ENERGY DEVELOPMENT AND TRANSMISSION COMMITTEE

The Energy Development and Transmission Committee was created in 2007 and was made permanent in 2011. Under North Dakota Century Code Section 54-35-18, the committee is directed to study the impact of a comprehensive energy policy for the state. The study may include reviewing and recommending policies related to extraction, generation, processing, transmission, transportation, marketing, distribution, and use of energy.

In addition to its statutory study responsibilities, the committee was assigned the following three studies for the 2021-22 interim:

- House Bill No. 1159 (2021) directed a study of natural gas and propane infrastructure development in the state. The study required consideration of the current infrastructure available for natural gas and propane, challenges related to the development of natural gas and propane infrastructure, community needs for natural gas and propane infrastructure, and a cost-benefit analysis of any state incentives to encourage the development of natural gas and propane infrastructure.
- Section 2 of House Bill No. 1455 (2021) directed a study of the need, cost, effect, and appropriate process for bonding and ensuring reclamation of coal conversion facilities. The study required an examination and assessment of the methods and amounts of financial assurance and schedules, the interaction of economics and the statutes, rules, and policies relating to the remaining useful life and early retirement of coal conversion facilities, the role of the Public Service Commission (PSC) in all electrical generation retirement, and the appropriate involvement of the public and local communities and political subdivisions in the retirement process. The study also required an evaluation of the effectiveness of government programs and incentives relating to energy production, reliability, and the state's role in that process.
- Senate Bill No. 2217 (2021) directed a study of deductions for postproduction costs under oil and gas leases. The study required consideration of the methods used to calculate the value of oil and gas, the point of sale used to determine the value, oil and gas sales in the absence of an arm's-length contract, any deductions or incentives applied to the value, and the methods used to report any deductions or incentives on mineral royalty statements. The study also required an analysis and review of state-mandated natural gas capture targets, federal land permitting restrictions, the effectiveness of using onsite flare mitigation technologies, and the infrastructure necessary to enhance oil and natural gas value. The study could include consideration of the desirability and feasibility of expanding the use and market access of natural gas, including value-added energy opportunities within the state.

The Legislative Management assigned the committee the responsibility to receive the following reports:

- An annual report from the State Energy Research Center regarding its research activities and accomplishments, pursuant to Section 15-11-40.
- A biennial report from the North Dakota Transmission Authority regarding its activities, pursuant to Section 17-05-13.
- A biennial report from the Energy Policy Commission regarding recommendations for a comprehensive energy policy, pursuant to Section 17-07-01.
- A report, beginning December 2014 and every 4 consecutive years thereafter, from the Industrial Commission regarding the amount of money in the carbon dioxide storage facility trust fund and the amount of fees needed to satisfy the fund's objectives, pursuant to Section 38-22-15.
- A biennial report from the High-Level Radioactive Waste Advisory Council regarding its findings, pursuant to Section 38-23-08.
- A biennial report from the North Dakota Pipeline Authority regarding its activities, pursuant to Section 54-17.7-13.
- A report from the Clean Sustainable Energy Authority regarding its activities and the program's financial impact on state revenues and the state's economy, pursuant to Section 54-63.1-04.
- A report from a coal conversion facility that achieves a 20 percent capture of carbon dioxide emissions and receives a tax credit, pursuant to Section 57-60-02.1.
- A report from the Energy and Environmental Research Center (EERC) regarding the results and recommendations of the underground energy storage study conducted under Section 14 of Senate Bill No. 2014 (2021).

- A report from the EERC regarding the study on development and implementation of hydrogen energy in the state conducted under Section 15 of Senate Bill No. 2014 (2021).
- A report from the Department of Environmental Quality regarding carbon reduction initiatives, rules, or policies that will affect North Dakota residents and industries under Section 7 of Senate Bill No. 2024 (2021).
- A report from the Insurance Commissioner regarding the availability, cost, and risks associated with insurance coverage in the lignite coal industry under Senate Bill No. 2287 (2021).

Committee members were Senators Jessica Bell (Chairman), Brad Bekkedahl, Kathy Hogan, Curt Kreun, Dale Patten, and Merrill Piepkorn and Representatives Dick Anderson, Tracy Boe, Mike Brandenburg, Alisa Mitskog, Todd Porter, and Don Vigesaa.

COMPREHENSIVE ENERGY STUDY

The committee is responsible for studying a comprehensive energy policy for the state pursuant to Section 54-35-18. As part of this study, the committee received a report from the Energy Policy Commission, also known as the EmPower ND Commission.

Energy Policy Commission

In 2009 the Energy Policy Commission was created by Section 17-07-01 to develop a comprehensive energy policy and to monitor progress toward reaching the goals of the policy. The commission consists of the Commissioner of Commerce as Chairman and members appointed by the Governor to represent the agriculture community, Lignite Energy Council, North Dakota Petroleum Council, biodiesel industry, biomass industry, wind industry, ethanol industry, North Dakota Petroleum Marketers Association, North Dakota investor-owned electric utility industry, generation and transmission electric cooperative industry, lignite coal-producing industry, refining or gas-processing industry, and additional nonvoting members.

The committee received a report from the Energy Policy Commission regarding updates from the commission's three subcommittees--public policy, research and development, and infrastructure. The commission did not have any specific energy policy recommendations for the 2021-22 interim, but continues to promote North Dakota's energy resources. The commission reviewed the benefits, location, and safety of using carbon dioxide captured from industrial sources like power plants, ethanol plants, and gas processing plants for enhanced oil recovery. The commission expressed its support for the development of carbon capture, usage and storage, and carbon dioxide enhanced oil recovery, and suggested the state continue its environmental, social, and governance investment criteria initiative to assist businesses, market state investment opportunities, and continue growing the state's energy industry.

