The Senate
Committee on
Natural Resources

Interim Report
to the 80th Legislature

Oil, Gas, and Alternative Fuel Issues

December 2006

TABLE OF CONTENTS

INTERIM CHARGE 3

INTERIM CHARGE 4 (IN PART)

INTERIM CHARGES 4 (IN PART) AND 8

INTERIM CHARGE 6

INTERIM CHARGE 7

INTERIM CHARGE 3

Identify areas of the state where surface or groundwater was contaminated by petroleum operations. Determine the appropriate regulatory and technical requirements to remediate the contamination and prevent future contamination, and recommend appropriate agency jurisdiction for preventing, responding and remediating such incidents.

BACKGROUND

In 1989, the 71st Legislature passed House Bill 1458 by Representative Lena Guerrero, establishing the State's groundwater protection goals. These goals are listed in Chapter 26 of the Texas Water Code:

> Legislative Findings:
>
> > (a) The Legislature finds that: (1) in order to safeguard present and future groundwater supplies, usable and potentially usable groundwater must be protected and maintained; (2) protection of the environment and public health and welfare requires that groundwater be kept reasonably free of contaminants that interfere with present and potential uses of groundwater; (3) groundwater contamination may result from many sources, including current and past oil and gas production and related practices, agricultural activities, industrial and manufacturing processes, commercial and business endeavors, domestic activities, and natural sources that may be influenced by or may result from human activities; (4) the various existing and potential groundwater uses are important to the state economy; and (5) aquifers vary both in their potential for beneficial use and in their susceptibility to contamination.
> >
> > (b) The Legislature determined that, consistent with the protection of the public health and welfare, the propagation and protection of terrestrial and aquatic life, the protection of the environment, the operation of existing industries, and the maintenance and enhancement of the long-term economic health of the state, it is the goal of groundwater policy in this state that the existing quality of groundwater not be degraded. This goal of nondegradation does not mean zero-contaminant discharge.
> >
> > (c) It is the policy of this state that : (1) discharges of pollutants, disposal of wastes, or other activities subject to regulation by state agencies be conducted in a manner that will maintain present uses and not impair potential uses of groundwater or pose a public health hazard; and (2) the quality of groundwater be restored if feasible.
> >
> > (d) The Legislature recognizes the important role of the use of the best professional judgment of the responsible state agencies in attaining the groundwater goal and policy of this state.[1]

In order to address the goals set forth by this statute, the 71st Legislature formed the Texas Groundwater Protection Committee (TGPC).

TEXAS GROUNDWATER PROTECTION COMMITTEE

To achieve optimal water-quality protection, the Legislature created TGPC with the aim of maximizing coordination between agencies involved in groundwater activities. Chapter 26 of the Texas Water Code establishes the membership of TGPC:

- Chair, Executive Director of the Texas Commission on Environmental Quality (TCEQ)
- Vice-Chair, Executive Administrator of the Texas Water Development Board (TWDB)
- Executive Director of the Railroad Commission (RRC)
- Commissioner of Health of the Texas Department of Health
- Deputy Commissioner of the Department of Agriculture
- Executive Director of the State Soil and Water Conservation Board
- Director of the Texas Agricultural Experiment Station
- Director of the Bureau of Economic Geology of The University of Texas at Austin
- a representative selected by the Texas Alliance of Groundwater Districts
- a representative of the Water Well Drillers and Water Well Pump Installers Program of the Texas Department of Licensing and Regulation selected by the Executive Director of the department

With the exception of the representatives selected by the Texas Alliance of Groundwater Districts and the Texas Department of Licensing and Regulation, members of TGPC, including the Chair and Vice-Chair, may designate someone from his/her agency to represent him/her on the committee. If a member chooses to exercise this option, he/she is responsible for the acts and decisions of his/her assigned representative.[2]

The TGPC issues an annual groundwater monitoring report that includes a list of all groundwater contamination cases associated with activities regulated by the agencies represented on TGPC. The report for any given year is based upon contamination data from the preceding year.

GROUNDWATER CONTAMINATION REMEDIATION

Texas Commission on Environmental Quality

The TCEQ is responsible for overseeing nearly all of the State's groundwater contamination cases. In 2005, the total number of groundwater contamination cases regulated by TCEQ was 5,792 (in 227 counties), 546 of which were new cases.[3] The TCEQ approaches the clean up of hazardous wastes and substances according to the methodology required by the Texas Risk Reduction Program (TRRP).[4]

Prior to the adoption of TRRP's risk-based cleanup rules, TCEQ's industrial and hazardous waste programs required all contaminated sites to be restored to background levels or to be closed as a landfill, with post-closure care and monitoring requirements imposed on the parties responsible for contamination. However, TCEQ recognized that in some circumstances a limited quantity of a contaminant could remain within an environmental medium without presenting an unacceptable risk to human health or the environment. The TRRP offers responsible parties flexibility in determining an appropriate cleanup level based on trade-offs of cost, long-term liability and site specific characteristics. Should a responsible party desire to remediate a site and retain no future liability, the party is required to clean the site so that it contains health-protective concentration levels of the contaminant of concern. This standard is referred to as Remedy Standard A. An alternative to this full cleanup standard is Remedy Standard B, which applies when the responsible party is prepared to accept some long-term liability for the maintenance of engineered controls (e.g. an impermeable barrier to restrict contaminant movement) or limitations on land use (industrial, residential, etc.). Responsible parties utilizing Standard B may find the associated costs to be significantly less than the cost of a total cleanup (see Appendix A). [5]

As an alternative to Remedy Standards A and B, a responsible party may develop an alternate, sight-specific cleanup standard, provided the party demonstrates that their approach will be as effective as Standards A and B. Alternate standards must employ a clear, scientifically-defensible methodology, and the responsible parties must bear the entire cost of developing and proving the effectiveness of their approach. When employing an alternate standard, increased analysis and data needs result in an increase of site assessment costs. However, the increased analysis may result in a significant reduction in overall remediation costs.[6]

Railroad Commission of Texas

The RRC regulates oil and gas exploration, oil and gas production, surface mining, mine reclamation, and pipelines. Regulations for pipelines are primarily safety standards, although the routes of new pipelines are also reviewed for environmental risk. [7]

In addition, RRC is responsible for all groundwater contamination cases caused by oil and gas operations. Any citizen complaints that involve matters under RRC jurisdiction -- such as spills, pollution, or abandoned wells -- trigger a RRC response. Complaints regarding issues such as noise, traffic, road damage, and non-payment of royalties are not within the jurisdiction of RRC, even though they may be related to oil and gas activities (see Appendix B).[8]

Contamination cases are prioritized on a case-by-case basis. Those cases that threaten or result in human exposure to a contaminant are considered the most urgent. Other factors considered when assigning priority are proximity to and exposure of the contamination to other environmental receptors (such as surface water bodies or water wells), toxicity of the contaminant, and the known stability of a contamination plume.[9]

For environmental remediation action, RRC first looks to the responsible party whose operations caused contamination. The costs associated with a site remediation can vary from approximately $30,000 to over $6 million, and the responsible party takes on these costs when remediation of a site occurs (see Appendix C).[10] Should they attempt to refuse remediation of a site, a responsible party may face legal action to require clean up of a site through RRC's Operator Cleanup Program (OCP). However, the party in question may preempt these legal measures by voluntarily participating in OCP remediation. Of the current groundwater contamination cases under RRC's jurisdiction, 246 are OCP sites.

Parties not responsible for contamination may also offer site remediation through participation in RRC's Volunteer Cleanup Program (VCP). Currently, seven of the cases under RRC's jurisdiction are VCP program sites.[11] There are a number of indirect incentives for VCP stakeholders:

- removal of perceived liability
- insulation from third-party law suits
- restoration of land values
- RRC certification of cleanup
- the cleanup schedule is proposed by the VCP applicant[12]

For contamination cases in which the responsible party cannot be located, RRC will oversee the remediation of groundwater conservation with funds from the State Funded Cleanup Program. Currently, there are 20 state funded cleanup cases in Texas.[13] As stated in the State's groundwater protection goal, RRC uses its "best professional judgment" when deciding what clean up options are the most feasible for each particular case.[14]

REMEDIATION PROCESS

A RRC response to a complaint generally begins with a meeting with the complainant to discuss the water well problem, collection of a preliminary sample, and an inspection of the area for possible oil field related sources of contamination. Should information (such as the site's proximity to oil and gas operations and/or the complainant's description of the problem) lead to the reasonable conclusion that the source of the contamination is related to an oil and gas related activity, RRC will proceed with further investigation and a more thorough scientific sampling process, including boreholes and the installation of monitor wells where samples are retrieved to be analyzed by qualified laboratories.

The RRC receives remediation progress reports from responsible parties throughout the entire cleanup process, from initial discovery of contamination through remediation completion.[15] All reports that include analytical results must also include laboratory quality assurance/quality control data in order to verify accuracy. Similar to TCEQ's remediation cases, if a risk-based approach is taken and some contamination is left in place, institutional and/or engineering controls are typically required. All current contamination cases are listed in TGPC's annual Joint Groundwater Monitoring and Contamination Report. Of the 337 contamination cases currently under RRC's jurisdiction, 108 were added to the report in 2005.[16] Also listed in the report is each case's most recent remediation status designation, reflecting what progress has been made on every case to date. Remediation has been completed on 10 of the RRC cases listed in the 2005 report with no further action required.[17] When the cleanup of a site is complete, the site remains listed in this annual report with its final activity status for the current year of publication. The case is then removed from the report the following year.[18] Twelve RRC cases were removed from the 2005 report.[19]

CONCLUSIONS

The oil and gas industry has deep, established roots in Texas and has remained an integral part of the economy since the first of the State's abundant petroleum resources were discovered. As the population in Texas booms, part of policy makers' efforts must include the monitoring of the oil and gas industry's activities in an attempt to keep contamination of the State's water resources to a minimum. The State must also be vigilant in its efforts to remediate contamination of water resources in an efficient and effective manner, placing strict guidelines and standards upon responsible parties. Contaminated water resources that may affect the current or future health of human and livestock populations must continue to be a top priority when enforcing and monitoring cleanup efforts. The Senate Committee on Natural Resources has thoroughly examined all aspects of site remediation as it pertains to the oil and gas industry, and has concluded that the system currently in place for addressing water contamination by the oil and gas industry is functioning properly and effectively. Therefore, the Committee finds no need for change to the current agency jurisdiction with regard to the prevention, response, or remediation of contamination of groundwater by petroleum operations.

[1] V.T.C.A., Water Code, §26.403
[2] Id.
[3] Texas Groundwater Protection Committee, "Joint Groundwater Monitoring and Contamination Report - 2005", Publication SFR-056/05, June 2006.
[4] Texas Groundwater Protection Committee, "Texas Groundwater Protection Strategy", publication AS-188, February 2003.
[5] Steve Minick, Texas Commission on Environmental Quality, Personal Communication, October 31, 2006.
[6] Id.
[7] Id. at 4.
[8] Byron Ellington and Bill Miertschin, Railroad Commission of Texas, Personal Communication, November 2, 2006.
[9] Id.
[10] Byron Ellington and Bill Miertschin, Railroad Commission of Texas, Personal Communication, December 8, 2006.
[11] Id. at 3.
[12] Id. at 8.
[13] Id. at 3.
[14] V.T.C.A., Water Code, §26.401
[15] Id. at 8.
[16] Id. at 3.
[17] Id.
[18] Id. at 8.
[19] Id. at 3.

INTERIM CHARGE 4 (IN PART)

Study the increasing use of liquefied natural gas (LNG), compressed natural gas (CNG) and propane. Examine the way those products fit into a diverse fuel mix. Review the current status of LNG terminals on the Texas coast. Study mineral owners and surface owners rights and obligations for the manner in which they enter and use property. Make recommendations on ways in which surface and mineral owners could communicate more effectively. Monitor the Railroad Commission study of competition in the Texas natural gas pipeline industry.

LIQUEFIED NATURAL GAS TERMINALS IN TEXAS

The United States consumes approximately 25 percent of the world's annual natural gas production, and the Energy Information Administration has predicted that demand for natural gas will increase approximately 33 percent by 2025.[1] Natural gas accounts for 23 percent of the nation's energy.[2]

Consumer demand for natural gas in the United States is met through domestic supply and Canadian imports.[3] However, projected decreases in the country's conventional natural gas production and declining imports from Canada will create a supply gap that must be filled.

Ninety-six percent of the world's proven natural gas reserves are abroad. The United States must look to these foreign sources to meet future demand.[4] Importing liquefied natural gas (LNG) is one way the United States can efficiently obtain natural gas from foreign suppliers.[5]

When natural gas is cooled to -260°F, the vapor transforms into a liquid, creating LNG. The liquefaction process removes oxygen, carbon dioxide, sulfur compounds and water from the natural gas, purifying the fuel and leaving an odorless, colorless, non-corrosive and nontoxic liquid.[6] Liquefaction allows for much more natural gas to be stored and transported than when it is in a gaseous state (The volume of the liquid is 600 times less than the volume of the vapor).[7]

In 2005, LNG made up 2.8 percent of the natural gas supply in the United States.
To meet natural gas demand projected for 2030, LNG imports need to increase more than 500 percent.[8]

Currently, there are 69 liquefaction plants in 12 countries worldwide.[9] Indonesia is the largest exporter of LNG in the world. Other large exporters include Algeria, Malaysia, Qatar and Trinidad. Russia and Iran, who possess half of the world's known reserves, may also become key LNG exporters in the years ahead.[10]

Ships carrying LNG require specially designed terminals for offloading of the chemical. Fifty LNG receiving terminals are in operation worldwide. Currently, only five of the world's operational receiving terminals are located in the United States, but there are 40 additional facilities that are either being considered by industry or have submitted applications to the Federal Energy Regulatory Commission (FERC).[11]

Liquefied natural gas receiving terminals are expensive to build and go through a lengthy permitting process at the state and federal level (processing the necessary permits at both the state and federal level takes an average of 12-24 months).[12] On average, construction costs for building a receiving terminal are between $750 million and $1 billion.[13]

Eight Texas sites have either been approved by FERC or are currently in the permitting process.[14] Freeport LNG Development, located in Freeport, Texas, is expected to be the first operational Texas plant. This facility began construction on January 17, 2005, and has an in-service goal of winter 2007. In addition, plans have been announced to expand the plant to increase capacity.[15] The next plant scheduled to be in operation is Corpus Christi LNG, owned by Cheniere LNG and located in Corpus Christi, Texas. This terminal has a target in-service goal of 2008.[16]

Of the remaining six Texas projects, five plan to be operating by mid 2008 or 2009. The most recently announced project, which will be constructed in Pelican Island, Texas, does not yet have a scheduled in-service date.[17] Once all of these projects are completed, facilities located on the Texas coast will have the capacity to import 18.3 billion cubic feet of LNG per day.[18] A detailed chart of all Texas LNG projects may be found in Appendix D.

INCREASED USE OF LIQUEFIED NATURAL GAS, COMPRESSED NATURAL GAS AND PROPANE

The federal and state governments have encouraged the use of non-petroleum based fuels to diversify our fuel sources and reduce our dependence on foreign oil. As gasoline prices continue to be volatile and unpredictable, identifying and adopting alternate fuel sources will continue to be a priority.

In 1989, the 71st Legislature initiated the State's Alternative Fuels Program. This program required state agencies acquiring new vehicles to purchase only vehicles capable of operating on alternative fuels. There were waiver conditions associated with this requirement, including lack of available fuel and cost effectiveness.[19]

Later, at the federal level, the Energy Policy Act of 1992 was implemented to promote energy efficiency, reduce our nation's dependency on foreign oil supplies, and improve environmental quality. This Act required state governments with 50 or more light-duty vehicles in one of 125 designated metropolitan areas to purchase a certain percentage of alternative fuel vehicles and operate on alternative fuels whenever possible.[20]

While both the state and federal legislation have been modified over the years, current law at both the state and federal level continues to require that state agencies purchase alternative fuel capable vehicles. The federal Energy Policy Act of 1992 requires 75 percent of new light-duty purchases to be alternative fuel capable, while Texas law requires that all state fleet vehicles purchased be alternative fuel capable unless a waiver is granted. Texas also requires 50 percent of the State's total fleet be alternative fuel capable.[21]

Impact on Air Quality

Because they produce fewer emissions than traditional vehicle fuel, LNG and Compressed Natural Gas (CNG) provide a positive air quality benefit. The low emissions levels of these alternative fuels can be attributed to the processing involved in making the gases.

When compared to emissions from older, diesel-powered vehicles, LNG significantly reduces emissions of particulate matter (PM) by 50 percent and nitrogen oxide (NO_X) by 50 percent. Liquefied natural gas also reduces carbon dioxide (CO_2) emissions by 25 percent.[22] Compared to conventional gasoline, CNG reduces carbon monoxide (CO) emissions 90 to 97 percent and CO_2 emissions by 25 percent. Compressed natural gas also reduces NO_X emissions by 35 to 60 percent.[23]

Emissions from propane are not as known. Research conducted by the Environmental Protection Agency (EPA) indicates that "rich calibrations of propane shows high nonmethane hydrocarbon and carbon monoxide emissions [compared to conventional gasoline], but lower nitrogen oxide emissions" and lean calibrations, when compared to conventional gasoline, release "slightly higher nitrogen oxide emissions, but lower carbon monoxide and nonmethane hydrocarbon emissions."[24]

Availability and Use

Liquefied natural gas powered vehicles tend to be more expensive than other diesel powered vehicles. According to EPA, "LNG heavy-duty trucks or buses can cost an additional $30,000 to $50,000."[25] This cost is expected to drop as market development and vehicle production rise.

Equipment for fuel storage and dispensing of LNG typically costs $15,000 to $22,000 per vehicle.[26] Because most vehicles powered by LNG are members of larger fleets, most LNG refueling stations are located at heavy-duty vehicle fleet operations that are not open to the public. There are only two LNG refueling stations in Texas, both of which are for private use only.[27]

In the United States, CNG is more widely used than LNG. Over 85,000 of the country's vehicles are currently powered by CNG.[28] In Texas, there are over 3,214 vehicles using CNG, including vehicles owned by the Texas Department of Transportation (TxDOT).[29] According to TxDOT, 55 percent of their light-duty, on-road fleet operates on propane or CNG.[30] Of the entire State vehicle fleet, seven percent use CNG as a fuel source.[31] Nationwide, there are 1,300 CNG refueling stations.[32] Twenty-two of these are located in Texas.[33]

Vehicles capable of operating on CNG cost $3,500 to $6,000 more than their gasoline counterparts because of the higher cost of the fuel cylinders. However, as production and popularity of these vehicles increases, the price is expected to decrease.[34]

Propane has been used as vehicle fuel since the 1940s, and is the most commonly used alternative fuel.[35] Today, over 4,000 vehicles in Texas[36] and over 350,000 vehicles nationwide operate on propane.[37] Ninety percent of the vehicles in the Texas State Alternative Fuel Vehicle Fleet are powered by propane.[38]

Refueling stations for propane fueled vehicles are much more abundant than LNG or CNG stations. There are 627 propane stations in Texas, and all of them are open to the public.[39]

Propane powered vehicles are typically more expensive to buy than gasoline powered automobiles. Light-duty vehicles generally cost an additional $3,000 to $4,000 and medium-duty vehicles may cost an additional $4,000 to $5,000.[40]

Fuel Cost

The price of LNG is dependent upon several things: geographic location, purity of feedstock, transportation costs and quantity of fuel purchased. Per mile, the cost of LNG is less than or equal to the price of diesel.[41]

Even though CNG typically costs 15 percent to 40 percent less than gasoline, fueling CNG powered vehicles may still be more expensive than fueling a gasoline-powered vehicle due to the power value of the fuel. By volume, CNG produces only 25 percent of the energy produced by gasoline, requiring consumers to refuel more frequently than if they use gasoline.[42]

The price of propane tends to fluctuate with oil prices and may increase when demand is high. In addition, the energy content of propane is less than that of gasoline, meaning drivers will have to refuel more frequently than if they used gasoline.[43]

NATURAL GAS PIPELINE COMPETITION STUDY

The Railroad Commission of Texas (RRC) regulates most of the activities associated with the oil and gas industry. During the 79th Legislature, legislation was filed that attempted to address many oil and gas industry issues, including transportation access, gathering rate regulation and the mediation procedure currently in place at RRC.[44]

While none of the bills referenced previously became law, they did call attention to several issues that the Texas Legislature felt warranted additional research. A rider was included in Article XI of the 2006-2007 General Appropriations Act, directing RRC to:

> conduct a study that examines and determines the extent to which viable competition exists in the Texas natural gas pipeline industry from wellhead to burner tip. The study shall recommend solutions to bring market competition to

any non-competitive segments of the industry. The study also shall include an assessment of the effectiveness of current laws, regulations, enforcement and oversight in addressing abuses of pipeline monopoly power and make recommendations for changes that may be necessary. In addition, the study shall include a comparative review of competition in the Texas intrastate gathering and pipeline industry with the open-access transportation in the interstate pipeline industry administered by the FERC.

The rider instructed RRC to submit results of the study to the Legislative Budget Board (LBB) and the Governor on or before November 1, 2006.

In October of 2005, RRC approved an outline for completing the Natural Gas Pipeline Competition Study (Study). This outline separated the Study into five phases, and can be found in Appendix E.

As a part of the Study, RRC Commissioners established a Natural Gas Pipeline Competition Study Advisory Committee (Committee). The Members of the Committee are Jon Brumley, Bill Easter, Dick Erskine, Dr. Stephen Holditch, Steve Howell, Mackie McCrea, Lee Parsley, Mary Ann Pearce and Bill Warnick.[45]

The Committee was charged with evaluating the following:

- whether further improvements to the Commission's informal complaint processes are warranted
- whether additional transparency is needed in the natural gas pipeline industry
- which transporters should be affected by any change in policy or law
- whether to give special treatment to marginal wells
- whether the Commission should exercise oversight regarding the types and categories of fees charged related to gas gathering and transportation
- whether other states methods for addressing discrimination relative to gas gathering and transportation should be adopted in Texas[46]

The final draft report of the Committee's findings and recommendations was submitted to RRC in August, 2006, and the final report was submitted to RRC in October, 2006. The RRC Commissioners approved the report and the recommendations made by the Committee on October 30, 2006, and submitted the final report to the Governor, Lieutenant Governor, Speaker of the House of Representatives and the LBB on November 1, 2006.[47]

Recommendations made by the Committee and approved by RRC may be found in Appendix F. The final report submitted by RRC to the appropriate parties may be found in Appendix G.

CONCLUSIONS

Liquefied Natural Gas Terminals in Texas

Texas has been very proactive in promoting the use of LNG as a means to increase natural gas supplies. With the need for LNG on the rise, Texas' access to the Gulf of Mexico positions the State to be a key player in the LNG market. The receiving terminal projects currently underway will provide a large capacity for importing and distributing LNG, allowing Texas to continue its tradition of being the nation's premier energy producing state.

Increased Use of Liquefied Natural Gas, Compressed Natural Gas and Propane

As federal and state governments continue to focus on using alternative fuels to decrease the United States' reliance on petroleum, the use of LNG, CNG and propane will remain key elements to meeting federal and state alternative fuel standards. Hopefully, the growing interest in the alternative fuels market will lead to higher availability of supply and more cost-efficient vehicles. Because they produce fewer emissions than traditional vehicle fuel, LNG and CNG should continue to provide a positive air quality benefit.

Railroad Commission of Texas Natural Gas Pipeline Competition Study

The final report on the Natural Gas Pipeline Competition Study, as submitted by RRC, calls for some improvements in several RRC programs. Many of these modifications will be accomplished through rule-making by RRC. However, some recommendations require legislative action. A final legislative agenda has not been finalized by RRC, but legislation stemming from the Study is expected to be included in that agenda.

[1] Federal Energy Regulatory Commission, "LNG - The Importance of LNG," www.ferc.gov.
[2] Energy Information Administration, Department of Energy, "Natural Gas--A Fossil Fuel," www.eia.doe.gov.
[3] Id.
[4] Id at 1.
[5] Id.
[6] Environmental Protection Agency, "Clean Alternative Fuels: Liquefied Natural Gas," March 2002.
[7] Federal Energy Regulatory Commission, "LNG Overview," www.ferc.gov.
[8] Center for Liquefied Natural Gas, "Filling the Supply/Demand Gap," www.lngfacts.org.
[9] Pat Outtrim, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[10] Energy Information Administration, Department of Energy, "LNG Exporters," www.eia.doe.gov.
[11] Federal Energy Regulatory Commission, "Liquefied Natural Gas," www.ferc.gov.
[12] Id at 9.
[13] Bill Henry, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[14] Railroad Commissioner Victor Carrillo, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[15] Id at 13.
[16] Id at 14.
[17] Id.
[18] Id.
[19] Steve Simmons, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[20] Id.
[21] Id.
[22] Id at 6.
[23] Environmental Protection Agency, "Clean Alternative Fuels: Compressed Natural Gas," March 2002.
[24] Environmental Protection Agency, "Clean Alternative Fuels: Propane," March 2002.
[25] Id at 6, page 2.
[26] Id.
[27] Dub Taylor, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[28] Id at 23.
[29] Id.
[30] Id at 27.
[31] Id.
[32] Id at 23.
[33] Id at 27.
[34] Id at 23.
[35] Id at 24.
[36] Id at 27.
[37] Id at 24.
[38] Id at 19.
[39] Id at 27.
[40] Id at 24.
[41] Id at 6.
[42] Id at 23.
[43] Id at 24.
[44] Steve Pitner, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[45] Id.
[46] Id.
[47] Id.

INTERIM CHARGES 4 (IN PART) & 8

Review mineral owners and surface owners rights and obligations for the manner in which they enter and use property. Make recommendations on ways in which surface and mineral owners could communicate more effectively.

BACKGROUND

Land ownership in Texas consists of two separate interests: the mineral estate and the surface estate. Initially, both estates are held by one party, but as land changes owners, the two may be severed and owned by different parties. Maintaining ownership of the mineral estate allows the owner to develop or lease a right to a mineral producer at a later date.[1] In areas of the State that have experienced major oil and gas development, it is common for a party owning both the mineral and surface estates to retain the mineral interest at the time the property is sold.

State law has never clearly defined the rights or responsibilities of owners in regard to severed estates. Thus, the issue has been defined over the years through case law. In this regard, Texas Courts have repeatedly maintained a dominance of the mineral estate over the surface estate.[2] For the mineral owner, this legal dominance is critical because without a right to use the surface, the mineral interest has practically no value.

In 1971, the Texas Supreme Court, in *Getty Oil Company v. Jones*, established principles for mineral owners to follow when operating on land they do not own.[3] Prior to *Getty*, there were no formal guidelines for mineral owners or mineral lessees to follow when entering or using land they did not own. Balancing the utilization of both mineral and surface resources, the Court set forth the Accommodation Doctrine in *Getty* stating that, "the oil and gas estate is the dominant estate in the sense that use of as much of the premises as is reasonably necessary to produce and remove the minerals is held to be impliedly authorized by the lease; but that the rights implied in favor of the mineral estate are to be exercised with due regard for the rights of the owner of the servient estate."[4]

In *Getty,* the Court established three important principles for mineral producers to follow. First, the producer can only use what land is necessary to develop the minerals. *Getty* established that it was no longer acceptable to use whatever means desired to access the minerals on the land.[5]

Second, the Court ruled that when practical alternatives exist to produce the minerals, the producer must exercise those options.[6] In *Getty*, the oil and gas producer planned to access the minerals through a route that would affect the sprinkler system used to irrigate the land.[7] The Court ruled that there were alternatives that would allow the producer to mine the oil or gas, while the sprinkler system was the "only reasonable means of developing the surface for agricultural purposes."[8] Therefore, in situations where practical alternatives exist that will not cause harm to the landowner, the producer must use one to develop the minerals.

Third, by stating that "the rights implied in favor of the mineral estate are to be exercised with due regard for the rights of the owner of the servient estate,"[9] the Court is requiring that the mineral owner, or producer, function on the land respecting the landowner and their private property. Adhering to this guideline is usually done through a contract between the landowner and the mineral producer. In such a contract, terms are negotiated for how the producer will work on the property. These terms may include how the producer will enter and exit the property, what path will be used to access the minerals, and what compensation will be necessary for any property or assets that may be damaged or destroyed during the drilling or production phases.[10] While some mineral producers may have guidelines for contracting with landowners, there are no legal requirements for what must be included. Landowners have the opportunity to negotiate terms for any concern they may have, including land reclamation once the drilling is complete, monetary compensation for land that will be unusable and notification of drilling activity on the land. Failure to abide by the contract can result in a lawsuit being filed by either the landowner or the mineral producer.[11]

Other than the principles based in the Accommodation Doctrine, there are no clear guidelines or regulations for a mineral owner to follow when using property they do not own to develop the minerals. However, cities may enact municipal ordinances specifically restricting oil and gas activities on property within city jurisdiction, and in "certain circumstances counties in or near large metropolitan areas can impose restrictions on drilling and operation sites by creation of a qualified subdivision as provided by Chapter 92 of the Texas Natural Resources Code."[12]

Another issue between severed estates arises in the transfer of ownership. Mineral production, such as oil and gas development, has been ongoing in Texas for over 100 years, long before there was a formal system for maintaining ownership records. As a property may have changed hands over the years, the surface estate of the property may have been severed from the mineral estate long before the current surface owner took title.[13] When a landowner chooses to sell land, but maintain the mineral interest, the reservation of the mineral interest is clearly stated in the initial deed of sale. However, this is the only time that the status of the mineral interest is clearly stated during a real estate transaction. In any subsequent title transfer or sale of the land, the status of the mineral interest is not disclosed.[14]

Complicating the matter, in Texas, if the mineral interest of a property is not clearly retained by the seller, that interest is automatically included in the sale of the land. Since the status of the mineral interest may not be disclosed in subsequent surface title transfers, many landowners incorrectly believe that they own the mineral interest of their property. Surface owners may not realize that they do not own their property's mineral rights until an oil and gas producer seeks to exercise their rights under a mineral lease or surface use contract that had been entered into by a previous owner of the property.[15]

Furthermore, because the mineral estate is dominant to the surface estate, a property owner must allow access to a party contracted to develop the minerals of the property.[16] Also, if the previous landowner entered into a contract with a mineral producer, and that contract has not expired, the new landowner is required to adhere to that contract; meaning that whatever terms negotiated by the preceding landowner still apply, including any compensatory obligations on the part of the producer.[17]

There is no current statutory requirement that a mineral producer notify a surface owner when preparing to work on their land, although, there have been some attempts to establish one.[18] During the 79th Legislature, Senate Bill (S.B.) 575, by Armbrister, and its companion, House Bill (H.B.) 753, by Gattis, would have required, with one exception, an oil or gas well producer to give written notice to the surface owner no later than three days after receiving a drilling permit from the Railroad Commission of Texas (RRC). The notice was to be sent to the address of the surface owner as shown by the records of the County Tax-Assessor Collector. Senate Bill 575 also expressly stated that the mineral estate would remain dominant to the surface estate and that failure to give this notice did not restrict, limit or forfeit any existing or future right to develop the mineral estate of the property.[19]

Senate Bill 575, the text of which can be found in Appendix H, was referred to the Senate Committee on Natural Resources and a Committee Substitute for the bill was voted out of committee unanimously. This legislation passed to engrossment in the Senate with a vote of 30-1. [20] In the House of Representatives, S.B. 575 was referred to the House Committee on Energy Resources, but did not receive a hearing. House Bill 753 was also referred to the House Committee on Energy Resources, but was left pending in committee.

The RRC has made efforts to educate and inform landowners about the implications of not owning the mineral estate of their property and recently released a white paper explaining surface owner rights and mineral owner rights. A copy of this paper, "Oil and Gas Exploration and Surface Ownership" may be found in Appendix I.

Several industry associations in states other than Texas have adopted "Good Neighbor Initiatives" in order to improve the relationship between the oil and gas industry and the landowner, lessee or resident in producing areas of their state. The New Mexico Oil and Gas Association is one organization that has adopted a "Good Neighbor Initiative".[21] A copy of that policy can be found in Appendix J.

