Senate Energy and Natural Resources Committee Natural Gas Conference
Independent Petroleum Association of America (IPAA)

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This document presents the comments of the Independent Petroleum Association of America and its Cooperating Associations (specifically including the Colorado Oil and Gas Association, the New Mexico Oil and Gas Association, and the Ohio Oil and Gas Association), and the US Oil & Gas Association.

Developing domestic natural gas supply will be an essential component to meet future domestic natural gas demand. This challenge requires action by Congress to encourage and allow supply to be developed. Broadly stated, it will require access to the national resource base, the capital to produce it, and a reasonable regulatory framework.

Access to the national resource base is significantly dependent upon resources underlying federal lands, both onshore and offshore. Access to onshore resources is constrained by a mosaic of restrictions that arise in the federal leasing and permitting process. Some of these arise because of the complexity of the process and the failure to adequately fund the agencies that must administer it under increasingly more complicated standards. Others, however, are a result of planned efforts to use the complexity of the process to delay or derail development. Access to key offshore resources is prohibited by moratoria.

Domestic natural gas cannot be developed without adequate capital. A stable federal permitting process is a key step. Without a belief that projects can be completed in a time certain, external capital will not be attracted to this inherently high risk industry. Similarly, internal capital - income from production - is dependent in part on federal tax policy and royalty policy.

The regulatory framework must be well reasoned. Environmental management of natural gas production remains an important component of supply development. However, novel interpretations of federal law and burdensome procedural requirements that do not benefit the environment must be avoided. For example, interpretations of the regulation of hydraulic fracturing under the Safe Drinking Water Act and of stormwater management during the construction of exploration and production facilities under the Clean Water Act are clearly at odds with the intent of these laws.

Detailed responses to the questions presented in this document address more comprehensively the challenges to natural gas supply. Recommendations are included for actions that the 109th Congress should take to improve natural gas supply

1. Increasing Domestic Natural Gas Supply
How can we increase domestic supplies from on-shore and off-shore resources?

Access to the federal resource base is the biggest challenge to developing domestic natural gas supplies both onshore and offshore. Some development opponents have suggested that access to the resource base is not an issue; they are wrong. For example, in 2003, the Department of Interior released a study on federal lands in the Intermountain West. It showed that 12 percent of natural gas resources were completely off limits. But, it also identified another 26-27 percent of the resources that were constrained by restrictions ranging from no surface occupancy to constraints on when development can occur. Collectively, close to 40 percent of the resource base is restricted. The remaining 60 percent is not restricted at the time of leasing, but can be limited as part of the federal permitting process and, obviously, producers must obtain a permit to develop the lease.

Some development opponents have argued that the existence of differences between the leases granted and those being developed, between the permits issued and wells being drilled suggest that leasing and permitting activities should slow. Natural gas exploration and production is not a "just in time" business. A viable natural gas project requires numerous factors to come together - leases need to be obtained that cover the potential scope of the "play", permits need to be obtained, exploration must be done, drilling rigs must be scheduled consistent with the limitations of the lease and/or permit. Each of these takes time and each depends on the prior action. Not all leases will be developed because the exploration process may show them to be undesirable or the reserve may be found to exist only under certain portions of the total lease group. This has always been the case, but when a snapshot of conditions is used to suggest lack of effort, it can only be characterized as misleading at best. Take for example, the recent comparison between the permitting of 6,100 wells in Fiscal Year 2004 compared to spudding of 2,700 wells. One obvious issue is whether it is appropriate to compare these actions in the same fiscal year. It would be more reasonable to compare new wells to permits in the prior year, where the number would be 3,800 permits in Fiscal Year 2003. Additionally, nothing in these raw number comparisons addresses whether the leases where the permits were issued or the permits limit when drilling can occur. Many parts of the Intermountain West have habitat management constraints that create such limits and most of the permits are in those states. And, it is important to recognize that drilling rigs and drilling labor are inelastic. There must be a sense that sustainable activity is likely before the service industry expand its capacity. The oil price crisis of 1998-99 resulted in a loss of 65,000 jobs in the E&P industry that has not been completely replaced. The persistent leasing and permitting challenges of the past several years has not generated the sense of sustainability that is necessary to expand this industry segment.

In the offshore, moratoria in the Eastern Gulf of Mexico, the Atlantic Ocean, and the Pacific Ocean prohibit access to over 70 trillion cubic feet of potential natural gas - a conservative estimate. Without access, these national resources are lost.

Onshore, challenges are largely wrapped up in the federal land management, leasing, and permitting process. At the heart of this challenge is the fundamental question of how the federal government makes its decisions. In large part, addressing this question involves the role of the National Environmental Policy Act (NEPA). NEPA has become the most significant visible factor in the federal decision-making process.