Conclusion

The committee makes no recommendation regarding the comprehensive energy policy study.

NATURAL GAS AND PROPANE INFRASTRUCTURE DEVELOPMENT STUDY

The Legislative Management assigned the committee the responsibility to study natural gas and propane infrastructure development in the state. The committee received information from state agencies and the propane industry regarding the infrastructure available for natural gas and propane, challenges related to the development of natural gas and propane infrastructure, community needs for natural gas and propane infrastructure, and a cost-benefit analysis of any state incentives to encourage the development of natural gas and propane infrastructure.

Background

Infrastructure Cost Ranges

The committee received information regarding the cost ranges for various types of natural gas and propane infrastructure.

Infrastructure	Cost Ranges
HDPE lateral pipeline	$400 - $500k per mile
Steel lateral pipeline	$750k - $1 million per mile
Pipeline interconnections	$300k - $3.5 million
Town border stations	$150k - $500k
Distribution systems	$750k - $2 million

Source: Montana-Dakota Utilities Co.

State Tax Incentives for Gas

Extracted oil and natural gas are subject to the oil and gas gross production tax and the oil extraction tax. Materials used in the extraction of oil and gas may be subject to sales or use taxes. Pipelines and other infrastructure used to transport oil and gas may be subject to property taxes. Generators of electricity from sources other than coal or wind, with a generation capacity of 100 kilowatts or more, are subject to payments in lieu of taxes pursuant to Section 57-33.2-04. Payments in lieu of taxes consist of a tax of 50 cents per kilowatt times the rated capacity of the generation unit, plus a tax of 1 mill per kilowatt-hour of electricity generated by the production unit during the taxable period.

Pursuant to Chapter 57-51, a gross production tax of 5 percent of the gross value at the well is levied upon all oil produced in the state except a royalty interest in oil produced from an interest held by an organized Indian tribe or produced from a state, federal, or municipal holding. A gross production tax is levied upon all gas produced in the state and is calculated by multiplying taxable production by an annually adjusted flat rate per thousand cubic feet. Exemptions from the gross production tax include:

- Gas used on the lease for production purposes and any royalty interest from gas produced from a state, federal, or municipal holding, or from an interest held by an organized Indian tribe.
- Shallow gas produced during the first 24 months of production following the date gas was first sold from a shallow gas well and gas produced from a shallow gas well during testing, but prior to well completion, or during connection to a pipeline pursuant to Section 57-51-02.4.
- Gas burned at the well site to power an electrical generator that consumes at least 75 percent of the gas from the well pursuant to Section 57-51-02.5.
- Gas collected at the well site by a system that intakes at least 75 percent of the gas and natural gas liquids volume from the well for beneficial consumption pursuant to Section 57-51-02.6.

Additional state tax incentives pertaining to oil and gas include:

- A sales and use tax exemption for materials used to reduce emissions, increase efficiency, or enhance the reliability of equipment at a new or existing oil refinery or gas processing plant pursuant to Sections 57-39.2-04.2 and 57-40.2-04.2.
- A sales and use tax exemption for gross receipts from sales of carbon dioxide used for enhanced recovery of oil or natural gas pursuant to Sections 57-39.2-04 and 57-40.2-04.
- A sales tax exemption for gross receipts from sales of natural gas or sales of fuels used for heating purposes pursuant to Section 57-39.2-04.
- A sales and use tax exemption for materials used to construct or expand a system used to compress, process, gather, collect, or refine gas recovered from an oil or gas well in this state or used to expand or build a gas processing facility in this state pursuant to Sections 57-39.2-04.5 and 57-40.2-03.3.
- A sales and use tax exemption for materials used to construct or expand a processing facility to produce liquefied natural gas pursuant to Sections 57-39.2-04.10 and 57-40.2-03.3.
- A sales tax exemption for materials used to construct or expand a system used to compress, gather, collect, store, transport, or inject carbon dioxide for use in enhanced recovery of oil or natural gas pursuant to Sections 57-39.2-04.14 and 57-40.2-03.3.
- A property tax exemption for equipment, machinery, tools, materials, and property necessary, and being used at the site of a producing well, for the production of oil and gas pursuant to Section 57-51-04. The property tax exemption does not apply to drilling rigs, gasoline extraction or absorption plants, water systems, fuel systems, hospitals, residences, and various other buildings.
- A property tax exemption for any equipment directly used for enhanced recovery of oil or natural gas pursuant to Section 57-60-06. The property tax exemption does not apply to the land on which the equipment is located.
- A property tax exemption for property, exclusive of land, and necessary associated equipment for the transportation or storage of carbon dioxide for use in enhanced recovery of oil or natural gas pursuant to Section 57-06-17.1. The property tax exemption applies for the first 10 full taxable years following the initial operation of the pipeline but does not apply to the land on which the property and associated equipment is located.

Testimony

The committee received information and testimony from representatives of the propane industry, Pipeline Authority, Propane Gas Association, and the Tax Department.

Testimony indicated North Dakota is the 11th largest gas-producing state. There are 91 communities served with natural gas in North Dakota, totaling approximately 150,000 customers, and 366 communities unserved with natural gas, totaling approximately 46,000 homes. The three driving forces for new gas pipelines are supply push, demand pull, and system reliability.

The committee was informed the proposed Grasslands South project will repurpose the Grasslands Pipeline, provide access to the Baker storage field, and create up to 94,000 equivalent dekatherms per day of new firm natural gas transportation capacity from the NBP-Manning receipt location, or other new or existing receipt locations into WBI Transmission's Line Section 26, to new or existing delivery locations on WBI Transmission's Line Sections 14, 26, and 29. The design of the project includes pipeline facilities and measurement facilities. The targeted in-service date is fall 2023.

