

IN THE MATTER OF
MIDCON CORP., ET AL.

FINAL ORDER, ETC., IN REGARD TO ALLEGED VIOLATION OF
SEC. 7 OF THE CLAYTON ACT AND
SEC. 5 OF THE FEDERAL TRADE COMMISSION ACT

Docket 9198. Complaint, Sept. 19, 1985—Final Order, July 18, 1989*

This final order adopts the initial decision in full, dismissing the complaint because of a failure to prove the likelihood of a substantial lessening of competition in a section of the country.

Appearances

For the Commission: *Marc G. Schildkraut and Robert Cheek.*

For the respondents: *Paul E. Goldstein, Philip R. Telleen, Priscilla A. Mims & Jane DiRenzo Segraves, Lombard, II. and James H. Sneed, Nathalie F. P. Gilfoyle, Carolyn Kay Weeder & Amy E. Hancock, McDermott, Will & Emery, Washington, D.C.*

INITIAL DECISION BY

LEWIS F. PARKER, ADMINISTRATIVE LAW JUDGE

FEBRUARY 2, 1987

I. HISTORY OF THE PROCEEDING

On September 19, 1985, the Federal Trade Commission issued a complaint charging that the acquisition of United Energy Resources, Inc. ("United")¹ by MidCon Corp. ("MidCon") violates Section 7 of

*Complaint previously published at 107 FTC 48 (1986).

¹ Abbreviations of the company names referred to in this decision are:

<u>Company</u>	<u>Abbreviation</u>
Midcon Corp.	MidCon
United Energy Resources, Inc.	United (or UER)
Natural Gas Pipeline Company of America	NGPL
United Gas Pipe Line Company	UGPL
High Island Offshore System	HIOS
U-T Offshore System	UTOS

(footnote cont'd)

the Clayton Act, 15 U.S.C. 18 and Section 5 of the Federal Trade Commission Act, 15 U.S.C. 45.

Count One of the complaint alleges that MidCon and United, through their ownership of pipeline companies, and in other ways, are direct and substantial competitors in the business of transporting natural gas out of producing fields and basins in certain areas of the Gulf of Mexico Outer Continental Shelf ("OCS") off the coasts of Texas and Louisiana, and that the effect of the acquisition may be substantially to lessen competition or tend to create a monopoly in the transportation of natural gas out of producing fields and basins in relevant sections of the OCS.

Count Two, which alleges anticompetitive effects in the transportation and sale of natural gas from the Baton Rouge-New Orleans corridor was withdrawn from adjudication, and the Commission accepted a consent order requiring divestiture of certain subsidiaries holding partnership interests in natural gas pipelines in Louisiana. [3]

Respondents filed their joint answer to the complaint on October 25, 1985, admitting in part and denying in part the complaint's allegations. After extensive discovery, hearings began on November 4, 1986 and concluded on February 26, 1987.

On June 30, 1987, MidCon sold the stock and assets of United and UER marketing company to LaSalle Energy Corporation, thus divesting itself of the company whose acquisition is challenged by complaint counsel. Shortly thereafter, respondents moved to dismiss the case, claiming that no controversy remained to be decided. I certified respondents' motion to dismiss to the Commission which, in a November 16, 1987 Order, denied the motion and returned the matter to me for further proceedings. Pursuant to the Commission's directions, I ordered the parties to file answers to the proposed findings which had been filed before respondents moved to dismiss this case. The record was closed on November 27, 1987.

This decision is based on the transcript of testimony, the exhibits

Stingray Pipeline Co.	Stingray
Sea Robin Pipeline Co.	Sea Robin
The Bluewater Project	Bluewater
Tennessee Gas Pipeline Co.	Tennessee
Columbia Gulf Transmission Co.	Columbia Gulf
America Natural Resources Co.	ANR
Transcontinental Gas Pipeline Co.	Transco
Texas Gas Transmission Co.	Texas Gas
Trunkline Gas Co.	Trunkline
Panhandle Eastern Corp.	Panhandle Eastern
Texas Eastern Corp.	Texas Eastern

which I received in evidence, and the proposed findings of fact and conclusions of law, and answers thereto filed by the parties. I have adopted several of the proposed findings verbatim. Others have been adopted in substance. All other findings are rejected either because they are not supported by the record or because they are irrelevant. This decision is written as though the sale of United to LaSalle had not taken place.