When NEPA passed, at issue was the need to include environmental implications in the factors that the federal government considered as it made decisions. NEPA's purpose was to assure that all stakeholders had the opportunity to participate in the federal decision-making process. NEPA is a vague statute passed in 1969 and largely unchanged since then. Its implementation has essentially been driven by Executive Orders and judicial decisions. Now, it has become the vehicle for multivolume Environmental Impact Statements that can be triggered at several points in the federal permitting process - the development of Resource Management Plans, the leasing process, and at times during the Application for Permits to Drill (APD).

Opponents of development understand that NEPA and other federal procedural requirements offer opportunities for delay. Delay in making decisions can have a critical impact on development. Producers must replace their production to account for the natural decline rate, a rate for natural gas that is now approximately 28 percent per year and increasing. Federal lands offer the most cost effective potential reserves to develop. Other basins are mature and require greater effort such as deep gas development to compete. These are more costly projects. Producers must reinvest their capital continuously and cannot allow it to stagnate because of permitting delays. Consequently, development opponents have embarked on a strategy to abuse the federal process by challenging decisions at every opportunity in both administrative adjudication procedures and the courts.

NEPA and the other federal processes were intended to assure that all factors were considered in making decisions; they were not created to prevent decisions.

Congress needs to develop a mechanism to expedite federal approval of natural gas projects while the nation faces current serious supply and demand challenges. Such an approach should assure that proper environmental factors are considered and addressed but should limit the opportunity to abuse the federal decision-making process to delay decisions.

Adequate funding to conduct the federal planning, leasing, and permitting process is essential to meet the challenge of developing domestic natural gas. While agencies like the Bureau of Land Management (BLM) and the Minerals Management Service (MMS) bear the greatest of these responsibilities, other federal agencies that must provide consultation and concurrence are similarly important. Moreover, during the past several years the BLM has faced diversion of its resources to respond to challenges to its decisions that diminish its principle functions.

Lack of funds contributes to permitting backlogs and uncertainty regarding the time in which permits will be approved. For example, during the past several years the BLM has been aggressively acting to reduce permit backlogs and provide timely action on permit applications. However, without continuing funding support the BLM will not be able to maintain the quality of this effort. Moreover, it is essential that funding translates into adequate staffing to meet the challenges of the permitting process and that it be directed to execution of the leasing and permitting process. Some progress has been made to improve the interaction between agencies and within agencies through the President's Energy Permit Streamlining Task Force, but this type of effort needs to continue. Similarly, regulatory agencies need to establish time limits to complete the approvals and use a goal-oriented measurement to determine if their efforts are achieving the goals.

Congress should assure that the federal planning, leasing, and permitting process receives funding to meet its responsibilities including funding for the ancillary agencies that must support these efforts.

Congress should pass the provisions in the H.R. 6 Conference Agreement requiring federal permits to be resolved in a timely manner after receipt.

A particular example showing the implications of limited funding relates to the development of NEPA-related documents during the federal process. NEPA's requirements that the federal government evaluate the environmental implications of federal actions places the responsibility for developing the documents needed for these decisions on the federal agency. However, because of inadequate federal funding, producers have been compelled to fund the development of these documents in order for the agency to have them and complete its decision. Congress purposely chose to make the development of NEPA documents a federal responsibility. It should not shift to the private sector because of a failure to adequately fund the federal process; but it has. Producers have no choice if they want expeditious action on their project. An equitable resolution of this situation is needed.

Congress should pass the provision in the H.R. 6 Conference Agreement that allows producers to be reimbursed from future federal royalties for the costs of financing these federally required studies if adequate federal funding is unavailable.

Offshore, challenges are driven by the moratoria on access to key portions of the federal offshore. These moratoria - both legislative and executive branch - are unreasonable. They rely on antiquated and inaccurate assessments of the risks of developing offshore resources. Current offshore development technology ranks with the most sophisticated in the world. It allows for rapid responses to potential environmental threats. As described in the 1999 Department of Energy report, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology*:

In the event of a well control emergency, advanced "intelligent" subsea trees allow live wells to be shut in quickly under a variety of well conditions and operational circumstances. Moreover, current measurement while drilling technology enables drillers to accurately steer a deepwater relief well to regain well control if necessary.

The use of these technologies has produced a record of success over the past decades. *Our Ocean Future*, prepared for the International Year of the Ocean in 1998 reported:

The number of significant spills from oil production in state and federal waters has been low, and the volume of oil spilled has declined fairly steadily over the years (Minerals Management Service, 1997). There has not been a spill larger than 1,000 barrels from oil and gas platforms on the outer continental shelf since 1980; in fact, natural seeps introduce approximately 100 times more oil into U.S. marine waters than do spills from offshore development and production activities. Increased precautions by industry, enhanced safety technologies (e.g., blowout prevention systems, shut-in valves), and strict adherence to government regulations most likely have minimized the risk of oil spills from offshore activities.

