquire or to keep itself informed. The commission may require the reports to be verified. The basic financial statements in the annual report of a public utility may, at the direction of the public utilities commission, be examined by an independent certified public accountant and the accountant's opinion thereof included in the annual report filed with the commission.

Subd. 5. **Audit.** The commission may require the examination and audit of all accounts, and all items shall be allocated to the accounts in the manner prescribed by the commission.

Subd. 6. [Repealed, 1981 c 142 s 3]

History: *1974 c 429 s 10; 1980 c 614 s 123; 1986 c 444*

216B.105 CUSTOMER SHARE OF MERCURY CONTROL COSTS.

A utility selling electricity at retail shall report in a biannual bill insert the amount of the customer's total bill that represents the utility's capital and operating costs to control mercury emissions to the atmosphere as required under sections 216B.68 to 216B.688.

History: *2006 c 201 s 3*

216B.11 DEPRECIATION RATES AND PRACTICES.

The commission shall fix proper and adequate rates and methods of depreciation, amortization, or depletion in respect of utility property, and every public utility shall conform its depreciation, amortization or depletion accounts to the rates and methods fixed by the commission.

History: *1974 c 429 s 11; 1981 c 142 s 2*

INVESTIGATORY REQUIREMENTS

216B.12 RIGHT OF ENTRANCE; INSPECTION.

Subdivision 1. **Authority of commission and department.** The commissioners and the duly authorized officers and employees of the department, during business hours, may enter upon any premises occupied by any public utility for the purpose of making examinations and tests and to inspect the accounts, books, papers, and documents of any public utility for the purpose of exercising any power provided for in Laws 1974, chapter 429, and may set up and use on the premises any apparatus and appliance necessary therefor. Such public utility shall have the right to be represented at the making of the examinations, tests, and inspections. The public utility, its officers and employees, shall facilitate the examinations, tests, and inspections by giving every reasonable aid to the commissioners and any person or persons designated by the department for the duties aforesaid.

Subd. 2. [Repealed, 1981 c 142 s 3]

History: *1974 c 429 s 12*

216B.13 PRODUCTION AND EXAMINATION OF RECORDS.

Subdivision 1. **Authority of commission.** The commission may require, by order served on any public utility in the manner provided herein for the service of orders, the production within this state at a reasonable time and place as the commission may designate, of any books, accounts, papers, or records of the public utility relating to its business or affairs within the state, pertinent to any lawful inquiry and kept by said public utility in any office or place within or without this state, or, at its option, verified or photostatic copies in lieu thereof, so that an examination thereof may be made by the commission or under its direction.

Subd. 2. [Repealed, 1981 c 142 s 3]

History: *1974 c 429 s 13*

216B.14 INVESTIGATION.

The commission upon complaint or upon its own initiative and whenever it may deem it necessary in the performance of its duties may investigate and examine the condition and operation of any public utility or any part thereof. In conducting the investigations the commission may proceed either with or without a hearing as it may deem best, but it shall make no order without affording the affected parties a hearing.

History: *1974 c 429 s 14*

RATE HEARINGS

216B.15 HEARINGS; EXAMINER.

The commission may, in addition to the hearings specifically provided for by Laws 1974, chapter 429, conduct any other hearings as may reasonably be required in the administration of the powers and duties conferred upon it by Laws 1974, chapter 429. The commission may designate one of its members to act as an examiner for the purpose of holding any hearing which the commission has the power or authority to hold or in the event parties to the hearing so stipulate the commission may designate a qualified commission employee as the examiner. Reasonable notice of all hearings shall be given the persons interested therein as determined by the commission.

History: *1974 c 429 s 15*

216B.16 RATE CHANGE; PROCEDURE; HEARING.

Subdivision 1. **Notice.** Unless the commission otherwise orders, no public utility shall change a rate which has been duly established under this chapter, except upon 60 days' notice to the commission. The notice shall include statements of facts, expert opinions, substantiating documents, and exhibits, supporting the change requested, and state the change proposed to be made in the rates then in force and the time when the modified rates will go into effect. If the filing utility does not have an approved energy conservation improvement plan on file with the department, it shall also include in its notice an energy conservation plan pursuant to section 216B.241. A filing utility subject to rate regulation under section 216B.026 shall reference in its notice the energy conservation improvement plans of the generation and transmission cooperative providing energy conservation improvement programs to members of the filing utility pursuant to section 216B.241. The filing utility shall give written notice, as approved by the commission, of the proposed change to the governing body of each municipality and county in the area affected. All proposed changes shall be shown by filing new schedules or shall be plainly indicated upon schedules on file and in force at the time.

Subd. 1a. **Settlement.** (a) When a public utility submits a general rate filing, the Office of Administrative Hearings, before conducting a contested case hearing, shall convene a settlement conference including all of the parties for the purpose of encouraging settlement of any or all of the issues in the contested case. If a stipulated settlement is not reached before the contested case hearing, the Office of Administrative Hearings may reconvene the settlement conference during or after completion of the contested case hearing at its discretion or a party's request. The Office of Administrative Hearings or the commission may, upon the request of any party and the public utility, extend the procedural schedule of the contested case in order to permit the parties to engage in settlement discussions. An extension must be for a definite period of time not to exceed 60 days.

(b) If the applicant and all intervening parties agree to a stipulated settlement of the case or parts of the case, the settlement must be submitted to the commission. The commission shall accept or reject the settlement in its entirety and, at any time until its final order is issued in the case, may require the Office of Administrative Hearings to conduct a contested case hearing. The commission may accept the settlement on finding that to do so is in the public interest and is supported by substantial evidence. If the commission does not accept the settlement, it may issue an order modifying the settlement subject to the approval of the parties. Each party shall have ten days in which to reject the proposed modification. If no party rejects the proposed modification, the commission's order becomes final. If the commission rejects the settlement, or a party rejects the commission's proposed modification, a contested case hearing must be completed.

Subd. 1b. **Definitions.** For the purposes of this section, "low-income" means a household:

(1) that is approved as qualified for energy assistance from the low-income home energy assistance program;

(2) with a household income that is 50 percent or less of the state median income; or

(3) that meets another qualification established by the commission.

Subd. 2. **Suspension of proposed rate; hearing; final determination defined.** (a) Whenever there is filed with the commission a schedule modifying or resulting in a change in any rates then in force as provided in subdivision 1, the commission may suspend the operation of the schedule by filing with the schedule of rates and delivering to the affected utility a statement in writing of its reasons for the suspension at any time before the rates become effective. The suspension shall not be for a longer period than ten months beyond the initial filing date except as provided in this subdivision or subdivision 1a.

(b) During the suspension the commission shall determine whether all questions of the reasonableness of the rates requested raised by persons deemed interested or by the department can be resolved to the satisfaction of the commission. If the commission finds that all significant issues raised have not been resolved to its satisfaction, or upon petition by ten percent of the affected customers or 250 affected customers, whichever is less, it shall refer the matter to the Office of Administrative Hearings with instructions for a public hearing as a contested case pursuant to chapter 14, except as otherwise provided in this section.

(c) The commission may order that the issues presented by the proposed rate changes be bifurcated into two separate hearings as follows: (1) determination of the utility's revenue requirements and (2) determination of the rate design. Upon issuance of both administrative law judge reports, the issues shall again be joined for consideration and final determination by the commission.

(d) All prehearing discovery activities of state agency intervenors shall be consolidated and conducted by the Department of Commerce.

(e) If the commission does not make a final determination concerning a schedule of rates within ten months after the initial filing date, the schedule shall be deemed to have been approved by the commission; except if:

(1) an extension of the procedural schedule has been granted under paragraph (f) or subdivision 1a, in which case the schedule of rates is deemed to have been approved by the commission on the last day of the extended period of suspension; or

(2) a settlement has been submitted to and rejected by the commission and the commission does not make a final determination concerning the schedule of rates, the schedule of rates is deemed to have been approved 60 days after the initial or, if applicable, the extended period of suspension.

(f) If the commission finds that it has insufficient time during the suspension period to make a final determination of a case involving changes in general rates because of the need to make a final determination of any pending case involving changes in general rates under this section or section 237.075, the commission may extend the suspension period to allow up to a total of 90 additional calendar days to make the final determination. An extension of the suspension period under this paragraph does not alter the setting of interim rates under subdivision 3.

(g) For the purposes of this section, "final determination" means the initial decision of the commission and not any order which may be entered by the commission in response to a petition for rehearing or other further relief. The commission may further suspend rates until it determines all those petitions.

Subd. 3. **Interim rate.** (a) Notwithstanding any order of suspension of a proposed increase in rates, the commission shall order an interim rate schedule into effect not later than 60 days after the initial filing date. The commission shall order the interim rate schedule ex parte without a public hearing. Notwithstanding the provisions of sections 216.25, 216B.27, and 216B.52, no interim rate schedule ordered by the commission pursuant to this subdivision shall be subject to an application for a rehearing or an appeal to a court until the commission has rendered its final determination.

(b) Unless the commission finds that exigent circumstances exist, the interim rate schedule shall be calculated using the proposed test year cost of capital, rate base, and expenses, except that it shall include: (1) a rate of return on common equity for the utility equal to that authorized by the commission in the utility's most recent rate proceeding; (2) rate base or expense items the same in nature and kind as those allowed by a currently effective order of the commission in the utility's most recent rate proceeding; and (3) no change in the existing rate design. In the case of a utility which has not been subject to a prior commission determination, the commission shall base the interim rate schedule on its most recent determination concerning a similar utility.

(c) If, at the time of its final determination, the commission finds that the interim rates are in excess of the rates in the final determination, the commission shall order the utility to refund the excess amount collected under the interim rate schedule, including interest on it which shall be at the rate of interest determined by the commission. The utility shall commence distribution of the refund to its customers within 120 days of the final order, not subject to rehearing or appeal. If, at the time of its final determination, the commission finds that the interim rates are less than the rates in the final determination, the commission shall prescribe a method by which the utility will recover the difference in revenues between the date of the final determination and the date the new rate schedules are put into effect. In addition, when an extension is granted for settlement discussions under subdivision 1a, the commission shall allow the utility to also recover the difference in revenues for a length of time equal to the length of the extension.

(d) If the public utility fails to make refunds within the period of time prescribed by the commission, the commission shall sue therefor and may recover on behalf of all persons entitled to a refund. In addition to the amount of the refund and interest due, the commission shall be entitled to recover reasonable attorney's fees, court costs and estimated cost of administering the distribution of the refund to persons entitled to it. No suit under this subdivision shall be maintained unless instituted within two years after the end of the period of time prescribed by the commission for repayment of refunds.

(e) The commission shall not order an interim rate schedule in a general rate case into effect as provided by this subdivision until at least four months after it has made a final determination concerning any previously filed change of the rate schedule or the change has otherwise become effective under subdivision 2, unless:

(1) the commission finds that a four-month delay would unreasonably burden the utility, its customers, or its shareholders and that an earlier imposition of interim rates is therefore necessary; or

(2) the utility files a second general rate case at least 12 months after it has filed a previous general rate case for which the commission has extended the suspension period under subdivision 2.

Subd. 4. **Burden of proof.** The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.

Subd. 5. **Determination after finding rate unacceptable.** If, after the hearing, the commission finds the rates to be unjust or unreasonable or discriminatory, the commission shall determine the rates to be charged or applied by the utility for the service in question and shall fix them by order to be served upon the utility. The rates shall thereafter be observed until changed, as provided by this chapter. In no event shall the rates exceed the level of rates requested by the public utility, except that individual rates may be adjusted upward or downward. Rate design changes shall be prospective from the effective date of the new rate schedules approved by the commission.

Subd. 6. **Factors considered, generally.** The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature. For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its estimated current replacement value. If the commission orders a generating facility to terminate its operations before the end of the facility's physical life in order to comply with a specific state or federal energy statute or policy, the commission may allow the public utility to recover any positive net book value of the facility as determined by the commission.

Subd. 6a. **Construction work in progress.** To the extent that construction work in progress is included in the rate base, the commission shall determine in its discretion whether and to what extent the income used in determining the actual return on the public utility property shall include an allowance for funds used during construction, considering the following factors:

(1) the magnitude of the construction work in progress as a percentage of the net investment rate base;

(2) the impact on cash flow and the utility's capital costs;

(3) the effect on consumer rates;

(4) whether it confers a present benefit upon an identifiable class or classes of customers; and

(5) whether it is of a short-term nature or will be imminently useful in the provision of utility service.

Subd. 6b. **Energy conservation improvement.** (a) Except as otherwise provided in this subdivision, all investments and expenses of a public utility as defined in section 216B.241, subdivision 1, paragraph (h), incurred in connection with energy conservation improvements shall be recognized and included by the commission in the determination of just and reasonable rates as if the investments and expenses were directly made or incurred by the utility in furnishing utility service.

(b) The commission shall not include investments and expenses for energy conservation improvements in determining (i) just and reasonable electric rates for retail electric service provided to large customer facilities whose electric utilities have been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (b), with respect to those large customer facilities; or (ii) just and reasonable gas rates for large energy facilities, large customer facilities whose natural gas utilities have been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (b), or commercial gas customer facilities whose natural gas utilities have been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (c).

(c) The commission may permit a public utility to file rate schedules providing for annual recovery of the costs of energy conservation improvements. These rate schedules may be applicable to less than all the customers in a class of retail customers if necessary to reflect the requirements of section 216B.241. The commission shall allow a public utility, without requiring a general rate filing under this section, to reduce the electric rates applicable to large customer facilities that have been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (b), and to reduce the gas rate applicable to a large energy facility, a large customer facility or commercial customer facility that has been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (b) or (c), or by the commission under section 216B.241, subdivision 2, by an amount that reflects the elimination of energy conservation improvement investments or expenditures for those facilities. In the event that the commission has set electric or gas rates based on the use of an accounting methodology that results in the cost of conservation improvements being recovered from utility customers over a period of years, the rate reduction may occur in a series of steps to coincide with the recovery of balances due to the utility for conservation improvements made by the utility on or before December 31, 2007.

(d) Investments and expenses of a public utility shall not include electric utility infrastructure costs as defined in section 216B.1636, subdivision 1, paragraph (b).

Subd. 6c. **Incentive plan for energy conservation and efficient fuel-switching improvement.** (a) The commission may order public utilities to develop and submit for commission approval incentive plans that describe the method of recovery and accounting for utility conservation and efficient fuel-switching expenditures and savings. For public utilities that provide electric service, the commission must develop and implement incentive plans designed to promote energy conservation separately from the plans designed to promote efficient fuel-switching. In developing the incentive plans the commission shall ensure the effective involvement of interested parties.

(b) In approving incentive plans, the commission shall consider:

(1) whether the plan is likely to increase utility investment in cost-effective energy conservation or efficient fuel switching;

(2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;

(3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation or efficient fuel switching;

(4) whether the plan is in conflict with other provisions of this chapter;

(5) whether the plan conflicts with other provisions of this chapter; and

(6) the likely financial impacts of the conservation and efficient fuel-switching programs on the utility.

(c) The commission may set rates to encourage the vigorous and effective implementation of utility conservation and efficient fuel-switching programs. The commission may:

(1) increase or decrease any otherwise allowed rate of return on net investment based upon the utility's skill, efforts, and success in improving the efficient use of energy through energy conservation or efficient fuel switching;

(2) share between ratepayers and utilities the net savings resulting from energy conservation and efficient fuel-switching programs to the extent justified by the utility's skill, efforts, and success in improving the efficient use of energy; and

(3) adopt any mechanism that satisfies the criteria of this subdivision, such that implementation of cost-effective conservation or efficient fuel switching is a preferred resource choice for the public utility considering the impact of conservation or efficient fuel switching on earnings of the public utility.

(d) Any incentives offered to electric utilities under this subdivision for efficient-fuel switching projects expire December 31, 2032.

Subd. 6d. **Wind energy; property tax.** An owner of a wind energy conversion facility which is required to pay property taxes under section 272.02, subdivision 22, or production taxes under section 272.029, and any related or successor provisions, or a public utility regulated by the Public Utilities Commission which purchases the wind-generated electricity may petition the commission to include in any power purchase agreement between the owner of the facility and the public utility the amount of property taxes and production taxes paid by the owner of the facility. The Public Utilities Commission shall require the public utility to amend the power purchase agreement to include the property taxes and production taxes paid by the owner of the facility in the price paid by the utility for wind-generated electricity if the commission finds:

(1) the owner of the facility has paid the property taxes or production taxes required by this subdivision;

(2) the power purchase agreement between the public utility and the owner does not already require the utility to pay the amount of property taxes or production taxes the owner has paid under this subdivision or, in the case of a power purchase agreement entered into prior to 1997, the amount of property or production taxes paid by the owner in any year of the power purchase agreement exceeds the amount of such property or production taxes included in the price paid by the utility to the owner, as reflected in the owner's bid documents; and

(3) the commission has approved a rate schedule containing provisions for the automatic adjustment of charges for utility service in direct relation to the charges ordered by the commission under section 272.02, subdivision 22, or 272.029.

Subd. 7. **Energy and emission control products cost adjustment.** Notwithstanding any other provision of this chapter, the commission may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in:

(1) federally regulated wholesale rates for energy delivered through interstate facilities;

(2) direct costs for natural gas delivered;

(3) costs for fuel used in generation of electricity or the manufacture of gas; or

(4) prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates. The utility must track and report annually the volumes and costs of sorbents, reagents, or chemicals using separate accounts by generating plant.

Subd. 7a. **Performance-based gas purchasing adjustment.** The commission may permit a public utility to file rate schedules providing for annual adjustments reflecting rewards or penalties provided for in performance-based gas purchasing plans approved by the commission under section 216B.167.

Subd. 7b. **Transmission cost adjustment.** (a) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues of:

(1) new transmission facilities that have been separately filed and reviewed and approved by the commission under section 216B.243 or new transmission or distribution facilities that are certified as a priority project or deemed to be a priority transmission project under section 216B.2425;

(2) new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system; and

(3) charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system.

(b) Upon filing by a public utility or utilities providing transmission service, the commission may approve, reject, or modify, after notice and comment, a tariff that:

(1) allows the utility to recover on a timely basis the costs net of revenues of facilities approved under section 216B.243 or certified or deemed to be certified under section 216B.2425 or exempt from the requirements of section 216B.243;

(2) allows the utility to recover charges incurred under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system. These charges must be reduced or offset by revenues received by the utility and by amounts the utility charges to other regional transmission owners, to the extent those revenues and charges have not been otherwise offset;

(3) allows the utility to recover on a timely basis the costs net of revenues of facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed and determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system;

(4) allows the utility to recover costs associated with distribution planning required under section 216B.2425;

(5) allows the utility to recover costs associated with investments in distribution facilities to modernize the utility's grid that have been certified by the commission under section 216B.2425;

(6) allows the utility to recover on a timely basis the costs of upgrades that are not allocated to participating distributed generation facilities under the commission order issued in docket No. E002, E015, or E017/CI-24-288;

(7) allows a return on investment at the level approved in the utility's last general rate case, unless a different return is found to be consistent with the public interest;

(8) provides a current return on construction work in progress, provided that recovery from Minnesota retail customers for the allowance for funds used during construction is not sought through any other mechanism;

(9) allows for recovery of other expenses if shown to promote a least-cost project option or is otherwise in the public interest;

(10) allocates project costs appropriately between wholesale and retail customers;

(11) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the project or projects or is otherwise in the public interest; and

(12) terminates recovery once costs have been fully recovered or have otherwise been reflected in the utility's general rates.

(c) A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved in paragraph (b). In its filing, the public utility shall provide:

(1) a description of and context for the facilities included for recovery;

(2) a schedule for implementation of applicable projects;

(3) the utility's costs for these projects;

(4) a description of the utility's efforts to ensure the lowest costs to ratepayers for the project; and

(5) calculations to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph (b).

(d) Upon receiving a filing for a rate adjustment pursuant to the tariff established in paragraph (b), the commission shall approve the annual rate adjustments provided that, after notice and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest feasible and prudent cost to ratepayers.

Subd. 7c. **Transmission assets transfer.** (a) Public utility owners of transmission facilities may, subject to Public Utilities Commission approval, transfer operational control or ownership of those transmission assets to a transmission company subject to Federal Energy Regulatory Commission jurisdiction. For transmission asset transfers by a public utility, the Public Utilities Commission must review the request to transfer either in the context of a general rate case under this section or by initiating other proceedings it determines provide adequate review of the transmission asset transfer. The Public Utilities Commission may limit, in whole or in part, the transfer of transmission assets or the timing of those transfers by a public utility if it finds the limitation in the public interest. The commission may only approve a transfer if it finds that the transfer is consistent with the public interest. In assessing the public interest, the commission shall evaluate, among other things, whether the transfer:

(1) facilitates the development of transmission infrastructure necessary to ensure reliability, encourages the development of renewable resources, and accommodates energy transfers within and between states;

(2) protects Minnesota ratepayers against the subsidization of wholesale transactions through retail rates;

(3) ensures, in the case of operational control of transmission assets, that the state retains jurisdiction over the transferring utility for all aspects of service under this chapter;

(4) impacts Minnesota retail rates; and

(5) protects Minnesota ratepayers from paying capital costs for transmission assets that have already been recovered.

(b) A transfer of operational control or ownership of transmission assets by a public utility under this subdivision is subject to section 216B.50. The relationship between a public utility transferring operational control of transmission assets to another entity under this subdivision is subject to the provisions of section 216B.48. If a public utility transfers ownership of its transmission assets to a transmission provider subject to the jurisdiction of the Federal Energy Regulatory Commission, the Public Utilities Commission may permit the utility to file a rate schedule providing for the automatic adjustment of charges to recover the cost of transmission services purchased under tariff rates approved by the Federal Energy Regulatory Commission.

(c) A municipal utility, a municipal power agency, or a joint venture pursuant to section 452.25 may transfer operational control or ownership of transmission assets to a transmission company, or make investments in a transmission company, if the governing body of the municipal utility, municipal power agency, or joint venture finds that the transfer or investment is consistent with the public interest and will facilitate the development of infrastructure necessary to ensure reliability.

Subd. 7d. **Central Corridor utility zone cost adjustment.** (a) The Central Corridor utility zone is the area extending from the Union Depot Station in St. Paul to the proposed multimodal station in Minneapolis along the route of the light rail transit project connecting those two points, and an area extending approximately one-quarter mile from that route and including the entire University of Minnesota, Minneapolis campus.

(b) A public utility that provides retail electric service within the Central Corridor utility zone and that is required to replace, relocate, construct, or install new facilities, may apply to the commission for approval of new facilities in the Central Corridor utility zone and facilities outside the zone that the utility demonstrates must be changed as a direct result of changes within the zone. Facilities proposed under this subdivision may include transmission facilities, distribution facilities, generation facilities, advanced technology-assisted efficiency devices, and energy storage facilities not otherwise subject to section 216B.243, or chapter 216E, 216F, or 216G. Upon approval under paragraph (c), the utility may construct and install the facilities.

(c) The commission may approve the construction and installation of facilities in the Central Corridor mass transit utility zone proposed by a utility under paragraph (b) upon a finding:

(1) that the facilities:

(i) are necessary to provide electric service;

(ii) assist future development of renewable energy, conservation, electric vehicles, and advanced technology-assisted efficiency programs and devices; or

(iii) are exploratory, experimental, or research facilities to advance the use of renewable energy, conservation, electric vehicles, and advanced technology-assisted efficiency programs and devices;

(2) that the utility has engaged in a cooperative process with affected local and state government agencies in the design, planning, or construction of the Central Corridor utility zone project and changes to utility facilities;

(3) that the utility and local units of government have made reasonable efforts to seek federal, state, or private funds that may be available to mass transit and energy projects;

(4) that the utility has made reasonable efforts to minimize the project costs and maximize the value of the facilities to customers;

(5) that the utility has a plan to offer a comprehensive array of programs for residential, commercial, and industrial customers located within the mass transit zone;

(6) that the utility directs existing and planned solar energy programs to develop solar energy along the mass transit utility zone; and

(7) that the utility has made reasonable efforts to apply for federal funds to develop technology-assisted efficiency programs and devices within the mass transit utility zone.

(d) Upon request of the commission, the utility shall submit periodic reports to the commission reviewing the cost and benefits of the facilities constructed within the Central Corridor utility zone and their potential applicability to other areas outside the Central Corridor utility zone.

(e) Notwithstanding any other provision of this chapter, the commission may approve a tariff mechanism for automatic adjustment of charges for new, replaced, or relocated facilities installed under this subdivision in a manner consistent with this subdivision and the standards and procedures contained in subdivision 7b, except that no approval under section 216B.243 or certification under section 216B.2425 is required unless otherwise required by law. This section does not authorize a city-requested facilities surcharge.

(f) For the purpose of this subdivision, "technology-assisted efficiency programs and devices" includes, but is not limited to, infrastructure that integrates digital information and controls technology to improve the reliability, security, and efficiency of the electric grid.

Subd. 7e. **Energy storage system pilot projects.** (a) A public utility may petition the commission under this section to recover costs associated with implementing an energy storage system pilot project. As part of the petition, the public utility must submit a report to the commission containing, at a minimum, the following information regarding the proposed energy storage system pilot project:

(1) the storage technology utilized;

(2) the energy storage capacity and the duration of output at that capacity;

(3) the proposed location;

(4) the purchase and installation costs;

(5) how the project will interact with existing distributed generation resources on the utility's grid; and

(6) the goals the project proposes to achieve, which may include controlling frequency or voltage, mitigating transmission congestion, providing emergency power supplies during outages, reducing curtailment of existing renewable energy generators, and reducing peak power costs.

(b) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with energy storage system pilot projects approved by the commission under this subdivision. A petition filed under this subdivision must include the elements listed in section 216B.1645, subdivision 2a, paragraph (b), clauses (1) to (4), and must describe the benefits of the pilot project.

(c) The commission may approve, or approve as modified, a rate schedule filed under this subdivision. The rate schedule filed by the public utility may include the elements listed in section 216B.1645, subdivision 2a, paragraph (a), clauses (1) to (5).

(d) For each pilot project that the commission has found is in the public interest, the commission must make its determination on the specific amounts that are eligible for recovery under the approved rate schedule within 90 days of final approval of the specific pilot program or within 90 days of the public utility filing for approval of cost recovery for the specific pilot program, whichever is later.

(e) Nothing in this subdivision prohibits or deters the deployment of energy storage systems.

(f) For the purposes of this subdivision:

(1) "energy storage system" has the meaning given in section 216B.2422, subdivision 1; and

(2) "pilot project" means a project that is (i) owned, operated, and controlled by a public utility to optimize safe and reliable system operations, and (ii) deployed at a limited number of locations in order to assess the technical and economic effectiveness of its operations.

Subd. 8. **Advertising expense.** (a) The commission shall disapprove the portion of any rate which makes an allowance directly or indirectly for expenses incurred by a public utility to provide a public advertisement which:

(1) is designed to influence or has the effect of influencing public attitudes toward legislation or proposed legislation, or toward a rule, proposed rule, authorization or proposed authorization of the Public Utilities Commission or other agency of government responsible for regulating a public utility;

(2) is designed to justify or otherwise support or defend a rate, proposed rate, practice or proposed practice of a public utility;

(3) is designed primarily to promote consumption of the services of the utility;

(4) is designed primarily to promote good will for the public utility or improve the utility's public image; or

(5) is designed to promote the use of nuclear power or to promote a nuclear waste storage facility.

(b) The commission may approve a rate which makes an allowance for expenses incurred by a public utility to disseminate information which:

(1) is designed to encourage efficient use of energy supplies;

(2) is designed to promote safety; or

(3) is designed to inform and educate customers as to financial services made available to them by the public utility.

(c) The commission shall not withhold approval of a rate because it makes an allowance for expenses incurred by the utility to disseminate information about corporate affairs to its owners.

Subd. 9. **Charitable contribution.** The commission shall allow as operating expenses only those charitable contributions that the commission deems prudent and that qualify under section 300.66, subdivision 3. Only 50 percent of the qualified contributions are allowed as operating expenses.

Subd. 10. **Intervenor compensation.** (a) A nonprofit organization or an individual granted formal intervenor status by the commission is eligible to receive compensation.

(b) The commission may order a utility to compensate all or part of an eligible intervenor's reasonable costs of participation in a general rate case that comes before the commission when the commission finds that the intervenor has materially assisted the commission's deliberation and when a lack of compensation would present financial hardship to the intervenor. Compensation may not exceed $50,000 for a single intervenor in any proceeding. For the purpose of this subdivision, "materially assisted" means that the intervenor's participation and presentation was useful and seriously considered, or otherwise substantially contributed to the commission's deliberations in the proceeding.

(c) In determining whether an intervenor has materially assisted the commission's deliberation, the commission must consider, among other factors, whether:

(1) the intervenor represented an interest that would not otherwise have been adequately represented;

(2) the evidence or arguments presented or the positions taken by the intervenor were an important factor in producing a fair decision;

(3) the intervenor's position promoted a public purpose or policy;

(4) the evidence presented, arguments made, issues raised, or positions taken by the intervenor would not have been a part of the record without the intervenor's participation; and

(5) the administrative law judge or the commission adopted, in whole or in part, a position advocated by the intervenor.

(d) In determining whether the absence of compensation would present financial hardship to the intervenor, the commission must consider:

(1) whether the costs presented in the intervenor's claim reflect reasonable fees for attorneys and expert witnesses and other reasonable costs; and

(2) the ratio between the costs of intervention and the intervenor's unrestricted funds.

(e) An intervenor seeking compensation must file a request and an affidavit of service with the commission, and serve a copy of the request on each party to the proceeding. The request must be filed 30 days after the later of (1) the expiration of the period within which a petition for rehearing, amendment, vacation, reconsideration, or reargument must be filed or (2) the date the commission issues an order following rehearing, amendment, vacation, reconsideration, or reargument.

(f) The compensation request must include:

(1) the name and address of the intervenor or representative of the nonprofit organization the intervenor is representing;

(2) proof of the organization's nonprofit, tax-exempt status;

(3) the name and docket number of the proceeding for which compensation is requested;

(4) a list of actual annual revenues and expenses of the organization the intervenor is representing for the preceding year and projected revenues, revenue sources, and expenses for the current year;

(5) the organization's balance sheet for the preceding year and a current monthly balance sheet;

(6) an itemization of intervenor costs and the total compensation request; and

(7) a narrative explaining why additional organizational funds cannot be devoted to the intervention.

(g) Within 30 days after service of the request for compensation, a party may file a response, together with an affidavit of service, with the commission. A copy of the response must be served on the intervenor and all other parties to the proceeding.

(h) Within 15 days after the response is filed, the intervenor may file a reply with the commission. A copy of the reply and an affidavit of service must be served on all other parties to the proceeding.

(i) If additional costs are incurred as a result of additional proceedings following the commission's initial order, the intervenor may file an amended request within 30 days after the commission issues an amended order. Paragraphs (e) to (h) apply to an amended request.

(j) The commission must issue a decision on intervenor compensation within 60 days of a filing by an intervenor.

(k) A party may request reconsideration of the commission's compensation decision within 30 days of the decision.

(l) If the commission issues an order requiring payment of intervenor compensation, the utility that was the subject of the proceeding must pay the compensation to the intervenor, and file with the commission proof of payment, within 30 days after the later of (1) the expiration of the period within which a petition for reconsideration of the commission's compensation decision must be filed or (2) the date the commission issues an order following reconsideration of its order on intervenor compensation.

(m) The implementation and enforcement of this subdivision is suspended while section 216B.631 is effective.

Subd. 11. **Pipeline safety programs.** All costs of a public utility that are necessary to comply with state pipeline safety programs under sections 216D.01 to 216D.07, 299F.56 to 299F.64, or 299J.01 to 299J.17 must be recognized and included by the commission in the determination of just and reasonable rates as if the costs were directly incurred by the utility in furnishing utility service.

Subd. 12. **Exemption for small gas utility franchise.** (a) A municipality may file with the commission a resolution of its governing body requesting exemption from the provisions of this section for a public utility that is under a franchise with the municipality to supply natural, manufactured, or mixed gas and that serves 650 or fewer customers in the municipality as long as the public utility serves no more than a total of 5,000 customers.

(b) The commission shall grant an exemption from this section for that portion of a public utility's business that is requested by each municipality it serves. Furthermore, the commission shall also grant the public utility an exemption from this section for any service provided outside of a municipality's border that is considered by the commission to be incidental. The public utility shall file with the commission and the department all initial and subsequent changes in rates, tariffs, and contracts for service outside the municipality at least 30 days in advance of implementation.

(c) However, the commission shall require the utility to adopt the commission's policies and procedures governing disconnection during cold weather. The utility shall annually submit a copy of its municipally approved rates to the commission.

(d) In all cases covered by this subdivision in which an exemption for service outside of a municipality is granted, the commission may initiate an investigation under section 216B.17, on its own motion or upon complaint from a customer.

(e) If a municipality files with the commission a resolution of its governing body rescinding the request for exemption, the commission shall regulate the public utility's business in that municipality under this section.

Subd. 12a. **Exemption for small electric utility franchise.** (a) An electric utility, operating as such in a bordering state and having fewer than 200 customers in Minnesota, is exempt from this section if the utility:

(1) charges Minnesota customers the same rates as those charged to customers in the bordering state;

(2) provides 60-day notice to the commission of rate increases for its Minnesota customers;

(3) provides individual, written notice of rate increases to its Minnesota customers;

(4) provides the commission with schedules of rates and tariffs charged in the bordering state and revenues by class under the former and proposed rates; and

(5) maintains an up-to-date tariff book with the department.

(b) The commission may initiate an investigation under section 216B.17, on its own motion or upon customer complaint with respect to the utility's rates and practices in Minnesota.

Subd. 13. **Economic and community development.** The commission may allow a public utility to recover from ratepayers the reasonable expenses incurred: (1) for economic and community development; and (2) to employ local workers, as defined in section 216B.2422, subdivision 1, to construct and maintain generation facilities that supply power to the public utility's customers.

Subd. 14. **Low-income electric rate discount.** A public utility shall fund an affordability program for low-income customers at a base annual funding level of $8,000,000. The annual funding level shall increase in the calendar years subsequent to each commission approval of a rate increase for the public utility's residential customers by the same percentage as the approved residential rate increase. Costs for the program shall be included in the utility's base rate. The affordability program must be designed to target participating customers with the lowest incomes and highest energy costs in order to lower the percentage of income they devote to energy bills, increase their payments, lower utility service disconnections, and decrease costs associated with collection activities on their accounts. For low-income customers who are 62 years of age or older or disabled, the program must include a $15 discount in each billing period. For the purposes of this subdivision, "public utility" includes only those public utilities with more than 200,000 residential electric service customers. The commission may issue orders necessary to implement, administer, and recover the costs of the program on a timely basis.

Subd. 15. **Low-income affordability programs.** (a) The commission must consider ability to pay as a factor in setting utility rates and may establish affordability programs for low-income residential ratepayers in order to ensure affordable, reliable, and continuous service to low-income utility customers. A public utility serving low-income residential ratepayers who use natural gas for heating must file an affordability program with the commission.

(b) Any affordability program the commission orders a utility to implement must:

(1) lower the percentage of income that participating low-income households devote to energy bills;

(2) increase participating customer payments over time by increasing the frequency of payments;

(3) decrease or eliminate participating customer arrears;

(4) lower the utility costs associated with customer account collection activities; and

(5) coordinate the program with other available low-income bill payment assistance and conservation resources.

(c) In ordering affordability programs, the commission may require public utilities to file program evaluations that measure the effect of the affordability program on:

(1) the percentage of income that participating households devote to energy bills;

(2) service disconnections; and

(3) frequency of customer payments, utility collection costs, arrearages, and bad debt.

(d) The commission must issue orders necessary to implement, administer, and evaluate affordability programs, and to allow a utility to recover program costs, including administrative costs, on a timely basis. The commission may not allow a utility to recover administrative costs, excluding start-up costs, in excess of five percent of total program costs, or program evaluation costs in excess of two percent of total program costs. The commission must permit deferred accounting, with carrying costs, for recovery of program costs incurred during the period between general rate cases.

(e) Public utilities may use information collected or created for the purpose of administering energy assistance to administer affordability programs.

Subd. 16. **Performance regulation plan tariffs.** A public utility providing natural gas services that has a performance regulation plan approved pursuant to section 216B.1675 shall file tariff provisions incorporating the provisions of that plan. Changes in the cost recovery of natural gas supplies must not be included within the plan.

Subd. 17. **Travel, entertainment, and related employee expenses.** (a) The commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service. In order to assist the commission in evaluating the travel, entertainment, and related employee expenses that may be allowed for ratemaking purposes, a public utility filing a general rate case petition shall include a schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories:

(1) travel and lodging expenses;

(2) food and beverage expenses;

(3) recreational and entertainment expenses;

(4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements;

(5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements;

(6) dues and expenses for memberships in organizations or clubs;

(7) gift expenses;

(8) expenses related to owned, leased, or chartered aircraft; and

(9) lobbying expenses.

(b) To comply with the requirements of paragraph (a), each applicable expense incurred in the most recently completed fiscal year must be itemized separately, and each itemization must include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization required by this paragraph may be provided using standard accounting reports already utilized by the utility involved in the rate case, in a written format or an electronic format that is acceptable to the commission. For expenses identified in response to paragraph (a), clauses (1) and (2), the utility shall disclose the total amounts for each expense category and provide separate itemization for those expenses incurred by or on behalf of any employee at the level of vice president or higher and for board members. The petitioning utility shall also provide a one-page summary of the total amounts for each expense category included in the petitioning utility's proposed test year.

(c) Except as otherwise provided in this paragraph, data submitted to the commission under paragraph (a) are public data. The commission or an administrative law judge assigned to the case may treat the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, as private data on individuals as defined in section 13.02, subdivision 12, or issue a protective order governing release of the salary, if the utility establishes that the competitive disadvantage to the utility that would result from release of the salary outweighs the public interest in access to the data. Access to the data by a government entity that is a party to the rate case must not be restricted.

Subd. 18. **Election or ballot question expenses.** The commission may not allow a public utility to recover from ratepayers expenses resulting from a contribution or expenditure incurred to promote or defeat a candidate for public office or to advocate approval or defeat of a ballot question. This subdivision does not prohibit a public utility from engaging in political activity or making a contribution or expenditure otherwise permitted by law.

Subd. 19. **Multiyear rate plan.** (a) A public utility may propose, and the commission may approve, approve as modified, or reject, a multiyear rate plan as provided in this subdivision. The term "multiyear rate plan" refers to a plan establishing the rates the utility may charge for each year of the specified period of years, which cannot exceed five years, to be covered by the plan. A utility proposing a multiyear rate plan shall provide a general description of the utility's major planned investments over the plan period. The commission may also require the utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies. The commission may allow the utility to adjust recovery of its cost of capital or other costs in a reasonable manner within the plan period. The utility may propose:

(1) recovery of the utility's forecasted rate base, based on a formula, a budget forecast, or a fixed escalation rate, individually or in combination. The forecasted rate base must include the utility's planned capital investments and investment-related costs, including income tax impacts, depreciation, and property taxes, as well as forecasted capacity-related costs from purchased power agreements that are not recovered through subdivision 7;

(2) recovery of operations and maintenance expenses, based on an electricity-related price index or other formula;

(3) tariffs that expand the products and services available to customers, including, but not limited to, an affordability rate for low-income residential customers; and

(4) adjustments to the rates approved under the multiyear plan for rate changes that the commission determines to be just and reasonable, including, but not limited to, changes in the utility's cost of operating its nuclear facilities, or other significant investments not addressed in the plan.

(b) A utility that has filed a petition with the commission to approve a multiyear rate plan may request to be allowed to implement interim rates for the first and second years of the multiyear plan. If the commission approves the request, interim rates shall be implemented in the same manner as allowed under subdivision 3.

(c) The commission may approve a multiyear rate plan only if it finds that the plan establishes just and reasonable rates for the utility, applying the factors described in subdivision 6. Consistent with subdivision 4, the burden of proof to demonstrate that the multiyear rate plan is just and reasonable is on the public utility proposing the plan.

(d) Rates charged under the multiyear rate plan must be based only upon the utility's reasonable and prudent costs of service over the term of the plan, as determined by the commission, provided that the costs are not being recovered elsewhere in rates. Rate adjustments authorized under subdivisions 6b and 7 may continue outside of a plan authorized under this subdivision.

(e) The commission may, by order, establish terms, conditions, and procedures for a multiyear rate plan necessary to implement this section and ensure that rates remain just and reasonable during the course of the plan, including terms and procedures for rate adjustment. At any time prior to conclusion of a multiyear rate plan, the commission, upon its own motion or upon petition of any party, has the discretion to examine the reasonableness of the utility's rates under the plan, and adjust rates as necessary.

(f) In reviewing a multiyear rate plan proposed in a general rate case under this section, the commission may extend the time requirements for issuance of a final determination prescribed in this section by an additional 90 days beyond its existing authority under subdivision 2, paragraph (f).

(g) A utility may not file a multiyear rate plan that would establish rates under the terms of the plan until after May 31, 2012.

(h) The commission may initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan.

History: *1974 c 429 s 16; 1977 c 359 s 1-6; 1977 c 364 s 5; 1978 c 694 s 1; 1980 c 579 s 16; 1980 c 614 s 123; 1980 c 615 s 60; 1981 c 357 s 70; 1Sp1981 c 4 art 4 s 15; 1982 c 414 s 1-6; 1982 c 424 s 130; 1983 c 179 s 5; 1983 c 247 s 95; 1983 c 289 s 104; 1986 c 346 s 1; 1986 c 409 s 6,7; 1987 c 353 s 6; 1988 c 457 s 1-3; 1991 c 147 s 1; 1991 c 184 s 1; 1991 c 235 art 1 s 1; art 6 s 1; 1993 c 49 s 1; 1993 c 327 s 4-7; 1994 c 483 s 1; 1994 c 641 art 4 s 2,3; 1994 c 644 s 2; 1995 c 17 s 2; 1995 c 125 s 1; 1995 c 224 s 74,75; 1997 c 25 s 1,3; 1997 c 231 art 2 s 5; 1999 c 140 s 1; 2001 c 212 art 4 s 4; 1Sp2001 c 4 art 6 s 37-40; 2004 c 138 s 4; 2004 c 216 s 2; 2005 c 97 art 1 s 2,3; art 12 s 1; 2007 c 57 art 2 s 18,19; 2007 c 136 art 2 s 1,2; 2008 c 296 art 1 s 5; 2009 c 110 s 6-9; 2010 c 328 s 2; 2010 c 361 art 5 s 5,6; 2010 c 397 s 19; 2011 c 97 s 8-12; 2013 c 85 art 7 s 1; 2013 c 125 art 1 s 38; 2014 c 254 s 8; 1Sp2015 c 1 art 3 s 17-19; 2016 c 189 art 6 s 4; 1Sp2019 c 7 art 11 s 2; 2023 c 7 s 1; 2023 c 60 art 12 s 11; 2024 c 126 art 6 s 6,7; 2024 c 127 art 42 s 6,7; 1Sp2025 c 7 art 3 s 2-5*

SPECIAL RATES AND PRACTICES

216B.161 AREA DEVELOPMENT RATE PLAN.

Subdivision 1. **Definitions.** (a) For purposes of this section, the following terms have the meanings given them in this subdivision.

(b) "Area development rate" means a rate schedule established by a utility that provides customers within an area development zone service under a base utility rate schedule, except that charges may be reduced from the base rate as agreed upon by the utility and the customer consistent with this section.

(c) "Area development zone" means a contiguous or noncontiguous area designated by an authority or municipality for development or redevelopment and within which one of the following conditions exists:

(1) obsolete buildings not suitable for improvement or conversion or other identified hazards to the health, safety, and general well-being of the community;

(2) buildings in need of substantial rehabilitation or in substandard condition; or

(3) low values and damaged investments.

(d) "Authority" means a rural development financing authority established under sections 469.142 to 469.151; a housing and redevelopment authority established under sections 469.001 to 469.047; a port authority established under sections 469.048 to 469.068; an economic development authority established under sections 469.090 to 469.108; a redevelopment agency as defined in sections 469.152 to 469.165; the Department of Iron Range Resources and Rehabilitation established under section 298.22; a municipality that is administering a development district created under sections 469.124 to 469.133 or any special law; a municipality that undertakes a project under sections 469.152 to 469.165, except a town located outside the metropolitan area as defined in section 473.121, subdivision 2, or with a population of 5,000 persons or less; or a municipality that exercises the powers of a port authority under any general or special law.

(e) "Municipality" means a city, however organized, and, with respect to a project undertaken under sections 469.152 to 469.165, "municipality" has the meaning given in sections 469.152 to 469.165, and, with respect to a project undertaken under sections 469.142 to 469.151 or a county or multicounty project undertaken under sections 469.004 to 469.008, also includes any county.

Subd. 2. **Area development rate.** The commission may allow gas or electric public utilities to offer area development rates. The program must be designed to assist industrial revitalization projects located within the service area of the participating utility.

Subd. 3. **Terms and conditions of rate.** An area development rate offered under this section must:

(1) be offered for a specified length of time to be determined by the commission;

(2) be offered as a supplement to other development incentives offered by the authority or municipality in which the rate is available;

(3) be available only to new or expanding manufacturing or wholesale trade customers;

(4) be designed to recover at least the incremental cost of providing service to the participating customers;

(5) be offered in a fixed number of area development zones; and

(6) include a provision that the utility provide participating customers with an energy audit and inform those customers of all existing energy conservation programs available from the utility.

Recovery of costs under clause (4) must not be from residential customers. A utility within a general rate case, may seek recovery of the difference in revenue collected under the area development plan rate and what would have been collected under the standard tariff.

Subd. 4. [Repealed by amendment, 1995 c 9 s 1]

History: *1990 c 370 s 2,7; 1995 c 9 s 1,2; 1996 c 471 art 7 s 2; 2013 c 125 art 1 s 107; 2017 c 94 art 7 s 14; 2024 c 85 s 50*

216B.1611 INTERCONNECTION OF ON-SITE DISTRIBUTED GENERATION.

Subdivision 1. **Purpose.** The purpose of this section is to:

(1) establish the terms and conditions that govern the interconnection and parallel operation of on-site distributed generation;

(2) provide cost savings and reliability benefits to customers;

(3) establish technical requirements that will promote the safe and reliable parallel operation of on-site distributed generation resources;

(4) enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity; and

(5) promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints.

Subd. 2. **Distributed generation; generic proceeding.** (a) The commission shall initiate a proceeding within 30 days of July 1, 2001, to establish, by order, generic standards for utility tariffs for the interconnection and parallel operation of distributed generation fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels of no more than ten megawatts of interconnected capacity. At a minimum, these tariff standards must:

(1) to the extent possible, be consistent with industry and other federal and state operational and safety standards;

(2) provide for the low-cost, safe, and standardized interconnection of facilities;

(3) take into account differing system requirements and hardware, as well as the overall demand load requirements of individual utilities;

(4) allow for reasonable terms and conditions, consistent with the cost and operating characteristics of the various technologies, so that a utility can reasonably be assured of the reliable, safe, and efficient operation of the interconnected equipment; and

(5) establish (i) a standard interconnection agreement that sets forth the contractual conditions under which a company and a customer agree that one or more facilities may be interconnected with the company's utility system, and (ii) a standard application for interconnection and parallel operation with the utility system.

(b) The commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation.

Subd. 3. **Distributed generation tariff.** Within 90 days of the issuance of an order under subdivision 2:

(1) each public utility providing electric service at retail shall file a distributed generation tariff consistent with that order, for commission approval or approval with modification; and

(2) each municipal utility and cooperative electric association shall adopt a distributed generation tariff that addresses the issues included in the commission's order.

Subd. 3a. **Project information.** (a) Beginning July 1, 2014, each electric utility shall request an applicant for interconnection of distributed renewable energy generation to provide the following information, in a format prescribed by the commissioner:

(1) the nameplate capacity of the facility in the application;

(2) the preincentive installed cost and cost components of the generation system at the facility;

(3) the energy source of the facility; and

(4) the zip code in which the facility is to be located.

(b) The commissioner shall develop or identify a system to collect and process the information under this subdivision for each utility, and make non-project-specific data available to the public on a periodic basis as determined by the commissioner, and in a format determined by the commissioner. The commissioner may solicit proposals from outside parties to develop the system. The commissioner may only collect data authorized in paragraph (a), and may not require submission of any additional data that could be used to personally identify any individual applicant or utility customer.

(c) Electric utilities collecting and transferring data under this subdivision are not responsible for the accuracy, completeness, or quality of the information under this subdivision.

(d) Except as provided in paragraph (b), any information provided by an applicant to the commissioner under this subdivision is nonpublic data as defined in section 13.02, subdivision 9.

Subd. 4. **Reporting requirements.** (a) Each electric utility shall maintain records concerning applications received for interconnection and parallel operation of distributed generation. The records must include the date each application is received, documents generated in the course of processing each application, correspondence regarding each application, and the final disposition of each application.

(b) Every electric utility shall file with the commissioner a distributed generation interconnection report for the preceding calendar year that identifies each distributed generation facility interconnected with the utility's distribution system. The report must list the new distributed generation facilities interconnected with the system since the previous year's report, any distributed generation facilities no longer interconnected with the utility's system since the previous report, the capacity of each facility, and the feeder or other point on the company's utility system where the facility is connected. The annual report must also identify all applications for interconnection received during the previous one-year period, and the disposition of the applications.

History: *2001 c 212 art 3 s 1; 2014 c 254 s 9*

216B.1612 [Repealed, 2016 c 189 art 6 s 16]

216B.1613 STANDARDIZED CONTRACT.

Within 60 days of May 20, 2009, each utility, as defined in section 216B.1691, subdivision 1, paragraph (d), shall file with the commission a standardized contract form for the purchase of electricity from projects with a nameplate capacity of five megawatts or less. The standardized contract form must be similar in all material respects to the standard contract form previously filed with the commission under section 216B.2423, subdivision 3, including any revisions to that contract on file with the commission as of May 20, 2009. After consultation with wind developers and producers, a utility governed by this section may modify the standardized contract currently on file under section 216B.2423 prior to submitting its standard contract form under this section if the modifications are reasonably necessary to account for circumstances that are unique to that particular utility. The commission shall not approve a contract that is not in compliance with this section.

History: *2009 c 110 s 10; 2023 c 7 s 32*

216B.1614 ELECTRIC VEHICLE CHARGING TARIFF.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Electric vehicle" has the meaning given in section 169.011, subdivision 26a.

(c) "Public utility" has the meaning given in section 216B.02, subdivision 4.

(d) "Renewable energy" has the meaning given in section 216B.169, subdivision 2, paragraph (d).

Subd. 2. **Required tariff.** (a) By February 1, 2015, each public utility selling electricity at retail must file with the commission a tariff that allows a customer to purchase electricity solely for the purpose of recharging an electric vehicle. The tariff must:

(1) contain either a time-of-day or off-peak rate, as elected by the public utility;

(2) offer a customer the option to purchase electricity:

(i) from the utility's current mix of energy supply sources; or

(ii) entirely from renewable energy sources, subject to the conditions established under section 216B.169, subdivision 2, paragraph (b), and subdivision 3, paragraph (a); and

(3) be made available to the residential customer class.

(b) The public utility may, at its discretion, offer the tariff to other customer classes.

(c) The commission shall, after notice and opportunity for public comment, approve, modify, or reject the tariff. The commission may approve the tariff if the public utility has demonstrated that the tariff:

(1) appropriately reflects off-peak versus peak cost differences in the rate charged;

(2) includes a mechanism to allow the recovery of costs reasonably necessary to comply with this section, including costs to inform and educate customers about the financial, energy conservation, and environmental benefits of electric vehicles and to publicly advertise and promote participation in the customer-optional tariff;

(3) provides for clear and transparent customer billing statements including, but not limited to, the amount of energy consumed under the tariff; and

(4) incorporates the cost of metering or submetering within the rate charged to the customer.

(d) Within 60 days of commission approval of a public utility's tariff filed under this section, the public utility shall make the tariff available to customers.

(e) The utility may at any time propose revisions to a tariff filed under this subdivision based on changing costs or conditions.

Subd. 3. **Data reporting.** Each public utility providing a tariff under this section shall periodically report to the commission, as established by the commission and on a form prescribed by the commission, the following information, organized on a per-quarter basis:

(1) the number of customers who have arranged to purchase electricity under the tariff;

(2) the total amount of electricity sold under the tariff; and

(3) other data required by the commission.

History: *2014 c 254 s 10*

216B.1615 ELECTRIC VEHICLE DEPLOYMENT PROGRAM.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the following terms have the meanings given.

(b) "Battery exchange station" means a physical location deploying equipment that enables a used electric vehicle battery to be removed and exchanged for a fresh electric vehicle battery.

(c) "Electric vehicle" means any device or contrivance that transports persons or property and is capable of being powered by an electric motor drawing current from rechargeable storage batteries, fuel cells, or other portable sources of electricity. Electric vehicle includes but is not limited to:

(1) an electric vehicle, as defined in section 169.011, subdivision 26a;

(2) an electric-assisted bicycle, as defined in section 169.011, subdivision 27;

(3) an off-road vehicle, as defined in section 84.797, subdivision 7;

(4) a motorboat, as defined in section 86B.005, subdivision 9; or

(5) an aircraft, as defined in section 360.013, subdivision 37.

(d) "Electric vehicle charging station" means a physical location deploying equipment that:

(1) transfers electricity to an electric vehicle battery;

(2) dispenses hydrogen into an electric vehicle powered by a fuel cell;

(3) exchanges electric vehicle batteries; or

(4) provides other equipment used to charge or fuel electric vehicles.

(e) "Electric vehicle infrastructure" means electric vehicle charging stations and any associated machinery, equipment, and infrastructure necessary for a public utility to supply electricity or hydrogen to an electric vehicle charging station and to support electric vehicle operation.

(f) "Fuel cell" means a cell that converts the chemical energy of hydrogen directly into electricity through electrochemical reactions.

(g) "Government entity" means the state, a state agency, or a political subdivision, as defined in section 13.02, subdivision 11.

(h) "Motor fuel" has the meaning given in section 296A.01, subdivision 33.

(i) "Public utility" has the meaning given in section 216B.02, subdivision 4.

Subd. 2. **Transportation electrification plan; contents.** (a) By November 1, 2023, and periodically as ordered by the commission, but at least every four years thereafter, a public utility must file a transportation electrification plan with the commission that may include but is not limited to elements that:

(1) maximize the overall benefits of electric vehicles and other electrified transportation while minimizing overall costs; and

(2) promote the:

(i) purchase of electric vehicles by the public utility's customers;

(ii) deployment of electric vehicle infrastructure in the public utility's service territory; and

(iii) development of partnerships, including with establishments that currently retail automotive fuel, in order to increase access to electric vehicle charging stations.

(b) A transportation electrification plan may include but is not limited to the following elements:

(1) programs to educate and increase the awareness and benefits of electric vehicles and electric vehicle charging equipment among individuals, electric vehicle dealers, single-family and multifamily housing developers and property management companies, building owners and tenants, vehicle service stations, vehicle fleet owners and managers, and other potential users of electric vehicles;

(2) investments and customer incentives offered by the public utility to support transportation electrification across all customer classes, including but not limited to investments and customer incentives to facilitate:

(i) the deployment of all types of electric vehicles, and the electric vehicle infrastructure and other electric utility infrastructure required to support them;

(ii) widespread access to publicly available and conveniently located electric vehicle charging stations, including through partnerships between public utilities and establishments that retail automotive fuel, and any Minnesota trade association predominantly composed of establishments that retail automotive fuel, provided that the establishments:

(A) collaborate with the public utility to determine optimal charging locations;

(B) operate 24 hours per day and are staffed at least 14 hours per day, excluding public holidays; and

(C) assume charging station operating and maintenance costs, while maintaining operating standards in a safe and efficient manner consistent with industry standards; and

(iii) the electrification of public transit and vehicle fleets owned or operated by a government entity;

(3) research and demonstration projects to increase access to electricity as a transportation fuel, minimize the system costs of electric transportation, and inform future transportation electrification plans;

(4) rate structures or programs that:

(i) incentivize electric vehicle charging at times of day that optimize electric grid operation through the deployment of time-varying rates and charging optimization programs;

(ii) are transparent to a charging customer and an owner of electric vehicle charging stations; and

(iii) ensure that the rates, terms, and conditions governing the operation of electric vehicle charging stations are uniform throughout a public utility's service area;

(5) programs targeting transportation electrification in low- and moderate-income communities and in neighborhoods most affected by transportation-related air emissions;

(6) proposals to expedite commission consideration of program adjustments requested by the public utility; and

(7) proposals to share information and results from transportation electrification projects with stakeholders to promote effective electrification in all areas of the state.

(c) A transportation electrification plan may include planned upgrades to and investments in a public utility's distribution system that are necessary to accommodate future growth in transportation electrification and support the plan's proposed programs and activities.

Subd. 3. **Transportation electrification plan; review and implementation.** The commission may approve, modify, or reject a transportation electrification plan. When reviewing a transportation electrification plan, the commission must consider whether the programs, investments, and expenditures as a whole are reasonable and in the public interest, and are reasonably expected to:

(1) improve the operation of the electric grid;

(2) increase access to the use of electricity as a transportation fuel for all customers, including those in low- and moderate-income communities, rural communities, and communities most affected by air emissions from the transportation sector;

(3) increase access to publicly available electric vehicle charging for all types of electric vehicles;

(4) support the electrification of medium-duty and heavy-duty vehicles and associated charging infrastructure;

(5) reduce statewide greenhouse gas emissions, as defined in section 216H.01, and emissions of other air pollutants that impair the environment and public health;

(6) stimulate nonutility investment and the creation of high-quality jobs for local workers;

(7) educate the public about the benefits of electric vehicles and related infrastructure;

(8) be transparent and incorporate reasonable public reporting of program activities, consistent with existing technology and data capabilities, to inform program design and commission policy with respect to electric vehicles;

(9) reasonably balance the benefits of ratepayer funded investments in transportation electrification and impacts on utility rates; and

(10) appropriately balance the participation of public utilities and private enterprise in the market for transportation electrification and related services.

