Approved February 23, 1984
Date

MINUTES OF THE Senate COMMITTEE ON Energy and Natural Resources.

The meeting was called to order by Senator Charlie L. Angell at
Chairperson

8:00 a.m./XXX. on Wednesday, February 22, 1984 in room 123-S of the Capitol.

All members were present except:
Senator Paul Hess
Senator Tom Rehorn

Committee staff present:
Ramon Powers, Research Department
Don Hayward, Revisor's Office
LaVonne Mumert, Secretary to the Committee

Conferees appearing before the committee:
Ron Sherwood, Amoco
Mike Skiles, Amoco
Jack Glaves, Panhandle Eastern Pipe Line Company
Karl Tripp, Northern Natural Gas Company

Senator Roitz moved that the minutes of the February 21, 1984 meeting be approved. Vice-Chairman Kerr seconded the motion, and the motion carried.

S.C.R. 1643 - Natural gas; encourage infill drilling

Ron Sherwood reviewed the information distributed to the Committee (Attachment 1). He discussed the complexity of the Chase formation and the highly variable porosity and permeability of the zones. Mr. Sherwood talked about the barriers to gas migration. It is necessary to do lab tests to measure the porosity and permeability of rock. He said it is very difficult to predict how much area any given bore hole will cover. Mr. Sherwood used charts to illustrate the lithology of the Chase formation and showed specimens of dolomite, limestone and sandstone.

Mike Skiles said that many fields have been incapable of fully draining on 640-acre spacing. In the early 1960's many of the wells in the Hugoton field were treated by fracturing. This eliminates the possibility of going in and testing the individual zones because all zones are in communication on these wells. Mr. Skiles testified that indications are that additional wells are needed to adequately drain the Hugoton field. New state of the art techniques for fracturing could be used on these new wells that cannot be used on old wells.

Jack Glaves summarized his written testimony (Attachment 2). He spoke in opposition to S.C.R. 1643. He feels it is inappropriate to encourage the State Corporation Commission to act on an issue in this manner, because they are a quasi-judicial body. Mr. Glaves said that it is a matter of speculation whether infill drilling would increase reserves. He stated that the State Corporation Commission is required to protect correlative rights and prevent waste but is not required to consider economic benefits.

Karl Tripp read his statement (Attachment 3). He stated that he has recently completed a study of the Hugoton field and finds that no additional reserves would be made available by infill drilling. He said even the slight acceleration in the rate of recovery would be insignificant and uneconomic. He estimated that the additional costs for infill drilling would cost consumers 14.5 billion dollars.

The meeting was adjourned at 8:58 a.m. by the Chairman. The next meeting of the Committee will be at 8:00 a.m. on Thursday, February 23, 1984.

Senate Energy + Natural Resources
Feb. 22. 1984

Name	~~Organization~~
R. A. Nichols	STANDARD Oil Co. (IND)
Chip Wheelen	KLPG
Dick Howard	PEPL
Jim Moss	PEPL
A.E. Benkqnus	KPL
BILL PERDUE	KPL / GAS SERVICE
D.S. Black	KPL / Gas Service
M.A. Skiles	Amoco Production Co.
[illegible]	[illegible]
Don Schnacke	KIOGA.
[illegible]	Panhandle Eastern
LON STANTON	NORTHERN NATURAL GAS
Karl Tripp	Northern Natural Gas.
Ed Reinert	KS League of Voters
Patti [illegible]	KCC
RH Longenecker	KPL
Rick Kready	KPL / Gas Service Co.
BILL RINEHART	GULF OIL CORP.
ROSS MARTIN	KS PETROLEUM COUNCIL
Steve Watson	Kansas Farmer magazine
David W Nichol	KCC

SUMMARY

1) The reservoir rocks of the Chase Formation are a complex package of interfingering sandstones, limestones and dolomites.

2) The porosity and permeability of these reservoir zones is highly variable.

3) The higher permeability zones drain larger areas at faster rates and the lower permeability zones drain smaller areas at slower rates.

4) The interfingering of the reservoir rocks creates barriers to gas migration.

5) It is difficult to predict how large an area a gas well can drain because it penetrates zones with varying porosity and permeability. It is also possible that permeability barriers which will limit drainage exist short distances from the borehole.

6) The existance of zones with varying porosity and permeability and the existance of gas migration barriers indicate that one well per section will not likely drain 640 acres in Hugoton Field.

Atch. 1

Mr. Chairman and members of the Committee, our intent today is to present information from the geological and engineering work Amoco is completing on the Permian Chase Formation in the Kansas portion of Hugoton Field. We wish to demonstrate the complexities of the field and the likely need for infill drilling.

The current limit of Hugoton Field is shown on Figure 1. It covers more than 2.6 MM acres, and contains over four thousand one hundred wells. The average well depth is 2700'.

The amount of gas in the Chase Reservoir prior to production has been estimated to be over 25 TCF. A TCF is enough gas to supply the entire U.S. for approximately three weeks. Eighteen TCF has been produced as of 1-1-82, leaving an estimated 7 TCF remaining.