The U.S. Commission on Ocean Policy report, *An Ocean Blueprint for the 21st Century*, reiterates this assessment:

According to MMS, 97 percent of OCS spills are one barrel or less in volume and U.S. OCS offshore facilities and pipelines accounted for only 2 percent of the volume of oil released into U.S. waters for the period 1985-2001 (Figure 24.3). The total volume and number of such spills over that period have been significantly declining due to industry safety practices and improved spill prevention technology. By comparison, the National Research Council (NRC) estimated that 690,000 barrels of oil enter North American ocean waters each year from land-based human activities, and another 1,118,000 barrels result from natural seeps emanating from the seafloor.

A review of the MMS publication, *OCS Oil Spill Facts* (September 2002), shows that no platform in the Outer Continental Shelf has generated a 1000 barrel oil spill over the 20 year period from 1980 through 2000.

These facts can be ignored no longer. The national need for natural gas to sustain and grow its economy and meet its environmental objectives compels a realistic consideration of its offshore resources. Coastal states have real concerns about the consequences of offshore development. Their opposition - where it occurs - is not founded on risks based on current offshore technology. Nonetheless, this opposition must be addressed.

Given the very significant potential resources on the Outer Continental Shelf lands currently off limits by congressional and Executive Branch moratoria to exploration, development and production of natural gas and crude oil, Congress should put in place a process to:

- *Begin lifting of moratoria; and,*
- *Allow states to share in revenues generated by federal lease bonuses and royalties in proportion to the amount of leasing and production that occurs off their coasts.*

Finally, development of the resource base - whether onshore or offshore - requires the continual development of the technology to find and produce it. The dramatic and environmentally protective successes in the offshore would not have been possible without research and development (R&D) funding. The new geological and geophysical exploration tools in the onshore started with federal research. Adequate funding of fossil energy research and development activities is essential to continue this progress. Federally funded research and development programs have enabled industry to extract more gas from more geologically complex formations, yet in a more environmentally sensitive manner. Unfortunately, these federal research programs have been threatened in recent years and likely will continue to be; their value will be understated in the budget process. Congress needs to support these federal research programs. As the domestic industry has shifted more to independents, historic funding sources for R&D are largely extinguished.

Congress should continue to adequately fund vitally important oil and gas R&D programs.

2. Liquefied Natural Gas
What should our expectations be regarding imported LNG as a supply source, and what policies should be considered on LNG terminal siting and safety?

Liquefied Natural Gas (LNG) will be an increasingly important supply component to meet domestic - and international - demand for natural gas. LNG must be considered a supplement to domestic natural gas production - not an alternative. The National Petroleum Council's 2003 Natural Gas study, *Balancing Natural Gas Policy -*

Fueling the Demands of a Growing Economy, presented three Findings that state well the situation.

Traditional North American producing areas will provide 75% of long-term U.S. gas needs, but will be unable to meet projected demand.

Increased access to U.S. resources (excluding designated wilderness areas and national parks) could save consumers $300 billion in natural gas costs over the next 20 years.

New, large-scale resources such as LNG and Arctic gas are available and could meet 20 25 % of demand, but are higher-cost, have longer lead times, and face major barriers to development.

The NPC Study goes on to state: A balanced future that includes increased energy efficiency, immediate development of new resources, and flexibility in fuel choice, could save $1 trillion in U.S. natural gas costs over the next 20 years. Public policy must support these objectives.

Congress needs to recognize the essential need to create these balanced solutions as it considers future natural gas policy.

3. Natural Gas Infrastructure
What legislative or regulatory policies should be implemented to encourage needed additional safe and adequate infrastructure for natural gas transmission and distribution lines and storage?

To encourage construction of necessary energy infrastructure, the Federal Energy Regulatory Commission (FERC) should be the lead agency in the regulatory process. Specifically, FERC's record in the certification process should be the exclusive record for any administrative appeals. Other relevant government agencies would be involved in the process concurrent with FERC, possibly avoiding administrative and judicial appeals or, at a minimum, shortening the time needed for review. While market-based rates may be appropriate for some new interstate infrastructure development, FERC should continue to apply its cost-based rate regulations to pipelines with market power. With appropriate FERC oversight, producers can be assured of the ability to get gas to market via interstate pipelines at fair prices and under non-discriminatory terms and conditions.

4. Environmental
What are environmental challenges and regulatory barriers related to expanding our natural gas supply and how can they be remedied?

Dual environmental challenges confront the expansion of domestic natural gas supplies during the exploration and production (E&P) phase. The first relates to specific regulatory requirements; the second involves the federal decision-making process. This latter issue was addressed in Question 1.

In general, natural gas E&P operations must address the costs of environmental regulation compliance largely driven by federal laws. However, several compliance issues pose significant threats to the development of future supply.

First, potential federal regulation of hydraulic fracturing well stimulation practices would affect new natural gas development, particularly in nonconventional gas plays. Hydraulic fracturing is a technique used to allow natural gas and oil to move more freely from the rock pores where they are trapped to a producing well that can bring them to the surface. The technology was developed in the late 1940s and has been continuously improved and applied since that time.