The proposed Bison Xpress project would add 430 million cubic feet per day of capacity on the Northern Border Pipeline and use the existing but empty Bison Pipeline to connect Bakken volumes to the Cheyenne hub in the Rockies. The capacity boost on the Northern Border Pipeline would be achieved through horsepower additions to compressor stations 4, 5, and 6 located in North Dakota. The capacity expansions in North Dakota would allow the Northern Border Pipeline to deliver 430 million cubic feet per day into the Bison pipeline, and with additional facility modifications on Bison, allow the gas to flow into the eastern Rockies. The targeted in-service date is early 2026.

The North Bakken Expansion Project consists of approximately 100 miles of new pipeline and compression and ancillary facilities to transport natural gas out of core Bakken production areas in western North Dakota. The project starts near Tioga and extends to a new connection point with Northern Border Pipeline in McKenzie County. Construction began in July 2021. The pipeline was placed in service on February 1, 2022. The expansion consists of 62.8 miles of 24-inch diameter natural gas pipeline that provides up to 250 million cubic feet per day of natural gas transportation service and provides residue gas service from north of Lake Sakakawea to Northern Border Pipeline in McKenzie County.

The committee received testimony indicating Senate Bill No. 2328 (2021) provides a producer employing a flare mitigation system installed on a qualifying well on or after June 30, 2021, a temporary credit against the oil extraction tax. The credit is equal to 75 cents per one million British thermal units of flare mitigation resulting from the onsite flare mitigation system. The credit may be claimed for up to 12 months per well and may not exceed $6,000 per well per month. The credit does not apply to production from wells located within the exterior boundaries of the Fort Berthold Reservation unless the Chairman of the Mandan, Hidatsa, and Arikara Nation submits to the Tax Commissioner a written request for the credit to apply. The credit is effective through June 30, 2023. The Tax Department has received certifications for 16 wells. The first certifications were received in December 2021. Certifications are issued by the Industrial Commission. The total value of credits received by the 16 wells is estimated to be $353,000 based on projected production.

Committee Considerations

The committee acknowledged several positive steps have been taken to promote and expand natural gas and propane infrastructure development to unserved and underserved communities in the state. Committee members recognized additional funds and tax exemptions might be needed to encourage improvement and expansion of natural gas and propane infrastructure. The committee indicated the state's tax incentive provisions for oil and gas are operating as intended.

Conclusion

The committee makes no recommendation regarding its study of natural gas and propane infrastructure development.

COAL CONVERSION FACILITY BONDING AND RECLAMATION STUDY

The Legislative Management assigned the committee the responsibility to study the need, cost, effect, and appropriate process for bonding and ensuring reclamation of coal conversion facilities. The committee received information from the PSC, utilities and cooperatives, and representatives of local communities and political subdivisions regarding the methods and amounts of financial assurance and schedules; the interaction of economics and the statutes, rules, and policies relating to the remaining useful life and early retirement of coal conversion facilities; the role of the PSC in all electrical generation retirement; and the appropriate involvement of the public, local communities, and political subdivisions in the retirement process.

Background

General Jurisdiction of the Public Service Commission

Section 49-02-01 sets out the general jurisdiction of the PSC. That section provides the general jurisdiction of the PSC extends to:

- Contract and common carriers engaged in the transportation of persons and property, excluding air carriers.
- Telecommunications companies engaged in the furnishing of telecommunications services as provided for in Chapter 49-21.

- Pipeline utilities engaged in the transportation of gas, oil, coal, and water.
- Electric utilities engaged in the generation and distribution of light, heat, or power.
- Gas utilities engaged in the distribution of natural, synthetic, or artificial gas.
- All heating utilities engaged in the distribution of heat.
- All other public utilities engaged in business in this state or in any county, city, township, or other political subdivision of the state.

Section 49-02-02 authorizes the PSC to require public utilities or other persons to conform to the laws of this state and to all rules, regulations, and orders of the commission not contrary to law. The 1975 Legislative Assembly passed Senate Bill No. 2050, the North Dakota Energy Conversion and Transmission Facility Siting Act, codified as Chapter 49-22. This chapter provides protection to individual landowners by regulating the siting of transmission and conversion facilities, such as granting the PSC authority to issue certificates of site compatibility or route permits for electric energy conversion or transmission facilities.

Solar and Wind

Section 49-02-27 requires the PSC to adopt rules governing the decommissioning of commercial wind energy conversion facilities and authorizes the PSC to adopt rules governing the decommissioning of commercial solar energy conversion facilities. Under the authority granted by Section 49-02-27, the PSC adopted North Dakota Administrative Code (NDAC) Chapters 69-09-09 and 69-09-10, pertaining to wind and solar facility decommissioning. Both chapters provide the owner of a wind or solar facility is responsible for decommissioning the facility and for all costs associated with decommissioning. In addition, an owner of a wind or solar facility is required to begin decommissioning within 12 months after abandonment or the end of the facility's useful life. A facility is presumed to be abandoned if, after commencement of construction and before completion, a period of 24 consecutive months has passed with no significant construction. A facility is presumed to be at the end of its useful life if its annual capacity factor is less than 10 percent for 2 consecutive years for wind facilities and less than 5 percent for solar facilities. Decommissioning requirements for wind or solar facilities include site restoration and reclamation to the approximate original topography that existed before construction of the facility with topsoil respread over the disturbed areas at a depth similar to that in existence before the disturbance, and grading and restoring topsoil of areas disturbed by the facility and reseeding according to natural resource conservation service recommendations.