In the next few minutes I will show you the data which supports the main points of my presentation. These points are:

1) The reservoir rocks of the Chase Formation are a complex package of interfingering sandstones, limestones and dolomites.

2) The porosity and permeability of these reservoir zones is highly variable.

3) The higher permeability zones drain larger areas at faster rates and the lower permeability zones drain smaller areas at slower rates.

4) The interfingering of the reservoir rocks creates barriers to gas migration.

5) It is difficult to predict how large an area a gas well can drain because it penetrates zones with varying porosity and permeability. It is also possible that permeability barriers which will limit drainage exist short distances from the borehole.

6) The existance of zones with varying porosity and permeability and the existance of gas migration barriers indicate that one well per section will not likely drain 640 acres in Hugoton Field.

In order for a rock to become a gas reservoir, it must meet two requirements. 1) It must contain void spaces where gas can be stored. The amount of void space in a rock is referred to as its <u>porosity</u>. This is illustrated in Figure 2 and is customarily given as a percent of the rock's volume.

Secondly, the rock must allow the gas to flow through interconnected void spaces to the well bores if the reservoir is to be drained and gas produced at the wellhead. The measure of the ease with which fluid can move through interconnected pores in a rock is known as its permeability.

Pieces of reservoir rock must be tested in a laboratory to determine the amount of porosity and permeability present. Amoco has obtained samples of the Chase reservoir rock by cutting approximately 1200' of core in the four wells shown on Figure 1.

Figure 3 is a photograph of a piece of rock from one of these wells. The blue is epoxy we have forced into a thin slice of rock to make the porosity or void spaces visible. You cannot see permeability or the interconnections between voids very well in this type of preparation but the existence of some larger void areas indicate that some permeability likely exists in this rock.

Figure 4 is a photograph of the same type of rock from another area of the field. Porosity and permeability are not present. This lack of permeability will create a barrier to gas flow. Such barriers can greatly restrict well drainage since the porosity over 640 acres must be interconnected with a borehole if the section is to be drained.

Figures 5 and 6 are graphic displays of the kinds of rock recovered in the cores from the four wells shown on Figure 1. These cores tell us that sandstone indicated in yellow; limestone in blue; dolomite in pink; shale indicated in grey, and siltstone in brown are the rocks that make up the majority of the Chase Formation.

The sandstones, limestones and dolomites contain the gas in Hugoton Field and are the reservoir rocks. Laboratory measurements on these rocks indicate that there is considerable variation in the amount of porosity and permeability found in each reservoir lithology. The range of porosity and permeability found in these lithologies is listed to the right of the core diagram for each well. If you compare the numbers, you see that there is a considerable range of values within a rock unit or between rock units.

If we look at the Herrington Sandstone Unit in the left hand well, we see porosity is about the same in the three wells but the permeability decreases by 50% as we move 27 miles North. The Krider Unit in the left hand well is a limestone and exhibits a little lower porosity (13%) than the Herrington sandstone above (17%). However, the limestone permeability (.7md) is less than one tenth that of the sand (9.0md). In the well at the center of the display, the limestone porosity (10%) is about half that of the sand (18%) while the permeability (.2 md) is less than one twentieth that of the sand (7.0 md.).

The point of all these numbers is that the porosity and permeability in the Hugoton Field reservoir varies widely depending upon geographic location and/or the reservoir unit you are examining.

This considerable amount of lateral and vertical variation in porosity and permeability makes it difficult to predict the drainage area of a gas well. There are two reasons for this: First the higher permeability zones will drain a larger area at a faster rate and the lower permeability zones drain smaller areas at slower rates. Secondly, the interfingering of rock types across the field produces boundary zones which lack permeability. These boundaries can restrict the drainage area that high or low permeability zones could otherwise drain. We do not know how frequently these boundaries occur across Hugoton Field. If they are common, it is quite likely they create restricted drainage areas for many wells. This condition will require infill drilling if all reserves are to be recovered.

I have six rock samples here which represent some of the best and poorest reservoir rock in the cores of the sandstones, limestones, and dolomites. I will pass these around so you can look at them.

Mike Skiles from our Engineering Department will now comment on the reservoir engineering work currently underway.

Gentlemen, as you've seen the Hugoton Gas Field is relatively complex, with many stratified "layered" zones of differing rock quality. But what exactly does this mean in terms of gas production and reserve recoveries?

As previously shown, the rock permeability is a measure of flow conductance, or in other words, a measure of how easy it is for gas or fluids to flow through the rock into a wellbore and be produced. The lower the permeability, the tighter the rock is and the more difficult for gas to flow to the wellbore. Within the geological system of the Hugoton Gas Field, with stacked layers of varying permeability, when a given pressure drop is made by opening the shut-in wellbore to a production line, these different rock layers will contribute different flowrates of gas. The tighter rocks will flow at lower rates, while the higher permeability rocks will contribute greater gas flowrates. These different flowrates were observed during early cable-tool drilling operations in the field during the 1930's and 1940's, and work done by our company during the late 1940's, using flow meter gauges lowered into producing wells, also confirmed these differing flowrates from the various rock layers.