Application of hydraulic fracturing to increase recovery is estimated to account for 30 percent of U.S. recoverable oil and gas reserves and has been responsible for the addition of more than 7 billion barrels of oil and 600 trillion cubic feet of natural gas to meet the nation's energy needs. The National Petroleum Council estimates that 60 to 80 percent of all the wells drilled in the next decade to meet natural gas demand will require fracturing.

Congress enacted the Safe Drinking Water Act (SDWA) in 1974. By then, hydraulic fracturing had been used for 25 years with no environmental problems. State permitting programs regulated it to assure its safe use. Under the Act, states developed extensive Underground Injection Control (UIC) programs to manage liquid wastes and the reinjection of produced waters. These programs addressed liquids intended to be injected and - to remain - in underground geologic formations.

At no time during these debates was there any suggestion of including hydraulic fracturing in the UIC waste management requirements. Yet, in the mid-1990s litigation challenged Environmental Protection Agency's (EPA) failure to regulate hydraulic fracturing of coalbed methane under the SDWA. The 11th Circuit Court ruled against EPA but never addressed the environmental risks of hydraulic fracturing; it merely decided that the plain language of the statute includes hydraulic fracturing as underground injection. Years of further litigation has resulted in EPA requiring Alabama to regulate hydraulic fracturing under its UIC program.

States are concerned about the implications of the court's decision. States recognize the large threat of the decision to state UIC regulatory programs. Currently, the two state organizations with the greatest involvement in oil and gas regulation - the Interstate Oil and Gas Compact Commission (IOGCC) and the Ground Water Protection Council (GWPC) - support the need for legislation to resolve the issue and return the SDWA to its original intent.

Meanwhile, EPA initiated a study of coalbed methane hydraulic fracturing environmental risks. EPA limited its study to coalbed methane partly because the court cases were directed toward coalbed operations and partly because, if hydraulic fracturing environmental risks existed, they would occur in the shallow coalbed fields. In June 2004, EPA released the results of its study. Its results were straightforward. "Based on the information collected and reviewed, EPA has concluded that the injection of hydraulic fracturing fluids into coalbed methane wells poses little or no threat to USDWs and does not justify additional study at this time."

The H.R. 6 Conference Agreement provided a straightforward resolution to the regulatory uncertainty facing hydraulic fracturing. The 109th Congress should adopt it.

A second regulatory issue posing significant implications for the E&P industry is the regulation of stormwater discharges during construction of its facilities. The 1987 Clean Water Act (CWA) included two stormwater provisions that are now intertwined regarding their application to oil and natural gas E&P facilities. The first provision - Section 402(l)(2) - excludes uncontaminated stormwater from oil and natural gas E&P facilities from the National Pollutant Discharge Elimination System (NPDES) permitting process. The second subsection - Section 402(p) - directs the EPA to permit municipal and industrial stormwater discharges.

In 1992, EPA promulgated stormwater construction permitting regulations affecting facilities greater than five acres. In *Natural Resources Defense Council v. Environmental Protection Agency (NRDC v EPA)*, the Court concluded that EPA had been arbitrary and capricious in proposing a one acre limit and finalizing the regulations at five acres. Following this litigation EPA developed stormwater construction permitting regulations in two Phases. Phase I covered facilities greater than five acres; Phase II covers facilities from one to five acres. During this period EPA also issued a guidance document in one Region that the stormwater construction regulations applied to the construction of E&P facilities. This guidance is inconsistent with the intent of the law. Congress was clear that E&P facilities should be regulated based on the nature of its discharge, not the mere act of construction.

The consequences of EPA's action are significant. Most oil and natural gas E&P sites fall within the one to five acre range. In 2000, a total of 31,732 exploratory and production wells were drilled - over 10,000 in Texas and Oklahoma. To meet future natural gas demand, the National Petroleum Council estimates that the number of natural gas wells alone needs to increase to approximately 48,000 wells annually. EPA's approach is inappropriate for oil and gas facilities; it is oriented for subdivision and shopping center projects. Oil and gas production operations involve the leasing of surface rights, construction occurs within a matter of weeks, and timing is critical because it involves obtaining a drilling rig that must be carefully scheduled and is paid for based on the number of days it is in use. Disruption in this process can place entire projects and substantial capital at risk. Some estimates conclude that the nation could lose between one and three trillion cubic feet of natural gas per year over the next 20 years because of EPA's regulations.

H.R. 6 included a provision to clarify this regulatory process by directing that regulation occur under subsection 402(l). It needs to be enacted by the 109th Congress.

Third, the Coastal Zone Management Act (CZMA) and its consistency provisions have a long history of impeding energy exploration, development and production at essentially every step of the process. The CZMA created a national program designed to encourage the States to develop programs to manage and balance competing uses of and impacts to coastal resources. The law was designed to enhance communications between federal agencies responsible for permitting activities on Federal lands and coastal states to minimize or eliminate conflicts with approved State goals and programs. It was viewed as a positive law designed to help resolve issues.