Subd. 4. **Cost recovery.** Notwithstanding any other provision of this chapter, the commission may approve cost recovery under section 216B.16, including an appropriate rate of return, of any prudent and reasonable investments made or expenses incurred by a public utility, including rebates for the installation of electric vehicle infrastructure, to administer and implement an approved transportation electrification plan.

Subd. 5. **Pending filings.** This section shall not apply to any proposals designed to satisfy the objectives established in subdivision 2 that are part of a proceeding that is pending before the commission as of April 1, 2023. In those proceedings, the commission shall have full authority and discretion to accept, modify, or reject the utility's proposals in accordance with the provisions of this chapter extant at the time the public utility's proposals were initially filed in the proceeding. In its filing due November 1, 2023, a public utility that is a party in such a pending proceeding shall not be required under this section to file proposals to satisfy the objectives of subdivision 2 in addition to those accepted or modified by the commission in the pending proceeding.

History: *2023 c 60 art 12 s 12*

216B.162 COMPETITIVE RATE FOR ELECTRIC UTILITY.

Subdivision 1. **Definitions.** (a) The terms used in this section have the meanings given them in this subdivision.

(b) "Effective competition" means a market situation in which an electric utility serves a customer that:

(1) is located within the electric utility's assigned service area determined under section 216B.39; and

(2) has the ability to obtain its energy requirements from an energy supplier that is not regulated by the commission under section 216B.16.

(c) "Competitive rate schedule" means a rate schedule under which an electric utility may set or change the price for its service to an individual customer or group of customers subject to effective competition.

(d) "Competitive rate" means the actual rate offered by the utility, and approved by the commission, to a customer subject to effective competition.

(e) "Discretionary rate reduction" means a specific reduction to an existing rate, offered voluntarily by the utility to an individual customer or group of customers and approved by the commission in accordance with subdivisions 10 and 11.

Subd. 2. **Competitive rate schedule permitted.** (a) Notwithstanding section 216B.03, 216B.05, 216B.06, 216B.07, or 216B.16, the commission shall approve a competitive rate schedule when:

(1) the provision of service to a customer or a class of customers is subject to effective competition; and

(2) the schedule applies only to customers requiring electric service with a connected load of at least 2,000 kilowatts.

(b) The commission may approve a competitive rate schedule that applies to customers subject to effective competition and requiring electric service with a connected load less than 2,000 kilowatts.

(c) The commission shall make a final determination in a proceeding begun under this section within 90 days of a miscellaneous rate filing by the electric utility.

Subd. 3. **Establishing or changing competitive rate schedule.** The commission shall establish or change a competitive rate schedule through a miscellaneous or general rate filing by the utility.

Subd. 4. **Rates and terms of competitive rate schedule.** When the commission authorizes a competitive rate schedule for a customer class, it shall set the terms and conditions of service for that schedule, which must include:

(1) that the minimum rate for the schedule recover at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential;

(2) that the maximum possible rate reduction under a competitive rate schedule does not exceed the difference between the electric utility's applicable standard tariff and the cost to the customer of the lowest cost competitive energy supply;

(3) that the electric utility, within a general rate case, be allowed to seek recovery of the difference between the standard tariff and the competitive rate times the usage level during the test year period;

(4) a determination that a rate within a competitive rate schedule meets the conditions of section 216B.03, for other customers in the same customer class;

(5) that the rate does not compete with district heating or cooling provided by a district heating utility as defined by section 216B.166, subdivision 2, paragraph (c); and

(6) that the rate may not be offered to a customer in which the utility has a financial interest greater than 50 percent.

Subd. 5. **Competitive rate offered.** Within its own assigned service territory, the utility, at its discretion and using its best judgment at the time, may offer a competitive rate to a customer subject to effective competition.

Subd. 6. **Interim competitive rate.** Notwithstanding section 216B.16, subdivision 3, a proposed competitive rate takes effect on an interim basis after filing the proposed rate with the commission and on the date established by the electric utility. While an interim competitive rate is in effect, the difference between rates under the competitive rate and rates under the standard tariff for that class are not subject to recovery or refund. If the commission does not approve the competitive rate, the electric utility may seek to recover the difference in revenues between the interim competitive rate and the standard tariff from the customer that was offered the competitive rate.

Subd. 7. **Commission determination.** (a) Except as provided under subdivision 6, competitive rates offered by electric utilities under this section must be filed with the commission and must be approved, modified, or rejected by the commission within 90 days. The utility's filing must include statements of fact demonstrating that the proposed rates meet the standards of this subdivision. The filing must be served on the department and the Office of the Attorney General at the same time as it is served on the commission.

(b) In reviewing a specific rate proposal, the commission shall determine:

(1) that the rate meets the terms and conditions in subdivision 4, unless the commission determines that waiver of one or more terms and conditions would be in the public interest;

(2) that the consumer can obtain its energy requirements from an energy supplier not rate-regulated by the commission under section 216B.16;

(3) that the customer is not likely to take service from the electric utility seeking to offer the competitive rate if the customer was charged the electric utility's standard tariffed rate; and

(4) that after consideration of environmental and socioeconomic impacts it is in the best interest of all other customers to offer the competitive rate to the customer subject to effective competition.

(c) If the commission approves the competitive rate, it becomes effective as agreed to by the electric utility and the customer. If the competitive rate is modified by the commission, the commission shall issue an order modifying the competitive rate subject to the approval of the electric utility and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modification, the commissioner's order becomes final. If either party rejects the commission's proposed modification, the electric utility, on its behalf or on the behalf of the customer, may submit to the commission a modified version of the commission's proposal. The commission shall accept or reject the modified version within 30 days. If the commission rejects the competitive rate, it shall issue an order indicating the reasons for the rejection.

Subd. 8. **Energy efficiency improvement; expense recovery.** If the commission approves a competitive rate or the parties agree to a modified rate, the commission may require the electric utility to provide the customer with an energy audit and assist in implementing cost-effective energy efficiency improvements to assure that the customer's use of electricity is efficient. An investment in cost-effective energy conservation improvements required under this section must be treated as an energy conservation improvement program and included in the department's determination of significant investments under section 216B.241. The utility shall recover energy conservation improvement expenses in a rate proceeding under section 216B.16 or 216B.17 in the same manner as the commission authorizes for the recovery of conservation expenditures made under section 216B.241.

Subd. 9. [Repealed, 1995 c 6 s 2]

Subd. 10. **Discretionary rate reduction permitted.** Notwithstanding sections 216B.03, 216B.06, 216B.07, and 216B.16, a public utility whose rates are regulated under this chapter may, at its discretion, offer a reduced rate for tariffed electric services to eligible customers. The commission may approve a discretionary rate reduction provided that:

(1) the reduction is offered to customers who are located within the exclusive service territory of the public utility that offers discretionary rate reductions or to potential customers who are not customers of a Minnesota electric utility, as defined in section 216B.38, but who propose to be located within the exclusive service territory of the public utility;

(2) the reduction applies to customers requiring electric service with a connected load of at least 2,000 kilowatts;

(3) the reduced rate recovers at least the incremental cost of providing the service, including the cost of additional capacity that is to be added while the rate is in effect and any applicable on-peak or off-peak differential;

(4) in the event the commission has approved unbundled rates, the reduction is not offered for any unbundled service other than generation, unless the unbundled service is available to the customer from a competitive supplier;

(5) the reduced rate does not compete with district heating or cooling services provided by a district heating utility as defined by section 216B.166, subdivision 2, paragraph (c); and

(6) the reduced rate does not compete with a natural gas service provided by a natural gas utility and regulated by the commission.

Subd. 11. **Commission determination.** (a) Proposals for discretionary rate reductions offered by utilities must be filed with the commission, with copies of the filing served upon the department and the office of attorney general at the same time it is served upon the commission. The commission shall review the proposals according to procedures developed under section 216B.05, subdivision 2a. The commission shall not approve discretionary rate reductions offered by public utilities that do not have an accepted resource plan on file with the commission. The commission shall not approve discretionary rate reductions unless the utility has made the customer aware of all cost-effective opportunities for energy efficiency improvements offered by the utility.

(b) Public utilities that provide service under discretionary rate reductions shall not, through increased revenue requirements or through prospective rate design changes, recover any revenues forgone due to the discretionary rate reductions, nor shall the commission grant such recovery.

History: *1990 c 370 s 3,7; 1993 c 190 s 1; 1995 c 6 s 1; 1997 c 191 art 1 s 2-5; 1Sp2001 c 4 art 6 s 41,42*

216B.1621 ELECTRIC SERVICE AGREEMENT.

Subdivision 1. **Agreement.** When a retail customer of a public utility proposes to acquire power from or construct a new electric power generation facility in the assigned service area of the utility serving the retail customer to provide all or part of the customer's electric service needs, the public utility may negotiate with and enter into an agreement with the customer to supply electric power to the customer in order to defer construction of the facility until the utility has need of power generated by the proposed facility, if the Public Utilities Commission approves the agreement under subdivision 2.

Subd. 2. **Commission approval.** (a) The commission shall approve an agreement under this section upon finding that:

(1) the proposed electric service power generation facility could reasonably be expected to qualify for a market value exclusion under section 272.0211;

(2) the public utility has a contractual option to purchase electric power from the proposed facility; and

(3) the public utility can use the output from the proposed facility to meet its future need for power as demonstrated in the most recent resource plan filed with and approved by the commission under section 216B.2422.

(b) Sections 216B.03, 216B.05, 216B.06, 216B.07, 216B.16, 216B.162, and 216B.23 do not apply to an agreement under this section.

History: *1996 c 444 s 1*

216B.1622 SERVICE TO VERY LARGE CUSTOMERS.

Subdivision 1. **Very large customer class or subclass.** By December 15, 2026, the commission shall establish by order the definition and appropriate characteristics of a very large customer class or subclass for each public utility providing electric service. The commission may do this in a rate case under section 216B.16 for that utility or in another proceeding.

Subd. 2. **Tariff or energy supply agreement.** The commission may approve, modify, or reject a tariff or electric service agreement proposed between a public utility and a very large customer establishing the terms and conditions under which the utility will provide electric service to the customer. As it evaluates a tariff or agreement under this section, the commission must consider how best to achieve the following required outcomes:

(1) all costs attributable to the utility's very large customers not exempt under subdivision 3 are assigned to the very large customer class or subclass determined by the commission under paragraph (a);

(2) the electricity to be provided by the utility to a very large customer achieves each quantitative benchmark of the state's electricity standards under section 216B.1691, as demonstrated by a plan submitted by the utility to serve the additional load without recourse to requesting a delay or modification of these standards;

(3) the tariff or agreement contains protections necessary to ensure that other customers of the public utility are not placed at risk for paying stranded costs associated with the utility serving the very large customer; and

(4) any other outcome deemed important by the commission to ensure the tariff or agreement is in the public interest.

Subd. 3. **Existing tariff or agreements.** This section shall not apply to existing, renewed, or extended electric service agreements of public utility customers meeting the threshold of a very large customer, or to very large customers that have been actively taking electric service from the public utility prior to 2020.

History: *1Sp2025 c 12 s 9*

216B.1623 CLEAN ENERGY AND CAPACITY TARIFF.

The commission shall require each public utility to offer a clean energy and capacity tariff for commercial and industrial customers. The clean energy and capacity tariff shall require a special contract between the utility and one or more customers that shall:

(1) be optional for participating customers;

(2) permit participating customers to elect to serve some or all of their energy or capacity usage from new clean energy or capacity resources as long as reliability is maintained;

(3) require the participating customers to pay all proportional costs associated with the addition of the new clean energy or capacity resources, including any utility costs caused by the addition of the new clean energy or capacity resources to the grid;

(4) develop an appropriate energy and capacity credit;

(5) prohibit cost shifting from the participating customers to other utility customers or vice versa; and

(6) allow a utility with an applicable tariff on file to demonstrate their existing tariff's compliance with this section.

History: *1Sp2025 c 12 s 10*

216B.163 FLEXIBLE TARIFF.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Effective competition" means that a customer of a gas utility who either receives interruptible service or whose daily requirement exceeds 50,000 cubic feet maintains or plans on acquiring the capability to switch to the same, equivalent or substitutable energy supplies or service, except indigenous biomass energy supplies composed of wood products, grain, biowaste, and cellulosic materials, at comparable prices from a supplier not regulated by the commission.

(c) "Flexible tariff" means a rate schedule under which a gas utility may set or change the price for its service to an individual customer or group of customers without prior approval of the commission within a range of prices determined by the commission to be just and reasonable.

Subd. 2. **Flexible tariff permitted.** Notwithstanding section 216B.03, 216B.05, 216B.06, 216B.07, or 216B.16, the commission may approve a flexible tariff for any class of customers of a gas utility when provision of service, including the sale or transportation of gas, to any customers within the class is subject to effective competition. Upon application of a gas utility, the commission shall find that effective competition exists for a class of customers taking interruptible service at a level exceeding 199,000 cubic feet per day. A gas utility may apply a flexible tariff only to a customer that is subject to effective competition and a gas utility may not apply a flexible tariff or otherwise reduce its rates to compete with indigenous biomass energy supplies. Customers of a gas utility whose only alternative source of energy is gas from a supplier not regulated by the commission and who must use the gas utility's system to transport the gas are not subject to effective competition unless the customers have or can reasonably acquire the capability to bypass the gas utility's system to obtain gas from a supplier not regulated by the commission. A customer subject to effective competition may elect to take service either under the flexible tariff or under the appropriate nonflexible tariff for that class of service set in accordance with section 216B.03, provided that a customer that uses an alternative energy supply or service from a supplier not regulated by the commission for reasons of price are deemed to have elected to take service under the flexible tariff.

Subd. 2a. [Expired]

Subd. 3. **Establishing or changing flexible tariff.** The commission may establish a flexible tariff through a miscellaneous rate filing only if the filing does not seek to recover revenues the utility expects to lose by implementing flexible tariffs from customers who do not take service under the flexible tariff, nor to change another rate. If a gas utility requests authority to establish a flexible tariff and as part of that request seeks to recover revenues the utility expects to lose by implementing flexible tariffs from customers who do not take service under the flexible tariff or to change other rates, the commission may only establish that flexible tariff within a general rate case for that gas utility.

Subd. 4. **Rates and terms of service.** Whenever the commission authorizes a flexible tariff, it shall set the terms, and conditions of service for that tariff, including:

(1) the minimum rate for the tariff, which must recover at least the incremental cost of providing the service;

(2) the maximum rate for the tariff; and

(3) a requirement that a customer who elects to take service under the flexible tariff remain on that tariff for a reasonable period of time.

The commission may set the terms and conditions of service for a flexible tariff in a gas utility proceeding, a miscellaneous filing, or a complaint proceeding under section 216B.17.

Subd. 5. **Recovery of revenues.** In a general rate case that establishes a flexible tariff for a gas utility, and in each general rate case of a gas utility for which a flexible tariff has been authorized, the commission shall determine a projected level of revenues and expenses from services under that tariff and use the projection to determine the utility's overall rates. That method used to establish a level of projected revenues may not limit the gas utility's ability or right to set rates for a customer taking service under the flexible tariff.

Subd. 6. **Interim flexible tariff.** Notwithstanding section 216B.16, subdivision 3, if a gas utility files with the commission to establish or change a flexible tariff the commission shall permit the proposed flexible tariff to take effect on an interim basis no later than 30 days after filing. If any customers receive an increase in rates during the period that an interim flexible tariff is in effect, the increase is subject to refund as provided in section 216B.16, subdivision 3. The gas utility shall provide ten days' written notice, or other notice as may be established by contract not to exceed 30 days, to a customer before implementing an interim rate change for that customer under this section.

Subd. 7. **Final determination.** The commission shall make a final determination in a proceeding begun under this section for approval of a flexible tariff, other than a filing made within a general rate case, within 180 days of the filing by the gas utility.

Subd. 8. MS 2002 [Obsolete]

History: *1987 c 371 s 1,4; 1990 c 593 s 1,2*

216B.1635 RECOVERY OF GAS UTILITY INFRASTRUCTURE COSTS.

Subdivision 1. **Definitions.** (a) "Gas utility" means a public utility as defined in section 216B.02, subdivision 4, that furnishes natural gas service to retail customers.

(b) "Gas utility infrastructure costs" or "GUIC" means costs incurred in gas utility projects that:

(1) do not serve to increase revenues by directly connecting the infrastructure replacement to new customers;

(2) are in service but were not included in the gas utility's rate base in its most recent general rate case, or are planned to be in service during the period covered by the report submitted under subdivision 2, but in no case longer than the one-year forecast period in the report; and

(3) do not constitute a betterment, unless the betterment is based on requirements by a political subdivision or a federal or state agency, as evidenced by specific documentation, an order, or other similar requirement from the government entity requiring the replacement or modification of infrastructure.

(c) "Gas utility projects" means:

(1) replacement of natural gas facilities located in the public right-of-way required by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota, or a political subdivision; and

(2) replacement or modification of existing natural gas facilities, including surveys, assessments, reassessment, and other work necessary to determine the need for replacement or modification of existing infrastructure that is required by a federal or state agency.

Subd. 2. **Gas infrastructure filing.** A public utility submitting a petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c). The report and petition must be made at least 150 days in advance of implementation of the rate schedule, provided that the rate schedule will not be implemented until the petition is approved by the commission pursuant to subdivision 5. The report must be for a forecast period of one year.

Subd. 3. **Gas infrastructure project plan report.** The gas infrastructure project plan report required to be filed under subdivision 2 shall include all pertinent information and supporting data on each proposed project including, but not limited to, project description and scope, estimated project costs, and project in-service date.

Subd. 4. **Cost recovery petition for utility's facilities.** Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section, including a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs. A gas utility's petition for approval of a rate schedule to recover gas utility infrastructure costs outside of a general rate case under section 216B.16 is subject to the following:

(1) a gas utility may submit a filing under this section no more than once per year; and

(2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:

(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;

(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;

(iii) a description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;

(iv) a comparison of the utility's estimated costs included in the gas infrastructure project plan and the actual costs incurred, including a description of the utility's efforts to ensure the costs of the facilities are reasonable and prudently incurred;

(v) calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;

(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;

(vii) the magnitude of GUIC in relation to the gas utility's base revenue as approved by the commission in the gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges;

(viii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and

(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.

Subd. 5. **Commission action.** Upon receiving a gas utility report and petition for cost recovery under subdivision 2 and assessment and verification under subdivision 4, the commission may approve the annual GUIC rate adjustments provided that, after notice and comment, the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.

Subd. 6. **Rate of return.** The return on investment for the rate adjustment shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.

Subd. 7. **Commission authority; rules.** The commission may issue orders and adopt rules necessary to implement and administer this section.

History: *2005 c 97 art 10 s 1,3; 2013 c 85 art 7 s 2,9; 2023 c 60 art 12 s 66*

NOTE: This section expires June 30, 2028. Laws 2005, chapter 97, article 10, section 3, as amended by Laws 2013, chapter 85, article 7, section 9, and Laws 2023, chapter 60, article 12, section 66.

216B.1636 RECOVERY OF ELECTRIC UTILITY INFRASTRUCTURE COSTS.

Subdivision 1. **Definitions.** (a) "Electric utility" means a public utility as defined in section 216B.02, subdivision 4, that furnishes electric service to retail customers.

(b) "Electric utility infrastructure costs" or "EUIC" means costs for electric utility infrastructure projects that were not included in the electric utility's rate base in its most recent general rate case.

(c) "Electric utility infrastructure projects" means projects owned by an electric utility that:

(1) replace or modify existing electric utility infrastructure, including utility-owned buildings, if the replacement or modification is shown to conserve energy or use energy more efficiently, consistent with section 216B.241, subdivision 1c; or

(2) conserve energy or use energy more efficiently by using waste heat recovery converted into electricity as defined in section 216B.241, subdivision 1, paragraph (o).

Subd. 2. **Filing.** (a) The commission may approve an electric utility's petition for a rate schedule to recover EUIC under this section. An electric utility may petition the commission to recover a rate of return, income taxes on the rate of return, incremental property taxes, if any, plus incremental depreciation expense associated with EUIC.

(b) The filing is subject to the following:

(1) an electric utility may submit a filing under this section no more than once per year; and

(2) an electric utility must file sufficient information to satisfy the commission regarding the proposed EUIC or be subject to denial by the commission. The information includes, but is not limited to:

(i) the location, description, and costs associated with the project;

(ii) evidence that the electric utility infrastructure project will conserve energy or use energy more efficiently than similar utility facilities currently used by the electric utility;

(iii) the proposed schedule for implementation;

(iv) a description of the costs, and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;

(v) the proposed rate design and an explanation of why the proposed rate design is in the public interest;

(vi) the magnitude and timing of any known future electric utility projects that the utility may seek to recover under this section;

(vii) the magnitude of EUIC in relation to the electric utility's base revenue as approved by the commission in the electric utility's most recent general rate case, exclusive of fuel cost adjustments;

(viii) the magnitude of EUIC in relation to the electric utility's capital expenditures since its most recent general rate case;

(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case;

(x) documentation supporting the calculation of the EUIC; and

(xi) a cost and benefit analysis showing that the electric utility infrastructure project is in the public interest.

(c) Upon approval of the proposed projects and associated EUIC rate schedule, the utility may implement the electric utility infrastructure projects.

Subd. 3. **Commission authority; orders.** The commission may issue orders necessary to implement and administer this section.

History: *2007 c 136 art 2 s 3; 2016 c 158 art 1 s 79*

216B.1637 [Repealed, 2013 c 85 art 13 s 6]

216B.1638 RECOVERY OF NATURAL GAS EXTENSION PROJECT COSTS.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Contribution in aid of construction" means a monetary contribution, paid by a developer or local unit of government to a utility providing natural gas service to a community receiving that service as the result of a natural gas extension project, that reduces or offsets the difference between the total revenue requirement of the project and the revenue generated from the customers served by the project.

(c) "Developer" means a developer of the project or a person that owns or will own the property served by the project.

(d) "Local unit of government" means a city, county, township, commission, district, authority, or other political subdivision or instrumentality of this state.

(e) "Natural gas extension project" or "project" means the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas.

(f) "Revenue deficiency" means the deficiency in funds that results when projected revenues from customers receiving natural gas service as the result of a natural gas extension project, plus any contributions in aid of construction paid by these customers, fall short of the total revenue requirement of the natural gas extension project.

(g) "Total revenue requirement" means the total cost of extending and maintaining natural gas service to a currently unserved or inadequately served area.

(h) "Transport customer" means a customer for whom a natural gas utility transports gas the customer has purchased from another natural gas supplier.

(i) "Unserved or inadequately served area" means an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers.

Subd. 2. **Filing.** (a) A public utility may petition the commission outside of a general rate case for a rider that shall include all of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas extension project.

(b) The petition shall include:

(1) a description of the natural gas extension project, including the number and location of new customers to be served and the distance over which natural gas will be distributed to serve the unserved or inadequately served area;

(2) the project's construction schedule;

(3) the proposed project budget;

(4) the amount of any contributions in aid of construction;

(5) a description of efforts made by the public utility to offset the revenue deficiency through contributions in aid to construction;

(6) the amount of the revenue deficiency, and how recovery of the revenue deficiency will be allocated among industrial, commercial, residential, and transport customers;

(7) the proposed method to be used to recover the revenue deficiency from each customer class, such as a flat fee, a volumetric charge, or another form of recovery;

(8) the proposed termination date of the rider to recover the revenue deficiency; and

(9) a description of benefits to the public utility's existing natural gas customers that will accrue from the natural gas extension project.

Subd. 3. **Review; approval.** (a) The commission shall allow opportunity for comment on the petition.

(b) The commission shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that:

(1) the project is designed to extend natural gas service to an unserved or inadequately served area; and

(2) project costs are reasonable and prudently incurred.

(c) The commission must not approve a rider under this section that allows a utility to recover more than 33 percent of the costs of a natural gas extension project.

(d) The revenue deficiency from a natural gas extension project recoverable through a rider under this section must include the currently authorized rate of return, incremental income taxes, incremental property taxes, incremental depreciation expenses, and any incremental operation and maintenance costs.

Subd. 4. **Commission authority; order.** The commission may issue orders necessary to implement and administer this section.

Subd. 5. **Implementation.** Nothing in this section commits a public utility to implement a project approved by the commission. The public utility seeking to provide natural gas service shall notify the commission whether it intends to proceed with the project as approved by the commission.

Subd. 6. **Evaluation and report.** By January 15, 2017, and every three years thereafter, the commission shall report to the chairs and ranking minority members of the senate and house of representatives committees having jurisdiction over energy policy:

(1) the number of public utilities and projects proposed and approved under this section;

(2) the total cost of each project;

(3) rate impacts of the cost recovery mechanism; and

(4) an assessment of the effectiveness of the cost recovery mechanism in realizing increased natural gas service to unserved or inadequately served areas from natural gas extension projects.

History: *1Sp2015 c 1 art 3 s 20*

216B.164 COGENERATION AND SMALL POWER PRODUCTION.

Subdivision 1. **Scope and purpose.** This section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.

Subd. 2. **Applicability; rights maintained.** (a) This section as well as any rules promulgated by the commission to implement this section or the Public Utility Regulatory Policies Act of 1978, Public Law 95-617, Statutes at Large, volume 92, page 3117, as amended, and the Federal Energy Regulatory Commission regulations thereunder, Code of Federal Regulations, title 18, part 292, as amended, shall, unless otherwise provided in this section, apply to all Minnesota electric utilities, including cooperative electric associations and municipal electric utilities.

(b) Nothing in this section shall be construed to alter the rights and duties of any person pursuant to the Public Utility Regulatory Policies Act of 1978, Public Law 95-617, Statutes at Large, volume 92, page 3117, as amended, and the Federal Energy Regulatory Commission regulations thereunder, Code of Federal Regulations, title 18, part 292, as amended.

Subd. 2a. **Definitions.** (a) For the purposes of this section, the following terms have the meanings given them.

(b) "Aggregated meter" means a meter located on the premises of a customer's owned or leased property that is contiguous with property containing the customer's designated meter.

(c) "Capacity" means the number of megawatts alternating current (AC) at the point of interconnection between a distributed generation facility and a utility's electric system.

(d) "Cogeneration" means a combined process whereby electrical and useful thermal energy are produced simultaneously.

(e) "Contiguous property" means property owned or leased by the customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way.

(f) "Customer" means the person who is named on the utility electric bill for the premises.

(g) "Designated meter" means a meter that is physically attached to the customer's facility that the customer-generator designates as the first meter to which net metered credits are to be applied as the primary meter for billing purposes when the customer is serviced by more than one meter.

(h) "Distributed generation" means a facility that:

(1) has a capacity of ten megawatts or less;

(2) is interconnected with a utility's distribution system, over which the commission has jurisdiction; and

(3) generates electricity from natural gas, renewable fuel, or a similarly clean fuel, and may include waste heat, cogeneration, or fuel cell technology.

(i) "High-efficiency distributed generation" means a distributed energy facility that has a minimum efficiency of 40 percent, as calculated under section 272.0211, subdivision 1.

(j) "Net metered facility" means an electric generation facility constructed for the purpose of offsetting energy use through the use of renewable energy or high-efficiency distributed generation sources.

(k) "Renewable energy" has the meaning given in section 216B.2411, subdivision 2.

(l) "Standby charge" means a charge imposed by an electric utility upon a distributed generation facility for the recovery of costs for the provision of standby services, as provided for in a utility's tariffs approved by the commission, necessary to make electricity service available to the distributed generation facility.

Subd. 3. **Purchases; small facilities.** (a) This paragraph applies to cooperative electric associations and municipal utilities. For a qualifying facility having less than 40-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. A cooperative electric association or municipal utility may charge an additional fee to recover the fixed costs not already paid for by the customer through the customer's existing billing arrangement. Any additional charge by the utility must be reasonable and appropriate for that class of customer based on the most recent cost of service study. The cost of service study must be made available for review by a customer of the utility upon request. In the case of net input into the utility system by a qualifying facility having less than 40-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c), (d), or (f).

(b) This paragraph applies to public utilities. For a qualifying facility having less than 1,000-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. In the case of net input into the utility system by a qualifying facility having: (1) more than 40-kilowatt but less than 1,000-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c); or (2) less than 40-kilowatt capacity, compensation to the customer shall be at a per-kilowatt rate determined under paragraph (c) or (d).

(c) In setting rates, the commission shall consider the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge and shall ensure that the costs charged to the qualifying facility are not discriminatory in relation to the costs charged to other customers of the utility. The commission shall set the rates for net input into the utility system based on avoided costs as defined in the Code of Federal Regulations, title 18, section 292.101, paragraph (b)(6), the factors listed in Code of Federal Regulations, title 18, section 292.304, and all other relevant factors.

(d) Notwithstanding any provision in this chapter to the contrary, a qualifying facility having less than 40-kilowatt capacity may elect that the compensation for net input by the qualifying facility into the utility system shall be at the average retail utility energy rate. "Average retail utility energy rate" is defined as the average of the retail energy rates, exclusive of special rates based on income, age, or energy conservation, according to the applicable rate schedule of the utility for sales to that class of customer.

(e) If the qualifying facility or net metered facility is interconnected with a nongenerating utility which has a sole source contract with a municipal power agency or a generation and transmission utility, the nongenerating utility may elect to treat its purchase of any net input under this subdivision as being made on behalf of its supplier and shall be reimbursed by its supplier for any additional costs incurred in making the purchase. Qualifying facilities or net metered facilities having less than 1,000-kilowatt capacity if interconnected to a public utility, or less than 40-kilowatt capacity if interconnected to a cooperative electric association or municipal utility may, at the customer's option, elect to be governed by the provisions of subdivision 4.

(f) A customer with a qualifying facility or net metered facility having a capacity below 40 kilowatts that is interconnected to a cooperative electric association or a municipal utility may elect to be compensated for the customer's net input into the utility system in the form of a kilowatt-hour credit on the customer's energy bill carried forward and applied to subsequent energy bills. Any kilowatt-hour credits carried forward by the customer cancel at the end of the calendar year with no additional compensation.

Subd. 3a. **Net metered facility.** (a) Except for customers receiving a value of solar rate under subdivision 10, a customer with a net metered facility having a capacity of 40 kilowatts or greater but less than 1,000 kilowatts that is interconnected to a public utility may elect to be compensated for the customer's net input into the utility system in the form of a kilowatt-hour credit on the customer's energy bill carried forward and applied to subsequent energy bills. Any net input supplied by the customer into the utility system that exceeds energy supplied to the customer by the utility during a calendar year must be compensated at the applicable rate.

(b) A public utility may not impose a standby charge on a net metered or qualifying facility:

(1) of 100 kilowatts or less capacity; or

(2) of more than 100 kilowatts capacity, except in accordance with an order of the commission establishing the allowable costs to be recovered through standby charges.

Subd. 4. **Purchases; wheeling; costs.** (a) Except as otherwise provided in paragraph (c), this subdivision shall apply to all qualifying facilities having 40-kilowatt capacity or more as well as qualifying facilities as defined in subdivision 3 and net metered facilities under subdivision 3a, if interconnected to a cooperative electric association or municipal utility, or 1,000-kilowatt capacity or more if interconnected to a public utility, which elect to be governed by its provisions.

(b) The utility to which the qualifying facility is interconnected shall purchase all energy and capacity made available by the qualifying facility. The qualifying facility shall be paid the utility's full avoided capacity and energy costs as negotiated by the parties, as set by the commission, or as determined through competitive bidding approved by the commission. The full avoided capacity and energy costs to be paid a qualifying facility that generates electric power by means of a renewable energy source are the utility's least cost renewable energy facility or the bid of a competing supplier of a least cost renewable energy facility, whichever is lower, unless the commission's resource plan order, under section 216B.2422, subdivision 2, provides that the use of a renewable resource to meet the identified capacity need is not in the public interest.

(c) For all qualifying facilities having 30-kilowatt capacity or more, the utility shall, at the qualifying facility's or the utility's request, provide wheeling or exchange agreements wherever practicable to sell the qualifying facility's output to any other Minnesota utility having generation expansion anticipated or planned for the ensuing ten years. The commission shall establish the methods and procedures to insure that except for reasonable wheeling charges and line losses, the qualifying facility receives the full avoided energy and capacity costs of the utility ultimately receiving the output.

(d) The commission shall set rates for electricity generated by renewable energy.

Subd. 4a. **Aggregation of meters.** (a) For the purpose of measuring electricity under subdivisions 3 and 3a, a public utility must aggregate for billing purposes a customer's designated meter with one or more aggregated meters if a customer requests that it do so. To qualify for aggregation under this subdivision, a meter must be owned by the customer requesting the aggregation, must be located on contiguous property owned by the customer requesting the aggregation, and the total of all aggregated meters must be subject to the size limitation in this section.

(b) A public utility must comply with a request by a customer-generator to aggregate additional meters within 90 days. The specific meters must be identified at the time of the request. In the event that more than one meter is identified, the customer must designate the rank order for the aggregated meters to which the net metered credits are to be applied. At least 60 days prior to the beginning of the next annual billing period, a customer may amend the rank order of the aggregated meters, subject to this subdivision.

(c) The aggregation of meters applies only to charges that use kilowatt-hours as the billing determinant. All other charges applicable to each meter account shall be billed to the customer.

(d) A public utility will first apply the kilowatt-hour credit to the charges for the designated meter and then to the charges for the aggregated meters in the rank order specified by the customer. If the net metered facility supplies more electricity to the public utility than the energy usage recorded by the customer-generator's designated and aggregated meters during a monthly billing period, the public utility shall apply credits to the customer's next monthly bill for the excess kilowatt-hours.

(e) With the commission's prior approval, a public utility may charge the customer-generator requesting to aggregate meters a reasonable fee to cover the administrative costs incurred in implementing the costs of this subdivision, pursuant to a tariff approved by the commission for a public utility.

Subd. 4b. **Limiting cumulative generation.** The commission may limit the cumulative generation of net metered facilities under subdivisions 3 and 3a. A public utility may request the commission to limit the cumulative generation of net metered facilities under subdivisions 3 and 3a upon a showing that such generation has reached four percent of the public utility's annual retail electricity sales. The commission may limit additional net metering obligations under this subdivision only after providing notice and opportunity for public comment. In determining whether to limit additional net metering obligations under this subdivision, the commission shall consider:

(1) the environmental and other public policy benefits of net metered facilities;

(2) the impact of net metered facilities on electricity rates for customers without net metered systems;

(3) the effects of net metering on the reliability of the electric system;

(4) technical advances or technical concerns; and

(5) other statutory obligations imposed on the commission or on a utility.

The commission may limit additional net metering obligations under clauses (2) to (4) only if it determines that additional net metering obligations would cause significant rate impact, require significant measures to address reliability, or raise significant technical issues.

Subd. 4c. **Individual system capacity limits.** (a) A public utility that provides retail electric service may require customers with a facility of 40-kilowatt capacity or more and participating in net metering and net billing to limit the total generation capacity of individual distributed generation systems by either:

(1) for wind generation systems, limiting the total generation system capacity kilowatt alternating current to 120 percent of the customer's on-site maximum electric demand; or

(2) for solar photovoltaic and other distributed generation, limiting the total generation system annual energy production kilowatt hours alternating current to 120 percent of the customer's on-site annual electric energy consumption.

(b) Limits under paragraph (a) must be based on standard 15-minute intervals, measured during the previous 12 calendar months, or on a reasonable estimate of the average monthly maximum demand or average annual consumption if the customer has either:

(1) less than 12 calendar months of actual electric usage; or

(2) no demand metering available.

Subd. 5. **Dispute; resolution.** (a) In the event of disputes between a public utility and a qualifying facility, either party may request a determination of the issue by the commission. In any such determination, the burden of proof shall be on the public utility. The commission in its order resolving each such dispute shall require payments to the prevailing party of the prevailing party's costs, disbursements, and reasonable attorneys' fees, except that the qualifying facility will be required to pay the costs, disbursements, and attorneys' fees of the public utility only if the commission finds that the claims of the qualifying facility in the dispute have been made in bad faith, or are a sham, or are frivolous.

(b) Notwithstanding subdivisions 9 and 11, a qualifying facility over 20 megawatts may, until December 31, 2022, request that the commission resolve a dispute with any utility, including a cooperative electric association or municipal utility, under paragraph (a).

Subd. 6. **Rules and uniform contract.** (a) The commission shall promulgate rules to implement the provisions of this section. The commission shall also establish a uniform statewide form of contract for use between utilities and a net metered or qualifying facility having less than 1,000-kilowatt capacity if interconnected to a public utility or less than 40-kilowatt capacity if interconnected to a cooperative electric association or municipal utility.

(b) The commission shall require the qualifying facility to provide the utility with reasonable access to the premises and equipment of the qualifying facility if the particular configuration of the qualifying facility precludes disconnection or testing of the qualifying facility from the utility side of the interconnection with the utility remaining responsible for its personnel.

(c) The uniform statewide form of contract shall be applied to all new and existing interconnections established between a utility and a net metered or qualifying facility having less than 40-kilowatt capacity, except that existing contracts may remain in force until terminated by mutual agreement between both parties.

Subd. 7. [Repealed, 1994 c 465 art 1 s 27]

Subd. 8. **Interconnection required; obligation for costs.** (a) Utilities shall be required to interconnect with a qualifying facility that offers to provide available energy or capacity and that satisfies the requirements of this section.

(b) Nothing contained in this section shall be construed to excuse the qualifying facility from any obligation for costs of interconnection and wheeling in excess of those normally incurred by the utility for customers with similar load characteristics who are not cogenerators or small power producers, or from any fixed charges normally assessed such nongenerating customers.

Subd. 9. **Municipal electric utility.** For purposes of this section only and with respect to municipal electric utilities only, the term "commission" means the governing body of each municipal electric utility that adopts and has in effect rules implementing this section which are consistent with the rules adopted by the Minnesota Public Utilities Commission under subdivision 6. As used in this subdivision, the governing body of a municipal electric utility means the city council of that municipality; except that, if another board, commission, or body is empowered by law or resolution of the city council or by its charter to establish and regulate rates and days for the distribution of electric energy within the service area of the city, that board, commission, or body shall be considered the governing body of the municipal electric utility.

Subd. 10. **Alternative tariff; compensation for resource value.** (a) A public utility may apply for commission approval for an alternative tariff that compensates customers through a bill credit mechanism for the value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs.

(b) If approved, the alternative tariff shall apply to customers' interconnections occurring after the date of approval. The alternative tariff is in lieu of the applicable rate under subdivisions 3 and 3a.

(c) The commission shall after notice and opportunity for public comment approve the alternative tariff provided the utility has demonstrated the alternative tariff:

(1) appropriately applies the methodology established by the department and approved by the commission under this subdivision;

(2) includes a mechanism to allow recovery of the cost to serve customers receiving the alternative tariff rate;

(3) charges the customer for all electricity consumed by the customer at the applicable rate schedule for sales to that class of customer;

(4) credits the customer for all electricity generated by the solar photovoltaic device at the distributed solar value rate established under this subdivision;

(5) applies the charges and credits in clauses (3) and (4) to a monthly bill that includes a provision so that the unused portion of the credit in any month or billing period shall be carried forward and credited against all charges. In the event that the customer has a positive balance after the 12-month cycle ending on the last day in February, that balance will be eliminated and the credit cycle will restart the following billing period beginning on March 1;

(6) complies with the size limits specified in subdivision 3a;

(7) complies with the interconnection requirements under section 216B.1611; and

(8) complies with the standby charge requirements in subdivision 3a, paragraph (b).

(d) A utility must provide to the customer the meter and any other equipment needed to provide service under the alternative tariff.

(e) The department must establish the distributed solar value methodology in paragraph (c), clause (1), no later than January 31, 2014. The department must submit the methodology to the commission for approval. The commission must approve, modify with the consent of the department, or disapprove the methodology within 60 days of its submission. When developing the distributed solar value methodology, the department shall consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions, and preliminary data.

(f) The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The department may, based on known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors.

(g) The credit for distributed solar value applied to alternative tariffs approved under this section shall represent the present value of the future revenue streams of the value components identified in paragraph (f).

(h) The utility shall recalculate the alternative tariff on an annual cycle, and shall file the recalculated alternative tariff with the commission for approval.

(i) Renewable energy credits for solar energy credited under this subdivision belong to the electric utility providing the credit.

(j) The commission may not authorize a utility to charge an alternative tariff rate that is lower than the utility's applicable retail rate until three years after the commission approves an alternative tariff for the utility.

(k) A utility must enter into a contract with an owner of a solar photovoltaic device receiving an alternative tariff rate under this section that has a term of at least 20 years, unless a shorter term is agreed to by the parties.

(l) An owner of a solar photovoltaic device receiving an alternative tariff rate under this section must be paid the same rate per kilowatt-hour generated each year for the term of the contract.

Subd. 11. **Cooperative electric association.** (a) For purposes of this section only, the term "commission" means the board of directors of a cooperative association that (1) elects, by resolution, to assume the authority delegated to the Public Utilities Commission over cooperative electric associations under this section, and (2) adopts and has in effect rules implementing this section. The rules must provide for a process to resolve disputes that arise under this section, and must include a provision that a request by either party for mediation of the dispute by an independent third party must be implemented in accordance with paragraph (b). A cooperative electric association that has adopted a resolution and rules under this subdivision is exempt from regulation by the Public Utilities Commission under this section.

(b) In the event of a dispute between a cooperative electric association and one or more of its members, either party may request mediation of the dispute only after all attempts to settle the dispute under the cooperative electric association's dispute resolution process have been exhausted. The parties must mutually agree upon the selection of a mediator, who must be listed on the roster of neutrals for civil matters established by the state court administrator under Rule 114.12 of Minnesota's General Rules of Practice for the District Courts. The cooperative electric association shall pay 90 percent of the cost of mediation, and the member or members who initiated the dispute shall pay ten percent of the cost of mediation.

(c) Except as provided in paragraph (d), any proceedings concerning the activities of a cooperative electric association under this section that are pending at the Public Utilities Commission on May 31, 2017, are terminated on that date.

(d) The Public Utilities Commission may complete its investigation in Docket No. 16-512 to assess whether the methodology used by cooperative associations to establish a fee under subdivision 3, paragraph (a), complies with state law if the commission determines that completing the investigation is necessary to protect the public interest, in which case it shall complete the investigation no later than December 31, 2017. A methodology that the commission determines complies with state law may not be challenged in a dispute under this section. If the commission determines that a methodology does not comply with state law, it shall clearly state the changes necessary to bring the methodology into compliance, and a cooperative electric association shall modify its methodology in accordance with the commission's directives.

(e) For a cooperative electric association that elects to operate under the provisions of paragraph (a), disputes arising under this section subsequent to a cooperative electric association's modification of its methodology under paragraph (d) shall be addressed under the cooperative association's rules and paragraph (b), as applicable.

Subd. 12. **Customer's access to electricity usage data.** A utility must provide a customer's electricity usage data to the customer within ten days of the date the utility receives a request from the customer that is accompanied by evidence that the energy usage data is relevant to the interconnection of a qualifying facility on behalf of the customer. For the purposes of this subdivision, "electricity usage data" includes but is not limited to: (1) the total amount of electricity used by a customer monthly; (2) usage by time period if the customer operates under a tariff where costs vary by time of use; and (3) usage data that is used to calculate a customer's demand charge.

History: *1981 c 237 s 1; 1983 c 301 s 166-171; 1984 c 640 s 32; 1991 c 315 s 1; 1993 c 356 s 1; 1996 c 305 art 2 s 38; 2013 c 85 art 9 s 1-10; 2013 c 125 art 1 s 39; 2013 c 132 s 1; 1Sp2015 c 1 art 3 s 21; 2017 c 94 art 10 s 5-8; 2023 c 60 art 12 s 13*

216B.1641 COMMUNITY SOLAR GARDEN.

Subdivision 1. **Legacy program.** (a) The public utility subject to section 116C.779 shall file by September 30, 2013, a plan with the commission to operate a community solar garden program which shall begin operations within 90 days after commission approval of the plan. Other public utilities may file an application at their election. The community solar garden program must be designed to offset the energy use of not less than five subscribers in each community solar garden facility of which no single subscriber has more than a 40 percent interest. The owner of the community solar garden may be a public utility or any other entity or organization that contracts to sell the output from the community solar garden to the utility under section 216B.164. There shall be no limitation on the number or cumulative generating capacity of community solar garden facilities other than the limitations imposed under section 216B.164, subdivision 4c, or other limitations provided in law or regulations.

(b) A solar garden is a facility that generates electricity by means of a ground-mounted or roof-mounted solar photovoltaic device whereby subscribers receive a bill credit for the electricity generated in proportion to the size of their subscription. The solar garden must have a nameplate capacity of no more than one megawatt. Each subscription shall be sized to represent at least 200 watts of the community solar garden's generating capacity and to supply, when combined with other distributed generation resources serving the premises, no more than 120 percent of the average annual consumption of electricity by each subscriber at the premises to which the subscription is attributed.

(c) The solar generation facility must be located in the service territory of the public utility filing the plan. Subscribers must be retail customers of the public utility located in the same county or a county contiguous to where the facility is located.

(d) The public utility must purchase from the community solar garden all energy generated by the solar garden. The purchase shall be at the rate calculated under section 216B.164, subdivision 10, or, until that rate for the public utility has been approved by the commission, the applicable retail rate. A solar garden is eligible for any incentive programs offered under section 116C.7792. A subscriber's portion of the purchase shall be provided by a credit on the subscriber's bill.

(e) The commission may approve, disapprove, or modify a community solar garden program. Any plan approved by the commission must:

(1) reasonably allow for the creation, financing, and accessibility of community solar gardens;

(2) establish uniform standards, fees, and processes for the interconnection of community solar garden facilities that allow the utility to recover reasonable interconnection costs for each community solar garden;

(3) not apply different requirements to utility and nonutility community solar garden facilities;

(4) be consistent with the public interest;

(5) identify the information that must be provided to potential subscribers to ensure fair disclosure of future costs and benefits of subscriptions;

(6) include a program implementation schedule;

(7) identify all proposed rules, fees, and charges; and

(8) identify the means by which the program will be promoted.

(f) Notwithstanding any other law, neither the manager of nor the subscribers to a community solar garden facility shall be considered a utility solely as a result of their participation in the community solar garden facility.

(g) Within 180 days of commission approval of a plan under this section, a utility shall begin crediting subscriber accounts for each community solar garden facility in its service territory, and shall file with the commissioner of commerce a description of its crediting system.

(h) For the purposes of this section, the following terms have the meanings given:

(1) "subscriber" means a retail customer of a utility who owns one or more subscriptions of a community solar garden facility interconnected with that utility; and

(2) "subscription" means a contract between a subscriber and the owner of a solar garden.

(i) This subdivision applies to a community solar garden that was approved before January 1, 2024.

Subd. 2. **Definitions.** (a) For purposes of subdivisions 3 to 14, the following terms have the meanings given.

(b) "Backup subscriber" means an individual or entity that temporarily assumes all or a portion of a community solar garden subscription in the event a subscriber exits the community solar garden or is delinquent in paying the subscriber's utility bill.

(c) "Community solar garden" means a facility (1) that generates electricity by means of a ground-mounted or roof-mounted solar photovoltaic device, (2) that is owned and operated by a subscriber organization, and (3) for which subscribers receive a bill credit for the electricity generated in proportion to the size of the subscriber's subscription.

(d) "Low- to moderate-income subscriber" or "LMI subscriber" means a subscriber that, at the time the community solar garden subscription is executed, is: (1) a low-income household, as defined under section

216B.2402, subdivision 16; or (2) a household whose income is 150 percent or less of the area median household income.

(e) "Public interest subscriber" means a subscriber that demonstrates status as a public or Tribal entity, school, nonprofit organization, house of worship, or social service provider.

(f) "Subscribed energy" means electricity generated by the community solar garden that is attributable to a subscriber's subscription.

(g) "Subscriber" means a retail customer who owns one or more subscriptions of a community solar garden interconnected with the retail customer's utility.

(h) "Subscriber organization" means a developer or owner of a community solar garden.

(i) "Subscription" means a contract between a subscriber and subscriber organization.

(j) "Utility" means the public utility subject to section 116C.779.

Subd. 3. **Applicability; scope; limitation.** (a) Subdivisions 2 to 13 apply to community solar gardens approved for the program beginning January 1, 2024.

(b) Except as otherwise modified, replaced, or superseded by subdivisions 2 to 13, any commission order that applies to the legacy program under subdivision 1 applies to subdivisions 2 to 13.

(c) Notwithstanding any other law, a subscriber organization or a subscriber must not be deemed a utility solely as a result of the subscriber organization's or subscriber's participation in a community solar garden.

Subd. 4. **Community solar garden program administration.** (a) The commissioner must administer the community garden program. The commissioner must:

(1) collect and evaluate community solar garden applications from subscriber organizations;

(2) audit or verify that project eligibility criteria have been met, as necessary;

(3) pursuant to subdivision 7, allocate community solar garden capacity to approved community solar gardens, subject to the annual capacity limit;

(4) develop procedures to carry out the duties under this section, including establishing procedures and a timeline to allocate community solar garden capacity under subdivision 7; and

(5) enforce the consumer protections under subdivisions 9 to 11.

(b) The commissioner is authorized to access information regarding a subscriber's net electricity bill savings or any charges that the subscriber pays.

Subd. 5. **Application; registration.** (a) A subscriber organization must submit an application to the commissioner, on a form prescribed by the commissioner, to receive approval for a proposed community solar garden project.

(b) A community solar garden application must contain, at a minimum:

(1) a copy of a signed interconnection agreement between the subscriber organization and the utility, except that information that the subscriber organization cannot reasonably determine without approval of the proposed community solar garden is not required;

(2) a copy of any required nonministerial permits that have been approved by the local authority that has jurisdiction over the project;

(3) a copy of the community solar garden's subscription contract, including: (i) the information provided to potential subscribers that discloses future costs and benefits of subscriptions; and (ii) any rules, fees, and charges;

(4) information regarding the community solar garden's program design with respect to potential subscribers, itemized by subscriber type;

(5) proof of legally binding site control of the community solar garden's proposed location;

(6) any information necessary for the commissioner to allocate annual community solar garden program capacity under subdivision 7, paragraph (b); and

(7) any other information the commissioner deems necessary to administer the community solar garden program.

(c) The commissioner must approve a community solar garden that submits the information required under paragraph (b), unless the total annual capacity threshold has been met or the commissioner determines approving the community solar garden is not in the public interest. An application that is deemed in the public interest, but not allocated capacity in a particular program year, must be held in queue for the program year and allocated capacity if any capacity becomes available during the program year.

Subd. 6. **Eligible project; other requirements.** (a) In order to be eligible for compensation under subdivision 8, a community solar garden must: (1) be connected to the utility's distribution system; (2) have a capacity, as defined under section 216B.164, subdivision 2a, paragraph (c), of no more than five megawatts; and (3) have at least 25 individual subscribers per megawatt of generation capacity, provided that a single subscriber does not possess more than a 40 percent interest in the community solar garden's total capacity.

(b) A community solar garden subscriber must be located within the Minnesota service territory of the utility.

(c) A contractor or subcontractor that constructs or installs a community solar garden that has a capacity of at least 1 megawatt: (1) must pay no less than the prevailing wage rate, as defined in section 177.42; and (2) is subject to the requirements and enforcement provisions under sections 177.27, 177.30, 177.32, 177.41 to 177.435, and 177.45.

Subd. 7. **Annual capacity limit; allocation.** (a) Each program year the commissioner must allocate the community solar garden program's annual new capacity to eligible community solar gardens. The maximum cumulative annual capacity of new community solar gardens approved each program year under this subdivision is:

(1) 100 megawatts in 2024, 2025, and 2026;

(2) 80 megawatts in 2027, 2028, 2029, and 2030; and

(3) 60 megawatts in 2031 and each year thereafter.

(b) When allocating capacity to eligible community solar gardens, the commissioner must evaluate and prioritize capacity allocation to community solar garden applicants based on information provided in the community solar garden application regarding:

(1) the degree to which subscribers, utility ratepayers, or the community surrounding the project receive the financial benefit of tax benefits and other incentives resulting from the community solar garden;

(2) the scale of financial benefits the community solar garden delivers to LMI subscribers, affordable housing residents, and public interest subscribers, as well as the number of, and project capacity attributable to, LMI subscribers, affordable housing residents, and public interest subscribers;

(3) community solar garden project ownership and financing arrangements that deliver benefits to public, nonprofit, cooperative, and Tribal entities;

(4) whether the community solar garden uses nongreenfield locations, especially rooftops, carports, or sites that contain a hazardous substance, pollutant, or contaminant;

(5) whether the community solar garden provides workforce development and apprenticeship opportunities, especially for workers who are Black, Indigenous, or Persons of Color; and

(6) the resiliency benefits the community solar garden provides to the electrical grid or the local community.

(c) The commissioner may allocate capacity to a community solar garden under this subdivision only if the application includes a subscription plan that ensures:

(1) at least 30 percent of the community solar garden's capacity is subscribed to by LMI subscribers; and

(2) at least 55 percent of the community solar garden's capacity is subscribed to by subscribers that are:

(i) LMI subscribers;

(ii) public interest subscribers; or

(iii) an affordable housing provider, as determined by the commissioner.

(d) A backup subscriber may subscribe to and receive bill credits for up to 15 percent of a community solar garden's annual capacity. In the event a community solar garden subscriber exits the community solar garden or is delinquent on the subscriber's utility bill, the backup subscriber may be automatically subscribed to up to 40 percent of the community solar garden's capacity for up to one year at the rates provided under subdivision 8, paragraph (b), clause (7).

Subd. 8. **Community solar garden compensation.** (a) A utility must purchase electricity generated by a community solar garden approved for a period of 25 years from the date the community solar garden begins operations. A utility must compensate a community solar garden using a bill credit on each individual subscriber's bill, in an amount proportional to the subscriber's share in the community solar garden.

(b) Beginning January 1, 2024, the utility must purchase energy generated by a community solar garden at the following rates provided for each subscriber type, as determined by the commission:

(1) for a LMI subscriber, the average retail rate for residential customers;

(2) for a residential subscriber that is not a LMI subscriber, 85 percent of the average retail rate for the applicable residential class customers;

(3) for master-metered affordable housing, 80 percent of the average retail rate for residential customers;

(4) for a public interest subscriber that is a small general commercial customer, 75 percent of the average retail rate for the customer's rate class;

(5) for a public interest subscriber that is a general service commercial customer, 100 percent of the average retail rate for the customer's rate class;

(6) for other commercial subscribers, 70 percent of the average retail rate for the customer's rate class;

(7) for a community solar garden with at least 50 percent total capacity subscribed to by LMI subscribers:

(i) up to one backup subscriber may receive 90 percent of the average retail rate for the regular commercial subscriber's customer class, plus additional compensation for demand charges based on 50 percent of the comparable photovoltaic demand credit rider; and

(ii) a backup subscriber that subscribes to more than 15 percent of a community solar garden's total capacity for more than 12 consecutive months, the rate provided for other commercial subscribers under clause (6); and

(8) for unsubscribed energy generated that is credited to the subscriber organization, the utility's avoided cost.

Subd. 9. **Subscriber organizations; prohibitions; requirements.** (a) A subscriber organization and a subscriber organization's marketing representatives are prohibited from, with respect to a community solar garden:

(1) checking the credit score or credit history of a new or existing residential subscriber;

(2) charging an exit fee to a residential subscriber;

(3) enrolling a subscriber without the subscriber's prior, voluntary consent;

(4) engaging in misleading or deceptive conduct; and

(5) making false or misleading representations.

(b) A subscriber organization must preserve the privacy of subscribers. Except as otherwise authorized under subdivision 4, paragraph (b), a subscriber organization must not publicly disclose a subscriber's account information, energy usage, energy data, or bill credits, unless (1) the subscriber provides express, written, informed consent that authorizes disclosure of the subscriber's information, or (2) the subscription contract otherwise authorizes disclosure of the information.

(c) A subscriber organization and a subscriber organization's marketing representatives must make reasonable efforts to provide subscribers with timely and accurate information regarding the community solar garden. The information must be provided in writing and in plain language, and must include but is not limited to information regarding rates, contract terms, termination fees, and the right to cancel a community solar garden subscription.

(d) Beginning one year after a community solar garden begins operations and annually thereafter, a subscriber organization must publish a signed and notarized report that details the community solar garden's operations for the previous 12-month period. The report must contain, at a minimum: (1) the energy produced by the community solar garden; (2) financial statements, including a balance sheet, income statement, and a sources and uses of funds statement; and (3) a list of the individuals that currently own and manage the subscriber organization. The report under this paragraph must be provided to the commissioner, on a form prescribed by the commissioner, and to each of the community solar garden's subscribers.

(e) A subscriber organization must annually publish a signed and notarized report that details the community solar garden's capacity allocated to relevant subscriber categories, including but not limited to: (1) LMI subscribers; (2) other residential subscribers; (3) affordable housing providers; (4) public interest subscribers, by type; (5) small subscriptions of up to 25 kilowatts; and (6) other subscribers, by type.

Subd. 10. **Subscriber protections.** (a) A community solar garden subscription is transferable and portable, but only within the utility's Minnesota service territory.

(b) The cost of a subscriber's community solar garden subscription must not exceed the value of the subscriber's community solar garden bill credit. For a LMI subscriber, the cost of the community solar garden subscription must not exceed 90 percent of the LMI subscriber's community solar garden bill credit and must not include any fees at the time the subscription is executed.

(c) A utility must offer consolidated billing for community solar garden subscribers so that a subscriber receives only one bill for both the subscribers's monthly electric service and the community solar garden subscription. A utility must offer consolidated billing under this paragraph for community solar garden subscribers no later than January 1, 2024. The commission may modify the date required by this paragraph if the utility demonstrates to the commission that implementing consolidated billing by January 1, 2024, is unreasonably burdensome. A subscriber may elect, but is not required, to use consolidated billing under this paragraph.