At the time of this report, no industry association in Texas has adopted a "Good Neighbor Initiative."

CONCLUSIONS

The Accommodation Doctrine currently in use has satisfied most concerns with oil and gas operations on property where the mineral estate has been severed from the surface estate. However, as oil and gas related activity grows rapidly in densely populated areas, such as the Barnett Shale in north-central Texas, landowners need to be more aware of the status of the mineral estate under their land. Fostering adequate communication between oil and gas producers and surface owners is imperative to ensuring that not only the mineral estate is protected, but that private property rights are also respected.

RECOMMENDATIONS

At this time, the Committee recommends that the Senate explore options to improve communications between seller and buyer at the time of sale if the surface and mineral estates have been previously severed.

[1] Colin Lineberry, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[2] Lansdown, Scott, "If It's Not Broken, Don't Fix It," *Texas Lawyer*, May 9, 2003.
[3] Getty Oil Company v. Jones, 470 S.W.2d618.
[4] Id, page 621.
[5] Fambrough, Judon, "Minerals, Surface Rights and Royalty Payments," Texas Real Estate Center, June 1996.
[6] Id.
[7] Id at 3.
[8] Id, page 622.
[9] Id, page 621.
[10] Adam Haynes, Personal Communication, November 10, 2006.
[11] Id.
[12] Id at 1, page 1.
[13] Id.
[14] Celia Flowers, Personal Communication, December 13, 2006.
[15] Id.
[16] Id at 1.
[17] Id at 10.
[18] Roger Welder, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[19] Id.
[20]Journal of the Senate, Regular Session of the Seventy-Ninth Legislature of the State of Texas, 2005, page 1003 et seq.
[21] New Mexico Oil and Gas Association, "Good Neighbor Initiatives," www.nmoga.org.

INTERIM CHARGE 6

Study and make recommendations relating to investment needs and economic barriers to developing bio-diesel, bio-fuels, ethanol, and other renewable products in Texas. Compare agriculturally-developed renewable fuel initiatives in other states.

BACKGROUND

Encouraging the use of alternative fuels in the United States has become both a practical and political necessity as the country addresses its environmental concerns, trade deficit and dependence on foreign petroleum sources. The Energy Policy Act of 1992 was one of the first federal measures to reflect that necessity by mandating federal, state and local governments to use alternative fuels in their fleets and setting standards for which non-petroleum fuel products would be considered alternative fuels.[1]

More recently, the federal government enacted the Energy Policy Act of 2005 to diversify fuel supplies and encourage new ways to meet the energy needs of the country by promoting the development and use of alternative and renewable fuels, spotlighting ethanol and biofuels through incentives and investments in infrastructure. Specifically, the Act directs the Department of Energy (DOE) to advance the development of biorefineries in the United States for the production of biofuels and to bring new technologies to the forefront of energy production.[2]

President George W. Bush has furthered the commitment to diversifying America's energy by introducing the Advanced Energy Initiative that mandates a Renewable Fuel Standard (RFS) of at least 7.5 billion gallons of renewable fuel supply by 2012.[3] The President has also proposed to "significantly increase our national investment in alternative fuel and clean energy technologies"[4] in order to reduce the dependency on foreign oil and has asked Congress to increase funding for clean energy technologies by 22 percent in 2007.[5]

With this heightened emphasis on alternative fuel policy, and the particular emphasis on ethanol and biofuels, Texas is in a favorable position to become a leader in biofuel production. In addition to the State's agricultural resources and expertise, the State's highway system, rail system and port access provide efficient means for transport of biofuels.[6]

Ethanol

Ethanol is an alcohol-based alternative fuel produced by fermenting and distilling starch crops, such as corn or sugar cane, that have been converted into simple sugars.[7] Ethanol is by no means new to the United States as a blend of ethanol and turpentine fueled the first American internal combustion engine in 1826.[8] Additionally, Henry Ford designed the original Model T automobile to run on ethanol calling it "the fuel of the future."[9]

Today, ethanol is commonly used as an additive to conventional fuel as a 10 percent blend (E10) to increase octane and improve combustion. In Flex Fuel Vehicles, ethanol blends of up to 85 percent ethanol and 15 percent petroleum gasoline (E85) may be used. Pure ethanol is not currently a feasible fuel source for most engines as most existing engine design can not properly utilize the fuel.[10]

The use of ethanol in vehicles has significant air quality benefit. The use of 10 percent ethanol blend reduces greenhouse gas emissions by 12-19 percent compared to conventional gasoline. In 2005, ethanol use reduced carbon dioxide (CO_2) greenhouse gas emissions by approximately 7.8 million tons in the United States. This reduction is equal to removing the annual emissions of more than 1.18 million cars from the road. Ethanol also reduces tailpipe emissions of carbon monoxide (CO) by 30 percent and emissions of particulate matter (PM) by 50 percent.[11]

Ethanol production has significant economic benefit as well. Ethanol production in the United States accounts for 40 percent of the worldwide supply. There are currently 112 ethanol plants in operation in the United States, enabling a production capacity of five billion gallons per year with 48 new plants under construction. By supplementing the country's requirement for foreign crude, the use of ethanol reduced the United States trade deficit by $8.7 billion, eliminating the need to import 170 million barrels of oil.[12]

The United States produces five billion gallons per year of E85 fuel, and in order to meet the goals set forth by President Bush, that production is expected to grow to 12 billion gallons per year by 2012.[13] There are 700 retail locations currently distributing the E85 fuel in the United States, with 12 public retail locations and five private federal refueling stations in Texas.[14] The direct economic benefit of ethanol production is that during 2005, the ethanol industry supported the creation of over 150,000 jobs and increased household income by $5.7 billion. Furthermore, between 2005 and 2012, the industry is expected to add $200 million to the country's gross domestic product.[15]

Specifically in Texas, Panda Ethanol is currently in the process of building the first two ethanol plants in the State, located in Hereford and Sherman.[16] Both plants will be able to produce 100 million gallons of ethanol per year and will primarily use corn or milo as feedstock for the fuel.[17]

Biodiesel

Biodiesel is a diesel-equivalent, processed fuel derived from biological sources. Biodiesel can be made using vegetable oils, recycled cooking grease or animal fats, but it is currently primarily manufactured from domestically produced soybean oil. Soybean oil is preferred because it produces a product that meets the Environmental Protection Agency (EPA) regulations for ultra-low sulfur diesel fuel.[18]

Biodiesel is commonly available in several forms: B100, B20 and B5. B100 is 100 percent biodiesel and, in this form, is not regulated by the State. B20 is a diesel blend consisting of 20 percent biodiesel and 80 percent petroleum diesel while B5 is a diesel blend made of five percent biodiesel and 95 percent petroleum diesel.[19] These forms of biodiesel are regulated by the Texas Commission on Environmental Quality (TCEQ) under the Texas Low Emission Diesel (TxLED) program because they are blended with petroleum diesel fuel. Under TxLED rules, petroleum diesel fuel must comply with regulations established by the TxLED program.[20] This program is limited to petroleum diesel fuels; petroleum gasoline or any petroleum gasoline blends, such as E85, do not fall under these regulations.

Biodiesel provides some air quality benefits. Test results show reductions in emissions of PM and CO by 10 percent and 11 percent respectively.[21] However, there are no consistent results proving any nitrogen oxide (NO_X) reductions. This is not necessarily an issue in all states, but in Texas, NO_X is a primary concern. Three regions in Texas, Dallas-Fort Worth, Houston-Galveston-Brazoria and Beaumont-Port Arthur, are listed as nonattainment for ground level ozone. Because NO_X is a precursor for ozone, NO_X emissions associated with biodiesel are of paramount importance, especially in nonattainment areas of the State.[22]

The United States produces 580 million gallons of biodiesel per year with 78 plants currently in operation. There are 33 additional plants under construction that will be able to produce 807 million gallons of biodiesel per year. Within the United States, there are over 800 retail pumps that distribute biodiesel.[23]

Texas is currently the largest producer of biodiesel in the United States.[24] In Texas, there are 12 plants in operation with a total biodiesel production capacity of 96 million gallons per year. Two additional plants are in the construction phase and will contribute an additional 50 million gallons of biodiesel per year to the State's production capacity.[25] Texas has 58 retail stations that offer biodiesel, primarily offering B20. Austin, Texas, has the highest concentration of B20 pumps in the country.[26]

BARRIERS TO DEVELOPING ETHANOL, BIODIESEL AND BIOFUELS IN TEXAS

Infrastructure

Success of any fuel depends on at least two primary factors: price and availability. While the State of Texas cannot control the price of biofuels, it can encourage the investment in infrastructure needed to transport and distribute these fuels.

Putting Texas' success in perspective, 12 public retail stations offer E85 fuel and 58 offer biodiesel compared to more than 170,000 conventional gas stations in the state. Several grocery companies that operate retail fuel stations, such as H-E-B and Kroger, have begun to offer E85 fuel to their customers. This is increasing E85 availability, but there is a long road ahead before it is widely available.[27]

In order to primarily use alternative fuels, a driver must have an alternative fuel vehicle. While companies such as General Motors have actively started manufacturing cars that can operate on alternative fuels, relatively few people own these types of vehicles, meaning that many people cannot use those fuels.[28]

The automobile and biofuels industries have encouraged state and federal governments to reward both citizens who drive alternative fuel vehicles, as well as, retailers who choose to install alternative fuel equipment at their gas stations. Some federal incentives exist for investing in this equipment, however, no similar state incentives are currently offered.[29]

Feedstock Supply

Both ethanol and biodiesel are almost totally dependent upon their feedstock. Price, energy and availability all depend upon what product is used to make the fuel. While Texas is the nation's second leading agricultural producing state, there is little feedstock grown or processed in Texas in support of biofuels.[30] The primary reason for this trend is that current market forces do not support the commitment of crops toward biofuel production.

Switchgrass, sugarcane and sorghum (which includes corn) crops have been studied as the most beneficial sources for creating ethanol. While Texas is the fourth largest sugarcane growing state in the country, it is more lucrative for sugarcane growers to sell their product to sugar refineries rather than ethanol distilleries, leaving little available for ethanol production. Sorghum crops grown in Texas are mainly used for livestock feed and only 15 percent are used to produce ethanol.[31]

The preferred feedstock for biodiesel in the United States is soy oil. There are approximately 175,000 acres of soy planted in Texas, which is not enough to support the industry, and there are no soy crushing facilities in operation.[32]

However, market forces are in flux with recent federal developments. In 2005, the federal government ruled that methyl tertiary butyl ether used in gasoline must be replaced with ethanol due to environmental concerns.[33] This change alone drastically increased the demand for ethanol, causing concern that there may not be enough feedstock supply to produce the amount of ethanol needed. The United States Department of Agriculture has projected that the RFS will double demand for ethanol production, requiring over two billion bushels of corn per year by 2010.[34] The federal government is currently encouraging farmers to grow crops needed to produce biofuels through incentives so that this demand may be met.

In successfully meeting this demand, it is crucial for Texas to identify the best crops for biofuels. Thus, Texas A&M University has started a research group called the Texas A&M Agriculture and Bioengineering Alliance. The purpose of this group is to research ways to make biofuels economically feasible for Texas. Finding exactly the right feedstock that provides the most power for the least cost is the key to keeping biofuels economically feasible and viable alternative fuels.[35]

Air Quality

While biofuels generally face barriers related to availability and the price of feedstock, another complicated obstacle specific to the market growth of biodiesel in Texas is the fuel's effect on air quality. Federal air quality standards have required Texas to make significant efforts to decrease certain emissions, specifically NO_X. Texas, in response, has created strict standards regarding which fuels may be used in areas of the State with air quality issues.[36]

In order to meet these air quality challenges, Texas enacted the TxLED program in 2000. The TxLED program ensures that cleaner burning diesel fuel is used in areas of the State with federal air attainment issues, and it was adopted as an air quality control strategy in the federal State Implementation Plan (SIP). The goal of TxLED is to lower NO_X emissions from diesel-powered motor vehicles and non-road equipment operating in nonattainment areas in Texas.[37]

The TxLED guidelines pertain to diesel fuels that contain at least some portion of petroleum-based diesel. Because of the petroleum-based definition, biodiesel is technically considered a fuel additive when blended with petroleum diesel. These blends, such as B5 or B20, must meet TxLED standards for air quality effects.[38] However, since pure biodiesel (B100) contains no petroleum-based diesel, the pure fuel falls technically outside of the scope of TxLED guidelines and thus is not subject to TCEQ regulation.

Diesel fuel producers and importers can satisfy the TxLED fuel standards by producing actual TxLED diesel, producing or importing a diesel approved by the California Air Resources Board (CARB), producing or importing a diesel that complies with an alternative diesel fuel formulation approved by TCEQ as achieving better emission reductions than TxLED, or by producing diesel under an alternative emission reduction plan (AERP).[39]

Biodiesel is currently operating under an AERP. Under this plan, TCEQ may accept the use of biodiesel if the specific biodiesel/diesel fuel blend or a specific biodiesel/fuel additive/diesel fuel blend meets one of two standards. First, the fuel must be verified by EPA or by CARB to reduce NO_X emissions by at least 5.78 percent when blended with conventional EPA diesel or, second, the fuel must be tested in accordance with procedures specified in the TxLED regulations and have been approved by TCEQ as a TxLED alternative diesel formulation.[40] These rules for biodiesel expire on December 31, 2006, and producers must then submit new AERPs that meet the new emission reduction requirements.[41]

As of December 31, 2006, the new regulations for an AERP are:

1. Using the EPA Unified Model, the average fuel properties of the on-road diesel fuel being supplied to affected counties must achieve at least a 5.5 percent NO_X reduction in 2007 and a 6.2 percent NO_X reduction from non-road diesel
2. Use of credits from early gasoline sulfur reductions
3. Combination of Options 1 and 2[42]

While biodiesel studies consistently show positive effects on emissions of PM, volatile organic compounds and toxins, there is a wide range of results in regard to NO_X emissions. Some testing results show that NO_X emissions are reduced or, at least on average, do not increase. However, these specific tests used certain testing methods that are not approved under the TxLED testing guidelines and, therefore, cannot be accepted by TCEQ. Tests performed according to the TxLED testing guidelines, which were approved by EPA, show that when a diesel fuel is blended with biodiesel there is at least a two percent increase in NO_X emissions.[43] The TxLED fuel testing guidelines, as adopted by TCEQ and approved by EPA, can be found in Appendix K.

Even though some tests do not show an increase in NO_X emissions, TCEQ has taken the official position that, according to testing methods acceptable to their testing standards as adopted under TxLED regulations, the use B20 increases NO_X emissions by at least two percent. The EPA supports this assessment and also holds the opinion that use of a biodiesel blended fuel increases NO_X emissions by at least two percent.[44]

As of December 31, 2006, unless it is proven through testing methods approved by TCEQ that biodiesel blends have no negative impact on NO_X emissions, biodiesel blends cannot be approved as an AERP under the new guidelines and will not qualify for use in the 110 TxLED counties.[45] The list of counties subject to TxLED rules can be found in Appendix L.

There are many other areas in Texas that are not affected by TxLED regulations. However, the more populated areas of the State are subject to these rules. If the use of biodiesel blends is prohibited in these areas, the biodiesel industry in Texas will lose their primary product market which could cause the production plants located in this State to close. Should this happen, millions of dollars in economic development and infrastructure will be lost, thousands of jobs could be eliminated and the growth of the biodiesel market in Texas will be stunted.[46]

While these are devastating effects to the biodiesel industry in Texas, it is important to note that the regulations in place were adopted to protect air quality and meet federal air attainment standards. Texas is not in a position to compromise the SIP currently underway to meet the attainment goals for 2009. Because TCEQ and EPA are of the opinion that biodiesel causes an increase in NO_X emissions, TCEQ believes that biodiesel use will have a negative impact on the SIP.[47]

Statutory Definitions

The previous discussion of biodiesel blends touches on another issue pertinent to the proper development of the biofuels market in Texas, the statutory definition of biofuels. Just as pure biodiesel is not regulated similarly to blended biodiesel, statutory definitions can create artificial boundaries resulting in unequal treatment of competing products.

The biofuel industry in Texas is fairly new, and the current definitions in place are specific to particular processes and feedstock.[48] As biofuel technology continues to advance and expand to new processes, it is apparent that the current definitions adopted by the State may ultimately and inadvertently exclude some portions of the industry. For example, biodiesel is currently defined in three sections of Texas statutory code. The Texas Tax Code, Section 162.001(7), states that:

> "Biodiesel fuel" means any motor fuel or mixture of motor fuels that is:
>
> (A) derived wholly or partly from agricultural products, vegetable oils, recycled greases, or animal fats, or the wastes of those products or fats; and
>
> (B) advertised, offered for sale, suitable for use, or used as a motor fuel in an internal combustion engine.[49]

As defined in the Texas Administrative Code, Title 34, Chapter 3.443 biodiesel is "a fuel comprised of monoalkyl esters of long chain fatty acids generally derived from vegetable oils or fats, designated B100, and meeting the requirements of ASTM D 6751."[50]

Finally, the Texas Agriculture Code, Section 16.001 defines biodiesel as:

> a monoalkyl ester that:
>
> (A) is derived from vegetable oils, rendered animal fats, or renewable lipids or a combination of those ingredients; and
>
> (B) meets the requirements of ASTM PS 121, the provision specification for biodiesel.[51]

While the definition found in the Tax Code is fairly broad, the definitions stated in the Administrative Code and Agriculture Code are specific to those fuels resulting from a monoalkyl ester process. Many production plants currently use a monoalkyl ester process, however, new technologies have also been developed that employ different methods.[52] If the State's definition of biodiesel excludes some companies from being considered "biodiesel" producers, it may also exclude them from any incentives designed to entice new investment in Texas. The limited definition may also prevent new fuels from being considered renewable in a RFS, if one was enforced at any time in Texas.[53]

More flexible and broad statutory definitions of biofuels would make Texas more appealing to biodiesel companies looking to expand their investments because it would ensure equal standing with other biodiesel companies already in our State.[54]

BIOFUELS INCENTIVE PROGRAMS

Federal Biofuels Incentive Programs

The Energy Policy Act of 2005 extended and created several tax credits for ethanol and biofuels producers.

This legislation granted an extension on the tax incentives created for ethanol and biodiesel by the American Jobs Creation Act of 2004. These credits are 51 cents per gallon of ethanol at 190 proof or greater, $1.00 per gallon of agri-biodiesel and 50 cents per gallon of waste-grease biodiesel.[55]

If the fuel is blended with either petroleum gasoline or petroleum diesel, the credit is $.0051 per percentage point of ethanol or $.01 per percentage point of biodiesel used or $.0050 per percentage point of waste-grease biodiesel. These credits are available until 2010 for ethanol and were extended through 2008 for biodiesel.[56] The B100 fuel is not eligible for this tax incentive. In order to comply with the requirements, some biodiesel producers have begun producing a B99 blend, which is 99 percent biodiesel blended with one percent petroleum diesel.

The Energy Policy Act of 2005 offers incentives to small producers of ethanol and biodiesel as well. Ethanol and agri-biodiesel producers making less than 60 million gallons of agri-biodiesel per year are eligible for a tax credit of 10 cents per gallon for up to 15 million gallons.[57]

The need for infrastructure is a significant obstacle to growing the renewable fuels market in the United States. As a result, a tax credit was created by the Energy Policy Act of 2005 to encourage building and installing alternative fuel infrastructure. This tax credit is equal to 30 percent of the cost of alternative refueling property, up to $30,000. This incentive is located in Section 1342 of the Energy Policy Act of 2005.[58] Alternative fuels included in this tax credit are natural gas, propane, hydrogen, E85 and biodiesel mixtures of B20 or higher.[59]

Buyers of residential refueling equipment are eligible for a $1,000 tax credit. If a buyer is a non-tax-paying entity, the credit can be forwarded to the equipment seller. This credit applies to equipment operating after December 31, 2005, and will expire December 31, 2009.[60]

In addition to providing tax credits for refueling infrastructure, the Energy Policy Act of 2005 created ways to help encourage and fund the construction of biofuels facilities and the development of new technology. An Advanced Biofuels Technologies Program was created and supplied with $550 million in an effort to explore new technology for making and using biofuels in the United States. Also, the Energy Policy Act of 2005 directed DOE to partner with industrial and academic institutions to advance the development of biofuels, bioproducts and biorefineries.[61]

Texas Fuel Ethanol and Biodiesel Production Incentive Program

In 2003, the Texas Legislature passed legislation providing a producer incentive to ethanol and biodiesel plants in the State. Most midwestern states provided a producer incentive, and Texas producers were previously unable to compete in the national market.[62]

During the 78th Legislature, the Fuel Ethanol and Biodiesel Production Incentive Program (Program) was included in Senate Bill (S.B.) 275, by Nelson/Solomons. The amendment can be found in Appendix M. Senate Bill 275 required that ethanol and biodiesel producers pay the State 3.2 cents for every gallon they produce, but in return, are entitled to receive from the State 20 cents for every gallon of fuel produced in each registered plant. Producers would be eligible for the incentive for up to 18 million gallons of fuel per year and may only receive the incentive for the first 10 years that the plant is in production.[63]

Funding for the Program, as stated in S.B. 275, was to come from unappropriated General Revenue of the State. However, the legislation prohibited the Comptroller from transferring funds from General Revenue for this incentive until September 1, 2005, leaving the Program inactive and unfunded for two years. As the Program came online, administrative and fiscal responsibility for the Program was transferred by the Governor's Office to the Texas Department of Agriculture (TDA) in February of 2006.[64]

For the 2006-2007 biennium, TDA has estimated that the Program will pay approximately $17 million to ethanol and biodiesel producers. This cost is expected to grow for the 2008-2009 biennium. In their Legislative Appropriation Request, TDA has asked that $100 million be allotted for the Program. After subtracting the amount of money producers must pay to the State, which is 3.2 cents per gallon, the State will be responsible for providing $83 million to fund the Program.[65]

Because there is no statutory cap on the amount of money the State is required to pay producers, there is no limit to the fiscal impact on the State. As long as there is unappropriated General Revenue available for the Program, the incentives can continue to be paid. If there is no unappropriated General Revenue available for the fund, the office administering the Program must "proportionally reduce the amount of each grant for each gallon of ethanol or biodiesel produced as necessary to continue the Program during the remainder of the fiscal year."[66]

Another State incentive available to biodiesel or ethanol producers is an exemption from the diesel fuel tax. House Bill 2458, by Krusee/Bivins, passed during the 78th Legislature, established a diesel fuel tax in Texas of 20 cents per gallon. This tax is paid when the fuel is removed from the terminal rack, such as when a supplier sells it to a distributor. The distributor then pays the tax to the supplier, who then remits it to the State.[67]

A diesel fuel is included in this tax if blended with biodiesel or ethanol. However, the entire gallon of fuel is not exempt. Only the percent of biodiesel or ethanol that is blended with the diesel fuel is eligible for the exemption.[68] For example, if a gallon of fuel contains 20 percent biodiesel and 80 percent diesel fuel, the producer is only exempt from 20 percent of the diesel fuel tax.

Ethanol and Biofuel Incentives in Other States

Many other states have enacted financial incentives to encourage the production and use of biodiesel and ethanol. Financial incentives in the form of tax credits are available to producers or suppliers of ethanol or biodiesel, but are not extended to agricultural producers who grow the feedstock necessary to make the fuel.[69]

Several states offer deductions or credits to offset the cost of purchasing or installing renewable energy equipment through income tax credits, sales tax credits or property tax credits.[70]

In Arkansas, biodiesel suppliers and producers can claim an income tax credit equal to five percent of the cost of facilities and equipment for up to three years. In Washington, purchasers of buildings or equipment used for manufacturing biodiesel or biodiesel feedstock are exempt from state and local sales taxes. Montana has developed a property tax exemption for all machinery, equipment and tools used to produce ethanol with grain. This exemption applies during the construction of the facility and for the first 10 years after it is operational.[71] A list of alternative fuel incentive programs offered in other states, provided by the National Conference for State Legislators, can be found in Appendix N.

The structure of the Texas tax system makes it difficult to implement programs seen in other states. As stated in the Senate Committee on Natural Resources hearing on October 11, 2006, there are no programs currently in effect in other states that would be a good fit for Texas.[72]

CONCLUSIONS

As the biofuels industry in Texas continues to grow, many of the challenges previously addressed will be solved by the nature of a growing market; an increase in demand will lead to an increase in supply. The air quality issue associated with biodiesel is one that falls within the jurisdiction of the TCEQ. The TCEQ is working diligently to provide a balanced solution that will allow the biodiesel industry to have a place in the Texas fuel market and also protect air quality.

[1] Energy Efficiency and Renewable Energy, Department of Energy, "Freedom CAR and Vehicle Technologies: Energy Policy Act (EPAct)," www.eere.energy.gov.
[2] Department of Energy, "On the Road to Energy Security," www.doe.gov.
[3] Id.
[4] Id, page 1.
[5] Id.
[6] Jim Kerlak, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[7] Dub Taylor, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[8] Todd Carter, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[9] Id, page 2.
[10] Id at 7.
[11] Id at 8.
[12] Id.
[13] Id.
[14] Id at 7.
[15] Id at 8.
[16] Id.
[17] Id at 7.
[18] Id.
[19] Id.
[20] David Schanbacher, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[21] Bob McCormick, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[22] Id at 20.
[23] Id at 7.
[24] Id at 21.
[25] Id at 7.
[26] Id.
[27] Id.
[28] Bob Babik, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[29] Id.
[30] Bill Spence, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[31] State Energy Conservation Office, "Biomass Energy: Growing Crops for Fuel," www.seco.cpa.state.tx.us.
[32] Id at 30.
[33] Energy Information Administration, Department of Energy, "Eliminating MTBE in Gasoline in 2006," February 2006.
[34] Baker, Allen and Zahniser, Steven, "Ethanol Reshapes the Corn Market," *Amber Waves*, Volume 4, Issue 2, April 2006.
[35] Joe Outlaw, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[36] Id at 20.
[37] Id.
[38] Id.
[39] Id.
[40] David Schanbacher, Staff Briefing, October 5, 2006.
[41] Id at 20.
[42] Id, page 13.
[43] Id.

[44] Id.
[45] Id.
[46] Joe Jobe, Letter to Governor Rick Perry, November 8, 2006.
[47] Id at 20.
[48] Gerry McKenna, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[49] V.T.A.C., Tax Code, § 162.001(7).
[50] V.T.A.C., Administration Code, § 3.443.
[51] V.T.A.C., Agriculture Code, § 16.001.
[52] Id at 48.
[53] Id.
[54] Id.
[55] Energy Efficiency and Renewable Energy, United States Department of Energy, "Federal E85 Incentives and Laws," www.eere.doe.gov.
[56] Id.
[57] Id.
[58] Id at 7.
[59] Id at 55.
[60] Id.
[61] Id at 7.
[62] Robert Wood, Testimony before the Senate Committee on Natural Resources, October 11, 2006, Austin, Texas.
[63] Id.
[64] Robert Wood, Personal Communication, November 14, 2006.
[65] Agriculture Commissioner Susan Combs, Testimony before the Senate Committee on Finance, October 9, 2006, Austin, Texas.
[66] V.T.A.C., Government Code, § 481.001 et seq.
[67] V.T.A.C., Tax Code, § 162.001 et seq.
[68] Id.
[69] DeCesaro, Jennifer A. and Brown, Matthew H., "Bioenergy: Power, Fuels and Products," National Conference of State Legislators, July 2006.
[70] Id.
[71] Id.
[72] Id at 7.

INTERIM CHARGE 7

Study the permitting exemptions and water well regulations in Sec. 36.117, Water Code. Review the jurisdiction over the regulation of groundwater pumping in conjunction with drilling and production of oil and gas.

BACKGROUND

In 1995, the 74th Legislature adopted House Bill (H.B.) 2294 by Yost/Armbrister. This bill created Chapter 36 of the Water Code, consolidating the State's groundwater management provisions into one chapter. Chapter 36 was later refined by the 77th Legislature in Senate Bill (S.B.) 2 by Brown/Lewis. Section 36.117 of that chapter sets forth a list of exemptions from, exceptions to, and limitations on a groundwater district's permitting requirements.

> § 36.117. EXEMPTIONS; EXCEPTION; LIMITATIONS. (a) A district may exempt wells from the requirement of obtaining a drilling permit, an operating permit, or any other permit required by this chapter or the district's rules.
>
> (b) A district may not require any permit issued by the district for:
>
> (1) a well used solely for domestic use or for providing water for livestock or poultry on a tract of land larger than 10 acres that is either drilled, completed, or equipped so that it is incapable of producing more than 25,000 gallons of groundwater a day;
>
> (2) the drilling of a water well used solely to supply water for a rig that is actively engaged in drilling or exploration operations for an oil or gas well permitted by the Railroad Commission of Texas provided that the person holding the permit is responsible for drilling and operating the water well and the well is located on the same lease or field associated with the drilling rig; or
>
> (3) the drilling of a water well authorized under a permit issued by the Railroad Commission of Texas under Chapter 134, Natural Resources Code, or for production from such a well to the extent the withdrawals are required for mining activities regardless of any subsequent use of the water.
>
> (c) A district may not restrict the production of any well that is exempt from permitting under Subsection (b)(1).
>
> (d) Notwithstanding Subsection (b), a district may require a well to be permitted by the district and to comply with all district rules if:
>
> (1) the purpose of a well exempted under Subsection (b)(2) is no longer solely to supply water for a rig that is actively engaged in drilling or exploration operations for an oil

or gas well permitted by the Railroad Commission of Texas; or

(2) the withdrawals from a well exempted under Subsection (b)(3) are no longer necessary for mining activities or are greater than the amount necessary for mining activities specified in the permit issued by the Railroad Commission of Texas under Chapter 134, Natural Resources Code.

(e) An entity holding a permit issued by the Railroad Commission of Texas under Chapter 134, Natural Resources Code, that authorizes the drilling of a water well shall report monthly to the district:

(1) the total amount of water withdrawn during the month;

(2) the quantity of water necessary for mining activities; and

(3) the quantity of water withdrawn for other purposes.

(f) Notwithstanding Subsection (d), a district may not require a well exempted under Subsection (b)(3) to comply with the spacing requirements of the district.

(g) A district may not deny an application for a permit to drill and produce water for hydrocarbon production activities if the application meets all applicable rules as promulgated by the district.

(h) A water well exempted under Subsection (a) or (b) shall:

(1) be registered in accordance with rules promulgated by the district; and

(2) be equipped and maintained so as to conform to the district's rules requiring installation of casing, pipe, and fittings to prevent the escape of groundwater from a groundwater reservoir to any reservoir not containing groundwater and to prevent the pollution or harmful alteration of the character of the water in any groundwater reservoir.

(i) The driller of a well exempted under Subsection (a) or (b) shall file the drilling log with the district.

(j) A well to supply water for a subdivision of land for which a plat approval is required by Chapter 232, Local Government Code, is not exempted under Subsection (b).

(k) Groundwater withdrawn from a well exempt from permitting or regulation under this section and subsequently transported outside the boundaries of the district is subject to any applicable production and export fees under Sections 36.122 and 36.205.