Coal Mining

Under Chapter 38-14.1, a surface coal mining operator in North Dakota must supply a performance bond before the PSC may issue a mining permit. Section 38-14.1-16 requires a performance bond and establishes the amount and sufficiency of the required surety. The Public Service Commission is required to set the bond amount sufficient to complete the reclamation plan in the event of forfeiture. The bond for the permit area must be at least $10,000. The bond must cover that area of land within the permit area upon which the permittee will initiate and conduct surface coal mining and reclamation operations for the ensuing year. The reason for requiring a performance bond is to ensure land disturbed for coal mining will be reclaimed at no cost to the state or to the public if an operator's mining permit is revoked or the operator goes out of business.

State Tax Incentives for Coal

The coal severance tax is imposed on the act of removing coal from the earth pursuant to Chapter 57-61. The tax is in lieu of both the sales and use taxes on coal and the property tax on minerals in the earth. The coal severance tax applies to all coal severed for sale or industrial purposes, except coal used for heating buildings in the state, coal used by the state or any political subdivision of the state, and coal used in agricultural processing facilities in the state or adjacent states. The tax is applied at a rate of 37.5 cents per ton. An additional 2 cents per ton tax is levied for the lignite research fund. A 50 percent reduction of the 37.5 cent tax is allowed for coal burned in a cogeneration facility designed to use renewable resources to generate 10 percent or more of its energy output. A county may grant a partial or complete exemption from the county's 70 percent portion of the 37.5 cent tax for coal that is shipped out of state. A county also may grant the operator of a mine a partial or complete exemption from up to 70 percent of the coal severance tax for a period not to extend past June 30, 2026, pursuant to Section 57-61-01(2).

The coal conversion tax is imposed in lieu of property taxes on the operator of each coal conversion facility pursuant to Chapter 57-60. The land on which the facility is located remains subject to property taxes.

In addition, there is a:

- Sales and use tax exemption for machinery or equipment used to produce coal from a new mine. The exemption for each mine is limited to the first $5 million of sales and use tax paid pursuant to Section 57-39.2-04.8.

- Sales tax exemption for materials used to construct or expand a facility used to extract or process byproducts associated with coal gasification pursuant to Section 57-39.2-04.11.
- Sales and use tax exemption for materials used to construct, expand, repower, or add environmental upgrades to an electrical generation plant, and all additions thereto, which processes or converts coal into electrical power pursuant to Sections 57-39.2-04.2 and 57-40.2-04.2.
- Sales and use tax exemption on gross receipts from the initial sale of beneficiated coal and the sale of coal which is exempt from the coal severance tax pursuant to Sections 57-39.2-04 and 57-40.2-04.
- Property tax exemption for each coal conversion facility and any carbon dioxide capture system located at a coal conversion facility pursuant to Section 57-60-06. The property tax exemption does not apply to the land on which the facility or capture system is located.

Testimony

The committee received information and testimony from a representative of a political subdivision indicating the closure of Coal Creek Station would have caused a regional depression. Three high schools would have been combined into one and the housing market and values in the central part of the state would have dropped. Testimony indicated although reclamation occurs immediately after coal is removed, the land may not be released for several years due to bonding procedures and the rehabilitation process required to occur on the land. The committee was informed the Legislative Assembly should learn from the obstacles Rainbow Energy Center faced when acquiring Coal Creek Station. Testimony recommended the enactment of regulatory schemes and financial incentives to help ease the burden and legal liabilities incurred by a sale or transfer similar to which occurred with the Coal Creek Station closure to avoid negative economic impacts.

Testimony from a representative of the PSC indicated there are no legal requirements regarding the decommissioning time schedules or financial assurance requirements for coal or natural gas generation facilities. Requiring decommissioning time schedules and financial assurances for coal and natural gas generation facilities will result in additional costs that will be passed on to consumers and create an economic burden for facilities. The three coal plants that have retired this century voluntarily decommissioned or are in the process of decommissioning. In the case of a facility being abandoned, a facility generally is owned by the energy generator, which has its own incentive to decommission and reclaim. Facilities also have a relatively small footprint. Rules and law do not address remaining useful life and early retirement of facilities. Facilities can last far beyond their original expected useful life if properly maintained and upgraded. Remaining useful life is more of an accounting concept than an accurate depiction of how much longer a generation facility can remain useful. The Public Service Commission has limited authority over cooperatives, which own the vast majority of North Dakota's coal generation. In the case of regulated utilities, the PSC provides input through rate recovery allowance or disallowance, advance determinations of prudence, and the new tools established in the 2021 legislative session for integrated resource plans.

Testimony from representatives of the utilities and cooperatives indicated there is a long history of precedent and obligation through self-governing principles to maintain and operate conversion facilities in the most environmentally responsible manner and also to restore and reclaim the land when infrastructure is taken out of service. Testimony indicated the utilities and cooperatives do not envision a circumstance where less than full site reclamation would occur.

Committee Considerations

The committee did not indicate a desire to add any legal requirements regarding decommissioning time schedules or financial assurances requirements for coal or natural gas generation facilities. The committee did not receive any testimony from interested parties indicating less than full site reclamation is occurring in the state by any utility or cooperative. The committee acknowledged legislation may be needed to address coal and natural gas generation reclamation if maintaining, operating, or decommissioning conversion facilities presents an environmentally irresponsible mitigation process or if there is an instance of less than full site reclamation in the state.

Conclusion

The committee makes no recommendation regarding its study of coal conversion facility bonding and reclamation.

OIL AND GAS LEASE POSTPRODUCTION DEDUCTIONS STUDY

The Legislative Management assigned the committee the responsibility to study deductions for postproduction costs under oil and gas leases. The committee received information from representatives of the oil and gas industry, representatives of royalty owner associations, the Department of Mineral Resources, the Department of Trust Lands, the Attorney General, and royalty owners, regarding the methods used to calculate the value of oil and gas, the point of sale used to determine the value, oil and gas sales in the absence of an arm's-length contract, any deductions or incentives applied to the value, and the methods used to report any deductions or incentives on mineral royalty statements.