II. FINDINGS OF FACT

A. *The Nature of Respondents' Businesses*

1. MidCon

1. MidCon, the acquiring company, is a Delaware corporation with principal executive offices in Lombard, Illinois (Cplt.² ¶ 2; Ans. ¶ 2). MidCon is the parent of energy-related companies [4] operating throughout the Mid-Continental United States (CX 139B). Most of MidCon's subsidiaries are engaged in the transportation, distribution or sale of natural gas (CX 139E; Cplt. ¶ 3; Ans. ¶ 3). In the fiscal year ending September 30, 1984, MidCon had sales of \$4.2 billion and assets of \$3.5 billion (Cplt. ¶ 4; Ans. ¶ 4). In 1986, MidCon was acquired by Occidental Petroleum Corp. (51 Fed. Reg. ¶ 9,060 (March 17, 1986)).

2. MidCon's major natural gas pipeline subsidiary is Natural Gas Pipeline Company of American ("NGPL") (Cplt. ¶ 6; Ans. ¶ 6; CX 139E). This system essentially flows from south to north and has two legs. The western leg (known as the Amarillo line) begins in the Permian Basin of West Texas and Southeastern New Mexico, and has two extensions reaching into South Central Oklahoma and North Central Texas. It crosses the Texas and Oklahoma Panhandles, runs through Kansas, Nebraska, and Iowa, and terminates near Chicago, Illinois. The eastern leg (known as the Gulf Coast line) begins in the Texas and Louisiana Gulf Coast areas. It runs through East Texas, Arkansas, Missouri, and Illinois, and also terminates near Chicago (Tr. 1660-61; RX 2003; CX 176C).

² The following abbreviations are used in this decision:

CX:	Commission Exhibit
RX:	Respondents' Exhibit
F.:	Finding number in this decision
Cplt.:	Complaint
Ans.:	Joint Answer
RPF:	Respondents' Proposed Findings
CPF:	Complaint Counsel's Proposed Findings

3. Prior to acquiring United, MidCon, through its ownership of NGPL, owned a 20 percent interest in the High Island Offshore System ("HIOS"), a 33⅓ percent interest in U-T Offshore System ("UTOS") and a 50 percent interest in the Stingray Pipeline Company ("Stingray") (Cplt. ¶¶24-26; Ans. ¶¶24-26).

2. United

4. United, the acquired company, is a Delaware corporation with principal executive offices in Houston, Texas (Cplt. ¶ 8; Ans. ¶ 8). United's principal business is the transportation and sale of natural gas (CX's 139C, 318B; Cplt. ¶ 9; Ans. ¶ 9). In 1984, it had revenues of \$4.0 billion and assets of \$2.5 billion (Cplt. ¶ 10; Ans. ¶ 10).

5. United's two major pipeline systems are United Gas Pipe Line Company ("UGPL") and United Texas Transmission Company (Cplt. ¶ 12; Ans. ¶ 12; CX 318B). UGPL is an interstate pipeline system located primarily in the State of Louisiana. United Texas is a Texas intrastate pipeline (Tr. 1662-63; RX 2003; CX 318D-E).

6. United, through its ownership of UGPL, holds a 20 percent interest in HIOS, a 33⅓ percent interest in UTOS, and a 50 percent interest in the Sea Robin Pipeline Company ("Sea Robin") (Cplt. ¶¶24, 25, 27; Ans. ¶¶24, 25, 27).

7. HIOS is an equally owned joint venture of five pipeline companies: NGPL, UGPL, Transcontinental Gas Pipeline Corp. ("Transco"), Texas Gas Transmission Co. ("Texas Gas"), and [5] American Natural Resources, Inc. ("ANR") (Tr. 145; CX's 128, 336A), and is located in the High Island and West Cameron areas of the Gulf of Mexico.

8. U-T Offshore System ("UTOS") is a joint venture owned in equal share by NGPL, UGPL and Transco (CX's 11, 330B, 337A).

9. Stingray is a partnership between a MidCon subsidiary, NGPL, and Trunkline Gas Company ("Trunkline"), a subsidiary of Panhandle Eastern Corporation (Tr. 1718). Each partner owns a 50 percent share (Tr. 1718; CX 54A).