As many of you may be familiar with, there have been many fields located around the country which have proven to be incapable of producing all their reserves through a single 640-acre-spacing well, and, as a result, have required infill drilling to be properly depleted. More often than not, the reason these fields have been unable to be depleted with 640-acre wells was due to low permeability rock. Even with the application of large hydraulic fracture treatments to the wells, to improve the flow capacity of the tighter reservoir rocks, many of these fields have still required increased well density to effectively drain the reserves. The basis of any such evaluation for increased density drilling is always technical geological and engineering data. With continued production over time, the performance of these fields showed they would not efficiently recover their in-place reserves defined by geological evaluation unless additional wells were drilled.

Focusing on the Hugoton Field, most development drilling had been completed by the early 1950's on a 640-acre well pattern. Although an appreciable amount of core and test data was obtained during that time period, much of today's technology was not available and, therefore, the analysis techniques used were poor by today's standards. During the early 1960's, the technique of massive hydraulic fracturing was developed and applied to the vast majority of Hugoton Field wells, significantly increasing their production. This technique involves the application of hydraulic pressure down the wellbore using a fluid (in this case water) carrying a proppant (in this case sand). The applied hydraulic pressure literally breaks apart the downhole formation, and the created rock fracture is filled with the injected proppant. When the fracture treatment is completed, the hydraulic pressure is removed at the surface whereupon the downhole created fracture closes, trapping the injected sand. The purpose of hydraulic fracture stimulations is to place a highly permeable conduit of sand many 100's of feet in length into a much lower permeability formation, which gives the tighter rock significantly more surface area from which to feed its gas or fluids into the wellbore. The net effect is increased production rates and better formation drainage from the well. Although these fracture treatments on Hugoton wells were highly successful in increasing production and drainage efficiency, they eliminated our ability to monitor the individual zones of the Chase Formation and depletion efficiency of same. The large fracture treatments created downhole fractures which communicated all the zones behind the casing, preventing any future tests of a single zone in these wells.

Work conducted by our company during recent years, using modern technology to develop the detailed geological descriptions you've seen earlier, emphasized the complexity and zone differences of the Chase Formation. This work provided renewed interest in how each of the Chase Formation zones was performing with time. Using the upper interval of deeper wells which were drilled as dry holes during recent years, we have conducted pressure tests of individual Chase zones in areas of our Hugoton acreage which have been producing since the early 1950's. This display shows the data from our first such test, performed on a well located in the far western portion of the Hugoton Field.