Background

North Dakota Law

In North Dakota, royalties due to mineral owners for the production and sale of oil and gas is governed by contract law, meaning the express oil and gas lease contract entered between the mineral owner and the lessee. Likewise, the manner in which royalties are calculated depends on the lease royalty clause. A royalty clause typically sets forth the point at which the value of the oil is determined and the deductions that may be applicable.

In *Bice v. Petro-Hunt, L.L.C.*, 2009 ND 124, the North Dakota Supreme Court joined the majority of states following the "at the well" rule for calculating royalties on oil and gas leases. The "at the well" rule defines the wellhead as the appropriate point for royalty calculation. Section 38-08-06.3 requires a person that makes a payment to an owner of a royalty interest in land for the purchase of oil or gas produced from that royalty interest to provide with the payment to the royalty owner an information statement that will allow the royalty owner to clearly identify the amount of oil or gas sold and the amount and purpose of each deduction made from the gross amount due. A violation of Section 38-08-06.3 is a Class B misdemeanor. Section 38-08-06.3 also tasks the Industrial Commission with approving the forms the statements must be on and adopt rules relating to the information the statements must contain.

State Regulations

North Dakota Administrative Code Chapter 43-02-06 sets forth the rules adopted by the Industrial Commission under Section 38-08-06.3 relating to royalty statements. North Dakota Administrative Code Chapter 43-02-06 provides the information that must be included on the check stub whenever payment is made for oil or gas production to an interest owner. The required information includes:

- The price;
- The month and year during which sales occurred for which payment is being made;
- The lease, property, or well name or any lease, property, or well identification number used to identify the lease, property, or well;
- The owner's share of sales value less taxes and deductions; and
- The amount and purpose of each owner adjustment or correction made.

North Dakota Administrative Code Chapter 43-02-06 requires an operator or payor to provide a mineral owner with a statement identifying the spacing unit for the well, and the effective date of the spacing unit change or decimal interest change if applicable, the net mineral acres owned by the mineral owner, the gross mineral acres in the spacing unit, and the mineral owner's decimal interest that will be applied to the well. This statement must be provided within 120 days after the end of the month of the first sale of production from a well or change in the spacing unit of a well or a decimal interest in a mineral owner.

Postproduction Deductions in Other States

Generally, states can be divided into two categories--those that follow the "at the well" rule and those that follow the marketable-product rule. Under the marketable-product rule, lessees impliedly covenant to bear the costs of getting gas into marketable condition and transporting it to market. A majority of oil and gas jurisdictions, including North Dakota, adhere to the "at the well" rule and calculate the royalty based on the value of the gas at the wellhead. In these jurisdictions, the workback method is used to calculate the value of the gas at the wellhead. A minority of jurisdictions have rejected the workback method. These jurisdictions, which include Colorado, Kansas, Oklahoma, and West Virginia, do not calculate the royalty based on the purported value of the gas at the wellhead. Instead, these jurisdictions calculate the royalty at the point the gas first becomes a marketable product--the marketable-product rule.

Testimony

The committee received information and testimony from representatives of the oil and gas industry, representatives of royalty owner associations, the Department of Mineral Resources, the Department of Trust Lands, the Attorney General, and royalty owners regarding the study of deductions for postproduction costs under oil and gas leases. Testimony received from the Department of Mineral Resources indicated royalties are paid on the value of the oil and gas at the well site, which is the first point of custody transfer. For oil, the value at the well site is the gross value minus transportation costs associated with moving the oil from the well site to the point of sale under the first arm's-length contract. For gas, the value at the well site is the gross value minus transportation costs associated with making the gas and natural gas liquids marketable and moving the gas and natural gas liquids from the well site to the point of sale under the first arm's-length contract. The testimony indicated the three options for computing the transportation costs are:

- The actual costs;

- The applicable common carrier rate established by the PSC or the appropriate federal jurisdictional agency; or
- The reasonable actual operating and maintenance expenses of the transportation system, overhead costs directly attributable and allocable to that operation and maintenance, and either depreciation and a return on undepreciated capital investment, or a cost equal to a return on the investment.

Testimony indicated for oil under a non-arm's-length transportation contract, where the operator or the operator's affiliate perform transportation services, the transportation allowance is based on reasonable, actual costs, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment or a cost equal to the initial capital investment in the transportation system multiplied by a rate of return. For gas under a non-arm's-length transportation contract, including situations in which the operator or the operator's affiliate provide processing and transportation services. The transportation deduction is based on reasonable, actual costs.

The committee received information indicating the Industrial Commission approved 16 wells representing a minimum flared volume reduction of 2.5 million cubic feet per day, and established the following natural gas capture targets:

- 74 percent for October 1, 2014, through December 31, 2014.
- 77 percent for January 1, 2015, through March 31, 2016.
- 80 percent for April 1, 2016, through October 31, 2016.
- 85 percent for November 1, 2016, through October 31, 2018.
- 88 percent for November 1, 2018, through October 31, 2020.
- 91 percent beginning November 1, 2020.

Testimony received from the Attorney General and the Department of Trust Lands indicated all leases issued by the Board of University and School Lands since 1979 are gross proceeds leases, with the board to be paid royalties based "on an amount equal to the full value of all consideration for such products in whatever form or forms, which directly or indirectly compensates, credits, or benefits lessee." The department could not address the deductions that may or may not be allowed on each lease because private mineral owners' lease terms vary from lease to lease. The department has a royalty reporting form that is required for reporting royalties under NDAC Section 85-06-01-12. The department does not prepare the mineral royalty statements. The department is aware of instances in which operators have deducted negative royalty payments for gas which have more than offset the value of other products. The department indicated a mineral royalty owner always should receive a positive royalty payment for all products. A royalty, by definition, requires a positive payment.