(l) This chapter applies to water wells, including water wells used to supply water for activities related to the exploration or production of hydrocarbons or minerals. This chapter does not apply to production or injection wells drilled for

> oil, gas, sulphur, uranium, or brine, or for core tests, or for injection of gas, saltwater, or other fluids, under permits issued by the Railroad Commission of Texas.[1]

Section 36.117(b)(2) specifically exempts from permitting requirements water wells used to supply water for "a rig actively engaged in drilling or exploration operations for an oil or gas well permitted by the Railroad Commission of Texas [RRC]…."[2] The oil and gas industry argues that this exemption is necessary because variation in lease terms and drilling rig availability do not allow for long-term planning, leaving insufficient lead time to obtain a groundwater permit. [3]

The oil and gas industry uses water in "nearly every aspect of exploration and production," with the largest volume supporting enhanced recovery operations.[4] In these operations, as the volume of gas falls, the pressure in the reservoir also falls. Once the pressure is too low, the gas well must be plugged. However, if water or another liquid is injected into the reservoir, the pressure increases and more gas can be recovered. It should be noted that Section 27.0511, Texas Water Code, requires the use of a liquid other than fresh water in enhanced recovery operations if such a liquid is available and economically and technically feasible for use.[5]

The (RRC) estimates that 6,112 million barrels of fluid were used in 2001 in enhanced recovery operations.[6] Of these 6,112 million barrels of fluid, approximately 212 million barrels were fresh or brackish water.[7]

BARNETT SHALE

The Barnett Shale is a geological formation underlying 16 counties in North Texas.[8] There exists a large amount of gas in the Barnett Shale (estimated at 26.2 trillion cubic feet of gas-in-place), but the low permeability of the shale previously made drilling for the gas economically unfeasible.[9]

During the 1990s, new technology was developed that allows the gas in the Barnett Shale to be extracted in an economically feasible manner. Known as hydraulic fracturing, or fracing, this extraction process involves pumping large volumes of fresh water -- treated with a friction reducer, surfactant, and clay stabilizer -- into the geological formation. The process increases the available surface area within the formation by creating fractures that are held open by agents added to the water, such as sand. The larger surface area increases the desorption and mobility of the gas.[10] Commonly, a gas well in the Barnett Shale will be fraced multiple times over the life of the well.[11]

Fracing has been performed in the Barnett Shale since 1997.[12] Gas wells in the Barnett Shale may be vertically fraced or horizontally fraced. Approximately 60,000 to 80,000 barrels of water are used to frac a vertical gas well. For a horizontally fraced gas well, 80,000 to 100,000 barrels of water are used.[13] In contrast, drilling an average gas well not located in the Barnett Shale requires between 3,000 and 15,000 gallons of water, depending on the depth of the oil and gas well.[14]

The RRC estimates that in 2005, approximately 82,190,000 barrels of water were used for fracing in the Barnett Shale.[15] This amount equals about 10,592 acre feet of water.[16]

There are projects underway that explore the re-use of water used in fracing. Devon Energy is exploring a process developed by Fountain Quail Water Management that could allow reuse of approximately 80 percent of the returned fracture fluid. The process utilizes on-site distilling units to boil the fracture fluid and produce fresh distilled water. The distilled water can then be used to frac another gas well, conserving and extending the life of the water resource.[17] Developing new re-use technologies will reduce the amount of wastewater that must be disposed of, generally through deep well injection.

Local citizens and groundwater conservation districts have raised concerns about the use of groundwater for fracing. As noted earlier, Section 36.117, Water Code, states that water wells drilled for the purpose of gas drilling or exploration are exempt from the permitting requirements of groundwater conservation districts.[18] There is some discussion regarding whether or not the exemption applies strictly to drilling and exploration and how fracing fits into that definition. Fracing did not exist at the time the exemption was created.

In addition, there are concerns about the ability of groundwater conservation districts to plan for future water needs. During the 79th Legislature, House Bill 1763 by Cook/Duncan established a process for groundwater conservation districts to work together in setting the desired conditions for local aquifers. Because Section 36.117 exempts water wells used for oil and gas exploration from the permitting requirements of groundwater conservation districts, the local district may not know the volume of water being pumped.[19] Without this information, it is difficult for the groundwater conservation districts to project current and future available resources, plan for future water needs and balance annual water budgets.[20]

Many Texans are also concerned about the spacing of water wells used to withdraw groundwater for oil and gas purposes and the impact of those wells on surrounding domestic water wells. If water wells are spaced too closely, the ability of those wells to yield water can be negatively impacted to the point that the wells go dry.

When an oil and gas company no longer needs a water well to supply water for an oil and gas operation, the company can turn the water well over to the surface land owner for his/her personal use. In most districts, the land owner must apply for a permit from the groundwater conservation district to continue using the water well. As long as the water well meets the spacing requirements of the groundwater conservation district, the land owner receives access to a water well at minimal cost. However, if the water well does not meet the spacing requirements of the district, the land owner must pay for plugging and capping the water well.[21]

CONCLUSIONS

Technological advances, such as fracing, that allow access to natural gas in the Barnett Shale have been very beneficial for oil and gas companies in Texas and the State's economy. However, fracing is a water intensive process and additional advances must be developed that allow continued access to the natural gas in the Barnett Shale while protecting the State's water resources.

RECOMMENDATIONS

1. Require oil and gas companies who own water wells exempt under Section 36.117(b), Water Code, to report the amount of water extracted to the local groundwater conservation district.

2. Consider requiring water wells drilled for oil and gas purposes to abide, when feasible, by the spacing requirements of the local groundwater conservation district.

3. Provide an incentive for oil and gas companies to re-use/recycle their water supply.

4. In cases where a water well exempt under Section 36.117(b), Water Code, does not meet the spacing requirements of the local groundwater conservation district -- and thus is not eligible for ordinary use by the landowner after the exemption has ceased -- require the oil and gas company responsible for the water well to plug it.

[1] V.T.A.C., Water Code, § 36.117.
[2] V.T.A.C., Water Code, § 36.117(b)(2).
[3] Adam Haynes, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[4] Adam Haynes, Ben Sebree, and Bill Stevens, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[5] V.T.A.C., Water Code, § 27.0511.
[6] Railroad Commission of Texas, "Water Use in Association with Oil and Gas Activities Regulated by the Railroad Commission of Texas," www.rrc.state.tx.us.
[7] Id.
[8] Charles Ross, Testimony before the Senate Committee on Natural Resources, June 28, 2006, Austin, Texas.
[9] Railroad Commission of Texas, "Water Use in the Barnett Shale," www.rrc.state.tx.us.
[10] Id.
[11] Id at 8.
[12] Id at 9.
[13] Id.
[14] Staci Fowler, Railroad Commission of Texas, Personal Communication, December 8, 2006.
[15] Id at 9.
[16] Id.
[17] Id.
[18] Id at 2.
[19] Id.
[20] Joe B. Cooper, Testimony before the Senate Committee on Natural Resources, June 28,2006, Austin, Texas.
[21] Id.

Appendix A

The following summary of the Texas Risk Reduction Program was provided by TCEQ staff on October 31, 2006, in response to an informal inquiry by Senate Natural Resources Committee staff for the purpose of inclusion in the Charge 3 interim report:

Texas Risk Reduction Program

The TCEQ TRRP is based on the use of risk-based corrective actions to address environmental contamination. This ensures protection of human health and the environment while making response actions more economically feasible. Prior to the adoption of risk-based cleanup rules, the commission's industrial and hazardous waste programs required all contaminated sites to be restored to background levels or to be closed as a landfill with post-closure care and monitoring requirements imposed on the operator. With the promulgation of the Risk Reduction Rules (Chapter 335) and PST rules (Chapter 334), the agency recognized, however, that in some circumstances, a limited quantity of a contaminant could remain within an environmental medium and not present an unacceptable risk to human health or the environment.

TRRP offers property owners and operators flexibility in determining an appropriate cleanup level based on trade-offs of cost, long-term liability and site specific characteristics. An operator who wants to clean up a site and walk away with no future liability will be required to clean up the site to Remedy Standard A, that is to health-protective concentrations of whatever contaminant is of concern. An operator can select Remedy Standard B if he is prepared to accept some long term liability for maintenance of engineered controls or limitations on land use and may find these costs to be significantly less than the cost of a total cleanup. These engineered controls could be the construction of an on-site, capped landfill or installation of an underground impermeable barrier to restrict movement of contaminants. Institutional controls could include deed recordation and limitations on future land use (industrial vs. residential for example).

In addition to the two remedy standards, "A" (clean) vs. "B" (controls), an operator can also use a tiered approach to determine an appropriate cleanup level. Essentially, an operator has the opportunity to demonstrate that a site-specific standard will still be protective, if he is willing to invest in the analysis to prove that point. This process establishes a clear, scientifically-defensible methodology for developing protective concentration levels while providing persons with the flexibility to balance cost considerations for their sites. As one moves through the tiers, assessment costs increase due to increased analysis and data needs. However, the result of the increased analysis may be a reduction in the size of area to be cleaned up, or a higher cleanup level due to site-specific factors, either of which in turn, could result in an even more significant reduction in overall project costs for remediation.

Also, just FYI, we are working on some revisions to the rule, which was last updated in 1999, to correct some inconsistencies, update some provisions, and bring the rule into line with current practices.

Appendix B

The following questions were submitted to the Railroad Commission staff by Senate Natural Resources staff regarding the Texas Groundwater Protection Committee's 2005 Joint Groundwater Contamination Report for the purpose of inclusion in the Charge 3 interim report. The Railroad Commission's responses were submitted on November 2, 2006, and follow each question:

November 2, 2006

On pages 66 and 67 of the report:

1. Pg 66, paragraph that begins with "Statewide Rule 8 Water Protection Program Description", there is a statement that "The RCT also responds to citizen complaints regarding alleged groundwater contamination or alleged unauthorized activities that may endanger groundwater. RCT may include investigation and sampling by the appropriate district office."

Questions:

Q: What is a "response" by the RCT composed of?

A: This depends on the nature of the problem. At a minimum, there is generally a meeting with the complainant to discuss the water well problem, get a preliminary sample from the well, and inspect the area for possible oil field related sources of contamination.

Does the RCT respond to ALL citizen complaints?

A: Yes, if complaint involves matters under RRC jurisdiction.

Q: If not, which are responded to and which are not?

A: All jurisdictional issues such as complaints about spills, pollution, or abandoned wells will trigger a field inspection/response. Examples of non-jurisdictional issues would be noise, traffic, road damae, non-payment of royalties, etc.

Q: The RCT "may include investigation and sampling", what are the deciding factors that trigger such actions.

A: This will occur if it is reasonable to conclude that the problem could be oilfield related based on the information provided by the complainant, such as location/proximity to oil and gas operations, and the description of the water problem.

2. In the first full paragraph on page 67 of the same report, it reads, "If groundwater contamination occurs at a site, the responsible party is required to remediate to acceptable levels. Responsible parties may volunteer remedial action or cleanup may be required by legal action (Operator Cleanup Program). Operators, developers, or individuals who are not responsible for the contamination may participate in the Voluntary Cleanup Program."

Questions:

Q: If the responsible parties volunteer remedial action, is this action checked on after it is completed to ensure it was adequate?

A: Yes. In the typical groundwater contamination case, the RRC is involved and conducting oversight of the cleanup from the initial discovery of the contamination through final cleanup. Only after cleanup or control is axkieved is a "no further action" letter issued. Risk-based closures where come contamination is left in place usually require institutional and/or engineering controls.

Q: If so, who checks on it and how do they go about it (groundwater sampling, etc.)?

A: Boreholes and monitor wells are installed; samples are retrieved and analyzed by qualified laboratories. The responsible party submits reports to RRC describing the progress of remediation. All reports that include analytical results must also include laboratory quality assurance/quality control data (QA/QC) to verify qccuracy. RRC personnel review the data to check the results and the quality.

Q: What is the incentive for someone not responsible for contamination to participate in the Voluntary Cleanup Program?

A: Indirect incentives often discussed by VCP stakeholders include:

- **Removal of perceived liability**
- **Insulation from 3rd party lawsuits**
- **Restoration of land values**
- **RRC certification of cleanup**
- **Schedule is proposed by VCP applicant**

Q: Are the actions of those who participate in the VCP checked afterwards and how are they checked?

A: Yes. The technical cleanup standards to achieve and how those standards are investigated and verified are the same for VCP sites as they are for any other groundwater contamination case. As mentioned above, boreholes and monitor wells are installed; samples are retrieved and analyzed by qualified

laboratories. The VCP Applicant submits reports to RRC describing the progress of remediation. All reports that include analytical results must also include laboratory quality assurance/quality control data (QA/QC) to verify accuracy. RRC personnel review the data to check the results and the quality.

3. On page 67, in the paragraph beginning with "Status of Groundwater Contamination", it reads, "There are 337 groundwater contamination cases, listed by county, in table 2 under the reading, RCT. The 337 cases are located in 110 counties. There are 108 new cases under RCT regulation that have been added to the report in 2005. Activities were completed on ten cases that are listed on the 2005 report. A total of 12 cases were removed."

Questions:

Q. What is the methodology by which the RCT choosed which cases are given priority over others, or in other words, if looking at any two given contamination cases side by side, how is it decided which is the more urgent of the two?

A: The most urgent contamination cases are those where human exposure may be occurring or threatening. Other factors to be considered when assigning priority are exposure of the contamination to other environmental receptors such as surface water bodies, proximity of the contamination to other receptors (e.g. distance to wells or surface water bodies, etc.), toxicity of the contaminant, or the known stability of a plume.

Q: What does "activities were completed" mean in this context?

A: Remediation has been completed and no further action is necessary.

Q: What does "removed" mean in this context?

A: When cleanup has occurred, and no further action is necessary, a site is listed with this status (activity status (e.g. 6a, 6b, 6c, etc.) and remains in the Annual Joint Groundwater Contamination Report for the year of publication. It is then removed from the report the following year.

Appendix C

<u>The following questions were submitted to the Railroad Commission staff by Senate Natural Resources staff regarding the Texas Groundwater Protection Committee's 2005 Joint Groundwater Contamination Report for the purpose of inclusion in the Charge 3 interim report. The Railroad Commission's responses were submitted on December 8, 2006, and follow each question:</u>

1. Can you briefly give an estimate of the average cost of a site remediation?

Answer: We do not track costs to operators for cleanup of a site, and operators are required to conduct the cleanup, regardless of the cost. However, based on costs incurred for state managed cleanups and experience with RRC ordered cleanups, we can estimate that possible cleanup costs could range from $30,000 to over $6 million. In this context, "cleanup" refers to the investigation of groundwater contamination and completion of a remedy that could include control of contaminated groundwater and/or provision of an alternate water supply.

2. Does this cost impact:

the speed of cleanup?

Answer: No. Cost is not a consideration the RRC takes into account when providing oversight of an operator cleaning up of a groundwater contamination site.

the prioritization of cases?

Answer: No. All groundwater contamination cases are high priority regardless of costs to cleanup. The most urgent contamination cases are those where human exposure may be occurring or is threatened, as indicated by proximity to receptors or possible plume growth.

the time allowed to clean a site?

Answer: No. Costs are not a consideration the RRC takes into account when timelines are submitted by operators to complete cleanup of groundwater contamination sites. Time to cleanup a site is generally a function of complexity of the groundwater contamination plume, the aquifer characteristics, and the chosen remedy.

3. How does the RRC decide how long someone has to cleanup a site, is there a formula or process you use to determine what is reasonable?

Answer: RRC staff typically requests that the operator determine a timeline with regular reports of progress of the cleanup. If the remedy and timeline are protective of current and potential future receptors (e.g., humans who drink the water, or springs where groundwater may discharge), then RRC staff will accept the remedy. In some cases, however, the RRC issues an order that dictates a timeline for completion of the remedy. In this case, the timeline would be performance based (i.e., based on expected performance of the selected remediation technology).

4. Who is responsible for incurring the cost of these cleanups?

Answer: The RRC holds the responsible person, typically the operator, who caused the pollution is responsible for the costs.

Appendix
D

Onshore LNG Supply Terminal Projects Proposed for Texas
6/27/2006
(subject to change)

Proposed Terminal	Terminal Location	Send out Capacity	Proposed Markets	Project Status
1. Freeport LNG Development, L.P. (ConocoPhillips; Cheniere)	Freeport, TX	1.5 Bcf/d Proposed expansion would increase send out capacity to 4.0 Bcf/d	Terminal to serve intrastate market	FERC issued authorization June 2004. Expansion permit pending. In Construction. Target in-service goal: 2007 Winter heating season
2. Corpus Christi LNG, L.P. (Cheniere)	Corpus Christi, TX	2.6 Bcf/d	Terminal to serve both interstate and intrastate markets	FERC issued authorization April 2005. Target in-service goal: 2008.
3. Vista del Sol LNG Terminal, L.P. (ExxonMobil)	San Patricio Co., TX (near Corpus Christi)	1.0 Bcf/d	Terminal to serve both interstate and intrastate markets	FERC issued authorization June 2005. In Construction Target in-service goal: 2nd qtr 2008
4. Golden Pass LNG Terminal LP (ExxonMobil)	Sabine Pass, TX (near Port Arthur)	I: 1.0 Bcf/d II: 2.0 Bcf/d	Terminal to serve both interstate and intrastate markets	FERC issued authorization July 2005. In Construction. Target in-service goal: 2nd qtr 2008
5. Port Arthur LNG Terminal and Pipeline Project (Sempra Energy)	Port Arthur, TX	I: 1.5 Bcf/d II: 3.0 Bcf/d	Terminal to serve both interstate and intrastate market	FERC issued authorization June 2006. Target in-service goal: 2009

Onshore LNG Supply Terminal Projects Proposed for Texas
6/27/2006
(subject to change)

Proposed Terminal	Terminal Location	Send out Capacity	Proposed Markets	Project Status
6. Ingleside Energy Center LLC (Occidental Energy)	San Patricio Co., TX (near Corpus Christi)	1.0 Bcf/d	Terminal to serve both interstate and intrastate markets	FERC issued authorization July 2005. Target in-service goal: 2008
7. Calhoun LNG (Gulf Coast LNG Partners, L.P.)	Calhoun County, TX (near Port Comfort)	1.0 Bcf/d	Terminal to serve intrastate market	Application to construct pending at FERC. Target in-service goal: 2009
8. Bay Crossing (BP)	Pelican Island, TX (near Galveston)	1.2 Bcf/d		Announced.
Proposed Non-Texas Facility To Impact Texas Markets				
9. Sabine Pass LA LNG and Pipeline Project (Cheniere Energy, Inc.)	Sabine, LA	4.0 Bcf/d	Terminal to serve both interstate and intrastate markets	FERC issued initial authorization December 2004. Expansion Authorization issued June 2006. In Construction. Target in-service goal: Winter 2007/2008

Appendix
E

RRC Natural Gas Competition Study

The Railroad Commission shall conduct a study that:

1. ***Examines and determines the extent to which viable competition exists in the Texas natural gas pipeline industry from the wellhead to the burner tip;***
2. ***Recommends solutions to bring market competition to any non-competitive segments of the industry; and***
3. ***Assesses the effectiveness of current laws, regulations, enforcement and oversight in addressing any abuses of pipeline monopoly power and makes recommendations for any necessary changes.***

PHASE 1: Background analysis (October 1, 2005 through November 30, 2005)

- Review past gas gathering surveys, including, but not limited to, industry and Railroad Commission surveys.
  1. Identify the level of competition that exists by region.
  2. Compile prioritized list of the key issues/complaints identified in the survey results.
  3. Summarize current jurisdiction of the Railroad Commission regarding gas gathering.
- Review the open-access process implemented by the FERC in the 1990s.
- Compare the FERC open-access process and tariff data requirements to those of the RRC.
- Review of complaints – informal & formal filed with the RRC.
- Review of testimony filed in 79th Legislative session regarding gas gathering legislation.
- Gather production and pricing data by RRC district or county from RRC and Comptroller data sources.

PHASE 2: Encourage affected parties to use the formal and informal complaint processes and workshop input to establish facts from which to

define issues and to make recommendations. (October 1, 2005 through March 31, 2006)

- Use the legislative study mandate as an impetus for all affected parties to provide the factual data needed to identify issues.
- Schedule workshops to include all RRC Districts.
  1. Establish a dialogue between the RRC and entities representing all sectors of the natural gas industry.
  2. Explain the study.
  3. Encourage affected parties to use the informal complaint process.
  4. Gather factual data and request input regarding possible solutions.
  5. Commissioner participation as schedules allow.
  6. Workshop locations:
     - San Antonio (RRC Districts 1, 2, & 4)
     - Houston (RRC Districts 3 & 6)
     - Dallas (RRC Districts 5 & 9)
     - Abilene (RRC Districts 7B & 7C)
     - Midland (RRC Districts 8 & 8A)
     - Amarillo (RRC District 10)
- Send a letter to all affected associations asking them to encourage their members to attend one of the scheduled workshops and to advise their members to use the informal and formal complaint processes to establish a base of facts, to develop data to identify issues, and to recommend policy.
- Advise all operators through the strip-out notice of the workshops and that we need factual cases to help formulate policy.
- Make the complaint process easier to find on the website by adding a link on the home page.
- Expedite informal and formal complaints and gather data for use in the study.

- When sufficient data have been gathered and analyzed, develop policy options and/or questions to address identified issues.

PHASE 3: Develop solutions/recommendations. (April through June 2006)

- Establish a "Blue Ribbon" panel.
  1. Panel will consist of nine members.
  2. Each RRC Commissioner will nominate three (3) members, and the RRC Chairman will select the Chair with concurrence by the other two Commissioners.
- Specific policy questions would be posed to the panel requesting that they develop proposals to address each of the posed questions.
- Commissioners evaluate panel recommendations and develop draft policy.
- Staff prepares "draft" report, based on Commissioner's decisions

PHASE 4: Report publication/comments. (July through September 2006)

- "Draft" report will be posted in Texas Register and RRC website, with a reasonable time allotted for public comments.
- Comments will be reviewed and Commissioners will make decisions on comments

PHASE 5: Final Report. (October, 2006)

- Staff will prepare the Final Report including specific action items and recommendations.
- Present Final Report for approval at a future RRC conference to provide for submission no later than November 1, 2006.
- When approved, provide copies to the Governor's office, Lieutenant Governor's office, Speaker's office, and the Legislative Budget Board.
- Post approved Final Report on RRC website.

Appendix
F

REPORT OF THE
NATURAL GAS PIPELINE COMPETITION STUDY
ADVISORY COMMITTEE
TO THE
RAILROAD COMMISSION OF TEXAS

July 1, 2006

NATURAL GAS PIPELINE COMPETITION STUDY ADVISORY COMMITTEE MEMBERS

Mary Ann Pearce, Chairman
ConocoPhillips Company

Jon S. Brumley
Encore Acquisition Company

W.H. (Bill) Easter, III
Duke Energy Field Services

Richard A. Erskine
Atmos Energy – Mid-Tex Division

Stephen A. Holditch, P.E.
Texas A&M University

Steve Howell
Howell Oil & Gas, Inc.

Mackie McCrea
Energy Transfer Company

Lee Parsley
E. Lee Parsley, P.C.

William Warnick
Texas General Land Office

EXECUTIVE SUMMARY

Background

The Texas Legislature, by inclusion of a rider to the 2006-2007 appropriations bill, required the Railroad Commission of Texas to "conduct a study that examines and determines the extent to which viable competition exists in the Texas natural gas pipeline industry from wellhead to burner tip. The study shall recommend solutions to bring market competition to any non-competitive segments of the industry. The study also shall include an assessment of the effectiveness of current laws, regulations, enforcement and oversight in addressing abuses of pipeline monopoly power and made recommendations for changes that may be necessary. In addition, the study shall include a comparative review of competition in the Texas interstate pipeline industry administered by the Federal Energy Regulatory Commission. The Railroad Commission shall submit a report of its findings to the Legislative Budget Board and the Governor on or before November 1, 2006."

By rule effective April 3, 2006, the Commission established the Natural Gas Pipeline Competition Study Advisory Committee. *See* 31 Tex. Reg. 2850; 16 TEX. ADMIN. CODE § 7.7201. "The purpose of the committee is to give the Commission the benefit of the members' collective business, technical, and operating expertise and experience to help the Commission review competition in the Texas intrastate pipeline industry, assess the effect of current statutes and rules on such competition, and develop recommendations for changes to statutes or rules that may be necessary." The Committee was required to report its advice and recommendations in writing to the Commission no later than July 1, 2006.

The Committee's Charge

The Commission announced the appointment of the Natural Gas Pipeline Competition Study Advisory Committee on April 11, 2006, and charged the Committee with evaluating:

- Whether further improvements to the Commission's informal complaint process are warranted.
- Whether additional transparency is needed in the natural gas pipeline industry.
- What transporters should be affected by any change in policy or law.
- Whether to give special treatment to marginal wells.

- Whether the Commission should exercise oversight regarding the types and categories of fees charged related to gas gathering and transportation.
- Whether other states methods for addressing discrimination relative to gas gathering and transportation should be adopted in Texas.

The Committee met ten times between May 1st and June 30th, 2006. This report is the result of the Committee's work and is intended to address the six issues presented to the Committee by the Commission.

Recommendations to the Commission

The Committee makes the following recommendations.

Informal Complaint Procedure

In regard to the informal complaint process the Committee recommends—

- That the Commission's proposed enhancements to the informal complaint procedure be adopted and further strengthened by the modifications proposed by the Committee.
- That the rule codifying the informal complaint procedure provides that the informal complaint process applies to *all* complaints about natural gas purchasing, selling, shipping, transportation, and gathering.
- That the informal complaint procedure allows the parties to agree to employ and pay an independent mediator rather than being required to use Commission staff.
- That the Commission publicize the informal complaint process in a manner it believes will be effective to reach a majority of natural gas producers, and inform and encourage producers to use, and encourage pipelines, gatherers, and industry trade associations to promote, the informal complaint process as an available, low-cost mechanism for resolving complaints regarding the transportation, treatment, and sale of natural gas.
- That the Commission include a clear policy statement in the informal complaint procedure rule to assure all natural gas purchasers, sellers, shippers, transporters and gatherers that the Commission is committed to a process that is fair, timely, and affordable.
- That the Commission's proposed rule, which prohibits retaliation by gathers and transporters, be adjusted slightly to:
    - o Remove the requirement that the mediator decide in advance whether service can be discontinued or denied because the

requirement may cause unwarranted delay when safety or other immediate concerns are present; and
    - Amend the provision allowing a gatherer or transporter to discontinue or deny service for out-of-specification gas in cases in which the gatherer or transporter is accepting such gas from other shippers in the area.
- That the Legislature give the Commission specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in the informal complaint process, and to punish purchasers, transporters, and gatherers for retaliating against shippers and sellers.

The Committee has included with this report a draft informal complaint procedure rule that incorporates its recommendations.

Transparency

In regard to Transparency, the Committee recommends—

- That the informal complaint procedure rule require mandatory participation and full access to contract information and any other materials requested by the mediator in accordance with Commission rules after an informal complaint is filed, which provides transparency in specific cases in which a party believes it has been treated in a discriminatory manner.
- That the Commission educate industry participants, and encourage industry trade associations to educate their members, about the amount of information already available through the Commission's website, through tariff filings with the Commission, and through the Comptroller of Public Accounts.
- That the Legislature provide by statute that producers have the option of not having a confidentiality provision in future sales, gathering, and transportation contracts.

Marginal Wells

In regard to marginal wells, the Committee recommends—

- That the Commission educates market participants, including royalty owners, of the benefits of commingling gas, as is allowed by Statewide Rule 26(b), to extend the economic viability of marginal wells.

- That the Legislature extend indefinitely the severance tax abatement applicable to marginal wells currently codified in Texas Tax Code § 201.059.
- That the Legislature continue in effect indefinitely the franchise tax abatement applicable to natural gas wells producing less than 250 Mcf per day that was included in H.B. 3 adopted by the 79th Legislature in its Third Called Session.

Gathering and Transportation Fees

- That the Legislature give the Commission the ability to use either a cost-of-service method or a market-based method (using the Oklahoma statute as a model) for setting a rate for natural gas gathering and/or transmission in a formal rate proceeding.

Appendix G

RAILROAD COMMISSION OF TEXAS

October 30, 2006

ELIZABETH A. JONES, *CHAIRMAN*
MICHAEL L. WILLIAMS, *COMMISSIONER*
VICTOR G. CARRILLO, *COMMISSIONER*

To the Honorable Governor and Legislative Budget Board:

We hereby submit our Natural Gas Pipeline Competition Study Advisory Committee report pursuant to the Legislature's rider to the 2006-2007 appropriations bill. As detailed in the report's executive summary, the rider directs the Commission to conduct a study that examines and determines the extent to which viable competition exists in the Texas natural gas pipeline industry.

Pursuant to the Legislature's charge, the Commission developed a multi-phase plan for accomplishing the directives of the study:

- From October through November 2005, the Commission performed initial background analyses which included: a review of past Commission efforts pertaining to pipeline competition; a review of the Federal Energy Regulatory Commission's (FERC) open access process and how it compares with the Commission's tariff information requirements; a review of Commission complaints concerning competition issues; a review of 79th Legislative session gas gathering legislation; and the compilation of gatherer market concentration data.
- From November 2005 through January 2006, the Commission conducted seven workshops in Amarillo, San Antonio, Midland, Abilene, Houston, Dallas, and Kilgore to receive feedback from all interested parties regarding pipeline competition issues. A summary of comments presented at the workshops can be found on the RRC website at http://www.rrc.state.tx.us/divisions/gs/naturalgasstudy/index.html.
- In April 2006, the Commission established an Advisory Committee, comprised of representatives from all segments in the natural gas industry. The Committee was charged to address the following issues that were identified in the workshops: enhancements to the Commission's informal complaint resolution process; ways to improve information transparency and comparability to better foster viable market competition; solutions for extending the life of marginal gas well production; and alternatives for setting gathering and transportation fees.
- In July 2006, the Advisory Committee submitted its report to the Commission. The Commission posted the report on its website and submitted it to the Texas Register to receive comments from interested parties.

Texas plays a leading role in the production of domestic oil and gas. The stability of supply, for the benefit of consumers and for the security of our country, is important to this Commission. We look forward to entertaining additional solutions to any problems that might be impeding the efficiency of Texas's energy industry, and we are willing to work with the Legislative branch, whenever necessary, to effect positive change for the benefit of the State.

Thank you for your consideration of this report and allowing us the opportunity to better serve the various segments of the energy industry in Texas.

Elizabeth A. Jones Chairman	Michael L. Williams Commissioner	Victor G. Carrillo Commissioner

1701 NORTH CONGRESS AVENUE ★ POST OFFICE BOX 12967 ★ AUSTIN, TEXAS 78711-2967 ★ PHONE 512/463-7158 FAX 512/463-7161

TDD 800-735-2989 OR 512-463-7284 AN EQUAL OPPORTUNITY EMPLOYER

NATURAL GAS PIPELINE COMPETITION STUDY

ADVISORY COMMITTEE

Mary Ann Pearce
Manager, Commercial Activities
US Lower 48

ConocoPhillips Company
P.O. Box 2197, 3WL-5092
Houston, TX 77252
Phone 832-486-2615

ConocoPhillips

June 30,2006

Elizabeth A. Jones
Michael L. Williams
Victor G. Carrillo
Railroad Commission of Texas
1701 North Congress Avenue
Austin, TX 78711

Dear Chairman Jones and Commissioners Williams and Carrillo:

By Rule §7.7201 dated April 3, 2006, the Railroad Commission of Texas (the Commission) established the Natural Gas Pipeline Competition Study Advisory Committee (the Committee) to "give the Commission the members' collective business, technical, and operating expertise and experience to help the Commission review competition in the Texas intrastate pipeline industry, assess the effect of current statutes and rules on such competition, and develop recommendations for changes to statutes or rules that may be necessary". The Committee's written report is due to the Commission by July 1, 2006.

The members of the Committee, Jon S. Brumley, William Easter, Richard Erskine, Stephen Holditch, Steve Howell, Mackie McCrea, Lee Parsley, Mary Ann Pearce and William Warnick, are pleased to submit our report to the Commission for further use as it may deem appropriate.

The members brought diverse personal expertise as lawyers, engineers, operators, educators, and executives; as well as, broad natural gas business experience in producing, gathering, transmission, processing, purchasing and selling. All members dedicated significant time and energy to the committee and engaged in rich debate of the issues. This report, the product of that debate, addresses all the questions provided in the charge and is the work product of all the members. The members developed a shared understanding of the complicated issues and made compromises to their individual opinions. Where the members did not reach total alignment, the report describes the agreed components, as well as, the divergent opinions of the individual members. The members do recommend that a strong and actively administered Informal Complaint Process is a necessary next step. Further, we believe, if implemented, our recommendations will benefit the natural gas portion of the Texas energy sector.