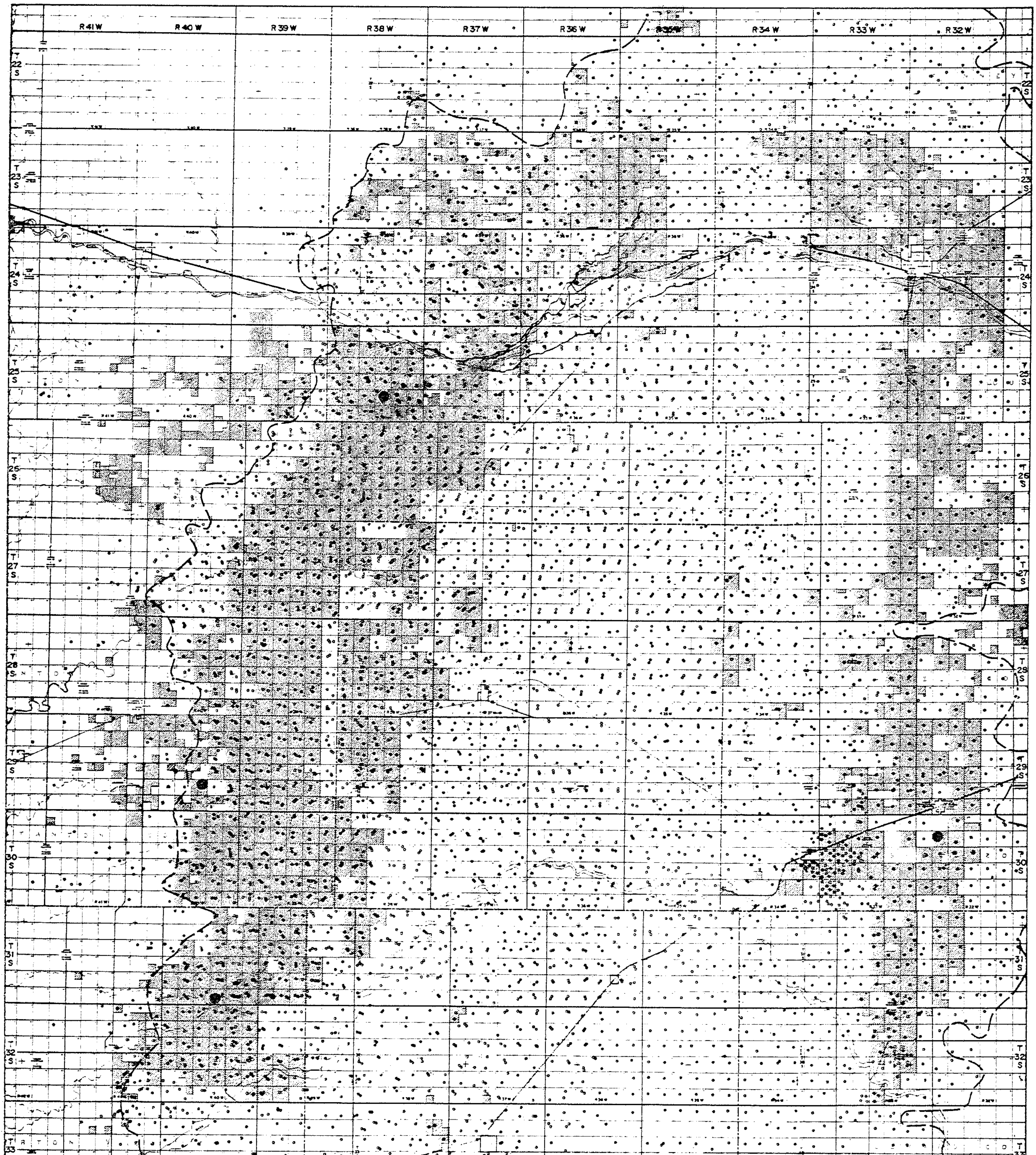
Shown on the display are, from left to right, an openhole electric log, the average core analysis by major zone and individual pressure tests by major zone of the Chase Formation in this well. The curve responses on the openhole log describe the Herrington, Krider, Winfield, and Lower Fort Riley zones of the Chase Formation. As noted on the core analysis data, the Herrington zone with approximately 0.5 millidarcy (Md) permeability, the Krider zone with 0.2 Md and the Lower Fort Riley zone with 0.2 Md permeability are the tightest zones in this well, while the Winfield at 1.8 Md is the highest permeability zone. The pressure test data shown on the right was obtained on each zone individually. Although several mechanical problems were encountered with the equipment during the pressure test work, the values shown are good for relative comparisons. The pressures support what would be expected, with the tighter lower permeability zones having significantly higher remaining pressure. The total well pressure with all zones open was 280 PSIG, which indicates approximately 42 percent depletion from the field's original reservoir pressure of 485 PSIG. However, certain tighter zones such as the Lower Fort Riley, Herrington and Krider are only 11 percent, 36 percent and 39 percent depleted, respectively. Since all the zones have been produced in this area for the same length of time (35 years), this confirms the tighter zones are producing their reserves at much lower flowrates.

We are currently completing additional well pressure tests to evaluate the areal extent and magnitude of these differences. This data will be used in various detailed computer simulation programs during the next few months to predict future performance of each zone. Although this work has not been completed yet, the remaining higher pressure of the lower permeability zones means a lower efficiency drainage in these zones, and likely means the gas reserves will not be effectively recovered from the tighter rock on only 640-acre spacing. This conclusion indicates additional wells in a portion or all of the Hugoton Field will most likely be needed to recover the gas reserves. The new wellbore would provide an additional pressure depletion point on the 640 acre section, as well as allow new state of the art fracture stimulation technology to be applied to particularly the lower permeability zones.

To summarize, we view the Hugoton Gas Field as relatively complex geologically, with many stratified zones of various rock quality. Work done by our company indicates these rock quality differences are resulting in different rates of reserve depletion between the zones in at least one well. More confirming work is in progress to evaluate whether our current drainage is effective, and this work should be completed in the near term. Although we do not yet have the answer to the drainage question, analogy to the infill drilling of other low permeability reservoirs around the country and our initial pressure test work indicate additional wells will likely be needed in portions or all of the Hugoton Field to effectively recover its gas reserves.

Our purpose today was to provide you gentlemen with a taste of the technical complexity of this reservoir and of the technical work being completed to better understand it.

We'd be glad to answer any questions you may have.