However, regulatory implementation and States' misuse of the consistency provisions of the CZMA have created uncertainty and have impeded federal offshore exploration and production projects as well as the siting of onshore and offshore energy infrastructure. Some coastal management policies conflict with the CZMA law, prohibiting siting of onshore and offshore infrastructure in the state coastal zone and on federal lands.

The National Oceanic and Atmospheric Administration's (NOAA) revised CZMA federal consistency regulations expand the ability for a state to use its coastal management program to impede federal permitting involving proposed activities that occur in federal waters off the coasts of other States. States have blocked or delayed federal offshore energy activities far outside of their coastal waters through unreasonable application of the CZMA consistency provisions. The Secretary of Commerce has not acted in a timely manner to make decisions on consistency appeals, thus making the appeals process last many years.

The H.R. 6 Conference Agreement included provisions to resolve these conflicts revising the CZMA consistency review process and bring its implementation into harmony with Congress's original goals. These changes should be passed by the 109th Congress.

Fourth, habitat management, particularly those related to the Endangered Species Act, can pose a significant challenge to natural gas development primarily on federal lands. Lease stipulations and permit restrictions that limit either the time or the location for development can effectively prevent access to the resource base. These restrictions need to be carefully crafted to balance the protection of wildlife habitat with the need to develop domestic natural gas. Both the temporal and spatial restrictions need to be essential to protect the wildlife. Similarly, the listing process of the Endangered Species Act and the subsequent constraints need to be based on sound science.

The H.R. 6 Conference Agreement included provisions to improve the coordination between agencies in the federal leasing and permitting process that need to be enhanced. The House Committee on Resources reported legislation to improve the procedures of the Endangered Species Act that need to be considered by the 109th Congress.

Fifth, when Congress passed the 1990 Clean Air Act Amendments, it decided that multiple oil and natural gas wells could not be aggregated to treat them as a single stationary source. It rejected efforts to consolidate these separate facilities - often owned by different companies. However, technically, the definition is within the hazardous air pollutants title of the Act and needs to be clarified.

Congress should clarify that oil and natural gas wells cannot be aggregated to treat them as a single stationary source for all purposes under the Clean Air Act.

Sixth, the Clean Water Act currently provides authority for the regulation of produced waters associated with natural gas development that are discharged to the environment. This authority is adequate and does not need to be altered.

Congress should reject efforts to alter the Clean Water Act produced water authority.

Seventh, offshore development requires the development of geological and geophysical data. Use of the equipment to develop this information has raised concerns about the effects of its sounds on marine mammals. The Marine Mammals Protection Act (MMPA) addresses harassment of marine mammals and incidental takings. However, its provisions are imprecise.

If Congress reauthorizes MMPA, it should address the definition of "harassment" under the Act and modify the Incidental Takings provisions to make the Act more responsive to genuine protection of marine mammals while considering the importance of human activities.

5. Diversification and Conservation
To what extent and how can demand be reduced through conservation and efficiency measures and through diversification of energy sources used for electric generation, industrial and other applications?

While conservation and efficiency measures and diversification of energy sources present opportunities to reduce natural gas demand, it is important to avoid policy options that deter the development of new supply. The Fuel Use Act of 1978 was one of the worst policy choices that could have been made. It rejected a market-based approach to resource development. It created disincentives to develop domestic natural gas resources. The objective of national energy policy should be to enhance energy availability including natural gas.

6. Tax Incentives
Could tax incentives help increase supply and/or reduce demand of natural gas?

Federal tax policy has played an important role in encouraging the development of domestic oil and natural gas resources essentially since the inception of the income tax. After successfully creating tax incentives to develop these resources, Congress then began to systematically reduce them. At the same time the Internal Revenue Service (IRS) has interpreted the remaining tax provisions to reduce their effectiveness. Looking forward, there are a number of areas where tax reforms could benefit the development of domestic natural gas.

Independent producers develop 90 percent of domestic wells and produce 85 percent of domestic natural gas. These producers principally generate the capital to expand their production through their revenues - through the wellhead. Consequently, to the degree that taxes reduce these revenues inappropriately, those funds cannot be reinvested in new exploration and production.

For example, development of new resources requires, in part, the development of geological and geophysical (G&G) data. G&G expenses include the costs incurred for geologists and geophysicists, seismic surveys, and the drilling of core holes. These surveys increasingly use 3-D technology rather than the conventional 2-D technology used for most of the last seven decades. Previously only very large companies were able to utilize this state-of-the-art, computer-intensive, 3-D technology because of its high cost and the considerable technical expertise it requires. However, as the costs of computer technology have declined, more and more domestic independent producers are making use of this technology. Still, while 3-D seismic provides a vastly superior tool for exploration, it is far more expensive than 2-D technology. 3-D seismic surveys usually cost between five or six times more per square mile onshore than the older technology and, in some instances can account for two-thirds of the costs of some wells. Encouraging use of this technology has many benefits:

- **More detailed information.** Conventional 2-D seismic is only able to identify large structural traps while 3-D seismic is able to pinpoint complex formations and stratigraphic plays. These are particularly important for developing nonconventional fuels.

