.... moves to amend H.F. No. 239 as follows:

Delete everything after the enacting clause and insert:

"Section 1. **TITLE.**

This bill may be referred to as the "Natural Gas Innovation Act."

EFFECTIVE DATE. This section is effective the day following final enactment.

Sec. 2. **[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) "District energy" means a heating or cooling system 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.

(f) "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.

(g) "Greenhouse gas emissions" means emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within the state 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.

(h) "Innovative resource" means biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture, strategic electrification, district energy, and energy efficiency.

(i) "Lifecycle greenhouse gas emissions" means the aggregate greenhouse gas emissions resulting from the production, processing, transmission, and consumption of an energy resource.

(j) "Lifecycle greenhouse gas emissions intensity" means lifecycle greenhouse gas emissions per unit of energy.

(k) Nonexempt customer" means a utility customer that has not been included in a utility's innovation plan under subdivision 3, paragraph (h).

(l) "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.

(m) "Power-to-hydrogen" means the use of electricity generated by a carbon-free resource to produce hydrogen.

(n) "Renewable energy" has the meaning given in section 216B.2422, subdivision 1.

(o) "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.

(p) "Solar thermal" has the meaning given to "qualifying solar thermal project" in section 216B.2411, subdivision 2, paragraph (d).

(q) "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 will receive natural gas service for one or more end-uses, provided that the electric end-use equipment:

(1) will result 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.

(r) "Total incremental cost" means the sum of the following components of a utility's innovation plan approved by the commission under subdivision 2:

(1) return of and on capital investments for the production, processing, pipeline interconnection, storage, and distribution of innovative resources;

(2) incremental operating costs associated with capital investments in infrastructure for the production, processing, pipeline interconnection, storage, and distribution of innovative resources;

(3) incremental costs to procure innovative resources from third parties;

(4) incremental costs to develop and administer programs; and

(5) incremental costs for research and development related to innovative resources, less the sum of:

(i) value received by the utility upon the resale of innovative resources or their 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 or avoided pipeline costs; and

(iii) other revenues received by the utility that are directly attributable to the utility's implementation of an innovation plan.

(s) "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 will be 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 element;

(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 those benefits will be 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 its 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 will benefit from innovative resources included in the plan;

(14) a report on the utility's progress toward implementing its 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 its previously approved innovation plan, if applicable; and

(16) collections of pilot programs included in the plan 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 may approve, modify, or reject a plan. The commission may not approve an innovation plan unless it finds that:

(1) the size, scope, and scale of the plan will produce net benefits under the cost-benefit framework established by the commission in section 216B.2428;

(2) the plan will promote the use of renewable energy resources and reduce or avoid greenhouse gas emissions at a cost level consistent with subdivision 3;

(3) the plan will promote 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) projected costs and revenues for any energy efficiency, district energy, or strategic electrification measures included in the plan are reasonable in comparison to the costs of renewable natural gas, biogas, hydrogen produced via power-to-hydrogen, or ammonia produced via power-to-ammonia resources that the utility could deploy to reduce greenhouse gas emissions;

(8) 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;

(9) 50 percent or more of estimated costs to be recovered in the plan are for the procurement and distribution of renewable natural gas, biogas, hydrogen produced via power-to-hydrogen, or ammonia produced via power-to-ammonia; and

(10) 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 will not increase the number of animal units at the facility solely or primarily for the purpose of producing 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) 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.

(e) 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.

(f) In 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.

(g) 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.

(h) 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 their receipt by the utility; and

(iii) avoided or reduced greenhouse gas emissions at the point of end use;

(2) may 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 such 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.

(i) 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 may not propose, and the commission may 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 the state 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 the state 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, provided that the additional costs under this paragraph 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 including 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) If the commission determines that the utility has successfully achieved the cost-effectiveness objectives established in the utility's most recently approved innovation plan, except as provided in paragraph (d), the next subsequent plan filed by the same 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 the state 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 the state 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 the provisions of 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 the state 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 0.75 percent of the utility's gross operating revenues from natural gas service in the state at the time of the plan's filing; or

(ii) $10 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 has been exempted by the commissioner of commerce 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 may 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 exempted from innovation plan costs from participating in innovation plans.

(g) A utility filing an innovation plan may also 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 exempted 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 will displace.

(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.

(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.** In 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 will achieve 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 business 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 such 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 this pilot program.

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 qualifying 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 this state. This subdivision does not require the utility to propose, construct, maintain, or own district energy infrastructure.

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 energy 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) 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 its leakage reduction programs over the next five years;

(2) total system 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 them over the next five years through investments in innovative sources and energy conservation;

(3) the quantity of pipe in service in the utility's natural gas network in this state, by material, size, coating, operating pressure, and decade of installation based on utility information reported to the U.S. 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 that equipment, how it 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 it 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 may not be used by the commission to set or limit utility rate recovery.

EFFECTIVE DATE. This section is effective June 1, 2022.

Sec. 3. **[216B.2428] PUBLIC UTILITIES COMMISSION; LIFECYCLE GREENHOUSE GAS EMISSIONS ACCOUNTING FRAMEWORK; COST-BENEFIT TEST FOR INNOVATIVE RESOURCES.**

By June 1, 2022, the Public Utilities Commission shall, by order, issue frameworks the commission will use to calculate lifecycle greenhouse gas emissions intensities of each innovative resource, as follows:

(1) a general framework for the comparison of the lifecycle greenhouse gas emissions intensities of power-to-hydrogen, strategic electrification, renewable natural gas, district energy, energy efficiency, biogas, carbon capture, and power-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 will 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. In 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.

EFFECTIVE DATE. This section is effective the day following final enactment.

Sec. 4. **PUBLIC UTILITIES COMMISSION; EVALUATION OF THE ROLE OF NATURAL GAS UTILITIES IN ACHIEVING STATE GREENHOUSE GAS REDUCTION GOALS.**

By August 1, 2021, the Public Utilities Commission must initiate a proceeding to evaluate changes to natural gas utility regulatory and policy structures needed to support the state's greenhouse gas emissions reductions goals, including those established in section 216H.02, subdivision 1, and to achieve net zero greenhouse gas emissions by 2050, as recommended by the Intergovernmental Panel on Climate Change.

EFFECTIVE DATE. This section is effective the day following final enactment.

Sec. 5. **APPROPRIATION.**

$189,000 in fiscal year 2022 and $189,000 in fiscal year 2023 are appropriated from the general fund to the commissioner of commerce for the work identified under Minnesota Statutes, section 216B.2427. This appropriation will be recovered under the commerce department's assessment authority under Minnesota Statutes, section 216B.62.

EFFECTIVE DATE. This section is effective the day following final enactment."

Amend the title accordingly