RAILROAD COMMISSION OF TEXAS

OFFICE OF GENERAL COUNSEL

OIL & GAS DOCKET NOS. 10-0229120 ET AL.

APPLICATIONS OF BP AMERICA PRODUCTION COMPANY FOR EXCEPTIONS TO STATEWIDE RULES 37 AND/OR 38 FOR NINETEEN WELLS ON ITS FLORES, FLORES "86", FLORES "95", AND HUBER ET AL. LEASES, TEXAS HUGOTON FIELD, SHERMAN AND MOORE COUNTIES, TEXAS

APPEARANCES:

FOR APPLICANT:	**APPLICANT:**
A. Andrew Gallo Sandra B. Buch John G. Soule Michael Holmes W. D. Griffin	BP America Production Company
FOR PROTESTANTS:	
W. Timothy George Joe Cochran Richard Strickland James Colliton Mack Shirley	Phillips Petroleum Company
David Jackson Matt Sjoberg	Travelers Oil Company

PROPOSAL FOR DECISION

PROCEDURAL HISTORY

APPLICATIONS FILED:	July 31, 2001
HEARING DATES:	March 4-14, 2002
HEARD BY:	James M. Doherty, Hearings Examiner Donna Chandler, Technical Examiner
BRIEFING CLOSED:	April 18, 2002
PFD CIRCULATION DATE:	April 14, 2003

STATEMENT OF THE CASE

Between July 23-31, 2001, Amoco Production Company filed applications requesting exceptions to either or both of Statewide Rule 37 and Statewide Rule 38 to drill a total of thirty-nine (39) wells on its Flores, Flores "86", Flores "95", Huber Et Al., Price Et Al., Brannon "C", W. N. Price, Price "B", Price and Sweny Leases, Texas Hugoton Field, Sherman and Moore Counties, Texas. Subsequent to the filing of the applications, applicant's name was changed to BP America Production Company, and applicant is hereinafter referred to as "BP". The applications were protested by Phillips Petroleum Company ("Phillips") and Travelers Oil Company ("Travelers"). A prehearing conference regarding the applications was held on October 5, 2001.

As a result of the prehearing conference and agreement of the parties, the 39 applications were consolidated into two groups, thereafter commonly referred to as the "Flores" group and the "Price 'D'" group, for purposes of hearing and preparation of proposals for decision. The "Flores" applications, to which this Proposal for Decision pertains, were heard during the period March 4-14, 2002. The "Price 'D'" applications were heard by the same examiners during the period April 22-May 1, 2002, and are the subject of a separate proposal for decision.

The 19 "Flores" applications were heard over a period of 9 hearing days. The testimony given during the "Flores" hearing is transcribed in 9 volumes of transcript containing 1,774 pages, and 302 exhibits were offered into evidence.

Field rules for the Texas Hugoton Field ("subject field") provide for spacing of 1,250 feet from any property line, lease line or subdivision line and 2,500 feet from any well on the same tract completed in or drilling to the same horizon. The field rules also provide for 640 acre density.

BP's Flores (16,020 acres), Flores "86" (640 acres), Flores "95" (640 acres), and Huber Et Al. (1,920 acres) Leases now have the maximum number of producing wells permitted by the 640 acre density rule governing the Texas Hugoton Field. BP requests exceptions to Statewide Rule 38 to drill 14 additional wells on its Flores Lease, 2 additional wells on the Flores "86" Lease, 1 additional well on the Flores "95" Lease, and two additional wells on the Huber Et Al. Lease. BP also requests Rule 37 exceptions for 3 of the proposed wells on the Flores Lease, 1 of the proposed wells on the Flores "86" Lease, the proposed well on the Flores "95" Lease, and 1 of the proposed wells on the Huber Et Al. Lease.

Appendix 1 to this Proposal for Decision summarizes the 19 applications in the "Flores" group by docket number, proposed well number, lease and lease acres, location data, type of exception(s) requested, proposed spacing to lease lines and between wells (feet), and reason for the requested exception(s). Appendix 2 to this Proposal for Decision (also BP Exhibit 14 herein) is a well status and ownership map of the Flores Ranch Lease Area which shows BP's subject leases, a ring of sections around the subject leases (sometimes hereinafter referred to as the "halo area"), lease ownership, existing wells and their status, cumulative recovery of existing wells, and the location of BP's proposed wells (indicated by red dots). Phillips is shown as the operator of offsetting tracts to the north, northeast, east, southwest, and west of BP's subject leases.

POSITIONS OF THE PARTIES

BP's Position

BP contends that its engineering, geological, and petrophysical evidence is sufficient to show that approval of its proposed Rule 37/38 exception wells is necessary to prevent waste and to prevent confiscation. BP says that existing wells on its subject leases will not recover remaining recoverable reserves, as demonstrated by pressure versus cumulative and rate versus time plot comparisons for existing wells, increased pressures and rates seen in replacement wells, lack of effect of newer wells on the production decline trend of other nearby wells, and evidence showing significant volumes of recoverable gas in rock with low permeability and inability of existing wells effectively and efficiently to drain 640 acres.

BP contends also that the evidence shows that the Flores Lease area is different from other parts of the Texas Hugoton Field, in terms of permeability, depositional environment, lithology, thickness of the formations, changes in rock properties over short distances, and production performance of wells.

In addition, BP says that Texas law provides that an owner of oil and gas is entitled to an opportunity to recover the reserves underlying the owner's tract and any denial of that opportunity amounts to confiscation.

Protestants' Position

Phillips argues that to prove waste, BP is required to show a localized abnormal condition under the Flores/Huber tracts that is not present in any other part of the Texas Hugoton Field, and that BP's own evidence proves that no unusual, unique or abnormal condition exists at any of the 19 proposed locations.

Phillips argues further that there will be no ultimate loss of gas without the 19 proposed Rule 38 exception wells because existing wells will produce the recoverable gas beneath the Flores/Huber tracts.

Phillips says that BP did not show that approval of the proposed Rule 38 exception wells is necessary to prevent confiscation. Phillips contends that BP failed to prove the volume of gas in place beneath the Flores/Huber tracts, and argues that existing wells on the Flores/Huber tracts are outperforming wells on surrounding tracts. Phillips contends that current pressure data shows that a pressure sink has been created on the Flores/Huber tracts, and wells on these tracts are already taking gas from surrounding tracts. According to Phillips, approval of BP's proposed Rule 38 exception wells would permit BP to produce far more than its fair share, causing harm to correlative rights.

Travelers says that it is the operator of 31 wells in the Texas Hugoton Field, each of which wells is on 640 acre density. It is concerned with net uncompensated drainage which might result to Travelers if BP's requested Rule 38 exceptions are granted. Otherwise, Travelers makes essentially the same arguments as Phillips.

DISCUSSION OF THE EVIDENCE

APPLICANT'S DIRECT EVIDENCE

The bulk of BP's reservoir engineering evidence was presented by W. D. "Bill" Griffin ("Griffin"), a consulting petroleum engineer who was formerly employed with Amoco Production Company during 1972-1999. Griffin holds a chemical engineering degree from Texas Tech University and has experience with carbonate reservoirs. BP's geological and petrophysical evidence primarily was presented by Dr. Michael Holmes ("Dr. Holmes"), an oil and gas consultant and President of Digital Formation, an oil and gas software development company. Dr. Holmes has a PhD in geology from the University of London and a Master's degree in petroleum engineering from the Colorado School of Mines where he is a teacher of petrophysics.

Griffin

(a) Background

The Texas Hugoton Field was discovered in 1918. It lies immediately to the north of the Panhandle West Field and covers the northernmost portion of Moore County, most of Sherman County, and the western portion of Hansford County. According to 1968 literature presented by BP, the Panhandle-Hugoton field as a whole, which extends from the Texas Panhandle through Oklahoma and into Kansas, was, at the time, the largest gas field in the United States. The Herington, Upper Krider, and Lower Krider are the productive formations in the Texas Hugoton Field, although the Winfield is also occasionally productive. The Herington and Krider formations in the Texas Hugoton Field are correlative to the Brown Dolomite in the Panhandle Field.

There are about 915 wells in the Texas Hugoton Field, most of which were drilled in the 1940's or early 1950's. Current field rules for the field were established in 1948, with no changes since that time. These rules provide for 1,250'/2,500' spacing and 640 acre density. Griffin does not suggest that these field rules should be changed, and believes that, for the most part, wells in the field are capable of adequately and efficiently draining 640 acres.

"The Flores Lease area" (including all of BP's subject leases) lies in the southern portion of the Texas Hugoton Field, just to the north of the Panhandle West Field, and straddles the boundary between Moore and Sherman Counties. Depth of the Texas Hugoton Field in the Flores Lease Area is 3,000'-3,500'. BP's "Price 'D'" Lease area lies about 4-5 miles to the north of the Flores Lease in the southern portion of Sherman County.

BP's Cartrite Lease lies between the Flores Lease area and the Price "D" Lease area. In 2000, BP had success in drilling a replacement well, the Cartrite Well No. 3, on the Cartrite Lease, which peaked its interest in the potential of infill drilling on the Flores and Price "D" Leases. The shut-in tubing pressure measured in the Cartrite Well No. 3 was 112 psi, about 50 psi higher than wells on offsetting sections to the north and northwest, and during June-December 2000, this well produced at a significantly greater rate than the well it replaced and other neighboring wells. Through the end of 2001, this well had produced 487 MMCF of gas. By use of rate versus time plots and least squares fit analysis, Griffin concluded that the Cartrite Well No. 3, now producing at a rate of 600 MCF per day, has already produced more gas than the wells it replaced would have produced if they had been allowed to continue production to the end of their economic life.

Griffin evaluated the Flores Lease and Price "D" Lease areas and concluded that there were areas where recovery was relatively low, even though it appeared to him that the gas in place was relatively equal to higher recovery areas. He concluded that the low recovery areas justified infill drilling.

Roughly 620 BCF of gas has been produced from wells in the Flores Lease area (including the "halo" area). In this area, BP holds 67.9% of the acreage and its wells have produced 65% of the cumulative production. Wells on BP's subject leases in the Flores Lease area have average daily production ranging from 62 MCF per day to 313 MCF per day. Wells in the halo of sections around the Flores Lease, including those operated by BP, Phillips or another operator, have average daily production ranging from 13 MCF per day to 560 MCF per day. The average well on the Flores Lease produces 155 MCF per day, and the average well in the halo area around the Flores Lease produces 118.58 MCF per day. Due to the low producing rates, Griffin concluded that the Texas Hugoton Field is in the latter stages of depletion, and currently producing wells are not draining large areas around the wells.

(b) Basis for Proposed Well Locations

Most area wells drilled in the 1940's or early 1950's were drilled with rotary tools to the top of the pay and then completed with cable tools. As a result, there are few logs available for the wells. Griffin was able to find electric logs for the following replacement wells which recently have been drilled in the Flores Lease area: Flores Well Nos. 28, 29, 30, 31, 32, 34, 37 and 38, and the BP Harrison "A" Well No. 2 in the halo area. Concluding that he had insufficient log coverage to construct a net pay isopach map, Griffin pursued the alternative of determining cable tooler's gross pay as reflected by description of the productive interval contained in cable toolers' completion forms (Form 2 Well Record) filed with the Commission for the older wells.

A structure map of the top of the productive interval of the subject field, as determined from the first show of gas reported on the cable tooler's completion forms depicts a relatively smooth, regular surface across an area of 8 miles by 8 miles comprising the Flores Lease area, with relief of only about 100'. A similar structure map of the base of the productive interval also shows a fairly uniform and regular base of gas across the mapped area, with relief of about 50'. These structure maps show no evidence of faulting in the Flores Lease area. A gross pay isopach map prepared from data gleaned from the cable tooler's completion forms depicts gross pay, including both productive and nonproductive formations, which appears to increase subtly from east to west across the Flores Lease area. Thickness of gross pay across BP's subject leases ranges from 146' to 369', although Griffin believes that gross pay across the leases is relatively constant.

A contour map of cumulative production for the Flores Lease area shows variances in cumulative production between wells and particular portions of the area. For example, Griffin characterizes the southwest portion of the area as being an area of high recovery, while the west central portion of the area has had relatively lower recovery.