10. Sea Robin is an unincorporated joint venture between UGPL and Southern Natural Resources, Inc. ("Sonat") (Tr. 1841; CX 335A). Each owner owns a 50 percent share (Tr. 1837; CX 335A).

B. The Acquisition

11. On August 13, 1985, MidCon filed a premerger notification for its acquisition of United Energy Resources, Inc., as required by

Section 7A of the Clayton Act, as amended, 15 U.S.C. 18a. MidCon proposed to acquire, through a subsidiary established for this sole purpose, up to 18,100,000 shares of United for \$41 per share. The approximate total value of this cash tender offer was \$1.1 billion (Cplt. ¶ 14; Ans. ¶ 14). Midcon acquired United in 1985 (Tr. 1649). Since the acquisition, United has been assimilated as a MidCon subsidiary (Tr. 184, 1703-09; RX 2762).

12. As a result of the acquisition, MidCon's ownership share in HIOS rose from 20 percent to 40 percent and MidCon's ownership share in UTOS rose from 33⅓ percent to 66⅔ percent. MidCon retained its 50 percent share in Stingray and gained a 50 percent interest in Sea Robin (Cplt. ¶¶24-27; Ans. ¶¶24-27).

C. Jurisdiction And Commerce

13. Respondents do not contest jurisdiction (Prehearing Conference Transcript, 16-18).

14. HIOS, UTOS, Stingray and Sea Robin are located in Federal waters (Tr. 1691; CX 904). Sea Robin, Stingray and UTOS cross state boundaries (*see* CX 904).

15. Some aspects of the operations of HIOS, UTOS, Stingray and Sea Robin are regulated by the Federal Energy Regulatory Commission ("FERC") as interstate pipelines (RX's 1987L, 1992X; CX's 1030Q, 1995D). [6]

16. Natural gas transported by HIOS, UTOS, Stingray and Sea Robin continues to destinations throughout the United States (Tr. 207-14, 1676-82; 1873; RX 2005).

17. The amount of natural gas flowing through each of these pipelines is substantial. For example, in 1984, HIOS delivered 500,065,579 Mcf (thousand cubic feet) of natural gas, Stingray delivered 284,175,462 Mcf, and Sea Robin delivered 289,745,636 Mcf (CX 1103A). In the same year, total natural gas consumption in the District of Columbia was 29,449,000 Mcf, and total United States consumption was 17,950,528,000 Mcf (CX 1015B). Thus, total deliveries on HIOS, Stingray and Sea Robin amounted to approximately six percent of total United States consumption in 1984.

D. The Natural Gas Industry

1. The Uses Of Natural Gas

18. Natural gas is a mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase

or in a solution with crude oil in underground reservoirs (CX 1046E). A reservoir is a porous permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system (CX 1047Z-27).

19. Natural gas is a major source of energy in the United States (CX's 1015A-B, 1046D) and is used in private dwellings for heating, air conditioning, cooking, waterheating, and other household uses, by manufacturing and mining establishments for heat, power, and as a chemical feedstock, and as a fuel in electric utility plants (CX 1046E-F).

2. Natural Gas Production In The OCS

a. *OCS Leasing*

20. This case involves natural gas produced on the Outer Continental Shelf of the Gulf of Mexico ("OCS"). The OCS consists of those submerged lands on the continental margin of the United States lying beyond the jurisdiction of the coastal states (CX 1040Z-87). In 1984, gas production from the OCS accounted for approximately 25 percent of all marketed gas production in the United States (RX 1513). In 1984, gas [7] discoveries in the OCS represented about one-third of all gas discoveries in the United States (CX 1047N).

21. Congress has authorized the Secretary of Interior to lease the submerged lands of the OCS for the exploration and production of minerals, including gas and oil (CX 1038W; 43 U.S.C. 1334). To carry out its leasing responsibilities, the Minerals Management Service of the Department of the Interior ("MMS") has divided the OCS into "blocks." A block is an area measuring three miles square (or 5,760 acres) (CX 1040Z-85). Each block has a unique identifying designation consisting of an area name and a number, *e.g.*, East Cameron block 264.³ Individual blocks can be located by area and block number on three maps in the record CX 902 (Offshore Texas); CX 903 (Western & Central Gulf of Mexico); CX 904 (Offshore Louisiana)).