(d) A subscriber must be provided an opportunity to submit comments to the subscriber organization regarding the annual report submitted under subdivision 9, paragraph (d), regarding the accuracy and completeness of the report.

Subd. 11. **Nonsubscriber protections.** (a) A utility must exclude from the fuel adjustment charged to a utility customer the net cost of community solar garden generation under this section if the utility customer (1) receives or is eligible for bill payment assistance, and (2) does not subscribe to a community solar garden under this section.

(b) The commission must determine the net cost of community solar garden generation under this section for purposes of paragraph (a).

Subd. 12. **Noncompliance.** A community solar garden that has begun commercial operation must notify the commissioner in writing within 30 days if the community solar garden is not in compliance with subdivision 6, 7, 9 or 10, and must comply within 12 months or the commissioner must revoke the solar garden's participation in the program. Nothing in this subdivision prevents a subscriber organization from reapplying to participate in the program after revocation.

Subd. 13. **Report.** No later than January 31 each year beginning in 2025, the commissioner must prepare and submit to the legislative committees having primary jurisdiction over energy and climate policy a report that aggregates the information received in the reports under subdivision 9, paragraphs (d) and (e).

Subd. 14. **Transition from legacy program.** (a) From May 25, 2023, to the date the commissioner begins allocating capacity under subdivision 7, but no later than December 31, 2023, a subscriber organization may submit a community solar garden project application to the utility for the legacy program under subdivision 1 or to the commissioner for the program under subdivisions 3 to 12.

(b) The utility administering the legacy program under subdivision 1 must act in good faith to continue processing applications for the legacy program until December 31, 2023. An application for the legacy program that is approved on or before December 31, 2023, is eligible to become a community solar garden under subdivisions 3 to 12, provided the proposed community solar garden complies with subdivisions 3 to 12.

History: *2013 c 85 art 10 s 2; 2020 c 83 art 1 s 66; 2023 c 60 art 12 s 14*

216B.1642 SOLAR SITE MANAGEMENT.

Subdivision 1. **Site management practices.** An owner of a ground-mounted solar site with a generating capacity of more than 40 kilowatts may follow site management practices that (1) provide native perennial vegetation and foraging habitat beneficial to game birds, songbirds, and pollinators, and (2) reduce stormwater runoff and erosion at the solar generation site. To the extent practicable, when establishing perennial vegetation and beneficial foraging habitat, a solar site owner shall use native plant species and seed mixes under Department of Natural Resources "Prairie Establishment & Maintenance Technical Guidance for Solar Projects."

Subd. 2. **Recognition of beneficial habitat.** An owner of a solar site implementing solar site management practices under this section may claim that the site provides benefits to game birds, songbirds, and pollinators only if the site adheres to guidance set forth by the pollinator plan provided by the Board of Water and Soil Resources or any other game bird, songbird, or pollinator foraging-friendly vegetation standard established by the Board of Water and Soil Resources. An owner making a beneficial habitat claim must:

(1) make the site's vegetation management plan available to the public;

(2) provide a copy of the plan to a Minnesota nonprofit solar industry trade association; and

(3) report on its site management practices to the Board of Water and Soil Resources, on a standard reporting form developed by the board for solar site management practices, by June 1, 2020, and every third year thereafter. An owner that enters into operation after June 1, 2019, must report to the board on the progress made toward establishing beneficial habitat on or before June 1 of the year after operations commence and every third year thereafter.

History: *2016 c 181 s 1; 2016 c 184 s 9; 1Sp2019 c 7 art 11 s 3*

216B.1645 POWER PURCHASE CONTRACT OR INVESTMENT.

Subdivision 1. **Commission authority.** Upon the petition of a public utility, the Public Utilities Commission shall approve or disapprove power purchase contracts, investments, or expenditures entered into or made by the utility to satisfy the wind and biomass mandates contained in sections 216B.169, 216B.2423, and 216B.2424, and to satisfy the renewable energy objectives and standards set forth in section 216B.1691, including reasonable investments and expenditures made to:

(1) transmit the electricity generated from sources developed under those sections that is ultimately used to provide service to the utility's retail customers, including studies necessary to identify new transmission facilities needed to transmit electricity to Minnesota retail customers from generating facilities constructed to satisfy the renewable energy objectives and standards, provided that the costs of the studies have not been recovered previously under existing tariffs and the utility has filed an application for a certificate of need or for certification as a priority project under section 216B.2425 for the new transmission facilities identified in the studies;

(2) provide storage facilities for renewable energy generation facilities that contribute to the reliability, efficiency, or cost-effectiveness of the renewable facilities; or

(3) develop renewable energy sources from the account required in section 116C.779.

Subd. 2. **Cost recovery.** (a) The following expenses are recoverable from utility ratepayers:

(1) expenses incurred to employ local workers, as defined in section 216B.2422, subdivision 1, to construct and maintain generation facilities that supply power to the utility's customers; and

(2) expenses incurred by the utility over the duration of an approved contract or the useful life of an investment and expenditures made pursuant to section 116C.779, provided they are not offset by utility revenues attributable to the contracts, investments, or expenditures.

(b) Upon petition by a public utility, the commission shall approve or approve as modified a rate schedule providing for the automatic adjustment of charges to recover the expenses or costs approved by the commission under subdivision 1, which, in the case of transmission expenditures, are limited to the portion of actual transmission costs that are directly allocable to the need to transmit power from the renewable sources of energy. The commission may not approve recovery of the costs for that portion of the power generated from sources governed by this section that the utility sells into the wholesale market.

Subd. 2a. **Cost recovery for utility's renewable facilities.** (a) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9. For facilities not subject to review by the commission under section 216B.2422 or 216B.243, a utility shall petition the commission for eligibility for cost recovery under this section prior to requesting cost recovery for the facility. The commission may approve, or approve as modified, a rate schedule that:

(1) allows a utility to recover directly from customers on a timely basis the costs of qualifying renewable energy projects, including:

(i) return on investment;

(ii) depreciation;

(iii) ongoing operation and maintenance costs;

(iv) taxes; and

(v) costs of transmission and other ancillary expenses directly allocable to transmitting electricity generated from a project meeting the specifications of this paragraph;

(2) provides a current return on construction work in progress, provided that recovery of these costs from Minnesota ratepayers is not sought through any other mechanism;

(3) allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;

(4) allocates recoverable costs appropriately between wholesale and retail customers;

(5) terminates recovery when costs have been fully recovered or have otherwise been reflected in a utility's rates.

(b) A petition filed under this subdivision must include:

(1) a description of the facilities for which costs are to be recovered;

(2) an implementation schedule for the facilities;

(3) the utility's costs for the facilities;

(4) a description of the utility's efforts to ensure that costs of the facilities are reasonable and were prudently incurred; and

(5) a description of the benefits of the project in promoting the development of renewable energy in a manner consistent with this chapter.

Subd. 3. **Applicability to recovery of other costs.** Nothing in this section shall be construed to determine the manner or extent to which revenues derived from other generation facilities of the utility may be considered in determining the recovery of the approved cost or expenses associated with the mandated contracts, investments, or expenditures in the event there is retail competition for electric energy.

Subd. 4. **Payments to the Prairie Island Indian Community.** (a) The commission shall approve a rate schedule providing for the automatic adjustment of charges to recover the costs or expenses of a settlement between the public utility that owns the Prairie Island nuclear generation facility and the Prairie Island Indian Community at Prairie Island, resolving outstanding disputes regarding the provisions of Laws 1994, chapter 641, article 1, section 4. The settlement must provide for annual payments, not to exceed $2,500,000 annually, by the public utility to the Prairie Island Indian Community, to be used for, among other purposes, acquiring land in Minnesota within 50 miles of the tribal community's reservation at Prairie Island to be taken into trust by the federal government for the benefit of the tribal community. The legislature acknowledges that the intent to purchase land by the tribe for relocation purposes is part of the settlement agreement and Laws 2003, First Special Session chapter 11. However, the state, through the governor, reserves the right to support or oppose any particular application to place land in trust status.

(b) In addition to payments required under paragraph (a), the public utility that owns the Prairie Island nuclear generating facility must make the following annual payments to the Prairie Island Indian Community:

(1) $7,500,000 for each year the Prairie Island nuclear generating facility is in licensed operation; and

(2) $50,000 for each dry cask or container containing spent fuel that is located at the Prairie Island nuclear generating facility, whether or not the plant is in licensed operation.

(c) The commission shall approve a rate schedule providing for the automatic adjustment of charges to retail electricity customers of the public utility that owns the Prairie Island nuclear generating facility to recover the amounts in paragraph (b), clauses (1) and (2).

(d) Paragraphs (b) and (c) apply only if the public utility that owns the Prairie Island nuclear generation facility enters into a new or amended settlement agreement with the Prairie Island Indian Community.

(e) Payments made under this subdivision may be used by the Prairie Island Indian Community for any purpose benefitting the Prairie Island Indian Community. Payments made under this subdivision shall constitute prudent operating expenses for the public utility that owns the Prairie Island nuclear generation facility, and shall constitute consideration for any amended settlement agreement entered into between the public utility and the Prairie Island Indian Community. This subdivision is intended to apply to any successors in interest or assignees of the Prairie Island nuclear generation facility and Prairie Island Independent Spent Fuel Storage Installation.

(f) The commission's approval of a certificate of need under section 216B.243 allowing for the additional storage of spent nuclear fuel necessary for the extended operation of the Prairie Island nuclear plant is effective only if the governor, on behalf of the state, and the public utility operating the Prairie Island nuclear generating plant enter into an agreement binding the parties to the required payments and payment recovery terms of paragraphs (b) and (c). The Prairie Island Indian Community is an intended beneficiary of this agreement and has standing to enforce the agreement.

History: *1997 c 176 s 1; 1998 c 345 s 1; 1999 c 200 s 2; 2001 c 212 art 8 s 1; 1Sp2003 c 11 art 1 s 3; 2005 c 97 art 2 s 2; 2007 c 136 art 4 s 8; 2008 c 296 art 1 s 6-8; 2009 c 110 s 11; 2023 c 7 s 2; 2023 c 60 art 12 s 15*

216B.1646 RATE REDUCTION; PROPERTY TAX REDUCTION.

(a) The commission shall, by any method the commission finds appropriate, reduce the rates each electric utility subject to rate regulation by the commission charges its customers to reflect, on an ongoing basis, the amount by which each utility's property tax on the personal property of its electric system from taxes payable in 2001 to taxes payable in 2002 is reduced. The commission must ensure that, to the extent feasible, each dollar of personal property tax reduction allocated to Minnesota consumers retroactive to January 1, 2002, results in a dollar of savings to the utility's customers. A utility may voluntarily pass on any additional property tax savings allocated in the same manner as approved by the commission under this paragraph.

(b) By April 10, 2002, each utility shall submit a filing to the commission containing:

(1) certified information regarding the utility's property tax savings allocated to Minnesota retail customers; and

(2) a proposed method of passing these savings on to Minnesota retail customers.

The utility shall provide the information in clause (1) to the commissioner of revenue at the same time. The commissioner shall notify the commission within 30 days as to the accuracy of the property tax data submitted by the utility.

(c) For purposes of this section, "personal property" means tools, implements, and machinery of the generating plant. It does not apply to transformers, transmission lines, distribution lines, or any other tools, implements, and machinery that are part of an electric substation, wherever located.

History: *1Sp2001 c 5 art 3 s 11; 2002 c 377 art 4 s 3; 2002 c 398 s 2; 2002 c 400 s 12*

216B.1647 PROPERTY TAX ADJUSTMENT; COOPERATIVE ASSOCIATION.

A cooperative electric association that has elected to be subject to rate regulation under section 216B.026 is eligible to file with the commission for approval an adjustment for real and personal property taxes, fees, and permits.

History: *2016 c 189 art 6 s 5*

216B.165 [Repealed, 2007 c 136 art 3 s 7]

216B.166 COGENERATING POWER PLANT.

Subdivision 1. **Findings.** The legislature finds and declares that significant public benefits may be derived from the cogeneration of electrical and thermal energy and that cogenerated district heating may result in improved utilization and conservation of fuel, the substitution of coal for scarce oil and natural gas, the substitution of domestic fuel for imported fuel, and the establishment of a reliable, competitively priced heat source. Since the cost of cogenerated thermal energy is dependent upon the method used to allocate costs between the production of electric and thermal energy at a power plant, and because the method of cost allocation can be a significant factor in determining investment in district heating, it is necessary to develop cost allocation methods rapidly.

Subd. 2. **Definitions.** For the purpose of this section, the following terms shall have the meanings given.

(a) "Cogeneration" means a combined process whereby electrical and thermal energy are simultaneously produced by a public utility power plant.

(b) "District heating" means a process whereby thermal energy is distributed within a community for use as a primary heat source.

(c) "District heating utility" means any person, corporation, or other legal entity which owns and operates a facility for district heating.

Subd. 3. **Cost allocation.** The methods used to allocate or assign costs between electrical and thermal energy produced by cogeneration power plants owned by public utilities shall be consistent with the following principles:

(a) The method used shall result in a cost per unit of electricity which is no greater than the cost per unit which would exist if the power plants owned by the public utility had been normally constructed and operated without cogenerating capability.

(b) Costs which the public utility incurs for the exclusive benefit of the district heating utility, including but not limited to backup and peaking facilities, shall be assigned to thermal energy produced by cogeneration.

(c) The methods and procedures may be different for retrofitted than for new cogeneration power plants.

(d) The methods should encourage cogeneration while preventing subsidization by electric consumers so that both heating and electricity consumers are treated fairly and equitably with respect to the costs and benefits of cogeneration.

History: *1981 c 334 s 9*

216B.167 PERFORMANCE-BASED GAS PURCHASING PLAN.

Subdivision 1. **Plan approval; commission findings.** A public utility that furnishes natural gas may petition the commission for approval of a performance-based gas purchasing plan under this section. The commission may approve a plan if it finds that:

(1) the plan provides incentives for the utility to achieve lower natural gas costs than would have been achieved in the absence of the plan, as measured by the benchmarks established in clause (3), by linking financial rewards and penalties to natural gas costs;

(2) the potential benefits of the plan apply, at a minimum, to each customer class purchasing firm natural gas service from the utility;

(3) the plan establishes one or more benchmarks against which actual natural gas costs will be measured and the benchmarks reflect relevant market conditions and represent reasonable and achievable natural gas costs in Minnesota for the term of the plan; and

(4) the plan provides that the utility cannot curtail or interrupt service to any customer class purchasing firm natural gas service during the term of the plan except for causes outside the reasonable control of the utility or causes not directly related to the gas purchasing practices of the utility.

Subd. 2. **Sharing mechanism.** A plan must include a mechanism through which the utility shares with its customers the difference between actual natural gas costs and the plan's benchmark costs during the term of the plan. A plan must provide details of the sharing mechanism and may include an allowed level of costs above and below the benchmark before any sharing is to take place. The commission must determine an appropriate percentage of the difference between the benchmark and actual natural gas costs to be shared between customers and the utility. The sharing mechanism shall be implemented annually under section 216B.16, subdivision 7a. Financial rewards or penalties under the plan shall not be considered in the determination of the utility's revenue requirements in a general rate case pursuant to section 216B.16.

Subd. 3. **Reliability of service.** A plan must allow for the imposition of penalties if the standard for reliability of service established in subdivision 1, clause (4), is not met.

Subd. 4. **Plan evaluation.** A plan must include an evaluation process and mechanism that is reasonable and capable of supporting a full review of the utility's performance under the plan. The commission shall evaluate the various customer and utility impacts of a plan based on this evaluation process and mechanism, including the impact on customer bills over time, the impact on utility revenues, and the effectiveness of the plan in meeting the purposes contained in subdivision 1. The evaluation must occur within a reasonable time following the end of the plan.

Subd. 5. **Annual report.** The utility shall provide an annual report to the commission documenting its performance in meeting the requirements of the plan. Upon review of this report, the commission shall determine and approve rewards or penalties as provided in the plan.

Subd. 6. **Adoption.** A plan may be filed and approved within a miscellaneous tariff filing pursuant to section 216B.16. The commission may approve, reject, or modify the plan in a manner which meets the requirements of this section. An approved plan is effective for a period of not less than two years unless:

(1) the plan is withdrawn by the utility within 30 days of a final appealable order approving the plan; or

(2) the commission, after notice and hearing, rescinds or amends its order approving the plan.

Subd. 7. [Repealed, 1999 c 21 s 1]

Subd. 8. [Repealed, 1999 c 21 s 1]

History: *1995 c 17 s 1*

216B.1675 PERFORMANCE REGULATION PLAN FOR GAS UTILITY SERVICE.

Subdivision 1. **Purpose.** Performance-based regulation plans for public utilities offering natural gas services are authorized in order to provide quality service at rates that can reasonably and reliably be expected to be materially lower than rates would be under current regulation and to reduce the cost of regulation. Performance-based regulation plans are intended to provide the utility with increased earnings for efficient performance and decreased earnings for inefficient performance.

Subd. 2. **Petition.** A public utility that furnishes natural gas service may petition and file with the commission for its approval a performance regulation plan pursuant to this section. The plan applies to the utility's rates for providing natural gas distribution service, excluding the portion of the rates recovering the cost of natural gas supplies. If adopted, the plan must apply to all of the utility's customers, except that nothing in this section requires the utility to adjust the rates collected from customers receiving service under tariffs authorized by sections 216B.16, subdivision 15, and 216B.163. A petition may be filed:

(1) as part of a general rate filing pursuant to section 216B.16, in which case the time provided for the commission to suspend rates and make a final determination shall be extended by two months; or

(2) as a miscellaneous tariff filing pursuant to section 216B.16, in which case the commission shall, within 120 days of the date of the filing, determine whether the utility's current rates are reasonable based on financial information for the most recent calendar year, amended to reflect appropriate regulatory adjustments. If the commission cannot resolve all material issues concerning the reasonableness of the utility's current rates to its satisfaction, it shall dismiss the filing. If the filing is not dismissed, the commission shall issue its decision on the plan within ten months from the date of the filing. The rates at the beginning of the plan shall be the same as the rates on file with the commission prior to the filing.

Subd. 3. **Plan contents.** The commission may approve a performance regulation plan for natural gas distribution services upon finding that the plan:

(1) contains a benchmark or measure of gas distribution costs that is a reasonable and reliable predictor of the utility's rates for gas distribution service under cost-of-service regulation;

(2) ensures that rates for gas distribution services to customers under the plan will be materially lower than the rates would be under cost-of-service regulation as predicted by the benchmark in clause (1);

(3) links the utility's earnings to its performance by permitting higher utility earnings than under cost-of-service regulation only when the utility's performance is more efficient than the benchmark;

(4) can be reasonably and reliably expected to offer lower administrative costs than would otherwise be experienced under cost-of-service regulation;

(5) contains a reasonable limit on utility earnings;

(6) has adequate provisions to prevent the degradation of service quality; and

(7) provides for gathering of relevant data and evaluation of the plan's effect on rates, service quality, utility earnings, competition in providing natural gas, and regulatory costs.

Subd. 4. **Rate change.** The initial rate adjustment under the plan may not be implemented for a minimum of 18 months following the final determination by the commission on the plan. The plan shall provide a methodology and procedures for changing rates thereafter not more frequently than on an annual basis. The commission may allow the utility to change rates to reflect material changes in cost due to compliance with government mandates provided that the cost is one that the commission would otherwise allow to be recovered in rates. Increases or decreases in revenues under the plan shall be applied on an equal percentage basis to each customer class, excluding the portion of the rate recovering the cost of natural gas supplies. Miscellaneous rate changes may be approved outside the operation of the plan.

Subd. 5. **Acceptance of petition for full review.** Interested parties have, unless the commission otherwise orders, 45 days from the date a petition containing a proposed plan is filed to submit comments on whether the plan, as proposed, addresses each of the requirements of this section sufficiently to merit further consideration. If the commission does not dismiss the petition proposing a plan as insufficient within 120 days from the date of the filing, the petition shall be deemed accepted for filing. A petition accepted for filing shall not be presumed accepted for final adoption.

Subd. 6. **Plan administration.** A plan must require the filing of information needed to administer the plan.

Subd. 7. **Notice to customer.** The petitioning utility must provide notice of the proposed plan to its customers and to the governing body of each municipality and county in the area affected, along with a summary description of the plan provisions and a notice of the dates, times, and locations of any public meetings scheduled by the commission.

Subd. 8. **Plan review; hearing; discovery.** In reviewing a proposed plan, the commission shall:

(1) conduct public meetings that it considers appropriate; and

(2) grant discovery, as appropriate.

Subd. 9. **Commission findings.** The commission shall issue findings concerning the appropriateness of the proposed plan. The commission may approve, reject, or modify the plan in a manner which meets the requirements of this section. An approved or modified plan becomes effective unless the plan is withdrawn by the utility within 30 days of a final appealable order. If the utility withdraws an approved or modified plan, all of the administrative costs related to the plan that are charged by the commission or the department to the utility may not be recovered from ratepayers in current or subsequent rates. A utility that withdraws an approved or modified plan may not file another plan under this section for a period of one year following the withdrawal of the plan.

Subd. 10. **Plan term; renewal.** The plan shall specify its term, which shall not be less than three years. Not less than six months before the completion of the term of an approved plan, the commission shall, at the request of the utility, commence a review of the plan to determine whether to renew the plan for an additional term. The commission may approve, reject, or modify the renewal plan in a manner that meets the requirements of this section. A plan approved or modified under this subdivision becomes effective unless the plan is withdrawn by the utility within 30 days of a final appealable order.

Subd. 11. **Plan termination.** On its own motion or upon the petition of any party other than the utility, the commission may initiate an investigation to determine whether to terminate the plan. The commission shall issue findings on the investigation within 120 days. If the commission finds that the plan has failed to meet the requirements of this section and is inconsistent with the public interest, it shall terminate the plan and may order the utility to initiate any proceedings necessary to correct the failure of the plan, including but not limited to, filing a general rate proceeding under section 216B.16. The utility must be allowed at least 120 days after the date of the commission's order to initiate the general rate proceeding.

Subd. 12. **Plan evaluation.** A plan must include an evaluation process and mechanism that is reasonable and capable of supporting a full review of the utility's performance under the plan. The commission shall evaluate the various customer and utility impacts of a plan based on this evaluation process and mechanism, including the impact on customer bills and service quality, over time, the impact on utility revenues, and the effectiveness of the plan in meeting the purposes of this section. The evaluation must occur within a reasonable time following the end of the plan.

Subd. 13. **General evaluation.** The commission shall evaluate the effectiveness of all plans approved under this section and submit its findings to the legislature by January 1, 2012.

History: *1997 c 25 s 2,3; 1Sp2001 c 4 art 6 s 43; 2004 c 138 s 1-4*

216B.168 [Expired, 1993 c 254 s 1]

216B.1681 CURTAILMENT PAYMENTS.

The commission shall conduct a study of curtailment payments for wind energy projects to assess whether utilities are unduly discriminating among project ownership structures in regard to the contractual availability of curtailment payments. The commission shall submit the study to the chairs and ranking minority members of the senate and house of representatives committees with primary jurisdiction over energy policy by January 15, 2008.

History: *2007 c 136 art 4 s 9*

216B.169 RENEWABLE AND HIGH-EFFICIENCY ENERGY RATE OPTIONS.

Subdivision 1. **Definitions.** For the purposes of this section, the following terms have the meanings given them.

(a) "Utility" means a public utility, municipal utility, or cooperative electric association providing electric service at retail to Minnesota consumers.

(b) "Renewable energy" has the meaning given in section 216B.2422, subdivision 1, paragraph (c).

(c) "High-efficiency, low-emissions, distributed generation" means a distributed generation facility of no more than ten megawatts of interconnected capacity that is certified by the commissioner under subdivision 3 as a high-efficiency, low-emissions facility.

Subd. 2. **Renewable and high-efficiency energy rate options.** (a) A utility may offer its customers one or more options that allow a customer to determine that a certain amount of the electricity generated or purchased on behalf of the customer is renewable energy or energy generated by high-efficiency, low-emissions, distributed generation such as fuel cells and microturbines fueled by a renewable fuel.

(b) Rates charged to customers must be calculated using the utility's cost of acquiring the energy for the customer and must:

(1) reflect the difference between the cost of generating or purchasing the additional renewable energy and the cost that would otherwise be attributed to the customer for the same amount of energy based on the utility's mix of renewable and nonrenewable energy sources; and

(2) be distributed on a per kilowatt-hour basis among all customers who choose to participate in the program.

(c) The utility may acquire the energy demanded by customers, in whole or in part, through procuring or generating the renewable energy directly, or through the purchase of credits from a provider that has received certification of eligible power supply pursuant to subdivision 3.

(d) For the purposes of this section, "renewable energy" has the meaning given to "eligible energy technology" in section 216B.1691, subdivision 1, paragraph (c), but does not include energy recovered from combustion of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste.

Subd. 3. **Certification and tradable credits.** (a) The commissioner shall certify a power supply or supplies as eligible to satisfy customer requirements under this section upon finding:

(1) the power supply is renewable energy or energy generated by high-efficiency, low-emissions, distributed generation; and

(2) the sales arrangements of energy from the supplies are such that the power supply is only sold once to retail consumers.

(b) To facilitate compliance with this section, the commission may, by order, establish a program for tradable credits for eligible power supplies.

History: *2001 c 212 art 8 s 2; 2007 c 3 s 3; 2009 c 110 s 12,38; 2023 c 7 s 32*

216B.1691 RENEWABLE ENERGY OBJECTIVES.

Subdivision 1. **Definitions.** (a) For purposes of this section, the following terms have the meaning given them.

(b) "Carbon-free" means a technology that generates electricity without emitting carbon dioxide.

(c) Unless otherwise specified in law, "eligible energy technology" means an energy technology that generates electricity from the following renewable energy sources:

(1) solar;

(2) wind;

(3) hydroelectric with a capacity of: (i) less than 100 megawatts; or (ii) 100 megawatts or more, provided that the facility is in operation as of February 8, 2023;

(4) hydrogen generated from the resources listed in this paragraph; or

(5) biomass, which includes, without limitation, landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge to produce electricity; and, except as provided in subdivision 1a, an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

(d) "Electric utility" means: (1) a public utility providing electric service; (2) a generation and transmission cooperative electric association; (3) a municipal power agency; (4) a power district; or (5) a cooperative electric association or municipal utility providing electric service that is not a member of an entity in clauses (2) to (4).

(e) "Environmental justice area" means an area in Minnesota that, based on the most recent data published by the United States Census Bureau, meets one or more of the following criteria:

(1) 40 percent or more of the area's total population is nonwhite;

(2) 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level;

(3) 40 percent or more of the area's residents over the age of five have limited English proficiency; or

(4) the area is located within Indian country, as defined in United State Code, title 18, section 1151.

(f) "Total retail electric sales" means the kilowatt-hours of electricity sold in a year by an electric utility to retail customers of the electric utility or to a distribution utility for distribution to the retail customers of the distribution utility.

Subd. 1a. **Exception; energy recovery facility.** An energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel is not an eligible energy technology, as defined in subdivision 1, if the energy recovery facility is located in a county with a population density that exceeds 1,500 persons per square mile but is less than 2,500 persons per square mile as of February 8, 2023.

Subd. 2. MS 2022 [Repealed, 2023 c 7 s 33]

Subd. 2a. **Eligible energy technology standard.** Each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from an eligible energy technology that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:

(1)	2012	12 percent
(2)	2016	17 percent
(3)	2020	20 percent
(4)	2025	25 percent
(5)	2035	55 percent.

Subd. 2b. **Modification or delay of standard.** (a) The commission shall modify or delay the implementation of a standard obligation under subdivision 2a, 2f, or 2g, in whole or in part, if the commission determines that modifying or delaying the standard obligation is in the public interest. The commission, when evaluating a request to modify or delay implementation of a standard, must consider:

(1) the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customers;

(2) the environmental costs that would be incurred as a result of a delay or modification, based on the full range of environmental cost values established in section 216B.2422, subdivision 3;

(3) the effects of implementing the standard on the reliability of the electric system;

(4) technical advances or technical concerns;

(5) delays in acquiring sites or routes due to rejection or delays of necessary siting or other permitting approvals;

(6) delays, cancellations, or nondelivery of necessary equipment for construction or commercial operation of an eligible energy technology facility;

(7) transmission constraints preventing delivery of service;

(8) other statutory obligations imposed on the commission or a utility;

(9) impacts on environmental justice areas; and

(10) additional electric load from beneficial electrification and the greenhouse gas emissions savings associated with those loads as compared to serving the load with nonelectric energy sources.

For the purposes of this paragraph, "beneficial electrification" means the substitution of electricity for a fossil fuel, provided that the substitution meets at least one of the following conditions without adversely affecting either of the other two, as determined by the commission:

(i) saves a consumer money over the long run compared with continued use of the fossil fuel;

(ii) enables an electric utility to better manage the electric utility's electric grid network; or

(iii) reduces negative environmental impacts of fuel use, including but not limited to statewide greenhouse gas emissions.

(b) The commission may modify or delay implementation of a standard obligation under paragraph (a), clauses (1) to (4), only if it finds implementation would cause significant rate impact, requires significant measures to address reliability, or raises significant technical issues. The commission may modify or delay implementation of a standard obligation under paragraph (a), clauses (5) to (7), only if it finds that the circumstances described in those clauses were due to circumstances beyond an electric utility's control and make compliance not feasible.

(c) When evaluating transmission capacity constraints under paragraph (a), clause (7), the commission must consider whether the utility has:

(1) taken reasonable measures that are under the utility's control and consistent with the utility's obligations under local, state, and federal laws and regulations, and the utility's obligations as a member of a regional transmission organization or independent system operator, to acquire sites, necessary permit approvals, and necessary equipment to develop and construct new transmission lines or upgrade existing transmission lines to transmit electricity generated by eligible energy technologies; and

(2) taken all reasonable operational measures to maximize cost-effective electricity delivery from eligible energy technologies in advance of transmission availability.

(d) When considering whether to delay or modify implementation of a standard obligation, the commission must give due consideration to a preference for electric generation through use of eligible energy technology and to the achievement of the standards set by this section.

(e) An electric utility that requests a modification or delay to the implementation of a standard must file a plan to comply with the electric utility's standard obligation as part of the same proceeding in which the electric utility requests the modification or delay.

Subd. 2c. **Use of integrated resource planning process.** The commission may exercise its authority under subdivision 2b to modify or delay implementation of a standard obligation as part of an integrated resource planning proceeding under section 216B.2422. The commission's authority must be exercised according to subdivision 2b. The order to delay or modify shall not be considered advisory with respect to any electric utility. This subdivision is in addition to and does not limit the commission's authority to modify or delay implementation of a standard obligation in other proceedings before the commission.

Subd. 2d. **Commission order.** (a) The commission shall issue necessary orders detailing the criteria and standards used to: (1) measure an electric utility's efforts to meet the standards under subdivisions 2a, 2f, and 2g; and (2) determine whether the utility is achieving the standards.

(b) In the order under paragraph (a), the commission shall include criteria and standards that: (1) protect against undesirable impacts on the reliability of the utility's system and economic impacts on the utility's ratepayers and that consider technical feasibility; and (2) require the commission to allow for partial compliance with subdivision 2g from:

(i) electricity generated from facilities that utilize carbon-free technologies for electricity generation, but only for the percentage that is carbon-free; and

(ii) an electric utility's annual purchases from a regional transmission organization net of the electric utility's sales to the regional transmission organization, but only for the percentage of annual net purchases that is carbon-free, which percentage the commission must calculate based on the regional transmission organization's systemwide annual fuel mix or an applicable subregional fuel mix.

Subd. 2e. **Rate impact of standard compliance; report.** Each electric utility must submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with this section. In consultation with the Department of Commerce, the commission shall determine a uniform reporting system to ensure that individual utility reports are consistent and comparable, and shall, by order, require each electric utility subject to this section to use that reporting system. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements. A report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility under section 216B.2422. The reporting obligation of an electric utility under this subdivision expires December 31, 2040.

Subd. 2f. **Solar energy standard.** (a) In addition to the requirements of subdivisions 2a and 2g, each public utility shall generate or procure sufficient electricity generated by solar energy to serve its retail electricity customers in Minnesota so that by the end of 2020, at least 1.5 percent of the utility's total retail electric sales to retail customers in Minnesota is generated by solar energy.

(b) For a public utility with more than 200,000 retail electric customers, at least ten percent of the 1.5 percent goal must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kilowatts or less.

(c) A public utility with between 50,000 and 200,000 retail electric customers:

(1) must meet at least ten percent of the 1.5 percent goal with solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kilowatts or less; and

(2) may apply toward the ten percent goal in clause (1) individual customer subscriptions of 40 kilowatts or less to a community solar garden program operated by the public utility that has been approved by the commission.

(d) The solar energy standard established in this subdivision is subject to all the provisions of this section governing a utility's standard obligation under subdivision 2a.

(e) It is an energy goal of the state of Minnesota that, by 2030, ten percent of the retail electric sales in Minnesota be generated by solar energy.

(f) For the purposes of calculating the total retail electric sales of a public utility serving fewer than 200,000 retail electric customers under this subdivision, there shall be excluded retail electric sales to customers that are:

(1) an iron mining extraction and processing facility, including a scram mining facility as defined in Minnesota Rules, part 6130.0100, subpart 16;

(2) a qualified large-scale data center; or

(3) a paper mill, wood products manufacturer, sawmill, or oriented strand board manufacturer.

Those customers may not have included in the rates charged to them by the public utility serving fewer than 200,000 retail electric customers any costs of satisfying the solar standard specified by this subdivision.

(g) A public utility may not use energy used to satisfy the solar energy standard under this subdivision to satisfy its standard obligation under subdivision 2a. A public utility may not use energy used to satisfy the standard obligation under subdivision 2a to satisfy the solar standard under this subdivision.

(h) Notwithstanding any law to the contrary, a solar renewable energy credit associated with a solar photovoltaic device installed and generating electricity in Minnesota after August 1, 2013, but before 2020 may be used to meet the solar energy standard established under this subdivision.

Subd. 2g. **Carbon-free standard.** In addition to the requirements under subdivisions 2a and 2f, each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:

(1)	2030	80 percent for public utilities; 60 percent for other electric utilities
(2)	2035	90 percent for all electric utilities
(3)	2040	100 percent for all electric utilities.

Subd. 2h. **Distributed solar energy standard.** (a) For the purposes of this subdivision, the following terms have the meanings given:

(1) "capacity" has the meaning given in section 216B.164, subdivision 2a;

(2) "industrial customer" means a retail electricity customer:

(i) whose numerical classification under the North American Industry Classification System begins with the numbers 31, 32, or 33;

(ii) that is a pipeline, as defined in section 216G.01, subdivision 3;

(iii) that is an iron mining extraction and processing facility, including a scram mining facility, as defined in Minnesota Rules, part 6130.0100, subpart 16; or

(iv) that is a qualified large-scale data center; and

(3) "solar energy generating system" has the meaning given in Minnesota Statutes Supplement 2023, section 216E.01, subdivision 9a.

(b) In addition to the other requirements of this section, by the end of 2030, the following proportions of a public utility's total retail electric sales in Minnesota must be generated from solar energy generating systems:

(1) for a public utility with at least 200,000 retail electric customers in Minnesota, at least three percent;

(2) for a public utility with at least 100,000 but fewer than 200,000 retail electric customers in Minnesota, at least three percent; and

(3) for a public utility with fewer than 100,000 retail electric customers in Minnesota, at least one percent.

For a public utility subject to clause (2) or (3), sales to industrial customers in Minnesota must be subtracted from the utility's total retail electric sales for the purpose of calculating total retail electric sales in Minnesota.

(c) To be counted toward a public utility's standard established in paragraph (a), a solar energy generating system must:

(1) have a capacity of ten megawatts or less;

(2) be connected to the public utility's distribution system;

(3) be located in the Minnesota service territory of the public utility; and

(4) be constructed or procured after August 1, 2023.

(d) A solar energy generating system with a capacity of 100 kilowatts or more does not count toward compliance with the standard established in paragraph (a) unless the public utility verifies that construction trades workers who constructed the solar energy generating system were all paid no less than the prevailing wage rate, as defined in section 177.42, and whose employer participated in an apprenticeship program that is registered under chapter 178 or Code of Federal Regulations, title 29, part 29.

(e) A public utility shall select projects to satisfy the standard established under this subdivision through a competitive bidding process approved by the commission.

(f) The commission may modify or delay the implementation of the standard established under this subdivision in accordance with the provisions of subdivision 2b.

Subd. 3. **Utility plans filed with commission.** (a) Each electric utility shall report on its plans, activities, and progress with regard to the standard obligations under this section in its filings under section 216B.2422 or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of:

(1) the status of the utility's renewable energy mix relative to the standard obligations;

(2) efforts taken to meet the standard obligations;

(3) any obstacles encountered or anticipated in meeting the standard obligations;

(4) potential solutions to the obstacles;

(5) the number of Minnesotans employed to construct facilities designed to meet the utility's standard obligations under this section;

(6) efforts taken to retain and retrain workers employed at electric generating facilities that the utility has ceased operating or designated to cease operating for new positions constructing or operating facilities used to meet a utility's standard obligation;

(7) the impacts of facilities designed to meet the utility's standard obligations under this section on environmental justice areas;

(8) efforts made to increase the diversity of both the utility's workforce and vendors; and

(9) for an electric utility utilizing renewable energy credits to satisfy any portion of the electric utility's obligations under this section, the following information:

(i) the name and location of energy facilities that generated the energy associated with the credits;

(ii) the dates when the energy associated with the credits was generated;

(iii) the type of fuel that generated the energy associated with the credits; and

(iv) whether the energy associated with the credits was purchased by the utility purchasing the credits.

(b) The commissioner shall compile the information provided to the commission under paragraph (a), and report to the chairs of the house of representatives and senate committees with jurisdiction over energy and environment policy issues as to the progress of utilities in the state, including the progress of each individual electric utility, in increasing the amount of renewable energy provided to retail customers, with any recommendations for regulatory or legislative action, by January 15 of each odd-numbered year.

Subd. 4. **Renewable energy credits.** (a) To facilitate compliance with this section, the commission, by rule or order, shall establish by January 1, 2008, a program for tradable renewable energy credits for electricity generated by eligible energy technology. The credits must represent energy produced by an eligible energy technology, as defined in subdivision 1. Each kilowatt-hour of renewable energy credits must be treated the same as a kilowatt-hour of eligible energy technology generated or procured by an electric utility if it is produced by an eligible energy technology. The program must permit a credit to be used only once, except that a credit may be used to satisfy both the carbon-free energy standard obligation under subdivision 2g and either the renewable energy standard obligation under subdivision 2a or the solar energy standard obligation under subdivision 2f, if the credit meets the requirements of each subdivision. The program must treat all eligible energy technology equally and shall not give more or less credit to energy based on the state where the energy was generated or the technology with which the energy was generated. The commission must determine the period in which the credits may be used for purposes of the program.

(b) In lieu of generating or procuring energy directly to satisfy a standard obligation under subdivision 2a, 2f, or 2g, an electric utility may utilize renewable energy credits allowed under the program to satisfy the standard.

(c) The commission shall facilitate the trading of renewable energy credits between states.

(d) The commission shall require all electric utilities to participate in a commission-approved credit-tracking system or systems. Once a credit-tracking system is in operation, the commission shall issue an order establishing protocols for trading credits.

Subd. 5. **Technology based on fuel combustion.** (a) Electricity produced by fuel combustion through fuel blending or co-firing under paragraph (b) may only count toward a utility's standard obligation under subdivision 2a if the generation facility:

(1) was constructed in compliance with new source performance standards promulgated under the federal Clean Air Act, United States Code, title 42, section 7401 et seq., for a generation facility of that type; or

(2) employs the maximum achievable or best available control technology available for a generation facility of that type.

(b) An eligible energy technology may blend or co-fire a fuel listed in subdivision 1, paragraph (c), clause (5), with other fuels in the generation facility, but only the percentage of electricity that is attributable to a fuel listed in that clause can be counted toward an electric utility's standard obligation under subdivision 2a.

Subd. 6. [Repealed by amendment, 2007 c 3 s 1]

Subd. 7. **Compliance.** The commission must regularly investigate whether an electric utility is in compliance with the electric utility's standard obligation under subdivisions 2a, 2f, and 2g. If the commission finds noncompliance, it may order the electric utility to construct facilities, purchase energy generated by eligible energy technology, purchase renewable energy credits, or engage in other activities to achieve compliance. If an electric utility fails to comply with an order under this subdivision, the commission may impose a financial penalty on the electric utility in an amount not to exceed the estimated cost of the electric utility to achieve compliance. The penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits. The commission must deposit financial penalties imposed under this subdivision in the energy and conservation account established in the special revenue fund under section 216B.241, subdivision 2a. This subdivision is in addition to and does not limit any other authority of the commission to enforce this section.

Subd. 8. **Relation to other law.** This section does not limit the authority of the commission under any other law, including, without limitation, sections 216B.2422 and 216B.243.

Subd. 9. **Local benefits.** (a) The commission shall take all reasonable actions within the commission's statutory authority to ensure this section is implemented in a manner that maximizes net benefits to all Minnesota citizens. Reasonable actions the commission must take and benefits that must be maximized include but are not limited to:

(1) the creation of high-quality jobs in Minnesota paying wages that support families;

(2) recognition of the rights of workers to organize and unionize;

(3) ensuring that workers have the necessary tools, opportunities, and economic assistance to adapt successfully during the energy transition, particularly in environmental justice areas;

(4) ensuring that all Minnesotans share (i) the benefits of clean and renewable energy, and (ii) the opportunity to participate fully in the clean energy economy;

(5) ensuring that statewide air emissions are reduced, particularly in environmental justice areas; and

(6) the provision of affordable electric service to Minnesotans, particularly to low-income consumers.

(b) The commission must also implement this section in a manner that balances factors such as local ownership of or participation in energy production, development and ownership of eligible energy technology facilities by independent power producers, Minnesota utility ownership of eligible energy technology facilities, the costs of energy generation to satisfy the renewable and carbon-free standards, and the reliability of electric service to Minnesotans.

(c) When making investments to meet the requirements under this section, utilities are encouraged to locate new energy generating facilities in Minnesota communities where fossil-fuel-generating plants have been retired or are scheduled for retirement.

Subd. 10. **Utility acquisition of resources.** A competitive resource acquisition process established by the commission prior to June 1, 2007, shall not apply to a utility for the construction, ownership, and operation of generation facilities used to satisfy the requirements of this section unless, upon a finding that it is in the public interest, the commission issues an order on or after June 1, 2007, that requires compliance by a utility with a competitive resource acquisition process. A utility that owns a nuclear generation facility and intends to construct, own, or operate facilities under this section shall file with the commission as part of the utility's filing under section 216B.2422 a renewable energy plan setting forth the manner in which the utility proposes to meet the requirements of this section. The commission shall approve the plan unless it determines, after public hearing and comment, that the plan is not in the public interest. As part of its determination of public interest, the commission shall consider the plan's impact on balancing the state's interest in:

(1) promoting the policy of economic development in rural areas through the development of renewable energy projects, as expressed in subdivision 9;

(2) maintaining the reliability of the state's electric power grid; and

(3) minimizing cost impacts on ratepayers.

History: *2001 c 212 art 8 s 3; 2002 c 398 s 3; 1Sp2003 c 11 art 2 s 3; 2007 c 3 s 1; 2007 c 136 art 4 s 10; art 6 s 1,2; 2008 c 258 s 1; 2009 c 110 s 13; 2010 c 382 s 45; 2011 c 76 art 1 s 30; 2011 c 97 s 14,15; 2013 c 85 art 7 s 3; art 10 s 3; 2016 c 189 art 6 s 6; 2017 c 94 art 10 s 9; 2018 c 193 s 2; 1Sp2021 c 4 art 8 s 16; 2023 c 7 s 3-16; 2023 c 60 art 12 s 16; 2025 c 20 s 183; 1Sp2025 c 12 s 11,12*

216B.1692 EMISSIONS-REDUCTION RIDER.

Subdivision 1. **Qualifying projects.** (a) Projects that may be approved for the emissions reduction-rate rider allowed in this section must:

(1) be installed on existing large electric generating power plants, as defined in section 216B.2421, subdivision 2, clause (1), that are located in the state and that are currently not subject to emissions limitations for new power plants under the federal Clean Air Act, United States Code, title 42, section 7401 et seq.;

(2) not increase the capacity of the existing electric generating power plant more than ten percent or more than 100 megawatts, whichever is greater; and

(3) result in the existing plant either:

(i) complying with applicable new source review standards under the federal Clean Air Act; or

(ii) emitting air contaminants at levels substantially lower than allowed for new facilities by the applicable new source performance standards under the federal Clean Air Act; or

(iii) reducing emissions from current levels at a unit to the lowest cost-effective level when, due to the age or condition of the generating unit, the public utility demonstrates that it would not be cost-effective to reduce emissions to the levels in item (i) or (ii).

(b) Notwithstanding paragraph (a), a project may be approved for the emission reduction rate rider allowed in this section if the project is to be installed on existing large electric generating power plants, as defined in section 216B.2421, subdivision 2, clause (1), that are located outside the state and are needed to comply with state or federal air quality standards, but only if the project has received an advance determination of prudence from the commission under section 216B.1695.

Subd. 1a. **Exemption.** Subdivisions 2, 4, and 5, paragraph (c), clause (1), do not apply to projects qualifying under subdivision 1, paragraph (b).

Subd. 2. **Proposal submission.** A public utility that intends to submit a proposal for an emissions-reduction rider under this section must submit to the commission, the department, the Pollution Control Agency, and interested parties its plans for emissions-reduction projects at its generating facilities. This submission must be made at least 60 days in advance of a petition for a rider and shall include:

(1) the priority order of emissions-reduction projects the utility plans to pursue at its generating facilities;

(2) the planned schedule for implementation;

(3) the analysis and considerations relied on by the public utility to develop that priority ranking;

(4) the alternative emissions-reduction projects considered, including but not limited to applications of the best available control technology and repowering with natural gas, and reasons for not pursuing them;

(5) the emissions reductions expected to be achieved by the projects and their relation to applicable standards for new facilities under the federal Clean Air Act, United States Code, title 42, section 7401 et seq.; and

(6) the general rationale and conclusions of the public utility in determining the priority ranking.

Subd. 3. **Filing petition to recover project costs.** (a) A public utility may petition the commission for approval of an emissions-reduction rider to recover the costs of a qualifying emissions-reduction project outside of a general rate case proceeding under section 216B.16. In its filing, the public utility shall provide:

(1) a description of the planned emissions-reduction project;

(2) the activities involved in the project;

(3) a schedule for implementation;

(4) any analysis provided to the Pollution Control Agency regarding the project;

(5) an assessment of alternatives to the project, including costs, environmental impact, and operational issues;

(6) the proposed method of cost recovery;

(7) any proposed recovery above cost; and

(8) the projected emissions reductions from the project.

(b) Nothing in this section precludes a public utility or interested party from seeking commission guidelines for emissions-reduction rider filings; however, commission guidelines are not required as a prerequisite to a public utility-initiated filing.

Subd. 4. **Environmental assessment.** The Pollution Control Agency shall evaluate the public utility's emissions-reduction project filing and provide the commission with:

(1) verification that the emissions-reduction project qualifies under subdivision 1;

(2) a description of the projected environmental benefits of the proposed project; and

(3) its assessment of the appropriateness of the proposed project.

Subd. 5. **Proposal approval.** (a) After receiving the Pollution Control Agency's environmental assessment, the commission shall allow opportunity for written and oral comment on the proposed emissions reduction-rate rider proposal. The commission must assess the costs of an emissions-reduction project on a stand-alone basis and may approve, modify, or reject the proposed emissions-reduction rider. In making its determination, the commission shall consider whether the project, proposed cost recovery, and any proposed recovery above cost appropriately achieves environmental benefits without unreasonable consumer costs.

(b) The commission may approve a rider that:

(1) allows the utility to recover costs of qualifying emissions-reduction projects net of revenues attributable to the project;

(2) allows an appropriate return on investment associated with qualifying emissions-reduction projects at the level established in the public utility's last general rate case;

(3) allocates project costs appropriately between wholesale and retail customers;

(4) provides a mechanism for recovery above cost, if necessary to improve the overall economics of the qualifying projects to ensure implementation;

(5) recovers costs from retail customer classes in proportion to class energy consumption; and

(6) terminates recovery once the costs of qualifying projects have been fully recovered.

(c) The commission must not approve an emissions-reduction project and its associated rate rider if:

(1) the emissions-reduction project is needed to comply with new state or federal air quality standards; or

(2) the emissions-reduction project is required as a corrective action as part of any state or federal enforcement action.

(d) The commission may not include any costs of a proposed project in the emissions-reduction rider that are not directly allocable to reduction of emissions.

Subd. 6. **Implementation.** Within 60 days of a final commission order, the public utility shall notify the commission and the Pollution Control Agency whether it will proceed with the project. Nothing in this section commits a public utility to implementing a proposed emissions-reduction project if the proposed project or terms of the emissions-reduction rider have been either modified or rejected by the commission. A public utility implementing a project under this section will not be required for a period of eight years after installation to undertake additional investments to comply with a new state requirement regarding pollutants addressed by the project at the project generating facility. This section does not affect requirements of federal law. The term of the rider shall extend for the period approved by the commission regardless of any subsequent state or federal requirement affecting any pollutant addressed by the approved emissions-reduction project and regardless of the sunset date in subdivision 8.

Subd. 7. **Evaluation and report.** By January 15, 2005, the commission, in consultation with the commissioner of commerce and commissioner of the Pollution Control Agency, shall report to the legislature:

(1) the number of participating public utilities and qualifying projects proposed and approved under this section;

(2) the total cost of each project and any associated incentives;

(3) the reduction in air emissions achieved;

(4) rate impacts of the cost recovery mechanisms; and

(5) an assessment of the effectiveness of the cost recovery mechanism in accomplishing power plant emissions reductions in excess of those required by law.

Subd. 8. **Sunset.** This section is effective until December 31, 2020, and applies to plans, projects, and riders approved before that date and modifications made to them after that date.

History: *1Sp2001 c 5 art 3 s 12; 2006 c 201 s 4; 2010 c 325 s 1; 2011 c 76 art 1 s 31,32; 2013 c 85 art 7 s 4-6*

216B.1693 MS 2010 [Expired, 1Sp2003 c 11 art 2 s 4]

216B.1694 INNOVATIVE ENERGY PROJECT.

Subdivision 1. **Definition.** For the purposes of this section, the term "innovative energy project" means a proposed energy-generation facility or group of facilities which may be located on up to three sites:

(1) that makes use of an innovative generation technology utilizing coal as a primary fuel in a highly efficient combined-cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions from those of traditional technologies;

(2) that the project developer or owner certifies is a project capable of offering a long-term supply contract at a hedged, predictable cost; and

(3) that is designated by the commissioner of Iron Range resources and rehabilitation as a project that is located in the taconite tax relief area on a site that has substantial real property with adequate infrastructure to support new or expanded development and that has received prior financial and other support from the board.

Subd. 2. **Regulatory incentives.** (a) An innovative energy project:

(1) is exempted from the requirements for a certificate of need under section 216B.243, for the generation facilities, and transmission infrastructure associated with the generation facilities, but is subject to all applicable environmental review and permitting procedures of chapter 216E;

(2) once permitted and constructed, is eligible to increase the capacity of the associated transmission facilities without additional state review upon filing notice with the commission;

(3) has the power of eminent domain, which shall be limited to the sites and routes approved by the Environmental Quality Board for the project facilities. The project shall be considered a utility as defined in section 216I.02, subdivision 19, for the limited purpose of section 216I.21. The project shall report any intent to exercise eminent domain authority to the board;

(4) shall, prior to the approval by the commission of any arrangement to build or expand a fossil-fuel-fired generation facility, or to enter into an agreement to purchase capacity or energy from such a facility for a term exceeding five years, be considered as a supply option for the generation facility, and the commission

shall ensure such consideration and take any action with respect to such supply proposal that it deems to be in the best interest of ratepayers;

(5) shall make a good faith effort to secure funding from the United States Department of Energy and the United States Department of Agriculture to conduct a demonstration project at the facility for either geologic or terrestrial carbon sequestration projects to achieve reductions in facility emissions or carbon dioxide;

(6) shall be entitled to enter into a contract with a public utility that owns a nuclear generation facility in the state to provide 450 megawatts of base-load capacity and energy under a long-term contract, subject to the approval of the terms and conditions of the contract by the commission. The commission may approve, disapprove, amend, or modify the contract in making its public interest determination, taking into consideration the project's economic development benefits to the state; the use of abundant domestic fuel sources; the stability of the price of the output from the project; the project's potential to contribute to a transition to hydrogen as a fuel resource; and the emissions reductions achieved compared to other solid fuel base-load technologies; and

(7) shall be eligible for a grant from the renewable development account, subject to the approval of the entity administering that account, of $2,000,000 a year for five years for development and engineering costs, including those costs related to mercury-removal technology; thermal efficiency optimization and emission minimization; environmental impact statement preparation and licensing; development of hydrogen production capabilities; and fuel cell development and utilization.

(b) This subdivision does not apply to nor affect a proposal to add utility-owned resources that is pending on May 29, 2003, before the Public Utilities Commission or to competitive bid solicitations to provide capacity or energy that is scheduled to be on line by December 31, 2006.

Subd. 3. **Staging and permitting.** (a) A natural gas-fired plant that is located on one site designated as an innovative energy project site under subdivision 1, clause (3), is accorded the regulatory incentives granted to an innovative energy project under subdivision 2, clauses (1) to (3), and may exercise the authorities therein.

(b) Following issuance of a final state or federal environmental impact statement for an innovative energy project that was a subject of contested case proceedings before an administrative law judge:

(1) site and route permits and water appropriation approvals for an innovative energy project must also be deemed valid for a plant meeting the requirements of paragraph (a) and shall remain valid until the later of (i) four years from the date the final required state or federal preconstruction permit is issued or (ii) June 30, 2025; and

(2) no air, water, or other permit issued by a state agency that is necessary for constructing an innovative energy project may be the subject of contested case hearings, notwithstanding Minnesota Rules, parts 7000.1750 to 7000.2200.

History: *1Sp2003 c 11 art 4 s 1; 2011 c 97 s 16; 2012 c 187 art 1 s 34; 2017 c 94 art 7 s 15; art 10 s 10; 2024 c 126 art 7 s 14; 2024 c 127 art 43 s 14*

216B.1695 ENVIRONMENTAL PROJECTS; ADVANCE DETERMINATION OF PRUDENCE.

Subdivision 1. **Qualifying project.** A public utility may petition the commission for an advance determination of prudence for a project undertaken to comply with federal or state air quality standards of states in which the utility's electric generation facilities are located, if the project has an expected jurisdictional cost to Minnesota ratepayers of at least $10,000,000. A project is undertaken to comply with federal or state air quality standards if it is required:

(1) by the state in which the generation facility is located in a state implementation plan, permit, or order; or

(2) to comply with section 111 or 112 of the federal Clean Air Act, United States Code, title 42, section 7411 or 7412.

Subd. 2. **Regulatory cost assessments and reports.** (a) A utility requesting an advance determination under subdivision 1 must, as part of the evidence required when filing a petition under subdivision 3, provide to the Public Utilities Commission and the Pollution Control Agency an assessment of all anticipated state and federal environmental regulations related to the production of electricity from the utility's facility subject to the filing, including regulations relating to:

(1) air pollution by nitrogen oxide and sulphur dioxide, including an assumption that Minnesota will be included in the federal Clean Air Interstate Rule region, hazardous air pollutants, carbon dioxide, particulates, and ozone;

(2) coal waste; and

(3) water consumption and water pollution.

(b) In addition, the utility shall provide an assessment of the financial and operational impacts of these pending regulations applicable to the generating facility that is the subject of the filing and provide a range of regulatory response scenarios that include, but are not limited to:

(1) the installation of pollution control equipment;

(2) the benefits of the retirement or repowering of the plant that is the subject of the filing with cleaner fuels considering the costs of complying with state and federal environmental regulations; and

(3) the use of pollution allowances to achieve compliance.

(c) The utility shall consult with interested stakeholders in establishing the scope of the regulatory, financial, and operational assessments prior to or during the 60-day period of the notice under subdivision 4.

Subd. 3. **Petition.** A petition filed under this section must include a description of the project, evidence supporting the project's reasonableness, a discussion of project alternatives, a project implementation schedule, a cost estimate and support for the reasonableness of the estimated cost, and a description of the public utility's efforts to ensure the lowest reasonable costs. Following receipt of the Pollution Control Agency's verification under subdivision 4, the commission shall allow opportunity for oral and written comment on the petition. The commission shall make a final determination on the petition within ten months of its filing date. The commission must make findings in support of its determination.

Subd. 4. **Verification.** At least 60 days prior to filing a petition to the commission under subdivision 3, the utility shall file notice with the Pollution Control Agency that describes the project and how it qualifies under subdivision 1. The Pollution Control Agency shall, within 60 days of receipt of the notice, verify that the project qualifies under subdivision 1, and shall forward written verification to the commission.

Subd. 5. **Cost recovery.** The utility may begin recovery of costs that have been incurred by the utility in connection with implementation of the project in the next rate case following an advance determination of prudence or in a rider approved under section 216B.1692. The commission shall review the costs incurred by the utility for the project. The utility must show that the project costs are reasonable and necessary, and demonstrate its efforts to ensure the lowest reasonable project costs. Notwithstanding the commission's prior determination of prudence, it may accept, modify, or reject any of the project costs. The commission may determine whether to require an allowance for funds used during construction offset.

Subd. 5a. **Rate of return.** The return on investment in the rider shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.

Subd. 6. **Expiration.** A petition for an advance determination of prudence may not be filed after December 31, 2015.