Griffin's plot of cumulative recovery versus cable tooler's gross pay shows no correlation between cumulative production and gross pay. Neither is there any correlation between initial potential of wells in the Flores Lease area and gross pay. However, Griffin did find correlation between cumulative production and initial potential. From these analyses, Griffin concluded that cumulative production is related to localized permeability and that additional wells should be located in the low recovery areas of BP's subject leases to increase ultimate recovery from the area.

To further identify low recovery areas of BP's subject leases, Griffin presented a contour map of cumulative production divided by cable tooler's gross pay. Average cumulative production per foot of cable tooler's gross pay for the Flores Lease area is 54 MMCF of gas. Using 60 MMCF of gas per foot of cable tooler's gross pay as the dividing line between areas of high recovery and areas of low recovery, Griffin identified areas of high recovery in the southern and northwestern portions of the Flores Lease and areas of low recovery in the central, west central and northeastern portions of the Lease.

Wells in the Flores Lease area are generally completed throughout the pay zone, and almost all wells were stimulated in one way or another. Griffin concluded that completion techniques are not the cause of relatively low recoveries of wells in the low recovery areas. Also, Griffin found that, with only two exceptions, wells on the Flores Lease produce very little water, and for this reason he reached the further conclusion that water production is not affecting ultimate recoveries on the lease.

In deciding upon the best locations for BP's proposed wells, Griffin wanted to avoid placing a well in the potential drainage areas of older wells having high cumulative recoveries. He therefore identified portions of the low recovery areas on BP's subject leases which were outside a 3,000' radius of the older high cumulative wells. He did not seek to avoid a similar radius around the newer replacement wells on the leases because as yet they do not have the cumulative production of older wells. BP attempted to locate its proposed wells in the areas so identified. The topography of BP's subject leases is flat except in an area where Palo Duro Creek traverses the Flores Lease where there is a large valley area. Terrain is steep near the edges of the creek. In addition, there are pivotal irrigation systems on the Flores Lease. In some cases, BP was required to move proposed well locations from the optimum location or closer than 1,250' to the lease line in order to accommodate topography or surface use, but Griffin believes that the proposed locations are reasonable for recovering the reserves which BP has targeted.

(c) Economics

Griffin performed an income stream of economics for BP's proposed wells. He determined that five replacement wells drilled on the Flores Lease during 1996-1998 would best represent the initial producing rate of new wells in the area. Analysis of these wells developed an initial producing rate in the first year of 257 MCF per day and a decline rate of 16% per year. Using this initial producing rate and decline rate, a gas price forecast, a royalty burden of 12.5%, severance tax of 7.5%, incremental operating expense of $750.00, and a capital investment of $225,000.00, Griffin calculated a net undiscounted profit of $966,665.00 per well for 2003-2012. Discounted by 10%, the net profit per well is estimated by Griffin to be $659,885.00. Since the initial producing rate and decline rate used in this analysis are based on a composite of five replacement wells after original wells were shut-in, they do not take into account a second well producing on the same 640 acre proration unit.

(d) Replacement Well Studies

Griffin studied a number of original and replacement wells on the same proration unit in the Flores Lease area to determine whether, in his opinion, the replacement wells will recover reserves which the wells they replaced would not have recovered. A total of 13 well pairs were studied, including wells on proration units within BP's subject leases and in the halo area around BP's leases. Some of the well pairs were in high recovery areas as defined by Griffin, and others were in low recovery areas. In some cases, a third well was included in Griffin's analysis for the purpose of determining what effect, if any, a replacement well had on another nearby well. These replacement well studies included shut-in tubing pressure versus time plots and rate versus time plots.

Most of the replacement wells studied by Griffin came on at higher pressure than the wells they replaced, although some had only slightly higher pressures. All pressures measured in the replacement wells were significantly reduced from original reservoir pressure. Griffin believes that some of the increased pressures for replacement wells are significant in this low pressure reservoir. For example, the Flores Well No. 31 came in at about 40 psi higher than the last pressure measured in the Flores Well No. 3, the well it replaced. However, some replacement wells that came in at pressures higher than the last pressure of the well they replaced subsequently settled into a pressure profile similar to the original well. For example, the Flores Well No. 33 came in at a higher pressure than last measured in the well it replaced, the Flores Well No. 11, but subsequently settled into the same pressure regime observed in the original well some ten years earlier. Griffin believes that the higher initial pressures seen in replacement wells is reflective of a two pressure system, with pressures in the Herington and Upper Krider zones contributing to the lower pressure Lower Krider zone.

Some of the replacement wells studied by Griffin came on with significantly higher production rates than those of the wells they replaced, and some did not. The Flores Well No. 31 came in at a rate about three times the last producing rate of the Flores Well No. 3, the well it replaced. The Flores Well Nos. 32, 33, 34, 35, 36, and 38, the Phillips Spear Well No. 1R, and the BP Harrison "A" Well No. 2 all came in with rates higher, in some cases significantly higher, than the last producing rates of the wells they replaced. Based on rate versus time extrapolation, Griffin concluded that these replacement wells will produce "incremental" reserves, that is, reserves that would not have been recovered by the wells they replaced, had such wells continued to produce.

Griffin also concluded from his replacement well studies that some replacement wells that came on with higher producing rates had no apparent effect on other nearby existing wells. Flores Well No. 31 which came on with a producing rate about 3 times higher than the last producing rate of the well it replaced had no effect on the production decline rate of Flores Well No. 30 only 2,200' away. Flores Well No. 32 came on with a producing rate about twice the last producing rate of the well it replaced, but had no effect on the production decline trend of Flores Well No. 23 about 2,500' away. Griffin concluded these wells are producing from separate sources of supply.

From his replacement well studies as a whole, Griffin concluded that while some replacement wells have been successes and some have not, in general drilling of replacement wells results in increases in ultimate recovery. He believes that this shows that some of the replacement wells should have been drilled as Rule 38 exception wells, allowing both wells on the proration unit to produce.

(e) Reservoir - Flores Lease Area

The zones of interest to BP in the Texas Hugoton Field are the Herington, Upper Krider, and Lower Krider. The Herington is separated from the Upper Krider by the Paddock Shale, and there is also a shale zone separating the Upper Krider from the Lower Krider. BP believes that there are porosity pods containing significant volumes of gas in the Herington and Upper Krider that have either limited or no communication with existing wellbores. Griffin concludes that this interpretation is supported by the performance of replacement wells, the lack of effect of replacement wells on other nearby wells, and measurement while drilling pressure data, but concedes that the interpretation cannot be proved until wells are drilled in the interwell area.

Depleted pressure is seen in existing wells because the Lower Krider is a high permeability zone through which most of the wells historically have been in communication. Griffin believes that communication is more limited today due to low bottomhole pressures and low producing rates of wells. BP believes that the incremental gas which it expects to recover through its proposed Rule37/38 wells will come primarily from the Herington and Upper Krider zones, and that the Herington, Upper Krider and Lower Krider are not in communication in the interwell area.

Using information generated by Dr. Holmes, Griffin prepared Lorenz Coefficient Plots for Flores Lease Area wells on which logs were available (Flores Well Nos. 28, 29, 30, 31, 32, 34, 37, and 38, Harrison "A" No. 2, and FSBS "A" No. 2), plotting the relative relationship between gas storage capacity and the ability of gas to flow (permeability). As an example, in Flores Well No. 28, 50% of the gas storage capacity contains less than 10% of the ability of gas to flow, and 26% of the gas storage capacity has less than 0.1 md permeability. These plots indicate that there is vertical heterogeneity in all the wells studied, and in almost all wells at least 50% of the gas storage capacity contains less than 10% of the permeability. Griffin believes that additional wells are necessary to recover gas in tight zones.

(f) Potential for Recovery of Incremental Reserves

Griffin prepared plots of pressures versus cumulative production for active wells on the Flores Lease proper to estimate gas in place that the wells are seeing in their drainage areas. He compared gas in place as determined from pressure versus cumulative for four original wells on the Flores Lease with Dr. Holmes' volumetric calculations of original gas in place from logs for four replacement wells in the low recovery area. This comparison indicated that there was 17 BCF of original gas in place under the four 640 acre proration units outside the original wells' drainage areas.

Griffin believes there is a two pressure system in the subject reservoir. The higher permeability zone influences the pressure during the early life of a well, and in the latter stages of life the lower permeability zones still having higher pressure begin to contribute more. Griffin believes this accounts for a break over in pressure data for a well when displayed graphically. Griffin accounted for the two pressure system he believes to be present in the reservoir in constructing his pressure versus cumulative plots. Griffin plotted a straight line through the early time pressure data and then a second intersecting straight line through the later time pressure data extrapolated to abandonment, thus to account for his interpretation of a break over in the pressure data believed to represent the effect of the two pressure system. Griffin noted that pressure versus cumulative extrapolations indicate the volume of gas the wells are seeing within their drainage areas, but do not say anything about the size of a well's drainage area.

Griffin believes that when a well is shut in, higher pressure zones counterflow into zones of lower pressure with which they are in communication in the wellbore. On pressure versus cumulative plots, the pressures plotted are the pressures of the lowest pressure zone, in this case the Lower Krider. The Flores Well No. 32 was drilled in 1996. After drilling to a depth of 3,150' (through the Herington and into the Upper Krider), the well was shut-in and a pressure of 159 psi was measured. Griffin believes that the fact that this pressure was about 300 psi below original reservoir pressure is due either to counterflow from somewhere in the interval between 3,072' and 3,150' or to withdrawals somewhere else on the Flores Lease. The well was then drilled further down to the base of the Upper Krider, and pressure was measured at 3,200' to be 116 psi.

Subsequent measured while drilling pressures in the Lower Krider were 69 psi and 66 psi. Griffin believes that the higher pressure Herington and Upper Krider counterflow into the low pressure Lower Krider zone, and that unless pressures are measured individually in each of the several zones while drilling, the pressure measured in a well will be the pressure of the Lower Krider and not indicative of the Upper Krider/Herington pressures.

Griffin also prepared cumulative production versus time plots based on a 9 years least squares fit for active wells on the Flores Lease proper in order to determine estimated ultimate recovery for existing wells and whether they will recover all the reserves the wells are seeing as disclosed by pressure versus cumulative extrapolations. The rate versus time plots are linear plots as contrasted with semilog plots. Griffin believes that semilog plots may be appropriate in the early life of a well when decline is exponential, but when the last 5-10 years of production of a well that has been producing for 50 years are being examined, a linear plot is the proper evaluation. Griffin asserts that when a pressure versus cumulative plot indicates that a well is seeing much more gas than a rate versus time plot shows the well ultimately will recover, there is an indication that the well is not recovering all of the gas within its drainage area and there is a need for additional wells.

BP contends that a rate versus time plot for the Flores Well No. 32, which replaced Flores Well No. 2 (now plugged and abandoned), shows that the replacement well is recovering incremental reserves. According to a rate versus time extrapolation, Flores Well No. 2 would have recovered an additional 212 MMCF had it continued to produce. A rate versus time extrapolation for Flores Well No. 32 shows that it will recover 515 MMCF through 2008, substantially more than the remaining reserves for Flores Well No. 2. This says to Griffin that either the Flores Well No. 32 is recovering different reserves (all of the 515 MMCF) from the remaining reserves which Flores Well No. 2 would have recovered, or, the Flores Well No. 32 is recovering incremental reserves of 303 MMCF which would not be recovered by Flores Well No. 2.

A rate versus time plot for Flores Well No. 23, about 2,570' away from Flores Well No. 32, indicates that Well No. 32 had no apparent effect on the production decline trend of Well No. 23, and Griffin concluded the wells were producing from different sources of supply, though the completion intervals are virtually identical. Griffin reached the same conclusion from rate versus time plots for Flores Well No. 31, a replacement for Flores Well No. 3, which he says had no apparent effect on the production decline trend of Flores Well No. 30 about 2,200' away. However, the available pressure data indicates that the pressure performance of Well No. 23 declined after Well No. 32 commenced production. A pressure performance decline was also seen in Well No. 30 after Well No. 31 commenced production. This pressure data indicates a possibility of pressure interference between wells.