● CHASE CORE WELLS

— — — HUGOTON FIELD OUTLINE, CHASE PRODUCTION

0 3 6
MILES

Amoco Production Company
Denver Region
SOUTHERN DIVISION

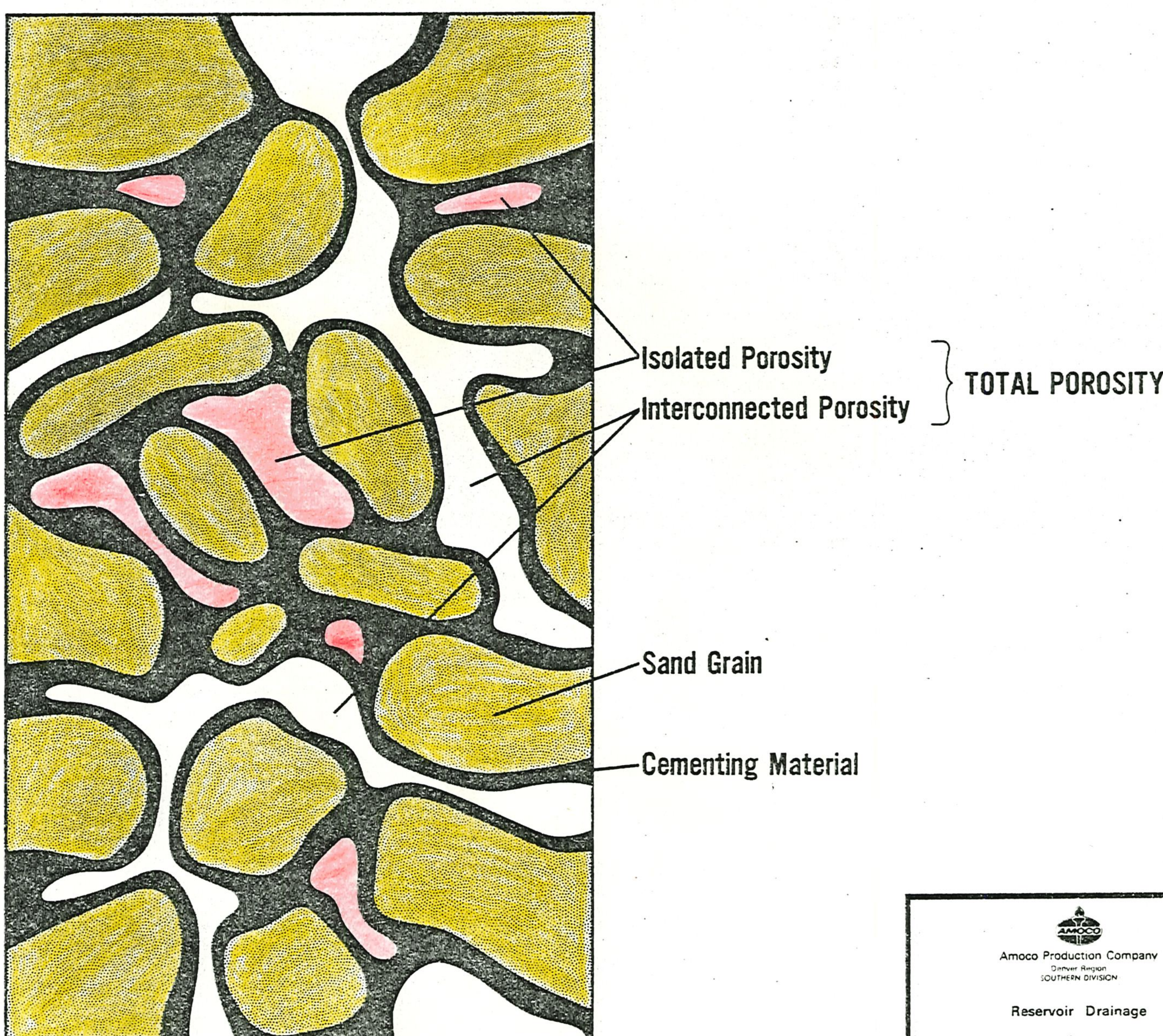
HUGOTON AREA-SW KANSAS

Chase And Council Grove Producing Gas Wells

R. Sherwood
Figure 1

Feb 1984

RESERVOIR DRAINAGE



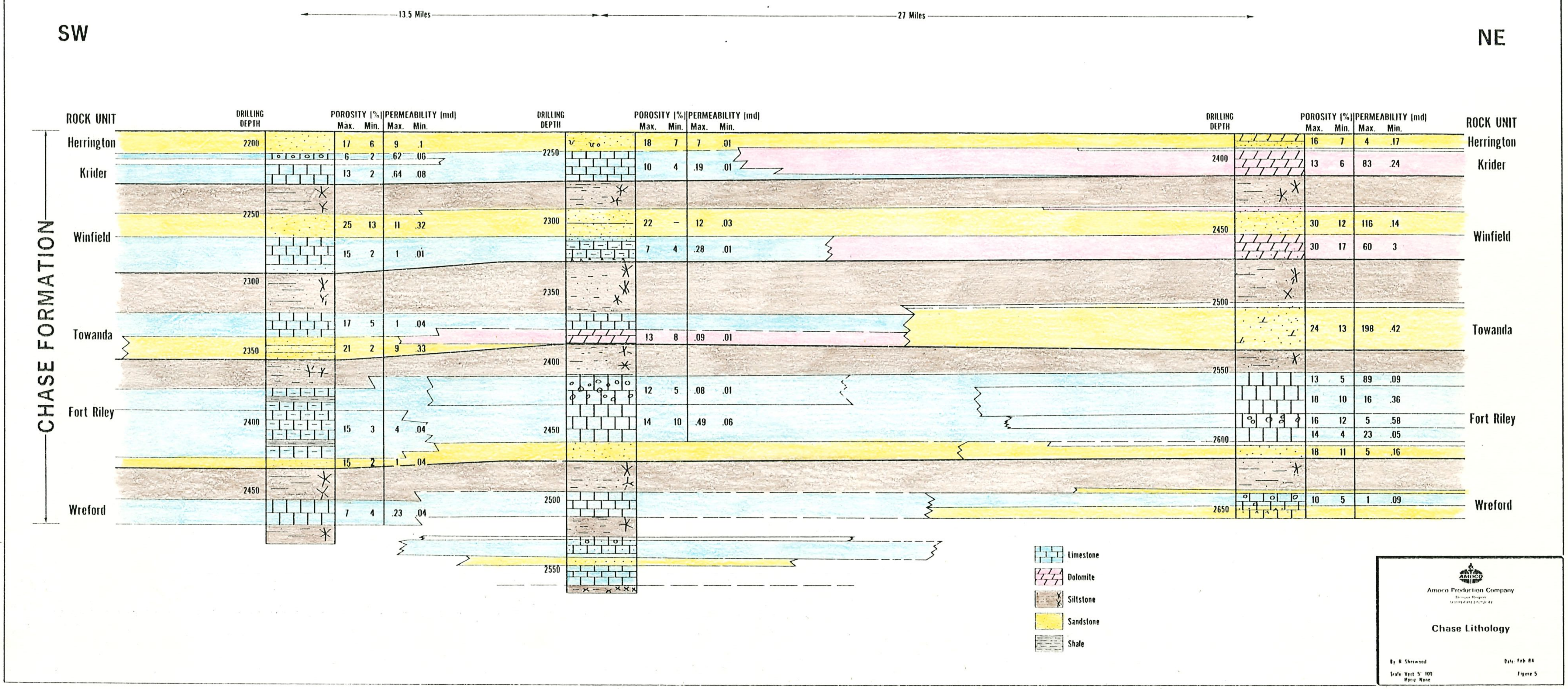
AMOCO
Amoco Production Company
Denver Region
SOUTHERN DIVISION

Reservoir Drainage

By: R. Sherwood

Date: Feb. 84
Figure 2

CHASE LITHOLOGY



Amoco Production Company

Chase Lithology