22. Periodically, the MMS offers to lease certain OCS blocks (CX 1040Z-4-Z-11). Relying on geological and geophysical information in their possession, companies bid for these leases (Tr. 843). Bids may be submitted by a single company; sometimes one or more groups of companies submit joint bids. MMS evaluates the bids submitted and may award the block lease to the highest bidder (CX 1040Z-4-Z-8).

³ Hereafter, blocks will be referred to by name and number only, *e.g.*, "East Cameron 264."

23. Leases are awarded for an initial period ranging from five years to ten years. The longer leases are awarded to encourage exploration and production in areas where the water is unusually deep or where other unusual adverse conditions exist so that additional time is needed to develop the block (CX 1040Z-11, Z-87). A lease for a tract that is not yet producing gas is said to be in its primary term. Once oil and gas is produced from the tract, the lease is extended indefinitely until production ceases (CX 1038W).

b. Production And Development

24. After securing a lease, a company proceeds with exploration. Exploration includes drilling one or more exploratory or wildcat wells to determine whether or not commercial volumes of oil or gas exist in reserves under the block (Tr. 843, 922). After evaluating the results of exploratory activity, the lessee must decide whether to proceed with development (Tr. 845, 923). Developing a tract may involve the construction of platforms and the drilling of development wells. If the decision to produce is made, a production platform is installed from which production will take place, and production wells are drilled. The largest single cost item [8] associated with offshore development is installation of the production platform; the drilling of the wells themselves is the second most costly (Tr. 847). During the production process, there is frequent opportunity for further exploration, most likely in the form of deeper drilling. Both the decision to develop a block initially and the decision to proceed with further development during the production stage are influenced by the anticipated prices for natural gas (Tr. 409, 686-87, 846, 927).

25. The OCS is one of the most attractive basins for oil and gas discoveries in the lower 48 states (Tr. 867; CX's 36N, 148M; *see also* Tr. 936-37). According to a 1984 MMS survey, the industry ranked the central and western Gulf as first and second on a list of all 24 MMS OCS planning areas for interest in exploration and development (CX 1040"O"). Of particular interest is exploration activity in the deep water of the Gulf of Mexico (CX 1040Z-17-Z-18; *see also* CX 1040Z-11-Z-16). Companies have invested heavily in leasing OCS blocks and drilling on OCS prospects (CX 1040Z-12, 1047M).

*c. Future Production In The Alleged
Relevant Geographic Markets*

26. The testimony of Edward H. Feinstein, a FERC petroleum

engineer, during rate case hearings for Sea Robin and Stingray detailed various reserve projections for the areas served by these pipelines. The models described by Mr. Feinstein showed substantial additional reserves available to both Sea Robin and Stingray (CX's 36C-Q, Z, Z-8, 169G-O, Z-55).

27. A 1983 study prepared by Trunkline, operator of Stingray, projected that during the next decade 182 developed leases would be available for connection to Stingray (CX 35I). A NGPL official, commenting upon the Trunkline study pointing out Stingray's "advantageous location," found the Trunkline document to be "somewhat conservative" in its estimates (CX 35B).

28. In 1984, NGPL studied the future gas supply in an area currently served by HIOS and Stingray and projected deepwater extensions of these two systems. In that study, NGPL forecast the connection of 235 new fields during the ensuing ten years (CX 105F).

29. In 1985, ANR, the operator of HIOS, prepared a long-range plan in which substantial additional reserves were forecast for shipment through this system (CX 399C).

30. There are 929 unconnected blocks in the alleged relevant geographical markets (Tr. 984; CX's 1107A-B, 1108A-B). Included in this figure are 288 blocks that are in their primary term (CX 1108A-B). These blocks have been awarded after [9] companies paid substantial sums of money for the right to develop the block. Winning bids have frequently been in the millions of dollars (CX 904). Producers bid with the expectation of recouping their investment. Dr. Uri, complaint counsel's economic expert, testified that the fact that producers are "voting with their money" indicates that it is likely that natural gas exists under some of these blocks (Tr. 986).