Testimony received from Hess Corporation indicated since 2014, Hess Corporation has paid over $2.3 billion to royalty owners, and royalty payments are paid pursuant to approximately 20,000 oil and gas leases. The lease governs the relationship between the royalty owner ("lessor") and working interest owner ("lessee") for as long as oil and gas is produced. The operator of a unit pays royalties in accordance with the terms of the lease. Royalty owners often negotiate leases to secure benefits, including an upfront per acre signing bonus to enter the lease; royalty percentage, point of valuation, and prohibited deductions; increases or specifications as to how royalties are paid; if applicable, permitted surface uses, including where drilling may occur; minimum or shut-in royalties when a unit is not producing; and water use and associated payment.

Testimony received from royalty owners and associations representing royalty owners indicated postproduction deductions from oil and gas leases are difficult to understand and can account for a large value deduction from the royalty payment. Oil and gas producers are for-profit businesses and need to make a profit to continue to conduct business. According to testimony, it is not uncommon to see gathering, drying, compression, and transportation deductions of over 80 percent of the gas royalty. For this reason, it was argued, using the "comparable sales method" would be the fairest method to calculate the value of oil and gas. In addition, testimony indicated actions the state can take to help mineral owners could include prohibiting lease-line allocation wells, maintaining a list of valid mailing addresses for oil companies on the Department of Mineral Resources' website, establishing a penalty for an oil company that does not provide a mineral owner with a response within 30 days as required under NDAC Section 43-02-06-01(12), and prohibiting postproduction deductions unless a lease specifically allows for the deductions.

Committee Considerations

Committee members generally empathized with the concerns and frustrations voiced by royalty owners regarding postproduction deductions and the request to have the Legislative Assembly restrict or regulate current oil and gas lease terms through legislation that could have retroactive application. However, the committee recognized Section 18 of Article I of the Constitution of North Dakota prohibits a law impairing contracts. In addition, courts generally are reluctant to uphold statutes that impair or interfere with existing contracts retroactively due to the inherent principle of a party's right to enter contracts freely. Several members of the committee expressed a desire to work with various stakeholders on the issue and introduce a bill during the 2023 legislative session.

Conclusion

The committee makes no recommendation regarding its study of oil and gas lease postproduction deductions.

STATE ENERGY RESEARCH CENTER REPORT

The committee received a report from a representative of the State Energy Research Center pursuant to Section 15-11-40. According to the report, the State Energy Research Center receives $5 million per biennium to conduct exploratory, transformational, and innovative research that advances future energy opportunities to benefit North Dakota's economy and environment.

The State Energy Research Center has eight new invention disclosures, including methods of production of graphene and its derivatives from coal intermediates, methods of upgrading coal to produce enhanced graphene precursors, and automatic detection of buried pipelines and spills. In addition, 59 innovative research concepts were brought forward for potential funding from the State Energy Research Center in three rounds of internal solicitation. Twenty-five new research projects were selected through significant vetting of the proposed concepts via a peer-led review process. The selected projects focus on coal, oil and gas, and renewable energy, and include methods of optimized extraction and utilization, critical element extraction, new materials, and environmental protection.

NORTH DAKOTA TRANSMISSION AUTHORITY REPORT

The committee received a report from the North Dakota Transmission Authority pursuant to Section 17-05-13. According to the report, Basin Electric Power Cooperative is constructing a new 230 kilovolt line from Tioga west to Ross. The line will complement a 115 kilovolt line that Mountrail Williams Electric is building from that location to New Town. The Midcontinent Independent System Operator queue contains 10 projects for a total of 2,390 megawatts (MW). This queue is reduced from 2,700 MW in 2020. The Minnkota queue contains six projects for a total of 350 MW. This queue remains the same as in 2020. The Southwest Power Pool queue contains 26 projects for a total of 5,045 MW. This queue has increased from 2,902 MW 2 years ago.

Portions of North Dakota served by the Southwest Power Pool experienced short rolling blackouts on 2 days in February 2021 due to winter storm Uri. Even though state generating resources operated well, North Dakota was affected because North Dakota is part of the power pool. Lack of available generation was the primary cause of the event's reliability impacts. Lack of fuel was the largest overall cause of generation unavailability.

According to the report, one of the easiest methods for increasing energy availability is through the addition of wind generation. Added generation brings additional transmission opportunities, which also bolsters the construction industry in the state.

The North Dakota Transmission Authority reported it will continue to engage potential transmission owners, encourage the Midcontinent Independent System Operator and Southwest Power Pool to identify lines needed to serve additional generation, and continue to be a voice for reliable and resilient solutions as the grid evolves.

CARBON DIOXIDE STORAGE FACILITY TRUST FUND REPORT

The committee received a report from the Industrial Commission regarding the status of the carbon dioxide facility trust fund pursuant to Section 38-22-15. The purpose of the fund is to pay the expenses associated with the long-term monitoring and management of underground carbon dioxide storage projects. As of October 11, 2022, the carbon dioxide facility trust fund has a zero balance. The fee established by the Industrial Commission is seven cents per ton of carbon dioxide injected underground for storage. According to the report, projects to store carbon dioxide underground include:

- Red Trail Energy's ethanol-manufacturing facility first injection in June 2022.
- Cedar Hills South Unit's first injection in February 2022.
- Tundra's expected first injection in 2026.
- Dakota Gasification Company's first injection in 2023.