The Committee wishes to acknowledge Lee Parsley for his excellent work in drafting the report and the Railroad Commission staff, Ron Kitchens, Steve Pitner and Danny Bivens, for their professional assistance through out our deliberations.

The members thank the Commissioners for the opportunity to be involved in such an important and challenging effort and to work with such experienced and capable colleagues. The members are committed to support our recommendations and will be happy to meet with the Commissioners individually or as a group to answer any questions and provide any other assistance the Commission may require.

Respectfully submitted,

Mary Ann Pearce
Chairman, for the Natural Gas Pipeline
Competition Study Advisory Committee

REPORT OF THE NATURAL GAS PIPELINE COMPETITION STUDY ADVISORY COMMITTEE TO THE RAILROAD COMMISSION OF TEXAS

July 1, 2006

NATURAL GAS PIPELINE COMPETITION STUDY ADVISORY COMMITTEE MEMBERS

Mary Ann Pearce, Chairman
ConocoPhillips Company

Jon S. Brumley
Encore Acquisition Company

W.H. (Bill) Easter, III
Duke Energy Field Services

Richard A. Erskine
Atmos Energy – Mid-Tex Division

Stephen A. Holditch, P.E.
Texas A&M University

Steve Howell
Howell Oil & Gas, Inc.

Mackie McCrea
Energy Transfer Company

Lee Parsley
E. Lee Parsley, P.C.

William Warnick
Texas General Land Office

CONTENTS

EXECUTIVE SUMMARY

Background

The Texas Legislature, by inclusion of a rider to the 2006-2007 appropriations bill, required the Railroad Commission of Texas to "conduct a study that examines and determines the extent to which viable competition exists in the Texas natural gas pipeline industry from wellhead to burner tip. The study shall recommend solutions to bring market competition to any non-competitive segments of the industry. The study also shall include an assessment of the effectiveness of current laws, regulations, enforcement and oversight in addressing abuses of pipeline monopoly power and made recommendations for changes that may be necessary. In addition, the study shall include a comparative review of competition in the Texas interstate pipeline industry administered by the Federal Energy Regulatory Commission. The Railroad Commission shall submit a report of its findings to the Legislative Budget Board and the Governor on or before November 1, 2006."

By rule effective April 3, 2006, the Commission established the Natural Gas Pipeline Competition Study Advisory Committee. *See* 31 Tex. Reg. 2850; 16 TEX. ADMIN. CODE § 7.7201. "The purpose of the committee is to give the Commission the benefit of the members' collective business, technical, and operating expertise and experience to help the Commission review competition in the Texas intrastate pipeline industry, assess the effect of current statutes and rules on such competition, and develop recommendations for changes to statutes or rules that may be necessary." The Committee was required to report its advice and recommendations in writing to the Commission no later than July 1, 2006.

The Committee's Charge

The Commission announced the appointment of the Natural Gas Pipeline Competition Study Advisory Committee on April 11, 2006, and charged the Committee with evaluating:

- Whether further improvements to the Commission's informal complaint process are warranted.
- Whether additional transparency is needed in the natural gas pipeline industry.
- What transporters should be affected by any change in policy or law.
- Whether to give special treatment to marginal wells.

- Whether the Commission should exercise oversight regarding the types and categories of fees charged related to gas gathering and transportation.
- Whether other states methods for addressing discrimination relative to gas gathering and transportation should be adopted in Texas.

The Committee met ten times between May 1st and June 30th, 2006. This report is the result of the Committee's work and is intended to address the six issues presented to the Committee by the Commission.

Recommendations to the Commission

The Committee makes the following recommendations.

Informal Complaint Procedure

In regard to the informal complaint process the Committee recommends—

- That the Commission's proposed enhancements to the informal complaint procedure be adopted and further strengthened by the modifications proposed by the Committee.
- That the rule codifying the informal complaint procedure provides that the informal complaint process applies to *all* complaints about natural gas purchasing, selling, shipping, transportation, and gathering.
- That the informal complaint procedure allows the parties to agree to employ and pay an independent mediator rather than being required to use Commission staff.
- That the Commission publicize the informal complaint process in a manner it believes will be effective to reach a majority of natural gas producers, and inform and encourage producers to use, and encourage pipelines, gatherers, and industry trade associations to promote, the informal complaint process as an available, low-cost mechanism for resolving complaints regarding the transportation, treatment, and sale of natural gas.
- That the Commission include a clear policy statement in the informal complaint procedure rule to assure all natural gas purchasers, sellers, shippers, transporters and gatherers that the Commission is committed to a process that is fair, timely, and affordable.
- That the Commission's proposed rule, which prohibits retaliation by gathers and transporters, be adjusted slightly to:
    - Remove the requirement that the mediator decide in advance whether service can be discontinued or denied because the

requirement may cause unwarranted delay when safety or other immediate concerns are present; and

  - Amend the provision allowing a gatherer or transporter to discontinue or deny service for out-of-specification gas in cases in which the gatherer or transporter is accepting such gas from other shippers in the area.

- That the Legislature give the Commission specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in the informal complaint process, and to punish purchasers, transporters, and gatherers for retaliating against shippers and sellers.

The Committee has included with this report a draft informal complaint procedure rule that incorporates its recommendations.

Transparency

In regard to Transparency, the Committee recommends—

- That the informal complaint procedure rule require mandatory participation and full access to contract information and any other materials requested by the mediator in accordance with Commission rules after an informal complaint is filed, which provides transparency in specific cases in which a party believes it has been treated in a discriminatory manner.
- That the Commission educate industry participants, and encourage industry trade associations to educate their members, about the amount of information already available through the Commission's website, through tariff filings with the Commission, and through the Comptroller of Public Accounts.
- That the Legislature provide by statute that producers have the option of not having a confidentiality provision in future sales, gathering, and transportation contracts.

Marginal Wells

In regard to marginal wells, the Committee recommends—

- That the Commission educates market participants, including royalty owners, of the benefits of commingling gas, as is allowed by Statewide Rule 26(b), to extend the economic viability of marginal wells.

- That the Legislature extend indefinitely the severance tax abatement applicable to marginal wells currently codified in Texas Tax Code § 201.059.
- That the Legislature continue in effect indefinitely the franchise tax abatement applicable to natural gas wells producing less than 250 Mcf per day that was included in H.B. 3 adopted by the 79th Legislature in its Third Called Session.

Gathering and Transportation Fees

- That the Legislature give the Commission the ability to use either a cost-of-service method or a market-based method (using the Oklahoma statute as a model) for setting a rate for natural gas gathering and/or transmission in a formal rate proceeding.

INFORMAL COMPLAINT PROCESS

The Commission's Charge

The Commission's charge to the Committee notes that the Commission has already initiated improving the existing informal complaint process, but asks if the Committee suggests any additional improvements. The Committee agrees that the Commission's proposed changes are appropriate and that other improvements to the informal complaint process should be made. The additional changes recommended by the Committee are outlined in more detail below.

Background

The Commission has in place an informal process using Commission staff to mediate disputes regarding the gathering and transportation of natural gas (called the "informal complaint process"). There, however, is no formal rule or statute codifying the process.

From November 2005 through January 2006, the Commission held workshops in seven Texas cities to take public comment on natural gas gathering- and transportation-related issues. Commission staff then aggregated the comments and compiled the following list of issues raised at the workshops about the informal complaint process (which are not presented verbatim).

1. Some producers testified that the informal complaint process is costly, time-consuming, and ineffective; that the Commission takes no action on enforcement measures; and that the Commission favors pipelines over producers.
2. Some producers complained that the Commission does not get involved in pricing disputes.
3. Several producers who testified at the workshops were not aware of the informal complaint process.
4. A number of producers indicated that they were afraid of retaliation or retribution by gatherers and transporters if they pursued an informal complaint.
5. Witnesses testifying on behalf of the pipeline companies generally supported the informal complaint process, stating that they believed that a case-by-case approach was the best way to address alleged abuses.
6. Taken together, the witnesses suggested that the informal complaint process could be improved by, among other things—

a. Requiring that participation in the informal complaint process be mandatory;
b. Setting deadlines for the expeditious resolution of disputes through the informal complaint process;
c. Requiring a reasonable amount of discovery in the informal complaint process;
d. Prohibiting retaliation by gatherers if a producer chooses to pursue a complaint through the informal complaint process;
e. Allowing the mediation to take place in the Commission's district offices rather than in Austin only;
f. Allowing reimbursement for costs incurred in the informal complaint process;

Based on the testimony received at the workshops, Commission staff recommended that the informal complaint process be codified as a rule and that the following six changes be made to the current process—

1. Require participation in the informal complaint process.
2. Allow the Commission staff to require the parties to provide needed information at any time during the process.
3. Prohibit retaliation by the gatherer/transporter against the producer for pursuing an informal complaint.
4. Institute specific deadlines for each step in the informal complaint process.
5. Allow the parties to choose to have the mediation conducted in a Commission field office.
6. Require the mediator to send to the parties a confidential memorandum stating the mediator's conclusions, if the mediation fails.

Recommendations

The Committee discussed the informal complaint process in detail. The Committee agreed that the informal complaint process should be codified as a rule and that the Commission's proposed changes are necessary. The Committee agreed that other changes also are necessary. The Committee drafted a revised rule for the Commission's consideration, and that proposed rule is attached to this paper. The proposed rule incorporates the Commission's proposed changes as well as those recommended by the Committee. The Committee's recommended substantive changes are outlined below.

Recommendation 1—Include Everyone

Based on the information garnered at the workshops and the experience of the Committee members, the Committee believes that real or perceived abuses can involve both utilities (as defined by statute) and non-utilities. The Commission is required by statute to prevent discrimination and has authority to address discrimination by all entities, whether a "utility" or not. The Committee therefore recommends that the Rule explicitly provide that the informal complaint process applies to *all* complaints about natural gas purchasing, selling, shipping, transportation, and gathering. This is intended to include wellhead purchasers and producer-owned gathering systems that transport and/or purchase third-party gas.

The Committee recognizes that the Commission does not have the authority to set natural gas purchase prices, and the Committee does not intend that its recommended changes to the informal complaint process be construed as giving the Commission authority to set natural gas prices through any process. Purchasers, however, often perform several functions (such as gathering and purchasing) in the natural gas supply chain, and the Commission has authority to prevent discrimination by any entity in the supply chain. The Committee, therefore, believes it appropriate to include purchasers in the group of market participants who may be compelled to participate in the informal complaint process.

Two parts of the Committee's proposed rule are intended to implement the Committee's recommendation. First, the opening paragraph provides that the informal complaint procedure "applies to any complaint within the Commission's jurisdiction, including, but not limited to, complaints about natural gas purchasing, selling, shipping, transportation, and gathering practices." Second, paragraph (b)(4) then defines "informal complaint proceeding" to mean "[t]he process set out in this section for addressing disputes among entities within the Commission's jurisdiction, including, but not limited to, natural gas purchasers, sellers, shippers, transporters, and gatherers."

Recommendation 2—Allow an Independent Mediator by Agreement

To address some producers' concerns that the Commission favors the pipelines over producers, the Committee believes that the informal complaint-resolution process should allow the parties to agree to employ and pay an independent mediator. If the parties do not agree to use an independent mediator, the informal complaint-resolution process would be conducted using Commission staff as the mediator.

This recommendation is expressed in paragraph (d)(4) of the proposed rule, which provides that a mediator "may be either a Commission employee or a non-Commission employee." If the complainant and respondent desire a mediator who is not a Commission employee, they must submit a written request to the Director of the Gas Services Division by which they must agree to share all costs of mediation. The proposed rule provides for the Commission to provide a "monitor" to act as a technical advisor to the mediator when the mediator is not a Commission employee.

The Commission's monitor, at the direction of the mediator, may participate in the mediation. The proposed rule further provides that a non-Commission-employee mediator be given the same duties and obligations as a Commission-employee mediator, including the authority to compel the parties to provide information to the mediator for use in the mediation.

Recommendation 3—Set-Out the Commission's Policy and Publicize the Process

Testimony from the workshops showed that some producers did not know about the informal complaint process, while others were doubtful of its effectiveness, concerned about perceived bias by the Commission, and worried about the cost of participating in the informal complaint process. The Committee believes these issues should be addressed in two ways. First, the Commission should publicize the informal complaint process in a manner it believes will be effective to reach a majority of natural gas producers. The Commission should endeavor to inform and encourage producers to use the informal complaint process, and encourage pipelines, gatherers, and industry trade associations to promote the informal complaint process, as an available, low-cost mechanism for resolving complaints regarding the transportation, treatment, and sale of natural gas.

Second, the Commission should assure all natural gas purchasers, sellers, shippers, transporters and gatherers that the Commission is committed to a process that is fair, timely, and affordable. This second goal may be achieved in part by including a clear policy statement in the informal complaint procedure rule. The Committee proposes the following policy statement, which is included in the Committee's proposed rule, which is attached.

> (1) It is the policy of the Commission to encourage the resolution and expedient settlement of disputes regarding natural gas purchasers, sellers, transporters and gatherers and to prevent discrimination among similarly situated shippers and sellers as is prohibited by the Texas Natural Resources Code, Chapter 111, entitled "Common Carriers, Public Utilities, and Common Purchasers," and Texas Utilities Code, Title 3, Subtitle A, entitled "Gas Utility Regulatory Act, and Subtitle B, entitled "Regulation Of Transportation and Use," and other matters of dispute subject to the Commission's jurisdiction. This section is adopted in furtherance of that policy.
>
> (2) To accomplish the policy set out in this section, Commission employees, acting pursuant to this section, will attempt to facilitate, encourage, and promote resolution and settlement of disputes among natural gas purchasers, sellers, shippers, transporters, gatherers, and other parties subject to the Commission's jurisdiction consistent with the public interest and without lengthy and potentially expensive formal proceedings. The informal complaint procedure is intended to establish a forum for communication with the goal of achieving mutually acceptable compromise and resolution that is in the public interest.

Recommendation 4—Clarify the Non-Retaliation Provisions

The Committee agrees with the Commission's concept to prohibit gatherers and transporters from retaliating against producers who pursue an informal complaint, but believe the retaliation provision should be broadened to include all parties, as proposed in Recommendation 1 above. In addition, there are two other points the Committee believes need clarification.

The Commission's proposed rule suggested that, once an informal complaint procedure was commenced, a natural gas gatherer or transporter could not discontinue or deny service to a producer unless the mediator determined that one of five listed exceptions applied (such as the insufficient capacity on the transporter's facility, or improper quality of gas, or because of environmental or safety concerns). The Committee was concerned that requiring the mediator to make such a determination before service could be discontinued was unworkable because of the time lag between filing the informal complaint and obtaining the mediator's decision. If, for example, the gas is of improper quality or a safety issue is present, the gatherer or transporter is not in a position to wait for the mediator's decision. Instead, in those circumstances, the gatherer or transporter must take immediate action.

By recommending this change, which is included in the Committee's proposed rule, it is not the Committee's intention to encourage or facilitate retaliatory actions by purchasers, transporters, or gatherers. The Committee's opinion is that the Director of the Gas Services Division should commence an enforcement action—as the Director is allowed to do under paragraph (d)(9)—any time a purchaser, transporter, or gatherer retaliates against a shipper or seller for commencing an informal complaint procedure.

The other point at which the Committee has differed slightly from the Commission's proposed rule has to do with the exception allowing the purchaser/gatherer/transporter to discontinue or deny service if the natural gas does not meet the quality specifications of the purchaser, transporter, gatherer, or downstream processors, pipelines or customers. The Committee feared that the Commission's formulation might allow discrimination. Consequently, the Committee suggests the following proviso, indicated by the underlined text below:

> (7) A transporter or Gas Purchaser shall not discontinue or deny service to a Shipper or Seller during the pendency of an informal complaint resolution proceeding in which both are participants unless one of the following reasons applies for discontinuing service:
>
> * * *

(B) the natural gas does not meet the quality specifications of the gatherer, purchaser or downstream processors, pipelines or customers; unless the natural gas is flowing under an agreement and at the impending termination of that agreement there is sufficient capacity and Transporter is blending out of spec gas for other shippers in the area, and the acceptance of such volumes from Shipper will not jeopardize downstream market deliverability of the gas, then Transporter shall continue to take the gas until the conclusion of the Informal Complaint Process, charging blending fees applicable to similarly situated shippers;

Recommendation 5—Give the Commission Enforcement Power

The Committee believes that the Legislature should give the Commission authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in the informal complaint process, and to punish purchasers, transporters, and gatherers for retaliating against shippers and sellers. Currently, the Commission's authority in regard to these matters is limited. A draft statute giving the Commission the proposed enforcement authority is provided below.

§ ____. ADMINISTRATIVE PENALTY. (a) The commission may impose an administrative penalty against a purchaser, transporter, or gatherer of natural gas who is found by the commission to have:

(1) violated the commission's natural gas standards and code of conduct, as provided in § 7.7001 of Title 16 of the Texas Administrative Code; or

(2) unreasonably discriminated against a seller of natural gas in the purchase of natural gas from such seller; or

(3) retaliated against a shipper or seller of natural gas for the shipper or seller having pursued at the commission a formal or informal complaint against the purchaser, transporter, or gatherer related to the purchaser, transporter, or gatherer's provision of natural gas transportation services or the purchase of natural gas.

(b) The commission may impose an administrative penalty against a purchaser, transporter, gatherer, shipper or seller of natural gas who is a party to an informal complaint resolution proceeding conducted pursuant to § 2.001 (proposed) of Title 16 of the Texas Administrative Code and found by the commission to have:

(1) failed to participate in the informal complaint resolution proceeding; or

(2) failed to provide information requested by a mediator in the informal complaint resolution proceeding.

(c) The penalty for a violation may be in an amount not to exceed $5,000. Each day a violation continues or occurs is a separate violation for purposes of imposing a penalty.

In regard to paragraph (a)(2), the Committee has recommended that the informal complaint process be broadened to include purchasers and sellers. Paragraph (a)(2) is included in this proposed penalty statute to make the administrative penalty provision parallel with the Committee's recommended changes to the informal complaint procedure. The Committee, however, is aware that unreasonable discrimination is not currently defined in the Commission's code of conduct or otherwise. Consequently, the Committee believes that the Commission will be required to define unreasonable discrimination in the purchaser/seller context in order for the Committee's recommendations to be fully effective.

TRANSPARENCY

The Commission's Charge

The Commission's charge to the Committee asks if additional transparency is needed in the Texas natural gas pipeline industry to better foster viable market competition. As part of this question, the Commission asks the Committee to consider:

a. How much transparency is needed? (e.g., full mandatory public disclosure of contractual terms and conditions; mandatory filing of contracts with the Commission with limited public disclosure or with public disclosure upon mutual agreement of the parties; mandatory electronic posting of terms and conditions by shippers on their websites or on the Commission website; etc.)
b. What specific items should be made public and how should they be made public? Should the Commission revise its tariff information rule to require filing of additional information?
c. Are there other market-based solutions that serve to provide the same effect as total transparency?

In response to these questions, the Committee recommends that the informal complaint procedure be strengthened to provide additional transparency in that process, that market participants be educated about the information currently available from the Commission and the Comptroller of Public Accounts, and that the Legislature be asked to prohibit gatherers and transporters from requiring confidentiality in future contracts so that producers may freely share information among themselves.

Background

Transparency and the Code of Conduct

In May 1997, the Commission published a proposed administrative rule "relating to natural gas transportation standards and code of conduct." *See* 22 TEX. REG. 4134 (May 13, 1997). In its preamble to the proposed rule, the Commission explained—

> The commission first began discussing a code of conduct in early 1996 to develop standards by which a gas gatherer or transporter must conduct business relative to any affiliated companies, adding information disclosure as a second step. The August 1996 decision by the D.C. Circuit Court of Appeals in Conoco, Inc. v. FERC, Number 94-1724, provided further impetus regarding the need for a

> rulemaking to govern interstate gathering and transportation of natural gas. The court upheld the Federal Energy Regulatory Commission's disclaimer of jurisdiction over the divested gathering facilities of interstate pipelines, leaving the state regulatory agencies as the institutions charged with protecting against unfair conduct by gatherers. Consequently, this commission has begun, through various methods, to collect relevant information on gas gathering for the purpose of identifying, preventing, and remedying unlawful discrimination. ... The results of these efforts have led the commission to conclude that the potential for discriminatory gathering practices exists, and that a system for timely information disclosure is needed to provide the public and the commission with the information necessary for making clear determinations of undue discrimination or the lack thereof.
>
> An information disclosure system is also fundamental for participants in all segments of the natural gas industry to compete fairly in a market-based environment. Information transparency is necessary for the existence of a competitive environment, and at present, the timely basic information regarding gathering and transportation rates is unavailable, not only to the commission, but also to industry members needing these types of services.

In August 1997, the Commission adopted a rule "concerning natural gas transportation standards and code of conduct, with changes to the proposed text as published in the May 13, 1997, issue of the *Texas Register*." *See* 22 TEX. REG. 8617 (August 29, 1997). At the time it adopted the rule, the Commission explained that "commenters challenged the need for industry-wide information disclosure ... argu[ing] that the mandatory information disclosure provisions in the proposed rule would be unduly costly and would impose a level of regulation that would yield little benefit, if any. Some further contended that the information disclosure provisions would actually result in a non-competitive environment in which transporters would offer fewer options in order to avoid the information disclosure obligation in the proposed rule." Consequently, the Commission determined that the information disclosure requirements in the proposed rule were "not warranted" and "in the adopted rule, the commission has eliminated the information disclosure requirements." The current Code of Conduct does not require information disclosure. *See* 16 TEX. ADMIN. CODE §§ 7.7001, 7.115.

Information Gathered at the Workshops and the Rulemaking Request

Among the complaints raised by participants at the Commission's seven workshops were complaints about contract terms and conditions and transparency. At the conclusion of the meeting, the Commission's staff prepared a summary of the comments received at the workshops (which are not presented verbatim) on these issues.

1. Some producers who appeared at the workshops expressed their belief that the gatherers and transporters' contracts include onerous pricing terms.

2. Some producers alleged that gatherers and transporters charge unnecessary fees with no supporting documentation for metering, compression, dehydration, and lost and unaccounted-for gas, etc. and that contracts are renegotiated with less favorable terms simply because pipeline ownership changes.
3. Some producers testified that standard contract provisions restrict information exchange or require producers to waive the ability to seek Commission relief or legal resolution of their complaints.
4. Some producer witnesses also testified that, because of the lack of transparency, there is no way for producers to determine if their particular contract terms and conditions are reasonable and that the current tariff information filed with the Commission is inadequate because much of the information is kept confidential by the Commission.
5. Some witnesses testifying on behalf of the pipelines asserted that the pipelines are faced with rising costs from pipeline safety, environmental, and other state and federal regulations.

Additionally, in early 2006, a petition for rulemaking was filed with the Commission asking the Commission to promulgate a rule requiring disclosure of all contract terms related to the gathering and transporting of natural in Texas. The Commission declined to engage in rulemaking. Instead, it has sought the advice of the Committee.

The Committee's Analysis

With both the decade-long debate and the workshop testimony in mind, the Committee engaged its own debate about "transparency" in the natural gas market. Reaching a consensus on the main question proved to be as difficult for the Committee as it has been for the Commission and market participants.

In evaluating this issue, the Committee learned that there is a significant amount of information currently available to market participants. Commission staff demonstrated the availability of information accessible through the Commission's website on natural gas wells and pipelines. The Commission's website appears to be a user-friendly, interactive system that allows the user to view gas, oil and pipeline data, including data about the location, size, and ownership of pipelines. This data can be cross-referenced with severance tax records available from the Comptroller's office to give a meaningful amount of information about specific wells. This publicly available information, however, does not provide a complete picture. It is not possible to tell from publicly available information the rates being charged for gathering, treating, compressing, processing, or transporting natural gas produced from a specific well, or the charges for connecting with a particular pipeline at a particular location.

Several Committee members expressed the view that "full transparency" would be detrimental to the market. Several members articulated that view as follows—

> The current gas market is a robust competitive market with an appropriate level of transparency. Complete transparency of contract information is unnecessary given the public information available to market participants, and significant harm will occur if transparency is increased significantly beyond existing levels. Transparency of contract information will damage the gas market for a number of reasons including: (i) transporters of gas will know what fees are being charged by their competitors and could increase rather than lower fees; (ii) complete transparency of contract information could lower prices being paid to producers once the lowest price paid in an area is made public; (iii) complete transparency will drive more standardization in contract terms making the industry less responsive particularly in light of the varied nature of gathering and transportation contracts and the need to be creative in negotiating specific terms to meet the requests of each producer/shipper; (iv) complete transparency will drive standardized pricing and create subsidies as production which could otherwise get a higher price gets a standard price while production which would otherwise get a lower price gets a standard price; (v) consumers on distribution systems that pay regulated cost of service rates may face higher costs due to the loss of industrial loads which carry some of the burden of costs on those systems; and (vi) complete transparency may disadvantage some producers in competing with other producers for acreage.
>
> In addition, concerns exist about creating an uneven playing field if less-than-complete transparency exists between various market segments and competitors within a market segment, as well as with imposing burdens (*e.g.*, administrative, electronic bulletin boards, tariff filings, *etc.*) on all market participants when the informal complaint process gives the Commission authority to address discrimination on a case-specific basis. The Commission should first adopt a more conservative approach given the existing availability of information identified by the Committee and the proposed changes to the informal complaint process.

Conversely, some members of the Committee expressed the view that, in order for the market to function properly, complete information about rates charged for gathering, treating, compressing, processing, and transporting natural gas must be available to market participants. As one Committee member expressed it—

> The proposed improvements made to the Informal Complaint Process represent incremental progress by those who wish to avail themselves of the existing complaint-based system. Many feel, however, that true and meaningful progress will not occur until the natural gas marketplace in Texas is made more transparent for the benefit of all stakeholders. Under the current regulatory approach, timely basic information is unavailable to producers, royalty owners, and working interest owners seeking a level of detail that can be employed to confirm that they are being treated fairly. It is the position of many independent producers, working interest owners, and royalty owners that the lack of available significant information regarding the basis upon which their gas price is paid is the single greatest hindrance to their ability to make reasonable decisions concerning prospect generation and gas

> sales arrangements. These parties believe that a meaningful level of transparency regarding price basis and fees will do more to encourage competition and curb discrimination in the natural gas sales and gathering marketplace than any other item being discussed with regard to this issue and that competition in a marketplace cannot be measured where information being kept confidential only protects buyers from each other at the expense of the suppliers and consumers.

Clearly, the Committee could see that a great deal of information is currently available, but that all information that might be desired is not available. Given the limitations of time and resources, the Committee could not ascertain with any certainty the extent to which the majority of market participants' desire transparency. All that the Committee could ascertain with certainty was: Some producers have publicly objected in the past to disclosure of their contracts while others have demanded full transparency; divergent views were expressed at the workshops about the need for greater transparency; and there are divergent views within the Committee about whether more transparency is necessary and if so, how best to achieve it without adversely affecting the gas industry.

Recommendations

Texas is the largest producer of gas in the United States and plays a critical role in meeting the energy needs of the state and nation. Texas has historically engaged in a market-based approach to regulation which has allowed the industry to remain responsive to meeting the needs of local and national energy markets as evidenced by the recent increase in the number of drilling permits, well completions, production, and pipeline construction in Texas. In many areas, the Commission has relied on agreement of the parties in lieu of cost-based rates and regulation to maintain a responsive and competitive natural gas industry in Texas. The Committee supports a market-based approach as the best way to maintain a responsive and competitive gas industry and has tried to make targeted changes based on the specific issues raised in the seven Commission workshops. The Committee is conscious of its obligation to avoid recommending changes that could have unforeseen or unintended consequences on the competitive gas gathering and transportation market that currently exists in many parts of Texas.

Recommendation 1—Strengthen the Informal Complaint Process

The Committee has recommended enhancements to the informal complaint process that provide for additional transparency. The enhancements to the informal complaint process require mandatory participation and full access to contract information and any other materials requested by the Commission after a complaint is filed. The Committee believes these enhancements will improve the level of transparency in cases where a party believes it has been treated in a discriminatory manner.

Recommendation 2—Education

A great deal of useful information is already available, but the availability is not generally known and the sources are not fully utilized within the industry. The Committee recommends the Commission and industry trade associations work together to educate industry participants on the current availability of information.

Recommendation 3—Confidentiality in Future Contracts

The Committee recommends that the Legislature provide producers have the option of not having a confidentiality provision in future sales, gathering, and transportation contracts. This will allow producers and their trade associations to freely compare fees and services. The Committee believes that the Legislature cannot lawfully apply this requirement to existing contracts containing confidentiality provisions. Consequently, the Committee recommends that any such statute be prospective in its application, applying only to new contracts.

The Committee discussed whether the requirement should be mandatory in all new contracts or whether producers should have the option to maintain confidential treatment of their contracts. The Committee recommends that confidentiality be allowed to the extent producers consent to the inclusion of confidentiality in any new contracts. This approach allows producers to determine the level of transparency they desire, but gives them the opportunity to review information with other like-minded producers. Additionally, it avoids putting administrative burdens on the Commission or other industry participants.

REACH OF POLICY CHANGES

The Commission's Charge

The Commission's charge to the Committee asks: "What transporters should be affected by any change in policy or law?" The Commission specifically inquires whether the changes in policy or laws recommended by the Committee should cover traditional gatherers and transporters that perform services for a fee, marketers, and producer-owned systems. The Commission further inquires whether "all gathering/transport systems [should] be open access and be required to provide service for any shipper?"

Recommendations

The Committee has attempted to answer these questions while addressing other issues presented in the Commission's charge to the Committee. As is discussed in the section addressing the Informal Complaint Process, the Committee believes the rule codifying that process should specifically apply to purchasers, gatherers, transporters, sellers and shippers. The rule proposed by the Committee is broadly worded to cover any complaint falling within the Commission's jurisdiction.

In the section addressing Transparency, the recommendation that the Legislature enact a statute providing that gatherers and transporters cannot require confidentiality clauses in contracts touches regulated utilities as well as unregulated non-utilities.

Finally, in the section addressing Gathering & Transportation Fees, the Committee specifically recommends against expansion of the current scope of open access.

MARGINAL WELLS

The Commission's Charge

The Commission's charge to the Committee notes that "[m]arginal gas well production ... is important to the State of Texas" and asks:

a. Should these wells be given special gathering/transportation and other consideration to make them more economically viable?

b. In underserved regions where need is determined, would alternative market-based solutions or tax incentives provide for a more competitive environment.

As is discussed below, the Committee concluded that marginal wells are economically important to the State and Nation and that there is value in keeping marginal gas wells producing for the longest possible time to allow the development of new technologies that often increase production from marginal wells. The Committee, however, did not conclude that these wells should be given special consideration other than to continue the existing severance and franchise tax abatement for marginal natural gas wells.

The Importance of Marginal Production

"A producing oil or natural gas well is considered to be 'marginal' if it is producing at such a rate that it is at the limit or margin of profitability. Obviously, this rate varies and is dependent upon many factors including: operating costs, product prices, tax rates, debt service, environmental costs, and plugging and abandonment liabilities to list just a few."[1] Despite the fact that marginal profitability varies from well to well and from time to time, both the Interstate Oil and Gas Compact Commission (IOGCC) and the Commission have a specific definition of marginal or stripper wells. Both define marginal or stripper wells as producing no more than 60 Mcf per day of natural gas.[2]

Using the IOGCC and Commission's definition, 36,946 (34.9%) of Texas's 105,827 total natural gas wells were classified as marginal wells in the fourth quarter of 2005. This calculation of the number of marginal wells is probably low because

---

[1] Duda, Covatch, Remson & Wang, PROJECTIONS OF MARGINAL WELLS AND THEIR CONTRIBUTIONS TO OIL AND NATURAL GAS SUPPLIES at 1 (Doc. # SPE 98014, Sept. 2005) (presented at the 2005 Society of Professional Engineers Eastern Regional Meeting, September 14-16, 2005) (hereafter, "PROJECTIONS OF MARGINAL WELLS").