By comparison of pressure versus cumulative plots with rate versus time extrapolations, Griffin calculated for all active wells in the Flores Lease area (including the halo area) the remaining reserves which the wells are seeing within their drainage areas from 2001 out and the amount of reserves the wells are estimated to recover from 2001 out. This data was posted to a map of the Flores Lease area, with the remaining reserves (red number) and the estimated recoveries (blue number) posted by each active well. A copy of this map is attached to this Proposal for Decision as Appendix 3. Griffin concluded that, with only few exceptions, wells in the Flores Lease area are not recovering and will not recover the gas in their drainage areas.

For the Flores Lease area as a whole, according to Griffin's pressure versus cumulative plots, wells are seeing 22.2 BCF of remaining gas within their drainage areas. Based on Griffin's rate versus time plots, original wells will recover 7.8 BCF of remaining reserves. Existing wells on the 16 proration units on the Flores Lease proper are seeing about 14.3 BCF of remaining gas within their drainage areas. Based on Griffin's rate versus time plots, these wells will recover an estimated 4.7 BCF of remaining reserves. Griffin believes that there will be 9.6 BCF of reserves in the area of BP's proposed Rule 38 exception wells that will not be recovered by existing wells.

According to Griffin's pressure versus cumulative plots, existing wells on BP's Huber Et Al. Lease are seeing 1.6 BCF of remaining reserves within their drainage areas, and according to Griffin's rate versus time plots, these wells will recover remaining reserves of about .5 BCF. Griffin believes that there will be 1.15 BCF of gas remaining within the drainage areas of existing wells on the Huber Et Al. Lease that will not be recovered by any existing well.

Dr. Holmes

(a) Depositional Environment

At BP's request, Dr. Holmes performed geological and petrophysical studies of the Flores Lease area. Dr. Holmes' study area lies just to the north of the Panhandle West Field in the southern portion of the Texas Hugoton Field. The Hugoton Field stretches from Texas through Oklahoma into Kansas.

The Trucial Coast of the United Arab Emirates on the southern side of the Persian Gulf is a modern day analog to the depositional environment in the area of the Texas Hugoton Field in Late Wolfcampian times. The Trucial Coast furnishes an example of a carbonate regression depositional model, with a variety of features including barrier islands sticking up out of the water with tidal channels in between where oolites might be deposited, burrowed intertidal areas, algal mats, and supratidal sebkha (mud flat). As the sea level changed, the complexity and heterogeneity of this kind of deposition and its spatial position changed over time. Grain size, porosity, and permeability in this kind of model changes rapidly over short distances. Dr. Holmes believes that the Texas Hugoton Field is most likely in the intertidal/subtidal environment.

(b) Lithology/Structure

When tides go out leaving small ponds of saltwater, evaporation causes the water to become concentrated in saline solution. The solutions then percolate downward and change limestones into dolomite. The dolomitization process replaces calcite with magnesium leading to a reduction in rock volume, and potentially porosity is created. Water percolates down to start the dolomitization process where there is permeability beneath ponds. Changes in permeability and porosity of rock types can cause dolomitization to be selective. In some cases, such as in the Guymon (Hugoton) in Oklahoma, dolomitization is pervasive, but Dr. Holmes believes it is only selective in the Flores Lease area because there is quite a bit of limestone left. In the Flores Lease area, areas not dolomitized consist of limestone and silica (sand or chert) which generally have lower porosity and permeability.

As a general proposition, as grain density increases from limestone to dolomite, porosity increases, but not always. Although it can't be proved in the absence of cores from wells in the Flores Lease area, conceptually the selective dolomitization process caused heterogeneity in the reservoir in this area. Dr. Holmes does not believe the Flores Lease area has been completely dolomitized, as shown by density log measurements. Logs for the Buf No. 3 Well and the Shiel 2R Well in the Guymon (Hugoton) Field, about 50 miles to the north of the Flores Lease area see quartz, dolomite, and anhydrite. Logs for wells in the Flores Lease area see limestone, silica, dolomite, anhydrite, and shale. Dr. Holmes' petrophysical analysis disclosed changes in the percentage of anhydrite, dolomite, limestone, shale, and quartz over short distances. Some Flores Lease wells looked like the Shiel 2R Well, and some did not.

North-South and East-West structural cross sections across the Flores Lease presented by Dr. Holmes showed no evidence of faulting. It is possible there could be faults with 10'-20' displacement that can't be seen, but this is not known by Dr. Holmes.

(c) Petrophysical Analysis

For use in constructing his petrophysical study, Griffin furnished Dr. Holmes digital data on a total of 25 wells, 10 on the Flores Lease and 15 on the Price "D" Lease. Petrophysical analysis disclosed to Dr. Holmes that quite a few of the wells had significant proportions of limestone, while others had none at all. This caused Dr. Holmes to conclude that perhaps a little bit differently from the Guymon (Hugoton) Field in Oklahoma, the Flores Lease appeared to be more complex and to have less predictable mineralogy which changed from well to well.

Dr. Holmes presented a North-South cross section incorporating the Flores Well Nos. 30, 31, 38, 28 and 37, showing his interpretations of gas bearing porosity. For this purpose, Dr. Holmes used a porosity cut-off of 5%, water saturation cut-off of less than 60%, and V-shale cut-off of less than 35%. This cross section extends over 3.9 miles and distances between wells range from 0.5 miles to 1.9 miles. In some instances, the cross section depicts continuous porosity between wells extending over the entire 3.9 miles. In other instances, discontinuities in porosity are depicted. While discontinuities in extensions of porosity between wells shown on the cross section are Dr. Holmes' interpretation, he agreed that there is no available proof of what happens to porosity between wells.

As a general proposition, Dr. Holmes interprets better developed continuity of porosity in the deeper zones than in shallower zones. The cross section shows better correlation across the area in the Lower Krider than in the Herington and Upper Krider. Dr. Holmes concluded that the Lower Krider tends to have better and more continuous porosity, while the Herington and Upper Krider have less well developed and continuous porosity. There is a great deal of vertical heterogeneity, particularly in the Herington and Upper Krider, and Dr. Holmes believes that lateral heterogeneity can be inferred.

Dr. Holmes also presented a second North-South cross section incorporating the FSB Stratford A-2, Flores Well Nos. 34, 32, and 29, and the Harrison A-2, prepared in the same manner as the previous cross section. This cross section extends over 7.7 miles, and the distances between wells range from 1.5 miles to 3.2 miles. Continuous porosity development between wells is shown to extend in some instances across the entire area covered by the cross section, but the cross section also shows Dr. Holmes' interpretation that there are discontinuities in porosity between wells. Dr. Holmes concluded that this cross section shows the same as the previous cross section, that is, better porosity and continuity in the Lower Krider than in the Herington and Upper Krider and heterogeneity of the reservoir over short distances.

Dr. Holmes believes that it is not logical that existing wells hit all porosity in the area. One interpretation is that there is porosity development not seen in any well. Dr. Holmes concluded that there are reserves in the area that will not be recovered by the existing wells.

Dr. Holmes presented an analysis of gamma ray curves for wells on the Flores Lease, calculating how much of each well is occupied by "clean formation" for each different stratigraphic level, i.e., how much of the well is shale and how much is clean formation. Variation is shown between wells. For example, in the Flores Well No. 29 in Dr. Holmes' Herington Zone 2, there is no clean formation, while 88% of the same zone in the Flores Well No. 31 is clean formation. Variation also exists between wells in the Upper Krider. Much more consistency exists in Dr. Holmes' Upper Krider Zone 4 and in the Lower Krider.

For Griffin's use, Dr. Holmes made volumetric calculations of original gas in place from logs for four replacement wells (Flores Well Nos. 28, 31, 32, and 34) assuming 640 acre drainage. In doing so, he observed characteristics seen on the logs and assumed that these characteristics extended over an entire 640 acres surrounding the wells, an assumption different from what is depicted geologically for the same wells on his cross sections. Using pneumonics supplied by Phillips in prehearing discovery for porosity, V-clay and water saturation, he observed that volumetrically calculated original gas in place using Phillips' data was consistently higher than his own. Dr. Holmes then calculated the average drainage areas of the original wells (Flores Well Nos. 2, 3, 7, and 20) which were replaced by the replacement wells. The BP calculated drainage areas are Flores Well No. 2: 210 acres; Flores Well No. 3: 600 acres; Flores Well No. 7: 395 acres; and Flores Well No. 20: 506 acres. The calculated drainage areas using Phillips' data are Flores Well No. 2:

155 acres; Flores Well No. 3: 505 acres; Flores Well No. 7: 260 acres; and Flores Well No. 20: 312 acres.

From random examination of cable tool driller's logs for Flores Well Nos. 1, 3, 5, 13, 14 and 28, Dr. Holmes concluded that at least in the early days of the wells, the upper zones contributed less gas than the deeper zones, and cable toolers saw increased permeability as reflected by increased rates as they drilled deeper. By use of modern logs to quantify the same type of differences in the reservoir seen in cable tool driller's logs, Dr. Holmes concluded that there is considerable gas in tight rocks in the Herington and Upper Krider, although the volume of this gas is 2-3 times less than the gas in the Lower Krider.

In the absence of any core data from wells in the Flores Lease area from which to make permeability calculations, Dr. Holmes performed a petrophysical analysis to try to determine permeability. Core data from the Fee 8-209 well was used to calibrate algorithms used to calculate permeability from petrophysical log data. A cross plot of permeability data from logs and permeability data from cores yielded a correlation coefficient of 59%, which Dr. Holmes believes is good for this kind of data.

Dr. Holmes prepared modified stratigraphic Lorenz plots comparing normalized storage (cumulative net volume of gas calculated from logs) with normalized flow capacity (cumulative net gas permeability) for the FSB Stratford A-2, Flores Well Nos. 27, 28, 29, 30, 32, and 34, and the Harrison "A' 2, excluding porosity of less than 5%. In the FSB Stratford A-2, Dr. Holmes' Lower Krider Zone 1 has cumulative permeability of 80%-90% but only10%-35% of the storage. Dr. Holmes believes that the different pattern between wells disclosed by the modified stratigraphic Lorenz plots shows the heterogeneity of the reservoir. For example, in the FSB Stratford A-2 about 80% of the permeability is in the Lower Krider, as compared to 35% in the Flores Well No. 32 and less than 15% in the Flores Well No. 31. The upper zones have considerable gas but low permeability.

BP is interested in recovering the gas in the tight Herington and Upper Krider by the drilling of its proposed Rule 38 exception wells. As an example, Dr. Holmes estimates that in the Flores Well No. 37 there is 4.8 BCF of gas in only 5% of the permeability of that well. Dr. Holmes believes that there is a lot of gas trapped in low permeability rocks, and drilling of Rule 38 exception wells is necessary to recover that gas.

(d) Conclusions

From his petrophysical analysis and geologic study, Dr. Holmes concluded that the Flores Lease is different from its neighbors, for example from the Buf and Shiel wells in the Guymon (Hugoton) Field where the reservoir is believed to be more homogeneous petrophysically. The Flores Lease is believed to be a little different from the Fee 8-209 well in the Panhandle West Field in terms of lithology, although the Fee 8-209 has some limestone and the same kind of distribution of porosity and permeability as seen in the Flores Lease. Dr. Holmes asserts that there are so few wells, at least with logs, on the Flores Lease, it is difficult, if not impossible, to make general conclusions as to continuity or lack thereof across the lease, but he believes it can be said that there are heterogeneities in the Flores Lease not seen at least in the Guymon (Hugoton) area. In the Flores area, there could be heterogeneities and dramatic changes in permeability both vertically and horizontally over short distances. Dr. Holmes concluded that there is evidence that in the low recovery areas defined by Griffin, existing wells cannot effectively drain 640 acres, and additional wells are required.

PROTESTANTS' EVIDENCE

Phillips' presented evidence pertaining to a petrophysical analysis of logs for area wells through the testimony and exhibits of James Edward Colliton ("Colliton"), who holds a Bachelor of Science degree in geological engineering from the University of Missouri. Phillips presented evidence and exhibits pertaining to area geology through the testimony and exhibits of Dr. Wayne Ahr ("Dr. Ahr"). Dr. Ahr holds a Bachelor of Science degree in geology from the University of Texas at El Paso, a Master's degree in oceanography from Texas A & M University, and a PhD in geology from Rice University. Dr. Ahr is a Professor of Geology at Texas A & M. In addition, Phillips' engineering evidence was presented through the testimony and exhibits of Richard Strickland ("Dr. Strickland"), who is President of The Strickland Group, a petroleum consulting firm. Dr. Strickland holds a Bachelor of Science and Master's degrees and a PhD in petroleum engineering from Texas A & M University. Travelers presented argument but did not present evidence.