History: *2010 c 361 art 5 s 7; 2010 c 373 s 1; 2013 c 85 art 7 s 7,8*

216B.1696 COMPETITIVE RATE FOR ENERGY-INTENSIVE, TRADE-EXPOSED ELECTRIC UTILITY CUSTOMER.

Subdivision 1. **Definitions.** (a) For purposes of this section, the following terms have the meanings given them.

(b) "Clean energy technology" is energy technology that generates electricity from a carbon neutral generating resource including, but not limited to, solar, wind, hydroelectric, and biomass.

(c) "Energy-intensive trade-exposed customer" is defined to include:

(1) an iron mining extraction and processing facility, including a scram mining facility as defined in Minnesota Rules, part 6130.0100, subpart 16;

(2) a paper mill, wood products manufacturer, sawmill, or oriented strand board manufacturer;

(3) a steel mill and related facilities; and

(4) a retail customer of an investor-owned electric utility that has facilities under a single electric service agreement that: (i) collectively imposes a peak electrical demand of at least 10,000 kilowatts on the electric utility's system, (ii) has a combined annual average load factor in excess of 80 percent, and (iii) is subject to globally competitive pressures and whose electric energy costs are at least ten percent of the customer's overall cost of production.

(d) "EITE rate schedule" means a rate schedule under which an investor-owned electric utility may set terms of service to an individual or group of energy-intensive trade-exposed customers.

(e) "EITE rate" means the rate or rates offered by the investor-owned electric utility under an EITE rate schedule.

Subd. 2. **Rates and terms of EITE rate schedule.** (a) It is the energy policy of the state of Minnesota to ensure competitive electric rates for energy-intensive trade-exposed customers. To achieve this objective, an investor-owned electric utility that has at least 50,000 retail electric customers, but no more than 200,000 retail electric customers, shall have the ability to propose various EITE rate options within their service territory under an EITE rate schedule that include, but are not limited to, fixed-rates, market-based rates, and rates to encourage utilization of new clean energy technology.

(b) Notwithstanding section 216B.03, 216B.05, 216B.06, 216B.07, or 216B.16, the commission shall, upon a finding of net benefit to the utility or the state, approve an EITE rate schedule and any corresponding EITE rate.

(c) The commission shall make a final determination in a proceeding begun under this section within 90 days of a miscellaneous rate filing by the electric utility.

(d) Upon approval of any EITE rate schedule, the utility shall create a separate account to track the difference in revenue between what would have been collected under the electric utility's applicable standard tariff and the EITE rate schedule. In its next general rate case or through an EITE cost recovery rate rider between general rate cases, the commission shall allow the utility to recover any costs, including reduced revenues, or refund any savings, including increased revenues, associated with providing service to a customer under an EITE rate schedule. The utility shall not recover any costs or refund any savings under this section from any energy-intensive trade-exposed customer or any low-income residential ratepayers as defined in section 216B.16, subdivision 15.

Subd. 3. **Low-income funding.** Upon the filing of a utility for approval of an EITE rate schedule under this section, the filing utility must deposit $10,000 into an account devoted to funding a program approved by the commission under section 216B.16, subdivision 15. The funds shall be used to expand the outreach of the commission-approved affordability program.

Subd. 4. **Assessment.** The commissioner of commerce shall assess reasonable costs it incurs for services it provides to implement this section to the utility proposing an EITE rate schedule to the commission. The department must not assess more than $854,000 per biennium under this subdivision.

History: *1Sp2015 c 1 art 3 s 26*

COMPLAINTS AND HEARINGS

216B.17 COMPLAINT INVESTIGATION AND HEARING.

Subdivision 1. **Investigation.** On the commission's own motion or upon a complaint made against any public utility by the governing body of any political subdivision, by another public utility, by the department, by any 50 consumers of a particular utility, or by a complainant under section 216B.172 that any of the rates, tolls, tariffs, charges, or schedules or any joint rate or any regulation, measurement, practice, act, or omission affecting or relating to the production, transmission, delivery, or furnishing of natural gas or electricity or any service in connection therewith is in any respect unreasonable, insufficient, or unjustly discriminatory, or that any service is inadequate or cannot be obtained, the commission shall proceed, with notice, to make such investigation as it may deem necessary. The commission may dismiss any complaint without a hearing if in its opinion a hearing is not in the public interest.

Subd. 2. **Notice of complaint.** The commission shall, prior to any formal hearing, notify the public utility complained of that a complaint has been made, and ten days after the notice has been given the commission may proceed to set a time and place for a hearing and an investigation as provided in this section.

Subd. 3. **Notice of hearing.** The commission shall give the public utility and the complainant ten days' notice of the time and place when and where the hearing will be held and the matters to be considered and determined. Both the public utility and complainant are entitled to be heard and to be represented by counsel. A hearing under this section is not a contested case under chapter 14.

Subd. 4. **Notice to local governments and interested persons.** Notice shall also be given to the governing bodies of affected municipalities and counties, and to any other persons the commission shall deem necessary.

Subd. 5. **Combined notice.** The notice provided for in subdivisions 2 and 3 may be combined but if combined the notice shall not be less than ten days.

Subd. 6. **Complaint petition.** The commission shall have the power to hear, determine, and adjust complaints made against any municipally owned gas or electric utility with respect to rates and services upon petition of ten percent of the nonresident consumers of the municipally owned utility or 25 such nonresident consumers whichever is less. The hearing of the complaints shall be governed by this section.

Subd. 6a. **Cooperative electric associations.** For the purposes of this section, public utility shall include cooperative electric associations with respect to service standards and practices only.

Subd. 7. **Evidence.** Section 14.60 shall be applicable to all contested cases before the commission.

Subd. 8. **Further action by commission.** If after making an investigation under subdivision 1 and holding a hearing under this section, the commission finds that all significant factual issues raised have not been resolved to its satisfaction:

(1) for investigations concerning the reasonableness of rates of a public utility, if the commission is unable to resolve the complaint with the utility, the commission may order the utility to initiate a rate proceeding under section 216B.16, provided, however, that the utility must be allowed at least 120 days after the date of the commission's order to initiate the proceeding; and

(2) for investigations of other matters, the commission shall order that a contested case proceeding be conducted under chapter 14.

Subd. 9. **Telecommunications and cable communications systems.** (a) The commission has authority under this section to investigate, upon complaint or on its own motion, conduct by or on behalf of a telecommunications carrier, telephone company, or cable communications system provider that impacts public utility or cooperative electric association infrastructure. If the commission finds that the conduct damaged or unreasonably interfered with the function of the infrastructure, the commission may take any action authorized under sections 216B.52 to 216B.61 with respect to the provider.

(b) For purposes of this subdivision:

(1) "telecommunications carrier" has the meaning given in section 237.01, subdivision 6;

(2) "telephone company" has the meaning given in section 237.01, subdivision 7; and

(3) "cable communications system provider" means an owner or operator of a cable communications system, as defined in section 238.02, subdivision 3.

History: *1974 c 429 s 17; 1978 c 795 s 4; 1980 c 614 s 113; 1982 c 424 s 130; 1990 c 370 s 4-6; 2023 c 60 art 12 s 17; 2024 c 127 art 13 s 4*

216B.172 CONSUMER DISPUTES.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the following terms have the meanings given.

(b) "Appeal" means a request a complainant files with the commission to review and make a final decision regarding the resolution of the complainant's complaint by the consumer affairs office.

(c) "Complainant" means an individual residential customer or a tenant who files with the consumer affairs office a complaint against a public utility or a landlord of a shared-metered residential building.

(d) "Complaint" means an allegation submitted to the consumer affairs office by a complainant that a public utility's or a landlord's action or practice regarding billing or terms and conditions of service:

(1) violates a statute, rule, tariff, service contract, or other provision of law;

(2) is unreasonable; or

(3) has harmed or, if not addressed, harms a complainant.

Complaint does not include an objection to or a request to modify any natural gas or electricity rate contained in a tariff that has been approved by the commission. A complaint under this section is an informal complaint under Minnesota Rules, chapter 7829.

(e) "Consumer affairs office" means the staff unit of the commission that is organized to receive and respond to complaints.

(f) "Informal proceeding" has the meaning given in Minnesota Rules, part 7829.0100, subpart 8.

(g) "Landlord" means an owner of a shared-metered residential building, a contract for deed vendee, receiver, executor, trustee, lessee, agent, or other person directly or indirectly in control of the shared-metered residential building that bills separately for natural gas or electricity, or both.

(h) "Public assistance" has the meaning given in section 550.37, subdivision 14.

(i) "Public utility" has the meaning given in section 216B.02, subdivision 4.

(j) "Shared-metered residential building" has the meaning given in section 216B.022, subdivision 1, paragraph (e).

(k) "Tenant" has the meaning given in section 216B.022, subdivision 1, paragraph (g).

(l) "Third-party billing agent" has the meaning given in section 216B.022, subdivision 1, paragraph (h).

Subd. 2. **Complaint resolution procedure.** A complainant must first attempt to resolve a dispute with a public utility or a landlord. If a complainant is dissatisfied with the proposed resolution by the public utility or the landlord, the complainant may seek assistance of the commission to resolve the dispute by filing a complaint with the consumer affairs office. The consumer affairs office must: (1) notify the complainant of the resolution of the complaint; and (2) provide written notice of (i) the complainant's right to appeal the resolution to the commission, and (ii) the steps the complainant may take to appeal the resolution. Upon request, the consumer affairs office must provide to the complainant a written notice containing the substance of and basis for the resolution. Nothing in this section affects any other rights existing under this chapter or other law.

Subd. 3. **Appeal; final commission decision.** (a) If a complainant is not satisfied with the resolution of a complaint by the consumer affairs office, the complainant may file an appeal with the commission requesting that the commission make a final decision on the complaint. The commission's response to an appeal filed under this subdivision must comply with the notice requirements under section 216B.17, subdivisions 2 to 5.

(b) Upon the commission's receipt of an appeal filed under paragraph (a), the chair of the commission or a subcommittee delegated under section 216A.03, subdivision 8, to review the resolution of the complaint must decide whether the complaint be:

(1) dismissed because there is no reasonable basis on which to proceed;

(2) resolved through an informal commission proceeding; or

(3) referred to the Office of Administrative Hearings for a contested case proceeding under chapter 14.

A decision made under this paragraph must be provided in writing to the complainant and the public utility.

(c) If the commission decides that the complaint be resolved through an informal proceeding before the commission or referred to the Office of Administrative Hearings for a contested case proceeding, the executive secretary must issue any procedural schedules, notices, or orders required to initiate an informal proceeding or a contested case.

(d) The commission's dismissal of an appeal request or a decision rendered after conducting an informal proceeding is a final decision constituting an order or determination of the commission.

Subd. 4. **Judicial review.** Notwithstanding section 216B.27, a complainant may seek judicial review in district court of an adverse final decision under subdivision 3, paragraph (b), clause (1) or (2). Judicial review of the commission's decision in a contested case referred under subdivision 3, paragraph (b), clause (3), is governed by chapter 14.

Subd. 5. **Right to service during pendency of dispute.** A public utility must continue or promptly restore service to a complainant during the pendency of an administrative or judicial procedure pursued by a complainant under this section, provided that the complainant:

(1) agrees to enter into a payment agreement under section 216B.098, subdivision 3;

(2) posts the full disputed payment in escrow;

(3) demonstrates receipt of public assistance or eligibility for legal aid services; or

(4) demonstrates the complainant's household income is at or below 50 percent of the median income in Minnesota.

Subd. 6. **Rulemaking authority.** The commission may adopt rules to carry out the purposes of this section.

History: *2023 c 60 art 12 s 18; 2024 c 107 s 5,6*

216B.18 SERVICE OF NOTICE.

Service of notice of all hearings, investigations, and proceedings pending before the commission and of complaints, reports, orders, and other documents must be made personally, by electronic service as provided in section 216.17, or by mail as the commission may direct. Regulated utilities and state agencies must provide an electronic address to the commission for electronic service purposes and agree to accept electronic service as official service.

History: *1974 c 429 s 18; 2007 c 10 s 4; 2013 c 135 art 3 s 20*

216B.19 JOINT HEARING AND INVESTIGATION.

In the discharge of its duties under Laws 1974, chapter 429, the commission or the department may cooperate with similar commissions of other states and any federal agency and may hold joint hearings and make joint investigations with other commissions.

History: *1974 c 429 s 19; 1980 c 614 s 114*

216B.20 SEPARATE RATE HEARING.

The commission may, in its discretion, when complaint is made of more than one rate or charge, order separate hearings thereon, and may consider and determine the several matters complained of separately and at times it may prescribe.

History: *1974 c 429 s 20*

216B.21 SUMMARY INVESTIGATION.

Subdivision 1. **Authority.** Whenever the commission has reason to believe that any rate or charge may be unreasonable or unjustly discriminatory or that any service is inadequate or cannot be obtained or that an investigation of any matter relating to any public utility should for any reason be made, it may on its own motion summarily investigate the same with or without notice.

Subd. 2. **Formal hearing.** If, after making the summary investigation, the commission becomes satisfied that sufficient grounds exist to warrant a formal hearing being ordered as to the matters investigated, it shall set a time and place for a hearing.

Subd. 3. **Notice.** Notice of the time and place for the hearing shall be made as provided in sections 216B.17 and 216B.18.

History: *1974 c 429 s 21*

216B.22 MUNICIPALITY; AMICUS CURIAE AUTHORITY.

Any municipality that regulates and controls the exercise of a public utility franchise by reason of its home rule charter on January 1, 1975, is authorized to assist the Public Utilities Commission as amicus curiae in any proceeding brought before the commission with respect to the rates, fares, prices, regulation, or control of any utility operating therein.

History: *1974 c 429 s 22; 1980 c 614 s 123*

216B.23 LAWFUL RATE; REASONABLE SERVICE.

Subdivision 1. **Determination as to rate; order.** Whenever upon an investigation made under the provisions of Laws 1974, chapter 429, the commission shall find rates, tolls, charges, schedules or joint rates to be unjust, unreasonable, insufficient, or unjustly discriminatory or preferential or otherwise unreasonable or unlawful, the commission shall determine and by order fix reasonable rates, tolls, charges, schedules, or joint rates to be imposed, observed, and followed in the future in lieu of those found to be unreasonable or unlawful.

Subd. 1a. **Authority to issue refund.** (a) On determining that a public utility has charged a rate in violation of this chapter, a commission rule, or a commission order, the commission, after conducting a proceeding, may require the public utility to refund to its customers, in a manner approved by the commission, any revenues the commission finds were collected as a result of the unlawful conduct. Any refund authorized by this section is permitted in addition to any remedies authorized by section 216B.16 or any other law governing rates. Exercising authority under this section does not preclude the commission from pursuing penalties under sections 216B.57 to 216B.61 for the same conduct.

(b) This section must not be construed as allowing:

(1) retroactive ratemaking;

(2) refunds based on claims that prior or current approved rates have been unjust, unreasonable, unreasonably preferential, discriminatory, insufficient, inequitable, or inconsistent in application to a class of customers; or

(3) refunds based on claims that approved rates have not encouraged energy conservation or renewable energy use, or have not furthered the goals of section 216B.164, 216B.241, or 216C.05.

(c) A refund under this subdivision does not apply to revenues collected more than six years before the date of the notice of the commission proceeding required under this subdivision.

Subd. 2. **Finding as to service; order.** Whenever the commission shall find any regulations, measurements, practices, acts, or service to be unjust, unreasonable, insufficient, preferential, unjustly discriminatory, or otherwise unreasonable or unlawful, or shall find that any service which can be reasonably demanded cannot be obtained, the commission shall determine and by order fix reasonable measurements, regulations, acts, practices, or service to be furnished, imposed, observed and followed in the future in lieu of those found to be unreasonable, inadequate, or otherwise unlawful, and shall make any other order respecting the measurement, regulation, act, practice, or service as shall be just and reasonable.

Subd. 3. **Copy of order served; notice.** A copy of the order shall be served upon the person against whom it runs or the person's attorney, and notice thereof shall be given to the other parties to the proceedings or their attorneys.

History: *1974 c 429 s 23; 1986 c 444; 2009 c 110 s 14*

ENERGY CONSERVATION; UTILITY CONSTRUCTION

216B.24 CONSTRUCTION OF MAJOR FACILITY; FILING PLANS.

Subdivision 1. **Major utility facility defined.** The words "major utility facility" means: (1) electric generating plant and associated facilities designed for, or capable of, operation at a capacity of 50 megawatts or more; (2) an electric transmission line and associated facilities of a design capacity of 125 kilovolts or more; and (3) a gas transmission line and associated facilities designed for, or capable of, transporting gas at pressures in excess of 125 pounds per square inch; provided, however, that the words "major utility facility" shall not include electric or gas distribution lines and gas gathering lines and associated facilities as defined by the commission.

Subd. 2. **Construction plan filed; rules.** Under rules as the commission may prescribe, every public utility shall file with the commission, within the time and in the form as the commission may designate, plans showing any contemplated construction of major utility facilities.

Subd. 3. **Applicability to municipalities.** The provisions of this section shall apply to the construction of major utility facilities by a municipally owned gas or electric utility.

History: *1974 c 429 s 24; 1985 c 248 s 70*

216B.2401 ENERGY SAVINGS AND OPTIMIZATION POLICY GOAL.

(a) The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. In addition, the legislature finds that optimizing the timing and method used by energy consumers to manage energy use provides significant benefits to the consumers and to the utility system as a whole. The legislature further finds that cost-effective energy savings and load management programs should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change. Therefore, it is the energy policy of the state of Minnesota to achieve annual energy savings equivalent to at least 2.5 percent of annual retail energy sales of electricity and natural gas through multiple measures, including but not limited to:

(1) cost-effective energy conservation improvement programs and efficient fuel-switching utility programs under sections 216B.2402 to 216B.241;

(2) rate design;

(3) energy efficiency achieved by energy consumers without direct utility involvement;

(4) advancements in statewide energy codes and cost-effective appliance and equipment standards;

(5) programs designed to transform the market or change consumer behavior;

(6) energy savings resulting from efficiency improvements to the utility infrastructure and system; and

(7) other efforts to promote energy efficiency and energy conservation.

(b) A utility is encouraged to design and offer to customers load management programs that enable: (1) customers to maximize the economic value gained from the energy purchased from the customer's utility service provider; and (2) utilities to optimize the infrastructure and generation capacity needed to effectively serve customers and facilitate the integration of renewable energy into the energy system.

(c) The commissioner must provide a reasonable estimate of progress made toward the statewide energy-savings goal under paragraph (a) in the annual report required under section 216B.241, subdivision 1c, and make recommendations for administrative or legislative initiatives to increase energy savings toward that goal. The commissioner must also annually report on the energy productivity of the state's economy by estimating the ratio of economic output produced in the most recently completed calendar year to the primary energy inputs used in that year.

History: *2007 c 136 art 2 s 4; 2010 c 361 art 5 s 8; 2011 c 97 s 17; 2013 c 85 art 12 s 2; 2021 c 29 s 2*

216B.2402 DEFINITIONS.

Subdivision 1. **Definitions.** For the purposes of section 216B.16, subdivision 6b, and sections 216B.2401 to 216B.241, the following terms have the meanings given them.

Subd. 2. **Consumer-owned utility.** "Consumer-owned utility" means a municipal gas utility, a municipal electric utility, or a cooperative electric association.

Subd. 3. **Cumulative lifetime savings.** "Cumulative lifetime savings" means the total electric energy or natural gas savings in a given year from energy conservation improvements installed in that given year and energy conservation improvements installed in previous years that are still in operation.

Subd. 3a. **Data mining facility.** "Data mining facility" means all buildings, structures, equipment, and installations at a single site where electricity is used primarily by computers to process transactions involving digital currency that is not issued by a central authority.

Subd. 4. **Efficient fuel-switching improvement.** "Efficient fuel-switching improvement" means a project that:

(1) replaces a fuel used by a customer with electricity or natural gas delivered at retail by a utility subject to section 216B.2403 or 216B.241;

(2) results in a net increase in the use of electricity or natural gas and a net decrease in source energy consumption on a fuel-neutral basis;

(3) otherwise meets the criteria established for consumer-owned utilities in section 216B.2403, subdivision 8, and for public utilities under section 216B.241, subdivisions 11 and 12; and

(4) requires the installation of equipment that utilizes electricity or natural gas, resulting in a reduction or elimination of the previous fuel used.

An efficient fuel-switching improvement is not an energy conservation improvement or energy efficiency even if the efficient fuel-switching improvement results in a net reduction in electricity or natural gas use.

Subd. 5. **Energy conservation.** "Energy conservation" means an action that results in a net reduction in electricity or natural gas consumption. Energy conservation does not include an efficient fuel-switching improvement.

Subd. 6. **Energy conservation improvement.** "Energy conservation improvement" means a project that results in energy efficiency or energy conservation. Energy conservation improvement may include waste heat that is recovered and converted into electricity or used as thermal energy, but does not include electric utility infrastructure projects approved by the commission under section 216B.1636.

Subd. 7. **Energy efficiency.** "Energy efficiency" means measures or programs, including energy conservation measures or programs, that: (1) target consumer behavior, equipment, processes, or devices; (2) are designed to reduce the consumption of electricity or natural gas on either an absolute or per unit of production basis; and (3) do not reduce the quality or level of service provided to an energy consumer.

Subd. 8. **Fuel.** "Fuel" means energy, including electricity, propane, natural gas, heating oil, gasoline, diesel fuel, or steam, consumed by a retail utility customer.

Subd. 9. **Fuel neutral.** "Fuel neutral" means an approach that compares the use of various fuels for a given end use, using a common metric.

Subd. 10. **Gross annual retail energy sales.** "Gross annual retail energy sales" means a utility's annual electric sales to all Minnesota retail customers, or natural gas throughput to all retail customers, including natural gas transportation customers, on a utility's distribution system in Minnesota. Gross annual retail energy sales does not include:

(1) gas sales to:

(i) a large energy facility;

(ii) a large customer facility whose natural gas utility has been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (a), with respect to natural gas sales made to the large customer facility; and

(iii) a commercial gas customer facility whose natural gas utility has been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (b), with respect to natural gas sales made to the commercial gas customer facility;

(2) electric sales to:

(i) a large customer facility whose electric utility has been exempted by the commissioner under section 216B.241, subdivision 1a, paragraph (a), with respect to electric sales made to the large customer facility;

(ii) a data mining facility, if the facility:

(A) has provided a signed letter to the utility verifying the facility meets the definition of a data mining facility; and

(B) imposes a peak electrical demand on a consumer-owned utility's system equal to or greater than 40 percent of the peak electrical demand of the system, measured in the same manner as the utility that serves the customer facility measures electric demand for billing purposes; and

(iii) a qualified large-scale data center; or

(3) the amount of electric sales prior to December 31, 2032, that are associated with a utility's program, rate, or tariff for electric vehicle charging based on a methodology and assumptions developed by the department in consultation with interested stakeholders no later than December 31, 2021. After December 31, 2032, incremental sales to electric vehicles must be included in calculating a public utility's gross annual retail sales.

Subd. 11. **Investments and expenses of a public utility.** "Investments and expenses of a public utility" means the investments and expenses incurred by a public utility in connection with an energy conservation improvement.

Subd. 12. **Large customer facility.** "Large customer facility" means all buildings, structures, equipment, and installations at a single site that in aggregate: (1) impose a peak electrical demand on an electric utility's system of at least 20,000 kilowatts, measured in the same way as the utility that serves the customer facility measures electric demand for billing purposes; or (2) consume at least 500,000,000 cubic feet of natural gas annually. When calculating peak electrical demand, a large customer facility may include demand offset by on-site cogeneration facilities and, if engaged in mineral extraction, may include peak energy demand from the large customer facility's mining processing operations.

Subd. 13. **Large energy facility.** "Large energy facility" has the meaning given in section 216B.2421, subdivision 2, clause (1).

Subd. 14. **Lifetime energy savings.** "Lifetime energy savings" means the amount of savings a particular energy conservation improvement is projected to produce over the improvement's effective useful lifetime.

Subd. 15. **Load management.** "Load management" means an activity, service, or technology that changes the timing or the efficiency of a customer's use of energy that allows a utility or a customer to: (1)

respond to local and regional energy system conditions; or (2) reduce peak demand for electricity or natural gas. Load management that reduces a customer's net annual energy consumption is also energy conservation.

Subd. 16. **Low-income household.** "Low-income household" means a household whose household income:

(1) is 80 percent or less of the area median household income for the geographic area in which the low-income household is located, as calculated by a body of the state or federal government; or

(2) meets the income eligibility standards, as determined by the commissioner, required for a household to receive financial assistance from a federal, state, municipal, or utility program administered or approved by the department.

Subd. 17. **Low-income programs.** "Low-income programs" means energy conservation improvement and efficient fuel-switching programs that directly serve the needs of low-income households, including low-income renters.

Subd. 18. **Member.** "Member" has the meaning given in section 308B.005, subdivision 15.

Subd. 19. **Multifamily building.** "Multifamily building" means a residential building containing five or more dwelling units.

Subd. 20. **Preweatherization measure.** "Preweatherization measure" means an improvement that is necessary to allow energy conservation improvements to be installed in a home.

Subd. 21. **Qualifying utility.** "Qualifying utility" means a utility that supplies a customer with energy that enables the customer to qualify as a large customer facility.

Subd. 22. **Waste heat recovered and used as thermal energy.** "Waste heat recovered and used as thermal energy" means capturing heat energy that would be exhausted or dissipated to the environment from machinery, buildings, or industrial processes, and productively using the recovered thermal energy where it was captured or distributing it as thermal energy to other locations where it is used to reduce demand-side consumption of natural gas, electric energy, or both.

Subd. 23. **Waste heat recovery converted into electricity.** "Waste heat recovery converted into electricity" means an energy recovery process that converts to electricity energy from the heat of exhaust stacks or pipes used for engines or manufacturing or industrial processes, or from the reduction of high pressure in water or gas pipelines, that would otherwise be lost.

History: *2021 c 29 s 3; 2023 c 60 art 12 s 19; 2024 c 126 art 6 s 8-10; 2024 c 127 art 42 s 8-10; 1Sp2025 c 7 art 3 s 6; 1Sp2025 c 12 s 13*

216B.2403 CONSUMER-OWNED UTILITIES; ENERGY CONSERVATION AND OPTIMIZATION.

Subdivision 1. **Applicability.** This section applies to:

(1) a cooperative electric association that provides retail service to more than 5,000 members;

(2) a municipality that provides electric service to more than 1,000 retail customers; and

(3) a municipality with more than 1,000,000,000 cubic feet in annual throughput sales to natural gas retail customers.

Subd. 2. **Consumer-owned utility; energy-savings goal.** (a) Each individual consumer-owned electric utility subject to this section has an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales and each individual consumer-owned natural gas utility subject to this section has an annual energy-savings goal equivalent to one percent of gross annual retail energy sales, to be met with a minimum of energy savings from energy conservation improvements equivalent to at least 0.90 percent of the consumer-owned utility's gross annual retail energy sales. The balance of energy savings toward the annual energy-savings goal may be achieved only by the following consumer-owned utility activities:

(1) energy savings from additional energy conservation improvements;

(2) electric utility infrastructure projects, as defined in section 216B.1636, subdivision 1, that result in increased efficiency greater than would have occurred through normal maintenance activity;

(3) net energy savings from efficient fuel-switching improvements that meet the criteria under subdivision 8, which may contribute up to 0.60 percent of the goal; or

(4) subject to department approval, demand-side natural gas or electric energy displaced by use of waste heat recovered and used as thermal energy, including the recovered thermal energy from a cogeneration or combined heat and power facility.

(b) The energy-savings goals specified in this section must be calculated based on weather-normalized sales averaged over the most recent three years. A consumer-owned utility may elect to carry forward energy savings in excess of 1.5 percent for a year to the next three years, except that energy savings from electric utility infrastructure projects may be carried forward for five years. A particular energy savings can only be used to meet one year's goal.

(c) A consumer-owned utility subject to this section is not required to make energy conservation improvements that are not cost-effective, even if the improvement is necessary to attain the energy-savings goal. A consumer-owned utility subject to this section must make reasonable efforts to implement energy conservation improvements that exceed the minimum level established under this subdivision if cost-effective opportunities and funding are available, considering other potential investments the consumer-owned utility intends to make to benefit customers during the term of the plan filed under subdivision 3.

Subd. 3. **Consumer-owned utility; energy conservation and optimization plans.** (a) By June 1, 2022, and at least every three years thereafter, each consumer-owned utility must file with the commissioner an energy conservation and optimization plan that describes the programs for energy conservation, efficient fuel-switching, load management, and other measures the consumer-owned utility intends to offer to achieve the utility's energy savings goal.

(b) A plan's term may extend up to three years. A multiyear plan must identify the total energy savings and energy savings resulting from energy conservation improvements that are projected to be achieved in each year of the plan. A multiyear plan that does not, in each year of the plan, meet both the minimum energy savings goal from energy conservation improvements and the total energy savings goal of 1.5 percent, or lower goals adjusted by the commissioner under paragraph (k), must:

(1) state why each goal is projected to be unmet; and

(2) demonstrate how the consumer-owned utility proposes to meet both goals on an average basis over the duration of the plan.

(c) A plan filed under this subdivision must provide:

(1) for existing programs, an analysis of the cost-effectiveness of the consumer-owned utility's programs offered under the plan, using a list of baseline energy- and capacity-savings assumptions developed in consultation with the department; and

(2) for new programs, a preliminary analysis upon which the program will proceed, in parallel with further development of assumptions and standards.

(d) The commissioner must evaluate a plan filed under this subdivision based on the plan's likelihood to achieve the energy-savings goals established in subdivision 2. The commissioner may make recommendations to a consumer-owned utility regarding ways to increase the effectiveness of the consumer-owned utility's energy conservation activities and programs under this subdivision. The commissioner may recommend that a consumer-owned utility implement a cost-effective energy conservation or efficient fuel-switching program suggested by an outside source such as a political subdivision, nonprofit corporation, or community organization.

(e) Beginning June 1, 2023, and every June 1 thereafter, each consumer-owned utility must file: (1) an annual update identifying the status of the plan filed under this subdivision, including: (i) total expenditures and investments made to date under the plan; and (ii) any intended changes to the plan; and (2) a summary of the annual energy-savings achievements under a plan. An annual filing made in the last year of a plan must contain a new plan that complies with this section.

(f) When evaluating the cost-effectiveness of a consumer-owned utility's energy conservation programs, the consumer-owned utility and the commissioner must consider the costs and benefits to ratepayers, the utility, participants, and society. The commissioner must also consider the rate at which the consumer-owned utility is increasing energy savings and expenditures on energy conservation, and lifetime energy savings and cumulative energy savings.

(g) A consumer-owned utility may annually spend and invest up to ten percent of the total amount spent and invested on energy conservation, efficient fuel-switching, or load management improvements on research and development projects that meet the applicable definition of energy conservation, efficient fuel-switching, or load management improvement.

(h) A generation and transmission cooperative electric association or municipal power agency that provides energy services to consumer-owned utilities may file a plan under this subdivision on behalf of the consumer-owned utilities to which the association or agency provides energy services and may make investments, offer conservation programs, and otherwise fulfill the energy-savings goals and reporting requirements of this subdivision for those consumer-owned utilities on an aggregate basis.

(i) A consumer-owned utility is prohibited from spending for or investing in energy conservation improvements that directly benefit a large energy facility or a large electric customer facility the commissioner has exempted under section 216B.241, subdivision 1a.

(j) The energy conservation and optimization plan of a consumer-owned utility may include activities to improve energy efficiency in the public schools served by the utility. These activities may include programs to:

(1) increase the efficiency of the school's lighting and heating and cooling systems;

(2) recommission buildings;

(3) train building operators; and

(4) provide opportunities to educate students, teachers, and staff regarding energy efficiency measures implemented at the school.

(k) A consumer-owned utility may request that the commissioner adjust the consumer-owned utility's minimum goal for energy savings from energy conservation improvements under subdivision 2, paragraph (a), for the duration of the plan filed under this subdivision. The request must be made by January 1 of the year when the consumer-owned utility must file a plan under this subdivision. The request must be based on:

(1) historical energy conservation improvement program achievements;

(2) customer class makeup;

(3) projected load growth;

(4) an energy conservation potential study that estimates the amount of cost-effective energy conservation potential that exists in the consumer-owned utility's service territory;

(5) the cost-effectiveness and quality of the energy conservation programs offered by the consumer-owned utility; and

(6) other factors the commissioner and consumer-owned utility determine warrant an adjustment.

The commissioner must adjust the energy savings goal to a level the commissioner determines is supported by the record, but must not approve a minimum energy savings goal from energy conservation improvements that is less than an average of 0.95 percent per year over the consecutive years of the plan's duration, including the year the minimum energy savings goal is adjusted.

(l) A consumer-owned utility filing a conservation and optimization plan that includes an efficient fuel-switching program must, as part of the filing, demonstrate that the requirements of subdivision 8 are met.

Subd. 4. **Consumer-owned utility; energy savings investment.** (a) Except as otherwise provided, a consumer-owned utility that the commissioner determines falls short of the minimum energy savings goal from energy conservation improvements established in subdivision 2, paragraph (a), for three consecutive years during which the utility has annually spent on energy conservation improvements less than 1.5 percent of the utility's gross operating revenues for an electric utility or less than 0.5 percent of the utility's gross operating revenues for a natural gas utility, must spend no less than the following amounts for energy conservation improvements:

(1) for a municipality, 0.5 percent of the municipality's gross operating revenues from the sale of gas and 1.5 percent of the municipality's gross operating revenues from the sale of electricity, excluding gross operating revenues from electric and gas service provided in Minnesota to large electric customer facilities; and

(2) for a cooperative electric association, 1.5 percent of the association's gross operating revenues from service provided in the state, excluding gross operating revenues from service provided in Minnesota to large electric customers facilities indirectly through a distribution cooperative electric association.

(b) The commissioner may not impose the spending requirement under this subdivision if the commissioner has determined that the utility has followed the commissioner's recommendations, if any, provided under subdivision 3, paragraph (d).

(c) Upon request of a consumer-owned utility, the commissioner may reduce the amount or duration of the spending requirement imposed under this subdivision, or both, if the commissioner determines that the consumer-owned utility's failure to maintain the minimum energy savings goal is the result of:

(1) a natural disaster or other emergency that is declared by the executive branch through an emergency executive order that affects the consumer-owned utility's service area;

(2) a unique load distribution experienced by the consumer-owned utility; or

(3) other factors that the commissioner determines justifies a reduction.

(d) Unless the commissioner reduces the duration of the spending requirement under paragraph (c), the spending requirement under this subdivision remains in effect until the consumer-owned utility has met the minimum energy savings goal for three consecutive years.

Subd. 5. **Energy conservation programs for low-income households.** (a) A consumer-owned utility subject to this section must provide energy conservation programs to low-income households. The commissioner must evaluate a consumer-owned utility's plans under this section by considering the consumer-owned utility's historic spending on energy conservation programs directed to low-income households, the rate of customer participation in and the energy savings resulting from those programs, and the number of low-income persons residing in the consumer-owned utility's service territory. A municipal utility that furnishes natural gas service must spend at least 0.2 percent of the municipal utility's most recent three-year average gross operating revenue from residential customers in Minnesota on energy conservation programs for low-income households. A consumer-owned utility that furnishes electric service must spend at least 0.2 percent of the consumer-owned utility's gross operating revenue from residential customers in Minnesota on energy conservation programs for low-income households. The requirement under this paragraph applies to each generation and transmission cooperative association's aggregate gross operating revenue from the sale of electricity to residential customers in Minnesota by all of the association's member distribution cooperatives.

(b) To meet all or part of the spending requirements of paragraph (a), a consumer-owned utility may contribute money to the energy and conservation account established in section 216B.241, subdivision 2a. An energy conservation optimization plan must state the amount of contributions the consumer-owned utility plans to make to the energy and conservation account. Contributions to the account must be used for energy conservation programs serving low-income households, including renters, located in the service area of the consumer-owned utility making the contribution. Contributions must be remitted to the commissioner by February 1 each year.

(c) The commissioner must establish energy conservation programs for low-income households funded through contributions to the energy and conservation account under paragraph (b). When establishing energy conservation programs for low-income households, the commissioner must consult political subdivisions, utilities, and nonprofit and community organizations, including organizations providing energy and weatherization assistance to low-income households. The commissioner must record and report expenditures and energy savings achieved as a result of energy conservation programs for low-income households funded through the energy and conservation account in the report required under section 216B.241, subdivision 1c, paragraph (f). The commissioner may contract with a political subdivision, nonprofit or community organization, public utility, municipality, or consumer-owned utility to implement low-income programs funded through the energy and conservation account.

(d) A consumer-owned utility may petition the commissioner to modify the required spending under this subdivision if the consumer-owned utility and the commissioner were unable to expend the amount required for three consecutive years.

(e) The commissioner must develop and establish guidelines for determining the eligibility of multifamily buildings to participate in energy conservation programs provided to low-income households. Notwithstanding the definition of low-income household in section 216B.2402, a consumer-owned utility or association may apply the most recent guidelines published by the department for purposes of determining the eligibility of multifamily buildings to participate in low-income programs. The commissioner must convene a stakeholder group to review and update these guidelines by August 1, 2021, and at least once every five years thereafter. The stakeholder group must include but is not limited to representatives of public utilities; municipal electric or gas utilities; electric cooperative associations; multifamily housing owners and developers; and low-income advocates.

(f) Up to 15 percent of a consumer-owned utility's spending on low-income energy conservation programs may be spent on preweatherization measures. A consumer-owned utility is prohibited from claiming energy savings from preweatherization measures toward the consumer-owned utility's energy savings goal.

(g) The commissioner must, by order, establish a list of preweatherization measures eligible for inclusion in low-income energy conservation programs no later than March 15, 2022.

(h) A Healthy AIR (Asbestos Insulation Removal) account is established as a separate account in the special revenue fund in the state treasury. A consumer-owned utility may elect to contribute money to the Healthy AIR account to provide preweatherization measures for households eligible for weatherization assistance from the state weatherization assistance program in section 216C.264. Remediation activities must be executed in conjunction with federal weatherization assistance program services. Money contributed to the account by a consumer-owned utility counts toward: (1) the minimum low-income spending requirement under paragraph (a); and (2) the cap on preweatherization measures under paragraph (f). Money in the account is annually appropriated to the commissioner of commerce to pay for Healthy AIR-related activities.

(i) This paragraph applies to a consumer-owned utility that supplies electricity to a low-income household whose primary heating fuel is supplied by an entity other than a public utility. Any spending on space and water heating energy conservation improvements and efficient fuel-switching by the consumer-owned utility on behalf of the low-income household may be applied to the consumer owned utility's spending requirement under paragraph (a). To the maximum extent possible, a consumer-owned utility providing services under this paragraph must offer the services in conjunction with weatherization services provided under section 216C.264.

Subd. 6. **Recovery of expenses.** The commission must allow a cooperative electric association subject to rate regulation under section 216B.026 to recover expenses resulting from: (1) a plan under this section; and (2) assessments and contributions to the energy and conservation account under section 216B.241, subdivision 2a.

Subd. 7. **Ownership of preweatherization measure or energy conservation improvement.** (a) A preweatherization measure or energy conservation improvement installed in a building under this section, excluding a system owned by a consumer-owned utility that is designed to turn off, limit, or vary the delivery of energy, is the exclusive property of the building owner, except to the extent that the improvement is subject to a security interest in favor of the consumer-owned utility in case of a loan to the building owner for the improvement.

(b) A consumer-owned utility has no liability for loss, damage, or injury directly or indirectly caused by a preweatherization measure or energy conservation improvement, unless a consumer-owned utility is determined to have been negligent in purchasing, installing, or modifying a preweatherization measure or energy conservation improvement.

Subd. 8. **Criteria for efficient fuel-switching improvements.** (a) A fuel-switching improvement is deemed efficient if, applying the technical criteria established under section 216B.241, subdivision 1d, paragraph (e), the improvement, relative to the fuel being displaced:

(1) results in a net reduction in the amount of source energy consumed for a particular use, measured on a fuel-neutral basis, using (i) the consumer-owned utility's or the utility's electricity supplier's annual system average efficiency, or (ii) if the utility elects, a seasonal, monthly, or more granular level of analysis for the electric utility system over the measure's life;

(2) results in a net reduction of statewide greenhouse gas emissions, as defined in section 216H.01, subdivision 2, over the lifetime of the improvement. For an efficient fuel-switching improvement installed by an electric consumer-owned utility, the reduction in emissions must be measured using (i) the consumer-owned utility's or the utility's electricity supplier's annual average emissions factor, or (ii) if the utility elects, a seasonal, monthly, or more granular level of analysis for the electric utility system over the measure's life; and

(3) is cost-effective, considering the costs and benefits from the perspective of the consumer-owned utility, participants, and society.

(b) For purposes of this subdivision, "source energy" means the total amount of primary energy required to deliver energy services, adjusted for losses in generation, transmission, and distribution, and expressed on a fuel-neutral basis.

Subd. 9. **Manner of filing and service.** (a) A consumer-owned utility must submit the filings required under this section to the department using the department's electronic filing system. The commissioner may approve an exemption from this requirement if an affected consumer-owned utility is unable to submit filings via the department's electronic filing system. All other interested parties must submit filings to the department via the department's electronic filing system whenever practicable but may also file by personal delivery or by mail.

(b) The submission of a document to the department's electronic filing system constitutes service on the department. If a department rule requires service of a notice, order, or other document by the department, a consumer-owned utility, or an interested party upon persons on a service list maintained by the department, service may be made by personal delivery, mail, or electronic service. Electronic service may be made only to persons on the service list that have previously agreed in writing to accept electronic service at an email address provided to the department for electronic service purposes.

Subd. 10. **Assessment.** The commission or department may assess consumer-owned utilities subject to this section to carry out the purposes of section 216B.241, subdivisions 1d, 1e, and 1f. An assessment under this subdivision must be proportionate to a consumer-owned utility's gross operating revenue from sales of gas or electric service in Minnesota during the previous calendar year, as applicable. Assessments under this subdivision are not subject to the cap on assessments under section 216B.62 or any other law.

History: *2021 c 29 s 4; 2024 c 126 art 6 s 11-14; 2024 c 127 art 42 s 11-14*

216B.241 PUBLIC UTILITIES; ENERGY CONSERVATION AND OPTIMIZATION.

Subdivision 1. MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 1a. **Large customer facility.** (a) The owner of a large customer facility may petition the commissioner to exempt both electric and gas utilities serving the large customer facility from contributing to investments and expenditures made under an energy and conservation optimization plan filed under subdivision 2 or section 216B.2403, subdivision 3, with respect to retail revenues attributable to the large customer facility. The filing must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate, and implement energy conservation and efficiency improvements. A filing submitted on or before October 1 of any year must be approved within 90 days and become effective January 1 of the year following the filing, unless the commissioner finds that the owner of the large customer facility has failed to take reasonable measures to identify, evaluate, and implement energy conservation and efficiency improvements. If a facility qualifies as a large customer facility solely due to its peak electrical demand or annual natural gas usage, the exemption may be limited to the qualifying utility if the commissioner finds that the owner of the large customer facility has failed to take reasonable measures to identify, evaluate, and implement energy conservation and efficiency improvements with respect to the nonqualifying utility. Once an exemption is approved, the commissioner may request the owner of a large customer facility to submit, not more often than once every five years, a report demonstrating the large customer facility's ongoing commitment to energy conservation and efficiency improvement after the exemption filing. The commissioner may request such reports for up to ten years after the effective date of the exemption, unless the majority ownership of the large customer facility changes, in which case the commissioner may request additional reports for up to ten years after the change in ownership occurs. The commissioner may, within 180 days of receiving a report submitted under this paragraph, rescind any exemption granted under this paragraph upon a determination that the large customer facility is not continuing to make reasonable efforts to identify, evaluate, and implement energy conservation improvements. A large customer facility that is, under an order from the commissioner, exempt from the investment and expenditure requirements of paragraph (a) as of December 31, 2010, is not required to submit a report to retain its exempt status, except as otherwise provided in this paragraph with respect to ownership changes. No exempt large customer facility may participate in a utility conservation improvement program unless the owner of the facility submits a filing with the commissioner to withdraw its exemption. A qualified large-scale data center that pays the required fee under section 216B.72 is exempt from the requirement to contribute to investments and expenditures made under an energy conservation optimization plan for electric service filed under subdivision 2, or section 216B.2403, subdivision 3, and is not required to comply with the provisions of this paragraph.

(b) A commercial gas customer that is not a large customer facility and that purchases or acquires natural gas from a public utility having fewer than 600,000 natural gas customers in Minnesota may petition the commissioner to exempt gas utilities serving the commercial gas customer from contributing to investments and expenditures made under an energy and conservation optimization plan filed under subdivision 2 or section 216B.2403, subdivision 3, with respect to retail revenues attributable to the commercial gas customer. The petition must be supported by evidence demonstrating that the commercial gas customer has acquired or can reasonably acquire the capability to bypass use of the utility's gas distribution system by obtaining natural gas directly from a supplier not regulated by the commission. The commissioner shall grant the exemption if the commissioner finds that the petitioner has made the demonstration required by this paragraph.

(c) A public utility, consumer-owned utility, or owner of a large customer facility may appeal a decision of the commissioner under paragraph (a) or (b) to the commission under subdivision 2. In reviewing a decision of the commissioner under paragraph (a) or (b), the commission shall rescind the decision if it finds the decision is not in the public interest.

(d) Notwithstanding paragraph (a), a large customer facility or commercial gas customer that is exempt from the investment and expenditure requirements of this section pursuant to an order from the commissioner as of December 31, 2020, is not required to submit additional documentation to maintain the exemption and must not be assessed any costs related to any energy conservation and optimization plan filed under this section or section 216B.2403, including but not limited to costs, incentives, or rates of return associated with investments in programs for efficient fuel-switching improvements.

(e) A utility is prohibited from spending for or investing in energy conservation improvements that directly benefit a large energy facility or a large electric customer facility the commissioner has issued an exemption to or that is otherwise exempted under this section.

Subd. 1b. MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 1c. **Public utility; energy-saving goals.** (a) The commissioner shall establish energy-saving goals for energy conservation improvements and shall evaluate an energy conservation improvement program on how well it meets the goals set.

(b) A public utility providing electric service has an annual energy-savings goal equivalent to 1.75 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (c). A public utility providing natural gas service has an annual energy-savings goal equivalent to one percent of gross annual retail energy sales, which cannot be lowered by the commissioner. The savings goals must be calculated based on the most recent three-year weather-normalized average. A public utility providing electric service may elect to carry forward energy savings in excess of 1.75 percent for a year to the succeeding three calendar years, except that savings from electric utility infrastructure projects allowed under paragraph (d) may be carried forward for five years. A public utility providing natural gas service may elect to carry forward energy savings in excess of one percent for a year to the succeeding three calendar years. A particular energy savings can only be used to meet one year's goal.

(c) In its energy conservation and optimization plan filing, a public utility may request the commissioner to adjust its annual energy-savings percentage goal based on its historical conservation investment experience, customer class makeup, load growth, a conservation potential study, or other factors the commissioner determines warrants an adjustment.

(d) The commissioner may not approve a plan of a public utility that provides for an annual energy-savings goal of less than one percent of gross annual retail energy sales from energy conservation improvements.

The balance of the 1.75 percent annual energy savings goal may be achieved through energy savings from:

(1) additional energy conservation improvements;

(2) electric utility infrastructure projects approved by the commission under section 216B.1636 that result in increased efficiency greater than would have occurred through normal maintenance activity; or

(3) subject to department approval, demand-side natural gas or electric energy displaced by use of waste heat recovered and used as thermal energy, including the recovered thermal energy from a cogeneration or combined heat and power facility.

(e) A public utility is not required to make energy conservation investments to attain the energy-savings goals of this subdivision that are not cost-effective even if the investment is necessary to attain the energy-savings goals. For the purpose of this paragraph, in determining cost-effectiveness, the commissioner shall consider: (1) the costs and benefits to ratepayers, the utility, participants, and society; (2) the rate at which a public utility is increasing both its energy savings and its expenditures on energy conservation; and (3) the public utility's lifetime energy savings and cumulative energy savings.

(f) On an annual basis, the commissioner shall produce and make publicly available a report on the annual energy and capacity savings and estimated carbon dioxide reductions achieved by the programs under this section and section 216B.2403 for the two most recent years for which data is available. The report must also include information regarding any annual energy sales or generation capacity increases resulting from efficient fuel-switching improvements. The commissioner shall report on program performance both in the aggregate and for each entity filing an energy conservation improvement plan for approval or review by the commissioner, and must estimate progress made toward the statewide energy-savings goal under section 216B.2401.

Subd. 1d. **Technical assistance.** (a) The commissioner shall evaluate energy conservation improvement programs filed under this section and section 216B.2403 on the basis of cost-effectiveness and the reliability of the technologies employed. The commissioner shall, by order, establish, maintain, and update energy-savings assumptions that must be used by utilities when filing energy conservation improvement programs. The department must track a public utility's or consumer-owned utility's lifetime energy savings and cumulative lifetime energy savings reported in plans submitted under this section and section 216B.2403.

(b) The commissioner shall establish an inventory of the most effective energy conservation programs, techniques, and technologies, and encourage all Minnesota utilities to implement them, where appropriate. The commissioner shall describe these programs in sufficient detail to provide a utility reasonable guidance concerning implementation. The commissioner shall prioritize the opportunities in order of potential energy savings and in order of cost-effectiveness.

(c) The commissioner may contract with a third party to carry out any of the commissioner's duties under this subdivision, and to obtain technical assistance to evaluate the effectiveness of any conservation improvement program.

(d) The commissioner may assess up to $850,000 annually for the purposes of this subdivision. The assessments must be deposited in the state treasury and credited to the energy and conservation account created under subdivision 2a. An assessment made under this subdivision is not subject to the cap on assessments provided by section 216B.62, or any other law.

(e) The commissioner must work with stakeholders to develop technical guidelines that public utilities and consumer-owned utilities must use to:

(1) determine whether deployment of a fuel-switching improvement meets the criteria established in subdivision 11, paragraph (d); subdivision 12, paragraph (a); or section 216B.2403, subdivision 8, as applicable; and

(2) calculate the amount of energy saved due to the deployment of a fuel-switching improvement.

The guidelines must be issued by the commissioner by order no later than March 15, 2022, and must be updated as the commissioner determines is necessary.

Subd. 1e. **Applied research and development grants.** (a) The commissioner may, by order, approve and make grants for applied research and development projects of general applicability that identify new technologies or strategies to maximize energy savings, improve the effectiveness of energy conservation programs, or document the carbon dioxide reductions from energy conservation programs. When approving projects, the commissioner shall consider proposals and comments from utilities and other interested parties. The commissioner may assess up to $3,600,000 annually for the purposes of this subdivision. The assessments must be deposited in the state treasury and credited to the energy and conservation account created under subdivision 2a. An assessment made under this subdivision is not subject to the cap on assessments provided by section 216B.62, or any other law.

(b) The commissioner, as part of the assessment authorized under paragraph (a), shall annually assess and grant up to $500,000 for the purpose of subdivision 9.

(c) The commissioner, as part of the assessment authorized under paragraph (a), each state fiscal year shall assess $500,000 for a grant to the partnership created by section 216C.385, subdivision 2. The grant must be used to exercise the powers and perform the duties specified in section 216C.385, subdivision 3.

(d) By February 15 annually, the commissioner shall report to the chairs and ranking minority members of the committees of the legislature with primary jurisdiction over energy policy and energy finance on the assessments made under this subdivision for the previous calendar year and the use of the assessment. The report must clearly describe the activities supported by the assessment and the parties that engaged in those activities.

Subd. 1f. **Facilities energy efficiency.** (a) The commissioner of administration and the commissioner of commerce shall maintain and, as needed, revise the sustainable building design guidelines developed under section 16B.325.

(b) The commissioner of administration and the commissioner of commerce shall maintain and update the benchmarking tool developed under Laws 2001, chapter 212, article 1, section 3, so that all public buildings can use the benchmarking tool to maintain energy use information for the purposes of establishing energy efficiency benchmarks, tracking building performance, and measuring the results of energy efficiency and conservation improvements.

(c) The commissioner shall require that utilities include in their conservation improvement plans programs that facilitate professional engineering verification to qualify a building as Energy Star-labeled, Leadership in Energy and Environmental Design (LEED) certified, or Green Globes-certified.

(d) The commissioner may assess up to $500,000 annually for the purposes of this subdivision. The assessments must be deposited in the state treasury and credited to the energy and conservation account created under subdivision 2a. An assessment made under this subdivision is not subject to the cap on assessments provided by section 216B.62, or any other law.

Subd. 1g. **Manner of filing and service.** (a) A public utility shall submit filings to the department via the department's electronic filing system. The commissioner may approve an exemption from this requirement in the event a public utility is unable to submit filings via the department's electronic filing system. All other interested parties shall submit filings to the department via the department's electronic filing system whenever practicable but may also file by personal delivery or by mail.

(b) Submission of a document to the department's electronic filing system constitutes service on the department. Where department rule requires service of a notice, order, or other document by the department, public utility, or interested party upon persons on a service list maintained by the department, service may be made by personal delivery, mail, or electronic service, except that electronic service may only be made upon persons on the service list who have previously agreed in writing to accept electronic service at an electronic address provided to the department for electronic service purposes.

Subd. 2. **Public utility; energy conservation and optimization plans.** (a) The commissioner may require a public utility to make investments and expenditures in energy conservation improvements, explicitly setting forth the interest rates, prices, and terms under which the improvements must be offered to the customers.

(b) A public utility shall file an energy conservation and optimization plan by June 1, on a schedule determined by order of the commissioner, but at least every three years. As provided in subdivisions 11 to 13, plans may include programs for efficient fuel-switching improvements and load management. An individual utility program may combine elements of energy conservation, load management, or efficient fuel-switching. The plan must estimate the lifetime energy savings and cumulative lifetime energy savings projected to be achieved under the plan. A plan filed by a public utility by June 1 must be approved or approved as modified by the commissioner by December 1 of that same year.

(c) The commissioner shall evaluate the plan on the basis of cost-effectiveness and the reliability of technologies employed. The commissioner's order must provide to the extent practicable for a free choice, by consumers participating in an energy conservation program, of the device, method, material, or project constituting the energy conservation improvement and for a free choice of the seller, installer, or contractor of the energy conservation improvement, provided that the device, method, material, or project seller, installer, or contractor is duly licensed, certified, approved, or qualified, including under the residential conservation services program, where applicable.

(d) The commissioner may require a utility subject to subdivision 1c to make an energy conservation improvement investment or expenditure whenever the commissioner finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of new supply of energy.

(e) Each public utility subject to this subdivision may spend and invest annually up to ten percent of the total amount that the public utility spends and invests on energy conservation, efficient fuel-switching, or load management improvements under this section on research and development projects that meet the applicable definition of energy conservation, efficient fuel-switching, or load management improvement.

(f) The commissioner shall consider and may require a public utility to undertake an energy conservation or efficient fuel-switching program, subject to the requirements of subdivisions 11 and 12, that is suggested by an outside source, including a political subdivision, a nonprofit corporation, or community organization. When approving a proposal under this paragraph, the commissioner must consider the qualifications and experience of the entity proposing the program and any other criteria the commissioner deems relevant.

(g) A public utility, a political subdivision, or a nonprofit or community organization that has suggested an energy conservation program, the attorney general acting on behalf of consumers and small business interests, or a public utility customer that has suggested an energy conservation program and is not represented by the attorney general under section 8.33 may petition the commission to modify or revoke a department decision under this section, and the commission may do so if it determines that the energy conservation program is not cost-effective, does not adequately address the residential conservation improvement needs of low-income persons, has a long-range negative effect on one or more classes of customers, or is otherwise not in the public interest. The commission shall reject a petition that, on its face, fails to make a reasonable argument that an energy conservation program is not in the public interest.

(h) The commissioner may order a public utility to include, with the filing of the public utility's annual status report, the results of an independent audit of the public utility's conservation improvement programs and expenditures performed by the department or an auditor with experience in the provision of energy conservation and energy efficiency services approved by the commissioner and chosen by the public utility. The audit must specify the energy savings or increased efficiency in the use of energy within the service territory of the public utility that is the result of the public utility's spending and investments. The audit must evaluate the cost-effectiveness of the public utility's conservation programs.

(i) The energy conservation and optimization plan of each public utility subject to this section must include activities to improve energy efficiency in public schools served by the utility. As applicable to each public utility, at a minimum the activities must include programs to increase the efficiency of the school's lighting and heating and cooling systems, and to provide for building recommissioning, building operator training, and opportunities to educate students, teachers, and staff regarding energy efficiency measures implemented at the school.

(j) The commissioner may require investments or spending greater than the amounts proposed in a plan filed under this subdivision or section 216C.17 for a public utility whose most recent advanced forecast required under section 216B.2422 projects a peak demand deficit of 100 megawatts or more within five years under midrange forecast assumptions.

(k) A public utility filing a conservation and optimization plan that includes an efficient fuel-switching program must, as part of the filing, demonstrate that the requirements of subdivisions 11 or 12 are met, as applicable.

Subd. 2a. **Energy and conservation account.** (a) The energy and conservation account is established in the special revenue fund in the state treasury.

(b) The commissioner must deposit money assessed or contributed under subdivisions 1d, 1e, 1f, and 7 in the state treasury and credit it to the energy and conservation account in the special revenue fund. Money in the account assessed or contributed under subdivisions 1d, 1e, 1f, and 7 is appropriated to the commissioner for the purposes of subdivisions 1d, 1e, 1f, and 7.

(c) The commissioner must deposit money transferred from the fee on qualified large-scale data centers established in section 216B.72 in the state treasury and credit it to the account. Money transferred from the fee on qualified large-scale data centers is appropriated to the commissioner to conduct energy conservation, weatherization, and associated activities allowed under sections 216B.2403 and 216B.241, and the rules applicable to those sections. The commissioner may spend money appropriated under this paragraph anywhere in the state, but only:

(1) on low-income programs; and

(2) as the result of a request for proposals process administered by the department.