[2] House Bill 3, passed by the 79th Legislature in its Third Called Session, gives a franchise tax abatement for gas wells whose production averages less than 250 mcf a day over a 90-day period.

30,901 wells did not report any production in the fourth quarter. Many of those wells likely belong in the marginal category. Thus, a total of 67,847 (64.1%) of the natural gas wells in Texas probably qualify as "marginal wells." Texas's marginal wells produced a total of about 77 Bcf of gas during the final three months of 2005, while all Texas natural gas production totaled 1.3 Tcf during that same period. Thus, the marginal wells (64.1% of all natural gas wells) contributed only 6% of the natural gas produced in Texas during the fourth quarter of 2005. For the year, marginal gas wells produced 371 Bcf (7.1%) of Texas's 5.2 Tcf of natural gas production.

If the average sales price at the wellhead of natural gas in Texas in 2005 was $7.50 per Mcf,[3] these marginal wells contributed almost $2.8 billion in direct economic activity. According the Texas's Comptroller of Public Accounts, each dollar of direct economic benefit from the production of oil and gas results in a total economic benefit to the State of almost six times the direct benefit. Consequently, Texas's marginal natural gas wells provide a total economic benefit to the State of about $16.8 billion in 2005.

Additionally, the State collects a severance tax of 7.5% on the producer's net proceeds from sales of natural gas. Approximately 40% of the marginal wells were exempt from the severance tax in fiscal year 2005, but the remaining 60% were not. In fiscal year 2005 (which ended August 31, 2005), Texas collected $1.66 billion through the severance tax on natural gas.[4] Assuming 222 Bcf (60% of the 371 Bcf) of marginal-well production generated severance tax, Texas's marginal gas wells generated around $125 million in severance tax revenues for the State of Texas in 2005.

Thus, these "marginal" wells—while individually insignificant—are collectively important. They provide a substantial economic benefit to the State and its citizens, and contribute a meaningful amount of natural gas to the Nation's energy supply. There, however, is another important reason to keep these wells in production. Marginal wells "serve as access to much of the remaining oil and natural gas resources." "To this day, the potential remains for advanced technologies to enhance the recovery of crude oil and natural gas both residual and by-passed in discovered reservoirs. If these wells are shut-in, and subsequently plugged and abandoned, it becomes much more unlikely these remaining reserves will ever be produced due to the significant costs associated with drilling, completing, and equipping new wells."[5]

---

[3] *U.S. Energy Information Administration, Natural Gas Navigator*, available at http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm (giving national average monthly wellhead price for 2005 as follows: January-$5.52; February-$5.59; March-$5.98; April-$6.44; May-$6.02; June-$6.15; July-$6.69; August-$7.68; September-$9.50; October-$10.97; November-$9.54 and December-$10.02); also available from the Texas Comptroller of Public Accounts at http://www.cpa.state.tx.us/ecodata/ecoind/ecoind4.html#natural.

[4] *See Comptroller of Public Accounts, Texas Revenue History by Source*, available at http://www.window.state.tx.us/taxbud/revenue.html.

[5] PROJECTIONS OF MARGINAL WELLS at 1-2.

In sum, the Committee agrees with the Commission's conclusion that "marginal gas well production is important to the State of Texas.

The Difficulty in Subsidizing Marginal Wells

It is undisputed that "not all gas is created equal." Differences in quality, quantity and location affect the value of natural gas. Producers, gatherers and transporters of natural gas face increasing costs as wells age and volumes decline. Transporters and gatherers are faced with increasing costs related to pipeline safety and environmental and other regulations. Additionally, end users of gas require a specific volume of gas having a uniform and specific quality. The failure to deliver the full amount of gas required, or the delivery of gas of a lesser quality, can have a significant negative impact on an end user and exposes the transporter to significant liability. Consequently, gatherers and transporters have an economic interest in obtaining stable quantities of high-quality gas.

Marginal wells sometimes produce gas of inferior quality, at low pressure, and in uneven quantities. Often, these wells require regular maintenance to ensure production. Furthermore, many marginal wells have been in production for a number of years and are served by gathering lines of the same age that require maintenance or replacement. In most cases, treatment and compression of the gas is necessary to ensure that it enters the pipeline under the appropriate pressure and having the proper characteristics. The equipment used to treat and compress gas is expensive, as is pipeline maintenance and replacement.

In the bundled environment that existed more than a decade ago, in which pipelines were allowed to be merchants, higher volume wells essentially subsidized marginal wells because transporters spread the costs of pipeline repair and construction, and the costs of treatment and compression, over their entire system. Under today's market-responsive regulatory framework, each well or group of wells must stand on its own. Gatherers and transporters charge the producer for the cost of maintaining or replacing the gathering lines associated with the particular well, and the cost of treatment and compression of gas associated with the particular well. The costs depend on the quantity and quality of the gas and the location of the well.

Producers appearing at the Commission's workshops provided a significant amount of testimony that some gatherers/transporters are gouging producers in regard to their charges for gathering, compressing, treating and transporting their gas. Many producers testified—correctly, the Committee believes—that the economic realities of marginal wells give them no real alternative for moving their gas to market than to continue to do business with their current gatherer/transporter. In a nutshell, these producers have little market power and are susceptible to being taken advantage of by unscrupulous gatherers/transporters. Additionally, many producers appearing at the workshops either did not know about the informal complaint process, did not believe it would be effective to address these problems, or were afraid of retaliation by the gatherer/transporter if they pursued a complaint.

Recommendations

As noted above, the Committee is convinced that it is important to maintain production from marginal gas wells for the longest period of time. A majority of the Committee, however, is not convinced that government regulation is superior to the self-regulation inherent in a free-market.

Continued production from marginal wells benefits society as a whole; not necessarily other gas producers. Arguably, it is unfair to other gas producers to spread the costs of gathering and transporting marginal-well gas across an entire gathering or transportation system. The cost, instead, should be carried by society generally. But there is no clearly appropriate method for subsidizing marginal wells given that no two wells are the same.

Recommendation 1—Continue Tax Abatements

The Legislature appears to have recognized this predicament in the past. Currently, Texas Tax Code § 201.059 provides for severance tax relief for marginal wells. Section 201.059 defines a "qualifying low-producing well" as "a gas well whose production during a three-month period is no more than 90 mcf per day, excluding gas flared pursuant to the rules of the commission." It requires the Comptroller to "certify the average taxable price of gas, adjusted to 2005 dollars, during the previous three months based on various price indices available to producers, including prices reported by Henry Hub, Houston Ship Channel, Mississippi Barge Transport, New York Mercantile Exchange, or other spot prices, as applicable." It then sets up a formula for severance tax abatement for low-producing wells if the price is at or below a certain level. Under § 201.059, an operator of a qualifying low-producing well is entitled to credit on the tax otherwise due on gas produced and saved from that well during a month of: 25 percent if the average taxable price of gas for the previous three-month period is more than $3 per mcf but not more than $3.50 per mcf; 50 percent if price of gas is more than $2.50 per mcf but not more than $3 per mcf; and 100 percent if the price of gas for the previous three-month period is not more than $2.50 per mcf. Section 201.059 will expire on September 1, 2007, unless extended by the Legislature. Additionally, House Bill 3, passed by the 79th Legislature in its Third Called Session, provides that the franchise tax does not reach "total revenue received from ... gas produced ... from ... a gas well designated by the Railroad Commission of Texas or similar authority of another state whose production averages less than 250 mcf a day over a 90-day period."

Based on the importance of marginal wells detailed above, the Committee suggests that Commission recommend to the Legislature that these franchise and severance tax abatement provisions be extended indefinitely.

Recommendation 2—Enhance the Informal Complaint Procedure

The Committee has recommended a number of changes to the informal complaint procedure. Because much of the producer feedback received at the seven Commission workshops related to this marginal wells issue, the Committee is hopeful that the changes recommended to the informal complaint process will alleviate producers' concerns about that process and that producers will use the informal complaint process to obtain relief when a gatherer or transporter is perceived to be taking advantage of the producer in regard to the rate charged for services.

Recommendation 3—Educate Operators about the Ability to Commingle Gas from Marginal Wells

A provision allowing the commingling of natural gas produced from marginal wells already is in place. An explanation of the process and its exceptions is contained in the Commission's Statewide Rule 26(b). Under Rule 26(b) operators, with the consent of the royalty interest owners, can aggregate marginal volumes of gas at a common separation/treating facility and sell the gas through a single meter. This process for aggregating and selling gas from marginal wells allows operators to eliminate the expenses associated with having multiple meters. In addition, there is an exception in Statewide Rule 27 to eliminate meters on marginal wells, identified in the rule as 20 Mcf per day or less. The Committee believes that few operators know of these provisions. The Committee therefore recommends that the Commission undertake to educate market participants, including royalty owners, of the benefits of commingling gas and eliminating metering requirements to extend the economic viability of marginal wells, and that the Commission amend Statewide Rule 27 to conform the marginal wells standard consistent with the Texas Tax Code § 201.059 definition of 90 Mcf/day.

GATHERING & TRANSPORTATION FEES

The Commission's Charge

The Commission's charge to the Committee asks if the Commission should exercise oversight regarding the types and categories of fees related to gas gathering and transportation. Should some pricing terms in gas gathering arrangements be standardized?

The Committee's Work

In considering the Commission's inquiry, the Committee viewed gathering and transportation fees in the broader context of the entire midstream portion of the natural gas value chain—from the producer's wellhead through gathering, processing, treating, transportation, storage and marketing. The Committee notes that the kind and number of midstream operations and transactions vary substantially by specific application and are conducted by many different parties. The transactions are often unique, with each transaction being tailored to the specific application and to the parties' needs and market conditions existing when the transaction was negotiated. Because of the complexity and variety in the different businesses involved in midstream operations, and the cost and time consumed in the regulatory process, the committee recommends that no additional regulations be imposed on the parties doing business in the midstream portion of the energy sector at this time. In the context of discussing the midstream portion of the natural gas value chain, the specific decisions the Committee made were—

- Producer-owned systems that transport only the producer's production, not production by a third-party, should not be subject to additional regulation.
- A producer owned gathering system should not be required to transport natural gas for a third-party.
- The criteria for becoming a gas utility, open-access pipeline, or common carriers should not be expanded.
- Regulating pipelines or gatherers based on a cost of service and requiring parties to file rate cases should be avoided. Rate cases are costly, time consuming, and do not encourage competition. A simple rate case can cost over $300,000 and take months to complete. A complex case can cost millions of dollars and take over a year to prosecute. This type of regulation would not work efficiently in Texas's competitive gathering and transportation market.
- A heavily regulated environment is not workable because of the complexity and uniqueness of gathering, processing and transportation transactions. A lightly regulated market, on the other hand, allows for beneficial variations in

the agreements between the market participants. For example, a producer and pipeline may agree to higher fees in return for lower pressures or more services. Or the parties may agree to a different fee than is charged to others in return for capital investments by one of the parties.

- Regulation in general and the informal complaint process in particular should not be used to abrogate the terms of an exiting contract while it is in force.
- Given the number and variety of parties involved in the natural gas value chain, regulating one portion, such as gathering, could create the opportunity for parties in other parts of the value chain to find a "loop hole" to improve their position, thus negating the anticipated benefit of the regulation.

Recommendation

The one area in which the Committee believes additional statutory authority—not regulation—will benefit the Commission's oversight of the natural gas value chain is in regard to the standard for setting rates when a formal complaint is filed. Currently, in a formal proceeding, the Commission is required to set rates based on cost of service. The cost-of-service methodology does not reflect the environment in which gatherers and transporters conduct their business. These entities are market-based businesses that simply do not keep books with cost-of-service regulation in mind. Furthermore, whether a gatherer or transporter is unfairly discriminating among similarly situated shippers is a market-based determination, not a cost-of-service-based determination. The Committee believes that the Legislature should give the Commission the ability to use either a cost-of-service method or a market-based method for setting a rate in a formal rate proceeding. The Oklahoma statute provides a model for a market-based methodology. It provides—

> D. In determining and setting a fee or terms and conditions of service, or both, … the Commission shall determine a fee or terms and conditions of service, or both, which would result from arm's-length bargaining in good faith in a competitive market between persons of equal bargaining power and shall consider all economically significant factors for gathering which it determines to be relevant which may include, but are not limited to:
>
> 1. The fees and terms and conditions of service which such gatherer receives from the complainant and other shippers for analogous levels of service for gathering within an area the Commission determines to be relevant;
> 2. The fees charged and the terms and conditions of service provided by other gatherers for gathering within an area the Commission determines to be relevant;
> 3. The reasonable financial risks of operating such a gathering system;
> 4. The reasonable capital, operating and maintenance costs of such a gathering system; and
> 5. Such other factors which the Commission determines to be relevant.
>
> Provided that neither such fee nor such terms and conditions of service shall be computed on a utility rate of return basis and that gatherers shall not be

regulated like public utilities in the setting of fees and terms and conditions of service.

OKLA. STAT. ANN. § 52-24.5.

OTHER STATES

The Commission's Charge

The Commission's charge to the Committee asks the Committee to study how other states address discrimination issues relative to gas gathering and transportation services and asks if their methods should be adopted in Texas.

Recommendation

The committee reviewed the statutes and rules pertaining to the complaint process associated with natural gas gathering and transportation in Oklahoma, Kansas, New Mexico, Arkansas and Louisiana. Of these states, Oklahoma and Kansas are the most advanced in their complaint procedures. The procedures in place in Oklahoma and proposed in Texas include conditions the Committee believes are essential to a successful complaint process, including a requirement to disclose pertinent information, confidentiality, speedy decisions, and prohibiting discrimination during the complaint period. Several states' regulations include specific fine and penalty provisions, which is consistent with the Committee's recommendation to clarify the Commissions' enforcement capabilities.

The Committee believes that Texas's informal complaint process, as proposed by the Commission and enhanced by the Committee, is superior to the procedures in place in other states. Like other states, Texas requires disclosure of pertinent information, confidentiality, and speedy decisions; and it prohibits retaliation during the complaint period. Texas's procedure is better than other states' procedures because it covers gathering, processing, and transporting natural gas while other states limit their procedure to gas gathering.

The one provision from another state that the Committee finds to be advisable is the Oklahoma provision discussed above under Gathering & Transportation Fees allowing the Oklahoma Corporation Commission to set rates based on a market-based methodology.

§2.001. Informal Complaint Procedure

(a) Scope and Jurisdiction. This section applies to any complaint within the Commission's jurisdiction, including, but not limited to, complaints about natural gas purchasing, selling, shipping, transportation, and gathering practices. This section does not apply to matters arising under Texas Utilities Code, Chapter 103, entitled "Jurisdiction and Powers of Municipality," or initiated under Texas Utilities Code, Chapter 104, Subchapter C, entitled "Rate Changes Proposed by Utility," or Subchapter G, entitled "Interim Cost Recovery and Rate Adjustment."

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Common purchaser--Has the same meaning as is given that term in Texas Natural Resources Code, §111.081.

(2) Complainant--A person who submits a complaint to the Commission pursuant to this section.

(3) Director--The Director of the Gas Services Division of the Railroad Commission of Texas or the director's delegate.

(4) Gatherer--A person providing gathering service for a fee for a third party.

(5) Gathering service--A pipeline that collects gas and brings it to a common point(s).

(6) Informal complaint proceeding--The process set out in this section for addressing disputes among entities within the Commission's jurisdiction, including, but not limited to, natural gas purchasers, sellers, shippers, transporters, and gatherers.

(7) Mediator--The individual who conducts an informal complaint resolution mediation .

(8) Monitor--The Commission employee appointed by the director to manage an informal complaint proceeding and/or assist a non-Commission mediator in the management of an informal complaint proceeding. A monitor may also be a mediator.

(9) Natural gas purchaser--An entity that purchases natural gas.

(10) Natural gas seller—An entity that sells natural gas, including, but not limited to, a producer.

(11) Natural gas utility--Has the same meaning as is given that term in Texas Utilities Code, §§101.003 and 121.001.

(12) Participant--A complainant, respondent, monitor, or mediator in an informal complaint-proceeding.

(13) Person--A person includes an individual, corporation, partnership, joint venture, or other legal entity of any kind.

(14) Respondent--A person who is the subject of a complaint submitted to the Commission pursuant to this section.

(15) Shipper--Any person for which a transporter is currently providing, has provided, or has pending a written request to provide transportation services.

(16) Similarly-situated shipper--Any shipper that seeks or receives transportation service under the same or substantially the same, physical, regulatory, and economic conditions of service as any other shipper of a transporter. In determining whether conditions of service are the same or substantially the same, the Commission shall evaluate the significance of relevant conditions, including, but not limited to, the following:

(A) service requirements;

(B) location of facilities;

(C) receipt and delivery points;

(D) length of haul;

(E) quality of service (firm, interruptible, etc.);

(F) quantity;

(G) swing requirements;

(H) credit worthiness;

(I) gas quality;

(J) pressure (including inlet or line pressure);

(K) duration of service;

(L) connect requirements; and

(M) conditions and circumstances existing at the time of agreement or negotiation.

(17) Transportation service--The receipt of a shipper's natural gas at a point or points on a transporter's facilities and redelivery of a shipper's natural gas by the transporter at another point or points on the transporter's facilities or on another person's facilities,. including exchange, backhaul, displacement, and other methods of transportation.

(18) Transporter--A person providing transportation service for a fee for a third party .

(c) Policy.

(1) It is the policy of the Commission to encourage the resolution and expedient settlement of disputes regarding natural gas purchasers, sellers, transporters and gatherers and to prevent discrimination among similarly situated shippers and sellers as is prohibited by the Texas Natural Resources Code, Chapter 111, entitled "Common Carriers, Public Utilities, and Common Purchasers," and Texas Utilities Code, Title 3, Subtitle A, entitled "Gas Utility Regulatory Act, and Subtitle B, entitled "Regulation Of Transportation and Use," and other matters of dispute subject to the Commission's jurisdiction. This section is adopted in furtherance of that policy.

(2) To accomplish the policy set out in this section, Commission employees, acting pursuant to this section, will attempt to facilitate, encourage, and promote resolution and settlement of disputes among natural gas purchasers, sellers, shippers, transporters, gatherers, and other parties subject to the Commission's jurisdiction consistent with the public interest and without lengthy and potentially expensive formal proceedings. The informal complaint procedure is intended to establish a forum for communication with the

goal of achieving mutually acceptable compromise and resolution that is in the public interest.

(d) General requirements and limitations.

(1) The Commission will not process anonymous complaints under this section.

(2) The communications, records, conduct, and demeanor of the participants in each informal complaint proceedings are confidential and handled in accordance with Texas Government Code, §2009.054, entitled "Confidentiality of Certain Records and Communications."

(3) A mediator shall have completed forty (40) hours of Texas mediation training that meets the standards of the Texas Alternative Dispute Resolution Procedures Act, and must follow the ethical guidelines for mediators adopted by the Alternative Dispute Resolution Section of the State Bar of Texas.

(4) A mediator may be either a Commission employee or a non-Commission employee. If the complainant and respondent submit a written request to the director agreeing to share all costs of mediation, they may retain a non-Commission employee to conduct the mediation. If the complainant and respondent are unable to agree on whether to engage a non-Commission employee as the mediator, or in the absence of a request for a non-Commission employee mediator, the director shall appoint a Commission employee to conduct the mediation. If the mediator is not a Commission employee, then the monitor will act as a technical advisor to the non-Commission employee mediator and may, at the direction of the non-Commission employee mediator, participate in the informal complaint proceeding. A non-Commission employee mediator shall have the same duties and obligations of a commission employee mediatory and may, in his sole discretion, compel the complainant and respondent to provide information pursuant to subsection (f)(9) of this section.

(5) Mediators and monitors shall not communicate with a Commission hearings examiner or any Commissioner about any material or substantive aspect of a complaint or reply filed pursuant to this section.

(6) Each complainant and respondent in an informal complaint proceeding shall cooperate fully in gathering and disclosing information requested by the mediator or monitor and shall participate in good faith in all aspects of the informal complaint proceeding.

(7) A natural gas purchaser, transporter, or gatherer shall not discontinue or deny service to a shipper or seller during the pendency of an informal complaint proceeding in which both are participants unless one of the following reasons applies for discontinuing service:

(A) there is insufficient capacity on the respective facility or facilities; provided, however that the purchaser, transporter, or gatherer provide any partial capacity that maybe available from time to time.

(B) the natural gas does not meet the quality specifications of the purchaser, transporter, gatherer, or downstream processors, pipelines or customers; unless the natural gas is flowing under an agreement and at the impending termination of that agreement there is sufficient capacity and out of spec gas is being blended for other shippers or sellers in the area, and the acceptance of such volumes from shipper or seller will not jeopardize downstream market deliverability of the gas, then the purchaser, transporter, or gatherer shall continue to take the gas until the conclusion of the informal complaint process, charging blending fees applicable to similarly situated shippers;

(C) continuing to take the natural gas would create a safety or environmental risk or cause a violation of a safety or environmental regulation or permit or interfere with necessary maintenance and repairs of facilities;

(D) there is no existing contractual agreement as to the price to be paid or fees charged for the production during the pendency of the informal complaint process, provided however, that the production will be taken if the complainant and respondent agree that the price or fees will be determined at a later date;

(E) for such good cause as the mediator may determine in the particular case.

(8) A transporter, gatherer, or purchaser shall not discriminate against a shipper or seller because the shipper or seller has, in good faith:

(A) filed an informal complaint at the Commission;

(B) filed a formal complaint at the Commission;

(C) instituted or caused to be instituted at the Commission any enforcement proceeding against a purchaser, transporter, or gatherer based on alleged violations of any rule or statute; or

(D) made inquiry to the Commission as to the facts or circumstances surrounding operation of a purchaser's, transporter's, or gatherer's system.

(9) The Commission may commence an enforcement action, initiated by the Director, for failure by the complainant or the respondent to comply with all provisions of the informal complaint proceeding.

(e) Informal Complaint Process.

(1) An informal complaint proceeding is initiated by filing a complaint with the Commission by:

(A) calling the Commission Helpline at (512) 463-7167. Commission staff will answer calls to the Helpline from 8:00 a.m. to 5:00 p.m. on regular Commission business days. A voice mail system will be in place to receive calls during non-business hours; or

(B) submitting a complaint in writing by:

(i) regular United States mail to the following address: Director, Gas Services Division, P. O. Box 12967, Austin, Texas 78711-2967;

(ii) facsimile transmission (fax) to the following number: (512) 463-7962; or

(iii) internet submission by accessing the following URL: http://www.rrc.state.tx.us/divisions/gs/mos/complaints/icp.html.

(2) Each complaint shall include the following information:

(A) the name of the individual submitting the complaint;

(B) the complainant's name, mailing address, telephone number, and, if applicable, e-mail address and fax number;

(C) the respondent's name, mailing address, telephone number, and if applicable, e-mail address and fax number;

(D) a factual description of the events that are the basis of the complaint, including the onset or duration of such events;

(E) a statement of the current status of negotiations between the complainant and the respondent and a description of any actions the complainant has taken to resolve the dispute;

(F) a statement of the relief sought by complainant; and

(G) all supporting documentation, unless the complaint is filed by telephone.

(3) The Director shall assign a complaint to a monitor, who shall promptly contact the complainant to confirm receipt of the complaint and to obtain any additional relevant and supporting documentation pertaining to the complaint. The monitor shall advise the complainant of its right to have the complaint mediated by a commission employee or by a non-commission employee mediator. If the complainant has submitted the complaint by telephone and wishes to pursue the matter, the monitor shall direct the complainant to submit the complaint by e-mail, facsimile, or letter, along with supporting documentation.

(4) After the monitor determines that the complainant has provided all required information, the monitor shall notify the respondent of the complaint by mailing to the respondent, via certified mail, return receipt requested, a copy of the complaint and all supporting documentation. This notification shall include notice to the respondent of its right to have the matter heard by a non-commission employee mediator pursuant to the agreement of the parties.

(5) The respondent shall reply in writing to both the monitor and the complainant within 14 calendar days from the date of the monitor's notification letter. The respondent's reply shall address the substance of the complaint and either propose a solution or explain why the complaint is incorrect.

(6) The complainant and the respondent will be given 14 calendar days from the date of the respondent's reply to resolve the complaint without the participation of a mediator.

(7) If the complainant and the respondent have made a good faith attempt to resolve the

complaint but have been unable to do so, the monitor shall determine within seven days after expiration of the period allowed for informal resolution in paragraph (6) of this subsection whether the parties want the matter referred to a Commission or non-Commission mediator and shall refer the matter back to the director.

(8) In the event the parties agree upon a non-commission employee mediator, then the monitor shall notify the agreed upon mediator. In the event the parties desire to use a non-commission employee mediator and are unable to agree upon the selection of a non-commission employee mediator, each party shall each submit the name of its preferred mediator and the preferred mediators so designated shall choose a third mediator who will preside over the process.

(9) In accordance with the procedure set forth in subsection (d)(4) of this section, the director shall appoint a mediator within seven days after receipt of the information in paragraph (7) of this subsection.

(10) The mediator shall,

within 14 calendar days after the appointment provided in paragraph (8) of this subsection, review all information received from the complainant and respondent. The mediator may request additional information as the mediator deems necessary. At any time during an informal complaint procedure, the mediator may request and review documents or information the mediator considers pertinent to the complaint. The mediator shall furnish the complainant and respondent with a written summary of all relevant documents and information reviewed. The mediator's summary shall not disclose confidential information.

(10) The commission shall schedule a mediation meeting with the complainant and respondent, which the mediator shall conduct, to occur within 14 calendar days after the date of the mediator's written summary.

The commission shall promptly notify the complainant and respondent of the date, time and location of the meeting, which may be conducted at the headquarters of the Commission in Austin, Texas, or in the Commission's offices in the district in which the complaint arises, or at any other location by agreement of the participants.

(11) The complainant and respondent shall participate in the mediation meeting and undertake in good faith to settle all issues raised in the complaint. The complainant and respondent shall make available during the mediation meeting, in person, representatives who are empowered to make decisions on their behalf.

(12) If the mediation process does not result in a settlement of all issues during the period for mediation provided herein, after completing the mediation, the mediator shall send a confidential memorandum to the complainant and the respondent that states one or more of the following conclusions, based on the information reviewed by the mediator. The mediator may conclude that:

(A) the complaint does not involve a violation of a Commission rule or statute;

(B) there are specific actions which, if taken by either the respondent or the complaint or both, could result in resolution of the complaint; or

(C) a formal evidentiary hearing is warranted. Such a hearing may be:

(i) initiated by the Director of the Gas Services Division as a show cause proceeding; or

(ii) requested by either the complainant or the respondent.

(g) Internal Report. The director shall maintain an internal report of all complaints received.

(1) The report shall be circulated no less often than once every six months to the Commissioners, the executive director, and the general counsel.

(2) The specific points of the participants' discussions and any negotiated resolution shall not be included in this internal report.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's authority to adopt.

Issued in Austin, Texas on ______________________, 2006.

Filed with the Office of the Secretary of State on ______________________, 2006.

____
Mary Ross McDonald
Managing Director, Special Counsel
Office of General Counsel
Railroad Commission of Texas

Appendix H

By: Armbrister S.B. No. 575

A BILL TO BE ENTITLED

AN ACT

relating to notice to a surface owner by an oil or gas well operator of certain oil and gas operations.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF TEXAS:

SECTION 1. Chapter 91, Natural Resources Code, is amended by adding Subchapter P to read as follows:

<u>SUBCHAPTER P. NOTICE OF OIL AND GAS OPERATIONS</u>

<u>Sec. 91.701. DEFINITION. In this subchapter, "surface owner" means the first person who is shown on the appraisal roll of the appraisal district established for the county in which a tract of land is located as owning an interest in the surface estate of the land at the time notice is required to be given under this subchapter.</u>

<u>Sec. 91.702. APPLICABILITY. This subchapter applies only to the drilling of a new oil or gas well or the reentry of a plugged and abandoned oil or gas well. This subchapter does not apply to:</u>

<u>(1) the plugging back, reworking, sidetracking, or deepening of an existing oil or gas well that has not been plugged and abandoned; or</u>

<u>(2) the use of an existing oil or gas well bore that has not been plugged and abandoned to drill a horizontal oil or gas well.</u>

<u>Sec. 91.703. NOTICE REQUIRED. (a) Not later than the third day after the date the commission issues an oil or gas well</u>

operator a permit to drill a new oil or gas well or to reenter a plugged and abandoned oil or gas well, the operator shall give written notice of the operator's intention to drill or reenter the well to the surface owner of the tract of land on which the well is located or is proposed to be located.

(b) An oil or gas well operator is not required to give notice under this subchapter to a surface owner if:

(1) the operator and the surface owner have entered into an agreement that contains alternative provisions regarding the operator's obligation to give notice of oil and gas operations; or

(2) the surface owner has waived in writing the owner's right to notice under this subchapter.

Sec. 91.704. ADDRESS FOR NOTICE. The notice must be given to the surface owner at the surface owner's address as shown by the records of the county tax assessor-collector at the time the notice is given.

Sec. 91.705. RIGHTS OF OWNER OF MINERAL ESTATE NOT AFFECTED. (a) This subchapter does not affect the status of any rule of law to the effect that the mineral estate in land is dominant over the surface estate.

(b) Failure to give notice as required by this subchapter does not restrict, limit, work as a forfeiture of, or terminate any existing or future right to develop the mineral estate in land.

SECTION 2. The change in law made by this Act applies only to oil and gas operations for which a permit is issued on or after October 1, 2005. Oil and gas operations for which a permit is issued before October 1, 2005, are governed by the law as it existed immediately before the effective date of this Act, and that law is continued in effect for that purpose.

SECTION 3. This Act takes effect September 1, 2005.

Appendix
I

Oil & Gas Exploration and Surface Ownership

Questions and concerns frequently arise when owners of residential property in suburban and rural areas discover that oil and gas operations are being conducted in the vicinity. Although the Railroad Commission generally lacks jurisdiction over these issues, this short paper is intended to provide general answers to some of the most common questions.

Mineral & Surface Estates

Under Texas law, land ownership includes two distinct sets of rights, or "estates," the surface estate and the mineral estate. Initially, these two estates were owned by the same person and they may continue to be owned together by one person. However, in many areas of Texas, especially those where there has been extensive historical oil and gas development, it is common for the mineral estate and surface estate to be owned by different people. The division, or "severance," of the mineral estate and surface estate occurs when an owner sells the surface and retains all or part of the minerals (or, less commonly, an owner sells the minerals and retains the surface). If an owner does not expressly retain the minerals when selling the surface, the mineral estate he owns automatically is included in the sale.

Dominance of Mineral Estate

Regardless of whether the mineral estate and surface estate are held by one owner or have been severed, Texas law holds that the mineral estate is dominant. This means that the owner of the mineral estate has the right to freely use the surface estate to the extent reasonably necessary for the exploration, development, and production of the oil and gas under the property. This right to freely use the surface estate for the benefit of the mineral estate may be exercised by a company or individual that has taken a mineral lease from the actual owner of the mineral estate. The company that takes a lease and actually operates the property is frequently referred to as the "lessee" and the mineral interest owner who granted the lease is the "lessor."

Lessee's have broad rights to use the surface for the purpose of exploring for and producing oil and gas. These rights include the right to conduct seismic tests, drill wells at locations they select, to enter and exit well sites and other facilities, to build, maintain, and use roads for access to and from well sites and facilities, to build and use pipelines to serve wells and facilities on the property, to use surface and subsurface water on the leased premises for drilling and production operations, and to drill and operate injection wells to enhance lease recovery and dispose of lease-produced water.

With the limited exceptions discussed below, the lessee has the right to conduct the activities set out above and otherwise reasonably use the surface without getting permission from the surface owner and without restoring the surface or paying for any non-negligent damages it causes. However, if a lessee's use of the surface is found to be negligent, unreasonable, or excessive, the lessee may be liable to pay damages to the surface owner for the resulting injury.