HIGH-LEVEL RADIOACTIVE WASTE ADVISORY COUNCIL REPORT

The committee received a report from the High-Level Radioactive Waste Advisory Council pursuant to Section 38-23-08. According to the report, the High-Level Radioactive Waste Advisory Council was created on July 1, 2019, through the enactment of Senate Bill No. 2037 (2019) and is responsible for:

- Reviewing high-level radioactive waste site suitability;

- Issuing reports for proposed high-level radioactive waste facilities to the Legislative Assembly or Industrial Commission;
- Reviewing and making recommendations to the Industrial Commission regarding administrative rules and standards relating to high-level radioactive waste and the duties of the Industrial Commission; and
- Making recommendations to the Industrial Commission regarding the administration of Chapter 38-23.

According to the report, the High-Level Radioactive Waste Advisory Council held two meetings since the council's last report. The two meetings featured speakers from the Nuclear Regulatory Commission, the Department of Energy, and the Environmental Protection Agency. The featured speakers provided information related to the federal government's role in permitting the disposal of radioactive waste and the status of high-level radioactive waste disposal in the United States. The Yucca Mountain disposal site was projected to be active for 120 years, consisting of 20 years of site characterization; 15 years of approvals, licensing, and construction; and 40 years of operation followed by 45 years of closure and monitoring. Yucca Mountain remains the only potential high-level radioactive waste disposal site under federal law.

The federal government has four priorities related to its nuclear energy mission:

1. Enable continued operation of existing United States nuclear reactors;
2. Enable deployment of advanced nuclear reactors;
3. Responsibly manage the nation's spent nuclear fuel;
4. Maintain United States leadership in nuclear energy technology.

According to the report, the Department of Energy is responsible for locating sites to store and dispose of spent nuclear fuel and focuses on consent-based siting. While spent nuclear fuel is being stored safely at or near nuclear power plant sites, nearby communities never agreed to host the materials on a long-term basis. Given the Department of Energy's recent difficulties in finding a deep-well test site and with permanent waste disposal at Yucca Mountain on hold, the department has begun to educate communities regarding the disposal of nuclear fuel. Before discussion may commence regarding a community hosting an interim site, the Department of Energy must carefully explain what spent nuclear fuel rods are, what is involved with the transportation of those spent fuel rods to an interim site, and what an interim waste site might look like.

NORTH DAKOTA PIPELINE AUTHORITY REPORT

The committee received multiple updates from a representative of the North Dakota Pipeline Authority on oil and gas pipelines in the state pursuant to Section 54-17.7-13. As of May 2021, 75 percent of the oil produced in North Dakota is exported out of the state by pipeline, while 2 percent is exported to Canada by truck or rail. Ninety-three percent of gas is captured and sold, while 2 percent of gas is flared from zero sales wells because of the lack of pipeline infrastructure. The remaining 5 percent of gas is flared from wells with at least 1,000 cubic feet sold due to challenges with existing infrastructure.

The North Bakken Expansion Project would provide 250 million cubic feet of natural gas transportation capacity per day. In addition, the project would provide approximately 60 miles of new pipeline construction and compression and ancillary facilities to transport natural gas from core Bakken production areas in western North Dakota to an interconnection point with Northern Border Pipeline. The project is expected to be completed during the 2021-22 interim, cost an amount exceeding $260 million, be designed using 24-inch and 12-inch diameter pipelines, and provide residue gas service from north of Lake Sakakawea to the Northern Border Pipeline in McKenzie County.

COAL CONVERSION FACILITY CARBON DIOXIDE EMISSIONS CAPTURE REPORT

The committee did not receive a report, pursuant to Section 57-60-02.1, from a coal conversion facility that received a tax credit for achieving a 20 percent capture of carbon dioxide emissions because no facilities received the credit during the reporting period.

CLEAN SUSTAINABLE ENERGY AUTHORITY REPORT

The committee received a report from the Clean Sustainable Energy Authority regarding the authority's activities and the program's financial impact on state revenues and the state's economy pursuant to Section 54-63.1-04. According to the report, the purpose of the Clean Sustainable Energy Authority is to enhance the production of clean sustainable energy, to make North Dakota a world leader in the production of clean sustainable energy, and to diversify and grow the state's economy. The Clean Sustainable Energy Authority's three grant rounds since 2021 totaled awards of $250 million in loans, $20 million in hydrogen grants from federal funds, and $24.3 million in state grants for 11 projects. The 11 projects include natural gas flaring projects, synfuels production, carbon dioxide sequestration, hydrogen production, manufacturing biodegradable polymers using methane as a feedstock, and a project to evaluate the potential of using geothermal power generation on oil and gas production sites. No additional grant rounds will be held until additional funding has been appropriated by the Legislative Assembly.

ENERGY AND ENVIRONMENTAL RESEARCH CENTER UNDERGROUND ENERGY STORAGE REPORT

The committee received a report from the EERC regarding the results and recommendations of the underground energy storage study pursuant to Section 14 of Senate Bill No. 2014 (2021). According to the report, gas storage is a proven technology that began in 1915. Typically, gas storage is used to supplement energy demands associated with seasonal heating needs. There are over 300 active gas storage locations in the United States.

The Dunham, Pine, and Opeche salt beds were identified as candidates for salt cavern development and product storage. The preliminary simulation results suggested the development of small caverns is achievable in North Dakota salt beds and the use of multiple caverns was found to be a viable design approach and geomechanically stable.

The report indicated preliminary results are encouraging. Cored intervals appear to have high halite concentrations which is beneficial for the development and stability of engineered salt caverns. Overlying formations are tight and have a thickness that will promote cavern roof stability. While significant halite is present in the Pine salt interval, other impurities exist such as thenardite, which is the most prevalent impurity. Thenardite is soluble in water, which is encouraging for cavern development. The Energy and Environmental Research Center will investigate development opportunities in the Pine salt bed to determine if thenardite persists or if halite becomes predominant.