(d) Interest on money in the account accrues to the account.

Subd. 2b. **Recovery of expenses.** (a) The commission shall allow a public utility to recover expenses resulting from an energy conservation and optimization plan approved by the department under this section and contributions and assessments to the energy and conservation account, unless the recovery would be inconsistent with a financial incentive proposal approved by the commission.

(b) A public utility may file annually, or the Public Utilities Commission may require the public utility to file, and the commission may approve, rate schedules containing provisions for the automatic adjustment of charges for utility service in direct relation to changes in the expenses of the public utility for real and personal property taxes, fees, and permits, the amounts of which the public utility cannot control. A public utility is eligible to file for adjustment for real and personal property taxes, fees, and permits under this subdivision only if, in the year previous to the year in which it files for adjustment, it has spent or invested at least 1.75 percent of its gross revenues from provision of electric service, excluding gross operating revenues from electric service provided in the state to large electric customer facilities for which the commissioner has issued an exemption under subdivision 1a, paragraph (b), and 0.6 percent of its gross revenues from provision of gas service, excluding gross operating revenues from gas services provided in the state to large electric customer facilities for which the commissioner has issued an exemption under subdivision 1a, paragraph (b), for that year for energy conservation improvements under this section.

Subd. 2c. MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 3. **Ownership of preweatherization measure or energy conservation improvement.** (a) A preweatherization measure or energy conservation improvement made to or installed in a building in accordance with this section, except systems owned by a public utility and designed to turn off, limit, or vary the delivery of energy, are the exclusive property of the owner of the building except to the extent that the improvement is subjected to a security interest in favor of the public utility in case of a loan to the building owner.

(b) A public utility has no liability for loss, damage or injury caused directly or indirectly by a preweatherization measure or energy conservation improvement except for negligence by the utility in purchasing, installing, or modifying a preweatherization measure or energy conservation improvement.

Subd. 4. MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 5. **Efficient lighting program.** (a) Each public utility and consumer-owned utility that provides electric service to retail customers and is subject to subdivision 1c or section 216B.2403 shall include as part of its conservation improvement activities a program to strongly encourage the use of LEDs. The program must include at least a public information campaign to encourage use of LEDs and proper management of spent lamps and LEDs by all customer classifications.

(b) A public utility that provides electric service at retail to 200,000 or more customers shall establish, either directly or through contracts with other persons, including lamp manufacturers, distributors, wholesalers, and retailers and local government units, a system to collect for delivery to a reclamation or recycling facility spent fluorescent and high-intensity discharge lamps from households and from small businesses as defined in section 645.445 that generate an average of fewer than ten spent lamps per year.

(c) A collection system must include establishing reasonably convenient locations for collecting spent lamps from households and financial incentives sufficient to encourage spent lamp generators to take the lamps to the collection locations. Financial incentives may include coupons for purchase of new LEDs, a cash back system, or any other financial incentive or group of incentives designed to collect the maximum number of spent lamps from households and small businesses that is reasonably feasible.

(d) A public utility that provides electric service at retail to fewer than 200,000 customers or a consumer-owned utility that provides electric service at retail to customers may establish a collection system under paragraphs (b) and (c) as part of conservation improvement activities required under this section.

(e) The commissioner of the Pollution Control Agency may not, unless clearly required by federal law, require a public utility or consumer-owned utility that establishes a household fluorescent and high-intensity discharge lamp collection system under this section to manage the lamps as hazardous waste as long as the lamps are managed to avoid breakage and are delivered to a recycling or reclamation facility that removes mercury and other toxic materials contained in the lamps prior to placement of the lamps in solid waste.

(f) If a public utility or consumer-owned utility contracts with a local government unit to provide a collection system under this subdivision, the contract must provide for payment to the local government unit of all the unit's incremental costs of collecting and managing spent lamps.

(g) All the costs incurred by a public utility or consumer-owned utility to promote the use of LEDs and to collect LEDs under this subdivision are conservation improvement spending under this section.

(h) For the purposes of this subdivision, "LED" means a light-emitting diode bulb or lighting product.

Subd. 5a. **Qualifying solar energy project.** (a) A utility or association may include in its conservation plan programs for the installation of qualifying solar energy projects as defined by section 216B.2411 to the extent of the spending allowed for generation projects by section 216B.2411. The cost-effectiveness of a qualifying solar energy project may be determined by a different standard than for other energy conservation improvements under this section if the commissioner determines it is in the public interest to do so to encourage solar energy projects. Energy savings from qualifying solar energy projects may not be counted toward the minimum energy-savings goal of at least one percent for energy conservation improvements required under subdivision 1c, but may, if the conservation plan is approved:

(1) be counted toward energy savings above that minimum percentage; and

(2) be eligible for a performance incentive under subdivision 2c or section 216B.16, subdivision 6c, that is distinct from the incentive for energy conservation and is based on the competitiveness and cost-effectiveness of solar projects in relation to other potential solar projects available to the utility.

(b) Qualifying solar energy projects may not be considered when establishing demand-side management targets under section 216B.2422, 216B.243, or any other section of this chapter.

Subd. 5b. **Biomethane purchases.** (a) A natural gas utility may include in its conservation plan purchases of biomethane, and may use up to five percent of the total amount to be spent on energy conservation improvements under this section for that purpose. The cost-effectiveness of biomethane purchases may be determined by a different standard than for other energy conservation improvements under this section if the commissioner determines that doing so is in the public interest in order to encourage biomethane purchases. Energy savings from purchasing biomethane may not be counted toward the minimum energy-savings goal of at least one percent for energy conservation improvements required under subdivision 1c, but may, if the conservation plan is approved:

(1) be counted toward energy savings above that minimum percentage; and

(2) be considered when establishing performance incentives under subdivision 2c.

(b) For the purposes of this subdivision, "biomethane" means biogas produced through anaerobic digestion of biomass, gasification of biomass, or other effective conversion processes, that is cleaned and purified into biomethane that meets natural gas utility quality specifications for use in a natural gas utility distribution system.

Subd. 5c. **Large solar electric generating plant.** (a) For the purpose of this subdivision:

(1) "project" means a solar electric generation project consisting of arrays of solar photovoltaic cells with a capacity of up to two megawatts located on the site of a closed landfill in Olmsted County owned by the Minnesota Pollution Control Agency; and

(2) "cooperative electric association" means a generation and transmission cooperative electric association that has a member distribution cooperative association to which it provides wholesale electric service in whose service territory a project is located.

(b) A cooperative electric association may elect to count all of its purchases of electric energy from a project toward only one of the following:

(1) its energy-savings goal under subdivision 1c; or

(2) its energy objective or standard under section 216B.1691.

(c) A cooperative electric association may include in its conservation plan purchases of electric energy from a project. The cost-effectiveness of project purchases may be determined by a different standard than for other energy conservation improvements under this section if the commissioner determines that doing so is in the public interest in order to encourage solar energy. The kilowatt hours of solar energy purchased by a cooperative electric association from a project may count for up to 33 percent of its one percent savings goal under subdivision 1c or up to 22 percent of its 1.5 percent savings goal under that subdivision. Expenditures made by a cooperative association for the purchase of energy from a project may not be used to meet the revenue expenditure requirements of subdivisions 1a and 1b.

Subd. 5d. **On-bill repayment programs.** (a) For the purposes of this subdivision:

(1) "utility" means a public utility, municipal utility, or cooperative electric association subject to subdivision 1c that provides electric or natural gas service to retail customers; and

(2) "on-bill repayment program" means a program in which a utility collects on a customer's bill repayment of a loan to the customer by an eligible lender to finance the customer's investment in eligible energy conservation or renewable energy projects, and remits loan repayments to the lender.

(b) A utility may include as part of its conservation improvement plan an on-bill repayment program to enable a customer to finance eligible projects with installment loans originated by an eligible lender. An eligible project is one that is either an energy conservation improvement, or a project installed on the customer's site that uses an eligible renewable energy source as that term is defined in section 216B.2411, subdivision 2, paragraph (b), but does not include mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste. An eligible renewable energy source also includes solar thermal technology that collects the sun's radiant energy and uses that energy to heat or cool air or water, and meets the requirements of section 216C.25. To be an eligible lender, a lender must:

(1) have a federal or state charter and be eligible for federal deposit insurance;

(2) be a government entity, including an entity established under chapter 469, that has authority to provide financial assistance for energy efficiency and renewable energy projects;

(3) be a joint venture by utilities established under section 452.25; or

(4) be licensed, certified, or otherwise have its lending activities overseen by a state or federal government agency.

The commissioner must allow a utility broad discretion in designing and implementing an on-bill repayment program, provided that the program complies with this subdivision.

(c) A utility may establish an on-bill repayment program for all customer classes or for a specific customer class.

(d) A public utility that implements an on-bill repayment program under this subdivision must enter into a contract with one or more eligible lenders that complies with the requirements of this subdivision and contains provisions addressing capital commitments, loan origination, transfer of loans to the public utility for on-bill repayment, and acceptance of loans returned due to delinquency or default.

(e) A public utility's contract with a lender must require the lender to comply with all applicable federal and state laws, rules, and regulations related to lending practices and consumer protection; to conform to reasonable and prudent lending standards; and to provide businesses that sell, maintain, and install eligible projects the ability to participate in an on-bill repayment program under this subdivision on a nondiscriminatory basis.

(f) A public utility's contract with a lender may provide:

(1) for the public utility to purchase loans from the lender with a condition that the lender must purchase back loans in delinquency or default; or

(2) for the lender to retain ownership of loans with the public utility servicing the loans through on-bill repayment as long as payments are current.

The risk of default must remain with the lender. The lender shall not have recourse against the public utility except in the event of negligence or breach of contract by the utility.

(g) If a public utility customer makes a partial payment on a utility bill that includes a loan installment, the partial payment must be credited first to the amount owed for utility service, including taxes and fees. A public utility may not suspend or terminate a customer's utility service for delinquency or default on a loan that is being serviced through the public utility's on-bill repayment program.

(h) An outstanding balance on a loan being repaid under this subdivision is a financial obligation only of the customer who is signatory to the loan, and not to any subsequent customer occupying the property associated with the loan. If the public utility purchases loans from the lender as authorized under paragraph (f), clause (1), the public utility must return to the lender a loan not repaid when a customer borrower no longer occupies the property.

(i) Costs incurred by a public utility under this subdivision are recoverable as provided in section 216B.16, subdivision 6b, paragraph (c), including reasonable incremental costs for billing system modifications necessary to implement and operate an on-bill repayment program and for ongoing costs to operate the program. Costs in a plan approved by the commissioner may be counted toward a utility's conservation spending requirements under subdivisions 1a and 1b. Energy savings from energy conservation improvements resulting from this section may be counted toward satisfying a utility's energy-savings goals under subdivision 1c.

(j) This subdivision does not require a utility to terminate or modify an existing financing program and does not prohibit a utility from establishing an on-bill financing program in which the utility provides the financing capital.

(k) A municipal utility or cooperative electric association that implements an on-bill repayment program shall design the program to address the issues identified in paragraphs (d) through (h) as determined by the governing board of the utility or association.

Subd. 6. MS 2008 [Expired]

Subd. 7. **Low-income programs.** (a) The commissioner shall ensure that each public utility subject to subdivision 1c provides energy conservation and efficient fuel-switching programs to low-income households. When approving spending and energy-savings goals for low-income programs, the commissioner shall consider historic spending and participation levels, energy savings achieved by low-income programs, and the number of low-income persons residing in the utility's service territory. Beginning January 1, 2022, a public utility furnishing gas service must spend at least one percent of its most recent three-year average gross operating revenue from residential customers in the state on low-income programs. A public utility that furnishes electric service must spend at least 0.4 percent of its gross operating revenue from residential customers in the state on low-income programs. Beginning in 2024, a public utility that furnishes electric service must spend 0.6 percent of the public utility's gross operating revenue from residential customers in the state on low-income programs.

(b) To meet the requirements of paragraph (a), a public utility may contribute money to the energy and conservation account established under subdivision 2a. An energy conservation improvement plan must state the amount, if any, of low-income energy conservation improvement funds the public utility will contribute to the energy and conservation account. Contributions must be remitted to the commissioner by February 1 of each year.

(c) The commissioner shall establish low-income energy conservation programs to utilize contributions made to the energy and conservation account under paragraph (b). In establishing low-income programs, the commissioner shall consult political subdivisions, utilities, and nonprofit and community organizations, especially organizations providing energy and weatherization assistance to low-income households. Contributions made to the energy and conservation account under paragraph (b) must provide programs for low-income households, including low-income renters, in the service territory of the public utility providing the money. The commissioner shall record and report expenditures and energy savings achieved as a result of low-income programs funded through the energy and conservation account in the report required under subdivision 1c, paragraph (f). The commissioner may contract with a political subdivision, nonprofit or community organization, public utility, or consumer-owned utility to implement low-income programs funded through the energy and conservation account.

(d) A public utility may petition the commissioner to modify its required spending under paragraph (a) if the utility and the commissioner have been unable to expend the amount required under paragraph (a) for three consecutive years.

(e) Representatives of each public utility must participate in the stakeholder group on multifamily building eligibility for low-income energy conservation programs, as provided under section 216B.2403, subdivision 5, paragraph (e). Notwithstanding the definition of low-income household under section 216B.2402, a public utility may apply the most recent guidelines for eligibility of multifamily buildings to participate in low-income energy conservation programs published by the commissioner under section 216B.2403, subdivision 5, paragraph (e).

(f) Up to 15 percent of a public utility's spending on low-income programs may be spent on preweatherization measures. A public utility is prohibited from claiming energy savings from preweatherization measures toward the public utility's energy savings goal.

(g) The commissioner must, by order, establish a list of preweatherization measures eligible for inclusion in low-income programs no later than March 15, 2022.

(h) A public utility may elect to contribute money to the Healthy AIR account under section 216B.2403, subdivision 5, paragraph (h), to provide preweatherization measures to households eligible for weatherization assistance under section 216C.264. Remediation activities must be executed in conjunction with federal weatherization assistance program services. Money contributed to the account counts toward: (1) the minimum low-income spending requirement in paragraph (a); and (2) the cap on preweatherization measures under paragraph (f).

(i) The costs and benefits associated with any approved low-income gas or electric conservation improvement program that is not cost-effective when considering the costs and benefits to the public utility may, at the discretion of the utility, be excluded from the calculation of net economic benefits for purposes of calculating the financial incentive to the public utility. The energy and demand savings may, at the discretion of the public utility, be applied toward the calculation of overall portfolio energy and demand savings for purposes of determining progress toward annual goals and in the financial incentive mechanism.

Subd. 8. **Assessment.** The commission or department may assess public utilities subject to this section to carry out the purposes of subdivisions 1d, 1e, and 1f. An assessment under this subdivision must be proportionate to a public utility's gross operating revenue from sales of gas or electric service within Minnesota during the last calendar year, as applicable. Assessments made under this subdivision are not subject to the cap on assessments provided by section 216B.62, or any other law.

Subd. 9. **Building performance standards; Sustainable Building 2030.** (a) The purpose of this subdivision is to establish cost-effective energy-efficiency performance standards for new and substantially reconstructed commercial, industrial, and institutional buildings that can significantly reduce carbon dioxide emissions by lowering energy use in new and substantially reconstructed buildings. For the purposes of this subdivision, the establishment of these standards may be referred to as Sustainable Building 2030.

(b) The commissioner shall contract with the Center for Sustainable Building Research at the University of Minnesota to coordinate development and implementation of energy-efficiency performance standards, strategic planning, research, data analysis, technology transfer, training, and other activities related to the purpose of Sustainable Building 2030. The commissioner and the Center for Sustainable Building Research shall, in consultation with utilities, builders, developers, building operators, and experts in building design and technology, develop a Sustainable Building 2030 implementation plan that must address, at a minimum, the following issues:

(1) training architects to incorporate the performance standards in building design;

(2) incorporating the performance standards in utility conservation improvement programs; and

(3) developing procedures for ongoing monitoring of energy use in buildings that have adopted the performance standards.

The plan must be submitted to the chairs and ranking minority members of the senate and house of representatives committees with primary jurisdiction over energy policy by July 1, 2009.

(c) Sustainable Building 2030 energy-efficiency performance standards must be firm, quantitative measures of total building energy use and associated carbon dioxide emissions per square foot for different building types and uses, that allow for accurate determinations of a building's conformance with a performance standard. Performance standards must address energy use by electric vehicle charging infrastructure in or adjacent to buildings as that infrastructure begins to be made widely available. The energy-efficiency performance standards must be updated every three or five years to incorporate all cost-effective measures. The performance standards must reflect the reductions in carbon dioxide emissions per square foot resulting from actions taken by utilities to comply with the renewable energy standards in section 216B.1691. The performance standards should be designed to achieve reductions equivalent to the following reduction schedule, measured against energy consumption by an average building in each applicable building sector in 2003: (1) 60 percent in 2010; (2) 70 percent in 2015; (3) 80 percent in 2020; and (4) 90 percent in 2025. A performance standard must not be established or increased absent a conclusive engineering analysis that it is cost-effective based upon established practices used in evaluating utility conservation improvement programs.

(d) The annual amount of the contract with the Center for Sustainable Building Research is up to $500,000. The Center for Sustainable Building Research shall expend no more than $150,000 of this amount each year on administration, coordination, and oversight activities related to Sustainable Building 2030. The balance of contract funds must be spent on substantive programmatic activities allowed under this subdivision that may be conducted by the Center for Sustainable Building Research and others, and for subcontracts with not-for-profit energy organizations, architecture and engineering firms, and other qualified entities to undertake technical projects and activities in support of Sustainable Building 2030. The primary work to be accomplished each year by qualified technical experts under subcontracts is the development and thorough justification of recommendations for specific energy-efficiency performance standards. Additional work may include:

(1) research, development, and demonstration of new energy-efficiency technologies and techniques suitable for commercial, industrial, and institutional buildings;

(2) analysis and evaluation of practices in building design, construction, commissioning and operations, and analysis and evaluation of energy use in the commercial, industrial, and institutional sectors;

(3) analysis and evaluation of the effectiveness and cost-effectiveness of Sustainable Building 2030 performance standards, conservation improvement programs, and building energy codes;

(4) development and delivery of training programs for architects, engineers, commissioning agents, technicians, contractors, equipment suppliers, developers, and others in the building industries; and

(5) analysis and evaluation of the effect of building operations on energy use.

(e) The commissioner shall require utilities to develop and implement conservation improvement programs that are expressly designed to achieve energy efficiency goals consistent with the Sustainable Building 2030 performance standards. These programs must include offerings of design assistance and modeling, financial incentives, and the verification of the proper installation of energy-efficient design components in new and substantially reconstructed buildings. A utility's design assistance program must consider the strategic planting of trees and shrubs around buildings as an energy conservation strategy for the designed project. A utility making an expenditure under its conservation improvement program that results in a building meeting the Sustainable Building 2030 performance standards may claim the energy savings toward its energy-savings goal established in subdivision 1c.

(f) The commissioner shall report to the legislature every three years, beginning January 15, 2010, on the cost-effectiveness and progress of implementing the Sustainable Building 2030 performance standards and shall make recommendations on the need to continue the program as described in this section.

Subd. 10. MS 2020 [Repealed, 2021 c 29 s 19]

Subd. 11. **Programs for efficient fuel-switching improvements; electric utilities.** (a) A public utility providing electric service at retail may include in the plan required under subdivision 2 a proposed goal for efficient fuel-switching improvements that the utility expects to achieve under the plan and the programs to implement efficient fuel-switching improvements or combinations of energy conservation improvements, fuel-switching improvements, and load management. For each program, the public utility must provide a proposed budget, an analysis of the program's cost-effectiveness, and estimated net energy and demand savings.

(b) The department may approve proposed programs for efficient fuel-switching improvements if the department determines the improvements meet the requirements of paragraph (d).

(c) A public utility may file a rate schedule with the commission that provides for annual cost recovery of reasonable and prudent costs to implement and promote efficient fuel-switching programs. The utility, department, or other entity may propose, and the commission may approve, modify, or reject, a proposal for a financial incentive to encourage efficient fuel-switching programs operated by a public utility providing electric service approved under this subdivision. When making a decision on the financial incentive proposal, the commission must apply the considerations established in section 216B.16, subdivision 6c, paragraphs (b) and (c).

(d) A fuel-switching improvement is deemed efficient if, applying the technical criteria established under section 216B.241, subdivision 1d, paragraph (e), the improvement meets the following criteria, relative to the fuel that is being displaced:

(1) results in a net reduction in the amount of source energy consumed for a particular use, measured on a fuel-neutral basis, using (i) the utility's annual system average efficiency, or (ii) if the utility elects, a seasonal, monthly, or more granular level of analysis for the electric utility system over the measure's life;

(2) results in a net reduction of statewide greenhouse gas emissions as defined in section 216H.01, subdivision 2, over the lifetime of the improvement. For an efficient fuel-switching improvement installed by an electric utility, the reduction in emissions must be measured using (i) the utility's annual average emissions factor, or (ii) if the utility elects, a seasonal, monthly or more granular level of analysis, for the electric utility system over the measure's life; and

(3) is cost-effective, considering the costs and benefits from the perspective of the utility, participants, and society.

(e) For purposes of this subdivision, "source energy" means the total amount of primary energy required to deliver energy services, adjusted for losses in generation, transmission, and distribution, and expressed on a fuel-neutral basis.

Subd. 12. **Programs for efficient fuel-switching improvements; natural gas utilities.** (a) As part of a public utility's plan filed under subdivision 2, a public utility that provides natural gas service to Minnesota retail customers may propose one or more programs to install electric technologies that reduce the consumption of natural gas by the utility's retail customers as an energy conservation improvement. The commissioner may approve a proposed program if the commissioner, applying the technical criteria developed under section 216B.241, subdivision 1d, paragraph (e), determines that:

(1) the electric technology to be installed meets the criteria established under section 216B.241, subdivision 11, paragraph (d), clauses (1) and (2); and

(2) the program is cost-effective, considering the costs and benefits to ratepayers, the utility, participants, and society.

(b) If a program is approved by the commission under this subdivision, the public utility may count the program's energy savings toward its energy savings goal under section 216B.241, subdivision 1c. Notwithstanding section 216B.2402, subdivision 4, efficient fuel-switching achieved through programs approved under this subdivision is energy conservation.

(c) A public utility may file rate schedules with the commission that provide annual cost-recovery for programs approved by the department under this subdivision, including reasonable and prudent costs to implement and promote the programs.

(d) The commission may approve, modify, or reject a proposal made by the department or a utility for an incentive plan to encourage efficient fuel-switching programs approved under this subdivision, applying the considerations established under section 216B.16, subdivision 6c, paragraphs (b) and (c). The commission may approve a financial incentive mechanism that is calculated based on the combined energy savings and net benefits that the commission has determined have been achieved by a program approved under this subdivision, provided the commission determines that the financial incentive mechanism is in the ratepayers' interest.

Subd. 13. **Cost-effective load management programs.** (a) A public utility may include in the utility's plan required under subdivision 2 programs to implement load management activities, or combinations of energy conservation improvements, fuel-switching improvements, and load management activities. For each program the public utility must provide a proposed budget, cost-effectiveness analysis, and estimated net energy and demand savings.

(b) The commissioner may approve a proposed program if the commissioner determines the program is cost-effective, considering the costs and benefits to ratepayers, the utility, participants, and society.

(c) A public utility providing retail electric service to Minnesota customers may file rate schedules with the commission that provide for annual cost recovery of reasonable and prudent costs incurred to implement and promote cost-effective load management programs approved by the department under this subdivision.

(d) The commission may approve, modify, or reject a proposal made by the department or a public utility for an incentive plan to encourage investments in load management programs. The commission may approve a proposal that the commission determines:

(1) is needed to increase the public utility's investment in cost-effective load management;

(2) is compatible with the interest of the public utility's ratepayers; and

(3) links the incentive to the public utility's performance in achieving cost-effective load management.

(e) The commission may structure an incentive plan to encourage cost-effective load management programs as an asset on which a public utility earns a rate of return at a level the commission determines is reasonable and in the public interest.

(f) The commission may include the net benefits from a load management activity integrated with an energy efficiency program approved under this section in the net benefits of the energy efficiency program for purposes of a financial incentive program under section 216B.16, subdivision 6c, if the department determines the primary purpose of the load management activity is energy efficiency.

(g) A public utility is not eligible for a financial incentive for a load management program in any year in which the utility achieves energy savings below one percent of gross annual retail energy sales, excluding savings achieved through load management programs.

(h) The commission may include net benefits from a particular load management activity in an incentive plan under this subdivision or section 216B.16, subdivision 6c, but not both.

Subd. 14. **Minnesota efficient technology accelerator.** (a) A nonprofit organization with extensive experience implementing energy efficiency programs in Minnesota and conducting efficient technology research in the state may file a proposal with the commissioner of commerce for a program to accelerate deployment and reduce the cost of emerging and innovative efficient technologies and approaches and lead to lower energy costs for Minnesota consumers. Accelerator activities include strategic initiatives with technology manufacturers to improve the efficiency and performance of products, as well as with equipment installers and other key actors in the technology supply chain. Benefits of activities expected from the accelerator include cost effective energy savings for Minnesota utilities, bill savings for Minnesota utility consumers, enhanced employment opportunities in Minnesota, and avoidance of greenhouse gas emissions.

(b) Prior to developing and filing a proposal, the nonprofit must submit to the commissioner of commerce a notice of intent to file a proposal under this subdivision. The notice of intent must describe the nonprofit's qualifications and eligibility to file a proposal under this subdivision. The commissioner must review the notice of intent and issue a determination of eligibility within 30 days if the commissioner determines the nonprofit meets the required qualifications.

(c) Upon receiving the determination by the commissioner under paragraph (b), the nonprofit organization must engage with interested stakeholders on at least the following attributes required of a program proposal under this subdivision:

(1) a proposed budget and operational guidelines for the accelerator;

(2) a proposed energy savings attribution, evaluation, and allocation methodology that includes a method for calculating net benefits from activities under the program. Energy savings and net benefits from activities under the program must be allocated to participating utilities and be considered when determining cost-effectiveness of achieved energy savings and related incentives;

(3) a process to ensure that the technologies that are selected for the program benefit electric and natural gas utility customers in proportion to the funds each utility sector contributes to the program and address residential, commercial, and industrial building energy use; and

(4) a process for identifying and tracking performance metrics for each technology selected against which progress can be measured, including one or more methods for evaluating cost-effectiveness.

(d) No earlier than 180 days from the date of the commissioner's eligibility determination under paragraph (b), the nonprofit may file a program proposal under this subdivision. The filing must describe how the proposal addresses each of the required attributes listed in paragraph (c), clauses (1) to (4), and how the proposal addresses the recommendations and concerns identified in the stakeholder engagement process required under paragraph (c).

(e) Within ten days of receiving the proposal, the commissioner must provide public notice of the proposal and solicit feedback from interested parties for a period of not less than ten business days.

(f) Within 90 days of the filing of the proposal, the commissioner must approve, modify, or reject a proposal under this subdivision. In making a determination, the commissioner must consider public comments, the expected costs and benefits of the program from the perspectives of ratepayers, the participating utilities, and society, and the expected costs and benefits relative to other energy conservation programming authorized under this section.

(g) The initial program term may be up to five years. At the request of the nonprofit, the commissioner may renew a program approved under paragraph (d) for up to five years at a time. The nonprofit must submit to the commissioner a request to renew the program no later than 180 days prior to the end of the term of the program approved or renewed under this subdivision. When making a request to renew and determination on renewal, the nonprofit and commissioner must follow the process established under this subdivision, except that a qualified nonprofit is not required to seek eligibility under paragraph (b).

(h) Upon approval, each public utility with over 30,000 customers must participate in the program and contribute to the approved budget of the program by depositing annually in the energy and conservation account under subdivision 2a an amount that is proportional to the utility's gross operating revenue from sales of gas or electric service in Minnesota, excluding revenues from large customer facilities exempted under subdivision 1a. A participating utility must not be required to contribute more than the following percentages of the utility's spending approved by the commission in the plan filed under subdivision 2: (1) two percent in the program's initial two years; (2) 3.5 percent in the program's third and fourth years; and (3) five percent thereafter. Other utilities may elect to participate in the accelerator program. Costs incurred by a public utility under this subdivision are recoverable under subdivision 2b as an assessment to the energy and conservation account. Amounts provided to the account under this subdivision are not subject to the cap on assessments in section 216B.62. The commissioner may make expenditures from the account for the purposes of this subdivision, including amounts necessary to cover administrative costs incurred by the department under this subdivision. Costs for research projects under this subdivision that the commissioner determines may be duplicative to projects that would be eligible for funding under subdivision 1e, paragraph (a), may be deducted from the assessment under subdivision 1e for utilities participating in the accelerator.

(i) The commissioner must not approve more than one program to be implemented or in operation at any given time under this subdivision.

(j) At least once during the term of a program that is approved or renewed, the commissioner must contract for an independent review of the program to determine if it meets the objectives and requirements of this section and any criteria established by the department as a condition of approval. The review may not be conducted by an entity or person that acted as a stakeholder or interested party, or otherwise participated in the program preparation, filing, or review process. Upon completion, the reviewer must prepare a report detailing findings and recommendations, and the commissioner must transmit a copy of the report to the chairs and ranking minority members of the house of representatives and senate committees with jurisdiction over energy policy. Money required to conduct the review and prepare the report must be deducted from the total contribution amount under paragraph (h).

History: *1980 c 579 s 18; 1980 c 614 s 123; 1981 c 356 s 182,248; 1982 c 561 s 4; 1983 c 179 s 6-8; 1989 c 338 s 2,3; 1991 c 235 art 1 s 2; 1992 c 478 s 2,3; 1993 c 249 s 31; 1994 c 483 s 1; 1994 c 641 art 3 s 1; art 4 s 4; 1994 c 644 s 3; 1998 c 273 s 11; 1998 c 350 s 1; 1999 c 140 s 2-7; 2001 c 212 art 8 s 4-7,12; 1Sp2001 c 4 art 6 s 44-46,77; 2003 c 130 s 12; 1Sp2003 c 11 art 2 s 5; art 3 s 4; 2004 c 216 s 3; 2005 c 97 art 7 s 1,2; 2007 c 10 s 5; 2007 c 57 art 2 s 21; 2007 c 136 art 2 s 5; 2008 c 278 s 2,3; 2008 c 296 art 1 s 9; 2009 c 86 art 1 s 31; 2009 c 110 s 15-18; 2009 c 134 s 5; 2010 c 372 s 1; 2011 c 97 s 18-21; 2013 c 85 art 13 s 2-4; 2013 c 132 s 2; 2014 c 254 s 11; 2014 c 312 art 3 s 10; 2016 c 189 art 6 s 7; 2017 c 94 art 10 s 11-17; 2020 c 105 s 1; 2021 c 29 s 5-18; 1Sp2021 c 4 art 8 s 17; 2024 c 126 art 6 s 15-18; 2024 c 127 art 42 s 15-18; 2025 c 20 s 184; 1Sp2025 c 12 s 14,15*

216B.2411 DISTRIBUTED ENERGY RESOURCES.

Subdivision 1. **Generation projects.** (a) Any municipality or rural electric association providing electric service and subject to section 216B.241 may, and each public utility may, use five percent of the total amount to be spent on energy conservation improvements under section 216B.241, on:

(1) projects in Minnesota to construct an electric generating facility that utilizes eligible renewable energy sources as defined in subdivision 2, such as methane or other combustible gases derived from the

processing of plant or animal wastes, biomass fuels such as short-rotation woody or fibrous agricultural crops, or other renewable fuel, as its primary fuel source;

(2) projects in Minnesota to install a distributed generation facility of ten megawatts or less of interconnected capacity that is fueled by natural gas, renewable fuels, or another similarly clean fuel; or

(3) projects in Minnesota to install a qualifying solar energy project as defined in subdivision 2.

(b) A municipality, rural electric association, or public utility that offers a program to customers to promote installing qualifying solar energy projects may request authority from the commissioner to exceed the five percent limit in paragraph (a), but not to exceed ten percent, to meet customer demand for installation of qualifying solar energy projects. In considering this request, the commissioner shall consider customer interest in qualifying solar energy and the impact on other customers. A municipality, rural electric association, or public utility may not participate in a qualifying solar energy project on a property unless it is provided evidence that all reasonable cost-effective conservation investments have previously been made to the property.

(c) For a municipality, rural electric association, or public utility, projects under this section must be considered energy conservation improvements as defined in section 216B.241.

Subd. 2. **Definitions.** (a) For the purposes of this section, the terms defined in this subdivision and section 216B.241, subdivision 1, have the meanings given them.

(b) "Eligible renewable energy sources" means fuels and technologies to generate electricity through the use of any of the resources listed in section 216B.1691, subdivision 1, paragraph (c), except that the incineration of wastewater sludge is not an eligible renewable energy source, "biomass" has the meaning provided under paragraph (c), and "solar" must be from a qualified solar energy project as defined in paragraph (d).

(c) "Biomass" includes:

(1) methane or other combustible gases derived from the processing of plant or animal material;

(2) alternative fuels derived from soybean and other agricultural plant oils or animal fats;

(3) combustion of barley hulls, corn, soy-based products, or other agricultural products;

(4) wood residue from the wood products industry in Minnesota or other wood products such as short-rotation woody or fibrous agricultural crops;

(5) landfill gas;

(6) the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works; and

(7) mixed municipal solid waste, and refuse-derived fuel from mixed municipal solid waste.

(d) "Qualifying solar energy project" means a qualifying solar thermal project or qualifying solar electric project.

(e) "Qualifying solar thermal project" means a flat plate or evacuated tube that meets the requirements of section 216C.25 with a fixed orientation that collects the sun's radiant energy and transfers it to a storage medium for distribution as energy to heat or cool air or water, but does not include equipment used to heat water at a residential property (1) for domestic use if less than one-half of the energy used for that purpose is derived from the sun or (2) for use in a hot tub or swimming pool.

(f) "Qualifying solar electric project" means:

(1) solar electric equipment that: (i) meets the requirements of section 216C.25; (ii) has a peak generating capacity of 100 kilowatts or less; and (iii) is used to generate electricity for use in a residential, commercial, or publicly owned property or facility; and

(2) if applicable, equipment that is used to store the electricity generated by a qualified solar electric project under clause (1) and that is located proximate to the property or facility using the electricity.

(g) "Residential property" means the principal residence of a homeowner at the time the solar equipment is placed in service.

Subd. 3. **Other provisions.** (a) Electricity generated by a facility constructed with funds provided under this section and using an eligible renewable energy source may be counted toward the renewable energy objectives in section 216B.1691, subject to the provisions of that section, except as provided in paragraph (c).

(b) Two or more entities may pool resources under this section to provide assistance jointly to proposed eligible renewable energy projects. The entities shall negotiate and agree among themselves for allocation of benefits associated with a project, such as the ability to count energy generated by a project toward a utility's renewable energy objectives under section 216B.1691, except as provided in paragraph (c). The entities shall provide a summary of the allocation of benefits to the commissioner. A utility may spend funds under this section for projects in Minnesota that are outside the service territory of the utility.

(c) Electricity generated by a solar photovoltaic device constructed with funds provided under this section may be counted toward a public utility's solar energy standard under section 216B.1691, subdivision 2f.

History: *2001 c 212 art 8 s 13,14; 2002 c 398 s 11; 1Sp2003 c 11 art 2 s 6; 2007 c 136 art 2 s 8; 2008 c 258 s 2; 2008 c 296 art 1 s 10,11; 2009 c 110 s 19,20; 2013 c 85 art 10 s 4; 2023 c 7 s 32*

216B.2412 DECOUPLING OF ENERGY SALES FROM REVENUES.

Subdivision 1. **Definition and purpose.** For the purpose of this section, "decoupling" means a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency.

Subd. 2. **Decoupling criteria.** The commission shall, by order, establish criteria and standards for decoupling. The commission may establish these criteria and standards in a separate proceeding or in a general rate case or other proceeding in which it approves a pilot program, and shall design the criteria and standards to mitigate the impact on public utilities of the energy-savings goals under section 216B.241 without adversely affecting utility ratepayers. In designing the criteria, the commission shall consider energy efficiency, weather, and cost of capital, among other factors.

Subd. 3. **Pilot programs.** The commission shall allow one or more rate-regulated utilities to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation. Each pilot program must utilize the criteria and standards established in subdivision 2 and be designed to determine whether a rate-decoupling strategy achieves energy savings. On or before a date established by the commission, the commission shall require electric and gas utilities that intend to implement a decoupling program to file a decoupling pilot plan, which shall be approved or approved as modified by the commission. A pilot program may not exceed three years in length. Any extension beyond three years can only be approved in a general rate case, unless that decoupling program was previously approved as part of a general rate case.

History: *2007 c 136 art 2 s 6; 2009 c 110 s 21; 1Sp2021 c 4 art 8 s 18*

216B.242 [Repealed, 2011 c 97 s 34]

RENEWABLE ENERGY INITIATIVES

216B.2421 DEFINITION OF LARGE ENERGY FACILITY.

Subdivision 1. **Applicability.** The definition in this section applies to this section and sections 216B.2422 and 216B.243.

Subd. 2. **Large energy facility.** "Large energy facility" means:

(1) any electric power generating plant or combination of plants at a single site with a combined capacity of 50,000 kilowatts or more and transmission lines directly associated with the plant that are necessary to interconnect the plant to the transmission system;

(2) any high-voltage transmission line with a capacity of 300 kilovolts or more and greater than one mile in length in Minnesota;

(3) any high-voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota;

(4) any pipeline greater than six inches in diameter and having more than 50 miles of its length in Minnesota used for the transportation of coal, crude petroleum or petroleum fuels or oil, or their derivatives;

(5) any pipeline for transporting natural or synthetic gas at pressures in excess of 200 pounds per square inch with more than 50 miles of its length in Minnesota;

(6) any facility designed for or capable of storing on a single site more than 1,000,000 gallons of liquefied natural gas or synthetic gas;

(7) any underground gas storage facility requiring a permit pursuant to section 103I.681;

(8) any nuclear fuel processing or nuclear waste storage or disposal facility; and

(9) any facility intended to convert any material into any other combustible fuel and having the capacity to process in excess of 75 tons of the material per hour.

Subd. 3. [Repealed, 2001 c 212 art 7 s 36]

History: *1974 c 307 s 2; 1975 c 170 s 1; 1977 c 381 s 8; Ex1979 c 2 s 11; 1981 c 356 s 248; 1982 c 561 s 1; 1991 c 199 art 2 s 1; 1993 c 327 s 8,9; 1993 c 356 s 2; 2001 c 212 art 7 s 29; 2005 c 97 art 1 s 4; 2024 c 126 art 8 s 1; 2024 c 127 art 44 s 1; 1Sp2025 c 7 art 3 s 7*

216B.2422 RESOURCE PLANNING; RENEWABLE ENERGY.

Subdivision 1. **Definitions.** (a) For purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Utility" means an entity with the capability of generating 100,000 kilowatts or more of electric power and serving, either directly or indirectly, the needs of 10,000 retail customers in Minnesota. Utility does not include federal power agencies.

(c) "Renewable energy" means electricity generated through use of any of the following resources:

(1) wind;

(2) solar;

(3) geothermal;

(4) hydro;

(5) trees or other vegetation;

(6) landfill gas; or

(7) predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge.

(d) "Resource plan" means a set of resource options that a utility could use to meet the service needs of its customers over a forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs. These resource options include using, refurbishing, and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation.

(e) "Refurbish" means to rebuild or substantially modify an existing electricity generating resource of 30 megawatts or greater.

(f) "Energy storage system" means a commercially available technology that:

(1) uses mechanical, chemical, or thermal processes to:

(i) store energy, including energy generated from renewable resources and energy that would otherwise be wasted, and deliver the stored energy for use at a later time; or

(ii) store thermal energy for direct use for heating or cooling at a later time in a manner that reduces the demand for electricity at the later time;

(2) is composed of stationary equipment;

(3) if being used for electric grid benefits, is operationally visible and capable of being controlled by the distribution or transmission entity managing it, to enable and optimize the safe and reliable operation of the electric system; and

(4) achieves any of the following:

(i) reduces peak or electrical demand;

(ii) defers the need or substitutes for an investment in electric generation, transmission, or distribution assets;

(iii) improves the reliable operation of the electrical transmission or distribution systems, while ensuring transmission or distribution needs are not created; or

(iv) lowers customer costs by storing energy when the cost of generating or purchasing it is low and delivering it to customers when the costs are high.

(g) "Local job impacts" means the impacts of a certificate of need, a power purchase agreement, or commission approval of a new or refurbished energy facility on the availability of construction employment opportunities to local workers.

(h) "Local workers" means workers who:

(1) are employed to construct and maintain energy infrastructure; and

(2) are Minnesota residents, are residents of the utility's service territory, or permanently reside within 150 miles of a proposed new or refurbished energy facility.

Subd. 2. **Resource plan filing and approval.** (a) A utility shall file a resource plan with the commission periodically in accordance with rules adopted by the commission. The commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, subdivision 4, consistent with the public interest.

(b) In the resource plan proceedings of all other utilities, the commission's order shall be advisory and the order's findings and conclusions shall constitute prima facie evidence which may be rebutted by substantial evidence in all other proceedings. With respect to utilities other than those defined in section 216B.02, subdivision 4, the commission shall consider the filing requirements and decisions in any comparable proceedings in another jurisdiction.

(c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.

Subd. 2a. **Historical data and advance forecast.** Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.

Subd. 2b. **Optional integrated resource plan compliance for certain cooperatives.** For the purposes of this subdivision, a "cooperative" means a generating and transmission cooperative electric association that has at least 80 percent of its member distribution cooperatives located outside of Minnesota and that provides less than four percent of the electricity annually sold at retail in the state of Minnesota. A cooperative may, in lieu of filing a resource plan under subdivision 2, elect to file a report to the commission under this subdivision. The report must include projected demand levels for the next 15 years and generation resources to meet any projected generation deficiencies. To supply the information required in a report under this subdivision, a cooperative may use reports submitted under section 216C.17, subdivision 2, reports to regional reliability organizations, or similar reports submitted to other state utility commissions. A report must be submitted annually by July 1, but the commission may extend the time if it finds the extension in the public interest. Presentation of the annual report shall be done in accordance with procedures established by the commission. Data in a report under this subdivision may be aggregate data and need not be separately reported for individual distribution cooperative members of the cooperative. The commission may take whatever action in response to a report under this subdivision that it could take with respect to a report by a cooperative under subdivision 2.

Subd. 2c. **Long-range emission reduction planning.** Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.

Subd. 2d. **Plan to minimize impacts to workers due to facility retirement.** A utility required to file a resource plan under subdivision 2 that has scheduled the retirement of an electric generating facility located in Minnesota must include in the filing a narrative describing the utility's efforts, in conjunction with the utility's workers and the workers' designated representatives, to develop a plan to minimize the dislocations employees may suffer as a result of the facility's retirement. The narrative must address, at a minimum, plans to:

(1) minimize financial losses to workers;

(2) provide a transition timeline to ensure certainty for workers;

(3) protect pension benefits;

(4) extend or replace health insurance, life insurance, and other employment benefits;

(5) provide training and skill development for workers who must or choose to leave the utility;

(6) create targeted transition plans for workers at all locations impacted by the facility retirement; and

(7) quantify any additional costs the utility would incur and specifying what costs, if any, the utility would request be recovered in the utility's rates as a result of efforts made under this subdivision to minimize impacts to workers.

Subd. 3. **Environmental costs.** (a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.

(b) The commission shall provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, released in September 2022, including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate. The commission shall adopt the estimates contained in the final version of the external review draft report when it becomes available.

(c) If, at any time, the estimates adopted by the commission under paragraph (a) are exceeded by estimates released by the federal Interagency Working Group on the Social Cost of Greenhouse Gases or its successors, the commission shall adopt the working group estimates.

(d) The commission shall establish interim environmental cost values associated with each method of electricity generation by March 1, 1994. These values expire on the date the commission establishes environmental cost values under paragraph (a).

Subd. 4. **Preference for renewable energy facility.** The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the commission must consider:

(1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f;

(2) impacts on local and regional grid reliability;

(3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and

(4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

Subd. 4a. **Preference for local job creation.** As part of a resource plan filing, a utility must report on associated local job impacts and the steps the utility and the utility's energy suppliers and contractors are taking to maximize the availability of construction employment opportunities for local workers. The commission must consider local job impacts and give preference to proposals that maximize the creation of construction employment opportunities for local workers, consistent with the public interest, when evaluating any utility proposal that involves the selection or construction of facilities used to generate or deliver energy to serve the utility's customers, including but not limited to an integrated resource plan, a certificate of need, a power purchase agreement, or commission approval of a new or refurbished electric generation facility. The commission must, to the maximum extent possible, prioritize the hiring of workers from communities hosting retiring electric generation facilities, including workers previously employed at the retiring facilities.

Subd. 4b. **Preference for domestic content.** The commission may give preference in resource selection to projects utilizing energy technologies produced domestically by entities who received an advanced manufacturing tax credit for those technologies under section 45X of the Internal Revenue Code, as allowed under the federal Inflation Reduction Act of 2022, Public Law 117-169.

Subd. 5. **Bidding; exemption from certificate of need proceeding.** (a) A utility may select resources to meet its projected energy demand through a bidding process approved or established by the commission. A utility shall use the environmental cost estimates determined under subdivision 3 and consider local job impacts when evaluating bids submitted in a process established under this subdivision.

(b) Notwithstanding any other provision of this section, if an electric power generating plant, as described in section 216B.2421, subdivision 2, clause (1), is selected in a bidding process approved or established by the commission, a certificate of need proceeding under section 216B.243 is not required.

(c) A certificate of need proceeding is also not required for an electric power generating plant that has been selected in a bidding process approved or established by the commission, or such other selection process approved by the commission, to satisfy, in whole or in part, the wind power mandate of section 216B.2423 or the biomass mandate of section 216B.2424.

Subd. 6. **Consolidation of resource planning and certificate of need.** A utility shall indicate in its resource plan whether it intends to site or construct a large energy facility. If the utility's resource plan includes a proposed large energy facility and construction of that facility is likely to begin before the utility files its next resource plan, the commission shall conduct the resource plan proceeding consistent with the requirements of section 216B.243 with respect to the proposed facility. If the commission approves the proposed facility in the resource plan, a separate certificate of need proceeding is not required.

Subd. 7. **Energy storage systems assessment.** (a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to:

(1) meeting identified generation and capacity needs; and

(2) evaluating ancillary services.

(b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).

Subd. 8. **Carbon dioxide emissions reduction.** (a) The commission may issue an order to reduce carbon dioxide emissions from coal-fired electric generating units located in Minnesota that do not have applicable capacity obligations with a regional transmission organization and are wholly owned by a public utility required to file a resource plan under this section. The order may:

(1) require the public utility to develop and implement a plan to operate coal-fired electric generating units only during the months of June, July, August, December, January, and February, other than for emergency or reliability purposes; or

(2) establish an annual limit on the carbon dioxide emissions from coal-fired electric generating units.

(b) Nothing in this subdivision affects a public utility's obligation to comply with the provisions of section 216B.1691.

History: *1993 c 356 s 3; 1994 c 644 s 4; 1997 c 176 s 2; 1997 c 198 s 1; 2008 c 258 s 3; 2012 c 268 s 1; 2013 c 132 s 3; 2014 c 254 s 12; 2017 c 94 art 10 s 18,19; 1Sp2019 c 7 art 11 s 4,5; 1Sp2021 c 4 art 8 s 19; 2023 c 7 s 17-22*

216B.2423 WIND POWER MANDATE.

Subdivision 1. **Mandate.** A public utility, as defined in section 216B.02, subdivision 4, that operates a nuclear-powered electric generating plant within this state must construct and operate, purchase, or contract to construct and operate: (1) 225 megawatts of electric energy installed capacity generated by wind energy conversion systems within the state by December 31, 1998; and (2) an additional 200 megawatts of installed capacity so generated by December 31, 2002.

For the purpose of this section, "wind energy conversion system" has the meaning given it in section 216C.06, subdivision 19.

Subd. 2. **Resource planning mandate.** The Public Utilities Commission shall order a public utility subject to subdivision 1, to construct and operate, purchase, or contract to purchase an additional 400 megawatts of electric energy installed capacity generated by wind energy conversion systems by December 31, 2002, subject to resource planning and least cost planning requirements in section 216B.2422.

Subd. 2a. **Site preference.** The Public Utilities Commission shall ensure that a utility subject to the requirements of subdivision 1, clause (2), shall implement that clause with a preference for wind energy conversion systems within the state. This preference shall not prevent the utility from constructing or contracting to construct wind energy conversion systems outside the state, if the Public Utilities Commission determines that selection of a facility within the state conflicts with the requirements of section 216B.03.

Subd. 3. **Standard contract for wind energy conversion systems.** The Public Utilities Commission shall require a public utility subject to subdivision 1 to develop and file in a form acceptable to the commission by October 1, 1997, a standard form contract for the purchase of electricity from wind conversion systems with installed capacity of two megawatts and less. For purposes of applying the two megawatts limit, the installed capacity sold to the public utility from a single seller or affiliated group of sellers shall be cumulated. The standard contract shall include all the terms and conditions for purchasing wind-generated power by the utility, except for price and any other specific terms necessary to ensure system reliability and safety, which shall be separately negotiable.

History: *1994 c 641 art 3 s 2; 1997 c 216 s 123; 1999 c 200 s 3*

216B.2424 BIOMASS POWER MANDATE.

Subdivision 1. **Farm-grown closed-loop biomass.** (a) For the purposes of this section, "farm-grown closed-loop biomass" means herbaceous crops, trees, agricultural waste, and aquatic plant matter that is used to generate electricity, but does not include mixed municipal solid waste, as defined in section 115A.03, and that:

(1) is intentionally cultivated, harvested, and prepared for use, in whole or in part, as a fuel for the generation of electricity;

(2) when combusted, releases an amount of carbon dioxide that is less than or approximately equal to the carbon dioxide absorbed by the biomass fuel during its growing cycle; and

(3) is fired in a new or substantially retrofitted electric generating facility that is:

(i) located within 400 miles of the site of the biomass production; and

(ii) designed to use biomass to meet at least 75 percent of its fuel requirements.

(b) The legislature finds that the negative environmental impacts within 400 miles of the facility resulting from transporting and combusting the biomass are offset in that region by the environmental benefits to air, soil, and water of the biomass production.

(c) Among the biomass fuel sources that meet the requirements of paragraph (a), clauses (1) and (2), are poplar, aspen, willow, switch grass, sorghum, alfalfa, cultivated prairie grass, and sustainably managed woody biomass.

(d) For the purpose of this section, "sustainably managed woody biomass" means:

(1) brush, trees, and other biomass harvested from within designated utility, railroad, and road rights-of-way;

(2) upland and lowland brush harvested from lands incorporated into brushland habitat management activities of the Minnesota Department of Natural Resources;

(3) upland and lowland brush harvested from lands managed in accordance with Minnesota Department of Natural Resources "Best Management Practices for Managing Brushlands";

(4) logging slash or waste wood that is created by harvest, by precommercial timber stand improvement to meet silvicultural objectives, or by fire, disease, or insect control treatments, and that is managed in compliance with the Minnesota Forest Resources Council's "Sustaining Minnesota Forest Resources: Voluntary Site-Level Forest Management Guidelines for Landowners, Loggers and Resource Managers" as modified by the requirement of this subdivision; and

(5) trees or parts of trees that do not meet the utilization standards for pulpwood, posts, bolts, or sawtimber as described in the Minnesota Department of Natural Resources Division of Forestry Timber Sales Manual, 1998, as amended as of May 1, 2005, and the Minnesota Department of Natural Resources Timber Scaling Manual, 1981, as amended as of May 1, 2005, except as provided in paragraph (a), clause (1), and this paragraph, clauses (1) to (3).

Subd. 1a. **Municipal waste-to-energy project.** (a) This subdivision applies only to a biomass project owned or controlled, directly or indirectly, by two municipal utilities as described in subdivision 5a, paragraph (b).

(b) Woody biomass from state-owned land must be harvested in compliance with an adopted management plan and a program of ecologically based third-party certification.

(c) The project must prepare a fuel plan on an annual basis after commercial operation of the project as described in the power contract between the project and the public utility, and must also prepare annually certificates reflecting the types of fuel used in the preceding year by the project, as described in the power contract. The fuel plans and certificates shall also be filed with the Minnesota Department of Natural Resources and the Minnesota Department of Commerce within 30 days after being provided to the public utility, as provided by the power contract. Any person who believes the fuel plans, as amended, and certificates show that the project does not or will not comply with the fuel requirements of this subdivision may file a petition with the commission seeking such a determination.

(d) The wood procurement process must utilize third-party audit certification systems to verify that applicable best management practices were utilized in the procurement of the sustainably managed biomass. If there is a failure to so verify in any two consecutive years during the original contract term, the farm-grown closed-loop biomass requirements of subdivision 2 must be increased to 50 percent for the remaining contract term period; however, if in two consecutive subsequent years after the increase has been implemented, it is verified that the conditions in this subdivision have been met, then for the remaining original contract term the closed-loop biomass mandate reverts to 25 percent. If there is a subsequent failure to verify in a year after the first failure and implementation of the 50 percent requirement, then the closed-loop percentage shall remain at 50 percent for each remaining year of the contract term.

(e) In the closed-loop plantation, no transgenic plants may be used.

(f) No wood may be harvested from any lands identified by the final or preliminary Minnesota County Biological Survey as having statewide significance as native plant communities, large populations or concentrations of rare species, or critical animal habitat.

(g) A wood procurement plan must be prepared every five years and public meetings must be held and written comments taken on the plan and documentation must be provided on why or why not the public inputs were used.

(h) Guidelines or best management practices for sustainably managed woody biomass must be adopted by:

(1) the Minnesota Department of Natural Resources for managing and maintaining brushland and open land habitat on public and private lands, including, but not limited to, provisions of sections 84.941, 84.942, and 97A.125; and

(2) the Minnesota Forest Resources Council for logging slash, using the most recent available scientific information regarding the removal of woody biomass from forest lands, to sustain the management of forest

resources as defined by section 89.001, subdivisions 8 and 9, with particular attention to soil productivity, biological diversity as defined by section 89A.01, subdivision 3, and wildlife habitat.

These guidelines must be completed by July 1, 2007, and the process of developing them must incorporate public notification and comment.

(i) The University of Minnesota Initiative for Renewable Energy and the Environment is encouraged to solicit and fund high-quality research projects to develop and consolidate scientific information regarding the removal of woody biomass from forest and brush lands, with particular attention to the environmental impacts on soil productivity, biological diversity, and sequestration of carbon. The results of this research shall be made available to the public.

(j) The two utilities owning or controlling, directly or indirectly, the biomass project described in subdivision 5a, paragraph (b), shall fund or obtain funding from nonstate sources of up to $150,000 by April 1, 2006, to complete the guidelines or best management practices described in paragraph (h). The expenditures to be funded under this paragraph do not include any of the expenditures to be funded under paragraph (i).

Subd. 2. **Interim exemption.** (a) A biomass project proposing to use, as its primary fuel over the life of the project, short-rotation woody crops, may use as an interim fuel agricultural waste and other biomass which is not farm-grown closed-loop biomass for up to six years after the project's electric generating facility becomes operational; provided, the project developer demonstrates the project will use the designated short-rotation woody crops as its primary fuel after the interim period and provided the location of the interim fuel production meets the requirements of subdivision 1, paragraph (a), clause (3).

(b) A biomass project proposing to use, as its primary fuel over the life of the project, short-rotation woody crops, may use as an interim fuel agricultural waste and other biomass which is not farm-grown closed-loop biomass for up to three years after the project's electric generating facility becomes operational; provided, the project developer demonstrates the project will use the designated short-rotation woody crops as its primary fuel after the interim period.

(c) A biomass project that uses an interim fuel under the terms of paragraph (b) may, in addition, use an interim fuel under the terms of paragraph (a) for six years less the number of years that an interim fuel was used under paragraph (b).

(d) A project developer proposing to use an exempt interim fuel under paragraphs (a) and (b) must demonstrate to the public utility that the project will have an adequate supply of short-rotation woody crops which meet the requirements of subdivision 1 to fuel the project after the interim period.

(e) If a biomass project using an interim fuel under this subdivision is or becomes owned or controlled, directly or indirectly, by two municipal utilities as described in subdivision 5a, paragraph (b), the project is deemed to comply with the requirement under this subdivision to use as its primary fuel farm-grown closed-loop biomass if farm-grown closed-loop biomass comprises no less than 25 percent of the fuel used over the life of the project. For purposes of this subdivision, "life of the project" means 20 years from the date the project becomes operational or the term of the applicable power purchase agreement between the project owner and the public utility, whichever is longer.

Subd. 3. **Fuel exemption.** Over the duration of the contract of a biomass power facility selected to satisfy the mandate in subdivision 5, fuel sources that are not biomass may be used to satisfy up to 25 percent of the fuel requirements of a biomass power facility selected to satisfy the biomass power mandate in subdivision 5, except that agricultural crop wastes, such as oat hulls, may be used to satisfy more than 25 percent of the fuel requirements of a power facility selected to satisfy the biomass power mandate in subdivision 5 if the wastes are co-fired with the fuel authorized for the facility. A biomass power facility selected to satisfy the mandate in subdivision 5 also may use fuel sources that are not biomass during any period when biomass fuel sources are not reasonably available to the facility due to any circumstances constituting an act of God. Fuel sources that are not biomass used during such a period of biomass fuel source unavailability shall not be counted toward the 25 percent exemption provided in this subdivision. For purposes of this subdivision, "act of God" means any natural disaster or other natural phenomenon of an exceptional, inevitable, or irresistible character, including, but not limited to, flood, fire, drought, earthquake, and crop failure resulting from climatic conditions, infestation, or disease.