- **Improved finding rates.** Producers are reporting 50-85% improvements in their finding rate. In prior years a producer might have to drill three to eight wells in order to find commercially viable production.

- **Reduced environmental impact.** Because the use of advanced seismic technology significantly improves the odds of drilling a commercially viable well on the first try, this reduces the number of wells that are drilled and, thus, reducing the footprint of the industry on the environment.

- **Investment capital.** Many investors are requiring producers to provide 3-D seismic surveys of potential development before committing their capital to the project in order to minimize their risk.

Currently, the IRS considers G&G costs nondeductible as ordinary and necessary business expenses but requires them to be treated as capital expenditures recovered through cost depletion over the life of the field. G&G expenditures allocated to abandoned prospects are deducted upon such abandonment.

These costs are an important and integral part of exploration and production for oil and natural gas. They affect the ability of domestic producers to engage in the exploration and development of our national oil and natural gas reserves. Thus, they are more in the nature of an ordinary and necessary cost of doing business.

These costs are similar to research and development costs for other industries. For those industries such costs are not only deductible but also a tax credit is available.

New exploration and development of natural gas resources is essential to address the current supply and demand challenges. Allowing the deduction of G&G costs would increase capital available for domestic exploration and production activity.

The technical "infrastructure" of the oil services industry, which includes geologists and engineers, has been moving into other industries due to reduced domestic exploration and production. Stimulating exploration and development activities would help rebuild the critical oil services industry.

Congress should act to clarify that G&G expenses can be expensed as other similar costs are treated in other industries.

Tax incentives to increase domestic development have a history of success. The nonconventional fuels tax credit (Section 29) resulted in increased development of natural gas sources that would not have otherwise occurred. Nonconventional gas sources - coalbed natural gas, tight formations, and shale formations - and deep conventional gas will need to be an essential component of domestic natural gas supply. The 2003 National Petroleum Council Natural Gas study reports that 35 percent of undiscovered resources will come from nonconventional sources.

While current natural gas prices are driving development activity now, the nation needs to be concerned about sustaining consistent development efforts. For example, while drilling activity increased dramatically when prices increased in 2000, it dropped significantly in 2001 when prices fell. Reduced drilling results in less supply and catching up takes time, thereby further pressuring the marketplace. Tax policies that would support domestic development would provide long-term benefits to the supply/demand balance.

Congress should examine tax policies that encourage domestic natural gas development, particularly nonconventional gas and deep conventional gas. These could include tax credits or deductions for actions that increase domestic natural gas development activity.

Additional tax policy provisions can further enhance domestic natural gas development.

- **Delay Rental Payments.** As a general rule, oil and natural gas exploration companies do not purchase the land on which they intend to search for minerals but instead lease the land and agree to pay royalties as the minerals, if any, are produced. A typical lease expires in one year unless exploration has begun or the lessee pays the lessor a fee for the privilege of deferring the commencement of exploration or production on the leased property. A host of legitimate reasons exist that may prevent oil and gas exploration companies from currently developing certain properties, and "delay rentals" are the payments made to retain the leases on those properties. For decades, it remained uncontested that lessees could elect to currently deduct these payments. However, during the 1990s, the IRS began to take the position that these payments must be capitalized and generally recovered through cost depletion over the life of the lease. Legislation clarifying the current deductibility of these payments would bring much-needed simplification by reducing the burdensome and costly compliance requirements associated with capitalizing these expenditures. In turn, these lower costs would help encourage new domestic natural gas production by making more money available for capital investment.

- **Net Income Limitation on Percentage Depletion.** Congress has suspended the property taxable income limitation on percentage depletion for marginal wells through 2005. The suspension that was in place in 1998 and 1999 saved many marginal wells during the price crisis. This provision should be permanently eliminated to provide domestic producers of these wells an incentive not to shut down these wells. Once the well is closed, the potential to produce the remaining reserves is lost forever.

- **Net Taxable Income Limit.** The H.R. 6 Conference Agreement tax title would have also suspended the 65 percent net overall taxable income limit on percentage depletion. This constraint on independent producers limits the amount of capital that can be retained for reinvestment into existing and new production. In an industry that typically reinvests its profits back into it operations, this constraint means less domestic natural gas. It too should be eliminated.