By R. Sherwood

Date: Feb 84

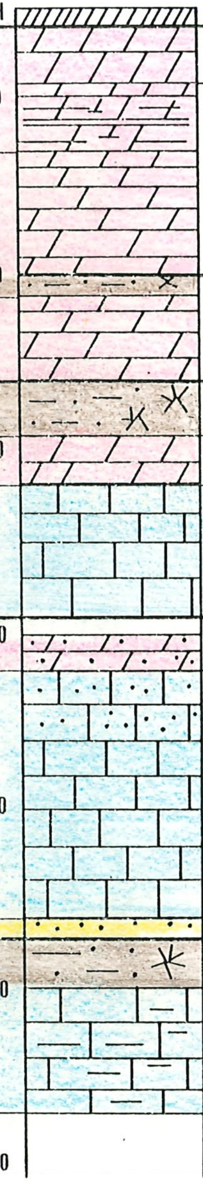
Scale: Vert. 5" 100
Horiz. None

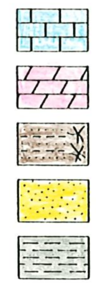
Figure 5

CHASE LITHOLOGY

CHASE FORMATION

ROCK UNIT	DRILLING DEPTH	POROSITY (%) Max.	POROSITY (%) Min.	PERMEABILITY (md) Max.	PERMEABILITY (md) Min.
Herrington		17	5	5	0.1
	2700	12	5	.5	.01
Krider		17	4	3	.01
	2750				
Winfield		23	1	82	.01
	2800				
Towanda		16	7	11	.01
	2850				
Fort Riley		14	4	.7	.01
	2900	15	.6	.06	.01
	2950				
Wreford		16	2	5	.01
	3000				