Subd. 4. **Financial viability.** A biomass project developer must demonstrate to the public utility evidence of sufficient financial viability necessary for the construction and operation of the biomass project.

Subd. 5. **Mandate.** (a) A public utility, as defined in section 216B.02, subdivision 4, that operates a nuclear-powered electric generating plant within this state must construct and operate, purchase, or contract to construct and operate (1) by December 31, 1998, 50 megawatts of electric energy installed capacity generated by farm-grown closed-loop biomass scheduled to be operational by December 31, 2001; and (2) by December 31, 1998, an additional 75 megawatts of installed capacity so generated scheduled to be operational by December 31, 2002.

(b) Of the 125 megawatts of biomass electricity installed capacity required under this subdivision, no more than 55 megawatts of this capacity may be provided by a facility that uses poultry litter as its primary fuel source and any such facility:

(1) need not use biomass that complies with the definition in subdivision 1;

(2) must enter into a contract with the public utility for such capacity, that has an average purchase price per megawatt hour over the life of the contract that is equal to or less than the average purchase price per megawatt hour over the life of the contract in contracts approved by the Public Utilities Commission before April 1, 2000, to satisfy the mandate of this section, and file that contract with the Public Utilities Commission prior to September 1, 2000; and

(3) must schedule such capacity to be operational by December 31, 2002.

(c) Of the total 125 megawatts of biomass electric energy installed capacity required under this section, no more than 75 megawatts may be provided by a single project.

(d) Of the 75 megawatts of biomass electric energy installed capacity required under paragraph (a), clause (2), no more than 33 megawatts of this capacity may be provided by a St. Paul district heating and cooling system cogeneration facility utilizing waste wood as a primary fuel source. The St. Paul district heating and cooling system cogeneration facility need not use biomass that complies with the definition in subdivision 1.

(e) The public utility must accept and consider on an equal basis with other biomass proposals:

(1) a proposal to satisfy the requirements of this section that includes a project that exceeds the megawatt capacity requirements of either paragraph (a), clause (1) or (2), and that proposes to sell the excess capacity to the public utility or to other purchasers; and

(2) a proposal for a new facility to satisfy more than ten but not more than 20 megawatts of the electrical generation requirements by a small business-sponsored independent power producer facility to be located within the northern quarter of the state, which means the area located north of Constitutional Route No. 8 as described in section 161.114, subdivision 2, and that utilizes biomass residue wood, sawdust, bark, chipped

wood, or brush to generate electricity. A facility described in this clause is not required to utilize biomass complying with the definition in subdivision 1, but must be under construction by December 31, 2005.

(f) If a public utility files a contract with the commission for electric energy installed capacity that uses poultry litter as its primary fuel source, the commission must do a preliminary review of the contract to determine if it meets the purchase price criteria provided in paragraph (b), clause (2). The commission shall perform its review and advise the parties of its determination within 30 days of filing of such a contract by a public utility. A public utility may submit by September 1, 2000, a revised contract to address the commission's preliminary determination.

(g) The commission shall finally approve, modify, or disapprove no later than July 1, 2001, all contracts submitted by a public utility as of September 1, 2000, to meet the mandate set forth in this subdivision.

(h) If a public utility subject to this section exercises an option to increase the generating capacity of a project in a contract approved by the commission prior to April 25, 2000, to satisfy the mandate in this subdivision, the public utility must notify the commission by September 1, 2000, that it has exercised the option and include in the notice the amount of additional megawatts to be generated under the option exercised. Any review by the commission of the project after exercise of such an option shall be based on the same criteria used to review the existing contract.

(i) A facility specified in this subdivision qualifies for exemption from property taxation under section 272.02, subdivision 45.

Subd. 5a. **Reduction of biomass mandate.** (a) Notwithstanding subdivision 5, the biomass electric energy mandate must be reduced from 125 megawatts to 110 megawatts.

(b) The Public Utilities Commission shall approve a request pending before the commission as of May 15, 2003, for amendments to and assignment of a power purchase agreement with the owner of a facility that uses short-rotation, woody crops as its primary fuel previously approved to satisfy a portion of the biomass mandate if the owner of the project agrees to reduce the size of its project from 50 megawatts to 35 megawatts, while maintaining an average price for energy in nominal dollars measured over the term of the power purchase agreement at or below $104 per megawatt-hour, exclusive of any price adjustments that may take effect subsequent to commission approval of the power purchase agreement, as amended. The commission shall also approve, as necessary, any subsequent assignment or sale of the power purchase agreement or ownership of the project to an entity owned or controlled, directly or indirectly, by two municipal utilities located north of Constitutional Route No. 8, as described in section 161.114, which currently own electric and steam generation facilities using coal as a fuel and which propose to retrofit their existing municipal electrical generating facilities to utilize biomass fuels in order to perform the power purchase agreement.

(c) If the power purchase agreement described in paragraph (b) is assigned to an entity that is, or becomes, owned or controlled, directly or indirectly, by two municipal entities as described in paragraph (b), and the power purchase agreement meets the price requirements of paragraph (b), the commission shall approve any amendments to the power purchase agreement necessary to reflect the changes in project location and ownership and any other amendments made necessary by those changes. The commission shall also specifically find that:

(1) the power purchase agreement complies with and fully satisfies the provisions of this section to the full extent of its 35-megawatt capacity;

(2) all costs incurred by the public utility and all amounts to be paid by the public utility to the project owner under the terms of the power purchase agreement are fully recoverable pursuant to section 216B.1645;

(3) subject to prudency review by the commission, the public utility may recover from its Minnesota retail customers the amounts that may be incurred and paid by the public utility during the full term of the power purchase agreement; and

(4) if the purchase power agreement meets the requirements of this subdivision, it is reasonable and in the public interest.

(d) The commission shall specifically approve recovery by the public utility of any and all Minnesota jurisdictional costs incurred by the public utility to improve, construct, install, or upgrade transmission, distribution, or other electrical facilities owned by the public utility or other persons in order to permit interconnection of the retrofitted biomass-fueled generating facilities or to obtain transmission service for the energy provided by the facilities to the public utility pursuant to section 216B.1645, and shall disapprove any provision in the power purchase agreement that requires the developer or owner of the project to pay the jurisdictional costs or that permit the public utility to terminate the power purchase agreement as a result of the existence of those costs or the public utility's obligation to pay any or all of those costs.

(e) Upon request by the project owner, the public utility shall agree to amend the power purchase agreement described in paragraph (b) and approved by the commission as required by paragraph (c). The amendment must be negotiated and executed within 45 days of May 14, 2013, and must apply to prices paid after January 1, 2014. The average price for energy in nominal dollars measured over the term of the power purchase agreement must not exceed $109.20 per megawatt hour. The public utility shall request approval of the amendment by the commission within 30 days of execution of the amended power purchase agreement. The amendment is not effective until approval by the commission. The commission shall act on the amendment within 90 days of submission of the request by the public utility. Upon approval of the amended power purchase agreement, the commission shall allow the public utility to recover the costs of the amended power purchase agreement, as provided in section 216B.1645.

(f) With respect to the power purchase agreement described in paragraph (b), and amended and approved by the commission pursuant to paragraphs (c) and (e), upon request by the project owner, the public utility shall agree to amend the power purchase agreement to include a fuel cost adjustment clause which requires the public utility to reimburse the project owner monthly for all costs incurred by the project owner during the applicable month to procure and transport all fuel used to produce energy for delivery to the public utility pursuant to the power purchase agreement to the extent such costs exceeded $3.40 per million metric British thermal unit (MMBTU), in addition to the price to be paid for the energy produced and delivered by the project owner. Reimbursable costs include but are not limited to: (1) all costs incurred to load fuel at its source; (2) costs to transport fuel (i) to the biomass-fueled generating facilities or to an intermediate woodyard, storage facility, or handling facility, or (ii) from a facility to the biomass-fueled generating facilities; (3) depreciation of any depreciable loading, woodyard, storage, handling, or transportation equipment whether the vehicle or equipment is located at the fuel source, a woodyard, storage facility, handling facility, or at the generating facilities; and (4) costs to unload fuel at the generating facilities. Beginning with 2014, at the end of each calendar year of the term of the power purchase agreement, the project owner shall calculate the amount by which actual fuel costs for the year exceeded $3.40 per MMBTU, and prior monthly payment for such fuel costs shall be reconciled against actual fuel costs for the applicable calendar year. If such prior monthly fuel payments for the year in the aggregate exceed the amount due based on the annual calculation, the project owner shall credit the public utility for the excess paid. If the annual calculation of fuel costs due exceeds the prior monthly fuel payments for the year in the aggregate, the project owner shall be entitled to be paid for the deficiency with the next invoice to the public utility. The amendment shall be negotiated and executed within 45 days of May 13, 2013, and shall be effective for fuel costs incurred and prices after January 1, 2014. The public utility shall request approval of the amendment by the commission, and the commission shall approve the amendment as reasonable and in the public interest and allow the public utility to recover from its Minnesota retail customers the amounts paid by the public utility to the project owner pursuant to the power purchase agreement during the full term of the power purchase agreement, including the reimbursement of fuel costs pursuant to the power purchase agreement amendment, reimbursable costs as provided in this paragraph, pursuant to section 216B.1645, or otherwise.

(g) With respect to the power purchase agreement described in paragraph (b) and approved by the commission pursuant to paragraphs (c) and (e), the public utility is prohibited from recovering from the project owner any costs which were not actually and reasonably incurred by the utility, notwithstanding any provision in the power purchase agreement to the contrary. In addition, beginning with 2012, the public utility shall pay for all energy delivered by the project owner pursuant to the power purchase agreement at the full price for such energy in the power purchase agreement approved and amended pursuant to paragraph (e), provided that the project owner does not deliver more than 110 percent of the amount scheduled for delivery in any year of the power purchase agreement, and does not deliver, on average over any five consecutive years of the power purchase agreement, an amount greater than 105 percent of the amount scheduled for delivery over the five-year period.

Subd. 5b. **Definitions.** (a) For the purposes of subdivision 5c, the following terms have the meanings given.

(b) "Agreement period" means the period beginning January 1, 2023, and ending December 31, 2024.

(c) "Ash" means all species of the genus *Fraxinus*.

(d) "Cogeneration facility" means the St. Paul district heating and cooling system cogeneration facility that uses waste wood as the facility's primary fuel source, provides thermal energy to St. Paul, and sells electricity to a public utility through a power purchase agreement approved by the Public Utilities Commission.

(e) "Department" means the Department of Agriculture.

(f) "Emerald ash borer" means the insect known as emerald ash borer, *Agrilus planipennis* Fairmaire, in any stage of development.

(g) "Renewable energy technology" has the meaning given to "eligible energy technology" in section 216B.1691, subdivision 1.

(h) "St. Paul district heating and cooling system" means a system of boilers, distribution pipes, and other equipment that provides energy for heating and cooling in St. Paul, and includes the cogeneration facility.

(i) "Waste wood from ash trees" means ash logs and lumber, ash tree waste, and ash chips and mulch.

Subd. 5c. **New power purchase agreement.** (a) No later than August 1, 2021, a public utility subject to subdivision 5 and the cogeneration facility may file a proposal with the commission to enter into a power purchase agreement that governs the public utility's purchase of electricity generated by the cogeneration facility. The power purchase agreement may extend no later than December 31, 2024, and must not be extended beyond that date except as provided in paragraph (f).

(b) The commission is prohibited from approving a new power purchase agreement filed under this subdivision that does not meet all of the following conditions:

(1) the cogeneration facility agrees that any waste wood from ash trees removed from Minnesota counties that have been designated as quarantined areas in Section IV of the Minnesota State Formal Quarantine for Emerald Ash Borer, issued by the commissioner of agriculture under section 18G.06, effective November 14, 2019, as amended, for utilization as biomass fuel by the cogeneration facility must be accompanied by evidence:

(i) demonstrating that the transport of biomass fuel from processed waste wood from ash trees to the cogeneration facility complies with the department's regulatory requirements under the Minnesota State Formal Quarantine for Emerald Ash Borer, which may consist of:

(A) a certificate authorized or prepared by the commissioner of agriculture or an employee of the Animal and Plant Health Inspection Service of the United States Department of Agriculture verifying compliance; or

(B) shipping documents demonstrating compliance; or

(ii) certifying that the waste wood from ash trees has been chipped to one inch or less in two dimensions, and was chipped within the county from which the ash trees were originally removed;

(2) the price per megawatt hour of electricity paid by the public utility demonstrates significant savings compared to the existing power purchase agreement, with a price that does not exceed $98 per megawatt hour;

(3) the proposal includes a proposal to the commission for one or more electrification projects that result in the St. Paul district heating and cooling system being powered by electricity generated from renewable energy technologies. The plan must evaluate electrification at three or more levels from ten to 100 percent, including 100 percent of the energy used by the St. Paul district heating and cooling system to be implemented by December 31, 2027. The proposal may also evaluate alternative dates for implementation. For each level of electrification analyzed, the proposal must contain:

(i) a description of the alternative electrification technologies evaluated and whose implementation is proposed as part of the electrification project;

(ii) an estimate of the cost of the electrification project to the public utility, the impact on the monthly energy bills of the public utility's Minnesota customers, and the impact on the monthly energy bills of St. Paul district heating and cooling system customers;

(iii) an estimate of the reduction in greenhouse gas emissions resulting from the electrification project, including greenhouse gas emissions associated with the transportation of waste wood;

(iv) estimated impacts on the operations of the St. Paul district heating and cooling system; and

(v) a timeline for the electrification project; and

(4) the power purchase agreement provides a net benefit to the utility customers or the state.

(c) The commission may approve, or approve as modified, a proposed electrification project that meets the requirements of this subdivision if it finds the electrification project is in the public interest, or the commission may reject the project if it finds that the project is not in the public interest. When determining whether an electrification project is in the public interest, the commission may consider the effects of the electrification project on air emissions from the St. Paul district heating and cooling system and how the emissions impact the environment and residents of affected neighborhoods.

(d) During the agreement period, the cogeneration facility must attempt to obtain funding to reduce the cost of generating electricity and enable the facility to continue to operate beyond the agreement period to address the removal of ash trees, as described in paragraph (b), clause (1). The cogeneration facility must submit periodic reports to the commission regarding the efforts made under this paragraph.

(e) Upon approval of the new power purchase agreement, the commission must require periodic reporting regarding progress toward development of a proposal for an electrification project.

(f) Except as provided in paragraph (a), the commission is allowed to approve a power purchase agreement after the agreement period without approving an electrification project. Nothing in this section shall require any utility to enter into a power purchase agreement with the cogeneration facility after December 31, 2024.

(g) Upon approval of an electrification project, the commission must require periodic reporting regarding the progress toward implementation of the electrification project.

(h) If the commission approves the proposal submitted under paragraph (b), clause (3), the commission may allow the public utility to recover prudently incurred costs net of revenues resulting from the electrification project through an automatic cost recovery mechanism that allows for cost recovery outside of a general rate case. The cost recovery mechanism approved by the commission must:

(1) allow a reasonable return on the capital invested in the electrification project by the public utility, as determined by the commission; and

(2) recover costs only from the public utility's Minnesota electric service customers.

Subd. 6. **Remaining megawatt compliance process.** (a) If there remain megawatts of biomass power generating capacity to fulfill the mandate in subdivision 5 after the commission has taken final action on all contracts filed by September 1, 2000, by a public utility, as amended and assigned, this subdivision governs final compliance with the biomass energy mandate in subdivision 5 subject to the requirements of subdivisions 7 and 8.

(b) To the extent not inconsistent with this subdivision, the provisions of subdivisions 2, 3, 4, and 5 apply to proposals subject to this subdivision.

(c) A public utility must submit proposals to the commission to complete the biomass mandate. The commission shall require a public utility subject to this section to issue a request for competitive proposals for projects for electric generation utilizing biomass as defined in paragraph (f) of this subdivision to provide the remaining megawatts of the mandate. The commission shall set an expedited schedule for submission of proposals to the utility, selection by the utility of proposals or projects, negotiation of contracts, and review by the commission of the contracts or projects submitted by the utility to the commission.

(d) Notwithstanding the provisions of subdivisions 1 to 5 but subject to the provisions of subdivisions 7 and 8, a new or existing facility proposed under this subdivision that is fueled either by biomass or by co-firing biomass with nonbiomass may satisfy the mandate in this section. Such a facility need not use biomass that complies with the definition in subdivision 1 if it uses biomass as defined in paragraph (f) of this subdivision. Generating capacity produced by co-firing of biomass that is operational as of April 25, 2000, does not meet the requirements of the mandate, except that additional co-firing capacity added at an existing facility after April 25, 2000, may be used to satisfy this mandate. Only the number of megawatts of capacity at a facility which co-fires biomass that are directly attributable to the biomass and that become operational after April 25, 2000, count toward meeting the biomass mandate in this section.

(e) Nothing in this subdivision precludes a facility proposed and approved under this subdivision from using fuel sources that are not biomass in compliance with subdivision 3.

(f) Notwithstanding the provisions of subdivision 1, for proposals subject to this subdivision, "biomass" includes farm-grown closed-loop biomass; agricultural wastes, including animal, poultry, and plant wastes; and waste wood, including chipped wood, bark, brush, residue wood, and sawdust.

(g) Nothing in this subdivision affects in any way contracts entered into as of April 25, 2000, to satisfy the mandate in subdivision 5.

(h) Nothing in this subdivision requires a public utility to retrofit its own power plants for the purpose of co-firing biomass fuel, nor is a utility prohibited from retrofitting its own power plants for the purpose of co-firing biomass fuel to meet the requirements of this subdivision.

Subd. 7. **Effect on existing projects.** The commission may not approve a project proposed after April 25, 2000, which would have an adverse impact on the ability of a project approved before April 25, 2000, to obtain an adequate supply of the fuel source designated for the project.

Subd. 8. **Agricultural biomass requirement.** Of the 125 megawatts mandated in subdivision 5, or 110 megawatts mandated in subdivision 5a, at least 75 megawatts of the generating capacity must be generated by facilities that use agricultural biomass as the principal fuel source. For purposes of this subdivision, agricultural biomass includes only farm-grown closed-loop biomass and agricultural waste, including animal, poultry, and plant wastes. For purposes of this subdivision, "principal fuel source" means a fuel source that satisfies at least 75 percent of the fuel requirements of an electric power generating facility. Nothing in this subdivision is intended to expand the fuel source requirements of subdivision 5.

Subd. 9. **Adjustment of biomass fuel requirement.** (a) Notwithstanding any provision in this section, the public utility subject to this section may, with respect to a facility approved under this section, file a petition with the commission for approval of:

(1) a new or amended power purchase agreement;

(2) the early termination of a power purchase agreement; or

(3) the purchase and closure of the facility.

(b) The commission may approve a new or amended power purchase agreement under this subdivision, notwithstanding the fuel requirements of this section, if the commission determines that:

(1) all parties to the original power purchase agreement, or their successors or assigns, as applicable, agree to the terms and conditions of the new or amended power purchase agreement; and

(2) the new or amended power purchase agreement is in the best interest of the customers of the public utility subject to this section, taking into consideration any savings realized by customers in the new or amended power purchase agreement and any costs imposed on customers under paragraph (e). A new or amended power purchase agreement approved under this paragraph may be for any term agreed to by the parties and may govern the purchase of any amount of energy.

(c) The commission may approve the early termination of a power purchase agreement or the purchase and closure of a facility under this subdivision if it determines that:

(1) all parties to the power purchase agreement, or their successors or assigns, as applicable, agree to the early termination of the power purchase agreement or the purchase and closure of the facility; and

(2) the early termination of the power purchase agreement or the purchase and closure of the facility is in the best interest of the customers of the public utility subject to this section, taking into consideration any savings realized by customers as a result of the early termination of the power purchase agreement or the purchase and closure of the facility and any costs imposed on the customers under paragraph (e).

(d) The commission's approval of a new or amended power purchase agreement under paragraph (b) or of the termination of a power purchase agreement or the purchase and closure of a facility under paragraph (c), shall not require the public utility subject to this section to purchase replacement amounts of biomass energy to fulfill the requirements of this section.

(e) A utility may petition the commission to approve a rate schedule that provides for the automatic adjustment of charges to recover investments, expenses and costs, and earnings on the investments associated with a new or amended power purchase agreement, the early termination of a power purchase agreement, or the purchase and closure of a facility. The commission may approve the rate schedule upon a showing that the recovery of investments, expenses and costs, and earnings on the investments is less than the costs that would have been recovered from customers had the utility continued to purchase energy under the power purchase agreement in effect before any option available under this section is approved by the commission. If approved by the commission, cost recovery under this paragraph may include all cost recovery allowed for renewable facilities under section 216B.1645, subdivisions 2 and 2a.

(f) This subdivision does not apply to a St. Paul district heating and cooling system cogeneration facility, and nothing in this subdivision precludes a public utility that operates a nuclear-power electric generating plant from filing a petition with the commission for approval of a new or amended power purchase agreement with such a facility.

(g) For the purposes of this subdivision, "facility" means a biomass facility previously approved by the commission to satisfy a portion of the biomass mandate in this section.

History: *1994 c 641 art 3 s 3; 1995 c 224 s 76; 1996 c 450 s 1; 1998 c 345 s 2; 2000 c 443 s 1-5; 2001 c 7 s 46; 1Sp2001 c 5 art 3 s 13; 2002 c 379 art 1 s 55; 2003 c 127 art 2 s 3; 1Sp2003 c 11 art 2 s 7,16; 2005 c 97 art 5 s 1-6; 1Sp2005 c 1 art 2 s 140; 2006 c 259 art 4 s 4; 2008 c 296 art 1 s 12; 2009 c 110 s 22; 2013 c 57 s 1; 2016 c 157 s 1; 2017 c 94 art 10 s 20; 2021 c 23 s 1,2; 2023 c 60 art 9 s 8*

216B.2425 STATE TRANSMISSION AND DISTRIBUTION PLAN.

Subdivision 1. **List.** The commission shall maintain a list of certified high-voltage transmission line and grid enhancing technology projects.

Subd. 1a. **Definitions.** (a) For the purposes of this section, the following terms have the meanings given.

(b) "Capacity" means the maximum amount of electricity that can flow through a transmission line while observing industry safety standards.

(c) "Congestion" means a condition in which a lack of transmission line capacity prevents the delivery of the lowest-cost electricity dispatched to meet load at a specific location.

(d) "Dynamic line rating" means hardware or software used to calculate the thermal limit of existing transmission lines at a specific point in time by incorporating information on real-time and forecasted weather conditions.

(e) "Grid enhancing technology" means hardware or software that reduces congestion or enhances the flexibility of the transmission system by increasing the capacity of a high-voltage transmission line or rerouting electricity from overloaded to uncongested lines, while maintaining industry safety standards. Grid enhancing technologies include but are not limited to dynamic line rating, advanced power flow controllers, and topology optimization.

(f) "Power flow controller" means hardware and software used to reroute electricity from overloaded transmission lines to underutilized transmission lines.

(g) "Thermal limit" means the temperature a transmission line reaches when heat from the electric current flow within the transmission line causes excessive sagging of the transmission line.

(h) "Topology optimization" means a software technology that uses mathematical models to identify reconfigurations in the transmission grid in order to reroute electricity from overloaded transmission lines to underutilized transmission lines.

(i) "Transmission line" has the meaning given to "high-voltage transmission line" in section 216I.02, subdivision 8.

(j) "Transmission system" means a network of high-voltage transmission lines owned or operated by an entity subject to this section that transports electricity to Minnesota customers.

Subd. 2. **List development; transmission and grid enhancing technology projects report.** (a) By November 1 of each odd-numbered year, a transmission projects report must be submitted to the commission by each utility, organization, or company that:

(1) is a public utility, a municipal utility, a cooperative electric association, the generation and transmission organization that serves each utility or association, or a transmission company; and

(2) owns or operates electric transmission lines in Minnesota, except a company or organization that owns a transmission line that serves a single customer or interconnects a single generating facility.

(b) The report may be submitted jointly or individually to the commission.

(c) The report must:

(1) list specific present and reasonably foreseeable future inadequacies in the transmission system in Minnesota;

(2) identify alternative means of addressing each inadequacy listed, including grid enhancing technologies such as dynamic line rating, power flow controllers, topology optimization, and other hardware or software that reduce congestion or enhance the flexibility of the transmission system;

(3) identify general economic, environmental, and social issues associated with each alternative; and

(4) provide a summary of public input related to the list of inadequacies and the role of local government officials and other interested persons in assisting to develop the list and analyze alternatives.

(d) To meet the requirements of this subdivision, reporting parties may rely on available information and analysis developed by a regional transmission organization or any subgroup of a regional transmission organization and may develop and include additional information as necessary.

(e) In addition to providing the information required under this subdivision, a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.

Subd. 3. **Commission approval.** (a) By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. Except as provided in paragraph (b), the commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is:

(1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers;

(2) needed, applying the criteria in section 216B.243, subdivision 3; and

(3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.

(b) The commission may certify a project proposed under subdivision 2, paragraph (e), only if the commission finds the proposed project is in the public interest.

Subd. 4. **List; effect.** Certification of a project as a priority electric transmission project satisfies section 216B.243. A certified project on which construction has not begun more than six years after being placed on the list, must be reapproved by the commission.

Subd. 5. **Transmission inventory.** The Department of Commerce shall create, maintain, and update annually an inventory of transmission lines in the state.

Subd. 6. **Exclusion.** This section does not apply to any transmission line proposal that has been approved by, or was pending before, a local unit of government, the Environmental Quality Board, or the Public Utilities Commission on August 1, 2001.

Subd. 7. **Transmission needed to support renewable resources.** (a) Each entity subject to this section shall determine necessary transmission upgrades to support development of renewable energy resources required to meet objectives under section 216B.1691 and shall include those upgrades in its report under subdivision 2.

(b) MS 2008 [Expired]

Subd. 8. **Distribution study for distributed generation.** Each entity subject to this section that is operating under a multiyear rate plan approved under section 216B.16, subdivision 19, shall conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources, and shall include the study in its report required under subdivision 2.

Subd. 9. **Integrated distribution plan; contents.** The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023:

(1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects, including energy storage systems;

(2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and

(3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.

History: *2001 c 212 art 7 s 30; 2002 c 379 art 1 s 56; 1Sp2003 c 11 art 2 s 8; 2005 c 97 art 1 s 7; art 2 s 3,7; 2011 c 97 s 22; 1Sp2015 c 1 art 3 s 22; 2023 c 60 art 12 s 20,21; 2024 c 126 art 6 s 19-21; 2024 c 127 art 42 s 19-21*

216B.2426 OPPORTUNITIES FOR DISTRIBUTED GENERATION.

The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.

History: *2005 c 97 art 8 s 1*

216B.2427 NATURAL GAS UTILITY INNOVATION PLANS.

Subdivision 1. **Definitions.** (a) For the purposes of this section and section 216B.2428, the following terms have the meanings given.

(b) "Biogas" means gas produced by the anaerobic digestion of biomass, gasification of biomass, or other effective conversion processes.

(c) "Carbon capture" means the capture of greenhouse gas emissions that would otherwise be released into the atmosphere.

(d) "Carbon-free resource" means an electricity generation facility whose operation does not contribute to statewide greenhouse gas emissions, as defined in section 216H.01, subdivision 2.

(e) "Disadvantaged community" means a community in Minnesota that is:

(1) defined as disadvantaged by the federal agency disbursing federal funds, when the federal agency is providing funds for an innovative resource; or

(2) an environmental justice area, as defined under section 216B.1691, subdivision 1.

(f) "District energy" means a heating or cooling system that is solar thermal powered or that uses the constant temperature of the earth or underground aquifers as a thermal exchange medium to heat or cool multiple buildings connected through a piping network.

(g) "Energy efficiency" has the meaning given in section 216B.241, subdivision 1, paragraph (f), but does not include energy conservation investments that the commissioner determines could reasonably be included in a utility's conservation improvement program.

(h) "Greenhouse gas emissions" means emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within Minnesota and from the generation of electricity imported from outside the state and consumed in Minnesota, excluding carbon dioxide that is injected into geological formations to prevent its release to the atmosphere in compliance with applicable laws.

(i) "Innovative resource" means biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture, strategic electrification, district energy, and energy efficiency.

(j) "Lifecycle greenhouse gas emissions" means the aggregate greenhouse gas emissions resulting from the production, processing, transmission, and consumption of an energy resource.

(k) "Lifecycle greenhouse gas emissions intensity" means lifecycle greenhouse gas emissions per unit of energy delivered to an end user.

(l) "Nonexempt customer" means a utility customer that has not been included in a utility's innovation plan under subdivision 3, paragraph (f).

(m) "Power-to-ammonia" means the production of ammonia from hydrogen produced via power-to-hydrogen using a process that has a lower lifecycle greenhouse gas intensity than does natural gas produced from conventional geologic sources.

(n) "Power-to-hydrogen" means the use of electricity generated by a carbon-free resource to produce hydrogen.

(o) "Renewable energy" has the meaning given in section 216B.2422, subdivision 1.

(p) "Renewable natural gas" means biogas that has been processed to be interchangeable with, and that has a lower lifecycle greenhouse gas intensity than, natural gas produced from conventional geologic sources.

(q) "Solar thermal" has the meaning given to qualifying solar thermal project in section 216B.2411, subdivision 2, paragraph (d).

(r) "Strategic electrification" means the installation of electric end-use equipment in an existing building in which natural gas is a primary or back-up fuel source, or in a newly constructed building in which a customer receives natural gas service for one or more end-uses, provided that the electric end-use equipment:

(1) results in a net reduction in statewide greenhouse gas emissions, as defined in section 216H.01, subdivision 2, over the life of the equipment when compared to the most efficient commercially available natural gas alternative; and

(2) is installed and operated in a manner that improves the load factor of the customer's electric utility.

Strategic electrification does not include investments that the commissioner determines could reasonably be included in the natural gas utility's conservation improvement program under section 216B.241.

(s) "Thermal energy network" means a project that provides heating and cooling to multiple buildings connected via underground piping containing fluids that, in concert with heat pumps, exchange thermal energy from the earth, underground or surface waters, wastewater, or other heat sources.

(t) "Total incremental cost" means the calculation of the following components of a utility's innovation plan approved by the commission under subdivision 2:

(1) the sum of:

(i) return of and on capital investments for the production, processing, pipeline interconnection, storage, and distribution of innovative resources;

(ii) incremental operating costs associated with capital investments in infrastructure for the production, processing, pipeline interconnection, storage, and distribution of innovative resources;

(iii) incremental costs to procure innovative resources from third parties;

(iv) incremental costs to develop and administer programs; and

(v) incremental costs for research and development related to innovative resources;

(2) less the sum of:

(i) value received by the utility upon the resale of innovative resources or innovative resource by-products, including any environmental credits included with the resale of renewable gaseous fuels or value received by the utility when innovative resources are used as vehicle fuel;

(ii) cost savings achieved through avoidance of purchases of natural gas produced from conventional geologic sources, including but not limited to avoided commodity purchases and avoided pipeline costs; and

(iii) other revenues received by the utility that are directly attributable to the utility's implementation of an innovation plan.

(u) "Utility" means a public utility, as defined in section 216B.02, subdivision 4, that provides natural gas sales or natural gas transportation services to customers in Minnesota.

Subd. 2. **Innovation plans.** (a) A natural gas utility may file an innovation plan with the commission. The utility's plan must include, as applicable, the following components:

(1) the innovative resource or resources the utility plans to implement to contribute to meeting the state's greenhouse gas and renewable energy goals, including those established in section 216C.05, subdivision 2, clause (3), and section 216H.02, subdivision 1, within the requirements and limitations set forth in this section;

(2) research and development investments related to innovative resources the utility plans to undertake;

(3) total lifecycle greenhouse gas emissions that the utility projects are reduced or avoided through implementing the plan;

(4) a comparison of the estimate in clause (3) to total emissions from natural gas use by utility customers in 2020;

(5) a description of each pilot program included in the plan that is related to the development or provision of innovative resources, and an estimate of the total incremental costs to implement each pilot program;

(6) the cost-effectiveness of innovative resources calculated from the perspective of the utility, society, the utility's nonparticipating customers, and the utility's participating customers compared to other innovative resources that could be deployed to reduce or avoid the same greenhouse gas emissions targeted for reduction by the utility's proposed innovative resource;

(7) for any pilot program not previously approved as part of the utility's most recent innovation plan, a third-party analysis of:

(i) the lifecycle greenhouse gas emissions intensity of the proposed innovative resources; and

(ii) the forecasted lifecycle greenhouse gas emissions reduced or avoided if the proposed pilot program is implemented;

(8) an explanation of the methodology used by the utility to calculate the lifecycle greenhouse gas emissions avoided or reduced by each pilot program included in the plan, including descriptions of how the utility's method deviated, if at all, from the carbon accounting frameworks established by the commission under section 216B.2428;

(9) a discussion of whether the plan supports the development and use of alternative agricultural products, waste reduction, reuse, or anaerobic digestion of organic waste, and the recovery of energy from wastewater, and, if it does, a description of the geographic areas of the state in which the benefits are realized;

(10) a description of third-party systems and processes the utility plans to use to:

(i) track the innovative resources included in the plan so that environmental benefits produced by the plan are not claimed for any other program; and

(ii) verify the environmental attributes and greenhouse gas emissions intensity of innovative resources included in the plan;

(11) projected local job impacts resulting from implementation of the plan and a description of steps the utility and the utility's energy suppliers and contractors are taking to maximize the availability of construction employment opportunities for local workers;

(12) a description of how the utility proposes to recover annual total incremental costs of the plan;

(13) steps the utility has taken or proposes to take to reduce the expected cost of the plan on low- and moderate-income residential customers and to ensure that low- and moderate-income residential customers benefit from innovative resources included in the plan;

(14) a report on the utility's progress toward implementing the utility's previously approved innovation plan, if applicable;

(15) a report of the utility's progress toward achieving the cost-effectiveness objectives established by the commission with respect to the utility's previously approved innovation plan, if applicable; and

(16) collections of pilot programs that the utility estimates would, if implemented, provide approximately 50 percent, 150 percent, and 200 percent of the greenhouse gas reduction or avoidance benefits of the utility's proposed plan.

(b) The commission must approve, modify, or reject a plan. The commission must not approve an innovation plan unless the commission finds:

(1) the size, scope, and scale of the plan produces net benefits under the cost-benefit framework established by the commission in section 216B.2428;

(2) the plan promotes the use of renewable energy resources and reduces or avoids greenhouse gas emissions at a cost level consistent with subdivision 3;

(3) the plan promotes local economic development;

(4) the innovative resources included in the plan have a lower lifecycle greenhouse gas intensity than natural gas produced from conventional geologic sources;

(5) the systems used to track and verify the environmental attributes of the innovative resources included in the plan are reasonable, considering available third-party tracking and verification systems;

(6) the costs and revenues projected under the plan are reasonable in comparison to other innovative resources the utility could deploy to reduce greenhouse gas emissions, considering other benefits of the innovative resources included in the plan;

(7) the total amount of estimated greenhouse gas emissions reduction or avoidance to be achieved under the plan is reasonable considering the state's greenhouse gas and renewable energy goals, including those established in section 216C.05, subdivision 2, clause (3), and section 216H.02, subdivision 1; customer cost; and the total amount of greenhouse gas emissions reduction or avoidance achieved under the utility's previously approved plans, if applicable; and

(8) any renewable natural gas purchased by a utility under the plan that is produced from the anaerobic digestion of manure is certified as being produced at an agricultural livestock production facility that has not and does not increase the number of animal units at the facility solely or primarily to produce renewable natural gas for the plan.

(c) In seeking to recover costs under a plan approved by the commission under this section, the utility must demonstrate to the satisfaction of the commission that the actual total incremental costs incurred to implement the approved innovation plan are reasonable. Prudently incurred costs under an approved plan, including prudently incurred costs to obtain the third-party analysis required in paragraph (a), clauses (6) and (7), are recoverable either:

(1) under section 216B.16, subdivision 7, clause (2), via the utility's purchased gas adjustment;

(2) in the utility's next general rate case; or

(3) via annual adjustments, provided that after notice and comment the commission determines that the costs included for recovery through rates are prudently incurred. Annual adjustments must include a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and incremental operation and maintenance expenses. The rate of return must be at the level approved by the commission in the utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.

(d) The commission may not approve a utility's initial plan filed under this section unless:

(1) 50 percent or more of the utility's costs approved by the commission for recovery under the plan are for the procurement and distribution of renewable natural gas, biogas, hydrogen produced via power-to-hydrogen, and ammonia produced via power-to-ammonia; and

(2) the utility's costs approved by the commission for recovery for any pilot program to facilitate the development, expansion, or modification of district energy systems, as required under subdivision 9, represent no more than 20 percent of the total costs approved by the commission for recovery under the plan.

(e) Upon approval of a utility's plan, the commission shall establish cost-effectiveness objectives for the plan based on the cost-benefit test for innovative resources developed under section 216B.2428. The cost-effectiveness objective for each plan must demonstrate incremental progress from the previously approved plan's cost-effectiveness objective.

(f) A utility operating under an approved plan must file annual reports to the commission on work completed under the plan, including:

(1) costs incurred;

(2) lifecycle greenhouse gas emissions reductions or avoidance achieved;

(3) a description of the processes used to track and verify the innovative resources and to retire the associated environmental attributes;

(4) an assessment of the degree to which the lifecycle greenhouse gas accounting methodology is consistent with current science;

(5) the economic impact of the plan, including job creation;

(6) the utility's progress toward achieving the cost-effectiveness objectives established by the commission; and

(7) modifications to elements of the plan proposed by the utility.

(g) When evaluating a utility's annual report, the commission may:

(1) approve the continuation of a pilot program included in the plan, with or without modifications;

(2) require the utility to file a new or modified pilot program or plan; or

(3) disapprove the continuation of a pilot program or plan.

(h) An innovation plan has a term of five years. A subsequent innovation plan must be filed no later than four years after the previous plan was approved by the commission so that, if approved, the new plan takes effect immediately upon expiration of the previous plan.

(i) For purposes of this section and the commission's lifecycle carbon accounting framework and cost-benefit test for innovative resources under section 216B.2428, any required analysis of lifecycle greenhouse gas emissions reductions or avoidance, or lifecycle greenhouse gas intensity:

(1) must include but is not limited to estimates of:

(i) avoided or reduced greenhouse gas emissions attributable to utility operations;

(ii) avoided or reduced greenhouse gas emissions from the production, processing, and transmission of fuels prior to receipt by the utility; and

(iii) avoided or reduced greenhouse gas emissions at the point of end use;

(2) must not count any unit of greenhouse gas emissions avoidance or reduction more than once; and

(3) may, where direct measurement is not technically or economically feasible, rely on emissions factors, default values, or engineering estimates from a publicly accessible source accepted by a federal or state government agency, provided that the emissions factors, default values, or engineering estimates can be demonstrated to the satisfaction of the commission to produce a reasonable estimate of greenhouse gas emissions reductions, avoidance, or intensity.

(j) Strategic electrification implemented in a plan approved by the commission under this section is not eligible for a financial incentive under section 216B.241, subdivision 2c. Electric end-use equipment installed under a plan approved by the commission under this section is the exclusive property of the building owner.

Subd. 3. **Limitations on utility customer costs.** (a) Except as provided in paragraph (b), the first innovation plan submitted to the commission by a utility must not propose, and the commission must not approve, annual total incremental costs exceeding the lesser of:

(1) 1.75 percent of the utility's gross operating revenues from natural gas service provided in Minnesota at the time of plan filing; or

(2) $20 per nonexempt customer, based on the proposed annual total incremental costs for each year of the plan divided by the total number of nonexempt utility customers.

(b) The commission may approve additional annual costs up to the lesser of:

(1) an additional 0.25 percent of the utility's gross operating revenues from service provided in Minnesota at the time of plan filing; or

(2) $5 per nonexempt customer, based on the proposed annual total incremental costs for each year of the plan divided by the total number of nonexempt utility customers of incremental costs.

The commission may approve the additional costs under this paragraph only if the commission determines that the additional costs are associated exclusively with the purchase of renewable natural gas produced from:

(i) food waste diverted from a landfill;

(ii) a municipal wastewater treatment system; or

(iii) an organic mixture that includes at least 15 percent, by volume, sustainably harvested native prairie grasses or locally appropriate cover crops, as determined by a local soil and water conservation district or the United States Department of Agriculture, Natural Resources Conservation Service.

(c) Unless the commission determines that paragraph (d) applies, if the commission determines that the utility has successfully achieved the cost-effectiveness objectives established in the utility's most recently approved innovation plan, the next subsequent plan filed by the utility under this section is subject to the provisions of paragraphs (a) and (b), except that:

(1) the cap on total incremental costs in paragraph (a) with respect to the second plan is the lesser of:

(i) 2.75 percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $35 per nonexempt customer; and

(2) the cap on additional costs in paragraph (b) is the lesser of:

(i) an additional 0.75 percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $10 per nonexempt customer.

(d) If the commission determines that the utility has successfully achieved the cost-effectiveness objectives established in two of the same utility's previously approved innovation plans, all subsequent plans filed by the utility under this section are subject to paragraphs (a) and (b), except that:

(1) the cap on total incremental costs in paragraph (a) with respect to the third or subsequent plan is the lesser of:

(i) four percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $50 per nonexempt customer; and

(2) the cap on additional costs in paragraph (b) is the lesser of:

(i) an additional 1.5 percent of the utility's gross operating revenues from natural gas service in Minnesota at the time of the plan's filing; or

(ii) $20 per nonexempt customer.

(e) For purposes of paragraphs (a) to (d), the limits on annual total incremental costs must be calculated at the time the innovation plan is filed as the average of the utility's forecasted total incremental costs over the five-year term of the plan.

(f) A large customer facility that the commissioner of commerce has exempted from a utility's conservation improvement program under section 216B.241, subdivision 1a, paragraph (b), is exempt from the utility's innovation plan offerings and must not be charged any costs incurred to implement an approved innovation plan unless the large customer facility files a request with the commissioner to be included in a utility's innovation plan. The commission may prohibit large customer facilities exempt from innovation plan costs from participating in innovation plans.

(g) A utility filing an innovation plan may include annual spending and investments on research and development of up to ten percent of the proposed total incremental costs related to innovative plans, subject to the limitations in paragraphs (a) to (e).

(h) For purposes of this subdivision, gross operating revenues do not include revenues from large customer facilities exempt from innovation plan costs.

Subd. 4. **Innovative resources procured outside of an innovation plan.** (a) Without filing an innovation plan, a natural gas utility may propose and the commission may approve cost recovery for:

(1) innovative resources acquired to satisfy a commission-approved green tariff program that allows customers to choose to meet a portion of the customers' energy needs through innovative resources; or

(2) utility expenditures for innovative resources procured at a cost that is within five percent of the average of Ventura and Demarc index prices for natural gas produced from conventional geologic sources at the time of the transaction per unit of natural gas that the innovative resource displaces.

(b) An approved green tariff program must include provisions to ensure that reasonable systems are used to track and verify the environmental attributes of innovative resources included in the program, taking into account any available third-party tracking or verification systems.

(c) For the purposes of this subdivision, "Ventura and Demarc index prices" means the daily index price of wholesale natural gas sold at the Northern Natural Gas Company's Ventura trading hub in Hancock County, Iowa, and its demarcation point in Clifton, Kansas.

Subd. 5. **Power-to-ammonia.** When determining whether to approve a power-to-ammonia pilot program as part of an innovative plan, the commission must consider:

(1) the risk of exposing any person to unhealthy concentrations of ammonia;

(2) the risk that any home or business might be affected by ammonia odors;

(3) whether the greenhouse gas emissions addressed by the proposed power-to-ammonia project could be more efficiently addressed using power-to-hydrogen; and

(4) whether the power-to-ammonia project achieves lifecycle greenhouse gas emissions reductions in the agricultural sector more effectively than power-to-hydrogen.

Subd. 6. **Thermal energy audits.** The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program to provide thermal energy audits to small- and medium-sized businesses in order to identify opportunities to reduce or avoid greenhouse gas emissions from natural gas use. The pilot program must provide incentives for businesses to implement recommendations made by the audit. The utility must develop criteria to identify businesses that achieve significant emissions reductions by implementing audit recommendations and must recognize the businesses as thermal energy leaders.

Subd. 7. **Innovative resources for certain industrial processes.** The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program to provide innovative resources to industrial facilities whose manufacturing processes, for technical reasons, are not amenable to electrification. A large customer facility exempt from innovation plan offerings under subdivision 3, paragraph (f), is not eligible to participate in the pilot program under this subdivision.

Subd. 8. **Electric cold climate air-source heat pumps.** (a) The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program that facilitates deep energy retrofits and the installation of cold climate electric air-source heat pumps in existing residential homes that have natural gas heating systems.

(b) For purposes of this subdivision, "deep energy retrofit" means the installation of any measure or combination of measures, including air sealing and addressing thermal bridges, that under normal weather and operating conditions can reasonably be expected to reduce a building's calculated design load to ten or fewer British Thermal Units per hour per square foot of conditioned floor area. Deep energy retrofit does not include the installation of photovoltaic electric generation equipment, but may include the installation of a solar thermal energy project.

Subd. 9. **District energy.** The first innovation plan filed under this section by a utility with more than 800,000 customers must include a pilot program to facilitate the development, expansion, or modification of district energy systems in Minnesota. This subdivision does not require the utility to propose, construct, maintain, or own district energy infrastructure.

Subd. 9a. **Thermal energy networks.** Innovation plans filed after July 1, 2024, under this section by a utility with more than 800,000 customers must include spending of at least 15 percent of the utility's proposed total incremental costs over the five-year term of the proposed innovation plan for thermal energy networks projects. If the utility has developed or is developing thermal energy network projects outside of an approved innovation plan, the utility may apply the budget for the projects toward the 15 percent minimum requirement without counting the costs against the limitations on utility customer costs under subdivision 3.

Subd. 10. **Throughput goal.** It is the goal of the state of Minnesota that through the Natural Gas Innovation Act and Conservation Improvement Program, utilities reduce the overall amount of natural gas produced from conventional geologic sources delivered to customers.

Subd. 11. **Utility system report and forecasts.** (a) A public utility filing an innovation plan shall concurrently submit a report to the commission containing the following information:

(1) the volume of methane gas emissions attributed to venting or leakage across the utility's system, including emissions information reported to the Environmental Protection Agency and gas leaks considered

to be hazardous or nonhazardous, and a narrative description of the utility's expectations regarding the cost and performance of the utility's leakage reduction programs over the next five years;

(2) total system greenhouse gas emissions and greenhouse gas emissions projected to be reduced or avoided through innovative resource investments and energy conservation investments, and a narrative description of the costs required to achieve the reductions over the next five years through investments in innovative resources and energy conservation;

(3) the quantity of pipe in service in the utility's natural gas network in Minnesota, by material, size, coating, operating pressure, and decade of installation, based on utility information reported to the United States Department of Transportation;

(4) a narrative description of other significant equipment owned and operated by the utility through which gas is transported or stored, including regulator stations and storage facilities, a discussion of the function of the equipment, how the equipment is maintained, and utility efforts to prevent leaks from the equipment;

(5) a five-year forecast of fuel prices and anticipated purchases including, as available, natural gas produced from conventional geologic sources, renewable natural gas, and alternative fuels;

(6) a five-year forecast of potential capital investments by the utility in existing infrastructure and new infrastructure for natural gas produced from conventional geologic sources and for innovative resources; and

(7) an inventory of the utility's current financial incentive programs for natural gas, including rebates and incentives offered for new and existing buildings and a description of the utility's projected changes in incentives the utility is likely to implement over the next five years.

(b) Information filed under this subdivision is intended to be used by the commission to evaluate a utility's innovation plan in the context of the utility's other planned investments and activities with respect to natural gas produced from conventional geologic sources. Information filed under this subdivision must not be used by the commission to set or limit utility rate recovery.

History: *1Sp2021 c 4 art 8 s 20; 2024 c 126 art 6 s 22,23; 2024 c 127 art 42 s 22,23*

216B.2428 LIFECYCLE GREENHOUSE GAS EMISSIONS ACCOUNTING FRAMEWORK; COST-BENEFIT TEST FOR INNOVATIVE RESOURCES.

By June 1, 2022, the commission shall, by order, issue frameworks the commission must use to calculate lifecycle greenhouse gas emissions intensities of each innovative resource, as follows:

(1) a general framework to compare the lifecycle greenhouse gas emissions intensities of power-to-hydrogen, strategic electrification, renewable natural gas, district energy, energy efficiency, biogas, carbon capture, and power-to-ammonia; and

(2) a cost-benefit analytic framework to be applied to innovative resources and innovation plans filed under section 216B.2427 that the commission must use to compare the cost-effectiveness of those resources and plans. This analytic framework must take into account:

(i) the total incremental cost of the plan or resource and the lifecycle greenhouse gas emissions avoided or reduced by the innovative resource or plan, using the framework developed under clause (1);

(ii) additional economic costs and benefits, programmatic costs and benefits, additional environmental costs and benefits, and other costs or benefits that may be expected under a plan; and

(iii) baseline cost-effectiveness criteria against which an innovation plan should be compared. When establishing baseline criteria, the commission must take into account options available to reduce lifecycle greenhouse gas emissions from natural gas end uses and the goals in section 216C.05, subdivision 2, clause (3), and section 216H.02, subdivision 1. To the maximum reasonable extent, the cost-benefit framework must be consistent with environmental cost values established under section 216B.2422, subdivision 3, and other calculations of the social value of greenhouse gas emissions reductions used by the commission. The commission may update frameworks established under this section as necessary.

History: *1Sp2021 c 4 art 8 s 21*

CERTIFICATE OF NEED

216B.243 CERTIFICATE OF NEED FOR LARGE ENERGY FACILITY.

Subdivision 1. **Assessment of need criteria.** The commission shall, pursuant to chapter 14 and sections 216C.05 to 216C.30 and this section, adopt assessment of need criteria to be used in the determination of need for large energy facilities pursuant to this section.

Subd. 2. **Certificate required.** No large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the commission pursuant to sections 216C.05 to 216C.30 and this section and consistent with the criteria for assessment of need.

Subd. 3. **Showing required for construction.** No proposed large energy facility shall be certified for construction unless the applicant can show that demand for electricity cannot be met more cost effectively through energy conservation and load-management measures and unless the applicant has otherwise justified its need. In assessing need, the commission shall evaluate:

(1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;

(2) the effect of existing or possible energy conservation programs under sections 216C.05 to 216C.30 and this section or other federal or state legislation on long-term energy demand;

(3) the relationship of the proposed facility to overall state energy needs, as described in the most recent state energy policy and conservation report prepared under section 216C.18, or, in the case of a high-voltage transmission line, the relationship of the proposed line to regional energy needs, as presented in the transmission plan submitted under section 216B.2425;

(4) promotional activities that may have given rise to the demand for this facility;

(5) benefits of this facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply in Minnesota and the region;

(6) possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation, except that the commission must not require evaluation of alternative end points for a high-voltage transmission line qualifying as a large energy facility unless the alternative end points are (i) consistent with end points identified in a federally registered planning authority transmission plan, or (ii) otherwise agreed to for further evaluation by the applicant;

(7) the policies, rules, and regulations of other state and federal agencies and local governments;

(8) any feasible combination of energy conservation improvements, required under section 216B.241, that can (i) replace part or all of the energy to be provided by the proposed facility, and (ii) compete with it economically;

(9) with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota;

(10) whether the applicant or applicants are in compliance with applicable provisions of sections 216B.1691 and 216B.2425, subdivision 7, and have filed or will file by a date certain an application for certificate of need under this section or for certification as a priority electric transmission project under section 216B.2425 for any transmission facilities or upgrades identified under section 216B.2425, subdivision 7;

(11) whether the applicant has made the demonstrations required under subdivision 3a; and

(12) if the applicant is proposing a nonrenewable generating plant, the applicant's assessment of the risk of environmental costs and regulation on that proposed facility over the expected useful life of the plant, including a proposed means of allocating costs associated with that risk.

Subd. 3a. **Use of renewable resource.** The commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive, including environmental costs, than power generated by a renewable energy source. For purposes of this subdivision, "renewable energy source" includes hydro, wind, solar, and geothermal energy and the use of trees or other vegetation as fuel.

Subd. 3b. **Nuclear power plant; new construction prohibited; relicensing.** (a) The commission may not issue a certificate of need for the construction of a new nuclear-powered electric generating plant.

(b) Any certificate of need for additional storage of spent nuclear fuel for a facility seeking a license extension shall address the impacts of continued operations over the period for which approval is sought.

Subd. 4. **Application for certificate; hearing.** Any person proposing to construct a large energy facility shall apply for a certificate of need and for a site or route permit under chapter 216I prior to construction of the facility. The application shall be on forms and in a manner established by the commission. In reviewing each application the commission shall hold at least one public hearing pursuant to chapter 14. The public hearing shall be held at a location and hour reasonably calculated to be convenient for the public. An objective of the public hearing shall be to obtain public opinion on the necessity of granting a certificate of need and, if a joint hearing is held, a site or route permit. The commission shall designate a commission employee whose duty shall be to facilitate citizen participation in the hearing process. Unless the commission determines that a joint hearing on siting and need under this subdivision and chapter 216I is not feasible or more efficient, or otherwise not in the public interest, a joint hearing under this subdivision and chapter 216I must be held.

Subd. 5. **Approval, denial, or modification.** Within 12 months of the submission of an application, the commission shall approve or deny a certificate of need for the facility. Approval or denial of the certificate shall be accompanied by a statement of the reasons for the decision. Issuance of the certificate may be made contingent upon modifications required by the commission. If the commission has not issued an order on the application within the 12 months provided, the commission may extend the time period upon receiving the consent of the parties or on its own motion, for good cause, by issuing an order explaining the good cause justification for extension.

Subd. 6. **Application fees; rules.** Any application for a certificate of need shall be accompanied by the application fee required pursuant to this subdivision. The application fee is to be applied toward the total costs reasonably necessary to complete the evaluation of need for the proposed facility. The maximum application fee shall be $50,000, except for an application for an electric power generating plant as defined in section 216B.2421, subdivision 2, clause (1), or a high-voltage transmission line as defined in section 216B.2421, subdivision 2, clause (2), for which the maximum application fee shall be $100,000. Costs exceeding the application fee and reasonably necessary to complete the evaluation of need for the proposed facility shall be recovered from the applicant. If the applicant is a public utility, a cooperative electric association, a generation and transmission cooperative electric association, a municipal power agency, a municipal electric utility, or a transmission company, the recovery shall be done pursuant to section 216B.62. The commission shall establish by rule pursuant to chapter 14 and sections 216C.05 to 216C.30 and this section, a schedule of fees based on the output or capacity of the facility and the difficulty of assessment of need. Money collected in this manner shall be credited to the general fund of the state treasury.

Subd. 7. **Participation by other agency or political subdivision.** (a) Other state agencies authorized to issue permits for siting, construction or operation of large energy facilities, and those state agencies authorized to participate in matters before the commission involving utility rates and adequacy of utility services, shall present their position regarding need and participate in the public hearing process prior to the issuance or denial of a certificate of need. Issuance or denial of certificates of need shall be the sole and exclusive prerogative of the commission and these determinations and certificates shall be binding upon other state departments and agencies, regional, county, and local governments and special purpose government districts except as provided in sections 116C.01 to 116C.08 and 116D.04, subdivision 9.

(b) An applicant for a certificate of need shall notify the commissioner of agriculture if the proposed project will impact cultivated agricultural land, as that term is defined in section 216G.01, subdivision 4. The commissioner may participate in any proceeding on the application and advise the commission as to whether to grant the certificate of need, and the best options for mitigating adverse impacts to agricultural lands if the certificate is granted. The Department of Agriculture shall be the lead agency on the development of any agricultural mitigation plan required for the project.

Subd. 8. **Exemptions.** (a) This section does not apply to:

(1) cogeneration or small power production facilities as defined in the Federal Power Act, United States Code, title 16, section 796, paragraph (17), subparagraph (A), and paragraph (18), subparagraph (A), and having a combined capacity at a single site of less than 80,000 kilowatts; plants or facilities for the production of ethanol or fuel alcohol; or any case where the commission has determined after being advised by the attorney general that its application has been preempted by federal law;

(2) a high-voltage transmission line proposed primarily to distribute electricity to serve the demand of a single customer at a single location, unless the applicant opts to request that the commission determine need under this section or section 216B.2425;

(3) the upgrade to a higher voltage of an existing transmission line that serves the demand of a single customer that primarily uses existing rights-of-way, unless the applicant opts to request that the commission determine need under this section or section 216B.2425;

(4) a high-voltage transmission line of one mile or less required to connect a new or upgraded substation to an existing, new, or upgraded high-voltage transmission line;

(5) conversion of the fuel source of an existing electric generating plant to using natural gas;

(6) the modification of an existing electric generating plant to increase efficiency, as long as the capacity of the plant is not increased more than ten percent or more than 100 megawatts, whichever is greater;

(7) a large wind energy conversion system, as defined in section 216I.02, subdivision 12, or a solar energy generating system, as defined in section 216I.02, subdivision 18, for which a site permit application is submitted by an independent power producer under chapter 216I;

(8) a large wind energy conversion system, as defined in section 216I.02, subdivision 12, or a solar energy generating system, as defined in section 216I.02, subdivision 18, engaging in a repowering project that:

(i) will not result in the system exceeding the nameplate capacity under its most recent interconnection agreement; or

(ii) will result in the system exceeding the nameplate capacity under its most recent interconnection agreement, provided that the Midcontinent Independent System Operator has provided a signed generator interconnection agreement that reflects the expected net power increase;

(9) energy storage systems, as defined in section 216I.02, subdivision 6;

(10) transmission lines that directly interconnect large wind energy conversion systems, solar energy generating systems, or energy storage systems to the transmission system; or

(11) relocation of an existing high voltage transmission line to new right-of-way, provided that any new structures that are installed are not designed for and capable of operation at higher voltage.