Colliton - Petrophysical Log Analysis

Colliton performed a petrophysical analysis of logs available to him for the Flores Lease area. Colliton had available for analysis a full suite of logs and core analysis for the Fee 8-209 well, located about 9 miles south of the Flores Lease in the Panhandle West Field. For the Otis Phillips 3-A well, located about 12 miles to the southeast of the Flores Lease in the Panhandle West Field, Colliton had available for analysis a conventional core analysis with a summation of fluid porosities, but not a full suite of logs. For the Buf No. 3 and Shiel 2R wells, located in the Guymon (Hugoton) Field in Texas County, Oklahoma, about 42 miles north of the Flores Lease, Colliton had available a full suite of logs, conventional core including measured porosities and grain densities, and a suite of x-ray diffraction data. For all of these wells, Colliton had available Dr. Ahr's rock descriptions. With this data, Colliton performed a multi-mineral interpretation of the logs, solving for 3 minerals plus porosity. Core data was used to develop methodology for log analysis.

X-ray diffraction is a lab technique for analysis of small rock samples for a full range of mineral constituents. X-ray diffraction data for the Shiel 2R well showed that for 74 rock samples taken at 74 separate depths, the average value bulk volume of dolomite was 56%. The next highest average bulk volumes were of quartz (16%) and anhydrite (14%). X-ray diffraction data for the Buf

No. 3 well showed average bulk volume for dolomite of 52%, for quartz of 17%, and for anhydrite of 12%.

Colliton calibrated his petrophysical model to available rock data from cores for the Shiel 2R and Fee 8-209 wells and performed a petrophysical check by using the model to analyze logs for the Buf No. 3 well, finding the comparison to be good. He concluded that his petrophysical model accurately and reasonably analyzed and calculated values from logs in the area in that it matched porosity values from core data, clay values from x-ray diffraction, and Dr. Ahr's rock description from core analysis. Colliton further concluded that his petrophysical log analysis model provided a reasonable and accurate basis for determining the mineral content of rocks in the Herington and Krider in the involved area. Colliton conceded, however, that there were some discrepancies between his petrophysical log analyses and core descriptions or mud logs at various depths, and that high porosity was indicated in some instances at depths where a substantial percentage of anhydrite was shown to be present.

Colliton also had available and analyzed a full suite of logs for the Flores Well Nos. 29, 30, 31, 32, 33, 34, 35, 36, and 37. Because no core data existed for any of the wells on the Flores Lease, Colliton worked with what his petrophysical log analysis model showed and qualitatively compared that to available mud logs. In addition to Flores Well Nos. 29-37, Colliton also analyzed with his petrophysical model the Flores Well No. 28 for which he did not have a full suite of logs and other wells in the area of the Flores Lease, some of which had a full suite of logs and some of which did not. Ultimately, he analyzed a total of 22 wells, 17 of which had a full suite of logs. Colliton used his petrophysical model and the density curve, neutron curve, and photoelectric factor curve from logs to solve for 3 minerals. Based on Dr. Ahr's rock description from cores for the Shiel 2R, Buf No. 3 and the Otis Phillips A-3, and the x-ray diffraction data, Colliton concluded that the most common mineral constituents were dolomite, quartz, and anhydrite. These are the 3 minerals which he solved for in his multi-mineral interpretation of the logs.

Colliton presented log plots with a track showing color coded mineral components for Flores Well Nos. 29-37, except for Flores Well No. 33 where the plot had a printing problem. In each instance, dolomite was shown to be the major mineral component. Colliton concluded that dolomite is pervasive throughout the Herington and Krider formations in the 9 Flores Lease wells he analyzed.

Colliton considers the subject reservoir to have complex mineralogy, and agrees that the Krider has better reservoir quality than the Herington, based on porosity. The Herington appears to contain more anhydrite and quartz, and less dolomite, than is the case with the Krider. Colliton did not study lateral changes in porosity, and did not solve for limestone in his multi-mineral interpretation of logs.

<u>Dr. Ahr - Geology</u>

Dr. Ahr presented a structure map of the top of the Herington formation across the Flores Lease area including BP's subject leases and a halo area of 2-3 sections around such leases. This structure map showed that over a distance of 6-7 miles there is only about 100' of relief on the structure. Dr. Ahr concluded that there was no evidence of faults or unusual mechanical breaks in the formation.

A fence diagram presented by Dr. Ahr, consisting of a series of four different cross sections to illustrate the distribution of formations (Herington, Upper Krider, and Lower Krider) across space, showed that all three formations are continuous across the Flores Lease, and although there are some variations in thickness of the formations, they are not dramatic and none pinch out across the lease.

Since no cores were available for wells on the Flores Lease, Dr. Ahr reviewed cores from other nearby wells, the Fee 8-209 and the Otis Phillips 3A to the south and southeast of the Flores Lease in the Panhandle West Field, and the Buf No. 3 and Shiel 2R in the Guymon (Hugoton) Field in Texas County, Oklahoma, to the north of the Flores Lease. He also reviewed the 9 logs for Flores Well Nos. 29-37, also analyzed in Colliton's testimony. Dr. Ahr concluded that the primary rock type under the Flores Lease is dolomite, and based on Colliton's work he concluded that similarity of reservoir characteristics in the Flores Lease area, the Panhandle West Field and the Guymon (Hugoton) Field can be demonstrated.

Dr. Ahr believes that log analysis shows a similarity between the Flores Lease wells having logs and the Fee 8-209 and Otis Phillips 3A cores. With the exception of total formation thickness and more pronounced Paddock and O'Dell shale formations in the Guymon (Hugoton) Field, the dolomite characteristics of the Buf No. 3 and Shiel 2R wells are virtually identical to those shown by analysis of logs on the 9 Flores Lease wells for which logs were available.

Dr. Ahr presented a coregraph of the Otis Phillips 3A well coded to show rock types and core analysis porosity and permeability at various depths and magnified photographs of rocks found in this well. In the Herington, at a log depth of 3,055.9', the measured porosity from core analysis was 13.9% and the measured permeability from core analysis was .45 millidarcies. At a log depth of 3,070', measured porosity from core analysis was 25.9% and measured permeability from core analysis was 1.2 millidarcies. Dr. Ahr also presented coregraphs, and photographic magnifications of rocks, for the Shiel 2R and Buf No. 3 wells. Dr. Ahr concluded that the coregraphs showed good porosity and permeability in the Herington and Krider formations.

The principal rock type found by Dr. Ahr in the Herington and Krider from core analysis is overwhelmingly dolomite. Dr. Ahr believes there is both interparticle and intercrystalline porosity in the Herington formation, with good connectivity from one rock pore to the next. The Krider has a wider range of pore types, including many large molds and solution pores. Dr. Ahr finds no evidence of any isolated pods that are unconnected or poorly connected to the surrounding rock in either the Herington or Krider formations. He found no limestone in the Herington or Krider in the cores which he examined. Shale is rare in the Herington and Krider, although he did find the Paddock and O'Dell shales in his core analysis, and agrees that shales are impermeable barriers to flow. Dr. Ahr does not believe that there are impermeable barriers to flow under the Flores Lease, but agrees that the O'Dell shale is beneath this lease. Dr. Ahr believes that all porosity and permeability in the Herington and Krider under the Flores Lease should be as good as seen in the cores which he studied.

Dr. Strickland

(a) Reservoir Continuity

Dr. Strickland presented a 1932 isobaric map of the East and West Panhandle Fields which had been an exhibit in the 1987 Panhandle Field Rules hearing. This map showed pressure sinks in two areas caused by wells that produced large volumes of gas and caused pressure waves to travel over many miles. These kind of experiences led Dr. Strickland to believe that gas wells can affect very large drainage areas.

According to Dr. Strickland, flow rates of wells do not control how far drainage areas extend. The radius of investigation for a well is greater with high permeability, and Dr. Strickland analyzed permeability in the Panhandle Field. A core statistical summary presented in the Panhandle Field Rules hearing summarized core statistics in the Brown Dolomite based on 10,318 samples. The Brown Dolomite in the Panhandle Field was shown to have an arithmetic mean porosity of 12.7% and a geometric mean permeability of 3.52 millidarcies. The Lorenz Coefficient for the Brown Dolomite of .82 indicated a measure of heterogeneity in the formation. Lorenz Coefficients have nothing to do with layering or lenticularity in the reservoir but are a measure of heterogeneity.

Dr. Strickland does not believe that a well's producing rate is a good indication of reservoir continuity. If two wells encounter different thicknesses in the reservoir, all other things being equal (porosity, permeability, etc.), the well encountering the greater thickness will have the higher producing rate. If both wells are shut-in and the same pressure response over time is seen, the wells are in pressure communication, unless the similar pressure response is purely coincidental. Dr. Strickland believes that to investigate the issue of reservoir continuity, it is appropriate to look at pressure behavior, not rate behavior.

According to Dr. Strickland, wells have different producing rates because they have different permeabilities, thicknesses of formations, pressures at external boundaries, completion efficiencies, and drainage areas. In the Flores Lease area, because wells have these different properties, they have a lot of different flow rates, and consequently have different cumulatives.

Dr. Strickland does not believe that higher rates seen in replacement wells, as compared to the last rate of the original wells replaced, necessarily indicate that the replacement wells are recovering incremental reserves. Gas production is due to a pressure gradient in the reservoir. While the original well is still producing, there is a sharp pressure gradient around the wellbore going out to a pressure at the external boundary. If a new well is drilled in the drainage area of the original well, the new well will have a greater initial producing rate, if for no other reason than it has a higher pressure than experienced at the original well. Were both wells permitted to produce, they would share reserves, and the new well would carve out its drainage area, causing the drainage area of the original well and other surrounding wells to change. Interference occurs at the drainage boundary (no flow boundary) of each well, which is difficult to see in flow rates.

Dr. Strickland presented his study of Phillips' replacement wells throughout the Texas Hugoton Field. This study covered 65 sections where Phillips drilled replacement wells. Some of these sections are within 2 miles of the Flores Lease. Dr. Strickland prepared a monthly rate versus time semilog plot and a bottomhole pressure versus time linear plot for each original well and each replacement well. Some of the replacement wells experienced greater initial producing rates than the last producing rate of the wells they replaced. However, in no instance did a replacement well encounter original reservoir pressure. Only 3 of the replacement wells encountered significantly higher pressure than the original well, and in these instances, the higher pressure encountered was still significantly depleted from original reservoir pressure. Dr. Strickland believes that this indicates that the original and replacement wells produced from the same source of supply.

Dr. Strickland also studied 24 replacement wells in the Flores Lease area, including replacement wells drilled on 21 sections on the Flores Lease plus a two mile band of sections around the Flores Lease. He prepared semilog plots of rate versus time and linear plots of pressure versus time for each original well and each replacement well. Some of the replacement wells experienced greater initial producing rates than the last producing rate of the wells they replaced. However, Dr. Strickland found that none of the replacement wells encountered original reservoir pressure, and the pressure performance of the replacement wells was similar to the original wells. Dr. Strickland concluded that the replacement wells encountered reserves that were in the drainage area of existing wells. He saw nothing different about the performance of replacement wells on the Flores Lease as compared to replacement wells in the 2 mile band around the Flores Lease.

Dr. Strickland investigated the issue of pay continuity in the Flores Lease area. Concluding that the best way to investigate pay continuity was to examine pressure behavior as it related to time, Dr. Strickland posted to a map pressure versus time data for all wells on the Flores and Huber Leases plus a 2 mile halo area, so as to be able visually to compare well to well, section to section, the level of pressure and the pressure profile with time. From this pressure versus time analysis showing apparent pressure communication between wells, and from his replacement well study, Dr. Strickland concluded that there is virtually no chance that BP's proposed Rule 38 exception wells will encounter commercial reserves that are not currently in the drainage area of an existing well.