Exceptions and Limitations

The general rules regarding free use of the surface to benefit the mineral estate may be changed by the specific terms of the mineral lease covering the property or of the deed that severed the mineral estate from the surface estate. In addition, many cities have municipal ordinances restricting oil and gas activities on property within city jurisdiction. The rights of the lessee may also be limited by the "accommodation doctrine." This legal doctrine applies in limited circumstances to require the lessee to modify its operations to accommodate an existing surface use when reasonable alternatives are available. In specific circumstances in counties in or near large metropolitan areas developers can impose restrictions on drilling and operations sites by creation of a qualified subdivision as provided by Chapter 92 of the Texas Natural Resources Code.

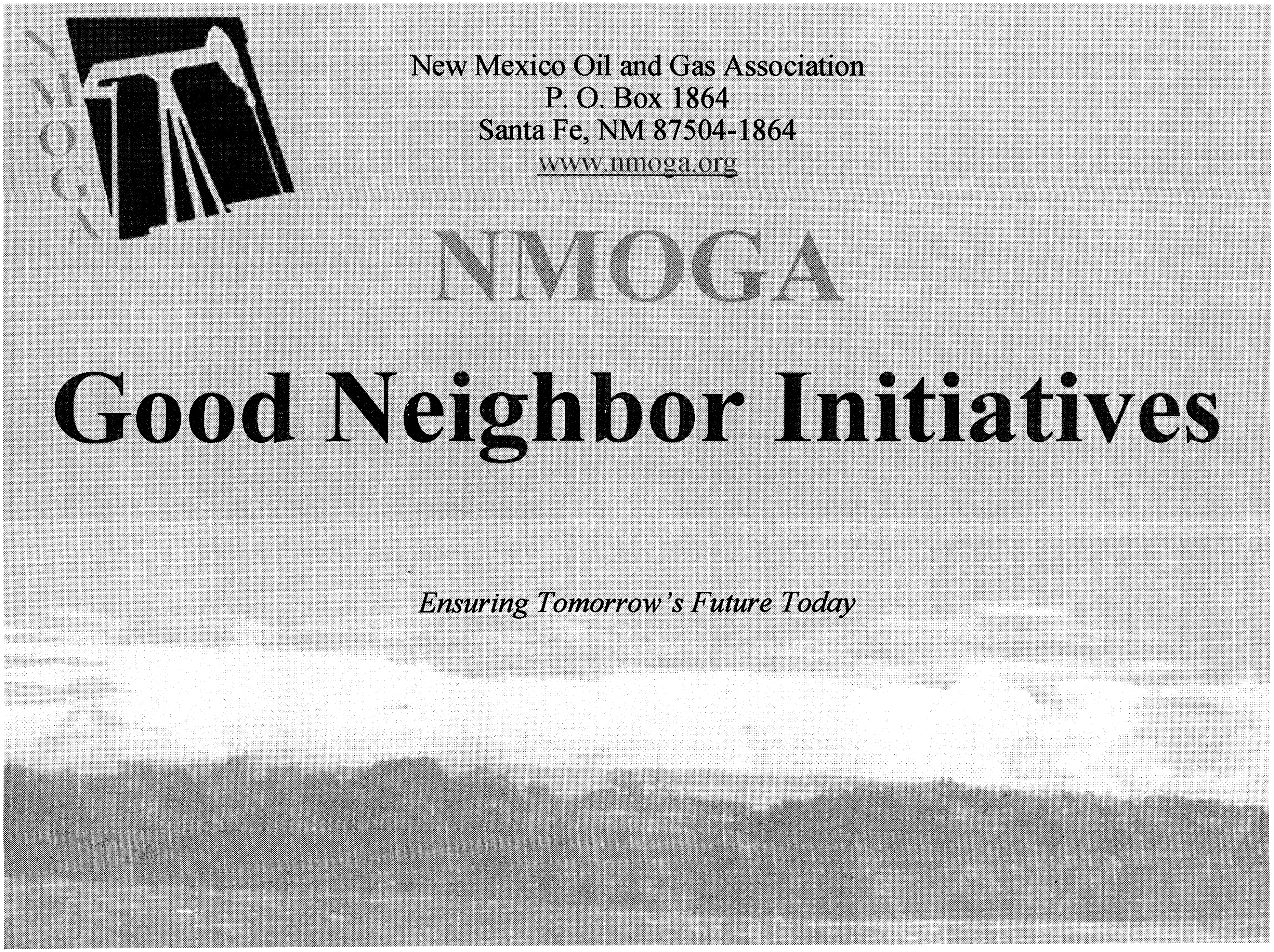
Control by Surface Owner

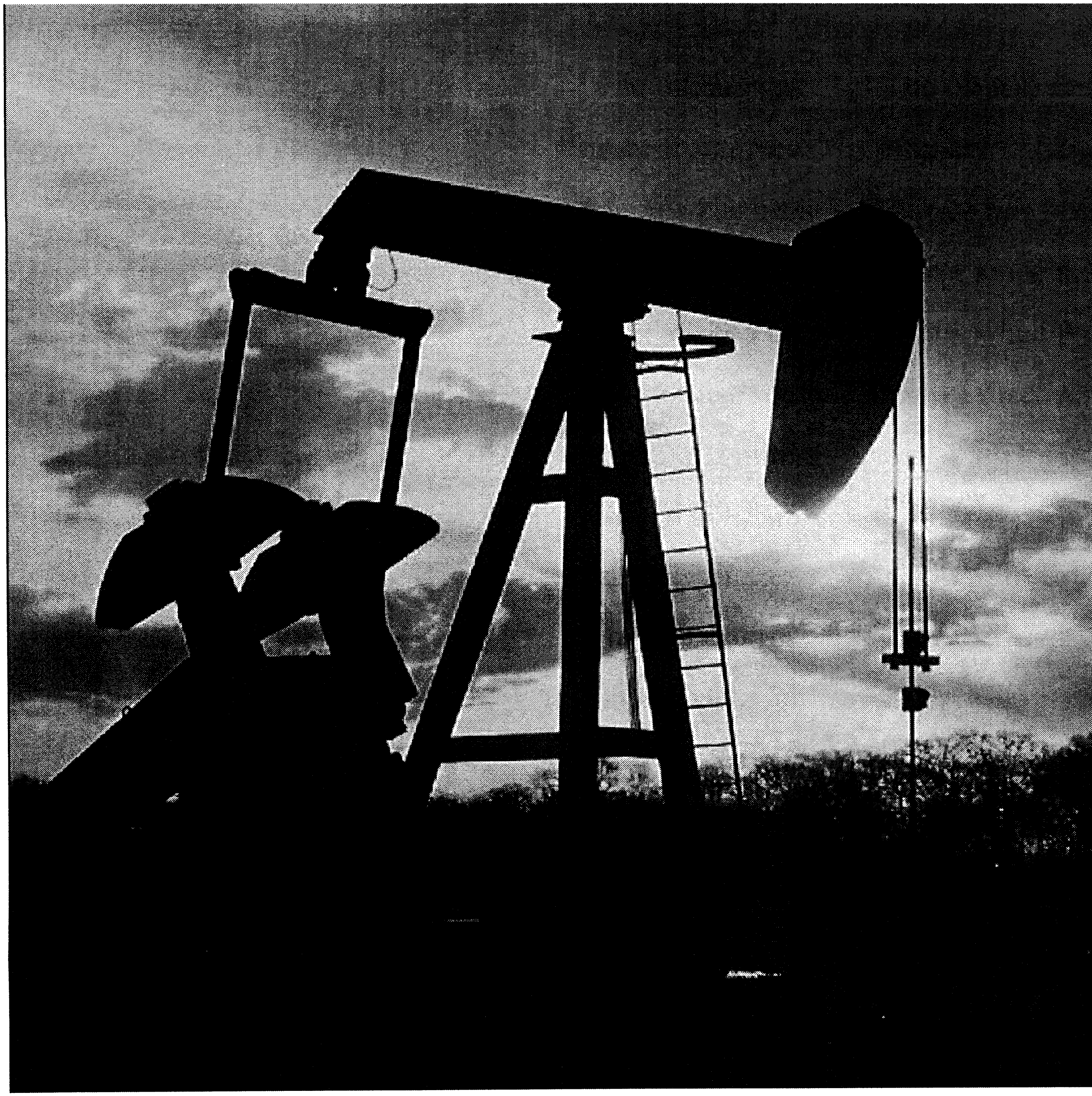
The best method of controlling oil and gas development by a surface owner is the purchase of all or a significant portion of an undivided interest in the mineral estate. This allows the surface owner to control the timing and terms of any future leases. However, purchase of the mineral estate is not always possible or practical. In the alternative, although under no obligation to do so, a mineral interest owner may be willing to agree to include surface use and surface damages clauses in future leases.

If the mineral estate is already under lease, the surface owner may wish to contact the lessee company to attempt to negotiate an agreement restricting use of the surface or agreeing to set damages for surface use. Although there is no legal requirement to do so, a lessee may be willing to enter into a reasonable surface use/damages agreement to avoid potential disputes.

This paper is provided for general information purposes only as a service by the Railroad Commission of Texas. It is not legal advice and is not a substitute for legal advice. For specific questions and situations, it is strongly recommended that you consult with an experienced oil and gas or real estate attorney.

Appendix
J


New Mexico Oil and Gas Association
P. O. Box 1864
Santa Fe, NM 87504-1864
www.nmoga.org
NMOGA
Good Neighbor Initiatives
Ensuring Tomorrow's Future Today



The oil and gas industry in New Mexico has been active since the 1920s when the first oil discovery was made in the San Juan Basin. Today, in the northwestern, southeastern and northeastern parts of the state, pump jacks and drilling rigs are familiar sights.

While regulatory compliance with applicable laws and regulations is an important component of being a "good neighbor," we believe that there are other "good neighbor initiatives" that are necessary.

On this brochure, we describe these initiatives. We welcome and encourage public feedback on our initiatives and on our performance as a "good neighbor."

We believe that the landowner, lessee, permittee and/or resident in the producing areas of New Mexico may have legitimate questions about oil or gas production activity occurring nearby or on their land.

It is important that New Mexico's oil and gas industry establish and maintain a dialogue with its neighbors to answer questions and respond to concerns in a timely manner.

New Mexico Oil and Gas Association
P. O. Box 1864
Santa Fe, NM 87504-1864
505.982.2568
www.nmoga.org
Ensuring Tomorrow's Future Today

The member companies of the New Mexico Oil and Gas Association (NMOGA) are dedicated to responsible development of New Mexico's oil and gas resources. Responsible development includes good relationships with our neighbors and a commitment to environmental protection. NMOGA works to increase community awareness of the oil and gas industry and to promote a safer, more productive industry. NMOGA and member companies pledge to be a "Good neighbor" in the areas where we operate. This policy describes specific area where we believe our actions as "good neighbors" are especially important.

The oil and gas industry is the state's leading revenue source for education. We provide more than 90% of all education capital dollars through payments made to the Permanent Fund. In addition to this substantial contribution to the citizens of New Mexico, the oil and gas industry is the largest single source of revenue for the state of New Mexico after the gross receipts tax.

Over the past five years, our industry's combined tax and royalty contributions to the state have made up between 19% and 25% of the General Fund revenues. These revenues are used to fund public schools and state colleges fund the construction of public roads, buildings, and state parks, and help fund New Mexico government. In all, the industry provides as much as $1.4 billion annually to the state of New Mexico.

Thousands of New Mexicans support their families through jobs related to the oil and gas industry. In short, there is no other industry that provides the quantity and quality of jobs, tax revenues, economic development and community support to the citizens of New Mexico than the oil and gas industry.

As our industry exercises its right to explore and develop oil and gas within the state, producers understand that good communication with our neighbors is essential.

NMOGA and its member companies are committed to the:

- Protection of public safety;
- Protection of the environment;
- Respect for the property rights of others.

We pledge to use best management practices and put them to work as part of our responsibility to act as a "good neighbor."

As we pursue responsible development of energy resources to meet the nation's energy needs, we are committed to better communication and understanding between NMOGA members and the land owner, lessee, permittee and/or residents impacted by our operations.

With respect to the regulatory environment in which we work, the oil and gas industry is the most regulated industry in New Mexico. From exploration to production, processing, refining and transportation, our operations are permitted and our commitment to compliance with applicable laws and regulations is enforced by a web of federal, state and local regulators. We continually seek to work in a collaborative manner with government officials to assure responsible development of the natural resources.

It should be added that emergency situations occur that require immediate response. The response is necessary to protect the location and the environment. During emergency operations, several of these items listed below may not be able to be achieved. This will only occur during emergencies.

GOOD NEIGHBOR INITIATIVES

Companies will listen to the landowner, lessee permittee, and/or resident concerns and respond appropriately.

Personnel (company employees and contractors) must:

- Respect rights of way;
- Protect livestock/wildlife;
- Drive safely;
- Report damages to public/private property to the appropriate parties;
- Assure mechanical integrity of production systems;
- Ensure that personnel know and understand the rules and regulations applicable to our operations.

1. Companies will strive to increase communication with the landowner, lessee, permittee and/or residents by:
    - Informing the landowner, lessee, permittee and/or resident of industry property use rights (including mineral rights) and surface use rights through NMOGA seminars or publications of other industry groups' seminars/communications;
    - Designating a company contact person who is responsible for responding to community questions;
    - Seeking to identify and understand the concerns of the landowner, lessee, permittee and/or resident affected by our operations;
    - Attempting to notify and reasonably accommodate the nearby landowner lessee, permittee and/or resident when commencing significant activity that will impact land or the immediate area. Areas of importance should include equipment and pit set up and placement.

2. Companies and company contractors will respect the property and the rights of others by:
   - Minimizing surface disturbances;
   - Complying with remediation and restoration requirements of government authorities having jurisdiction;
   - Protecting livestock with appropriate measures;
   - Practicing good housekeeping;
   - Driving responsibly on public and private roads.
3. Companies will promote public safety by:
   - Conducting emergency planning;
   - Proper signage and warnings required by government authorities having jurisdiction.
4. Companies will promote the responsible maintenance and use of roads. Company personnel will:
   - Stay on rights-of-way;
   - Adhere to state and local road maintenance policies;
   - Obey established public speed limits;
   - Drive at appropriate speed for conditions;
   - Report and repair damage beyond the established rights-of-way caused exclusively by our activities;
   - Repair road damage in a timely manner if such damage is caused exclusively by our activities.
5. Companies will protect the environment. Companies and their personnel will:
   - Comply with applicable environmental laws and regulations;
   - Maintain equipment property and utilize good work practices
   - Seek to understand the landowner, lessee, permittee and/or resident concerns and possible questions regarding

√ Groundwater aquifers √ Surface water √ Air quality
√ Wildlife/livestock protection √ Housekeeping √ Noise
√ Surface Disturbance √ Noxious weeds and brush

- Ensure that pits are properly managed after completion in accordance with regulatory requirements.

6. Companies will emphasize education by:

- Educating our personnel about being a good neighbor:
- Educating the public about oil and gas operations including access, safety and environmental issues and the importance and positive impact of energy development at the state and federal levels.

CITY LIMITS OR HEAVILY POPULATED AREAS

7. Companies will communicate with appropriate government officials, including city and county officials. The oil and gas industry will be proactive in building relationships with city, county, state and federal officials. We will provide information to help officials understand that we are committed to:

- Full compliance with all applicable laws and regulations of government authorities having jurisdiction;
- Protection of the public and the environment by cooperating and working with governmental inspection and enforcement personnel;
- An ongoing process of education for personnel and for the public;
- Good housekeeping at our operations;
- The provision of adequate security at our locations;
- Applicable regulatory setback distances from our facilities and where no regulations exist, we are committed to the application of responsible engineering standards;
- Application of responsible engineering standards;
- The safe management of our operations;
- The posting of adequate safety signage at our locations.

We gratefully acknowledge the hard work and research completed for this document by the Petroleum Recovery Research Center at New Mexico Tech in Socorro, New Mexico.

Appendix K

SUBCHAPTER H: LOW EMISSION FUELS
DIVISION 1: GASOLINE VOLATILITY
§§114.301, 114.304 - 114.307, 114.309
Effective October 4, 2001

§114.301. Control Requirements for Reid Vapor Pressure.

(a) In the counties listed in §114.309 of this title (relating to Affected Counties), no person shall sell, offer for sale, supply, offer for supply, dispense, transfer, allow the transfer, place, store, or hold in any stationary tank, reservoir, or other container any gasoline with a Reid vapor pressure greater than 7.8 pounds per square inch, on a per gallon basis, which may ultimately be used to power a gasoline engine in the affected counties according to the schedule in subsection (b) of this section.

(b) Beginning May 1, 2000, all adjustments in the operation of affected facilities and all transfers or alterations of gasoline not meeting the requirements of this section must be completed as necessary to conform with the provisions of subsection (a) of this section during the following periods of each calendar year:

(1) June 1 through October 1 of each year for gasoline dispensing facilities; and

(2) May 1 through October 1 of each year for all other affected facilities.

(c) No producer shall the increase the use of methyl-tertiary-butyl-ether in gasoline on an average per gallon basis during the period of May 1 through October 1 of any calendar year over that used in the period May 1 through October 1, 1998 to conform with subsection (a) of this section.

Adopted April 5, 2000 Effective April 27, 2000

§114.304. Registration of Gasoline Producers and Importers.

Each producer and importer that, as of May 1, 2000, sells, offers for sale, supplies, or offers for supply from its production facility or import facility gasoline to counties listed in §114.309 of this title (relating to Affected Counties) shall register with the executive director, or his designated representative, by July 1, 2000. Beginning July 1, 2000, gasoline producers and importers that are not supplying gasoline to the affected counties as of May 1, 2000, shall register within 30 days after the first date that such person will produce or import gasoline intended to be sold, offered for sale, supplied, or offered for supply from its production or import facility to counties listed in §114.309 of this title. Registration shall be on forms prescribed by the executive director, or his designated representative, and shall include a statement of acceptance of the standards and enforcement provisions of this division; and shall include a statement of consent by the registrant that the executive director, or his designated representative, shall be permitted access to documentation and records. The executive director, or his designated representative, shall maintain a listing of all registered producers and importers.

Adopted April 5, 2000 Effective April 27, 2000

§114.305. Approved Test Methods.

(a) Compliance with the Reid vapor pressure (RVP) limitations of §114.301 of this title (relating to Control Requirements for Reid Vapor Pressure) shall be determined by the American Society for Testing and Materials (ASTM) Test Method D5191-99 (Standard Test Method for Vapor Pressure of Petroleum Products (Mini Method)) for the measurement of RVP using the following correlation correction equation to calculate RVP equivalent to that determined by test methods prescribed in Title 40 Code of Federal Regulations Part 80, Appendix E, Method 3, dated March 17, 1993.

$$RVPE = 0.956(x) - 0.347;$$

where:

RVPE = equivalent RVP with units in pounds per square inch (psi)

x = measured total vapor pressure in psi

(b) Minor modifications to these test methods may be used, if approved by the executive director.

(c) Test methods other than those specified in subsection (a) of this section, may be used if validated by 40 CFR 63, Appendix A, Test Method 301 (effective December 29, 1992). For the purposes of this subsection, substitute "executive director" each place that Test Method 301 references "administrator."

Adopted April 5, 2000 Effective April 27, 2000

§114.306. Recordkeeping, Reporting, and Certification Requirements.

(a) The owner or operator of any gasoline storage vessel, gasoline terminal, or gasoline bulk plant subject to the provisions of §114.301 of this title (relating to Control Requirements for Reid Vapor Pressure) shall maintain records of the Reid vapor pressure of all gasoline stored or transferred during the compliance period. All records shall be maintained for two years and be made available for review by the executive director, EPA, and local air pollution control agencies. Records do not have to be stored on-site, but must be made available for inspection at the site within five business days.

(b) All parties in the distribution chain (producers, importers, terminals, pipelines, truckers, rail carriers, and retail fuel dispensing outlets) subject to the provisions of §114.301 of this title must maintain copies or records of product transfer documents for a minimum of two years and shall upon request, make such copies or records available to representatives of the commission, EPA, or local air pollution agency having jurisdiction in the area. The product transfer documents must contain, at a minimum, the following information:

(1) the date of transfer;

(2) the name and address of the transferor;

(3) the name and address of the transferee;

(4) in the case of transferors or transferees who are producers or importers, the registration number of those persons as assigned by the commission under §114.304 of this title (relating to Registration of Gasoline Producers and Importers);

(5) the volume of gasoline being transferred;

(6) the location of the gasoline at the time of transfer; and

(7) the following certification statement: "This product complies with the requirements for Reid vapor pressure specified in Title 30 Texas Administrative Code, §114.301 and may be used in any Texas county requiring gasoline with a maximum RVP of 7.8 pounds per square inch."

(c) Each producer and importer subject to the provisions of §114.301 of this title shall submit to the executive director, or his designated representative, by November 30 of each year, a report which includes a quantification of the total gallons of gasoline and the total gallons of MTBE contained in gasoline for which the transfer documents contain the statement in subsection (b)(7) of this section during the periods May 1 through October 1 of 1998 and May 1 through October 1 of the current calendar year. The certifying report shall attest that all information contained in the report is true and accurate and is based on knowledge of the certifying official. The report must also include either:

(1) a certification statement that the use of MTBE in gasoline for which the transfer documents contain the statement in subsection (b)(7) of this section during the period May 1 through October 1 of the current calendar year has not increased on an average per gallon basis over that in the period May 1 through October 1, 1998; or

(2) if the average per gallon use of MTBE during the period May 1 through October 1 of the current calendar year exceeds the average per gallon use of MTBE during the period May 1 through October 1, 1998, documentation and explanation of the basis for the increased use in a manner sufficient to demonstrate that the producer or importer did not increase the use of MTBE during the period covered by the certification to conform with §114.301(a) of this title.

Adopted April 5, 2000 Effective April 27, 2000

§114.307. Exemptions.

(a) The following uses are exempt from §§114.301, 114.305, and 114.306 of this title (relating to Control Requirements for Reid Vapor Pressure; Approved Test Methods; and Recordkeeping, Reporting, and Certification Requirements):

(1) any stationary tank, reservoir, or other container:

(A) used exclusively for the fueling of implements of agriculture; or

(B) with a nominal capacity of 500 gallons (1,893 liters) or less; and

(2) all gasoline solely intended for use as aviation gasoline ("av-gas").

(b) Any gasoline that is either in a research, development, or test status; or is sold to petroleum, automobile, engine, or component manufacturers for research, development, or test purposes; or any gasoline to be used by, or under the control of petroleum, additive, automobile, engine, component manufacturers for research, development, or test purposes; or any independent research laboratories or academic institutions for use in research, development, or testing of petroleum, additive, automobile, engine, component products, is exempt from the provisions of this division (relating to Gasoline Volatility), provided that:

(1) the gasoline is kept segregated from non-exempt product, and the person possessing the product maintains documentation identifying the product as research, development, or testing fuel, as applicable, and stating that it is to be used only for research, development, or testing purposes; and

(2) the gasoline is not sold, dispensed, or transferred, or offered for sale, dispensing, or transfer from a retail fuel dispensing facility. It shall also not be sold, dispensed, or transferred, or offered for sale, dispensing, or transfer from a wholesale purchaser-consumer facility, unless such facility is associated with fuel, automotive, or engine research, development, or testing.

(c) Any gasoline that is refined, sold, dispensed, transferred, or offered for sale, dispensing, or transfer as competition racing fuel is exempted from the provisions of this division, provided that:

(1) the fuel is kept segregated from non-exempt fuel, and the party possessing the fuel for the purposes of refining, selling, dispensing, transferring, or offering for sale, dispensing, or transfer as competition racing fuel maintains documentation identifying the product as racing fuel, restricted for non-highway use in competition racing motor vehicles or engines;

(2) each pump stand at a regulated facility, from which the fuel is dispensed, is labeled with the applicable fuel identification and use restrictions described in paragraph (1) of this subsection; and

(3) the fuel is not sold, dispensed, transferred, or offered for sale, dispensing, or transfer for highway use in a motor vehicle.

(d) The owner or operator of a retail fuel dispensing outlet is exempt from all requirements of §114.306 of this title, except §114.306(b) of this title.

(e) Gasoline that does not meet the requirements of §114.301 of this title is not prohibited from being transferred, placed, stored, and/or held within the affected counties so long as it is not ultimately used to power:

(1) a gasoline-powered spark-ignition engine in a motor vehicle in the counties listed in §114.309 of this title (relating to Affected Counties), except for that used in conjunction with purposes stated in subsections (a) - (c) of this section; or

(2) a gasoline-powered spark-ignition engine in non-road equipment in the counties listed in §114.309 of this title, except for that used in conjunction with purposes stated in subsections (a) - (c) of this section.

Adopted September 12, 2001 Effective October 4, 2001

§114.309. Affected Counties.

All affected persons in the following counties shall be in compliance with §§114.301 and 114.304 - 114.307 of this title (relating to Control Requirements for Reid Vapor Pressure; Registration of Gasoline Producers and Importers; Approved Test Methods; Recordkeeping, Reporting, and Certification Requirements; and Exemptions) no later than the dates specified in §114.301(b) of this title: Anderson, Angelina, Aransas, Atascosa, Austin, Bastrop, Bee, Bell, Bexar, Bosque, Bowie, Brazos, Burleson, Caldwell, Calhoun, Camp, Cass, Cherokee, Colorado, Comal, Cooke, Coryell, De Witt, Delta, Ellis, Falls, Fannin, Fayette, Franklin, Freestone, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jackson, Jasper, Johnson, Karnes, Kaufman, Lamar, Lavaca, Lee, Leon, Limestone, Live Oak, Madison, Marion, Matagorda, McLennan, Milam, Morris, Nacogdoches, Navarro, Newton, Nueces, Panola, Parker, Polk, Rains, Red River, Refugio, Robertson, Rockwall, Rusk, Sabine, San Jacinto, San Patricio, San Augustine, Shelby, Smith, Somervell, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Washington, Wharton, Williamson, Wilson, Wise, and Wood.

Adopted September 12, 2001 Effective October 4, 2001

DIVISION 2: LOW EMISSION DIESEL
§§114.312 - 114.319
Effective May 17, 2006

§114.312. Low Emission Diesel Standards.

(a) No person shall sell, offer for sale, supply, or offer for supply, dispense, transfer, allow the transfer, place, store, or hold any diesel fuel in any stationary tank, reservoir, or other container in the counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates), that may ultimately be used to power a diesel fueled compression-ignition engine in the affected counties, that does not meet either the low emission diesel fuel (LED) standards of subsections (b) and (c) of this section, or the requirements of subsection (f) of this section.

(b) The maximum aromatic hydrocarbon content of LED is 10% by volume per gallon; or the LED has been reported in accordance with all of the requirements of §114.313 of this title (relating to Designated Alternative Limits), where:

(1) the aromatic hydrocarbon content does not exceed the designated alternative limit (DAL); and

(2) the DAL exceeds 10% by volume, the excess aromatic hydrocarbon content is fully offset in accordance with §114.313 of this title.

(c) The minimum cetane number for LED is 48.

(d) Subsection (a) of this section does not apply to a sale, offer for sale, or supply of diesel fuel to a producer where the producer further processes the diesel fuel at the producer's production facility prior to any subsequent sale, offer for sale, or supply of the diesel fuel.

(e) Diesel fuel that has been produced to comply with all specifications for a Certified Diesel Fuel Formulation as approved by an executive order by the California Air Resources Board on or before January 18, 2005, for compliance with California diesel fuel regulations that were in effect as of October 1, 1993, except for those approved for small refinery compliance, or diesel fuel that has been produced to meet all specifications for diesel fuel under regulations adopted by the California Air Resources Board, except for those approved for small refinery compliance, that were in effect as of January 18, 2005, may be used to satisfy the requirements of subsection (a) of this section.

(f) Alternative diesel fuel formulations that the producer has demonstrated to the satisfaction of the executive director, through emissions and performance testing methods prescribed in §114.315(c) and (d) of this title (relating to Approved Test Methods), as achieving comparable or better reductions in emissions of oxides of nitrogen and particulate matter may be used to satisfy the requirements of subsections (b) and (c) of this section. For alternative diesel fuel formulations that incorporate additive systems, the estimated emissions benefits of the alternative diesel fuel formulation may be determined by comparing the emissions and performance characteristics of the alternative diesel fuel with the additive system versus the emissions and performance characteristics of a diesel fuel without the additive system, as determined by the testing methods prescribed in §114.315(c) and (d) of this title.

Adopted April 26, 2006 Effective May 17, 2006

§114.313. Designated Alternate Limits.

(a) A producer or importer may assign a designated alternative limit (DAL) for aromatic hydrocarbon content to a final blend of low emission diesel fuel (LED) produced or imported by the producer or importer, except for that LED produced in accordance with §114.312(f) of this title (relating to Low Emission Diesel Standards), if the following conditions are met.

(1) In no case may the aromatic hydrocarbon content of the final blend shown by the sample and test conducted in accordance with §114.315 of this title (relating to Approved Test Methods) exceed the assigned DAL.

(2) The producer or importer shall notify the executive director of the volume (in barrels) and the DAL of the final blend. This notification must be received by the executive director before the start of physical transfer of the LED from the production or import facility, and in no case less than 12 hours before the producer completes physical transfer of the final blend.

(3) Within 90 days before or after the start of physical transfer of any final blend of LED to which a producer or importer has assigned a DAL exceeding the limit for aromatic hydrocarbon content specified in §114.312(b) of this title, the producer or importer shall complete physical transfer from the production or import facility of LED in sufficient quantity and with a DAL sufficiently below the standard specified in §114.312(b) of this title to offset the volume of aromatic hydrocarbons in the LED reported in excess of the standard.

(b) No person shall sell, offer for sale, or supply LED, in a final blend to which a producer or importer has assigned a DAL:

(1) exceeding the standard specified in §114.312(b) of this title for aromatic hydrocarbon content, where the total volume of the final blend sold, offered for sale, or supplied exceeds the volume reported to the executive director in accordance with subsection (a)(2) of this section; nor

(2) less than the standard specified in §114.312(b) of this title for aromatic hydrocarbon content, where the total volume of the final blend sold, offered for sale, or supplied is less than the volume reported to the executive director in accordance with subsection (a)(2) of this section.

(c) Whenever the final blend of a producer or importer includes volumes of diesel fuel the producer or importer has produced or imported, and volumes it has not produced or imported, the producer's or importer's DAL shall apply only to the volume of diesel fuel the producer or importer has produced or imported. In such a case, the producer or importer shall report to the executive director in accordance with subsection (a)(2) of this section, both the volume of diesel fuel produced or imported and the total volume of the final blend.

Adopted April 26, 2006 Effective May 17, 2006

§114.314. Registration of Diesel Producers and Importers.

(a) Each producer and importer that sold, offered for sale, supplied, or offered for supply diesel fuel from its production facility or import facility that may have been used in counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates) on or before April 1, 2005, shall register with the executive director by May 1, 2005.

(b) Each producer or importer that did not begin to sell, offer for sale, supply, or offer to supply diesel fuel from its production facility or import facility that may ultimately be used in counties listed in §114.319 of this title until after April 1, 2005, shall register with the executive director at least 30 days prior to the first date the diesel fuel is to be made available for use in the listed counties.

(c) Registration must be submitted on forms prescribed by the executive director and must include, at a minimum:

(1) a signed statement indicating whether the producer or importer does or does not intend to produce or import low emission diesel for use in the counties listed in §114.319 of this title on or after October 1, 2005;

(2) a statement of the total number of barrels of diesel fuel produced or imported in the 12 months prior to the date of registration that the producer or importer sold, offered for sale, supplied, or offered for supply from its production facility or import facility that was intended for use in the counties listed in §114.319 of this title;

(3) if appropriate, a statement of the estimated total number of barrels of low emission diesel that the producer or importer is planning to produce or import in the 12 months following the compliance date listed in §114.319(c)(1) of this title that the producer or importer intends to sell, offer for sale, supply, or offer to supply from its production facility or import facility for use in the counties listed in §114.319 of this title;

(4) if appropriate, a statement of the estimated total number of barrels of diesel fuel that the producer or importer is planning to produce or import under an alternative emission reduction plan under §114.318 of this title (relating to Alternative Emission Reduction Plan) in the 12 months following the compliance date listed in §114.319(c)(1) of this title that the producer or importer intends to sell, offer for sale, supply, or offer to supply from its production facility or import facility for use in the counties listed in §114.319 of this title;

(5) any other information determined by the executive director to be necessary to determine the adequacy of diesel supply in the affected counties; and

(6) a signed statement of consent by the registrant that the executive director is permitted to collect samples and access documentation and records.