- **Percentage Depletion Rates and Limits.** The number of independent producers qualifying for percentage depletion has decreased. Percentage depletion has been further limited as a result of mergers and acquisitions of the various producers as they seek ways of reducing their costs, consolidating production fields, and operating more efficiently. However, percentage depletion remains very important to the small producer with marginal well production. Limiting the number of barrels qualifying for percentage depletion and artificially lowering the rate in a declining industry is counterproductive. Increasing the number of barrels qualifying and/or increasing the depletion rate would help the small independent develop resources more effectively

- **Intangible Drilling Costs (IDC).** Despite great advances in geological and geophysical know-how and technology, drilling a well is still the only means of determining with absolute certainty the presence of hydrocarbons in reservoir rock or sand. Once a discovery is made, a series of wells may be required to produce the underground deposit economically. The well costs with no salvage value are called "intangible drilling and development costs" or IDC ("since they produce nothing 'tangible' but only a hole in the ground"). These intangible costs include the amounts paid for labor, fuel, materials and necessary technical services such as clearing ground, road making, surveying and constructing such physical structures as are necessary for the production of oil and gas. IDC represent the normal day-to-day costs of doing business for an oil and gas exploration and production company. For exploratory and development wells, IDC account for approximately 90% and 70% of total costs, respectively. About 60% of an offshore production platform are IDC.

The preference for IDC from oil and gas wells does not apply to taxpayers who are independent producers with the following limitation: If the taxpayer's Alternative Minimum Tax (AMT) IDC exceed the taxpayer's AMT income by 40%, the excess is a preference item. The IDC preference should be eliminated for independent oil and gas producers.

Collectively, these provisions would further enhance domestic natural gas development by providing more capital for producers.

Congress should consider enactment of these capital enhancing tax provisions. Equally important, they must be crafted in such a manner to assure that the AMT does not nullify the benefits that they would create. The mistake of 1986 should not be repeated.

7. Investment
What is needed to encourage more investment in natural gas supplies and infrastructure?

Oil and natural gas exploration and production - despite significant technological advances - remains a capital intensive, high risk business. Yet, it does not historically yield high returns. At the same time, it must compete for capital with higher yielding, lower risk investments. Domestic production opportunities must also compete against the lure of foreign, lower cost opportunities.

One factor that encourages investment in natural gas production is a sense of certainty that projects can be completed - and completed in a predictable time. Many of the issues described in the previous questions address federal government practices that generate uncertainty. Congressional action to improve the pace of federal actions and, more importantly, to improve the predictability of a successful outcome are an essential element to attract more investment into development of natural gas supplies.

Financial factors play a similarly significant role. Early on, after the creation of the federal income tax, the treatment of costs associated with the exploration and development of this critical national resource helped attract capital and retain it, despite its risk. Allowing the expensing of geological and geophysical costs and percentage depletion rates of 27.5 percent are examples of policy decisions that resulted in the United States' extensive development of its petroleum and natural gas.

But, the converse is equally true. By 1969, Congress reduced the depletion rate and later eliminated it for all producers except independents. However, even for independents, the rate was dropped to 15 percent and allowed for only the first 1000 barrels per day of petroleum (or natural gas equivalent) produced. A higher rate is allowed for marginal wells (? 90 mcf/d) which increases as the petroleum price drops, but even this is constrained - in the underlying code - by net income limitations and net taxable income limits. In the Windfall Profits Tax, federal tax policy extracted some $44 billion from the industry that could have otherwise been invested in more production. Then, in 1986 as the industry was trying to recover from the last long petroleum price drop before the 1998-99 crisis, federal tax policy was changed to create the Alternative Minimum Tax that sucked millions more dollars from the exploration and production of petroleum and natural gas. These changes have discouraged capital from flowing toward this industry.

Even now, in the midst of the current challenges to increase domestic natural gas production, tax policy options remain controversial because of these prior actions. Additionally, they may be constrained by the federal budget process.

Thus, another continuing challenge to draw investment to the E&P component of the natural gas industry will be assuring the capital marketplace and investors that a reasonable return can be obtained relative to the risk the venture poses. Absent use of federal tax policy, there are limited but useful federal options to support domestic E&P investment.

The Deep Water Royalty Relief Act provided royalty incentives to encourage production in the deep water portions of the Gulf of Mexico. All estimates indicate that it has been a highly successful effort. Similar royalty incentives have been implemented for the development of deep natural gas formations in the shallow waters of the Outer Continental Shelf. These royalty incentives work because they provide producers with a better potential economic return for the risk they are taking in these frontier developments. They attract investment.

Congress should continue its support for offshore royalty incentives by enacting provisions from the H.R. 6 Conference Agreement with updates reflecting the passage of time.

The economic pressures on E&P companies to increase their production and reserves, to generate the capital necessary for additional development, and to demonstrate their ability to compete in the marketplace have compelled a consolidation in the industry. Mergers and acquisitions have always been part of the E&P industry, but they have intensified over the past decade. One aspect of these mergers has been the aggregation of federal lease acreage under one company's control that exceeds the allowable acreage limit. Without some alteration of the current acreage limitations, companies will be reluctant to expand their efforts on federal lands if the possibility exists that they may later be faced with divesting themselves of profitable properties. Industry understands the importance of providing for broad opportunities to develop the federal resource base. Consequently, there is a consensus that properties where production already exists should not be subject to the acreage limitation.

Congress should enact the provision of the H.R. 6 Conference Agreement that exempts "held by production" acreage from the federal acreage limitations.