Dr. Strickland presented a series of isobaric maps for various dates from the pre-1951 era through 2001 for the Flores Lease area. In the Texas Hugoton Field, wells are usually shut-in once a year for a pressure measurement, and the pressure data is accumulated over time. The isobaric maps are graphical displays showing contour lines of equal pressure at one point in time. In general, the Flores Lease area was drilled up in 1945 through 1951. In a formation that is in pressure communication, drainage areas are determined by well density and by relative rates of offset wells. Over time, the isobaric maps show changes in the shape of isobars which Dr. Strickland relates to changes in the drainage areas of wells. Changes in the shape of isobars over time is indicative of changes in drainage areas over time caused by the producing rates of wells, so that wells are seeing a different volume of gas each year.

From observation of changes in the pressure profile of the Flores Lease from his isobaric maps, Dr. Strickland concluded that drainage areas are determined by well density and relative rates, the effective gas in place that each well "sees" changes with time, having implications concerning reserves calculated from pressure versus cumulative plots, and the entire area of interest appears to be in pressure communication so that there is little chance that infill wells will find commercial reserves not currently in the drainage area of an existing well.

(b) Potential for Recovery of Incremental Reserves

Concluding that it would be instructive to examine formations in which wells on the Flores Lease are completed against the background of pressure information shown on his arrow map and isobaric maps, Dr. Strickland presented four stick diagram cross sections across the Flores Lease showing where existing wells are completed in relationship to the locations of BP's proposed Rule 38 exception wells. Where the proposed Rule 38 exception wells are located, the surrounding wells are generally completed throughout the producing intervals in the Herington, Upper Krider and Lower Krider. Dr. Strickland believes this supports his conclusion that the Rule 38 exception wells, if drilled, will encounter reserves that are currently in the drainage area of an existing well.

Dr. Strickland performed an average well analysis of certain replacement wells drilled in the Flores Lease area for the purpose of determining whether they produced incremental reserves. For this purpose, he chose 9 replacement wells drilled after 1995, which replaced 11 original wells. He decided to study replacement wells drilled after 1995 because he wanted to examine contemporary wells with current data and needed a few years of history to make extrapolations from historical performance.

Dr. Strickland built a "normalized average well" from the 9 replacement wells and the 11 original wells they replaced by totaling each well's production for each month and dividing by the total number of wells. He then prepared a semilog plot of rate versus time for the normalized average original well and a similar plot for the normalized average replacement well. The decline rate for the normalized average original well was 5.7% per year, and depending on the interpretation, the decline rate for the normalized average replacement well was 15%-16.8% per year. Dr. Strickland calculated that if the normalized average original well had continued to produce it would have had future gas production of .753 BCF to an estimated economic limit of 300 MCF per month. The same calculation for the normalized average replacement well was .628 BCF to .71 BCF, depending on the interpretation. Conceding uncertainty in this type of extrapolation, Dr. Strickland nonetheless concluded that his average well analysis did not indicate that replacement wells in the Flores Lease area produce incremental reserves.

There were 24 replacement wells drilled in the Flores Lease area on which Dr. Strickland believed he could make an estimate of ultimate recovery. By rate versus time decline curve analysis, he estimated ultimate recovery of the original wells had they been allowed to continue to produce and then estimated ultimate recovery consisting of a combination of the original wells' cumulative production plus the future estimated ultimate recovery from the replacement wells. In some cases, the combined original well's cumulative plus the estimated ultimate recovery of the replacement well exceeded the estimated ultimate recovery of the original well, and in some cases it was less. While there is uncertainty in decline curve analysis where there is not much data, Dr. Strickland concluded that the original wells would have produced 157.574 BCF, and the replacement wells' estimated ultimate recovery plus the original wells' cumulative is 159.0 BCF, a difference of only 1.5 BCF for 24 wells, about 63 MMCF per well. These wells cost $200,000-$225,000 to drill, so Dr. Strickland believes that in the aggregate it doesn't make sense to drill additional wells to try to recover this small additional amount of gas.

Due to low reservoir pressures and high cumulative production relative to remaining reserves in the Texas Hugoton Field, Dr. Strickland believes that it is very difficult to estimate reserves from pressure versus cumulative extrapolations.

By comparison of data furnished by BP in prehearing discovery pertaining to Griffin's estimated ultimate recovery for existing wells with his own calculations of estimated ultimate recovery, Dr. Strickland concluded that Griffin's methodology for calculating estimated future production under predicts recovery of reserves. The Griffin data used for comparison was not presented into evidence by BP, but Dr. Strickland believes that Griffin used the same methodology to develop the estimates of ultimate recovery that BP did present.

Griffin used a linear least squares fit to calculate future production rates and volumes, which is a methodology Dr. Strickland thinks inappropriate. Dr. Strickland says that if historical gas production is looked at on a linear plot and a straight line is fitted through the historical data and extrapolated in the future, it will look like a straight line on a linear plot. On a semilog plot the line will concave downward dramatically in future years. Dr. Strickland believes that Griffin's methodology dramatically underestimates future gas production. The Arps decline curve analysis technique suggests that gas production should be linear (plot a straight line) on a semilog plot.

Dr. Strickland believes that Dr. Holmes' volumetric calculations of original gas in place based on logs of certain replacement wells (Flores Well Nos. 29, 31, 32, 34, 37, and 38, FSBS "A" 2, and Harrison "A" 2) are flawed. Dr. Strickland prepared pressure versus cumulative and P/Z versus cumulative plots from pressure data for the original wells, and extrapolation of this data indicated that the original wells were seeing significantly less original gas in place than that developed by Dr. Holmes' volumetrics. Dr. Strickland believes that in a pressure depletion reservoir, if calculated volumetrics do not match pressure performance, the volumetrics must be adjusted until a match is achieved. In his volumetric calculations, Dr. Holmes calculated porosities, saturations, and thicknesses and summed them up for a wellbore value. The wellbore value was then extrapolated in all directions over 640 acres, based on an assumption that the wellbore values applied over the 640 acres and there is pressure communication throughout the 640 acres. Because Dr. Holmes' volumetrics do not match pressure performance, Dr. Strickland concludes that it is not appropriate to apply wellbore values to a 640 acre section. Based on this conclusion, he also believes that it is not appropriate to compare the wellbore volumetric calculation of original gas in place with other estimates of ultimate recovery based on decline curve analysis to draw conclusions about incremental reserves.

Dr. Strickland examined measured while drilling pressure data for four wells on the Flores Lease, Flores Well Nos. 32, 33, 35 and 37, drilled in 1996-1997. These wells are located in Sections 24, 90, 89 and 94, extending from the west side to the east side, and across the midsection, of the lease. These wells were drilled and shut-in for 20 hours for pressure measurements at various intervals in the Herington, Upper Krider, and/or Lower Krider formations. These measurements are summarized below:

Flores No. 33		**Flores No. 35**	
3,090 feet (Herington)	86 psig	3,150 feet (Upper Krider)	81 psig
3,160 feet (Upper Krider)	36 psig	3,225 feet (Upper Krider)	43 psig
3,230 feet (Lower Krider)	32 psig		

Flores No. 32		**Flores No. 37**	
3,150 feet (Upper Krider)	159 psig	3,150 feet (Upper Krider)	71 psig
3,200 feet (Upper Krider)	116 psig	3,200 feet (Upper Krider)	71 psig
3,250 feet (Lower Krider)	69 psig	3,250 feet (Lower Krider)	65 psig
3,300 feet (Lower Krider)	66 psig	3,300 feet (Lower Krider)	64 psig

From the measured while drilling pressure data for these four wells, Dr. Strickland observed a pressure gradient across the Flores Lease from west to east, with higher pressures on the east. He noted that no original reservoir pressure was encountered and saw no evidence of any zone with original pressure counterflowing into a lower pressure zone. He concluded that the depleted pressures measured in these four wells while drilling resulted from offsetting wells producing from interconnected net pay (lateral flow) or from vertical flow in the interwell area where gas is traveling down to higher permeability, lower pressure regions.

Dr. Strickland also examined Griffin's testimony that a two pressure system exists in the reservoir as evidenced by a break in pressure versus cumulative plots. Dr. Strickland examined pressure versus cumulative graphs for 30 wells and saw a strong indication of the break in 17 and some indication in 7 others. Examination of shut-in pressure versus time graphs for the same wells disclosed that all 30 wells seemed to indicate a break in wellhead pressure versus time. Examination of flowing tubing pressure versus time graphs for the same wells disclosed a strong indication of the break for 25 wells and a moderate indication for 3 others. From this analysis, Dr. Strickland concluded that what is seen in the break in the pressure versus cumulative graphs is a reflection of the surface operating conditions of changing flowing tubing pressure.

Dr. Strickland reviewed Dr. Holmes' correlation between log calculated permeabilities and core permeabilities for the Fee 8-209 well. Dr. Strickland performed a depth shifted log to core comparison and a similar comparison where the log data was not depth shifted, using the reduced major axis equation. By this methodology, he developed a correlation coefficient of .373 for the depth shifted comparison and a correlation coefficient of .208 for the comparison which was not depth shifted. This compared to Dr. Holmes' correlation coefficient of .59. According to Dr. Strickland, least squares fit methodology is appropriate where there is uncertainty in only one variable, but where there is uncertainty in both variables, reduced major axis should be used. The correlation coefficient calculated by Dr. Strickland indicates that there is not an adequate fit of the log calculated permeability data to core permeability data to justify use of the log calculated values in an analysis.

(c) Conclusions

From his studies, Dr. Strickland concluded that no unusual conditions underneath BP's subject leases require the drilling of additional wells to recover reserves underlying the leases, existing wells will recover the recoverable hydrocarbons underneath the Flores and Huber Leases, and BP's proposed Rule 38 exception wells are not needed to recover incremental reserves.

APPLICANT'S REBUTTAL EVIDENCE

Dr. Holmes-Rebuttal

Dr. Holmes presented literature pertaining to the general geology of the Panhandle-Hugoton District which he believes supports his testimony regarding geology of the Flores Lease area. Among other things, the literature states that in the District, local variations in permeability are common, and the line dividing the Panhandle oil and gas field from the Hugoton gas field has been placed in one fairly widespread area of low permeability. The Flores Lease area is just to the north of the dividing line between the Panhandle West Field and the Texas Hugoton Field, and Dr. Holmes believes that this area was recognized early on as different from the Panhandle West Field to the south. He also believes that there is a structural saddle in the vicinity of the Flores Lease that makes it different from the area surrounding it. Dr. Holmes also believes there is correlation of some anomalies shown in Dr. Ahr's mapping and Griffin's high recovery and low recovery areas.

Stratigraphy changes across the Flores Lease from east to west with different "marine" and "mostly marine" environments coming together during Late Wolfcampian time. Dr. Holmes believes this could contribute to the difference between Griffin's high recovery and low recovery areas. As it applies to the Hugoton Field, the coming together of the "marine" and "mostly marine" environments appears to apply all the way from the Flores Lease area north into Kansas. Dr. Holmes believes that in the Flores Lease area there is a greater influence of shales and clastics than in the area of the Buf No. 3 and Shiel 2R wells in the Guymon (Hugoton) Field. He also distinguishes the Flores Lease area on the basis that it is less dolomitized than the Guymon (Hugoton) Field and the Fee 8-209 well in the Panhandle West Field north and east of the Flores Lease. That the Flores

Lease has significant amounts of limestone and the Buf No. 3, Shiel 2R, and the Fee 8-209 do not is another distinguishing factor seen by Dr. Holmes.

There is also a variability in thickness from the top of the Herington to the Lower Krider in the Buf No. 3, Shiel 2R and Fee 8-209 as compared with the Flores Lease. The Fee 8-209 well has a thickness of these formations which is about 100' greater than any of the wells on the Flores Lease.

Dr. Holmes determined that limestone is present in wells on the Flores Lease, and he believes the presence of limestone is confirmed by cable tool driller's logs and mud logs. Of the Flores Lease wells covered by Dr. Strickland's stick diagram cross sections, 17%-28% of the perforated intervals are limestone. Dr. Holmes does not believe that a multi-mineral model, such as was presented by Colliton, that assumes no limestone is appropriate. Based on rock descriptions in mud logs and cable tool driller's logs, Dr. Holmes believes that 15.5% of Colliton's rock descriptions in the wells studied by Colliton are wrong and an additional 4.3% are probably wrong. Because Colliton did not assume the presence of any limestone, Dr. Holmes contends that everything which Colliton coded as dolomite is in doubt. However, Dr. Holmes' work confirms Colliton's conclusion that the Herington, Upper Krider, and Lower Krider formations under the Flores Lease area consist predominantly of dolomite.