(b) For the purpose of this subdivision, "repowering project" means:

(1) modifying a large wind energy conversion system or a solar energy generating system that is a large energy facility to increase its efficiency without increasing its nameplate capacity;

(2) replacing turbines in a large wind energy conversion system without increasing the nameplate capacity of the system; or

(3) increasing the nameplate capacity of a large wind energy conversion system.

Subd. 9. **Renewable energy standard and carbon-free energy standard facilities.** This section does not apply to a wind energy conversion system or a solar electric generation facility that is intended to be used to meet the obligations of section 216B.1691, subdivision 2a or 2g; provided that, after notice and comment, the commission determines that the facility is a reasonable and prudent approach to meeting a utility's obligations under that section. When making this determination, the commission must consider:

(1) the size of the facility relative to a utility's total need for renewable resources;

(2) alternative approaches for supplying the renewable energy to be supplied by the proposed facility;

(3) the facility's ability to promote economic development, as required under section 216B.1691, subdivision 9;

(4) the facility's ability to maintain electric system reliability;

(5) impacts on ratepayers; and

(6) other criteria as the commission may determine are relevant.

History: *1974 c 307 s 13; 1975 c 170 s 3,4; 1977 c 381 s 19; Ex1979 c 2 s 32; 1980 c 579 s 10,11; 1980 c 614 s 123; 1981 c 356 s 159,248; 1982 c 424 s 130; 1982 c 561 s 2; 1983 c 289 s 46,115 subd 2; 1984 c 558 art 4 s 10; 1984 c 655 art 1 s 22,23; 1985 c 304 s 1; 1987 c 312 art 1 s 10 subd 1; 1991 c 235 art 4 s 1; art 6 s 2; 1994 c 641 art 2 s 2; 2001 c 212 art 7 s 31-33; 2002 c 398 s 4; 1Sp2003 c 11 art 1 s 4; 2005 c 97 art 1 s 5,6; art 2 s 4; art 3 s 13-15; 2008 c 296 art 1 s 13; 2009 c 110 s 23,24; 2014 c 254 s 13; 2016 c 189 art 6 s 8; 2023 c 7 s 23; 2023 c 60 art 12 s 22; 2024 c 126 art 8 s 2-6; 2024 c 127 art 44 s 2-6*

MISCELLANY

216B.244 NUCLEAR PLANT CAPACITY REQUIREMENTS.

A reactor unit at a nuclear power electric generating plant that has an annual load capacity factor of less than 55 percent for each of three consecutive calendar years must be shut down and cease operating no later than 500 days after the end of the third such consecutive calendar year. For the purposes of this section, "load capacity factor" means the ratio between a reactor unit's average load and its peak load.

History: *1994 c 641 art 2 s 3*

216B.2445 DECOMMISSIONING NUCLEAR PLANT; STORING USED FUEL.

Subdivision 1. **Decommissioning costs.** (a) The Public Utilities Commission shall, when considering approval of a plan for the accrual of funds for the decommissioning of nuclear facilities filed in accordance with a commission order, include an evaluation of the costs, if any, arising from storage of used nuclear fuel that may be incurred by the state of Minnesota, and any tribal community, county, city, or township where used nuclear fuel is located following the cessation of operations at a nuclear plant.

(b) To assist the commission in making the determination required in paragraph (a), the filing shall provide cost estimates, including ratepayer impacts, assuming used nuclear fuel will be stored in the state for 60 years, 100 years, and 200 years following the cessation of operation of the nuclear plant.

Subd. 2. **Rate.** A public utility filing a decommissioning plan in accordance with a commission order and this section may include, as part of a general rate case petition, the costs of decommissioning accrual incurred in complying with a commission order implementing this section.

Subd. 3. **Commission report.** The commission shall prepare a nuclear decommissioning report after each of the commission's periodic review of nuclear decommissioning costs. The report shall be submitted within 180 days of the date of the final order related to that review to the chairs and ranking minority members of the legislative committees with primary jurisdiction over energy policy and public safety. That report shall, without limitation, include the following:

(1) an explanation of the commission's funding decisions regarding nuclear decommissioning;

(2) the progress of the United States Department of Energy to remove from Minnesota spent fuel produced by nuclear generating plants in Minnesota;

(3) an analysis of the financial and other obligations related to decommissioning and storage of used fuel of the utility holding title to spent nuclear fuel to the state and to host communities, including affected tribal communities; and

(4) any recommendations to the legislature on legislation or other actions that may be necessary for addressing long-term or indefinite storage costs.

History: *2011 c 97 s 13*

216B.245 PUMP AND STORE HYDROPOWER FACILITY; PROHIBITION.

A state agency may not issue a permit for the construction of a facility for generating electricity if the facility would be located on top of the bluffs along the Mississippi River and would pump water from any portion of the river, store the water on top of the bluffs, and release the water at a later time to generate the electricity.

History: *1993 c 147 s 1*

216B.246 FEDERALLY APPROVED TRANSMISSION LINES; INCUMBENT TRANSMISSION LINEOWNER RIGHTS.

Subdivision 1. **Definitions.** (a) For purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Electric transmission line" means a high-voltage transmission line with a capacity of 100 kilovolts or more and associated transmission facilities.

(c) "Incumbent electric transmission owner" means any public utility that owns, operates, and maintains an electric transmission line in this state; any generation and transmission cooperative electric association; any municipal power agency; any power district; any municipal utility; or any transmission company as defined under section 216B.02, subdivision 10.

Subd. 2. **Incumbent electric transmission owner rights.** An incumbent electric transmission owner has the right to construct, own, and maintain an electric transmission line that has been approved for construction in a federally registered planning authority transmission plan and connects to facilities owned by that incumbent electric transmission owner. The right to construct, own, and maintain an electric transmission line that connects to facilities owned by two or more incumbent electric transmission owners belongs individually and proportionally to each incumbent electric transmission owner, unless otherwise agreed upon in writing. This section does not limit the right of any incumbent electric transmission owner to construct, own, and maintain any transmission equipment or facilities that have a capacity of less than 100 kilovolts.

Subd. 3. **Commission procedure.** (a) If an electric transmission line has been approved for construction in a federally registered planning authority transmission plan, the incumbent electric transmission owner, or owners if there is more than one owner, shall give notice to the commission, in writing, within 60 days of approval, regarding its intent to construct, own, and maintain the electric transmission line. If an incumbent electric transmission owner gives notice of intent to build the electric transmission line then, unless exempt from the requirements of section 216B.243, within 12 months from the date of the notice described in this paragraph, the incumbent electric transmission owner shall file an application for a certificate of need under section 216B.243 or certification under section 216B.2425.

(b) If the incumbent electric transmission owner indicates that it does not intend to build the transmission line, such notice shall fully explain the basis for that decision. If the incumbent electric transmission owner, or owners, gives notice of intent not to build the electric transmission line, then the commission may determine whether the incumbent electric transmission owner or other entity will build the electric transmission line, taking into consideration issues such as cost, efficiency, reliability, and other factors identified in this chapter.

History: *2012 c 179 s 1; 2024 c 126 art 8 s 7; 2024 c 127 art 44 s 7*

COMMISSION ORDERS; PROCEDURAL RESPONSIBILITIES

216B.25 FURTHER ACTION ON PREVIOUS ORDER.

The commission may at any time, on its own motion or upon motion of an interested party, and upon notice to the public utility and after opportunity to be heard, rescind, alter, or amend any order fixing rates, tolls, charges, or schedules, or any other order made by the commission, and may reopen any case following the issuance of an order therein, for the taking of further evidence or for any other reason. Any order rescinding, altering, amending, or reopening a prior order shall have the same effect as an original order.

History: *1974 c 429 s 25*

216B.26 ORDER; EFFECTIVE DATE.

Every decision made by the commission constituting an order or determination is in force and effective 20 days after it has been filed and has been served by personal delivery, electronic service as provided in section 216.17, or by mailing a copy thereof to all parties to the proceeding in which the decision was made or to their attorneys, unless the commission specifies a different date upon which the order becomes effective.

History: *1974 c 429 s 26; 2007 c 10 s 6*

216B.27 REHEARING; CONDITION PRECEDENT TO JUDICIAL REVIEW.

Subdivision 1. **Applying for rehearing.** Within 20 days after the service by the commission of any decision constituting an order or determination, any party to the proceeding and any other person, aggrieved by the decision and directly affected thereby, may apply to the commission for a rehearing in respect to any matters determined in the decision. The commission may grant and hold a rehearing on the matters, or upon any of them as it may specify in the order granting the rehearing, if in its judgment sufficient reason therefor exists.

Subd. 2. **Contents of application; condition precedent for review.** The application for a rehearing shall set forth specifically the grounds on which the applicant contends the decision is unlawful or unreasonable. No cause of action arising out of any decision constituting an order or determination of the commission or any proceeding for the judicial review thereof shall accrue in any court to any person or corporation unless the plaintiff or petitioner in the action or proceeding within 20 days after the service of the decision, shall have made application to the commission for a rehearing in the proceeding in which the decision was made. No person or corporation shall in any court urge or rely on any ground not so set forth in the application for rehearing.

Subd. 3. **Rules; procedural requirements; commission's authority.** Applications for rehearing shall be governed by general rules which the commission may establish. In case a rehearing is granted the proceedings shall conform as nearly as may be to the proceedings in an original hearing, except as the commission may otherwise direct. If in the commission's judgment, after the rehearing, it shall appear that the original decision, order, or determination is in any respect unlawful or unreasonable, the commission may reverse, change, modify, or suspend the original action accordingly. Any decision, order, or determination made after the rehearing reversing, changing, modifying, or suspending the original determination shall have the same force and effect as an original decision, order, or determination. Only one rehearing shall be granted by the commission; but this shall not be construed to prevent any party from filing a new application or complaint. No order of the commission shall become effective while an application for a rehearing or a rehearing is pending and until ten days after the application for a rehearing is either denied, expressly or by implication, or the commission has announced its final determination on rehearing.

Subd. 4. **Deadline to grant application.** Any application for a rehearing not granted within 60 days from the date of filing thereof, shall be deemed denied.

Subd. 5. **Effect of decision on application.** It is hereby declared that the legislative powers of the state, insofar as they are involved in the issuance of orders and decisions by the commission, have not been completely exercised until the commission has acted upon an application for rehearing, as provided for by this section and by the rules of the commission, or until the application for rehearing has been denied by implication, as above provided for.

History: *1974 c 429 s 27; 1995 c 224 s 77*

216B.28 SUBPOENA; WITNESS FEE AND MILEAGE.

The commission and each commissioner, or the secretary of the commission may issue subpoenas and all necessary processes in proceedings pending before it; and each process shall extend to all parts of the state and may be served by any person authorized to serve processes of courts of record. Each witness who shall appear before the commission, or at a hearing before one of the individuals designated by it as provided in section 216B.15, or whose deposition is taken, shall receive for attendance the fees and mileage now provided for witnesses in civil cases in courts of record.

History: *1974 c 429 s 28; 1986 c 444*

216B.29 HEARING AND SUBPOENA COMPLIANCE POWERS.

The commission and each of the commissioners or authorized examiner, for the purpose mentioned in Laws 1974, chapter 429, may administer oaths and examine witnesses. In case of failure on the part of any person to comply with any subpoena, or in the case of the refusal of any witness to testify concerning any matter on which the witness may be interrogated lawfully, any court of record of general jurisdiction or a judge thereof, on application of the commission, may compel obedience by proceedings for contempt as in the case of disobedience of the requirements of a subpoena issued from the court or a refusal to testify therein.

History: *1974 c 429 s 29; 1986 c 444*

216B.30 DEPOSITION.

The commission or any party to the proceedings may, in any investigation or hearing before the commission, cause the deposition of witnesses residing within or without the state to be taken in the manner prescribed by law for taking depositions in civil actions in the district court.

History: *1974 c 429 s 30*

216B.31 TESTIMONY AND PRODUCTION OF RECORDS; PERJURY.

No person shall be excused from testifying or from producing any book, document, paper, or account in any investigation, or inquiry by, or hearing before, the commission or any commissioner, or person designated by it to conduct hearings, when ordered to do so, upon the ground that the testimony or evidence, book, document, paper, or account required may tend to incriminate the person or subject the person to penalty or forfeiture; but no person shall be prosecuted, punished, or subjected to any forfeiture or penalty for or on account of any act, transaction, matter, or thing concerning which the person shall have been compelled under oath to testify or produce documentary evidence; provided, that no person so testifying shall be exempt from prosecution or punishment for any perjury committed in testimony.

History: *1974 c 429 s 31; 1986 c 444*

216B.32 CERTIFIED COPY OF DOCUMENT AS EVIDENCE.

Copies of official documents and orders filed or deposited according to law in the office of the commission, certified by a commissioner or by the secretary under the official seal of the commission to be true copies of the original shall be evidence in like manner as the originals, in all matters before the commission and in the courts of this state.

History: *1974 c 429 s 32*

216B.33 COMMISSION RULING WRITTEN, FILED, AND CERTIFIED.

Every order, finding, authorization, or certificate issued or approved by the commission under this chapter must be in writing and retained in the commission's official record system. A certificate under the seal of the commission that any order, finding, authorization, or certificate has not been modified, stayed, suspended, or revoked, must be received in any proceeding as evidence as to the facts therein stated.

History: *1974 c 429 s 33; 2007 c 10 s 7*

216B.34 PUBLIC RECORDS.

All decisions, transcripts, and orders of the commission shall be public records.

History: *1974 c 429 s 34*

216B.35 TRANSCRIBED RECORD.

A full and complete record shall be kept of all proceedings at any formal hearing had before the commission or any commissioner or hearing examiner and all testimony shall be taken down by a reporter appointed by the commission. A copy of the transcript shall be furnished on demand to any party to the proceedings upon payment of reasonable costs of reproduction.

History: *1974 c 429 s 35*

MUNICIPAL POWERS

216B.36 MUNICIPAL REGULATORY AND TAXING POWERS.

Any public utility furnishing the utility services enumerated in section 216B.02 or occupying streets, highways, or other public property within a municipality may be required to obtain a license, permit, right, or franchise in accordance with the terms, conditions, and limitations of regulatory acts of the municipality, including the placing of distribution lines and facilities underground. Under the license, permit, right, or franchise, the utility may be obligated by any municipality to pay to the municipality fees to raise revenue or defray increased municipal costs accruing as a result of utility operations, or both. The fee may include but is not limited to a sum of money based upon gross operating revenues or gross earnings from its operations in the municipality so long as the public utility shall continue to operate in the municipality, unless upon request of the public utility it is expressly released from the obligation at any time by such municipality.

Notwithstanding the definition of "public utility" in section 216B.02, subdivision 4, a municipality may require payment of a fee under this section by a cooperative electric association organized under chapter 308A that furnishes utility services within the municipality. All existing licenses, permits, franchises, and other rights acquired by any public utility or municipality prior to April 11, 1974, including the payment of existing franchise fees, shall not be impaired or affected in any respect by the passage of this chapter, except with respect to matters of rate and service regulation, service area assignments, securities, and indebtedness that are vested in the jurisdiction of the commission by this chapter. However, in the event that a court of competent jurisdiction determines, or the parties by mutual agreement determine, that an existing license, permit, franchise, or other right has been abrogated or impaired by this chapter, or its execution, the municipality affected shall impose and the public utility shall collect an excise tax on the utility charges which from year to year yields an amount which is reasonably equivalent to that amount of revenue which then would be due as a fee, charges or other thing or service of value to the municipality under the franchise, license, or permit. The authorization shall be over and above taxing limitations including, but not limited to, those of section 477A.016. Franchises granted pursuant to this section shall be exempt from the provisions of chapter 80C. For purposes of this section, a public utility shall include a cooperative electric association.

History: *1974 c 429 s 36; 1978 c 795 s 5; 1Sp1981 c 1 art 6 s 8; 1982 c 378 s 1; 1991 c 291 art 9 s 4*

TOWNSHIP NATURAL GAS UTILITY AGREEMENT

216B.361 TOWNSHIP AGREEMENT WITH NATURAL GAS UTILITY.

A township may enter into an agreement with a public utility providing natural gas services to provide services within a designated portion or all of the township. If a city annexes township land for which a utility has an agreement with a township to serve, the utility shall continue to have a nonexclusive right to offer and provide service in the area identified by the agreement with the township for the term of that agreement, subject to the authority of the annexing city to manage public rights-of-way within the city as provided in sections 216B.36, 237.162, and 237.163.

Nothing in this section precludes a city from acquiring the property of a public utility under sections 216B.45 to 216B.47 for the purpose of allowing the city to own and operate a natural gas utility, or to extend natural gas and other utility services into newly annexed areas.

History: *1Sp2003 c 11 art 3 s 5*

ASSIGNED ELECTRIC SERVICE AREAS

216B.37 ASSIGNED SERVICE AREA; ELECTRIC UTILITY; LEGISLATIVE POLICY.

It is hereby declared to be in the public interest that, in order to encourage the development of coordinated statewide electric service at retail, to eliminate or avoid unnecessary duplication of electric utility facilities, and to promote economical, efficient, and adequate electric service to the public, the state of Minnesota shall be divided into geographic service areas within which a specified electric utility shall provide electric service to customers on an exclusive basis.

History: *1974 c 429 s 37*

216B.38 DEFINITIONS.

Subdivision 1. MS 1974 [Renumbered subd 1a]

Subdivision 1. **Scope.** For the purpose of sections 216B.37 to 216B.44 only, the following definitions shall apply.

Subd. 1a. [Renumbered subd 8]

Subd. 1b. **Assigned service area.** "Assigned service area" means the geographical area in which the boundaries are established as provided in section 216B.39.

Subd. 2. **Customer.** "Customer" means a person contracting for or purchasing electric service at retail from an electric utility.

Subd. 3. [Renumbered subd 4a]

Subd. 4. **Electric line.** "Electric line" means lines for conducting electric energy at a design voltage of 25,000 volts phase to phase or less used for distributing electric energy directly to customers at retail.

Subd. 4a. **Electric service.** "Electric service" means electric service furnished to a customer at retail for ultimate consumption, but does not include wholesale electric energy furnished by an electric utility to another electric utility for resale.

Subd. 5. **Electric utility.** "Electric utility" means persons, their lessees, trustees, and receivers, separately or jointly, now or hereafter operating, maintaining, or controlling in Minnesota equipment or facilities for providing electric service at retail and which fall within the definition of "public utility" in section 216B.02, subdivision 4, and includes facilities owned by a municipality or by a cooperative electric association.

Subd. 6. [Renumbered subd 1b]

Subd. 7. **Municipality.** "Municipality" means any city, however organized.

Subd. 8. **Person.** "Person" means a natural person, a partnership, a private corporation, a public corporation, a municipality, an association, a cooperative whether incorporated or not, a joint stock association, a business trust, any political subdivision or agency, or two or more persons having joint or common interest.

History: *1974 c 429 s 38; 1978 c 795 s 6*

216B.39 ASSIGNED SERVICE AREA.

Subdivision 1. **Line map and service list.** On or before six months from April 12, 1974, or, when requested in writing by an electric utility and for good cause shown, and at a further time as the commission may fix by order, each electric utility shall file with the commission a map or maps showing all its electric lines outside of incorporated municipalities as they existed on April 12, 1974. Each electric utility shall also submit in writing a list of all municipalities in which it provides electric service on the effective date of Laws 1974, chapter 429. Where two or more electric utilities serve a single municipality, the commission may require each utility to file with the commission a map showing its electric lines within the municipality.

Subd. 2. **Determination; map prepared.** On or before 12 months from April 12, 1974, the commission shall after notice and hearing establish the assigned service area or areas of each electric utility and shall prepare or cause to be prepared a map or maps to accurately and clearly show the boundaries of the assigned service area of each electric utility.

Subd. 3. **Geographic, historic, and contractual considerations.** To the extent that it is not inconsistent with the legislative policy stated in section 216B.37, the boundaries of each assigned service area, outside of incorporated municipalities, shall be a line equidistant between the electric lines of adjacent electric utilities as they exist on April 12, 1974; provided that these boundaries may be modified by the commission to take account of natural and other physical barriers including, but not limited to, highways, waterways, railways, major bluffs, and ravines and shall be modified to take account of the contracts provided for in subdivision 4; and provided further that at any time after April 12, 1974, the commission may on its own or at the request of an electric utility make changes in the boundaries of the assigned service areas, but only after notice and hearing as provided for in sections 216B.17 and 216B.18.

Subd. 4. **Service area contract between utilities.** Contracts between electric utilities, which are executed on or before 12 months from April 12, 1974, designating service areas and customers to be served by the electric utilities when approved by the commission shall be valid and enforceable and shall be incorporated into the appropriate assigned service areas. The commission shall approve a contract if it finds that the contract will eliminate or avoid unnecessary duplication of facilities, will provide adequate electric service to all areas and customers affected, and will promote the efficient and economical use and development of the electric systems of the contracting electric utilities.

Subd. 5. **Assigned service area in municipality.** Where a single electric utility provides electric service within a municipality on April 12, 1974, that entire municipality shall constitute a part of the assigned service area of the electric utility in question. Where two or more electric utilities provide electric service in a municipality on April 12, 1974, the boundaries of the assigned service areas shall conform to those contained in municipal franchises with the electric utilities on April 12, 1974. In the absence of a franchise, the boundaries of the assigned service areas within an incorporated municipality shall be a line equidistant between the electric lines of the electric utilities as they exist on April 12, 1974; provided that these boundaries may be modified by the commission to take account of natural and other physical barriers including, but not limited to, major streets or highways, waterways, railways, major bluffs, and ravines and shall be modified to take account of the contracts provided for in subdivision 4.

Subd. 6. **Determination for exceptional case.** In those areas where, on April 12, 1974, the existing electric lines of two or more electric utilities are so intertwined that subdivisions 2 to 5 cannot reasonably be applied, the commission shall determine the boundaries of the assigned service areas for the electric utilities involved as will promote the legislative policy in section 216B.37.

History: *1974 c 429 s 39; 2014 c 275 art 1 s 35*

216B.40 EXCLUSIVE SERVICE RIGHT; SERVICE EXTENSION.

Except as provided in sections 216B.42, 216B.421, and 216B.422, each electric utility shall have the exclusive right to provide electric service at retail to each and every present and future customer in its assigned service area and no electric utility shall render or extend electric service at retail within the assigned service area of another electric utility unless the electric utility consents thereto in writing; provided that any electric utility may extend its facilities through the assigned service area of another electric utility if the extension is necessary to facilitate the electric utility connecting its facilities or customers within its own assigned service area.

History: *1974 c 429 s 40; 1977 c 99 s 1; 1Sp2025 c 4 art 7 s 14*

216B.41 EFFECT OF INCORPORATION, ANNEXATION, OR CONSOLIDATION.

After April 12, 1974, the inclusion by incorporation, consolidation, or annexation of any part of the assigned service area of an electric utility within the boundaries of any municipality shall not in any respect impair or affect the rights of the electric utility to continue and extend electric service at retail throughout any part of its assigned service area unless a municipality which owns and operates an electric utility elects to purchase the facilities and property of the electric utility as provided in section 216B.44.

History: *1974 c 429 s 41*

216B.42 SERVICE EXTENSION IN CERTAIN SITUATIONS.

Subdivision 1. **Large customer outside municipality.** Notwithstanding the establishment of assigned service areas for electric utilities provided for in section 216B.39, customers located outside municipalities and who require electric service with a connected load of 2,000 kilowatts or more shall not be obligated to take electric service from the electric utility having the assigned service area where the customer is located if, after notice and hearing, the commission so determines after consideration of following factors:

(1) the electric service requirements of the load to be served;

(2) the availability of an adequate power supply;

(3) the development or improvement of the electric system of the utility seeking to provide the electric service, including the economic factors relating thereto;

(4) the proximity of adequate facilities from which electric service of the type required may be delivered;

(5) the preference of the customer;

(6) any and all pertinent factors affecting the ability of the utility to furnish adequate electric service to fulfill customers' requirements.

Subd. 2. **Service line extension to utility's property.** Notwithstanding the provisions in section 216B.39, any electric utility may extend electric lines for electric service to its own utility property and facilities.

History: *1974 c 429 s 42*

216B.421 HOMESTEAD; OPTION OF ELECTRIC SERVICE.

Subdivision 1. **Multiple service areas; customer election.** Notwithstanding the establishment of assigned service areas for electric utilities provided for in section 216B.39, when a customer requires electric service for buildings or other structures located on land constituting the customer's homestead and the buildings or structures are located within more than one assigned service area, the customer may elect to contract for or purchase the customer's entire electric service requirements from either of the electric utilities providing the customer with electric service. An electric utility may extend its facilities through the assigned service area of another electric utility if the extension is necessary to facilitate the electric utility connecting a customer who elects to purchase or contract for service from it pursuant to this section.

Subd. 2. **Restriction.** The provisions of subdivision 1 shall only apply to the provision of electric service to buildings and other structures that were under construction on April 11, 1974.

History: *1977 c 99 s 2; 1986 c 444*

216B.422 ELECTRICITY SALES FOR CHARGING ELECTRIC VEHICLES.

A retail seller of electricity used to recharge a battery that powers an electric vehicle, as defined in section 169.011, subdivision 26a, and that is not otherwise a public utility under this chapter, is not in violation of section 216B.40 if the electricity the retailer sells was provided by the utility serving the location of the charging station.

History: *1Sp2025 c 4 art 7 s 15*

216B.43 HEARING ON COMPLAINT.

Upon the filing of an application under section 216B.42 or upon complaint by an affected utility that the provisions of sections 216B.39 to 216B.42 have been violated, the commission shall hold a hearing, upon notice, within 30 days after the filing of the complaint, and shall render its decision within 30 days after the hearing.

History: *1974 c 429 s 43; 1993 c 327 s 10*

MUNICIPAL ACQUISITION OF UTILITY PROPERTY

216B.44 MUNICIPAL SERVICE TERRITORY EXTENSION.

(a) Notwithstanding the provisions of sections 216B.38 to 216B.42, whenever a municipality which owns and operates an electric utility (1) extends its corporate boundaries through annexation or consolidation, or (2) determines to extend its service territory within its existing corporate boundaries, the municipality shall thereafter furnish electric service to these areas unless the area is already receiving electric service from an electric utility, in which event, the municipality may purchase the facilities of the electric utility serving the area.

(b) The municipality acquiring the facilities shall pay to the electric utility formerly serving the area the appropriate value of its properties within the area which payment may be by exchange of other electric utility property outside the municipality on an appropriate basis giving due consideration to revenue from and value of the respective properties. In the event the municipality and the electric utility involved are unable to agree as to the terms of the payment or exchange, the municipality or the electric utility may file an application with the commission requesting that the commission determine the appropriate terms for the exchange or sale. After notice and hearing, the commission shall determine appropriate terms for an exchange, or in the event no appropriate properties can be exchanged, the commission shall fix and determine the appropriate value of the property within the annexed area, and the transfer shall be made as directed by the commission. In making that determination the commission shall consider the original cost of the property, less depreciation, loss of revenue to the utility formerly serving the area, expenses resulting from integration of facilities, and other appropriate factors.

(c) Until the determination by the commission, the facilities shall remain in place and service to the public shall be maintained by the owner. However, the electric utility being displaced, serving the annexed area, shall not extend service to any additional points of delivery within the annexed area if the commission, after notice and hearing, with due consideration of any unnecessary duplication of facilities, shall determine that the extension is not in the public interest.

(d) When property of an electric utility located within an area annexed to a municipality which owns and operates an electric utility is proposed to be acquired by the municipality, ratification by the electors is not required.

(e) When property of an electric utility located within the existing corporate boundaries of a municipality that currently operates a municipal electric utility is proposed to be included within the service territory of the municipal electric utility, ratification by the electors is not required.

History: *1974 c 429 s 44; 1983 c 301 s 173*

216B.45 MUNICIPAL PURCHASE OF PUBLIC UTILITY.

Any public utility operating in a municipality under a license, permit, right, or franchise shall be deemed to have consented to the purchase by the municipality, for just compensation, of its property operated in the municipality under such license, permit, right, or franchise. The municipality, subject to the provisions of Laws 1974, chapter 429, may purchase the property upon notice to the public utility as herein provided. Whenever the commission is notified by the municipality or the public utility affected that the municipality has, pursuant to law, determined to purchase the property of the public utility, and that the parties to the purchase and sale have been unable to agree on the amount to be paid and received therefor, the commission shall set a time and place for a public hearing, after not less than 30 days' notice to the parties, upon the matter of just compensation or the matter of the property to be purchased. Within a reasonable time the commission shall, by order, determine the just compensation for the property to be purchased by the municipality. In determining just compensation, the commission shall consider the original cost of the property less depreciation, loss of revenue to the utility, expenses resulting from integration of facilities, and other appropriate factors. The order of the commission may be reviewed as provided in section 216B.52. Commission expenses arising out of the exercise of its jurisdiction under this section shall be assessed to the municipality. For purposes of this section, a public utility shall include a cooperative electric association.

History: *1974 c 429 s 45; 1978 c 795 s 7*

216B.46 MUNICIPAL ACQUISITION PROCEDURES; NOTICE; ELECTION.

Any municipality which desires to acquire the property of a public utility as authorized under the provisions of section 216B.45 may determine to do so by resolution of the governing body of the municipality taken after a public hearing of which at least 30 days' published notice shall be given as determined by the governing body. The determination shall become effective when ratified by a majority of the qualified electors voting on the question at a special election to be held on a date authorized by section 205.10, subdivision 3a.

History: *1974 c 429 s 46; 2017 c 92 art 2 s 15*

216B.465 VOTER RATIFICATION OF MUNICIPAL PURCHASE; LIMITED APPLICATION.

The provisions of sections 216B.45 and 216B.46 apply only to the purchase of public utility property by a municipality that, prior to the time of the purchase, did not operate a municipal utility providing the type of utility service delivered by the utility property being purchased.

In cases where the municipality operates, prior to the purchase of public utility property, a municipal utility providing the type of utility service delivered by the utility property being purchased, the provisions of section 216B.44 apply and voter ratification is not required.

History: *1983 c 301 s 174*

216B.47 ACQUISITION BY EMINENT DOMAIN.

Nothing in this chapter may be construed to preclude a municipality from acquiring the property of a public utility by eminent domain proceedings; provided that damages to be paid in eminent domain proceedings must include the original cost of the property less depreciation, loss of revenue to the utility, expenses resulting from integration of facilities, and other appropriate factors. A municipality seeking to acquire the property of a public utility in eminent domain proceedings may not acquire the right to furnish electric service during the pendency of the proceedings through the use of section 117.042 but may petition the commission under section 216B.44 for service rights. For purposes of this section, a public utility includes a cooperative electric association.

History: *1974 c 429 s 47; 1978 c 795 s 8; 1994 c 610 s 1*

FINANCIAL ACTIVITIES AND BUSINESS PRACTICES

216B.48 RELATIONS WITH AFFILIATED INTEREST.

Subdivision 1. **Definition of affiliated interests.** "Affiliated interests" with a public utility means the following:

(1) every corporation and person owning or holding directly or indirectly five percent or more of the voting securities of such public utility;

(2) every corporation and person in any chain of successive ownership of five percent or more of voting securities;

(3) every corporation five percent or more of whose voting securities is owned by any person or corporation owning five percent or more of the voting securities of such public utility or by any person or corporation in any such chain of successive ownership of five percent or more of voting securities;

(4) every person who is an officer or director of such public utility or of any corporation in any chain of successive ownership of five percent or more of voting securities;

(5) every corporation operating a public utility or a servicing organization for furnishing supervisory, construction, engineering, accounting, legal, and similar services to utilities, which has one or more officers or one or more directors in common with the public utility, and every other corporation which has directors in common with the public utility where the number of the directors is more than one-third of the total number of the utility's directors;

(6) every corporation or person which the commission may determine as a matter of fact after investigation and hearing is actually exercising any substantial influence over the policies and actions of the public utility even though the influence is not based upon stockholding, stockholders, directors or officers to the extent specified in this section;

(7) every person or corporation who or which the commission may determine as a matter of fact after investigation and hearing is actually exercising substantial influence over the policies and actions of the public utility in conjunction with one or more other corporations or persons with which or whom they are related by ownership or blood relationship or by action in concert that together they are affiliated with such public utility within the meaning of this section even though no one of them alone is so affiliated;

(8) every subsidiary of a public utility;

(9) every part of a corporation in which an operating division is a public utility.

Subd. 2. **Construing the term "person."** The term "person" as used in subdivision 1 shall not be construed to exclude trustees, lessees, holders of beneficial equitable interest, voluntary associations, receivers, and partnerships.

Subd. 3. **Contract between utility and affiliated interest.** No contract or arrangement, including any general or continuing arrangement, providing for the furnishing of management, supervisory, construction, engineering, accounting, legal, financial, or similar services, and no contract or arrangement for the purchase, sale, lease, or exchange of any property, right, or thing, or for the furnishing of any service, property, right, or thing, other than those above enumerated, made or entered into after January 1, 1975 between a public utility and any affiliated interest as defined in subdivision 1, clauses (1) to (8), or any arrangement between a public utility and an affiliated interest as defined in subdivision 1, clause (9), made or entered into after August 1, 1993, is valid or effective unless and until the contract or arrangement has received the written approval of the commission. Regular recurring transactions under a general or continuing arrangement that has been approved by the commission are valid if they are conducted in accordance with the approved terms and conditions. Every public utility shall file with the commission a verified copy of the contract or arrangement, or a verified summary of the unwritten contract or arrangement, and also of all the contracts and arrangements, whether written or unwritten, entered into prior to January 1, 1975, or, for the purposes of subdivision 1, clause (9), prior to August 1, 1993, and in force and effect at that time. The commission shall approve the contract or arrangement made or entered into after that date only if it clearly appears and is established upon investigation that it is reasonable and consistent with the public interest. No contract or arrangement may receive the commission's approval unless satisfactory proof is submitted to the commission of the cost to the affiliated interest of rendering the services or of furnishing the property or service to each public utility. Proof is satisfactory only if it includes the original or verified copies of the relevant cost records and other relevant accounts of the affiliated interest, or an abstract or summary as the commission may deem adequate, properly identified and duly authenticated, provided, however, that the commission may, where reasonable, approve or disapprove the contracts or arrangements without the submission of cost records or accounts. The burden of proof to establish the reasonableness of the contract or arrangement is on the public utility.

Subd. 4. **Contract not exceeding $50,000.** The provisions of this section requiring the written approval of the commission shall not apply to transactions with affiliated interests where the amount of consideration involved is not in excess of $50,000 or five percent of the capital equity of the utility whichever is smaller; provided, however, that regularly recurring payments under a general or continuing arrangement which aggregate a greater annual amount shall not be broken down into a series of transactions to come within the aforesaid exemption. Such transactions shall be valid or effective without commission approval under this section. However, in any proceeding involving the rates or practices of the public utility, the commission may exclude from the accounts of such public utility any payment or compensation made pursuant to the transaction unless the public utility shall establish the reasonableness of the payment or compensation.

Subd. 5. **Applicability to determining rates and costs.** In any proceeding, whether upon the commission's own motion or upon application or complaint, involving the rates or practices of any public utility, the commission may exclude from the accounts of the public utility any payment or compensation to an affiliated interest for any services rendered or property or service furnished, as above described, under existing contracts or arrangements with the affiliated interest unless the public utility shall establish the reasonableness of the payment or compensation.

Subd. 6. **Commission retains continuing authority over contract.** The commission shall have continuing supervisory control over the terms and conditions of the contracts and arrangements as are herein described so far as necessary to protect and promote the public interest. The commission shall have the same jurisdiction over the modifications or amendment of contracts or arrangements as are herein described as it has over such original contracts or arrangements. The fact that the commission shall have approved entry into such contracts or arrangements as described herein shall not preclude disallowance or disapproval of payments made pursuant thereto, if upon actual experience under such contract or arrangement it appears that the payments provided for or made were or are unreasonable.

Subd. 7. [Repealed, 1978 c 795 s 10]

History: *1974 c 429 s 48; 1993 c 327 s 11-13*

216B.49 SECURITIES; PUBLIC FINANCING.

Subdivision 1. **Definition of security.** For the purpose of this section, "security" means any note; stock; treasury stock; bond; debenture; evidence of indebtedness; assumption of any obligation or liability as a guarantor, endorser, surety, or otherwise in the security of another person; certificate of interest or participation in any profit-sharing agreement; collateral trust certificate; preorganization certificate or subscription; transferable shares; investment contract; voting trust certificate; certificate of deposit for a security; certificate of interest or participation in an oil, gas, or mining right, title, or lease or in payments out of production under an oil, gas, or mining right, title, or lease; or, in general, any interest or instrument commonly known as a security, or any certificate for, receipt for guarantee of, or warrant or right to subscribe to or purchase, any of the foregoing.

Subd. 2. [Repealed, 1998 c 350 s 6]

Subd. 3. **Commission approval required.** It is unlawful for any public utility organized under the laws of this state to offer or sell any security or, if organized under the laws of any other state or foreign country, to subject property in this state to an encumbrance for the purpose of securing the payment of any indebtedness unless the security issuance of the public utility is first approved by the commission, either as an individual issuance or as one of multiple possible issuances approved in the course of a periodic proceeding reviewing the utility's proposed sources and uses of capital funds. Approval by the commission must be by formal written order.

Subd. 4. **Considerations for approval for public financing.** Upon the application of a public utility for approval of its security issuance and prior to the issuance of any security or the encumbrance of any property for the purpose of securing the payment of any indebtedness, the commission may make such inquiry or investigation, hold such hearings, and examine such witnesses, books, papers, documents, or contracts, as in its discretion it may deem necessary. Prior to approval the commission shall ascertain that the amount of securities of each class which any public utility may issue shall bear a reasonable proportion to each other and to the value of the property, due consideration being given to the nature of the business of the public utility, its credit and prospects, the possibility that the value of the property may change from time to time, the effect which the issue shall have upon the management and operation of the public utility, and other considerations which the commission as a matter of fact shall find to be relevant. If the commission shall find that the proposed security issuance is reasonable and proper and in the public interest and will not be detrimental to the interests of the consumers and patrons affected thereby, the commission shall by written order grant its permission for the proposed public financing.

Subd. 5. **Applicability of other law; preemption.** The requirements of this section are in addition to any other requirements of law and, specifically, the requirements of chapter 80A, and the rules promulgated pursuant thereto. Notwithstanding any charter or ordinance to the contrary, no city shall have jurisdiction over the securities or indebtedness of a public utility.

Subd. 6. [Repealed, 1978 c 795 s 10]

Subd. 7. **Investment in municipal industrial development.** When a public utility is engaged in a project pursuant to sections 469.152 to 469.165, notwithstanding the provisions of section 469.155, funds or accounts established in connection with the project or payment of bonds issued for the project may also be invested in investments of the type authorized in section 11A.24, subdivisions 1 to 5.

History: *1974 c 429 s 49; 1982 c 378 s 2; 1983 c 167 s 1; 1985 c 248 s 70; 1987 c 291 s 203; 1998 c 350 s 2,3; 2011 c 97 s 23*

216B.491 DEFINITIONS.

Subdivision 1. **Scope.** For the purposes of sections 216B.491 to 216B.499, the terms defined in this section have the meanings given.

Subd. 2. **Ancillary agreement.** "Ancillary agreement" means a bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with extraordinary event bonds that is designed to promote the credit quality and marketability of extraordinary event bonds or to mitigate the risk of an increase in interest rates.

Subd. 3. **Assignee.** "Assignee" means a person to which an interest in extraordinary event property is sold, assigned, transferred, or conveyed, other than as security, and any successor to or subsequent assignee of the person.

Subd. 4. **Bondholder.** "Bondholder" means a holder or owner of extraordinary event bonds.

Subd. 5. **Customer.** "Customer" means a person who purchases natural gas or natural gas transportation services from a utility in Minnesota. Customer does not include a person who:

(1) purchases natural gas transportation services from a utility in Minnesota that serves fewer than 350,000 natural gas customers in Minnesota; and

(2) does not purchase natural gas from a utility in Minnesota.

Subd. 6. **Extraordinary event.** (a) "Extraordinary event" means an event arising from unforeseen circumstances of sufficient magnitude, as determined by the commission:

(1) to impose significant costs on customers; and

(2) for which the issuance of extraordinary event bonds in response to the event meets the conditions of section 216B.492, subdivision 2.

(b) Extraordinary event includes but is not limited to a storm event or other natural disaster, an act of God, war, terrorism, sabotage, vandalism, a cybersecurity attack, or a temporary significant increase in the wholesale price of natural gas.

Subd. 7. **Extraordinary event activity.** "Extraordinary event activity" means an activity undertaken by or on behalf of a utility to restore or maintain the utility's ability to provide natural gas service following one or more extraordinary events, including but not limited to activities related to mobilizing, staging, constructing, reconstructing, replacing, or repairing natural gas transmission, distribution, storage, or general facilities.

Subd. 8. **Extraordinary event bonds.** "Extraordinary event bonds" means debt securities, including but not limited to senior secured bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership, that: (1) have a scheduled maturity of no longer than 30 years and a final legal maturity date that is not later than 32 years from the issue date; (2) are rated AA, Aa2, or higher by a major independent credit rating agency at the time of issuance; and (3) are issued by a utility or an assignee under a financing order.

Subd. 9. **Extraordinary event charge.** "Extraordinary event charge" means a nonbypassable charge that:

(1) a utility that is the subject of a financing order or the utility's successor or assignee imposes on all of the utility's customers;

(2) is separate from the utility's base rates; and

(3) provides a source of revenue used only to repay, finance, or refinance extraordinary event costs.

Subd. 10. **Extraordinary event costs.** "Extraordinary event costs":

(1) means all incremental costs of extraordinary event activities that are approved by the commission in a financing order issued under section 216B.492 as being:

(i) necessary to enable the utility to restore or maintain natural gas service to customers after the utility experiences an extraordinary event; and

(ii) prudent and reasonable;

(2) includes costs to repurchase equity or retire any indebtedness relating to extraordinary event activities;

(3) are net of applicable insurance proceeds, tax benefits, and any other amounts intended to reimburse the utility for extraordinary event activities, including government grants or aid of any kind;

(4) do not include any monetary penalty, fine, or forfeiture assessed against a utility by a government agency or court under a federal or state environmental statute, rule, or regulation; and

(5) must be adjusted to reflect:

(i) the difference, as determined by the commission, between extraordinary event costs that the utility expects to incur and actual, reasonable, and prudent costs incurred; or

(ii) a more fair or reasonable allocation of extraordinary event costs to customers over time, as expressed in a commission order, provided that after the issuance of extraordinary event bonds relating to the extraordinary event costs, the adjustment must not (A) reduce or impair the extraordinary event property relating to the extraordinary event bonds, or (B) reduce, impair, postpone, or terminate extraordinary event charges relating to the extraordinary event bonds until all principal, interest, and redemption premium, if any, payable on the extraordinary event bonds, all financing costs for the extraordinary event bonds, and all amounts that must be paid to an assignee or financing party under an ancillary agreement relating to the extraordinary event bonds are paid in full.

Subd. 11. **Extraordinary event property.** "Extraordinary event property" means:

(1) all rights and interests that a utility or the utility's successor or assignee possess under a financing order to impose, bill, collect, receive, and obtain periodic adjustments to extraordinary event charges authorized under a financing order issued by the commission; and

(2) all revenue, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in clause (1), regardless of whether any are commingled with other revenue, collections, rights to payment, payments, money, or proceeds.

Subd. 12. **Extraordinary event revenue.** "Extraordinary event revenue" means revenue, receipts, collections, payments, money, claims, or other proceeds arising from extraordinary event property.

Subd. 13. **Financing costs.** "Financing costs" means:

(1) principal, interest, and redemption premiums, if any, that are payable on extraordinary event bonds;

(2) payments required under an ancillary agreement and amounts required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing document pertaining to extraordinary event bonds;

(3) other demonstrable costs related to issuing, supporting, repaying, refunding, and servicing extraordinary event bonds, including but not limited to servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, financial adviser fees, administrative fees, placement and underwriting fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other demonstrable costs necessary to otherwise ensure and guarantee the timely payment of extraordinary event bonds, other amounts payable in connection with extraordinary event bonds, or other extraordinary event charges payable in connection with extraordinary event bonds;

(4) taxes and license fees imposed on the revenue generated from collecting an extraordinary event charge;

(5) state and local taxes, including franchise, sales and use, and other taxes or similar charges, including but not limited to regulatory assessment fees, whether paid, payable, or accrued; and

(6) costs incurred by the commission to (i) hire and compensate additional temporary staff needed to perform the commission's responsibilities under this section, and (ii) engage specialized counsel and expert consultants experienced in securitized utility ratepayer-backed bond financings similar to extraordinary event bonds financings, as provided under section 216B.494.

Subd. 14. **Financing order.** "Financing order" means an order issued by the commission under section 216B.492 that authorizes an applicant to:

(1) issue extraordinary event bonds in one or more series;

(2) impose, charge, and collect extraordinary event charges; and

(3) create extraordinary event property.

Subd. 15. **Financing party.** "Financing party" means a holder of extraordinary event bonds and a trustee, a collateral agent, a party under an ancillary agreement, or any other person acting for the benefit of extraordinary event bondholders.

Subd. 16. **Natural gas facility.** "Natural gas facility" means natural gas pipelines, including distribution lines, underground storage areas, liquefied natural gas facilities, propane storage tanks, and other facilities the commission determines are used and useful to provide natural gas service to retail and transportation customers in Minnesota.

Subd. 17. **Nonbypassable.** "Nonbypassable" means an extraordinary event charge that a retail customer located within a utility service area cannot avoid and must pay.

Subd. 18. **Pretax costs.** "Pretax costs" means costs incurred by a utility and approved by the commission, including but not limited to:

(1) unrecovered capitalized costs of replaced natural gas facilities damaged or destroyed by an extraordinary event;

(2) costs to decommission and restore the site of a natural gas facility damaged or destroyed by an extraordinary event;

(3) other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance, and salvage proceeds; and

(4) costs to retire any existing indebtedness, fees, costs, and expenses to modify existing debt agreements, or for waivers or consents related to existing debt agreements.

Subd. 19. **Storm event.** "Storm event" means a tornado, derecho, ice or snow storm, wildfire, flood, earthquake, or other significant weather or natural disaster that causes substantial damage to a utility's infrastructure.

Subd. 20. **Successor.** "Successor" means a legal entity that succeeds by operation of law to the rights and obligations of another legal entity as a result of bankruptcy, reorganization, restructuring, other insolvency proceeding, merger, acquisition, consolidation, or sale or transfer of assets.

Subd. 21. **Utility.** "Utility" means a public utility, as defined in section 216B.02, subdivision 4, that provides natural gas service to Minnesota customers. Utility includes the utility's successors or assignees.

History: *1Sp2025 c 7 art 4 s 1*

216B.492 FINANCING ORDER.

Subdivision 1. **Application.** (a) A utility may file an application with the commission requesting a financing order to enable the utility to recover extraordinary event costs by issuing extraordinary event bonds under this section.

(b) The application must include the following information, as applicable:

(1) a description of each natural gas facility to be repaired or replaced;

(2) the undepreciated value remaining in each natural gas facility under clause (1) that the utility proposes to repair or replace using financing obtained by issuing extraordinary event bonds under sections 216B.491 to 216B.499, and the method used to calculate the undepreciated value remaining;

(3) the estimated costs imposed on customers resulting from an extraordinary event that involves no physical damage to natural gas facilities;

(4) the estimated savings or estimated mitigation of rate impacts to utility customers if the financing order is issued as requested in the application, calculated by comparing the costs to customers that are expected to result from implementing the financing order and the estimated costs associated with implementing traditional utility financing mechanisms with respect to the same undepreciated balance, expressed in net present value terms;

(5) a description of (i) the nonbypassable extraordinary event charge utility customers must pay in order to fully recover financing costs, and (ii) the method and assumptions used to calculate the nonbypassable extraordinary event charge;

(6) a proposed methodology to allocate the revenue requirement for the extraordinary event charge among the utility's customer classes;

(7) a description of a proposed adjustment mechanism that is implemented when necessary to correct any overcollection or undercollection of extraordinary event charges, in order to complete payment of scheduled principal and interest on extraordinary event bonds and other financing costs in a timely fashion;

(8) a memorandum with supporting exhibits, developed by a securities firm that is experienced in the marketing of securitized utility ratepayer-backed bonds, indicating the proposed issuance satisfies: (i) the current published AA, Aa2, or higher rating; or (ii) equivalent rating criteria of at least one nationally recognized securities rating organization for issuances similar to the proposed extraordinary event bonds;

(9) an estimate of: (i) the timing of the extraordinary event bonds issuance; and (ii) the term of the extraordinary event bonds or series of bonds, provided that the scheduled final maturity for each bond issuance does not exceed 30 years;

(10) identification of plans to sell, assign, transfer, or convey, other than as a security, interest in extraordinary event property, including identification of an assignee and demonstration that the assignee is a financing entity that is wholly owned, directly or indirectly, by the utility;

(11) identification of ancillary agreements that may be necessary or appropriate;

(12) one or more alternative financing scenarios in addition to the preferred scenario contained in the application;

(13) the extent of damage to the utility's natural gas facility caused by an extraordinary event and the estimated costs to repair or replace the damaged natural gas facility;

(14) a schedule of the proposed repairs to and replacement of the damaged natural gas facility;

(15) a description of the steps taken to provide customers interim natural gas service while the damaged natural gas facility is being repaired or replaced; and

(16) a description of the impacts on the utility's current workforce resulting from implementing a repair or replacement plan following an extraordinary event.

Subd. 2. **Findings.** After providing notice and holding a public hearing on an application filed under subdivision 1, the commission may issue a financing order if the commission finds that:

(1) the extraordinary event costs described in the application are reasonable;

(2) the proposed issuance of extraordinary event bonds and the imposition and collection of extraordinary event charges:

(i) are just and reasonable;

(ii) are consistent with the public interest;

(iii) constitute a prudent and reasonable mechanism to finance the extraordinary event costs; and

(iv) provide tangible and quantifiable benefits to customers, either by providing lower overall costs or mitigating rate impacts relative to traditional methods of financing, that exceed the benefits achieved absent the issuance of extraordinary event bonds; and

(3) the proposed structuring, marketing, and pricing of the extraordinary event bonds:

(i) lower overall costs to customers or mitigate rate impacts to customers relative to traditional methods of financing; and

(ii) achieve customer savings or mitigate rate impacts to customers, as determined by the commission in a financing order, consistent with market conditions at the time of sale and the terms of the financing order.

Subd. 3. **Contents.** (a) A financing order issued under this section must:

(1) determine the maximum amount of extraordinary event costs that may be financed from proceeds of extraordinary event bonds issued pursuant to the financing order;

(2) describe the proposed customer billing mechanism for extraordinary event charges and include a finding that the mechanism is just and reasonable;

(3) describe the financing costs that may be recovered through extraordinary event charges and the period over which the costs may be recovered, which must end no earlier than the date of final legal maturity of the extraordinary event bonds;

(4) describe the extraordinary event property that is created and that may be used to pay, and secure the payment of, principal and interest on the extraordinary event bonds and other financing costs authorized in the financing order;

(5) authorize the utility to finance extraordinary event costs by issuing one or more series of extraordinary event bonds. A utility is not required to secure a separate financing order for each extraordinary event bonds issuance or for each scheduled phase to replace natural gas facilities approved in the financing order;

(6) include a formula-based mechanism that must be used to make expeditious periodic adjustments to the extraordinary event charges authorized by the financing order that are necessary to (i) correct for any overcollection or undercollection, or (ii) otherwise provide for the timely payment of extraordinary event bonds, other financing costs, and other required amounts and charges payable in connection with extraordinary event bonds;

(7) specify the degree of flexibility afforded to the utility to establish the terms and conditions of the extraordinary event bonds, including but not limited to repayment schedules, expected interest rates, and other financing costs;

(8) specify that the extraordinary event bonds must be issued, subject to market conditions and the financing order's terms, as soon as feasible following the financing order's issuance;

(9) require the utility, at the same time extraordinary event charges are initially collected and independent of the schedule to close and decommission any natural gas facility replaced as the result of an extraordinary event, if any, to remove the natural gas facility from the utility's rate base and commensurately reduce the utility's base rates;

(10) specify a future ratemaking process to reconcile any difference between the projected pretax costs included in the amount financed by extraordinary event bonds and the final actual pretax costs incurred by the utility to retire or replace the natural gas facility, if any;

(11) specify information regarding extraordinary event bonds issuance and repayments, financing costs, energy transaction charges, extraordinary event property, and related matters that the natural gas utility is required to provide to the commission on a schedule determined by the commission;

(12) allow or require the creation of a utility's extraordinary event property to be conditioned on, and occur simultaneously with, the sale or other transfer of the extraordinary event property to an assignee and the pledge of the extraordinary event property to secure the extraordinary event bonds;

(13) ensure that the structuring, marketing, and pricing of extraordinary event bonds result in reasonable extraordinary event charges and customer savings or rate impact mitigation, consistent with market conditions and the financing order's terms; and

(14) specify that a utility that finances the replacement of one or more natural gas facilities after the natural gas facilities that are subject to the financing order are removed from the utility's rate base is prohibited from:

(i) operating the natural gas facilities; or

(ii) selling the natural gas facilities to another entity to operate as natural gas facilities.

(b) A financing order issued under this section may:

(1) include conditions different from those requested in the application that the commission determines are necessary to:

(i) promote the public interest; and

(ii) maximize the financial benefits or minimize the financial risks of the transaction to customers and to directly impacted Minnesota workers and communities; and

(2) select one or more underwriters for the extraordinary event bonds.

Subd. 4. **Duration; irrevocability; subsequent order.** (a) A financing order remains effective until the extraordinary event bonds issued under the financing order and all financing costs related to the extraordinary event bonds have been paid in full.

(b) A financing order remains effective and unabated notwithstanding the bankruptcy, reorganization, or insolvency of the utility to which the financing order applies or any affiliate, successor, or assignee of the utility to which the financing order applies.

(c) Subject to judicial review under section 216B.52, a financing order is irrevocable and is not reviewable by a future commission. The commission must not: (1) reduce, impair, postpone, or terminate extraordinary event charges approved in a financing order; (2) reduce or impair the extraordinary event property approved in a financing order or impair the collection or recovery of extraordinary event charges and extraordinary event revenue; or (3) change the customers required to pay extraordinary event charges.

(d) Notwithstanding paragraph (c), the commission may, on the commission's own motion or at the request of a utility or any other person, commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding extraordinary event bonds issued under the original financing order if:

(1) the commission makes all of the findings specified in subdivision 2 with respect to the subsequent financing order; and

(2) the modification contained in the subsequent financing order does not in any way impair the covenants and terms of the extraordinary event bonds being refinanced, retired, or refunded.

Subd. 5. **Effect on commission jurisdiction.** (a) Except as provided in paragraph (b), the commission, in exercising the powers and carrying out the duties under this section, is prohibited from:

(1) considering extraordinary event bonds issued under this section to be debt of the utility other than for income tax purposes, unless considering the extraordinary event bonds to be debt is necessary to achieve consistency with prevailing utility debt rating methodologies;

(2) considering the extraordinary event charges paid under the financing order to be revenue of the utility;

(3) considering the extraordinary event costs or financing costs specified in the financing order to be regulated costs or assets of the utility; or

(4) determining that any prudent action taken by a utility that is consistent with the financing order is unjust or unreasonable.

(b) Nothing in this subdivision:

(1) affects the authority of the commission to apply or modify a billing mechanism designed to recover extraordinary event charges;

(2) prevents or precludes the commission from (i) investigating a utility's compliance with the financing order's terms and conditions, and (ii) requiring compliance with the financing order; or

(3) prevents or precludes the commission from imposing regulatory sanctions against a utility for failure to comply with (i) the financing order's terms and conditions, or (ii) the requirements of this section.

(c) The commission is prohibited from refusing to allow a utility to recover any costs associated with the replacement of natural gas facilities solely because the utility has elected to finance the natural gas facility replacement through a financing mechanism other than extraordinary event bonds.

History: *1Sp2025 c 7 art 4 s 2*

216B.493 POSTORDER COMMISSION DUTIES.

Subdivision 1. **Financing costs review.** Within 120 days after the date extraordinary event bonds are issued, a utility subject to a financing order must file with the commission the actual initial and ongoing financing costs, the final structure and pricing of the extraordinary event bonds, and the actual extraordinary event charge. The commission must review the prudence of the natural gas utility's actions to determine whether the actual financing costs were the lowest that could reasonably be achieved given the financing order's terms and market conditions prevailing at the time the extraordinary event bonds are issued.

Subd. 2. **Enforcement.** If the commission determines that a utility's actions under this section are not prudent or are inconsistent with the financing order, the commission may apply remedies deemed appropriate for utility actions, provided that any remedy applied must not directly or indirectly: (1) reduce or impair the extraordinary event property approved in the financing order or impair the collection or recovery of extraordinary event charges and extraordinary event revenue; (2) reduce, impair, postpone, or terminate extraordinary event charges approved in the financing order until all principal, interest, and redemption premium, if any, payable on the extraordinary event bonds, all financing costs, and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid in full; or (3) change the customers required to pay extraordinary event charges.

History: *1Sp2025 c 7 art 4 s 3*

216B.494 USE OF OUTSIDE EXPERTS.

(a) To carry out the duties under this section, the commission may:

(1) contract with outside consultants and counsel experienced in securitized utility customer-backed bond financing similar to extraordinary event bonds; and

(2) hire and compensate additional temporary staff as needed.

Expenses incurred by the commission under this paragraph must be treated as financing costs paid by the extraordinary event revenue. The costs incurred under clause (1) are not an obligation of the state and are assigned solely to the transaction.

(b) A utility presented with a written request from the commission to reimburse the commission's expenses incurred under paragraph (a), accompanied by a detailed account of the subject expenses, must provide the issuer of the extraordinary event bonds and the indenture trustee for the extraordinary event bonds with such documentation. The indenture trustee must remit full payment of the expenses to the commission on the next interest payment date of the extraordinary event bonds after the payment of interest and scheduled principal of the extraordinary event bonds in accordance with the payment waterfall included in the indenture governing the extraordinary event bonds.