AMOCO

Amoco Production Company

Denver Region

SOUTHERN DIVISION

Chase Lithology

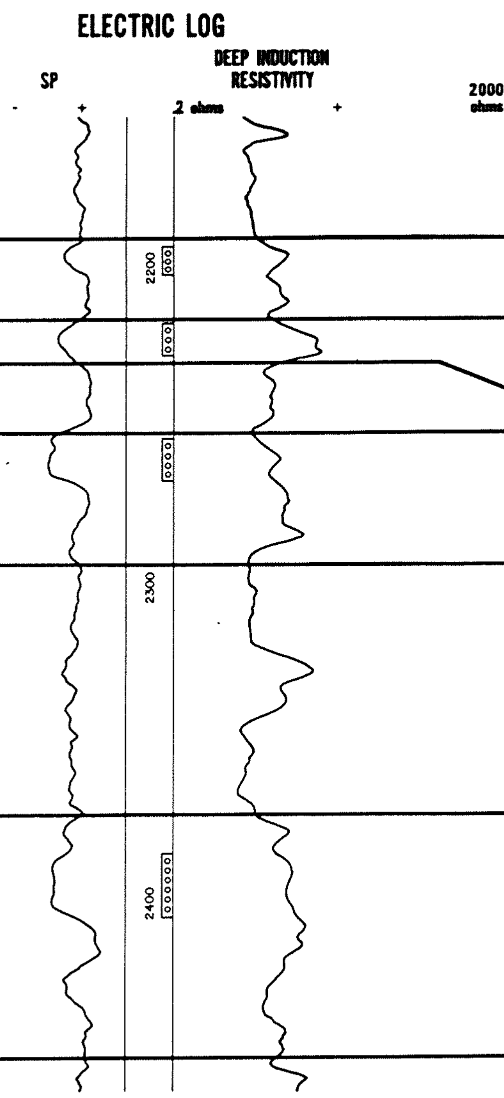
By: R. Sherwood

Date: Feb. 84

Scale: Vert. 5"=100'
Horiz. None

Figure 6

ZONAL PRESSURE TESTS



	ZONES TESTED	CORE ANALYSIS AND PBU DATA	RECENT PRESSURE DATA BHP(PSIG)
CHASE	HERRINGTON	POROSITY = 14.3% PERMEABILITY = 0.48 md NET PAY THICKNESS = 10'	P = 311 PSIG
CHASE	KRIDER	POROSITY = 10.7% PERMEABILITY = 0.20 md NET PAY THICKNESS = 11'	P = 295 PSIG*
CHASE			
CHASE	WINFIELD	POROSITY = 20.6% PERMEABILITY = 1.8 md NET PAY THICKNESS = 14'	P = 192 PSIG
CHASE			
CHASE	FORT RILEY	POROSITY = 11.7% PERMEABILITY = 0.20 md NET PAY THICKNESS = 20'	P = 433 PSIG

* PRESSURE EQUIPMENT FAILURE

P = 280 PSIG
ALL ZONES COMBINED

Amoco Production Company
Denver Region
SOUTHERN DIVISION

Zonal Pressure Tests

By: M. Skiles
Date: Feb. 84
Scale: Vert. 5"=100'
Horiz. None
Encl. No.

TO: Senate Energy and Natural Resources Committee

FROM: Panhandle Eastern Pipe Line Company

DATED: February 22, 1984

RE: SCR 1643

The basic problem with this Resolution is, as we lawyers would say, it assumes facts not in evidence. Although the Resolution applies generally to all natural gas fields, the Interim Study frames this issue as centering on the low price of Hugoton gas as an alternative to decontrol of old gas.(Page 409) The Hugoton field is very complex and very extensive. It, of course, exists not only in Kansas where there are over 4,000 wells, but the same field extends into Oklahoma and Texas, with those states having approximately 2,260 more wells producing from the same reservoir. The pressures vary widely in the field; the lithology varies greatly from one part of the field to another. It is not a homogeneous reservoir. The Resolution is premised on the assumption that infill drilling will increase significantly the total reserves of the Kansas natural gas fields. There are 23 prorated fields and a multitude of unprorated fields, with an estimated 13,500 producing gas wells existing in the State of Kansas. I would submit that evidence of increased reserves is speculative at this point. It has not been revealed as to the Hugoton field, and I don't know of any source for its existence as to the myriad of other fields in the State. Mr. Wulff's report, which has been presented to you, makes the statement that infill wells in Kansas Hugoton would add 5 to 20% of total reserves (Page 7 of his August 1983 article entitled "Rediscovering Hugoton"), and indeed, that statement is assumed to be factual in the Interim Study Report.(Page 409) Mr. Wulff made it quite clear in his statement to this committee last week that he is not a reservoir engineer, and is certainly in no position to support a projected reserve calculation.

Mr. Wulff did correctly observe that:

> "while the driving force for infill drilling is undoubtedly economic, the ultimate rationale in the legal sense must be consistent with the encouragement of the conservation of natural gas resources, which is the basis for state regulation of field rules."

Atch. 2

(also from Page 7) It is quite clear that the legal basis for action by the Corporation Commission must be premised on either the prevention of waste or the protection of correlative rights, or a combination thereof. The Resolution recites that the basis of regulation of gas is the promotion of its maximum recovery. A more correct statement would be recovery at a rate consistent with the protection of your neighbor's rights, i.e., ratable production. The Commission has no authority to allocate production on the basis of economics.