Dr. Holmes contends that the reservoir in the Flores Lease area is laterally heterogeneous and that isolated pods of porosity might exist, almost certainly they are not pervasive. The pore network is tortuous, and Dr. Holmes believes there are rapid, erratic changes in permeability. Reduced pressures found when new wells are drilled could be a consequence of cross flow, or they could mean that the intervals are genuinely pressure depleted to some degree. However, Dr. Holmes does not believe that this means that the reserves are accessible by existing wells. In Holmes' opinion they won't be, because existing wells will be abandoned before these reserves can be produced.

<u>Griffin-Rebuttal</u>

The pressure in the formation near an existing wellbore is low due to drawdown. Moving away from the wellbore the pressure increases as it reaches an interwell pressure level. Griffin believes that when a new well is added in the interwell area, it draws down the pressure there, and usually has an increased producing rate and produces incremental reserves. Dr. Strickland does not interpret a dramatic increase in production by area replacement wells as meaning incremental reserves will be recovered, but Griffin does. Conceptually, if Dr. Strickland is correct that the abandonment pressure in the Herington and Upper Krider is 200 psi, Griffin believes that at that point there is 1.6 BCF of gas remaining in each 640 acre proration unit in the Herington and Upper Krider, which is a target of BP's proposed Rule 38 exception wells.

Griffin does not believe that Dr. Strickland's interpretation of pressure communication between wells in the Flores Lease area is correct. If all the wells depicted in Strickland's arrow map were in pressure communication, and thicknesses of the reservoir were the same, Griffin would expect the wells to be producing comparably. This is not the case, however. For example, the Phillips Lera Well No. 1 in Section 120 in the halo area produces 620 MCF per day, whereas just to the west in Section 40, also in the halo area, the Phillips Spear Well No. 1R produces about 80 MCF per day. Dr. Strickland's arrow map connects these two wells. Griffin believes that these two wells, and others like them, do not produce comparably because they are not in pressure communication.

Griffin does not agree with Dr. Strickland's conclusion that the break in pressure performance seen on pressure versus cumulative plots is related to flowing tubing pressure. Flowing tubing pressure is affected by factors such as the size of the flowline, pressure in the flowline, and whether there is compression. When the well is shut-in to measure shut-in wellhead pressure, the valve is closed and nothing downstream affects the pressure which is measured. Griffin concludes that if the flowing tubing pressure performance follows the bottomhole pressure performance, it is a coincidence, and the break seen on pressure versus cumulative plots is caused by the influence of the two pressure system in the reservoir. Griffin believes that pressure versus cumulative plots may be used to accurately predict recoverable reserves.

According to Griffin, there are limitations on the usefulness of the Arps decline curve analysis technique described by Dr. Strickland. Producing bottomhole pressure must remain relatively constant, and the Arps equation assumes a constant drainage area. Because drainage areas in the subject reservoir are changing, Dr. Griffin believes that the Arps equation technique could have flaws.

Based on Dr. Strickland's testimony at a prehearing deposition that abandonment pressure in the formations under the Flores Lease area would be zero, Griffin recalculated remaining recoverable gas as per pressure versus cumulative extrapolation, assuming a zero abandonment pressure, and compared the result with estimated remaining recovery for existing wells as per rate versus time extrapolation. Griffin says that this comparison shows that neither the wells on the Flores Lease nor those in the halo area around the lease are going to recover all the gas the wells are seeing. He says also that this comparison indicates that there is no drainage to or from the individual proration units on the Flores/Huber Leases and in the halo area. No gas will migrate from the Flores/Huber Leases to the halo area or vice versa. Griffin believes that wells on the Flores Lease are seeing, on the average, .8 BCF, and wells in the halo area are seeing, on the average, 1.1 BCF. The Flores Lease has about 51% of the acreage in this area and has produced 34% of the gas.

EXAMINERS' OPINION

BP requests Statewide Rule 38 exceptions for a total of 19 wells on its subject leases, and Statewide Rule 37 exceptions for 6 of these wells. Exceptions to Statewide Rule 38 may be granted to prevent waste or to protect correlative rights. BP contends that the granting of the requested Rule 37 and 38 exceptions is necessary both to prevent waste and to prevent confiscation.

An applicant seeking exceptions to Statewide Rule 38 based on prevention of waste must establish three elements: (1) that unusual conditions, different from conditions in adjacent parts of the field, exist under the tracts for which the exceptions are sought; (2) that, as a result of these unusual conditions, hydrocarbons will be recovered by the wells for which exception permits are sought that would not be recovered by any existing well or by additional wells drilled at regular locations; and (3) that the volume of otherwise unrecoverable hydrocarbons is substantial. An applicant seeking exceptions to Statewide Rule 38 based on prevention of confiscation must show that: (1) it is not possible for the applicant to recover its fair share of minerals under its tracts from regular locations; and (2) that the proposed irregular location is reasonable.

An applicant seeking exceptions to Statewide Rule 37 also has the burden to show that the exceptions are necessary to prevent waste or to prevent the confiscation of property. As with Rule 38 exceptions, where Rule 37 exceptions are sought based on the prevention of waste, the applicant must show unusual conditions and that no regular location is available which will satisfy the goal of preventing waste. An owner of oil and gas is entitled to an opportunity to recover the reserves underlying his tracts, and any denial of that opportunity amounts to confiscation. *Atlantic Refining Co. v. Railroad Commission*, 346 S.W.2d 801 (Tex. 1961); *Imperial American Resources Fund, Inc. v. Railroad Commission*, 557 S.W.2d 280 (Tex. 1977). When the subject tract is capable of supporting a regular location, the applicant for a Rule 37 exception based on confiscation must prove that the proposed irregular location is necessary because of surface or subsurface conditions and that the proposed location is reasonable. To do this, the applicant must show that it is not feasible to recover his fair share of the oil or gas under his tract from regular locations. A mineral interest owner's fair share is measured by the currently recoverable reserves under his property.

An applicant who undertakes the burden of showing that Rule 37/38 exceptions are necessary to prevent waste due to unusual conditions must show conditions underlying the tracts on which the exception well is sought to be drilled different from those in the adjacent area or the part of the field in which the tract is situated. *Hawkins v. Texas Company*, 209 S.W.2d 338, 342-343 (Tex. 1948). The conditions affecting the drainage of wells on the particular tract for which exceptions are sought must be so peculiar, unusual and abnormal that the tract is removed from the same category of the surrounding area to which the general rule applies. When these peculiar and unusual conditions are found to exist in a localized area, exceptions may then be granted for the drilling of additional wells to the extent necessary to offset the abnormality and place the subject tract on parity, from the standpoint of efficient drainage, with other areas where ordinary and usual reservoir conditions prevail. *Wrather v. Humble Oil & Refining Company*, 214 S.W.2d 112, 117 (Tex. 1948). Exceptions based on prevention of waste must be based on actually known or ascertainable conditions at the time the Commission acts, and not upon the bare possibility that conditions warranting the exceptions might later develop or come to light. *Marine Production Co. v. Shell Oil Co.*, 165 S.W. 2d 934, 936 (Tex.Civ.App.-Austin 1942, writ ref'd w.o.m.).

Based on the entirety of the evidence in the record, the examiners conclude that BP failed to prove that its requested Rule 37/38 exceptions are necessary either to prevent waste or to prevent confiscation.

BP did not prove that the granting of Rule 37/38 exceptions are necessary to prevent waste because BP did not show that conditions underlying its Flores/Huber tracts are so peculiar, unusual, and abnormal as to set them apart from the adjacent area and the part of the field in which the tracts are situated. The first and most obvious difficulty presented by BP's evidence bearing on this issue is the scarcity of proof of conditions in other portions of the Texas Hugoton Field with which to compare conditions found to exist beneath the Flores/Huber tracts. Dr. Holmes studies of this field, for example, included only the Flores Lease area (including a "halo" of sections around the Flores Lease itself) and the Price "D" Lease area 4-5 miles to the north, and Dr. Holmes' findings were to the effect that essentially the same conditions exist beneath these two areas of the field.

Comparison of proven conditions beneath the adjacent and surrounding portions of the Texas Hugoton Field in the "halo" of sections around the Flores Lease with conditions shown to exist beneath the Flores/Huber tracts does not disclose material respects in which the Flores/Huber tracts can be said to be "unusual". BP's comparisons of wells and conditions on the Flores/Huber tracts with the Fee 8-209 well, about 9 miles to the southeast in the Panhandle West Field, and the Buf No. 3 and Shiel 2R wells, about 42 miles to the north in the Guymon (Hugoton) Field in Texas County, Oklahoma, do not show that conditions beneath the Flores/Huber tracts are so peculiar, unusual, and abnormal as to remove these tracts from the same category of the surrounding area to which the general spacing and density rules for the Texas Hugoton Field apply.

There is no serious contention by BP that the carbonate regression depositional model and the intertidal/subtidal environment described by Dr. Holmes applies to the Flores/Huber tracts, but not to the adjacent parts of the Texas Hugoton Field in the halo of sections around the Flores Lease. The coming together in Late Wolfcampian time of marine and mostly marine environments that applies to the Flores Lease area appears to apply as well to portions of the Hugoton Field extending all the way north into Kansas. That the Flores/Huber tracts lie between two uplifts appears also to be true of a goodly portion of the Texas Hugoton Field, and if the Flores/Huber tracts lie in the vicinity of a saddle historically recognized as an area of low permeability, this is equally true of the adjacent parts of the Texas Hugoton Field that immediately surround the Flores/Huber tracts.

Dr. Holmes believes that the formations beneath the Flores/Huber tracts may be less dolomitized than the particular areas of the Guymon (Hugoton) Field where the Buf No. 3 and Shiel 2R wells are located, as evidenced by the presence of limestone in some Flores Lease wells, but the Flores/Huber tracts are not similarly distinguished from adjacent areas of the Texas Hugoton Field. No claim is made by BP, for example, that wells on BP's Price "D" Lease do not have limestone. Even within the boundaries of the Flores Lease, some wells are said to have limestone and some not. Dr. Holmes believes that the Fee 8-209 well also has limestone, and it is virtually undisputed that dolomite is the predominant rock type in the Fee 8-209, Buf No. 3, and Shiel 2R wells, as it is in wells in the Flores Lease area.

Heterogeneity in the reservoir under the Flores/Huber tracts does not set these tracts apart from surrounding areas of the Texas Hugoton Field. Dr. Holmes described the reservoir generally as laterally heterogeneous and found the same heterogeneity in the Herington and Upper Krider beneath the Price 'D' Lease. Both Mr. Griffin and Dr. Strickland believe that there is heterogeneity in the Brown Dolomite in the Panhandle Field.

There is no evidence of faulting in the formations beneath the Flores/Huber tracts that can be said to make these tracts unusual. Dr. Holmes believes that there are changes in permeability over short distances under the Flores/Huber tracts, but there is no persuasive evidence that the same condition does not apply in adjacent parts of the Texas Hugoton Field. The literature pertaining to general geology of the Panhandle-Hugoton District sponsored into evidence by Dr. Holmes suggests that local variations in permeability are common in the Texas Hugoton Field, Panhandle Field, Guymon (Hugoton) Field, and Kansas Hugoton Field. This literature says that in the Panhandle Field vertical and lateral variation of permeability may be the most critical reservoir parameter.

Insofar as the evidence disclosed, thickness of the producing formations does not distinguish the Flores/Huber tracts from adjacent areas of the Texas Hugoton Field. Dr. Holmes made the point that according to Phillips' data, the Fee 8-209 well in the Panhandle West Field has a thickness about 100' greater than any well on the Flores Lease. However, according to the same data, the thicknesses in the Harrison A-2 and Stratford A 2 wells in the halo area around the Flores Lease are more comparable to thicknesses seen in Flores Lease wells. On the Flores Lease itself there are variations in thickness of gross pay as disclosed by Mr. Griffin's gross pay isopach, ranging from 146' in the Flores Well No. 2 in Section 89 to 369' in the Flores Well No. 1 in Section 8. Mr. Griffin's gross pay isopach also shows variations in thickness in wells in the halo of sections surrounding the Flores Lease, ranging from 115' to 399'. Average gross pay for wells on the Flores Lease, as disclosed by Mr. Griffin's gross pay isopach, is 224.7', and average gross pay for wells on the halo of sections surrounding the Flores Lease is 221.7'. Mr. Griffin found no correlation of gross pay as determined from cable tool drillers' logs and cumulative production.