31. Although no pipelines exist in the Garden Banks deepwater area of the alleged geographic market and there is no natural gas being produced in this area (Tr. 692, 1716; RX 2004), it is of interest to both producers and pipelines because of its potential for development (Tr. 868-69). There has been increased bidding, leasing, and exploration activity in Garden Banks (*see* CX 399F, H, Q, T, U), as there has been in other deepwater areas of the Gulf (Tr. 860; CX 1040Z-11-Z-18). Over 100 Garden Banks blocks are in their primary term (CX 1108A).

32. There are no pipelines in the Garden Banks area, but several pipelines have considered connecting Garden Banks 236 (CX's 71A-F, 504, 512A-G, 513A-F), and, as recently as June 1986, Trunkline considered developing a pipeline system to serve future transportation needs of several large Garden Banks area producers (*see* CX 638A).

33. Thus, while Garden Banks is only a potential future market (Tr. 1468), it is possible that this area, as well as non-producing blocks in other areas in the alleged geographic markets, will experience future production of natural gas.

3. The Sale And Transportation Of OCS Natural Gas

a. *Pipelines*

34. After gas is produced, it is transported to various destinations via pipelines (Tr. 847). There are two types of pipelines: laterals and trunklines. A lateral is a relatively small diameter pipeline which carries gas from a production platform to a trunkline (Tr. 160). A lateral can be connected to a trunkline either at a platform constructed at the end of the trunkline or at valves installed at intervals along the trunkline (Tr. 161). Laterals deliver gas to a main trunkline, a large-diameter pipeline. The trunkline moves the gas towards shore (*see* CX 903).

35. Gas flows from an area of high pressure to an area of low pressure. The greater the difference in pressure between the pipeline intake and the outlet points, the greater the quantity of gas that flows through a pipeline of a given diameter during any period of time. At a number of places along a route, pressure may be increased by using a compressor. This increases [10] the capacity of the pipeline (Tr. 165-66). Compression may also be used at the production platform as the well depletes and the natural pressure from the reservoir declines (Tr. 79-80).

b. *The Sale Of OCS Natural Gas*

36. A wellhead gas purchase contract contains the terms under which a producer sells production from natural gas reserves from a block which has not been previously connected to a trunkline (*see, e.g.*, CX's 196A-Z-26, 197A-Z-26, 1220A-Z-30). The contract is usually a long-term agreement, extending for 15 years or the estimated life of the reserves (*see, e.g.*, CX's 196Z-20, 197Z-12-Z-13, 1045F, 1220Z-24; 15 U.S.C. 3375(a)(3)). Long-term wellhead contracts assure each party that the large investment in production and transmission facilities will be recouped over time (CX 1045F). A producer would not sell gas on a short-term basis if it had to incur the cost of building a lateral (Tr. 673).

37. A gas purchase contract typically obligates the producer to sell to the purchaser the producer's share of the gas produced from

reserves located under a particular block (Tr. 662-63; CX's 196F, 197F, 1220G) and specifies the initial price and the formula by which the price will be determined over the life of the contract (Tr. 667-68; *see, e.g.*, CX's 197N-S, 1220W-Z-26). The gas purchase contract usually obligates a purchaser to take a quantity of gas expressed as a percentage of the well's deliverability on a daily, monthly or annual basis. A well's deliverability is determined by periodically conducting well flow tests and other engineering studies as specified in the contract (*see, e.g.*, CX's 1220M-V, 1971I-N).

38. Traditionally, the parties to a wellhead gas purchase contract were the producer, as seller, and an interstate natural gas pipeline company, as buyer. The pipeline company would purchase the gas at the production platform, transport the gas to some onshore destination and resell the gas either to the direct user (such as industrial concerns or electric utilities) or to a local distribution company ("LDC") (Tr. 294, 527, 672, 1653-54, 2460-61) which is a company engaged in the retail sale of natural gas to end-users, such as homeowners, commercial or industrial establishments (Tr. 1656, 1667). More recently, industrial customers, utilities, intrastate pipelines and LDCs have become purchasers under wellhead gas purchase contracts (Tr. 678, 801, 930-31). In such transactions, either the producer or the purchaser may be responsible for securing transportation of the gas on pipeline facilities owned by third parties (Tr. 294, 801-02, 932-33, 1674). [11]

c. The Transportation Of OCS Natural Gas

1. Types Of Transactions

39. Natural gas may be transported from the OCS in two ways: in the first, the purchaser is an interstate pipeline company that ships the gas to shore over its own pipeline system. In this case, there is no separately stated transportation charge (*see, e.g.*, CX 1038A-Z-85), but there is an implicit transportation margin for each unit of gas which is equal to the difference between the price the pipeline pays for the gas at the wellhead and the price at which it resells the gas (Tr. 992, 1003).