A decision on Hugoton infill drilling could be made only after extensive hearings before the Commission, which would undoubtedly be very extensive and adversarial in nature. Those hearings have not been held, but this Resolution assumes that such hearings would result in the conclusion of a significant increase in natural gas reserves. As you know, hearings have been held by the Commission as to each field that has field rules and a determination was made by the Commission in each of those cases as to what one well would efficiently and effectively drain, as to the particular formation. The spacing does vary widely in Kansas, because of the diverse nature of formations existing in the various fields. We have spacing from just big enough to fit a well on up to 800 acres; but such is officially determined only after hearings held before the Commission. The Hugoton Order was premised on a finding of the Commission, after extensive hearings that one well would efficiently and effectively drain 640 acres. Specifically, the Order provides as follows:

> "(g) That one well completed in said formation can adequately and sufficiently drain 640 acres without causing waste, and considering the cost of drilling, equipping and operating one well in comparison with the estimated recovery per acre and the slow rate at which the production for said field can be ratably and nonwastefully marketed, the Commission finds that the basic acreage unit to be used in the proration formula hereinafter prescribed should be 640 acres, . . ."

That is not to say that the Commission cannot decide, after additional hearings, that such spacing is no longer appropriate and that there is a need for more dense spacing, but that is for the Commission to decide after application is made to it by an interested party. No such application has been made to date, but the existing law certainly does not preclude one from being filed tomorrow, and presumably, this Resolution anticipates such filing.

The Resolution is also premised on contended economic benefits to the State through increased taxes, to the Counties through increased Ad Valorem taxes, to royalty owners, and miraculously to consumers through reduced costs of natural gas. Testimony of this sort of economic benefit would, I believe, be legally objectionable, if it were presented to the Commission in support of an application for infill drilling. It is ironic that the legislature should interject and try to persuade a body created by it on the basis of economic and, indeed, political considerations that the Commission would be justly criticized for utilizing in deciding a case before it.

If the legislature desires to change the basis for regulation of the oil and gas industry in Kansas from one of conservation to one of economics and political expediency, it should do so directly, by changing the law. It is submitted that a resolution which, in effect, advises the Commission how it should decide issues which aren't even pending before it, not only is contrary to the traditional separation of powers concept, but raises some serious questions of legal due process and fundamental property rights.

I would respectfully submit that it is inappropriate for the legislature to prejudge this issue by "encouraging" the Commission to decide the case in a particular fashion. Presumably, the legislature would not think it proper to "encourage" the Courts to decide that all quiet title suits should be decided in favor of the plaintiff(s)? Or to sentence all convicted persons to the maximum permitted by law? Or to be more favorably disposed towards husbands (or wives) in divorce cases? Or any other "popular" result on some issue that might come before the Court for a decision? The Corporation Commission is a quasi judicial body and should be permitted to function within the parameter of the law adopted by the legislature and interpreted by the courts. Encouragement to decide cases in a particular fashion is hardly conducive to a judicious atmosphere that is required for the affected parties to have confidence in an unbiased, deliberative and reasoned result. I have not made a study of precedents for "advising" administrative agencies on how to determine matters that may come before them, even though such advice is termed "encouragement", but I would suggest that this is a bad precedent.

Respectfully submitted,

PANHANDLE EASTERN PIPE LINE COMPANY

By: ______________________________

Jack Glaves
GLAVES, WEIL, EVANS & HOKE
600 One Twenty Building
Wichita, Kansas 67202

Attorneys for Panhandle Eastern
Pipe Line Company

TESTIMONY OF NORTHERN NATURAL GAS COMPANY
ON SCR-1643 - TOPEKA, KANSAS - FEB. 22, 1984

Mr. Chairman and Members of the Committee:

My name is Karl Tripp, and I am appearing here for Northern Natural Gas Company in opposition to infill drilling in the Kansas Hugoton gas field.

I recently completed an in-depth engineering study of the Hugoton Field and the conclusions of this study have a direct bearing on the subject.

The reservoir characteristics of the Hugoton Field are such that each infill well would merely re-divide the production from the surrounding wells. No additional reserves would be made available. And even the slight acceleration in the rate of recovery of existing reserves would be both insignificant and uneconomic.

We are aware of the many claims which have been made publicly on the subject of increased reserves through infill drilling. We cannot over emphasize the fact that we believe there is no technological basis for these claims for the Hugoton Field. Furthermore, the economics of this proposal would have a seriously adverse effect on the consumers of this gas.

Northern's remaining Hugoton reserves at year-end 1983 were 2.3 TCF. If half those reserves are produced at $3.00 per MCF (under infill drilling), this would add 3.45 billion dollars to Northern's gas purchase costs. This increase in gas purchase costs, as well as an estimated additional 80 million dollars required to connect the infill wells to our system, would adversely impact Northern's customers. The above estimated costs are representative of Northern Natural Gas alone. On a total field basis, the estimated additional costs of gas and connection of wells would amount to approximately 14 billion dollars. Add to this the cost of drilling 4,000 wells, of half a billion dollars, and the total monetary impact on the consuming public reaches 14.5 billion dollars. Infill drilling of the Kansas Hugoton Gas Field would require the consuming public to pay an additional 14.5 billion dollars for no additional reserves and no appreciable deliverability increase.

It is therefore, neither technically nor economically sound to divert the rig effort and funds of this magnitude away from exploration drilling, which is still finding new gas reserves in Kansas for $1.00 to $1.50 per MCF.