ENERGY AND ENVIRONMENTAL RESEARCH CENTER HYDROGEN REPORT

The committee received a report from the EERC regarding the study on development and implementation of hydrogen energy in the state pursuant to Section 15 of Senate Bill No. 2014 (2021). According to the report, hydrogen provides a tool for decarbonization, is an energy carrier without carbon or other greenhouse gas emissions, and causes minimal human health issues. The geologic storage of hydrogen requires unique properties and formations in North Dakota are being studied for viability.

According to the report, a hydrogen economy is likely to evolve incrementally and near-term applications that are possible today include:

- Ammonia production with low carbon hydrogen to decarbonize the agricultural industry.
- Hydrogen blending into existing natural gas pipelines to decarbonize natural gas use.
- Supplying decarbonized hydrogen to existing demand at petroleum and renewable oil refineries.

Inclusion of hydrogen in the gas stream can reduce the carbon intensity of the natural gas. A 20 percent hydrogen blend equates to a 7 percent reduction in carbon emissions. Refinery demand for hydrogen has increased as demand for diesel fuel has risen and as sulfur content regulations have become more stringent. Supplying lower carbon intensity hydrogen to the refineries and generating lower carbon intensity hydrogen will result in lower carbon intensity diesel. Every major manufacturer is marketing hydrogen ready gas turbines; most accept blends up to 50 percent hydrogen but some models claim to accept 100 percent hydrogen.

DEPARTMENT OF ENVIRONMENTAL QUALITY REPORT

The committee received a report, pursuant to Section 7 of Senate Bill No. 2024 (2021), from the Department of Environmental Quality regarding carbon reduction initiatives, rules, or policies that will affect North Dakota residents and industries. According to the report, in 2021, Governor Doug Burgum expressed a goal that North Dakota be carbon neutral by 2030 because of the state's unique geology coupled with the development of new innovative technologies. Carbon neutrality is a state of net zero carbon dioxide emissions, which can be achieved by balancing carbon dioxide emissions with carbon dioxide capture or by eliminating emissions entirely. North Dakota's total emissions in 2018 were 54.97 million metric tons of carbon dioxide equivalent from fossil fuel combustion.

According to the report:

- 79 percent of United States greenhouse gas emissions in 2020 was carbon dioxide.
- 27 percent of United States greenhouse gas emissions came from the transportation sector, 25 percent came from the electricity sector, and 11 percent came from the agriculture sector.

- Between 1990 and 2020, total United States greenhouse gas emissions decreased by 7.3 percent, carbon dioxide emissions decreased by 7.9 percent, and carbon dioxide emissions from fossil fuel combustion decreased by 8.2 percent.
- Between 2019 and 2020, total United States greenhouse gas emissions decreased by 9.0 percent, carbon dioxide emissions decreased by 10.3 percent, and carbon dioxide emissions from fossil fuel combustion decreased by 10.5 percent.
- In 2018, of the 54.97 million metric tons of carbon dioxide equivalent from fossil fuel combustion in North Dakota, 31.16 million metric tons came from the electric power sector, 12.05 million metric tons came from the industrial sector, and 9.41 million metric tons came from the transportation sector.
- Between 2015 and 2018, total North Dakota greenhouse gas emissions increased by 0.37 percent.
- Between 1990 and 2018, total North Dakota greenhouse gas emissions increased by 34 percent. Commercial emissions increased by 39 percent, residential emissions by 5 percent, and transportation emissions by 103 percent.

INSURANCE COMMISSIONER'S LIGNITE COAL REPORT

The committee received a report, pursuant to Senate Bill No. 2287 (2021), from the Insurance Commissioner regarding the availability, cost, and risks associated with insurance coverage in the lignite coal industry. According to the report, North Dakota's lignite industry plays a critical role in the state's economy, generating $3 billion in annual economic activity and over $100 million in annual tax revenue. In combination with oil and gas extraction, the lignite industry generates nearly 24 percent of the gross domestic product in the state. North Dakota is one of the country's top 10 coal-producing states, mining approximately 30 million tons every year since 1988. In 2018, North Dakota overtook Texas as the leading producer of lignite coal. According to the report, the state supports 4,000 megawatts of lignite and other coal generation at seven locations and provides affordable, reliable electric power to over 2 million customers in North Dakota, South Dakota, Minnesota, Montana, and Iowa. According to the United States Energy Information Administration, North Dakota has some of the lowest-cost electricity for residential use, ranking 46th out of 51 states, which includes the District of Columbia. The lignite coal sector also is a major employer in North Dakota and counties with lignite production activity have some of the highest wages in the state. Coal mining supported 3,500 jobs in 2017, and according to one study was responsible for as many as 14,000 jobs due to indirect and induced economic activity.

According to the report, Lignite Energy Council member companies experienced premium increases ranging from 10 to 300 percent from 2017 through 2020. Since 2018, obtaining adequate, affordable insurance coverage has proven challenging for companies in the lignite coal sector. Of the Lignite Energy Council member companies surveyed, 80 percent reported decreasing limits in their most recent policies. The situation has been driven primarily by external market forces, which have been exacerbated by the reduction of insurance underwriting capacity from the coal sector due to net-zero carbon emissions efforts and related environmental movements. The need for reliable, affordable energy production, especially unencumbered by geopolitical risk, has been highlighted in recent years.

The report indicated Lignite Energy Council members and stakeholders should consider alternatives to the commercial insurance market given the importance of the lignite sector to North Dakota's energy consumers, labor market, and overall economy. The report recommended conducting a study to assess the feasibility of forming one or more captive insurance companies for members of the lignite coal sector. The feasibility study should include an analysis of the business, regulatory, risk, and financial and tax requirements and implications of captive insurance companies.