(c) If a utility's application for a financing order is denied or withdrawn for any reason and extraordinary event bonds are not issued, the commission's costs to retain expert consultants under this section must be paid by the applicant utility and are deemed a prudent deferred expense eligible for recovery in the utility's future rates.

History: *1Sp2025 c 7 art 4 s 4*

216B.495 EXTRAORDINARY EVENT CHARGE; BILLING TREATMENT.

(a) A utility that obtains a financing order and issues extraordinary event bonds must:

(1) include on each customer's monthly natural gas bill:

(i) a statement that a portion of the charges represents extraordinary event charges approved in a financing order;

(ii) the amount and rate of the extraordinary event charge as a separate line item titled "extraordinary event charge"; and

(iii) if extraordinary event property has been transferred to an assignee, a statement that the assignee is the owner of the rights to extraordinary event charges and that the utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee; and

(2) file annually with the commission:

(i) a calculation that identifies the impact financing the retirement or replacement of natural gas facilities has on customer rates, itemized by customer class; and

(ii) evidence demonstrating that extraordinary event revenues are applied solely to pay (A) principal and interest on extraordinary event bonds, and (B) other financing costs.

(b) Extraordinary event charges are nonbypassable and must be paid by all existing and future customers receiving service from the utility or the utility's successors or assignees under commission-approved rate schedules or special contracts.

(c) A utility's failure to comply with this section does not invalidate, impair, or affect any financing order, extraordinary event property, extraordinary event charge, or extraordinary event bonds, but does subject the utility to penalties under applicable commission rules provided that any penalty applied must not directly or indirectly: (1) reduce or impair the extraordinary event property approved in the financing order or impair the collection or recovery of extraordinary event charges and extraordinary event revenue; (2) reduce, impair, postpone, or terminate extraordinary event charges approved in the financing order until all principal, interest, and redemption premium, if any, payable on the extraordinary event bonds, all financing costs, and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid in full; or (3) change the customers required to pay extraordinary event charges.

History: *1Sp2025 c 7 art 4 s 5*

216B.496 EXTRAORDINARY EVENT PROPERTY.

Subdivision 1. **General.** (a) Extraordinary event property is an existing present property right or interest in a property right, even though the imposition and collection of extraordinary event charges depend on the utility collecting extraordinary event charges and on future natural gas consumption. The property right or interest exists regardless of whether the revenues or proceeds arising from the extraordinary event property have been billed, have accrued, or have been collected.

(b) Extraordinary event property exists until all extraordinary event bonds issued under a financing order are paid in full and all financing costs and other extraordinary event bonds costs have been recovered in full.

(c) All or any portion of extraordinary event property described in a financing order issued to a utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the utility and created for the limited purpose of acquiring, owning, or administering extraordinary event property or issuing extraordinary event bonds authorized by the financing order. All or any portion of extraordinary event property may be pledged to secure extraordinary event bonds issued under a financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Each transfer, sale, conveyance, assignment, or pledge by a utility or an affiliate of extraordinary event property is a transaction in the ordinary course of business.

(d) If a utility defaults on any required payment of charges arising from extraordinary event property described in a financing order, a court, upon petition by an interested party and without limiting any other remedies available to the petitioner, must order the sequestration and payment of the revenues arising from the extraordinary event property to the financing parties.

(e) The interest of a transferee, purchaser, acquirer, assignee, or pledgee in extraordinary event property specified in a financing order issued to a utility, and in the revenue and collections arising from the property, is not subject to setoff, counterclaim, surcharge, or defense by the utility or any other person, or in connection with the reorganization, bankruptcy, or other insolvency of the utility or any other entity.

(f) A successor to a utility, whether resulting from a reorganization, bankruptcy, or other insolvency proceeding, merger or acquisition, sale, other business combination, transfer by operation of law, utility restructuring, or otherwise: (1) must perform and satisfy all obligations of, and has the same duties and rights under, a financing order as the utility to which the financing order applies; and (2) must perform the duties and exercise the rights in the same manner and to the same extent as the utility, including (i) collecting extraordinary event bonds revenues, collections, payments, or proceeds, and (ii) paying a person entitled to receive extraordinary event bonds revenues, collections, payments, or proceeds.

Subd. 2. **Security interests in extraordinary event property.** (a) The creation, perfection, and enforcement of any security interest in extraordinary event property to secure the repayment of the principal and interest on extraordinary event bonds, amounts payable under any ancillary agreement, and other financing costs are governed by this section only.

(b) A security interest in extraordinary event property is created, valid, and binding when:

(1) the financing order that describes the extraordinary event property is issued;

(2) a security agreement is executed and delivered; and

(3) value is received for the extraordinary event bonds.

(c) Once a security interest in extraordinary event property is created, the security interest attaches without any physical delivery of collateral or any other act. The lien of the security interest is valid, binding, and perfected against all parties having claims of any kind in tort, in contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien, upon the filing of a financing statement with the secretary of state.

(d) The description or indication of extraordinary event property in a transfer or security agreement and a financing statement is sufficient only if the description or indication refers to this section and the financing order creating the extraordinary event property.

(e) A security interest in extraordinary event property is a continuously perfected security interest and has priority over any other lien, created by operation of law or otherwise, that may subsequently attach to the extraordinary event property unless the person that holds the security interest has agreed otherwise in writing.

(f) The priority of a security interest in extraordinary event property is not affected by the commingling of extraordinary event property or extraordinary event revenue with other money. An assignee, bondholder, or financing party has a perfected security interest in the amount of all extraordinary event property or extraordinary event revenue that is pledged to pay extraordinary event bonds even if the extraordinary event property or extraordinary event revenue is deposited in a cash or deposit account owned by the utility in which the extraordinary event revenue is commingled with other money. Any other security interest that applies to the other money does not apply to the extraordinary event revenue.

(g) A subsequent commission order amending a financing order under section 216B.492, subdivision 4, or the application of an adjustment mechanism authorized by a financing order under section 216B.492, subdivision 3, does not affect the validity, perfection, or priority of a security interest in or transfer of extraordinary event property.

Subd. 3. **Sales of extraordinary event property.** (a) A sale, assignment, or transfer of extraordinary event property is an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the extraordinary event property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer. A transfer of an interest in extraordinary event property may be created when:

(1) the financing order creating and describing the extraordinary event property is effective;

(2) the documents evidencing the transfer of the extraordinary event property are executed and delivered to the assignee; and

(3) value is received.

(b) The characterization of a sale, assignment, or transfer as an absolute transfer and true sale, and the corresponding characterization of the property interest of the assignee, is not affected or impaired by:

(1) commingling extraordinary event revenue with other money;

(2) the seller retaining:

(i) a partial or residual interest, including an equity interest, in the extraordinary event property, whether (A) direct or indirect, or (B) subordinate or otherwise; or

(ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of extraordinary event revenue;

(3) any recourse that the extraordinary event property purchaser may have against the seller;

(4) any indemnification rights, obligations, or repurchase rights made or provided by the extraordinary event property seller;

(5) the extraordinary event property seller's obligation to collect extraordinary event revenues on behalf of an assignee;

(6) the treatment of the sale, assignment, or transfer for tax, financial reporting, or other purposes;

(7) any subsequent financing order amending a financing order under section 216B.492, subdivision 4, paragraph (d); or

(8) any application of an adjustment mechanism under section 216B.492, subdivision 3, paragraph (a), clause (6).

History: *1Sp2025 c 7 art 4 s 6*

216B.497 EXTRAORDINARY EVENT BONDS.

(a) A bank, trust company, savings and loan association, insurance company, executor, administrator, guardian, trustee, or other fiduciary may legally invest any money within the individual's or entity's control in extraordinary event bonds.

(b) Extraordinary event bonds issued under a financing order are not debt of or a pledge of the faith and credit or taxing power of the state, any agency of the state, or any political subdivision. An extraordinary event bonds holder does not possess the ability to compel taxes to be levied by the state or a political subdivision in order to pay the principal or interest on extraordinary event bonds. The issuance of extraordinary event bonds does not directly, indirectly, or contingently obligate the state or a political subdivision to levy any tax or make any appropriation to pay principal or interest on the extraordinary event bonds.

(c) The state pledges to and agrees with an extraordinary event bonds holder, assignee, and financing party that the state and state agencies, including the commission, are prohibited from:

(1) taking or permitting an action that reduces or impairs the extraordinary event property approved in the financing order or impairs the collection or recovery of extraordinary event charges or extraordinary event revenue;

(2) reducing, impairing, postponing, or terminating extraordinary event charges approved in the financing order that are imposed, collected, and remitted for the benefit of an extraordinary event bonds holder, assignee, and financing party until all principal, interest, and redemption premium, if any, payable on extraordinary event bonds, all financing costs, and all amounts to be paid to an assignee or financing party under an ancillary agreement are paid in full; or

(3) changing the customers required to pay the extraordinary event charges.

(d) The commission may include a pledge in the financing order similar to the pledge included in paragraph (c).

(e) A person who issues extraordinary event bonds may include the pledge specified in paragraphs (c) and (d) in the extraordinary event bonds, ancillary agreements, and documentation related to the issuance and marketing of the extraordinary event bonds.

History: *1Sp2025 c 7 art 4 s 7*

216B.498 ASSIGNEE OR FINANCING PARTY NOT SUBJECT TO COMMISSION REGULATION.

An assignee or financing party that is not already regulated by the commission does not become subject to commission regulation solely as a result of engaging in any transaction authorized by or described in sections 216B.491 to 216B.499.

History: *1Sp2025 c 7 art 4 s 8*

216B.499 EFFECT ON OTHER LAWS.

(a) If a provision of sections 216B.491 to 216B.499 conflicts with other law regarding the attachment, assignment, perfection, effect of perfection, or priority of a security interest in or transfer of extraordinary event property, sections 216B.491 to 216B.499 govern.

(b) Nothing in this section precludes a utility for which the commission has initially issued a financing order from applying to the commission for:

(1) a subsequent financing order amending the financing order under section 216B.492, subdivision 4, paragraph (d); or

(2) approval to issue extraordinary event bonds to refund all or a portion of an outstanding series of extraordinary event bonds.

History: *1Sp2025 c 7 art 4 s 9*

216B.50 RESTRICTIONS ON PROPERTY TRANSFER AND MERGER.

Subdivision 1. **Commission approval required.** No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $1,000,000, or merge or consolidate with another public utility or transmission company operating in this state, without first being authorized so to do by the commission. Upon the filing of an application for the approval and consent of the commission, the commission shall investigate, with or without public hearing. The commission shall hold a public hearing, upon such notice as the commission may require. If the commission finds that the proposed action is consistent with the public interest, it shall give its consent and approval by order in writing. In reaching its determination, the commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or disposed of, or merged and consolidated.

This section does not apply to the purchase of property to replace or add to the plant of the public utility by construction.

Subd. 2. [Repealed, 1978 c 795 s 10]

Subd. 3. **Exempt from other law.** Mergers and consolidations as enumerated in subdivision 1 hereof shall be exempt from the provisions of chapter 80B.

History: *1974 c 429 s 50; 2005 c 97 art 1 s 8; 2023 c 60 art 12 s 23*

216B.51 STOCK PURCHASE.

Subdivision 1. **Stock of another utility.** No public utility shall purchase voting stock in another public utility doing business in Minnesota without first having made application to and received the consent of the commission in writing or by order.

Subd. 2. [Repealed, 1978 c 795 s 10]

Subd. 3. **Exempt from other law.** Mergers and consolidations as enumerated in subdivision 1 hereof shall be exempt from the provisions of chapter 80B.

History: *1974 c 429 s 51*

VIOLATIONS, PENALTIES, JUDICIAL CONSIDERATIONS

216B.52 APPEAL.

Subdivision 1. **Appeal under Administrative Procedure Act.** Any party to a proceeding before the commission or any other person, aggrieved by a decision and order and directly affected by it, may appeal from the decision and order of the commission in accordance with chapter 14.

Subd. 2. [Repealed, 1983 c 247 s 219]

Subd. 3. [Repealed, 1983 c 247 s 219]

Subd. 4. [Repealed, 1983 c 247 s 219]

Subd. 5. [Repealed, 1983 c 247 s 219]

History: *1974 c 429 s 52; 1978 c 674 s 60; 1983 c 247 s 96*

216B.53 SUSPENSION OF COMMISSION ORDER.

The pendency of proceedings on appeal shall not of itself stay or suspend the operation of the order of the commission unless the commission so orders, but during the pendency of the proceedings the court in its discretion may stay or suspend, in whole or in part, the operation of the commission's order on terms it deems just, and in accordance with the practice of courts exercising equity jurisdiction. No stay shall be granted by the court without notice to the parties and opportunity to be heard. Any party shall have the right to secure from the court in which an appeal of an order of the commission is sought an order suspending or staying the operation of an order of the commission, pending an appeal of the order, but no commission order relating to rates or rules shall be stayed or suspended absent a finding that great or irreparable damage would otherwise result to the party seeking the stay or suspension, and any order staying or suspending a commission order shall specify the nature of the damage.

In case the order of the commission is stayed or suspended, the court shall require a bond with good and sufficient surety, conditioned that the public utility petitioning for review shall answer for all damages caused by the delay in enforcing the order of the commission, and for all compensation for whatever sums for transmission or service any person shall be compelled to pay pending review proceedings in excess of the sum the person or corporation would have been compelled to pay had the commission's order not been stayed or suspended. The court, may, in addition or in lieu of the bond require other further security for the payment of such excess damages or charges it deems proper.

History: *1974 c 429 s 53; 1977 c 364 s 6*

216B.54 LEGAL ACTION AGAINST VIOLATION.

Whenever the commission or department shall be of the opinion that any person or public utility is failing or omitting or is about to fail or omit to do anything required of it by Laws 1974, chapter 429 or by any order of the commission, or is doing anything or about to do anything, or permitting anything or about to permit anything to be done, contrary to or in violation of Laws 1974, chapter 429 or of any order of the commission, it shall refer the matter to the attorney general who shall take appropriate legal action.

History: *1974 c 429 s 54; 1980 c 614 s 115*

216B.55 [Repealed, 1983 c 247 s 219]

216B.56 BURDEN OF PROOF.

In all proceedings before the commission in which the modification or vacation of any order of the commission is sought, the burden of proof shall be on the person seeking such modification or vacation.

History: *1974 c 429 s 56*

216B.57 PENALTY FOR VIOLATION OF ACT.

Any person who knowingly and intentionally violates any provision of Laws 1974, chapter 429, or who knowingly and intentionally fails, omits, or neglects to obey, observe, or comply with any lawful order, or any part or provision thereof, of the commission is subject to a penalty of not less than $100 nor more than $1,000 for each violation.

History: *1974 c 429 s 57*

216B.58 PENALTIES; CONSTRUING ACT, OMISSION, AND FAILURE.

In construing and enforcing the provision of Laws 1974, chapter 429 relating to penalties, the act, omission, or failure of any officer, agent, or employee of any person acting within the scope of official duties of employment shall in every case be deemed to be also the act, omission, or failure of that person.

History: *1974 c 429 s 58; 1986 c 444*

216B.59 CONTINUING VIOLATION.

Every violation of the provisions of Laws 1974, chapter 429 or of any lawful order of the commission, or any part or portion thereof by any person, is a separate and distinct offense, and in case of a continuing violation after a first conviction thereof each day's continuance thereof shall be deemed to be a separate and distinct offense.

History: *1974 c 429 s 59*

216B.60 PENALTIES CUMULATIVE.

All penalties accruing under Laws 1974, chapter 429 shall be cumulative, and a suit for the recovery of one penalty shall not be a bar to or affect the recovery of any other penalty or forfeiture or be a bar to any criminal prosecution against any public utility or any officer, director, agent, or employee thereof or any person.

History: *1974 c 429 s 60*

216B.61 ACTIONS TO RECOVER PENALTIES.

Actions to recover penalties under this chapter shall be brought in the name of the state of Minnesota in the district court of Ramsey County.

History: *1974 c 429 s 61; 2005 c 10 art 1 s 34*

ASSESSMENTS

216B.62 REGULATORY EXPENSES.

Subdivision 1. [Repealed, 1980 c 614 s 191]

Subd. 2. **Assessing specific utility.** Whenever the commission or department, in a proceeding upon its own motion, on complaint, or upon an application to it, shall deem it necessary, in order to carry out the duties imposed under this chapter (1) to investigate the books, accounts, practices, and activities of, or make appraisals of the property of, any public utility, (2) to render any engineering or accounting services to any public utility, or (3) to intervene before an energy regulatory agency, the public utility shall pay the expenses reasonably attributable to the investigation, appraisal, service, or intervention. The commission and department shall ascertain the expenses, and the department shall render a bill therefor to the public utility, either at the conclusion of the investigation, appraisal, or services, or from time to time during its progress, which bill shall constitute notice of the assessment and a demand for payment. The amount of the bills so rendered by the department shall be paid by the public utility into the state treasury within 30 days from the date of rendition. The total amount, in any one calendar year, for which any public utility shall become liable, by reason of costs incurred by the commission within that calendar year, shall not exceed two-fifths of one percent of the gross operating revenue from retail sales of gas, or electric service by the public utility within the state in the last preceding calendar year. Where, pursuant to this subdivision, costs are incurred within any calendar year which are in excess of two-fifths of one percent of the gross operating revenues, the excess costs shall not be chargeable as part of the remainder under subdivision 3, but shall be paid out of the general appropriation to the department and commission. In the case of public utilities offering more than one public utility service only the gross operating revenues from the public utility service in connection with which the investigation is being conducted shall be considered when determining this limitation.

Subd. 3. **Assessing all public utilities.** The department and commission shall quarterly, at least 30 days before the start of each quarter, estimate the total of their expenditures in the performance of their duties relating to public utilities under sections 216B.01 to 216B.67, other than amounts chargeable to public utilities under subdivision 2, 6, 7, 8, or 9. The remainder shall be assessed by the commission and department to the several public utilities in proportion to their respective gross operating revenues from retail sales of gas or electric service within the state during the last calendar year. The assessment shall be paid into the state treasury within 30 days after the bill has been transmitted via mail, personal delivery, or electronic service to the several public utilities, which shall constitute notice of the assessment and demand of payment thereof. The total amount which may be assessed to the public utilities, under authority of this subdivision, shall not exceed one-sixth of one percent of the total gross operating revenues of the public utilities during the calendar year from retail sales of gas or electric service within the state. The assessment for the third quarter of each fiscal year shall be adjusted to compensate for the amount by which actual expenditures by the commission and department for the preceding fiscal year were more or less than the estimated expenditures previously assessed.

Subd. 3a. **Supplemental staffing assessment.** In addition to other assessments in subdivision 3, the commission may assess up to $800,000 per year for supplemental staffing to implement requirements of this chapter. The amount in this subdivision shall be assessed to the several public utilities in proportion to their respective gross operating revenues from retail sales of gas or electric service within the state during the last calendar year and shall be deposited into an account in the special revenue fund. An assessment made under this subdivision is not subject to the cap on assessments provided in subdivision 3 or any other law.

Subd. 3b. **Assessment for department regional and national duties.** In addition to other assessments in subdivision 3, the department may assess up to $1,000,000 per fiscal year to perform the duties under section 216A.07, subdivision 3a, and to conduct analysis that assesses energy grid reliability at state, regional, and national levels. The amount in this subdivision shall be assessed to energy utilities in proportion to their respective gross operating revenues from retail sales of gas or electric service within the state during the last calendar year and shall be deposited into an account in the special revenue fund and is appropriated to the commissioner of commerce for the purposes of section 216A.07, subdivision 3a. An assessment made under this subdivision is not subject to the cap on assessments provided in subdivision 3 or any other law. For the purpose of this subdivision, an "energy utility" means public utilities, generation and transmission cooperative electric associations, and municipal power agencies providing natural gas or electric service in the state.

Subd. 4. **Objections.** Within 30 days after the date of the transmittal of any bill as provided by subdivisions 2, 3, 7, and 8, the public utility against which the bill has been rendered may file with the commission objections setting out the grounds upon which it is claimed the bill is excessive, erroneous, unlawful, or invalid. The commission shall within 60 days hold a hearing and issue an order in accordance with its findings. The order shall be appealable in the same manner as other final orders of the commission.

Subd. 5. **Assessing cooperatives and municipals.** The commission and department may charge cooperative electric associations, generation and transmission cooperative electric associations, municipal power agencies, and municipal electric utilities their proportionate share of the expenses incurred in the review and disposition of resource plans, adjudication of service area disputes, proceedings under section 216B.1691, 216B.2425, or 216B.243, and the costs incurred in the adjudication of complaints over service standards, practices, and rates. Cooperative electric associations electing to become subject to rate regulation by the commission pursuant to section 216B.026, subdivision 4, are also subject to this section. Neither a cooperative electric association nor a municipal electric utility is liable for costs and expenses in a calendar year in excess of the limitation on costs that may be assessed against public utilities under subdivision 2. A cooperative electric association, generation and transmission cooperative electric association, municipal power agency, or municipal electric utility may object to and appeal bills of the commission and department as provided in subdivision 4.

Subd. 5a. **Assessing transmission companies.** The commission and department may charge transmission companies their proportionate share of the expenses incurred in the review and disposition of proceedings under sections 216B.2425, 216B.243, 216B.48, 216B.50, and 216B.79. A transmission company is not liable for costs and expenses in a calendar year in excess of the limitation on costs that may be assessed against public utilities under subdivision 2. A transmission company may object to and appeal bills of the commission and department as provided in subdivision 4.

Subd. 5b. **Assessments for certain right-of-way proceedings.** The commission and department may charge a railroad, as defined in section 237.045, subdivision 1, paragraph (e), and a utility as defined in section 237.045, subdivision 1, paragraph (f), for the railroad and utility's proportionate share of expenses incurred by the commission and department in the review and disposition of disputes contained in petitions filed under section 237.045. A railroad or utility that objects to an assessment of the commission or department made under this subdivision has the same right to appeal the assessment under subdivision 4 as does a public utility.

Subd. 6. **Administrative hearing costs.** Any amounts billed to the commission or the department by the Office of Administrative Hearings for public utility contested case hearings shall be assessed by the commission or the department against the public utility. The assessment shall be paid into the state treasury within 30 days after a bill, which constitutes notice of the assessment and demand for payment of it, has been transmitted to the public utility. Money received shall be credited to a special account and is appropriated to the commission or the department for payment to the Office of Administrative Hearings.

Subd. 7. **Assessing all utilities.** The department shall assess public utilities, cooperative electric associations, and municipal utilities for the costs of activities under chapter 216C. The department shall not assess for costs of grants, loans, or other aids or for costs that can be recovered through other assessment authority. Each public utility, cooperative, and municipal utility shall be assessed in the proportion that its gross operating revenue for the sale of gas and electric service within the state for the last calendar year bears to the total of those revenues for all public utilities, cooperatives, and municipalities.

Subd. 8. **Audit investigation costs; account, appropriation.** The audit investigation account is created as a separate account in the special revenue fund in the state treasury. If the commission, in a proceeding upon its own motion, on complaint, or upon an application to it, determines that it is necessary, in order to carry out its duties imposed under this chapter or chapter 216, 216A, 216E, 216F, or 216G, to conduct an investigation or audit of any public utility operations, practices, or policies requiring specialized technical professional investigative services for the inquiry, the commission may request the commissioner of commerce to seek authority from the commissioner of management and budget to incur costs reasonably attributable to the specialized services. If the investigation or audit is approved by the commissioner of management and budget, the commissioner of commerce shall carry out the investigation in the manner directed by the commission and shall render separate bills to the public utility for the costs incurred for such technical professional investigative services. The bill constitutes notice of the assessment and demand for payment. The amount assessed must be paid by the public utility to the commissioner of commerce within 30 days after the date of assessment. Money received under this subdivision must be deposited in the state treasury and credited to the audit investigation account, and is appropriated to the commissioner of commerce for the purposes of this subdivision.

Subd. 9. **Administrative costs for extraordinary event bonds.** The commission and the department may assess gas utilities for the actual commission and department costs incurred to administer extraordinary event bonds under sections 216B.491 to 216B.499. The money received from the assessment must be deposited into an account in the special revenue fund. All money deposited in the account is appropriated to the commission or the department for the purposes of this subdivision. The commission and department may initially assess for estimated costs under sections 216B.491 to 216B.499, then must adjust subsequent assessments for actual costs incurred under sections 216B.491 to 216B.499. An assessment made under this subdivision is not subject to the cap on assessments provided in subdivision 3 or any other law.

Subd. 10. **Administrative costs for discontinuation of telecommunication services.** The commission may assess fees for the actual commission costs to administer the discontinuation of telecommunication services under section 237.181. The money received from the assessment must be deposited into an account in the special revenue fund and all money deposited is appropriated to the commission for the purposes specified under this subdivision. The commission may initially assess for estimated costs under section 237.181, then must adjust subsequent assessments for actual costs incurred under section 237.181. An assessment made under this subdivision is not subject to the cap on assessments provided in subdivision 3 or any other law.

[See Note.]

History: *1974 c 429 s 62 subds 1-4; 1978 c 674 s 60; 1978 c 795 s 9; 1980 c 614 s 116; 1981 c 357 s 71,72; 1983 c 289 s 105,106; 1990 c 598 s 1; 1991 c 234 s 2; 1992 c 478 s 4; 1993 c 356 s 4; 1993 c 369 s 66,67; 2001 c 212 art 7 s 34; 2005 c 97 art 1 s 9,10; 2007 c 10 s 8-10; 2009 c 37 art 2 s 8-11; 2009 c 101 art 2 s 109; 2009 c 110 s 25-27; 2010 c 361 art 5 s 9; 2011 c 97 s 24-26; 1Sp2015 c 1 art 3 s 23; 2016 c 180 s 1; 2017 c 94 art 8 s 8; 1Sp2019 c 7 art 11 s 6; 1Sp2021 c 4 art 8 s 22; 2023 c 60 art 12 s 24; 1Sp2025 c 4 art 7 s 16; 1Sp2025 c 7 art 4 s 10,11*

NOTE: Subdivision 10, as added by Laws 2025, First Special Session chapter 4, article 7, section 16, is effective July 1, 2026. Laws 2025, First Special Session chapter 4, article 7, section 16, the effective date.

216B.63 INTEREST ON ASSESSMENT.

The amounts assessed against any public utility not paid after 30 days after the transmittal of a notice advising the public utility of the amount assessed against it, draw interest at the rate of six percent per annum; and, upon failure to pay the assessment, the attorney general shall proceed by action in the name of the state against the public utility to collect the amount due, together with interest and the cost of the suit.

History: *1974 c 429 s 63; 2007 c 10 s 11*

216B.631 COMPENSATION FOR PARTICIPANTS IN PROCEEDINGS.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the following terms have the meanings given.

(b) "Participant" means a person who files comments or appears in a commission proceeding concerning one or more public utilities, excluding public hearings held in contested cases and commission proceedings conducted to receive general public comments.

(c) "Party" means a person by or against whom a proceeding before the commission is commenced or a person permitted to intervene in a proceeding, other than public hearings, concerning one or more public utilities.

(d) "Proceeding" means:

(1) a rate change proceeding under section 216B.16, including a request to withdraw, defer, or modify a petition to change rates;

(2) a proceeding in which the commission considers a utility request for cost recovery through general rates or riders;

(3) a proceeding in which the commission considers a determination related to ratepayer protections, service quality, or disconnection policies and practices, including but not limited to utility compliance with the requirements of sections 216B.091 to 216B.0993;

(4) a proceeding in which the commission considers determinations directly related to low-income affordability programs, including but not limited to utility compliance with the requirements of section 216B.16, subdivisions 14, 15, and 19, paragraph (a), clause (3);

(5) a proceeding related to the design or approval of utility tariffs or rates;

(6) a proceeding related to utility performance measures or incentives, including but not limited to proceedings under sections 216B.16, subdivision 19, paragraph (h); 216B.167; and 216B.1675;

(7) proceedings related to distribution system planning and grid modernization, including but not limited to proceedings in compliance with the requirements in section 216B.2425, subdivision 2, paragraph (e);

(8) investigations or inquiries initiated by the commission or the Department of Commerce; or

(9) proceedings related to utility pilot programs in which the commission considers a proposal with a proposed cost of at least $5,000,000.

(e) "Public utility" has the meaning given in section 216B.02, subdivision 4.

Subd. 2. **Participants; eligibility.** Any of the following participants is eligible to receive compensation under this section:

(1) a nonprofit organization that:

(i) is exempt from taxation under section 501(c)(3) of the Internal Revenue Code;

(ii) is incorporated or organized in Minnesota;

(iii) is governed under chapter 317A or section 322C.1101; and

(iv) the commission determines under subdivision 3, paragraph (c), would suffer financial hardship if not compensated for the nonprofit organization's participation in the applicable proceeding; or

(2) a Tribal government of a federally recognized Indian Tribe that is located in Minnesota.

Subd. 3. **Compensation; conditions.** (a) The commission may order a public utility to compensate all or part of a participant's reasonable costs incurred to participate in a proceeding before the commission if the participant is eligible under subdivision 2 and the commission finds:

(1) that the participant has materially assisted the commission's deliberation; and

(2) if the participant is a nonprofit organization, that the participant would suffer financial hardship if the nonprofit organization's participation in the proceeding was not compensated.

(b) In determining whether a participant has materially assisted the commission's deliberation, the commission must find that:

(1) the participant made a unique contribution to the record and represented an interest that would not otherwise have been adequately represented;

(2) the evidence or arguments presented or the positions taken by the participant were an important factor in producing a fair decision;

(3) the participant's position promoted a public purpose or policy;

(4) the evidence presented, arguments made, issues raised, or positions taken by the participant would not otherwise have been part of the record;

(5) the participant was active in any stakeholder process included in the proceeding; and

(6) the proceeding resulted in a commission order that adopted, in whole or in part, a position advocated by the participant.

(c) In determining whether a nonprofit participant has demonstrated that a lack of compensation would present financial hardship, the commission must find that the nonprofit participant:

(1) had an average annual payroll expense less than $600,000 for participation in commission proceedings over the previous three years; and

(2) has fewer than 30 full-time equivalent employees.

(d) In reviewing a compensation request, the commission must consider whether the costs presented in the participant's claim are reasonable. If the commission determines that an eligible participant materially assisted the commission's deliberation, the commission shall award all or part of the requested compensation, up to the maximum amounts provided under subdivision 4.

Subd. 4. **Compensation; amount.** (a) Compensation must not exceed $50,000 for a single participant in any proceeding, except that:

(1) if a proceeding extends longer than 12 months, a participant may request and be awarded compensation of up to $50,000 for costs incurred in each calendar year; and

(2) for a contested case proceeding, a participant may request and be awarded up to $75,000.

(b) No single participant may be awarded more than $200,000 under this section in a single calendar year.

(c) Compensation requests from joint participants must be presented as a single request.

(d) Notwithstanding paragraphs (a) and (b), the commission must not, in any calendar year, require a single public utility to pay aggregate compensation under this section that exceeds the following amounts:

(1) $100,000, for a public utility with up to $300,000,000 annual gross operating revenue in Minnesota;

(2) $275,000, for a public utility with at least $300,000,000 but less than $900,000,000 annual gross operating revenue in Minnesota;

(3) $375,000, for a public utility with at least $900,000,000 but less than $2,000,000,000 annual gross operating revenue in Minnesota; and

(4) $1,250,000, for a public utility with $2,000,000,000 or more annual gross operating revenue in Minnesota.

(e) When requests for compensation from any public utility approach the limits established in paragraph (d), the commission may give priority to requests from participants that received less than $150,000 in total compensation during the previous two years and from participants who represent residential ratepayers, particularly those residential ratepayers who the participant can demonstrate have been underrepresented in past commission proceedings.

Subd. 5. **Compensation; process.** (a) A participant seeking compensation must file a request and an affidavit of service with the commission, and serve a copy of the request on each party to the proceeding. The request must be filed no more than 30 days after the later of:

(1) the expiration of the period within which a petition for rehearing, amendment, vacation, reconsideration, or reargument must be filed; or

(2) the date the commission issues an order following rehearing, amendment, vacation, reconsideration, or reargument.

(b) A compensation request must include:

(1) the name and address of the participant or nonprofit organization the participant is representing;

(2) evidence of the organization's nonprofit, tax-exempt status, if applicable;

(3) the name and docket number of the proceeding for which compensation is requested;

(4) for a nonprofit participant, evidence supporting the nonprofit organization's eligibility for compensation under the financial hardship test under subdivision 3, paragraph (c);

(5) amounts of compensation awarded to the participant under this section during the current year and any pending requests for compensation, itemized by docket;

(6) an itemization of the participant's costs, not including overhead costs;

(7) participant revenues dedicated to the proceeding;

(8) the total compensation request; and

(9) a narrative describing the unique contribution made to the proceeding by the participant.

(c) A participant must comply with reasonable requests for information by the commission and other parties or participants. A participant must reply to information requests within ten calendar days of the date the request is received, unless doing so would place an extreme hardship upon the replying participant. The replying participant must provide a copy of the information to any other participant or interested person upon request. Disputes regarding information requests may be resolved by the commission.

(d) A party or participant objecting to a request for compensation must, within 30 days after service of the request for compensation, file a response and an affidavit of service with the commission. A copy of the response must be served on the requesting participant and all other parties to the proceeding.

(e) The requesting participant may file a reply with the commission within 15 days after a response is filed under paragraph (d). A copy of the reply and an affidavit of service must be served on all other parties to the proceeding.

(f) If additional costs are incurred by a participant as a result of additional proceedings following the commission's initial order, the participant may file an amended request within 30 days after the commission issues an amended order. Paragraphs (b) to (e) apply to an amended request.

(g) The commission must issue a decision on participant compensation within 120 days of the date a request for compensation is filed by a participant.

(h) The commission may extend the deadlines in paragraphs (d), (e), and (g) for up to 30 days upon the request of a participant or on the commission's own initiative.

(i) A participant may request reconsideration of the commission's compensation decision within 30 days of the decision date.

Subd. 6. **Compensation; orders.** (a) If the commission issues an order requiring payment of participant compensation, the public utility that was the subject of the proceeding must pay the full compensation to the participant and file proof of payment with the commission within 30 days after the later of:

(1) the expiration of the period within which a petition for reconsideration of the commission's compensation decision must be filed; or

(2) the date the commission issues an order following reconsideration of the commission's order on participant compensation.

(b) If the commission issues an order requiring payment of participant compensation in a proceeding involving multiple public utilities, the commission must apportion costs among the public utilities in proportion to each public utility's annual revenue.

(c) The commission may issue orders necessary to allow a public utility to recover the costs of participant compensation on a timely basis.

Subd. 7. **Report.** By July 1, 2026, the commission must report to the chairs and ranking minority members of the legislative committees with primary jurisdiction over energy policy on the operation of this section. The report must include but is not limited to:

(1) the amount of compensation paid each year by each utility;

(2) each recipient of compensation, the commission dockets in which compensation was awarded, and the compensation amounts; and

(3) the impact of the participation of compensated participants.

Subd. 8. **Sunset.** This section expires July 1, 2031.

History: *2023 c 60 art 12 s 25*

MISCELLANEOUS

216B.64 ATTORNEY GENERAL'S RESPONSIBILITIES.

The attorney general of the state shall, upon request of the commission or department, represent and appear for the commission or department in all actions and proceedings involving any question under Laws 1974, chapter 429, and shall aid in any investigation or hearing had under the provisions of Laws 1974, chapter 429. The attorney general shall perform all duties and services in connection with Laws 1974, chapter

429 and the enforcement thereof as the commission or department may require. The attorney general shall also bring all actions to collect penalties herein provided.

History: *1974 c 429 s 64; 1980 c 614 s 117; 1986 c 444*

216B.65 DEPARTMENT TO EMPLOY NECESSARY STAFF.

The department may employ experts, engineers, statisticians, accountants, inspectors, clerks, hearing examiners who may be attorneys and employees it deems necessary to carry out the provisions of Laws 1974, chapter 429.

History: *1974 c 429 s 67*

216B.66 CONSTRUCTION.

Laws 1974, chapter 429 is complete in itself and other Minnesota statutes are not to be construed as applicable to the supervision or regulation of public utilities by the commission. All acts and parts of acts in conflict with Laws 1974, chapter 429 are repealed insofar as they pertain to the regulation of public utilities as defined herein.

History: *1974 c 429 s 69*

216B.67 CITATION.

Laws 1974, chapter 429, may be cited as the "Minnesota Public Utilities Act."

History: *1974 c 429 s 71*

MERCURY EMISSIONS REDUCTION

216B.68 DEFINITIONS; MERCURY EMISSIONS REDUCTION.

Subdivision 1. **Scope.** Terms used in sections 216B.68 to 216B.688 have the meanings given them in this section and section 216B.02.

Subd. 2. **Agency.** "Agency" means the Minnesota Pollution Control Agency.

Subd. 3. **Dry scrubbed unit.** "Dry scrubbed unit" means a targeted unit at which pollution control technology that uses a spray dryer and fabric filter system to remove pollutants from air emissions is installed or will be installed by December 31, 2007.

Subd. 4. **Federal mercury regulations.** "Federal mercury regulations" means the federal Clean Air Mercury Rule as of January 1, 2006, published in Code of Federal Regulations, title 40, parts 60, 63, 70, and 72.

Subd. 5. **Mercury emissions reduction.** "Mercury emissions reduction" means the amount of mercury reduced from the emissions of a targeted or supplemental unit, relative to the emissions baseline from that unit established under section 216B.681, expressed as a percentage.

Subd. 6. **Qualifying facility.** "Qualifying facility" means an electric generating power plant in Minnesota that, as of January 1, 2006, had a total net dependable capacity in excess of 500 megawatts from all coal-fired electric generating units at the power plant.

Subd. 7. **Start-up period.** "Start-up period" means a period of one year after the date mercury-control equipment is installed at a targeted unit under an approved mercury emissions-reduction plan, or such longer period as the commission may approve after consultation with the Pollution Control Agency, if a longer period is necessary to optimize equipment performance for mercury reduction.

Subd. 8. **Targeted unit.** "Targeted unit" means a coal-fired electric generation unit greater than 100 megawatts at a qualifying facility.

Subd. 9. **Wet scrubbed unit.** "Wet scrubbed unit" means a targeted unit at which pollution control technology that uses water or solutions to remove pollutants from air emissions is installed.

History: *2006 c 201 s 5*

216B.681 MONITORING MERCURY EMISSIONS.

By July 1, 2007, a public utility that owns or operates a qualifying facility shall install, maintain, and operate continuous mercury emission-monitoring systems or other method of monitoring approved by the agency on each targeted unit and, where applicable, on each supplemental unit pursuant to section 216B.6851. The monitoring systems must use methods set forth in federal mercury regulations or such other methods as may be approved by the agency. The public utility shall report to the agency as public data the quality assured data produced from monitoring implemented pursuant to this section on a quarterly basis in a form prescribed by the agency. The data from at least six months' monitoring must be used to establish a baseline for mercury emissions reductions under sections 216B.68 to 216B.688.

History: *2006 c 201 s 6*

216B.682 MERCURY EMISSIONS-REDUCTION PLANS.

Subdivision 1. **Dry scrubbed units.** (a) By December 31, 2007, a public utility that owns a dry scrubbed unit at a qualifying facility shall develop and submit to the agency and the commission a plan for mercury emissions reduction at each such unit. At each dry scrubbed unit owned and operated by the utility, the plan must propose to employ the available technology for mercury removal that is most likely to result in the removal of at least 90 percent of the mercury emitted from the unit.

(b) A plan submitted under this subdivision must provide for mercury emissions reduction at each dry scrubbed unit to be implemented by December 31, 2010. A public utility that owns two dry scrubbed targeted units must submit a plan that provides for implementation at one unit by December 31, 2009, and at the other unit by December 31, 2010.

Subd. 2. **Wet scrubbed units.** (a) By December 31, 2009, a public utility that owns a wet scrubbed unit at a qualifying facility shall develop and submit to the agency and the commission a plan for mercury emissions reduction at each such unit. At each wet scrubbed unit owned by the utility, the plan must propose to employ the available technology for mercury removal that is most likely to result in the removal of at least 90 percent of the mercury emitted from the unit.

(b) A plan submitted under this subdivision must provide for mercury emissions reduction at each wet scrubbed unit to be implemented by December 31, 2014.

Subd. 3. **Mercury emissions plans generally.** (a) In each plan submitted under this section, a utility shall present information assessing that plan's ability to optimize human health benefits and achieve cost efficiencies. Each plan must provide the cost, technical feasibility, and mercury emissions reduction expected for the utility's preferred technology option and each alternative considered. The utility shall demonstrate that it has considered achieving the mercury emissions reduction required under this section through multiple pollutant control technology.

(b) A plan submitted under this section may also:

(1) provide measures to reduce the cost and maximize the flexibility of each option proposed or considered; and

(2) specify permit targets or conditions proposed by the public utility for each mercury emission-control option proposed or considered, including, but not limited to, numeric emission targets, percent removal expectations, emission control technology installation and operation requirements or work practice standards, and potential changes in the performance of the mercury emissions-reduction technology over time.

(c) The utility may submit an emissions rate rider to the commission under section 216B.683 to recover the costs associated with plans filed under this section.

History: *2006 c 201 s 7*

216B.683 MERCURY EMISSIONS REDUCTION; COST RECOVERY, FINANCIAL INCENTIVES.

Subdivision 1. **Emissions-reduction riders.** (a) A public utility required to file a mercury emissions-reduction plan under sections 216B.68 to 216B.688 may also file for approval of emissions-reduction rate riders pursuant to section 216B.1692, subdivision 3, for its mercury control and other environmental improvement initiatives under sections 216B.68 to 216B.688.

(b) In addition to the cost recovery provided by section 216B.1692, subdivision 3, the emissions-reduction rate riders may include recovery of costs associated with (1) the purchase and installation of continuous mercury emission-monitoring systems, (2) costs associated with the purchase and installation of emissions-reduction equipment, (3) construction work in progress, (4) ongoing operation and maintenance costs associated with the utility's emission-control initiatives, including, but not limited to, the cost of any sorbent or emission-control reagent injected into the unit, (5) any project costs incurred before plan approval that are demonstrated to the commission's satisfaction to be part of the plan, and (6) any studies undertaken by the utility in support of the emissions-reduction plan.

(c) The utility may propose to phase in the emissions-reduction riders to recover these costs over the development and life of the projects.

Subd. 2. **Performance-based incentives.** A mercury emissions-reduction rider approved by the commission may include performance-based financial incentives if the commission determines that the incentives will increase the likelihood that the utility will exceed 90 percent mercury emissions reductions, provided the incentives do not impose excessive costs on the utility's consumers when added to the costs recovered under subdivision 1. These incentives may include increased returns on investments or other performance-based incentives. The commission may structure the financial incentives to escalate for each additional increment of mercury emissions reduction achieved by the utility above the 90 percent mercury emissions reduction.

Subd. 3. **Application of other law; associated rider.** (a) Section 216B.1692 applies to plans and emissions-control riders proposed under sections 216B.68 to 216B.688, except that:

(1) projects included in a plan approved under sections 216B.68 to 216B.688 are deemed to be qualifying projects for the purposes of section 216B.1692; and

(2) section 216B.1692, subdivisions 5, paragraph (c), and 6, do not apply to plans or riders submitted under sections 216B.68 to 216B.688.

(b) Commission approval of an emissions-reduction plan under this section includes approval of an emissions-reduction rider associated with that plan if submitted by the utility.

History: *2006 c 201 s 8*

216B.684 ENVIRONMENTAL ASSESSMENT OF MERCURY EMISSIONS-REDUCTION PLAN.

The Pollution Control Agency shall evaluate a utility's mercury emissions-reduction plans filed under sections 216B.682 and 216B.6851 and submit its evaluation to the Public Utilities Commission within 180 days of the date the plan is filed with the agency and commission. In its review, the agency shall (1) assess whether the utility's plan meets the requirements of section 216B.682 or 216B.6851, as applicable, (2) evaluate the environmental and public health benefits of each option proposed or considered by the utility, including benefits associated with reductions in pollutants other than mercury, (3) assess the technical feasibility and cost-effectiveness of technologies proposed or considered by the utility for achieving mercury emissions reduction, and (4) advise the commission of the appropriateness of the utility's plan. In preparing its assessment, the agency may request additional information from the utility, especially with regard to alternative technologies or configurations applicable to the specific unit, and the estimated costs of those alternatives.

History: *2006 c 201 s 9*

216B.685 MERCURY EMISSIONS-REDUCTION PLAN APPROVAL.

Subdivision 1. **Commission review and evaluation.** The Public Utilities Commission shall review and evaluate a utility's mercury emissions-reduction plans and associated emissions-reduction riders submitted under section 216B.682 or pursuant to subdivision 2, paragraph (b). In its review, the commission shall consider the environmental and public health benefits, the agency's assessment of technical feasibility, competitiveness of customer rates, and cost-effectiveness of the utility's proposed mercury-control initiatives in light of the Pollution Control Agency's report under section 216B.684.

Subd. 2. **Commission approval.** (a) Within 180 days of receiving the agency's report on a utility's plan filed under section 216B.682, subdivision 1 or 2, the commission shall order the implementation of a utility's mercury emissions-reduction plan and associated emissions-reduction rider that complies with the requirements of the applicable subdivision of section 216B.682, unless the commission determines that the plan as proposed fails to provide for increased environmental and health benefits or would impose excessive costs on the utility's customers.

(b) If the commission is unable to approve the utility's plan and associated emissions-reduction riders as proposed, it shall direct the utility to amend and resubmit its proposed plan in light of the record developed on the proposed plan or, at the utility's option, to file a new plan consistent with the requirements of the applicable subdivision of section 216B.682.

Subd. 3. **Technical issues.** The commission shall give due consideration to the assessment of the Pollution Control Agency on compliance issues under sections 216B.68 to 216B.688, technical feasibility of emission-control technology, and environmental and public health benefits associated with emissions reductions.

Subd. 4. **Equipment replacement; deadline extensions.** (a) Unless the utility proposes to do so, the commission may not require the replacement of existing pollution control equipment at a targeted or supplemental unit as a condition for approving a plan pursuant to this section or section 216B.6851.

(b) The commission may allow a utility up to two extensions of any deadline established under sections 216B.68 to 216B.688 or commission order under those sections, if the utility demonstrates the unavailability of necessary equipment or other extraordinary circumstances. An extension under this paragraph may last no longer than 12 months. The commission may not extend a deadline for final installation of pollution control equipment for longer than 12 months.

Subd. 5. **Equipment optimization required.** A commission order under this section must require the utility to optimize the operation of equipment installed under a plan approved under this section to obtain maximum mercury reductions and to report the utility's efforts and results annually to the Pollution Control Agency, until such time as the agency determines the reports to be no longer necessary.

History: *2006 c 201 s 10*

216B.6851 UTILITY OPTION.

Subdivision 1. **Election.** A public utility with less than 200,000 customers subject to sections 216B.68 to 216B.688 that owns two wet scrubbed units at a qualifying facility may opt to be regulated under this section for those units in lieu of section 216B.682. Plans under this section are subject to section 216B.682, subdivision 3. Except where otherwise provided, all other provisions of sections 216B.68 to 216B.688 apply.

Subd. 2. **Supplemental unit.** "Supplemental unit" means a coal-fired electric generation unit at an electric generating power plant in Minnesota at which mercury emissions-reduction measures are taken as part of an emissions-reduction plan under this section.

Subd. 3. **Plan for 90 percent reduction required.** A public utility that elects to be regulated under this section must file a mercury emissions-reduction plan that is designed to achieve total mercury reduction at targeted and supplemental units owned by the utility equivalent to a goal of 90 percent reduction of mercury emissions at the utility's targeted units by December 31, 2018.

Subd. 4. **Alternative plans.** The utility shall also submit one or more alternatives to the 90 percent reduction plan required under subdivision 3. Alternative plans must be designed to come as near as technically possible to achieving the goal established in subdivision 3 without imposing excessive costs on the utility's customers.

Subd. 5. **Early action; wet scrubbed units.** (a) The utility electing for regulation under this section shall file an initial plan for mercury emissions reduction at one of its two wet scrubbed units on or before December 31, 2007. The plan must provide for mercury emissions reduction to be implemented at that unit by December 31, 2010. If the plan is approved by the commission, and implemented by the utility, the utility may have until July 1, 2015, to file its plans for reduction at its other wet scrubbed unit at the qualifying facility, and may have until December 31, 2018, to implement mercury emissions reduction at that unit.

(b) Until the utility files its plans for the other wet scrubbed unit, the utility must submit to the commission and agency, by July 1 each year, beginning in 2011, a report containing the following information:

(1) mercury control plans for units subject to this section, including how elements of the plans may affect the performance and cost-effectiveness of emission controls for air pollutants other than mercury;

(2) an assessment of the impacts of federal laws regulating various air pollutants emitted by coal-fired power plants that can reasonably be expected to be enacted by 2018 on the utility's units subject to this section, and potential utility responses to those laws, including, but not limited to:

(i) installing pollution control equipment;

(ii) using pollution allowances to achieve regulatory compliance; and

(iii) retiring or repowering the plant that is the subject of the filing with cleaner fuels considering the costs of complying with state and federal environmental regulations.

For each potential response, the report must include an analysis of the impacts on ratepayers, the utility's financial position, and utility operations, including the impacts on the service life of affected units.

(c) The utility shall consult with the agency, the Department of Commerce, and other interested stakeholders to determine which future federal laws to assess under paragraph (b), clause (2), and the scope of the assessment of the impact of those laws.

Subd. 6. **Agency review and commission approval.** (a) The agency shall review the utility's plans as provided in section 216B.684.

(b) The Public Utilities Commission shall review and evaluate a utility's mercury emissions-reduction plans submitted under this section. In its review, the commission shall consider the environmental and public health benefits, the agency's determination of technical feasibility, competitiveness of customer rates, and cost-effectiveness of the utility's proposed mercury-control initiatives in light of the Pollution Control Agency's review under paragraph (a). Within 180 days of receiving the agency's report, the commission shall approve a utility's mercury emissions-reduction plan that the commission reasonably expects will come closest to achieving total mercury reductions at targeted and supplemental units owned by the utility equivalent to a goal of 90 percent reduction of mercury emissions at the utility's targeted units by December 31, 2018, in a manner that provides for increased environmental and public health benefits without imposing excessive costs on the utility's customers. If the commission is unable to approve the utility's 90 percent reduction plan filed under subdivision 3, the commission, in consultation with the Pollution Control Agency, shall order the utility to implement the most stringent mercury-control alternative proposed by the utility under this section that provides for increased environmental and public health benefits without imposing excessive costs on the utility's customers.

(c) At each targeted and supplemental unit included in a plan under this section, a utility shall propose to implement mercury emissions-control measures that will result in the greatest reduction of mercury emitted from that unit that is technically feasible without imposing excessive costs.

History: *2006 c 201 s 11; 2010 c 325 s 2-4*

216B.686 OTHER ENVIRONMENTAL IMPROVEMENT PLANS.

Subdivision 1. **Utility filing.** (a) In order to encourage a utility to address multiple pollutants, a utility required to submit mercury-reduction plans under sections 216B.68 to 216B.688 may also propose plans for investments and related expenses in pollution control equipment to be installed at facilities in Minnesota needed to comply with state or federal emission-control statutes or regulations that became effective after December 31, 2004.

(b) For each plan, the utility must show that the investments in pollution control equipment to be installed at facilities in Minnesota under the plan will provide for increased environmental and public health benefits, do not impose excessive costs on the utility's customers, and will achieve at least the pollution control required by applicable state or federal regulations.

Subd. 2. **Emissions-reduction riders.** A public utility that files a plan under this section may also file for approval of an emissions-reduction rate rider under section 216B.683, subdivision 1.

Subd. 3. **Agency review.** (a) The Pollution Control Agency shall evaluate a utility's plans filed under this section and, within 180 days of receiving the filing, provide the commission with:

(1) verification that the emissions-reduction project qualifies under subdivision 1;

(2) a description of the projected environmental benefits of the proposed project; and

(3) its assessment of the appropriateness of the proposed plans.

(b) In preparing its review under this subdivision, the agency may request additional information from the utility, especially with regard to alternative technologies or configurations applicable to a specific unit, and the estimated costs of those alternatives.

Subd. 4. **Commission approval.** The commission shall review and evaluate a utility's plans and associated emissions-reduction riders for other environmental improvement initiatives submitted under this section. The commission shall consider the overall environmental and public health benefits, total costs, and competitiveness of customer rates. Within 180 days of receiving the agency's report prepared under subdivision 3, the commission shall approve the plan and associated emissions-reduction rider if the commission finds that it meets the requirements of subdivision 1, paragraph (b).

History: *2006 c 201 s 12*

216B.687 MERCURY EMISSIONS REDUCTION IMPLEMENTATION, OPERATION.

Subdivision 1. **Permit conditions for mercury reductions.** The agency shall establish the mercury emissions reduction for each targeted unit included in a plan approved under section 216B.685, or where applicable, for each targeted and supplemental unit included in a plan approved under section 216B.6851.

Subd. 2. **Enforcement by agency.** (a) Except as required by federal regulation, any mercury reduction incorporated into the permit for a targeted unit as established under a plan approved under section 216B.685, or where applicable, for each targeted and supplemental unit included in a plan approved under section 216B.6851, must be a state-only condition of the permit and will not be enforced by the agency during the start-up period.

(b) After the start-up period ends, the Pollution Control Agency shall incorporate into the permit the mercury reduction reasonably expected to be achieved at each unit or facility as an enforceable state-only reduction. For a qualifying facility with multiple units that has one or more units included in approved plans, the agency may establish the mercury emissions reduction for the facility covering all targeted and supplemental units at that facility after the start-up periods for all units have concluded, and the actual mercury emissions for the units have been determined. In setting the reduction, the agency shall give due consideration to the results of monitoring before implementation of the plan, the results of monitoring during the start-up period, and any factors that may impact the performance of the unit for the next five years.

Subd. 3. **Equipment optimization required.** The agency shall revise the unit's air permit every five years to ensure optimal mercury emissions reduction by equipment installed under an approved plan, in light of technical and operational advances made since the date of plan approval. In revising the unit's air permit, the agency may recommend, but shall not require, additional investments in pollution control equipment, or the removal of equipment installed pursuant to an approved plan. The utility may seek commission review of the costs associated with a permit requirement or request for equipment optimization proposed by the agency and, if review is requested, the revision is not effective until approved by the commission. The commission shall approve the revision unless the utility or other party shows that it will impose excessive consumer costs.

History: *2006 c 201 s 13*

216B.688 RELATIONSHIP TO OTHER STATE FINANCIAL REQUIREMENTS.

Except as otherwise provided for equipment optimization as specified in section 216B.687, a public utility implementing an approved mercury emissions-reduction plan is not required to undertake additional investments or incur additional operating or maintenance costs to reduce mercury at a unit included in a plan approved under section 216B.685 or 216B.6851.

History: *2006 c 201 s 14*

216B.72 QUALIFIED LARGE-SCALE DATA CENTER FEE.

(a) The commissioner must collect an annual fee from the qualified large-scale data center, on a schedule prescribed by the commissioner and deposited in the energy and conservation account established in section 216B.241, subdivision 2a.

(b) The fee is based on the qualified large-scale data center's peak demand the utility arranges to serve, reflecting the qualified large-scale data center's peak demand forecast provided to the utility, expressed in megawatts (MW), as follows:

Peak Demand	Fee
(1) 100 to 250 MW	$2,000,000
(2) above 250 MW but below 500 MW	$3,000,000
(3) 500 MW but below 750 MW	$4,000,000
(4) 750 MW or greater	$5,000,000

(c) The fee data collected under this section must be treated as nonpublic data, as defined under section 13.02, subdivision 9.

History: *1Sp2025 c 12 s 16*

PREVENTATIVE MAINTENANCE

216B.79 PREVENTATIVE MAINTENANCE.

The commission may order public utilities to make adequate infrastructure investments and undertake sufficient preventative maintenance with regard to generation, transmission, and distribution facilities. The commission's authority under this section also applies to any transmission company that owns or operates electric transmission lines in Minnesota.

History: *2001 c 212 art 3 s 2; 2005 c 97 art 1 s 11*

216B.81 [Renumbered 216B.029]

216B.8109 MS 2016 [Repealed, 2017 c 94 art 10 s 30]

216B.811 MS 2016 [Repealed, 2017 c 94 art 10 s 30]

216B.812 MS 2016 [Repealed, 2017 c 94 art 10 s 30]

216B.813 MS 2016 [Repealed, 2017 c 94 art 10 s 30]

216B.815 MS 2016 [Repealed, 2017 c 94 art 10 s 30]

LOCAL POWER QUALITY ZONES

216B.82 LOCAL POWER QUALITY ZONES.

(a) Upon joint petition of a public utility as defined in section 216B.02, subdivision 4, and any customer located within the utility's service territory, the commission may establish a zone within that utility's service territory where the utility will install additional, redundant, or upgraded components of the electric distribution infrastructure that are designed to decrease the risk of power outages, provided the utility and all of its customers located within the proposed zone have approved the installation of the components and the financial recovery plan prior to the creation of the zone. Prior to commission approval, the utility must notify each customer within the proposed zone of the total costs of the installation, an estimate of the customer's share of those costs, and the potential benefits of the local power quality zone to the customer.

(b) The commission shall authorize the utility to collect all costs of the installation of any components under this section, including initial investment, operation, and maintenance costs, and taxes from all customers within the zone, through tariffs and surcharges for service in a zone that appropriately reflect the cost of service to those customers, provided the customers agree to pay all costs for a predetermined period, including costs of component removal, if appropriate.

(c) Nothing in this section limits the ability of the utility and any customer to enter into customer-specific agreements pursuant to applicable statutory, rule, or tariff provisions.

Nothing in this section shall be construed to permit the quality of service outside a designated zone to decline.

History: *2005 c 97 art 8 s 2*