(d) The executive director shall maintain a listing of all registered producers and importers.

Adopted March 9, 2005 Effective March 31, 2005

§114.315. Approved Test Methods.

(a) Compliance with the diesel fuel content requirements of this division must be determined by applying the appropriate test methods and procedures specified in the active version of American Society for Testing and Materials (ASTM) D975 (Standard Specification for Diesel Fuel Oils), or the following supplementary methods, as appropriate.

(1) The aromatic hydrocarbon content may be determined by the active version of ASTM Test Method D5186 (Standard Test Method for Determination of Aromatic Content and Polynuclear Aromatic Content of Diesel Fuels and Aviation Turbine Fuels by Supercritical Fluid Chromatography). The following correlation equation must be used to convert the supercritical fluid chromatography (SFC) results in mass percent to volume percent: aromatic hydrocarbons expressed in percent by volume = 0.916 x (aromatic hydrocarbons expressed in percent by weight) + 1.33.

(2) The polycyclic aromatic hydrocarbon (also referred to as polynuclear aromatic hydrocarbons or PAH) content may be determined by the active version of ASTM Test Method D5186 (Standard Test Method for Determination of Aromatic Content and Polynuclear Aromatic Content of Diesel Fuels and Aviation Turbine Fuels by Supercritical Fluid Chromatography). The correlation equation specified in paragraph (1) of this subsection must be used to convert the SFC results in mass percent to volume percent.

(3) The nitrogen content may be determined by the active version of ASTM Test Method D4629 (Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection).

(4) The American Petroleum Institute (API) gravity index may be determined by the active version of ASTM Test Method D287 (Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)).

(5) The viscosity may be determined by the active version of ASTM Test Method D445 (Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (the Calculation of Dynamic Viscosity)).

(6) The flashpoint may be determined by the active version of ASTM Test Method D93 (Standard Test Methods for Flash-Point by Pesky-Martens Closed Cup Tester).

(7) The distillation temperatures may be determined by the active version of ASTM Test Method D86 (Standard Test Method for Distillation of Petroleum Products at Atmospheric Pressure).

(b) Modifications to the testing methods and procedures in this section may be approved by the executive director after consultation with and agreement by the United States Environmental Protection Agency (EPA).

(c) The executive director, upon application, may approve alternative diesel fuel formulations as prescribed under §114.312(f) of this title (relating to Low Emission Diesel Standards) in accordance with the following procedures.

(1) The applicant shall initially submit a proposed test protocol to the executive director for approval, that must include:

(A) the identity of the entity that will conduct the tests described in paragraph (4) of this subsection;

(B) a testing plan with test procedures that are consistent with the requirements of paragraphs (2) and (4) of this subsection;

(C) fuel analysis test data showing that the candidate fuel meets the specifications for the appropriate Grade No. 1-D S15 or Grade No. 2-D S15 diesel fuel as specified in the active version of ASTM D975, except for lubricity, and identifying the characteristics of the candidate fuel identified in paragraph (2) of this subsection;

(D) fuel analysis test data showing that the fuel to be used as the reference fuel satisfies the characteristics identified in paragraph (3) of this subsection;

(E) a detailed description of the reasonable quality assurance and quality control procedures that will be implemented by the entity identified in subparagraph (A) of this paragraph to ensure the validity of the testing being performed; and

(F) notification of any outlier identification and exclusion procedure that will be used, and a demonstration that any such procedure meets generally accepted statistical principles.

(2) The applicant shall supply the candidate fuel to be used in the comparative testing in accordance with paragraph (4) of this subsection.

(A) The sulfur content, total aromatic hydrocarbon content, polycyclic aromatic hydrocarbon, nitrogen content, cetane number, API gravity index, viscosity at 40 degrees Celsius, flash point, and distillation (in degrees Fahrenheit) of the candidate fuel must be determined as the average of three tests conducted in accordance with the referenced test method specified in subsection (a) of this section.

(B) For alternative diesel fuel formulations that use an additive in the candidate fuel to achieve reductions, the applicant shall provide to the executive director upon application, the identity, chemical composition, and concentration of each additive used in the formulation and the test method by which the presence and concentration of the additive may be determined.

(C) The applicant may also specify any other parameters for the candidate fuel, along with the test method for determining the parameters. The applicant shall provide the chemical composition of each additive in the candidate fuel, except when the chemical composition of an additive is not known to either the applicant or to the manufacturer of the additive (if other), the applicant may provide a full disclosure of the chemical process of manufacture of the additive in lieu of its chemical composition.

(3) The reference fuel used in the comparative testing described in paragraph (4) of this subsection must be produced from straight-run diesel fuel by a hydrodearomatization process and must have the following characteristics determined in accordance with the referenced test method specified in subsection (a) of this section:

(A) sulfur content - 15 parts per million maximum;

(B) total aromatic hydrocarbon content - 10% maximum, volume percent;

(C) polycyclic aromatic hydrocarbon content - 1.4%, maximum weight percent;

(D) nitrogen content - ten parts per million, maximum;

(E) cetane number - 48, minimum;

(F) API gravity index - 33 to 39 degrees;

(G) viscosity at 40 degrees Celsius - 2.0 to 4.1 centistokes;

(H) flash point - 130 degrees Fahrenheit, minimum; and

(I) distillation:

(i) initial boiling point - 340 to 420 degrees Fahrenheit;

(ii) 10% point - 400 to 490 degrees Fahrenheit;

(iii) 50% point - 470 to 560 degrees Fahrenheit;

(iv) 90% point - 550 to 610 degrees Fahrenheit; and

(v) end point - 580 to 660 degrees Fahrenheit.

(4) Exhaust emission tests using the candidate fuel and the reference fuel specified in paragraph (3) of this subsection must be conducted in accordance with the federal test procedures as specified in 40 Code of Federal Regulations Part 86 (Control of Emissions from New and In-Use Highway Vehicles and Engines), Subpart N (Emission Regulations for New Otto-Cycle and Diesel Heavy-Duty Engines - Gaseous and Particulate Exhaust Test Procedures), as amended.

(A) The tests must be performed using a Detroit Diesel Corporation Series-60 engine or an engine specified by the applicant and approved by the executive director to be equally representative of the post-1990 model year heavy-duty diesel engine fleet. The test engine must have a minimum of 125 hours of use and exhibit stable operation before beginning the testing specified in this paragraph and must not exceed 110% of its applicable exhaust emission standards when using the reference fuel specified in paragraph (3) of this subsection.

(B) The comparative testing must be conducted by a third party that is mutually agreed upon by the executive director and the applicant. The applicant shall be responsible for all costs of the comparative testing.

(C) The applicant shall ensure that one of the test sequences in clause (i) or (ii) of this subparagraph is used to conduct the exhaust emissions tests.

(i) If both cold start and hot start exhaust emission tests are conducted, a minimum of five exhaust emission tests, each test consisting of at least one cold start and two hot start cycles, must be performed on the engine with each fuel, using either of the following sequences, where "R" is a test on the reference fuel and "C" is a test on the candidate fuel: RC RC RC (and continuing in the same order) or RC CR RC CR RC (and continuing in the same order). The engine mapping procedures and a conditioning transient cycle must be conducted with the reference fuel before each cold start procedure using the reference fuel. The reference cycle used for the candidate fuel must be the same cycle as that used for the fuel preceding it.

(ii) If only hot start exhaust emission tests are conducted, one of the following test sequences must be used throughout the testing, where "R" is a test on the reference fuel and "C" is a test on the candidate fuel, each test consisting of at least three hot start cycles:

(I) Alternative 1: RC CR RC CR (continuing in the same order for a given calendar day; a minimum of 20 individual hot start cycles must be completed with each fuel);

(II) Alternative 2: RR CC RR CC (continuing in the same order for a given calendar day; a minimum of 20 individual hot start cycles must be completed with each fuel);

(III) Alternative 3: RRR CCC RRR CCC (continuing in the same order for a given calendar day; a minimum of 21 individual hot start cycles must be completed with each fuel); or

(IV) Alternative 4: RR CCC RR (a minimum of six hot start cycles must be performed on the reference fuel followed with a conditioning period not to exceed 72 hours of engine operation on the candidate fuel before the first individual hot start emission test on the candidate fuel is performed; the conditioning cycle must represent normal engine operation; a minimum of nine hot start cycles must be performed on the candidate fuel after the conditioning period; only the emissions from the tests on the reference fuel conducted before the candidate fuel tests must be used in the calculations conducted in accordance with paragraph (5) of this subsection; a minimum of six hot start cycles must be performed on the reference fuel after the candidate fuel tests to determine any carry-over effect that may occur from the use of the candidate fuel).

(iii) For alternatives 1, 2, and 3, an equal number of tests must be conducted using the reference fuel and the candidate fuel on any given calendar day. At the beginning of each calendar day, the sequence of testing must begin with the fuel that was tested at the end of the preceding day.

(iv) For all alternatives, the engine mapping procedures and a conditioning transient cycle must be conducted after every fuel change and/or at the beginning of each day. The reference cycle generated from the reference fuel for the first test must be used for all subsequent tests.

(v) Each paired or triplicate series of individual tests must be averaged to obtain a single value that would be used in the calculations conducted in accordance with paragraph (5) of this subsection.

(D) The applicant shall submit a test schedule to the executive director at least one week prior to commencement of the tests. The test schedule must identify the days that the tests will be conducted, and must provide for conducting the test consecutively without substantial interruptions other than those resulting from the normal hours of operations at the test facility. The executive director or his designee shall be permitted to observe any tests. The party conducting the testing shall maintain a test log that identifies all tests conducted, all engine mapping procedures, all physical modifications to or operational tests of the engine, all re-calibrations or other changes to the test instruments, and all interruptions between tests and the reason for each such interruption. All tests conducted in accordance with the test schedule, other than any tests rejected in accordance with an outlier identification and exclusion procedure included in the approved test protocol, must be included in the comparison of emissions in accordance with paragraph (5) of this subsection.

(E) In each test of a fuel, exhaust emissions of oxides of nitrogen (NO_x), total hydrocarbons (THC), non-methane hydrocarbons (NMHC), and particulate matter (PM) must be measured.

(F) The exhaust emissions tests described in this paragraph must not be conducted until the test protocol as described in paragraph (1) of this subsection is approved by the executive director.

(G) Upon completion of the tests described in this paragraph, the applicant may submit an application for certification to the executive director. The application must include the approved test protocol, all of the fuel analysis and emissions test data, a copy of the complete test log prepared in accordance with subparagraph (D) of this paragraph, a demonstration that the candidate fuel meets the requirements for certification specified in this subsection, and other information as the executive director may reasonably require. Upon review of the certification application, the executive director shall grant or deny the application. Any denial must be accompanied by a written statement of the reasons for denial.

(5) The average emissions during testing with the candidate fuel must be compared to the average emissions during testing with the reference fuel specified in paragraph (3) of this subsection, applying one-sided Student's t statistics as set forth in Snedecar and Cochran, *Statistical Methods* (7th edition), page 91, Iowa State University Press, 1980. The executive director may issue a certification in accordance with this paragraph only if the executive director makes all of the following determinations:

(A) the average individual emissions of NO_x and PM, respectively, recorded during testing with the candidate fuel are comparable or better than the average individual emissions of NO_x and PM, respectively, recorded during testing with the reference fuel;

(B) use of any additive identified in accordance with paragraph (2)(B) of this subsection in diesel powered engines will not increase emissions of noxious or toxic substances that would not be emitted by such engines operating without the additive;

(C) in order for the determinations in subparagraph (A) of this paragraph to be made, for each referenced pollutant the candidate fuel must satisfy the following relationship; and

$$\bar{X}_C < \bar{X}_R + \delta - S_p \cdot \sqrt{2/n} \cdot t\,(a, 2n\text{-}2)$$

Where:

$\bar{X}_C$	=	Average emissions during testing with the candidate fuel.
$\bar{X}_R$	=	Average emissions during testing with the reference fuel.
δ	=	Tolerance level equal to 1% of $\bar{X}_R$ for oxides of nitrogen (NO_x), and 2% of $\bar{X}_R$ for particulate matter (PM).
S_p	=	Pooled standard deviation.
t (a, 2n-2)	=	The one-sided upper percentage point of t distribution with a = 0.15 and 2n-2 degrees of freedom.
n	=	Number of tests of candidate and reference fuel.

(D) the average individual emissions of THC and NMHC, respectively, recorded during testing with the candidate fuel do not exceed the test engine's applicable exhaust emission standards.

(6) If the executive director finds that a candidate fuel has been properly tested in accordance with this subsection, and makes the determinations specified in paragraph (5) of this subsection, then the

executive director may, after consultation with the EPA, issue an approval notification certifying that the alternative diesel fuel formulation represented by the candidate fuel may be used to satisfy the

requirements of §114.312(a) of this title. The approval notification must identify all of the relevant characteristics of the candidate fuel determined in accordance with paragraph (2) of this subsection.

(A) The approval notification must identify the following specifications of the alternative diesel fuel formulation as approved under this subsection:

(i) the total aromatic hydrocarbon content, cetane number, or other characteristics as appropriate and as determined in accordance with the test methods identified in subsection (a) of this section; or

(ii) for an alternative diesel fuel formulation using an additive to achieve reductions, the identity and minimum concentration or treatment rate of the additive, the minimum specifications of the base diesel fuel used in the approved formulation, and the test method or methods that must be used to satisfy the monitoring requirements of §114.316 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements).

(B) The approval notification must assign an identification number to the specific approved alternative diesel fuel formulation.

(d) Notwithstanding subsection (c) of this section, the executive director, upon application, may approve alternative diesel fuel formulations as prescribed under §114.312(f) of this title that may be used to satisfy the requirements of §114.312(b) and (c) of this title if the applicant has demonstrated to the satisfaction of the executive director and the EPA that the formulation will achieve comparable or better reductions in emissions of NO_x and PM.

(1) For alternative diesel fuel formulations that use an additive to achieve reductions, the applicant shall provide to the executive director upon application, the identity, chemical composition, and concentration of each additive used in the formulation, and the test method by which the presence and concentration of the additive may be determined.

(2) If the alternative diesel fuel formulation has been demonstrated to the satisfaction of the executive director and the EPA to achieve comparable or better reductions in emissions of NO_x and PM under this subsection, then the executive director may issue an approval notification certifying that the alternative diesel fuel formulation may be used to satisfy the requirements of §114.312(a) of this title.

(A) The approval notification must identify the following specifications of the alternative diesel fuel formulation as approved under this subsection:

(i) the total aromatic hydrocarbon content, cetane number, or other parameters as appropriate and as determined in accordance with the test methods identified in subsection (a) of this section; or

(ii) for an alternative diesel fuel using an additive to achieve reductions, the identity and minimum concentration or treatment rate of the additive, the minimum specifications of the base fuel used in the approved formulation, and the test method or methods that must be used to satisfy the monitoring requirements of §114.316 of this title.

(B) The approval notification must assign an identification number to the specific approved alternative diesel fuel formulation.

(3) The demonstration required under this subsection may be satisfied using the Unified Model as described in the EPA staff discussion document, *Strategies and Issues in Correlating Diesel Fuel Properties with Emissions*, Publication Number EPA420-P-01-001, published July 2001, to demonstrate that the applicable fuel properties of the alternative diesel fuel formulation will achieve at least a 5.5% reduction in NO_x emissions from on-road diesel fuel for the year 2007, and at least a 6.2% reduction in NO_x emissions from non-road diesel.

(4) The demonstration required under this subsection may be satisfied by the verification of an alternative diesel fuel formulation by the Air Pollution Control Technologies Center, a center under the EPA's Environmental Technology Verification Program, and the EPA's Office of Transportation and Air Quality's Voluntary Diesel Retrofit Program, demonstrating at least a 5.78% reduction in NO_x emissions when compared against a base diesel fuel with fuel properties within the ranges as described for nationwide average fuel in EPA's *Verification Protocol for Determination of Emissions Reductions Obtained by Use of Alternative or Reformulated Liquid Fuels, Fuel Additives, Fuel Emulsions, and Lubricants for Highway and Nonroad Use Diesel Engines and Light Duty Gasoline Engines and Vehicles* (Revision No. 03, September 2003).

Adopted April 26, 2006 Effective May 17, 2006

§114.316. Monitoring, Recordkeeping, and Reporting Requirements.

(a) Every producer or importer that has elected to sell, offer for sale, supply, or offer for supply diesel fuel that may ultimately be used in counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates) is subject to the applicable requirements of this section.

(b) All records relating to low emission diesel (LED) sampling must contain a statement declaring whether the aromatic hydrocarbon content of the sample conforms to the basic standard as specified in §114.312(b) of this title (relating to Low Emission Diesel Standards), to a designated alternative limit (DAL) in accordance with §114.313 of this title (relating to Designated Alternative Limits), to a limit as accepted under §114.312(e) of this title, or whether the diesel fuel conforms to an alternative diesel fuel formulation approved under §114.312(f) of this title.

(c) Each producer or importer of a diesel fuel that conforms to §114.312(a) - (e) of this title shall sample and test for the aromatic hydrocarbon content and minimum cetane number in each final blend of LED that the producer or importer has produced or imported, by collecting and analyzing a representative sample of diesel fuel taken using the methodologies specified in §114.315 of this title (relating to Approved Test Methods). The producer or importer shall maintain, for two years from the date of each sampling, records showing the sample date, identity of blend sampled, container or other vessel sampled, final blend volume, and the aromatic hydrocarbon content and minimum cetane number. All diesel fuel produced by the producer or imported by the importer and not tested as LED by the producer or importer as required by this section will be deemed to exceed the standards specified in §114.312 of this title, unless the producer or importer demonstrates that the diesel fuel meets those standards and limits.

(d) Each producer or importer of a diesel fuel that conforms to §114.312(f) of this title shall sample and test for the appropriate components of the alternative diesel fuel formulation as listed in the approval notification issued by the executive director under §114.315(c) or (d) of this title in each final blend of LED that the producer or importer has produced or imported, by collecting and analyzing a representative sample of diesel fuel taken from the final blend, using the methodologies specified in §114.315 of this title. If a producer or importer blends the diesel fuel components of the approved alternative diesel fuel formulation to produce a final blend of LED directly to pipelines, tank ships, railway tank cars, or trucks and trailers, the loading(s) must be sampled and tested for the appropriate components of the alternative diesel fuel formulation as approved by the executive director by the producer or importer or authorized contractor at a rate of one sample and test per 250,000 gallons of LED produced. The producer or importer shall maintain records showing the sample date, identity of blend sampled, container or other vessel sampled, final blend volume, and the content of the appropriate fuel components for two years from the date of each sampling. All diesel fuel produced by the producer or imported by the importer and not tested as LED by the producer or importer as required by this section will be deemed to exceed the standards specified in §114.312 of this title, unless the producer or importer demonstrates that the diesel fuel meets those standards and limits.

(e) If the alternative diesel fuel formulation being sampled and tested under subsection (d) of this section contains an additive system, the final blend must be sampled and tested for the content of the appropriate fuel components of the base fuel and additive as listed in the approval notification issued by the executive director under §114.315(c) or (d) of this title, and the producer or importer or authorized contractor shall maintain records showing that sufficient additive was added to maintain the appropriate additive concentration as approved by the executive director. If the additive is approved by the executive director for use with diesel fuel produced to comply with the fuel content standards specified in 40 Code of Federal Regulations §80.520, the testing for the content of the fuel components of the base fuel is not required.

(f) A producer or importer subject to the requirements of this division shall provide to the executive director any records required to be maintained by the producer or importer in accordance with this section within 15 days of a written request from the executive director, if the request is received before expiration of the period during which the records are required to be maintained. Whenever a producer or importer fails to provide records regarding a final blend of LED in accordance with the requirements of this section, the final blend of diesel fuel will be presumed to have been sold by the producer or importer in violation of the standards specified in §114.312 of this title, to which the producer or importer has elected to be subject.

(g) All parties in the distribution chain (producer, importer, terminals, pipelines, truckers, rail carriers, and retail fuel dispensing outlets) subject to the provisions of §114.312 of this title shall maintain copies or records of product transfer documents for a minimum of two years and shall upon request, make such copies or records available to representatives of the commission, United States

Environmental Protection Agency, or local air pollution agency having jurisdiction in the area. The product transfer documents must contain, at a minimum, the following information:

(1) the date of transfer;

(2) the name and address of the transferor;

(3) the name and address of the transferee;

(4) in the case of transferors or transferees who are producers or importers, the registration number of those persons as assigned by the commission under §114.314 of this title (relating to Registration of Diesel Producers and Importers);

(5) the volume of diesel fuel being transferred;

(6) the location of the diesel fuel at the time of transfer; and

(7) one of the following certification statements, as appropriate:

(A) "This product is Texas low emission diesel and may be used as fuel for diesel engines in any Texas county requiring the use of low emission diesel fuel."; or

(B) "This product may not be used as fuel for diesel engines in any Texas county requiring the use of low emission diesel fuel without further processing."; or

(C) "This product has been produced under a TCEQ approved alternative emission reduction plan and may be used as fuel for diesel engines in any Texas county requiring the use of low emission diesel fuel."

(h) For each final blend that is sold or supplied by a producer or importer from the party's production facility or import facility, and that contains volumes of diesel fuel that the party has produced and imported and volumes that the party neither produced nor imported, the producer or importer shall establish, maintain, and retain adequately organized records containing the following information.

(1) The volume of diesel fuel in the final blend that was not produced or imported by the producer or importer, the identity of the person(s) from whom such diesel fuel was acquired, the date(s) that it was acquired, and the invoice(s) representing the acquisition(s).

(2) The aromatic hydrocarbon content and the cetane number of the volume of diesel in the final blend that was not produced or imported by the producer or importer, determined either by:

(A) sampling and testing by the producer or importer of the acquired diesel fuel represented in the final blend; or

(B) written results of sampling and test of the diesel fuel supplied by the person(s) from whom the diesel fuel was acquired.

(3) A producer or importer subject to this subsection shall establish such records by the time the final blend triggering the requirements is sold or supplied from the production or import facility, and shall retain such records for two years from such date. During the period of required retention, the producer or importer shall make any of the records available to the executive director upon request.

(i) Each producer or importer electing to sell, offer for sale, supply, or offer to supply LED in accordance with §114.312 of this title shall provide a quarterly summation report to the executive director no later than the 45th day following the end of the calendar quarter. The quarterly report must provide, at a minimum, the information required to be collected by subsections (c) - (e), and (h) of this section and a reconciliation of the quarter's transactions relative to the requirements of subsections (c) - (e), and (h) of this section. Updates or revisions to estimated transaction volumes required by subsections (c) - (e) of this section must be included in this report.

(j) Each producer or importer electing to sell, offer for sale, supply, or offer to supply LED under §114.312(e) of this title shall provide to the executive director, as applicable, a copy of the executive order issued by the California Air Resources Board (CARB) for the Certified Diesel Fuel Formulation used to produce the LED or documentation demonstrating that the LED has been produced to meet all specifications for diesel fuel under regulations adopted by the CARB, except for those approved for small refinery compliance, that were in effect as of January 18, 2005, and shall comply with the requirements of subsections (c) and (h) of this section using the fuel specifications for aromatic hydrocarbon and cetane set by this executive order or regulations.

(k) Each producer electing to sell, offer for sale, supply, or offer to supply diesel fuel in accordance with §114.318 of this title (relating to Alternative Emission Reduction Plan) shall comply with the sampling and testing requirements of subsections (d) and (e) of this section for the appropriate fuel components of the diesel upon which the projected emission reductions were based. Each producer shall provide a quarterly report to the executive director no later than the 45th day following the end of the calendar quarter. The quarterly report must provide, at a minimum, the following information:

(1) the volume of diesel fuel produced by the producer that is subject to the provisions of the alternative emission reduction plan as approved by the executive director;

(2) the volume of diesel fuel that was not produced by the producer but was sold or supplied by the producer in the counties listed in §114.319 of this title and is subject to the provisions of the alternative emission reduction plan as approved by the executive director and the identity of the persons(s) from whom such diesel fuel was acquired and the date(s) that it was acquired. The producer shall retain records of the invoice(s) representing the acquisition(s) for two years from such date; and

(3) the information required to be collected in accordance with the sampling and testing requirements of this subsection and a reconciliation of the quarter's transactions relative to the requirements of this subsection for the appropriate fuel components of the diesel fuel that the projected

emission reductions demonstrated in the producer's alternative emission reduction plan were based upon.

Adopted April 26, 2006 Effective May 17, 2006

§114.317. Exemptions to Low Emission Diesel Requirements.

(a) Any diesel fuel that is either in a research, development, or test status; or is sold to petroleum, automobile, engine, or component manufacturers for research, development, or test purposes; or any diesel fuel to be used by, or under the control of, petroleum, additive, automobile, engine, or component manufacturers for research, development, or test purposes, is exempted from the provisions of this division (relating to Low Emission Diesel), provided that:

(1) the diesel fuel is kept segregated from non-exempt product, and the person possessing the product maintains documentation identifying the product as research, development, or testing fuel, as applicable, and stating that it is to be used only for research, development, or testing purposes; and

(2) the diesel fuel is not sold, dispensed, or transferred, or offered for sale, dispensing, or transfer from a retail fuel dispensing facility. It shall also not be sold, dispensed, or transferred, or offered for sale, dispensing, or transfer from a wholesale purchaser-consumer facility, unless such facility is associated with fuel, automotive, or engine research, development, or testing.

(b) Any diesel fuel that is refined, sold, dispensed, transferred, or offered for sale, dispensing, or transfer as competition racing fuel is exempted from the provisions of this division, provided that:

(1) the fuel is kept segregated from non-exempt fuel, and the party possessing the fuel for the purposes of refining, selling, dispensing, transferring, or offering for sale, dispensing, or transfer as competition racing fuel maintains documentation identifying the product as racing fuel, restricted for non-highway use in competition racing motor vehicles or engines;

(2) each pump stand at a regulated facility, from which the fuel is dispensed, is labeled with the applicable fuel identification and use restrictions described in paragraph (1) of this subsection; and

(3) the fuel is not sold, dispensed, transferred, or offered for sale, dispensing, or transfer for highway use in a motor vehicle.

(c) The owner or operator of a retail fuel dispensing outlet is exempt from all requirements of §114.316 of this title (relating to Monitoring, Recordkeeping, and Reporting Requirements) except §114.316(g) of this title.

(d) Diesel fuel that does not meet the requirements of §114.312 of this title (relating to Low Emission Diesel Standards) is not prohibited from being transferred, placed, stored, and/or held within the affected counties so long as it is not ultimately used:

(1) to power a diesel fueled compression-ignition engine in a motor vehicle in the counties listed in §114.319 of this title (relating to Affected Counties and Compliance Dates), except for that used in conjunction with purposes stated in subsections (a) and (b) of this section; or

(2) to power a diesel fueled compression-ignition engine in non-road equipment in the counties listed in §114.319(b) of this title, except for that used in conjunction with purposes stated in subsections (a) and (b) of this section.

Adopted April 26, 2006 Effective May 17, 2006

§114.318. Alternative Emission Reduction Plan.

(a) Diesel fuel that is sold, offered for sale, supplied, or offered for supply by a producer who submits an alternative emission reduction plan in accordance with subsection (b) of this section that is approved by the executive director will be considered in compliance with the requirements of §114.312(a) of this title (relating to Low Emission Diesel Standards).

(b) An alternative emission reduction plan must demonstrate that the emission reductions associated with compliance of this division (relating to Low Emission Diesel) that are attributable to the volume of diesel fuel that is sold, offered for sale, supplied, or offered for supply by the producer to the affected counties listed under §114.319(b) of this title (relating to Affected Counties and Compliance Dates) each year will be achieved through an equivalent substitute fuel strategy in accordance with either one or a combination of the following procedures.

(1) A producer shall demonstrate for each specific group of affected counties listed under each paragraph of §114.319(b) of this title, using the Unified Model as described in the United States Environmental Protection Agency (EPA) staff discussion document, *Strategies and Issues in Correlating Diesel Fuel Properties with Emissions*, Publication Number EPA420-P-01-001, published July 2001, and using only the diesel fuel that is sold, offered for sale, supplied, or offered for supply by the producer in the specific counties listed in each group to determine the average fuel properties to be used for the demonstration applicable to each group of affected counties, the following:

(A) the average fuel properties of all on-road diesel fuel produced in any given calendar year that is sold, offered for sale, supplied, or offered for supply by the producer in the applicable group of affected counties achieve at least a 5.5% reduction in oxides of nitrogen (NO_x) emissions for the year 2007; and

(B) the average fuel properties of all non-road diesel produced in any given calendar year that is sold, offered for sale, supplied, or offered for supply by the producer in the applicable group of affected counties achieve at least a 6.2% reduction in NO_x emissions.

(2) A producer shall demonstrate for the counties listed in §114.319(b)(4) of this title, the total number of barrels of noncompliant diesel fuel that may be offset by credits from early gasoline sulfur reduction using the following methodology or the methodology specified in paragraph (3) of this subsection.

(A) The credits from early gasoline sulfur reduction as determined in subparagraph (C) of this paragraph and paragraph (3)(A) of this subsection will be based on the actual level of sulfur in a producer's gasoline that was below the sulfur levels identified in the EPA's MOBILE6 model as the default refinery average and cap for conventional gasoline in each applicable year and as reported by the producer to EPA in accordance with 40 Code of Federal Regulations (CFR) §80.105 for 2003, and 40 CFR §80.370 for 2004 and 2005.

(B) The credits from early gasoline sulfur reduction can only be generated from the gasoline supplied by the producer in calendar years 2003, 2004, and 2005, to the counties listed in §114.319(b)(4) of this title and these credits, as determined in accordance with the applicable gasoline-to-diesel offset ratios calculated under subparagraph (D) of this paragraph, can only be used in the counties listed in §114.319(b)(4) of this title to demonstrate compliance through December 31, 2010.

(C) The credits from early gasoline sulfur reduction will be determined based on the level of sulfur reduction in each year using the following methodologies and subject to the applicable gasoline-to-diesel offset ratios determined using the methodology specified under subparagraph (D) of this paragraph.

(i) Methodology 1 - valid only for 2003 gasoline sulfur values between 259 parts per million (ppm) and 30 ppm.

$$M6 = (0.0000007 \cdot X^2) - (0.0007 \cdot X) + (0.137)$$

Where: M6 = The percent reduction in oxides of nitrogen (NO_x) emission reductions as determined using factors calculated by MOBILE6.2.

X = The gasoline sulfur level in 2003 in parts per million (ppm).

(ii) Methodology 2 - valid only for 2004 gasoline sulfur values between 121 ppm and 30 ppm.

$$M6 = (0.000003 \cdot X^2) - (0.0012 \cdot X) + (0.1042)$$

Where: M6 = The percent reduction in oxides of nitrogen (NO_x) emission reductions as determined using factors calculated by MOBILE6.2.

X = The gasoline sulfur level in 2004 in parts per million (ppm).

(iii) Methodology 3 - valid only for 2005 gasoline sulfur values between 92 ppm and 30 ppm.

$$M6 = (0.000005 \cdot X^2) - (0.0016 \cdot X) + (0.1046)$$

Where: M6 = The percent reduction in oxides of nitrogen (NO_x) emission reductions as determined using factors calculated by MOBILE6.2.

X = The gasoline sulfur level in 2005 in parts per million (ppm).