40. In the second case, where the shipper (the owner of the gas) and the transporter (a pipeline company) are different parties, they negotiate a transportation agreement (*see, e.g.*, CX's 178Z-70-Z-100, 701A-U, 702A-Y, 703A-V, 704A-Z, 705A-Z). This can occur even where the shipper owns an interest in the pipeline (CX 180C-Z-14).

2. The Transportation Agreement

41. The following terms are typically included in a transportation agreement.

(aa). *Type Of Service*

42. A transporter may offer different priorities of service. Two of the most common classifications are referred to as firm service and interruptible (or "best efforts") service (CX 201W). A transportation agreement will state whether the service being offered is firm or interruptible or part firm and part interruptible (*see, e.g.*, CX's 640F-G, 703D). A customer with firm service is entitled to capacity in the pipeline in an amount up to its "contract demand," the daily quantity of gas that the transporter is obligated to accept from the shipper for transportation (CX 405D; *see also* CX 1014Z-60 (§ 284.8(a)). A customer entitled only to interruptible service can be displaced by a firm service customer up to the amount of the contract demand of the firm service customer if sufficient capacity is not available for both customers (Tr. 276-77, 2319-20). [12]

(bb). *Demand And Commodity Charges*

43. A commodity charge is a charge per unit of gas transported (*see, e.g.*, CX 167E), and it is computed by multiplying the volume actually shipped by the commodity rate (Tr. 2346). Generally, an interruptible customer pays only a commodity charge (Tr. 1185, 2346; CX 705G-I).

44. A demand charge is a charge per unit of contract demand (*see, e.g.*, CX 167E), and it is computed by multiplying the contract demand by the demand rate (CX's 167E, 178Z-439). The shipper pays the demand charge, usually monthly, regardless of the actual volume shipped (Tr. 194-95, 355). A firm service customer usually pays a two-part charge: a commodity charge and demand charge (*see, e.g.*, CX 167Z).

(cc). *Duration*

45. The duration of a transportation agreement may be stated as a primary term (initial term), with the right of renewal for subsequent time periods until cancelled by either party (*see, e.g.*, CX's 178Z-11, 405I-J).

46. A shipper generally wants the duration of a transportation agreement to match its contractual obligation to buy gas or the

expected time it would take to deplete the wells whose production is being transported (Tr. 95-96, 280, 396; CX 201Z-4-Z-5, Z-12-Z-13).

47. Prior to 1982, a shortage of natural gas existed in the interstate market (F.'s 57, 63) and during that period, Federal regulations encouraged long-term contracts (Tr. 556). Many of the transportation agreements signed in the late 1960's and 1970's contained long-term commitments on the part of shippers (Tr. 1149-50; *see* RX 1059A-F). Since 1982, however, shippers have shown increased desire to control costs by attempting to match the duration of the contract to the requirements of the particular block being connected (CX 201Z-27; *see also* Tr. 399).

(dd). *Contract Demand Levels And
Contract Demand Reduction Options*

48. A shipper typically seeks to have the contract demand approximate the average maximum deliverability of the connected reserves over the initial three or four years of the transportation contract (CX 201Z-17-Z-18). Under some agreements, the shipper may elect periodically to reduce its contract demand (Tr. 96, 282-83, 1186; [13] CX's 178Z-51, 180Z-19-Z-20). This feature enables the shipper to adjust its monthly demand charge obligations as the volume of gas that can be produced from connected wells declines (Tr. 96-97, 283; CX 201Z-19-Z-20).

(ee). *Charges For Fuel And Gas Loss*

49. Shippers are charged for fuel use and gas loss. The charge is deducted by permitting the carrier to deliver less than it receives (*see, e.g.*, CX 764G). These charges account for gas that the carrier uses as fuel for compressors and other equipment and for any loss that occurs when gas escapes during transmission (Tr. 105-07). All of the contract provisions described above are negotiated by the shipper and the transporter (Tr. 279, 282-84, 293, 931-32).