Another element of the H.R. 6 Conference Agreement provided for marginal well royalty relief on federal lands when prices are low. This provision does not directly encourage new investment in natural gas production, but it does encourage production from both onshore and offshore wells during times of economic distress. It builds on existing provisions that have helped maintain domestic onshore oil production from federal lands.

Congress should adopt this safety net for federal natural gas production.

Ultimately, a stable natural gas market with prices that are adequate to provide acceptable returns will draw investment to natural gas exploration and production. Congress can support this effort through tax policies and royalty incentives that encourage such investment.

8. FERC and EIA Natural Gas Market Data

Is storage and market information adequate to ensure well-functioning natural gas markets?

The current voluntary system by which industry participants report pricing data to index developers works. While confidence in the integrity of natural gas price indices was undermined by the inappropriate activities of some gas traders, the efforts by industry, the FERC, and the Commodity Futures Trading Commission (CFTC) have resulted in increased accuracy, reliability, and transparency of wholesale energy prices.

A balanced, workable framework for natural gas price reporting has developed, and FERC continues to exercise its oversight authority. FERC has taken an active interest in the process by which price indices reflect and influence the formation of wholesale prices for natural gas and electricity. After hosting technical conferences, issuing a policy statement on standards for price index developers and market participants, conducting surveys of industry practices in price reporting, and issuing a staff report, FERC approved an order on November 19, 2004, directing staff to continue to monitor price formation in wholesale markets. In the order, FERC reports on improvement in (a) the amount of transaction data being reported to index developers, (b) the processes by which market participants provide data to index developers; (c) the amount and quality of information provided by indices, and (d) the confidence market participants currently have in price indices.

Specifically, one of the index publishers, Platts, reported that volumes and transactions for its monthly gas survey from February through June 2004 increased 35 and 38 percent, respectively, from 2003 levels. In the daily gas survey, Platts stated that the number of natural gas transactions reported in May 2004 was double that of November 2002. Another index publisher, Intelligence Press/NGI reported that 13 of the top 20 trading companies are reporting or plan to begin reporting, and that these 13 companies represent 96 percent of the volumes traded by the top 20 firms. Nearly two-thirds of the companies that report to index developers now report through a department independent from trading. The number of companies conducting annual independent audits of their price reporting practices has risen from 5 percent to 58 percent. Index developers now provide more information in their indices. Because of these improvements, the overall average level of confidence in price indices is 6.93 on a scale of one to ten. The confidence level for gas utilities is even higher, at 7.49. Industrials, as exemplified by the Process Gas Consumers group, noted that their "faith in the price indices has been strengthened by the events of the past two years."

The CFTC amended its larger-trader reporting rules to raise contract-reporting levels and subsequently will alter the number of reportable positions and the information provided by those positions in its weekly Commitments of Traders reports. The new final rules become effective January 20, 2005.

While the focus on market data has centered on pricing information, the accuracy of storage data has been in the headlines since the Energy Information Administration (EIA) issued its weekly storage report on November 24, 2004. In that report, EIA reported a storage withdrawal that greatly exceeded market expectations, and subsequently issued a downward correction from 49 Bcf to 17 Bcf. Based on preliminary investigation, it appears that this error was administrative in nature, not the result of market manipulation. The operator submitting the incorrect data has revised its system for reporting to EIA to ensure the accuracy of future reports. It is likely that other operators also will review their reporting systems to ensure that accurate data is submitted to EIA.

The Committee needs to look beyond the concerns with storage data and market information to the underlying issues of adequacy of storage capacity and natural gas supply availability. The focus on market data stems from actual manipulation, which has been curbed through oversight, and from volatility that naturally arises in a commodity market where supply and demand are not in balance.

Some industry participants have called on the CFTC to put in place more limited "stops" for natural gas trading. Under current NYMEX rules, a $3/MMBtu change in price results in a stop in trading for 5 minutes. Those advocating tighter stops compare this unfavorably with stops on the beef exchange, where a movement of 1.5 cents results in a stop in trading for 24 hours. This proposal should not be adopted.

- The current stop of $3 is reasonable for natural gas; the cattle market is not as volatile, so 1.5 cents is reasonable for that commodity.
- If you place limits on NYMEX trading, parties will go to the over-the-counter market. This is particularly true for natural gas, which does not have substitutes and is a necessity.
- Limits are intended to prevent a runaway market, not to alleviate volatility.
- NYMEX keeps prices honest.
- Stops wreak havoc with contract expirations.

While market oversight and transparency are important to assure the trading activities are legal and understandable, natural gas - like it or not - now trades through commodity markets. By their very nature, commodity markets, like stock markets, are inherently subject to volatility. Volatility can be diminished by greater transparency or greater storage capacity, but it cannot be eliminated.

Congress should not enact legislation to interfere with a market that is responding to the need to control its abuse by past practices. Existing governmental authority is adequate to address these improper practices.