(D) To determine the number of barrels of noncompliant diesel fuel that may be offset by credits from early gasoline sulfur reduction, the actual number of barrels of lower sulfur gasoline supplied by the producer to the counties listed in §114.319(b)(4) of this title annually in 2003, 2004, and 2005, must be divided by the gasoline-to-diesel offset ratio determined in accordance with the following methodology.

$$(450.56 \cdot (5.78\%))/(GNEI \cdot M6) = \text{Gasoline-to-Diesel Offset Ratio}$$

Where: GNEI = Total oxides of nitrogen (NO_x) emissions inventory in tons per day attributed to gasoline engines for the counties listed in §114.319(b)(4) of this title as follows: 229.51 tons per day for 2003, 215.37 tons per day for 2004, and 201.24 tons per day for 2005.

M6 = The appropriate percent reduction as determined using the applicable methodology specified under subparagraph (C) of this paragraph.

(3) A producer shall demonstrate for the counties listed in §114.319(b)(4) of this title the total number of barrels of noncompliant diesel fuel that may be offset by credits from early gasoline sulfur reduction using the percentage of NO_x emission reductions attributed to on-road diesel for 2007 calculated with the Unified Model as described in paragraph (1) of this subsection, and the average fuel properties of the diesel fuel that is sold, offered for sale, supplied, or offered for supply by the producer in these specific counties, to determine the applicable offset ratio to be applied to the actual number of barrels of lower sulfur gasoline supplied by the producer to the counties listed in §114.319(b)(4) of this title annually in 2003, 2004, and 2005.

(A) To determine the number of barrels of noncompliant diesel fuel that may be offset by credits from early gasoline sulfur reduction, the actual number of barrels of lower sulfur gasoline supplied by the producer to the counties listed in §114.319(b)(4) of this title annually in 2003, 2004, and 2005, must be divided by the gasoline-to-diesel offset ratio determined in accordance with the following methodology.

$$(450.56 \cdot (5.78\%-UM))/(GNEI \cdot M6) = \text{Gasoline-to-Diesel Offset Ratio}$$

Where: UM = Percentage of oxides of nitrogen (NO_x) emission reductions attributed to on-road diesel for 2007 as calculated with the Unified Model.

GNEI = Total NO_x emissions inventory in tons per day attributed to gasoline engines for the counties listed in §114.319(b)(4) of this title as follows: 229.51 tons per day for 2003, 215.37 tons per day for 2004, and 201.24 tons per day for 2005.

M6 = The appropriate percent reduction as determined using the applicable methodology specified under paragraph (2)(C) of this subsection.

(B) The credits from early gasoline sulfur reduction can only be generated from the gasoline supplied by the producer in calendar years 2003, 2004, and 2005, to the counties listed in §114.319(b)(4) of this title and these credits, as determined in accordance with the applicable gasoline-to-diesel offset ratios as calculated in accordance with subparagraph (A) of this paragraph, can only be used in the counties listed in §114.319(b)(4) of this title for compliance through December 31, 2010.

(4) A producer shall demonstrate for the counties listed in §114.319(b)(1) or (2) of this title, respectively, the total number of barrels of noncompliant diesel fuel that may be offset by credits from the residual effects of early gasoline sulfur reduction on the NO_x emission reduction efficiencies of catalytic converters installed in gasoline-powered motor vehicles by using the following methodology.

(A) The credits from the residual effect of early gasoline sulfur reduction may only be generated by the volume of reformulated gasoline supplied by the producer in 2004 and 2005 to the counties listed in §114.319(b)(1) or (2) of this title, that had an average sulfur level reported by the producer to EPA in accordance with 40 CFR §80.370 that was below the sulfur level of 92 ppm in 2004, and 77 ppm in 2005.

(B) The number of barrels of noncompliant diesel fuel that may be offset by credits from the residual effects of early gasoline sulfur reduction will be determined by dividing the actual number of barrels of lower sulfur gasoline determined to be eligible to generate credit in accordance with subparagraph (A) of this paragraph by the following gasoline-to-diesel offset ratio as applicable.

(i) The gasoline-to-diesel offset ratio for eligible lower sulfur gasoline supplied to the counties listed in §114.319(b)(1) of this title will be 32.0 for calendar years 2006 through 2008.

(ii) The gasoline-to-diesel offset ratio for eligible lower sulfur gasoline supplied to the counties listed in §114.319(b)(2) of this title will be 66.0 for calendar years 2006 through 2008.

(C) The credits from the residual effects of early gasoline sulfur reduction as determined in accordance with subparagraph (B)(i) or (ii) of this paragraph can only be used in the counties listed in §114.319(b)(1) or (2) of this title, respectively, for compliance through December 31, 2008.

(c) All alternative emission reduction plans approved by the executive director prior to December 16, 2005, will expire on December 31, 2006, with the following exception. The executive director may allow a producer operating under an alternative emission reduction plan approved by the executive director prior to December 16, 2005, to continue to operate under that plan for a limited time beyond December 31, 2006, if all the following conditions are demonstrated to the satisfaction of the executive director:

(1) the producer's alternative emission reduction plan relied on the use of an alternative diesel formulation that has not been approved by the executive director under §114.315(c) of this title (relating to Approved Test Methods);

(2) the producer has submitted an application to the Air Pollution Control Technologies (APCT) Center, a center under the EPA's Environmental Technology Verification (ETV) Program, and the EPA's Office of Transportation and Air Quality's Voluntary Diesel Retrofit Program to pursue verification of this alternative diesel fuel formulation to demonstrate that it will achieve at least a 5.78% reduction in NO_x emissions when compared against a base diesel fuel with fuel properties within the ranges as described for nationwide average fuel in EPA's *Verification Protocol for Determination of Emissions Reductions Obtained by Use of Alternative or Reformulated Liquid Fuels, Fuel Additives, Fuel Emulsions, and Lubricants for Highway and Nonroad Use Diesel Engines and Light Duty Gasoline Engines and Vehicles* (Revision No. 03, September 2003);

(3) the producer has a contract with the APCT Center to perform the verification testing that is signed by both parties and paid in full by September 1, 2006; and

(4) the emissions testing as specified under an ETV test plan approved by both the APCT Center and EPA is completed before December 1, 2006.

(d) An alternative emission reduction plan must be approved by the executive director prior to the use of that plan for compliance with the requirements of this section.

(e) The executive director shall approve or disapprove alternative emission reduction plans that have been submitted by producers in accordance with subsection (b) of this section within 45 days of submittal.

(f) Alternative emission reduction plans submitted to the executive director in accordance with subsection (b) of this section must contain sufficient documentation to validate the average diesel fuel properties used in accordance with subsection (b)(1) or (2) of this section and, as appropriate, the sulfur properties and volumes of the gasoline that is being used to generate credit in accordance with subsection (b)(3) or (4) of this section.

Adopted April 26, 2006 Effective May 17, 2006

§114.319. Affected Counties and Compliance Dates.

(a) Affected persons in the counties listed in subsection (b) of this section shall be in compliance in accordance with the schedule listed in subsection (c) of this section with §§114.312 - 114.317 of this title (relating to Low Emission Diesel Standards; Designated Alternate Limits; Registration of Diesel Producers and Importers; Approved Test Methods; Monitoring, Recordkeeping, and Reporting Requirements; and Exemptions to Low Emission Diesel Requirements), as applicable, for diesel fuel that may ultimately be used to power a diesel-fueled compression-ignition engine in a motor vehicle or in non-road equipment.

(b) The following counties are subject to subsection (a) of this section:

(1) Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant;

(2) Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller;

(3) Hardin, Jefferson, and Orange; and

(4) Anderson, Angelina, Aransas, Atascosa, Austin, Bastrop, Bee, Bell, Bexar, Bosque, Bowie, Brazos, Burleson, Caldwell, Calhoun, Camp, Cass, Cherokee, Colorado, Comal, Cooke, Coryell, De Witt, Delta, Falls, Fannin, Fayette, Franklin, Freestone, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jackson, Jasper, Karnes, Lamar, Lavaca, Lee, Leon, Limestone, Live Oak, Madison, Marion, Matagorda, McLennan, Milam, Morris, Nacogdoches, Navarro, Newton, Nueces, Panola, Polk, Rains, Red River, Refugio, Robertson, Rusk, Sabine, San Jacinto, San Patricio, San Augustine, Shelby, Smith, Somervell, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Washington, Wharton, Williamson, Wilson, Wise, and Wood.

(c) Affected persons subject to subsection (a) of this section shall be in compliance with this division according to the following schedule:

(1) beginning October 1, 2005, for producers and importers;

(2) beginning November 15, 2005, for bulk plant distribution facilities; and

(3) beginning January 1, 2006, for retail fuel dispensing outlets, wholesale bulk purchaser/consumer facilities, and all other affected persons.

Appendix
L

110 County Area

Anderson, Angelina, Aransas, Atascosa, Austin, Bastrop, Bee, Bell, Bexar, Bosque, Bowie, Brazoria, Brazos, Burleson, Caldwell, Calhoun, Camp, Cass, Chambers, Cherokee, Collin, Colorado, Comal, Cooke, Coryell, Dallas, De Witt, Delta, Denton, Ellis, Falls, Fannin, Fayette, Fort Bend, Franklin, Freestone, Galveston, Goliad, Gonzales, Grayson, Gregg, Grimes, Guadalupe, Harris, Harrison, Hays, Henderson, Hill, Hood, Hopkins, Houston, Hunt, Jackson, Jasper, Johnson, Karnes, Kaufmann, Lamar, Lavaca, Lee, Leon, Liberty, Limestone, Live Oak, Madison, Marion, Matagorda, McLennan, Milam, Montgomery, Morris, Nacogdoches, Navarro, Newton, Nueces, Panola, Parker, Polk, Rains, Red River, Refugio, Robertson, Rockwall, Rusk, Sabine, San Jacinto, San Patricio, San Augustine, Shelby, Smith, Somervell, Tarrant, Titus, Travis, Trinity, Tyler, Upshur, Van Zandt, Victoria, Walker, Waller, Washington, Wharton, Williamson, Wilson, Wise, and Wood.

Appendix M

Amend **CSSB 275** (House Committee Printing) by adding the following appropriately numbered ARTICLE and renumbering subsequent ARTICLES accordingly:

ARTICLE ___. CERTAIN ECONOMIC DEVELOPMENT PROGRAMS

ADMINISTERED BY TEXAS ECONOMIC DEVELOPMENT AND TOURISM OFFICE

SECTION ___.01. Title 2, Agriculture Code, is amended by adding Chapter 16 to read as follows:

CHAPTER 16. FUEL ETHANOL AND BIODIESEL PRODUCTION

INCENTIVE PROGRAM

Sec. 16.001. DEFINITIONS. In this chapter:

(1) "Account" means the fuel ethanol and biodiesel production account.

(2) "ASTM" means the American Society for Testing and Materials.

(3) "Biodiesel" means a monoalkyl ester that:

(A) is derived from vegetable oils, rendered animal fats, or renewable lipids or a combination of those ingredients; and

(B) meets the requirements of ASTM PS 121, the provisional specification for biodiesel.

(4) "Fuel ethanol" means ethyl alcohol that:

(A) has a purity of at least 99 percent, exclusive of added denaturants;

(B) has been denatured in conformity with a method approved by the Bureau of Alcohol, Tobacco and Firearms of the United States Department of the Treasury;

(C) meets the requirements of ASTM D4806, the standard specification for ethanol used as a motor fuel; and

(D) is produced exclusively from agricultural products or by-products or municipal solid waste.

(5) "Office" means the Texas Economic Development and Tourism Office.

(6) "Producer" means a person who operates a fuel ethanol or biodiesel plant in this state.

Sec. 16.002. PLANT REGISTRATION. (a) To be eligible for a grant for fuel ethanol or biodiesel produced in a plant, a producer must apply to the office for the registration of the plant. A producer may apply for the registration of more than one plant.

(b) An application for the registration of a plant must show to the satisfaction of the office that:

(1) the plant is capable of producing fuel ethanol or biodiesel;

(2) the producer has made a substantial investment of resources in this state in connection with the plant; and

(3) the plant constitutes a permanent fixture in this state.

(c) The office, after consultation with the department, shall register each plant that qualifies under this section. The office shall notify the department of plants registered under this section.

Sec. 16.003. REPORTS. (a) On or before the fifth day of each month, a producer shall report to the office on:

(1) the number of gallons of fuel ethanol or biodiesel produced at each registered plant operated by the producer during the preceding month;

(2) the number of gallons of fuel ethanol or biodiesel imported into this state by the producer during the preceding month;

(3) the number of gallons of fuel ethanol or biodiesel sold or blended with motor fuels by the producer during the preceding month; and

(4) the total value of agricultural products consumed in each registered plant operated by the producer during the preceding month.

(b) A producer who fails to file a report as required by this section is ineligible to receive a grant for the period for which the report is not filed.

(c) The office shall send a copy of each report to the department.

Sec. 16.004. FUEL ETHANOL AND BIODIESEL PRODUCTION ACCOUNT. (a) The fuel ethanol and biodiesel production account is an account in the general revenue fund that may be appropriated only to the office for the purposes of this chapter, including the making of grants under this chapter.

(b) The account is composed of:

(1) fees collected under Section 16.005; and

(2) money transferred to the account under Subsection (c).

(c) The comptroller shall transfer from the undedicated portion of the general revenue fund to the account an amount of money equal to 5.25 times the amount of the fees collected under Section 16.005.

Sec. 16.005. FEE ON FUEL ETHANOL AND BIODIESEL PRODUCTION. (a) The office shall impose a fee on each producer in an amount equal to 3.2 cents for each gallon of fuel ethanol or biodiesel produced in each registered plant operated by the producer.

(b) For each fiscal year, the office may not impose fees on a producer for more than 18 million gallons of fuel ethanol or biodiesel produced at any one registered plant.

(c) The office shall transfer the fees collected under this section to the comptroller for deposit to the credit of the account.

(d) The office may not impose fees on a producer for fuel ethanol or biodiesel produced at a registered plant after the 10th anniversary of the date production from the plant begins.

(e) The office may enter into an interagency contract with the department authorizing the department to impose and collect fees on behalf of the office under this section.

Sec. 16.006. FUEL ETHANOL AND BIODIESEL GRANTS. (a) The office, after consultation with the department, shall make grants to producers as an incentive for the development of the fuel ethanol and biodiesel industry and agricultural production in this state.

(b) A producer is entitled to receive from the account 20 cents for each gallon of fuel ethanol or biodiesel produced in each registered plant operated by the producer until the 10th anniversary of the date production from the plant begins.

(c) For each fiscal year a producer may not receive grants for more than 18 million gallons of fuel ethanol or biodiesel produced at any one registered plant.

(d) The office by rule shall provide for the distribution of grant funds under this chapter to producers. The office shall make grants not less often than quarterly.

(e) If the office determines that the amount of money credited to the account is not sufficient to distribute the full amount of grant funds to eligible producers as provided by this chapter for a fiscal year, the office shall proportionately reduce the amount of each grant for each gallon of fuel ethanol or biodiesel produced as necessary to continue the incentive program during the remainder of the fiscal year.

SECTION __.02. Notwithstanding Section 16.004(c), Agriculture Code, as added by this Act, the comptroller may not make transfers from general revenue under that subsection during the fiscal biennium ending August 31, 2005.

Appendix N

NATIONAL CONFERENCE *of* STATE LEGISLATURES

The Forum for America's Ideas

7700 East First Place Denver, CO 80230
phone (303) 364-7700 fax (303) 364-7800
www.ncsl.org

MEMORANDUM

TO: Dub Taylor - Director - Texas Energy Conservation Office

FROM: Jennifer A. DeCesaro – Policy Specialist – National Conference of State Legislatures

DATE: 24 July 2006

RE: Biodiesel and Ethanol Incentives and Programs

Please find below information on biodiesel and ethanol incentives and programs in other states. What you will find are summaries of enacted bills from 2000 - 2005 as well as a link to the full text of the bill where available.

In addition, I would like to provide a link to a recently published NCSL article on state energy revenues located at: http://www.ncsl.org/programs/fiscal/severtax05.htm.

If you have any questions, or if you need any additional information, please feel free to contact me at 303.856.1379 or jennifer.decesaro@ncsl.org.

Arkansas
AR S.B. 363 - Act No. 1287 - 2003
The Biodiesel Incentive Act
Created an income tax incentive for biodiesel suppliers and grants for biodiesel producers.
Full text of the act is available at:
http://www.arkleg.state.ar.us/ftproot/acts/2003/public/act1287.pdf.

Hawaii
HI S.B. 2221 - Act No. 289 - 2000
Provides an investment credit for investment in a qualifying ethanol production facility.

HI S.B. 3207 - Act No. 140 - 2004
Changes the ethanol investment tax credit to the ethanol facility tax credit (EFTC). Bars other

credits if EFTC is claimed and limits EFTC to investment amount. Allows EFTC only in years that the facility is operating at 75% of nameplate capacity or more and if production commences on or before 1/1/12. Effective 7/1/03 for tax years after 12/31/03.
Full text of the act is available at: http://www.capitol.hawaii.gov/session2004/bills/sb3207_.htm.

Illinois
IL S.B. 2370 - Public Act No. 93-724 - 2004
Amends the Use Tax Act. Provides that "gasohol" means motor fuel that is a blend of denatured ethanol and gasoline that contains no more than 1.25% water by weight. Provides that the blend must contain 90% gasoline and 10% denatured alcohol. Allows a maximum of one percent error factor in the amount of denatured ethanol used in the blend to compensate for blending equipment variations. Provides that an violation is a business offense subject to a fine. Effective immediately.

IL H.B. 931 - Public Act No. 94-62 - 2005
Amends the Alternate Fuels Act. Provides that beginning July 1, 2005, owners of vehicles using domestic renewable fuel are eligible to apply for a fuel cost differential rebate. Provides that biodiesel blended fuel facilities may be included in the Alternate Fuel Infrastructure Program administered by the Department of Commerce and Economic Opportunity. Provides for three types of rebates.
Full text of the act is available at: http://www.ilga.gov/legislation/publicacts/94/PDF/094-0062.pdf.

IL H.B. 112 - Public Act No. 94-346 - 2005
Amends the Vehicle Code. Provides that, beginning July 1, 2006, all diesel powered vehicles owned or operated by the State, any county or unit of local government, any school board, state college, university or mass transit agency as well as all diesel powered Chicago Transit Authority vehicles must use a blend containing at least 2% biodiesel fuel. Provides that the requirement does not apply to vehicles designed or retrofitted to operate on ultra low sulfur fuel.
Full text of the act is available at: http://www.ilga.gov/legislation/publicacts/94/PDF/094-0346.pdf.

Indiana
IN H.B. 1032 - Public Law No. 6 - 2005
Requires the use of blended biodiesel fuel in state vehicles when feasible.
Full text of the act is available at: http://www.in.gov/legislative/bills/2005/PDF/HE/HE1032.1.pdf.

Minnesota
MN S.B. 1495 - Chapter No. - 2002
Providing for a biodiesel fuel mandate. Requires all diesel fuel sold in the state for use in internal combustion engines to contain at least 2% biodiesel fuel oil by volume; exempts equipment at electric generation facilities, mining equipment and railroad locomotives; provides that distributors who made expenditures necessary to adapt equipment to blend biodiesel fuel may be eligible for reimbursement.
Full text of the bill is available at:
http://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=S1495.3&session=ls82.

MN H.B. 2633 - Chapter No. 217 - 2004
Provides for exemptions from environmental review for certain ethanol plants.

Full text of the act is available at:
http://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=H2633.1&session=ls83.

MN S.B. 4 - Chapter No. 52 - 2005
Increases the minimum ethanol content required for gasoline sold or offered for sale in the state; establishes a petroleum replacement goal; requires certain studies and reports.
Full text of the bill is available at:
http://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=S0004.3&session=ls84.

Montana
MT H.B. 362 - Chapter No. - 2001
Exempts from taxation all manufacturing machinery, fixtures, equipment, and tools used for the production of ethanol from grain during the course of the construction of an ethanol manufacturing facility and for 10 years after completion of construction of the manufacturing facility.
Full text of the bill is available at: http://data.opi.state.mt.us/bills/2001/billhtml/HB0362.htm.

MT H.B. 644 - Chapter No. - 2001
Encourages economic development by creating an energy market demand for agricultural based biofuels. Taxes gasohol and biodiesel at a percentage of the rate for gasoline of special fuels. Defines gasohol and biodiesel. Provides that biofuel pumps be labeled with a statement of the tax advantage of the fuel. Expands the uses of the research and commercialization expendable trust fund to foster market demand for value added products.
Full text of the bill is available at: http://data.opi.state.mt.us/bills/2001/billhtml/HB0644.htm.

Maine
ME H.B. 1032 - Public Law No. 474 - 1999
Establishes the Agriculturally Derived Fuel Fund to promote the production and use of methanol and ethanol from agricultural biomass.

ME H.B. 1089 - Public Law No. 698 - 2003
Promotes production and use of fuels derived from agricultural and forest products. Provides that biofuels may include ethanol, methanol derived from biomass, pyrolysis oils from wood, hyrogen or methane from biomass or combinations of the above; provides a tax credit to a certificated producer. Requires a producer claiming a tax credit to provide information to the Commissioner of Environmental Protection regarding the nature and composition of the fuel.
Full text of the bill is available at:
http://www.mainelegislature.org/legis/bills_121st/billdocs/LD149201.doc.

ME S.B. 160 - Public Law No. 266 - 2003
Defines biodiesel fuel as renewable fuel composed of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats that is registered with the United States Environmental Protection Agency as a fuel and a fuel additive under the federal Clean Air Act and as otherwise specified in the American Society for Testing Materials Standard or its subsequent Standard Specification for Biodiesel Fuel Blend Stock.
Full text of the bill is available at:
http://www.mainelegislature.org/legis/bills_121st/billdocs/LD044102.doc.

Michigan
MI H.B. 4010 - Public Act No. 5 - 2003
Provides tax abatements for plants that manufacture biodiesel fuel. Provides for the establishment of plant rehabilitation districts and industrial development districts and exemption from taxes.
Full text of the bill is available at: http://www.legislature.mi.gov/documents/2003-2004/publicact/pdf/2003-PA-0005.pdf.

Mississippi
MS H.B. 928 - Chapter No. - 2003
Provides that the Commissioner of Agriculture may make cash payments to producers of ethanol, anhydrous alcohol, bio-diesel and wet alcohol that is produced in the State from non-State originated products if the State originated products are not available. Declares legislative intent that corn, biomass and resource commodities be furnished totally by State farmers insofar as the supply is available.

Nebraska
NE L.B. 605 - Signed by Governor - 1999
Relates to the Ethanol Development Act. Changes and eliminates ethanol production credit provisions. Changes provisions relating to the Ethanol Production Incentive Cash Fund and an excise tax on corn and grain sorghum. Eliminates provisions relating to written agreements and powers and duties of the board and department and changes the motor vehicle fuel tax.

NE L.B. 479 - Signed by Governor - 2003
Amends provisions related to ethanol tax credits and funds used for such credits.

NE L.B. 983 - Signed by Governor - 2004
Changes provisions relating to motor fuel taxes and motor vehicle fuel taxes. Eliminates provisions relating to tax credit gasoline and the Diesel Fuel Tax Act; amends provisions regarding the International Fuel tax Agreement Act. Provides for ethanol or biodiesel facilities, agricultural ethyl alcohol, kerosene and aircraft fuel.

NE L.B. 1065 - Signed by Governor - 2004
Provides funding for ethanol production incentives. Changes tax credits, tax rates, and fee rates and distribution as prescribed; eliminates a fuel tax provision. Mends provisions regarding excise taxes on corn and grain sorghum and employment and investment incentives.

North Dakota
ND H.B. 1390 - Signed by Governor - 2001
Relates to the biodiesel content of diesel fuel and its integration into the agricultural economy of this state.

ND S.B. 2019 - Signed by Governor - 2001
Provides an appropriation for defraying the expenses of the Department of Economic Development and Finance and to the Agricultural Products Utilization Commission for grants; provides for the transfer of funds. Relates to ethanol plant production incentives and tax refunds for fuel used for

agricultural purposes.

ND S.B. 2454 - Signed by Governor - 2001
Relates to a special fuels tax reduction for sales of diesel fuel blended with biodiesel fuel.
ND H.B. 1309 - Filed with Secretary of State - 2003
Relates to a biodiesel fuel mandate and a corporate income tax credit for a portion of the cost of retrofitting a facility for producing or blending diesel fuel containing biodiesel fuel. Provides for a special fuels tax reduction for fuel containing biodiesel.

ND S.B. 2222 - Filed with Secretary of State - 2003
Relates to ethanol production subsidies. Relates to the distribution of motor vehicle registration fees and the taxation of motor vehicle fuel for agricultural purposes. Relates to the duration and limitation of ethanol plant production incentives.

New Jersey
NJ S.B. 2313 - Chapter No. 56 - 2005
Appropriates Federal funds for the Garden State Ethanol Project for costs related to an ethanol plant to covert corn to ethanol, an additive that stretches gasoline supplies, and will be owned by a company established by area farmers who grow corn.
Full text of the bill is available at: http://www.njleg.state.nj.us/2004/Bills/S2500/2313_I1.PDF.

Oklahoma
OK S.B. 878 - Signed by Governor - 2002
Directs the Oklahoma Department of Agriculture to conduct certain feasibility study to attract ethanol processing plant to the State.
Full text of the bill is available at:
http://www2.lsb.state.ok.us/2001%2D02bills/sb/sb878%5Fsflr.rtf.

OK S.B. 429 - Chapter No. - 2003
Relates to revenue and taxation. Authorizes tax credits for certain ethanol facilities; defines terms; specifies amount of tax credits; provides procedures; sets certain limitations; provides for applications; specifies certain duties of Oklahoma Tax Commission; provides for codification; provides an effective date; declares an emergency.
Full text of the bill is available at:
http://www2.lsb.state.ok.us/2003%2D04bills/sb/sb429%5Fsflr.rtf.

OK H.B. 1398 - Signed by Governor - 2005
Relates to revenue and taxation. Authorizes tax credits for certain biodiesel facilities. Provides for transferability of credit and defines terms. Authorizes amount of tax credits against income tax for biodiesel credit; provides procedures; sets certain limitations; provides for applications; specifies certain duties of the Tax Commission; relates to definition of alternative biodiesel fuels; modifies definition of fill station; adds biodiesel to list of nonregulated fuels for sale in the state.
Full text of the bill is available at: http://www2.lsb.state.ok.us/2005%2D06hb/hb1398%5Fenr.rtf.

OK H.B. 1556 - Signed by Governor - 2005
Relates to revenue and taxation. Relates to tax credits for ethanol facilities and allows for transfer of

credit. Requires the transfer agreement to be filed with the Tax Commission. Modifies maximum gallonage eligible for credits; authorizes a credit against a motor fuel tax levy; authorizes refund claims.
Full text of the bill is available at: http://www2.lsb.state.ok.us/2005%2D06hb/hb1556%5Fenr.rtf.

Rhode Island
RI H.B. 8085 - Public Law No. 484 - 2004
Exempts organically produced biodiesel fuel from the motor fuel tax.
Full text of the bill is available at:
http://www.rilin.state.ri.us/BillText/BillText04/HouseText04/H8085.pdf.

South Dakota
SD H.B. 1279 - Filed with Secretary of State - 2003
Defines biodiesel blend fuels.
Full text of the bill is available at: http://legis.state.sd.us/sessions/2003/bills/HB1279enr.pdf.

SD S.B. 162 - Filed with Secretary of State - 2003
Revises the definition of E85 ethanol blend fuel.
Full text of the bill is available at: http://legis.state.sd.us/sessions/2003/bills/HB1279enr.pdf.

SD S.B. 31 - Filed with Secretary of State - 2004
Clarifies certain provisions that levy the fuel excise tax on biodiesel, biodiesel blends and ethyl alcohol. Amends provisions regarding fuel imports and exports.
Full text of the bill is available at: http://legis.state.sd.us/sessions/2004/bills/SB31enr.pdf.

Tennessee
TN H.B. 3067 - Chapter No. 89 - 2004
Provides for a review of alternative fuels such as biodiesel and gasohol as a means to enhance consumption of agricultural products; provides for recommendations and explanation of use of such fuels on contemporary motor vehicle engines.
Full text of the bill is available at:
http://www.legislature.state.tn.us/info/Leg_Archives/103GA/Bills/BillText/HB3067.pdf.

TN H.B. 1740 - Chapter No. 370 - 2005
Authorizes the Department of Transportation to undertake public-private partnerships with transportation fuel providers, including by not limited to farmer co-ops, to install a network of refueling facilities, including storage tanks and fuel pumps, dedicated to dispensing biofuels, including but limited to ethanol (E85) and biodiesel (B20). Provides for the establishment of a grant program to render financial assistance to help pay the costs for such at private sector fuel stations.
Full text of the bill is available at:
http://www.legislature.state.tn.us/bills/currentga/BILL/HB1740.pdf.

Washington
WA S.B. 6508 - Awaiting Governor's signature - 2005
Mandates fuel dealers to sell two percent biodiesel out of total diesel sales and two percent ethanol out of total gasoline sales. The two percent requirements for biodiesel and ethanol will act as a

baseline—the law is designed to boost the use of biofuels as the state's capacity to grow and produce biofuels increases. The standards eventually increase to five percent for biodiesel and 10 percent for ethanol.

In addition to establishing market access for ethanol and biodiesel in the state, the bill includes a number of incentives for in-state fuel crops and production facilities.
Full text of the bill is available at: http://www.leg.wa.gov/pub/billinfo/2005-06/Pdf/Bills/Senate%20Passed%20Legislature/6508-S.PL.pdf.

WA H.B. 1240 - Chapter No. 261 - 2003
Provides tax incentives for biodiesel and alcohol fuel production.
Full text of the bill is available at: http://www.leg.wa.gov/pub/billinfo/2003-04/Pdf/Bills/Session%20Law%202003/1240-S2.SL.pdf.

WA H.B. 1241 - Chapter No. 63 - 2003
Provides tax incentives for the distribution and retail sale of biodiesel and alcohol fuels. Exempts certain equipment, machinery and vehicles used in the distribution of such fuels from the sales tax. Exempts the use of machinery, equipment and services related to the sale of such fuels from the use tax.
Full text of the bill is available at: http://www.leg.wa.gov/pub/billinfo/2003-04/Pdf/Bills/Session%20Law%202003/1241-S2.SL.pdf.

WA H.B. 1242 - Chapter No. 17 - 2003
Establishes requirements for the use of biodiesel by state agencies.
Full text of the bill is available at: http://www.leg.wa.gov/pub/billinfo/2003-04/Pdf/Bills/Session%20Law%202003/1242-S.SL.pdf.

WA H.B. 1243 - Chapter No. 64 - 2003
Establishes a biodiesel pilot project for school buses powered by ultra low sulfur diesel fuel. Provides for the selection of participating school districts.
Full text of the bill is available at: http://www.leg.wa.gov/pub/billinfo/2003-04/Pdf/Bills/Session%20Law%202003/1243-S.SL.pdf.

Wisconsin
WI S.B. 378 - Signed by Governor - 2000
Relates to payments to ethanol producers; grants rule-making authority; makes appropriation.

WI S.B. 39 - Act No. 43 - 2005
Relates to school transportation bio-diesel fuel cost assistance; makes appropriations. Proves state aid for pupil bus transportation. Provides that for state aid payments for school districts not participating in the program shall be prorated as though the minimum amount had not been made.
Full text of the bill is available at: http://www.legis.state.wi.us/2005/data/acts/05Act43.pdf.

WI S.B. 41 - Act No. 83 - 2005
Relates to the definition of biodiesel fuel and the labeling, advertising, and promoting of biodiesel

fuel and biodiesel fuel blends for sale. Requires such biodiesel blends to be correctly identified as to name when sold at retail.
Full text of the bill is available at: http://www.legis.state.wi.us/2005/data/acts/05Act83.pdf.

Wyoming
WY H.B. 5 - Chapter No. - 2003
Removes limitations on the ethanol tax credit. Modifies the requirements necessary to qualify for the tax credit.