Neither do areas of low recovery appear to make the Flores/Huber tracts materially different from the adjacent and surrounding areas of the Texas Hugoton Field. Mr. Griffin defined low recovery areas as areas having cumulative production of less than 60 MMCF of gas per foot of cable tool drillers' gross pay. By this standard, there are areas of low recovery in the halo of sections around the Flores Lease extending in every direction. BP is correct that the Phillips Lera Well No. 1 in the halo area to the southwest of the Flores Lease has significantly higher cumulative production than nearby Flores Lease wells, but the same is true of the cumulative production of the Lera well relative to that of other wells in the halo area. There is considerable variation in the cumulative production of older currently producing wells on the Flores Lease generally, in the low recovery area of the Flores Lease as defined by Mr. Griffin, and in the halo area of sections surrounding the Flores Lease.

BP's waste prevention theory also fails because BP did not prove that substantial hydrocarbons will be recovered by the wells for which exception permits are sought that would not be recovered by any existing well. The requested Rule 37/38 exceptions cannot be granted on the theory that they are necessary to prevent confiscation because BP did not persuasively show that the exceptions are necessary to enable BP to recover its fair share of hydrocarbons under the Flores/Huber tracts or the equivalent in kind.

The evidence which BP was able to present was limited by the scarcity of logs for wells on the Flores/Huber tracts. This prevented presentation of a net pay isopach map for the Flores/Huber tracts, and Dr. Holmes presented volumetric calculations of original gas in place from logs for only four wells on the Flores Lease. In addition, there were no cores available for any well on the Flores/Huber tracts to determine rock types or measure permeability.

BP did not persuasively establish that its existing wells on the Flores/Huber tracts are not capable of efficiently and effectively recovering the recoverable gas in place beneath these tracts. The reservoir appears to be continuous and in pressure communication across the Flores/Huber tracts. The experts agree that dolomite is by far the predominant rock type, and is pervasive, in Flores Lease area wells, and Dr. Ahr's testimony and exhibits show that there is good porosity and permeability in the producing formations, particularly in the Lower Krider. According to Mr. Griffin's analysis of cable tool driller's completion forms, although there are some variations, gross pay across the Flores/Huber tracts is relatively constant and does not pinch out in any direction across the tracts. Existing wells on the Flores/Huber tracts, including those surrounding the locations of BP's proposed Rule 38 exception wells, generally are completed throughout the pay zone.

Most of the wells in the Texas Hugoton Field, including most wells on the Flores/Huber tracts, were drilled in the 1940's or early 1950's, and the field is now in the latter stages of depletion. Mr. Griffin testified that, for the most part, wells in the field are capable of adequately and efficiently draining 640 acres. He agreed that the Lower Krider, in particular, is a high permeability zone through which most of the wells in the field historically have been in communication, though he also believes that communication is more limited today due to low bottomhole pressures and low producing rates of wells.

Isobaric maps for the pre-1951 era through 2001 show that drainage areas of wells in the entire Flores Lease area have changed significantly over time. Pressure in the entire area is now very low, with a slight pressure gradient across the Flores/Huber tracts, lower on the west to slightly higher on the east. Pressure versus time plots for wells on the Flores/Huber tracts presented by Dr. Strickland show a remarkably similar pressure decline for each of these wells over time. The pressure data, as a whole, appears to show that the entire Flores Lease area is in pressure communication.

Dr. Holmes testified that there might be isolated pods of porosity beneath the Flores/Huber tracts that have only limited or no communication with existing wellbores, and it is his interpretation that there are lateral discontinuities in porosity in the interwell area beneath these tracts. These interpretations are constrained, however, by the limited amount of log data which is available, and are not known conditions or definitively ascertainable from the evidence which BP presented.

The fact that some of the existing wells on the Flores/Huber tracts have lower producing rates than others does not necessarily show that the reservoir beneath these tracts is not continuous and in pressure communication. Wells have different producing rates because they have different permeabilities, thicknesses of formations, pressures at external boundaries, completion efficiencies, and drainage areas. Wells that have different flow rates have different cumulatives over time.

BP contends that its theory about discontinuity and separate sources of supply in the reservoir is supported by initial producing rates of certain replacement wells drilled on the Flores Lease. Some of the replacement wells on the Flores Lease studied by Mr. Griffin came on at higher pressures and initial producing rates than the last pressures and producing rates of the wells they replaced, and BP contends that the replacement wells with significantly higher producing rates will recover incremental reserves.

Higher initial pressures and producing rates seen in replacement wells, however, do not necessarily indicate that the replacement wells will recover incremental reserves. While an original well is still producing, pressure in the reservoir is drawn down at the wellbore, and there is a sharp pressure gradient around the wellbore going out to a pressure at the external boundary of the drainage area. If a replacement well is drilled in the drainage area of the original well, the replacement well will have a greater initial producing rate, as compared to the last producing rate of the original well, if for no other reason than it has a higher pressure than experienced at the original well. This is true even though the pressure in the replacement well may rapidly deplete in a pressure profile similar to the original well.

Initial pressures observed in replacement wells on the Flores Lease, and in replacement wells drilled by Phillips elsewhere in the Texas Hugoton Field, were significantly depleted from original reservoir pressure, and insofar as the evidence discloses, none of these replacement wells encountered original pressure. The overall pressure performance of replacement wells drilled on the Flores Lease, and by Phillips elsewhere in the field, has been similar to the pressure performance of the original wells they replaced. This is an indication that the replacement wells encountered reserves that were in the drainage area of an existing well.

BP contends that rate versus time plots for some replacement wells on the Flores Lease, and for the original wells they replaced, show that the replacement wells will recover incremental reserves. However, Dr. Strickland's semilog plot of rate versus time for a normalized average replacement well on the Flores Lease, averaging data for 9 replacement wells and the 11 wells they replaced, did not indicate that replacement wells will recover incremental reserves. Dr. Strickland's rate versus time analysis of 24 replacement wells in the Flores Lease area and the wells they replaced showed some winners and some losers in terms of recovery of reserves by replacement wells that would not have been recovered by the original wells, but the analysis showed that overall the replacement wells would not recover substantial incremental reserves, particularly in relation to the cost of drilling new wells in this area.

BP also makes the contention that the fact that newer replacement wells had no apparent effect on the production decline trend of other nearby wells is evidence that wells produce from separate sources of supply. However, interference between wells occurs at the drainage boundary of each well and is difficult to see in flow rates. In addition, replacement wells that had no apparent effect on the production decline trend of other nearby wells did have an effect on the pressure performance of the nearby wells. For example, a pressure decline was seen in Flores Well No. 23 after Flores Well No. 32, about 2,570' away, commenced production. A pressure decline was seen in Flores Well No. 30 after Flores Well No. 31, about 2,200' away, commenced production. This is an indicator of possible pressure interference between wells.

Measured while drilling pressures were presented for 4 Flores Lease wells, Flores Well Nos. 32, 33, 35, and 37, drilled in 1996-1997. These wells are in 4 different sections extending across the midsection of the Flores Lease from the west side of the lease to the east side. The measured while drilling pressures show significant pressure depletion of the Herington, Upper Krider, and Lower Krider formations. This pressure depletion appears to have resulted from production by offset wells from interconnected net pay (lateral flow) or from vertical flow of gas down to the higher permeability, lower pressure region of the producing formations. The measured while drilling pressures are further evidence of pressure communication in the reservoir across the Flores Lease.

BP contends that Mr. Griffin's pressure versus cumulative plots for existing wells on the Flores/Huber tracts, indicating reserves that the wells are seeing within their drainage areas, as compared with rate versus time plots indicating the remaining reserves that the wells will recover, show that the proposed Rule 37/38 exception wells are needed to recover reserves beneath the Flores/Huber tracts that will not be recovered by any existing well. The examiners conclude, however, that BP's pressure/cumulative and rate/time studies are not sufficiently reliable to establish that this is so.

While pressure versus cumulative analysis may be useful to estimate gas being "seen" within a well's drainage area in some reservoirs, the experts appear to agree that this type of analysis says nothing about the size of a well's drainage area. Pressure versus cumulative analysis does not serve to estimate gas in place beneath a 640 acre proration unit or beneath any particular tract of land. If a well's drainage area extends across a lease line, estimates of reserves derived from pressure versus cumulative may include some portion of reserves beneath an adjacent lease, and pressure versus cumulative analysis for a particular well does not necessarily furnish a reliable estimate of reserves under that well's proration unit.

Uncertainty or variability in available pressure data, and the fact that only limited pressure data may be available for particular wells, create difficulty in estimation of reserves from pressure versus cumulative analysis. How to draw a trend line through the pressure data on pressure versus cumulative plots to extrapolate reserves is a subjective determination. There may be several plausible interpretations as to how the trend line should be drawn, with widely varying reserve estimates depending upon the interpretation which is selected. It is not well established in the evidence that pressure versus cumulative analysis is commonly used to estimate reserves in the Texas Hugoton Field, and Dr. Strickland testified that due to low reservoir pressures and high cumulative production relative to remaining reserves, it is his opinion that it is very difficult to estimate reserves by pressure versus cumulative in the Texas Hugoton Field.

Considerable doubt also exists about the reliability of BP's rate versus time estimates of remaining reserves that existing wells on the Flores/Huber Leases will recover. BP's rate versus time recovery estimates for existing wells are forecast with a linear decline instead of with an exponential decline. The conventional decline curve analysis technique is a semilog decline curve based on Arps' rate/time decline equation, a decline which is exponential in form. Use of BP's linear decline technique tends to substantially underestimate recovery of reserves for existing wells on the Flores/Huber Leases.

BP was unable to make volumetric calculations of original gas in place for the Flores/Huber Leases as a whole. Dr. Holmes made volumetric calculations from logs for a total of only 4 wells on the subject leases. The usefulness of these calculations is limited in that: (1) they assume that wellbore values are uniform throughout 640 acres in a reservoir that is heterogeneous and which is described by BP's experts as having widely varying properties over short distances; and (2) they are unrelated to any particular proration unit or tract of land.

BP did not prove the amount of recoverable gas in place beneath the Flores/Huber tracts or beneath the BP-defined low recovery area of the leases where BP's proposed Rule 37/38 wells are located. Neither did it prove that existing wells are not efficiently and effectively draining the reservoir beneath the Flores/Huber tracts.

BP made no claim that gas is being drained from the Flores/Huber tracts by wells on surrounding tracts. In fact, Mr. Griffin testified that no gas is migrating, or will migrate, from the Flores/Huber tracts to any tract consisting of the sections surrounding the Flores/Huber tracts. Mr. Griffin also thinks that no gas is migrating from the surrounding tracts to the Flores/Huber tracts. However, there is evidence in the 2001 isobaric map of the Flores Lease area of relatively lower pressures in the eastern, northeastern, and southeastern portions of the Flores Lease as compared with pressures of adjacent tracts, which may be causing migration of gas from the adjacent tracts to the Flores/Huber tracts.

According to BP's estimates of remaining gas which existing wells on the Flores/Huber tracts are seeing within their drainage areas and estimates of remaining gas which the existing wells will recover, in some instances, existing wells will recover either all or substantially all (within 70 MMCF) of the gas they are seeing. This is the case for Flores Lease Well No. 1 in Section 8, Flores Lease Well No. 5 in Section 60, Flores Lease Well No. 32 in Section 89, and Flores Lease Well No.

26 in Section 118. Rule 38 exception wells are proposed on all of these sections. BP estimates that its Rule 38 exception wells will recover an average of .5 BCF of gas, and if this is correct, the proposed Rule 38 exception wells on Sections 59 and 88 will recover 2-3 times the remaining recoverable reserves which BP claims will go unrecovered by existing wells on these sections.

As is the case with the Flores/Huber tracts, the 640 acre sections surrounding the Flores/Huber tracts have only one producing well per section. Mr. Griffin's estimates of remaining gas which existing wells in the Flores Lease area are seeing and estimates of remaining gas which the existing wells will recover tend to show that the Flores Lease is doing quite a bit better than the tracts in the halo area surrounding the Flores Lease in terms of percentage of recovery, perhaps twice as good. BP did not prove that the proposed Rule 37/38 wells are necessary to enable BP to recover its fair share of hydrocarbons beneath the Flores/Huber Leases.

Because BP did not persuasively show that unusual conditions exist in the reservoir beneath the Flores/Huber tracts, or that the proposed Rule 37/38 exception wells will recover substantial reserves beneath the tracts that will not be recovered by any existing well, or that BP will not be able to recover its fair share of hydrocarbons beneath the tracts, the examiners cannot conclude that granting of the requested Rule 37/38 exceptions is necessary to prevent waste or to prevent confiscation. Accordingly, the examiners recommend that the applications be denied.

Based on the record in these dockets, the examiners recommend adoption of the following Findings of Fact and Conclusions of Law.

FINDINGS OF FACT

1. At least ten (10) days notice of the hearing in these dockets was sent to all parties entitled to notice.

2. BP America Production Company ("BP"), formerly Amoco Production Company, seeks exceptions to Statewide Rule 38 for a total of 19 wells on its Flores, Flores "86", Flores "95", and Huber Et Al. Leases, Texas Hugoton Field, Sherman and Moore Counties, Texas. Exceptions to Statewide Rule 38 are requested to drill 14 wells on the Flores Lease, 2 wells on the Flores "86" Lease, 1 well on the Flores "95" Lease, and 2 wells on the Huber Et Al. Lease.

3. BP also requests exceptions to Statewide Rule 37 for 3 of the proposed wells on the Flores Lease, 1 of the proposed wells on the Flores "86" Lease, the proposed well on the Flores "95" Lease, and 1 of the proposed wells on the Huber Et Al. Lease.

4. The wells proposed to be drilled by BP, their proposed locations, and reasons why Rule 37 and/or Rule 38 exceptions are required are as set forth in Appendix 1 to this Proposal for Decision, which is incorporated into this finding by reference.

5. Field rules for the Texas Hugoton Field provide for spacing of 1,250 feet from any property line, lease line or subdivision line and 2,500 feet from any well on the same tract completed in or drilling to the same horizon. The field rules also provide for 640 acre density.

6. BP's Flores, Flores "86", Flores "95", and Huber Et Al. Leases ("Flores/Huber tracts") now have the maximum number of producing wells permitted by the 640 acre density rule governing the Texas Hugoton Field.

7. The BP applications for exceptions to Statewide Rules 37/38 are opposed by Phillips Petroleum Company ("Phillips"), an operator of offsetting tracts to the north, northeast, east, southwest, and west of the Flores/Huber tracts, and Travelers Oil Company ("Travelers"), another operator in the Texas Hugoton Field.

8. The Texas Hugoton Field was discovered in 1918. It lies immediately to the north of the Panhandle West Field and covers the northern portion of Moore County, most of Sherman County, and the western portion of Hansford County.

9. There are about 915 wells in the Texas Hugoton Field, most of which were drilled in the 1940's or early 1950's. The field is now in the latter stages of depletion.

10. The Texas Hugoton Field has producing formations that correlate to the producing formations in the adjoining Guymon (Hugoton) Field to the north and the Panhandle West Field to the south.

11. Wells on the Flores, Flores "86", Flores "95", and Huber Et. Al. Leases ("Flores/Huber tracts") generally encounter three potentially productive formations in the Texas Hugoton Field, the Herington, the Upper Krider, and the Lower Krider. Some wells in the subject area are also completed in the deeper Winfield formation.

12. Wells on the Flores/Huber tracts and in adjacent or surrounding areas encounter predominantly dolomite in the Herington, Upper Krider, and Lower Krider formations. Dolomite has good connectivity and porosity development in these formations.

13. The Lower Krider formation has higher permeability and better porosity than do the more shallow Herington and Upper Krider formations. There are good lateral communication and wide drainage in the Lower Krider in the area of the Flores/Huber tracts.

14. There is reservoir continuity and interwell communication among wells on the Flores/Huber tracts and the adjacent or surrounding area.

    a. Continuity and communication is not interrupted by faulting or other geological condition.

b. Interpretive cross sections across the Flores/Huber tracts depict porosity intervals that correlate over distances ranging up to 4.7 miles in the Upper Krider and 7.7 miles in the Lower Krider.

c. Adjoining wells on and in the area of the Flores/Huber tracts have similar pressures, all of which are substantially depleted from original reservoir pressure.

d. Pressure performance for replacement wells drilled in the area of the Flores/Huber tracts is similar to the pressure performance for the original wells they replaced.

e. Differences in flow rates and cumulative production of wells on the Flores/Huber tracts and adjacent areas do not necessarily indicate a lack of reservoir continuity or lack of interwell communication. Wells may have different producing rates because they have different permeabilities, thicknesses of formations, pressures at external boundaries, completion efficiencies and drainage areas.

15. Existing wells on the Flores/Huber tracts are effectively and efficiently draining the Herington, Upper Krider, and Lower Krider formations in the Texas Hugoton Field.

a. Original reservoir pressure in the Texas Hugoton Field ranged from 450 psi to 500 psi. Current measured pressures typically range from 20 psi to 30 psi in the Flores/Huber area.

b. Historic and current isobaric maps for the area of the Flores/Huber tracts show uniform decline in pressure over time, as wells have drained the reservoir.

c. Pressures of adjoining wells on the Flores/Huber tracts and surrounding sections have declined similarly over time with effective areal drainage.

d. Twenty-four replacement wells drilled in the Flores/Huber area since 1975 have encountered pressures substantially below the original reservoir pressure, and the pressure performance of these replacement wells is similar to the pressure performance of the original wells they replaced.

e. Measured while drilling pressures taken in the Herington, Upper Krider, and Lower Krider formations in four wells on four different sections drilled across the middle of the Flores Lease in 1996-1997 were significantly reduced from original reservoir pressure. These pressures ranged from 33% to less than 10% of original reservoir pressure at various intervals.

f. Existing wells on the Flores/Huber tracts generally are completed throughout the Herington, Upper Krider, and Lower Krider formations.

g. The Herington, Upper Krider, and Lower Krider formations beneath the Flores/Huber tracts are being depleted by vertical communication between formations and/or by completions in existing wells.

16. BP's proposed wells will not recover a substantial quantity of incremental reserves, that is, reserves that will not be recovered by any existing well.

a. Existing wells are effectively and efficiently draining the reserves beneath the Flores/Huber tracts.

b. Estimated ultimate recovery of gas from 24 replacement wells drilled in the Flores/Huber Lease area since 1975 is comparable to the amount of gas that would have been recovered by the original wells had they continued production.

c. High initial pressures observed in some replacement wells do not necessarily mean that the replacement well will recover incremental reserves.

d. BP's pressure versus cumulative estimates of gas that existing wells are seeing as compared to rate versus time recovery estimates for existing wells do not reliably forecast the need for additional wells to recover incremental reserves.

i. Rate versus time recovery estimates for existing wells forecast with a linear decline as opposed to an exponential decline, tend to underestimate future recovery by existing wells.

ii. Pressure versus cumulative estimates of gas that existing wells are seeing within their drainage areas do not define the size of drainage areas or necessarily estimate reserves beneath any particular tract of land or proration unit.

iii. Usefulness of pressure versus cumulative extrapolations to estimate reserves is limited by the quantity and quality of the pressure data which is available.

iv. Pressure versus cumulative plots are subject to differing subjective interpretations as to how pressure data should be extrapolated to estimate reserves.

17. BP did not prove that peculiar, unusual, or abnormal conditions exist in the subject reservoir beneath the Flores/Huber tracts as compared to adjacent and surrounding parts of the Texas Hugoton Field.

a. Wells on the Flores/Huber tracts, and in the adjacent sections surrounding the Flores Lease, as well as the Fee 8-209 well about 9 miles to the southeast in the Panhandle

West Field, and the Buf No. 3 and Shiel 2R wells about 42 miles to the north in the Guymon (Hugoton) Field, encounter predominantly dolomite in the Herington, Upper Krider, and Lower Krider formations.

b. Conditions existing in the reservoir beneath the Flores/Huber tracts are essentially the same as exist beneath BP's Price 'D' Lease about 4-5 miles to the north.

c. Heterogeneity in the reservoir existing beneath the Flores/Huber tracts exists also in other portions of the Texas Hugoton Field and the Panhandle West Field.

d. Local variations in permeability are common in the Texas Hugoton Field, Panhandle Field, Guymon (Hugoton) Field, and Kansas Hugoton Field.

e. Wells with different flow rates and different cumulative production exist both on the Flores/Huber tracts and in the sections surrounding the Flores/Huber tracts. Areas of relatively low recovery on the Flores/Huber tracts also exist on adjacent sections.

f. Depositional environment and geological models relevant to the Flores/Huber tracts apply to other areas of the Texas Hugoton Field, including areas adjacent to and surrounding the Flores/Huber tracts.

g. Thicknesses of gross pay calculated from cable tool driller's logs in wells on the Flores/Huber tracts are comparable to those in wells on sections surrounding the Flores/Huber tracts.

h. BP's claim based on pressure versus cumulative and rate versus time extrapolations that existing wells will not recover all the gas they are seeing applies both to wells on the Flores/Huber tracts and to wells on sections surrounding the Flores/Huber tracts.

18. BP did not prove that its proposed wells are necessary to afford BP an opportunity to recover its fair share of the hydrocarbons under the Flores/Huber tracts.

a. Volume of gas in place beneath the Flores/Huber tracts is not reliably established.

i. BP's estimates of what existing wells on the Flores/Huber tracts are seeing within their drainage areas are not the same thing as gas in place beneath the tracts or beneath any particular proration unit.

ii. Insufficient logs were available to enable BP to estimate gas in place by volumetric calculation.

iii. BP's volumetric calculations of original gas in place from logs for four wells on the Flores Lease are based on an assumption that wellbore values extend out over an entire 640 acres notwithstanding heterogeneity in the reservoir. These calculations relate to an undefined 640 acres that does not coincide with any particular tract or proration unit.

b. BP will have a reasonable opportunity to recover currently recoverable reserves beneath its Flores/Huber tracts from existing wells.

c. Sections offsetting the Flores/Huber tracts are drilled to the same density in the subject reservoir as are sections on the Flores/Huber tracts.

d. Wells on offsetting tracts are not draining reserves from the Flores/Huber tracts.

e. Lower pressures in the eastern, northeastern, and southeastern portions of the Flores Lease as compared with pressures of adjacent tracts may cause gas to migrate from the adjacent tracts to the Flores Lease.

f. BP's estimates of gas being seen by existing wells in their drainage areas versus gas which existing wells will recover show that wells on the Flores/Huber tracts are outperforming wells on offsetting tracts in terms of percentage of recovery.

19. Denial of the requested Rule 37/38 exceptions will not cause waste of a substantial volume of hydrocarbons that will not be recovered by any existing well.

20. Denial of the requested Rule 37/38 exceptions will not deny to owners of the Flores/Huber tracts an opportunity to recover the reserves underlying the tracts.

CONCLUSIONS OF LAW

1. Proper notice of hearing was timely given to all persons legally entitled to notice.

2. All things have occurred and been accomplished to give the Commission jurisdiction to decide this matter.

3. BP is required to obtain exceptions pursuant to Statewide Rule 38 to the field rules regarding well density in order to drill the applied-for wells.

4. BP is required to obtain exceptions pursuant to Statewide Rule 37 to the field rules regarding spacing in order to drill the proposed Flores Lease, Well Nos. 44, 47, and 49, Flores "86" Lease, Well No. 51, Flores "95" Lease, Well No. 57, and Huber Et Al. Lease, Well No. 5.

5. Approval of the requested exception permits is not necessary to give owners of the Flores/Huber tracts a reasonable opportunity to recover their fair share of hydrocarbons in the applied-for field underlying the Flores/Huber tracts, or the equivalent in kind.

6. Approval of the requested exception permits is not necessary to prevent the waste of a substantial volume of hydrocarbons in the Texas Hugoton Field.

7. Exceptions to Statewide Rules 37 and 38 for wells at the applied-for locations are not necessary to prevent confiscation or to prevent waste.

RECOMMENDATION

The examiners recommend that the subject applications be denied in accordance with the attached final order.

Respectfully submitted,

James M. Doherty

James M. Doherty
Hearings Examiner

Donna K Chandler

Donna Chandler
Technical Examiner