(ff). *Capital Costs For Lateral Construction*

50. Usually a lateral must be constructed to move gas from the production platform to the trunkline. Negotiations between the parties determine who bears the cost of the lateral (Tr. 279-80, 857-58, 864-66, 874-75).

(gg). *Shipper Flexibility To Change Receipt Points*

51. A receipt point is the location at which a transporter will accept

gas from a shipper. Receipt points are specified in the transportation agreement (*see, e.g.*, CX's 167Z-9-Z-12, 178Z-61, Z-86). Most contracts require the shipper to get the transporter's approval to add new receipt points (*see, e.g.*, Tr. 91, 1764-65; CX's 29A-K, 167X, 180K).

4. The Sale Of OCS Gas To Onshore United States Customers

52. Natural gas produced in the OCS is not consumed there but is shipped onshore to LDC's, which, in turn, sell the gas to "burner tip" or end-use residential, commercial and industrial customers (Tr. 360, 2461-62; RX's 1515-16).

53. LDC's are usually state-regulated public utilities that are given exclusive franchises by their regulators to serve particular geographic areas (Tr. 576, 1667). LDC's have historically purchased most of their natural gas from interstate and intrastate pipeline companies (Tr. 576). Sales to LDC's [14] occur in what are called "city-gate" markets where the interstate pipeline connects with, and transfers custody of its gas to, the LDC's distribution system (Tr. 359, 1668, 2463; RX 1516).

54. In the past, interstate pipeline companies have performed a "merchant" function by purchasing natural gas at the wellhead (Tr. 1656, 2490-92; RX's 2007-10), transporting it over their own or other facilities, and selling it to customers in city-gate markets (described as "bundling" by Dr. Hall, respondents' expert economist) (Tr. 1654, 2460-61). The sales price included the cost of the gas at the wellhead and the cost of transporting it from wellhead to city-gate (Tr. 2173-74). Both NGPL and UGPL have performed this merchant function (Tr. 1653, 1812, 1814).

55. FERC policies during the 1970's encouraged pipelines to perform the merchant function (Tr. 566), but in recent years, it has become common for LDC's and large end-users to purchase gas directly from producers and to purchase transportation services on an unbundled basis. A marketer or broker arranges these unbundled services (Tr. 2461, 2485-86).

5. Regulation In The Natural Gas Industry

a. *Historical Perspective*

56. The federal government has regulated natural gas pipelines since 1938 when the Natural Gas Act, 15 U.S.C. 717-717w, was passed (Tr. 549, 1655, 2026). At first, natural gas pipeline companies

were regulated by the Federal Power Commission ("FPC"), which also, by virtue of the decision in *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954), was required to regulate the wellhead price of natural gas that was delivered into the interstate market (Tr. 550).

57. The FPC's control of wellhead prices created significant shortages of natural gas in the 1970's because the prices it allowed were too low to stimulate enough production for the interstate market (Tr. 553, 1083-84).

58. Another consequence of federal wellhead price controls was that buyers in the intrastate markets purchased virtually all the new onshore gas supplies available because they were allowed to pay more than FPC-controlled prices. Intrastate companies, however, were effectively prohibited from buying OCS gas. In the 1970's, this market imbalance led to shortages on many interstate pipeline systems. Many pipelines could not meet their contractual obligations to deliver gas to all their customers and had to file curtailment plans with FERC (Tr. 1816-18; CX 506E). [15]

59. To encourage producers to explore for and develop gas supplies in the OCS in the early 1970's, interstate pipelines made interest-free loans (called "advanced payments" or "prepayments") to producers to enable them to explore specific OCS tracts. In exchange, producers agreed to commit all reserves discovered on these tracts to the pipeline that made the advance payments (Tr. 98-99, 818, 928-29, 1686-87, 1822-23; CX 197C).

60. Producers received maximum lawful prices for their OCS production throughout the gas-shortage period (Tr. 688, 920, 1825). Pipelines would accept delivery of the gas at the platform and pay for construction of a lateral (Tr. 672, 940). Contracts frequently had deregulation clauses which set a formula to determine price in the event wellhead price controls were eliminated (Tr. 1825). In the 1950's and 1960's, contracts would typically obligate a pipeline to take 50 percent or less of the well's deliverability. As the shortage developed, "minimum take" provision increased to 80 or 90 percent of deliverability (Tr. 1689). During the period of shortage, producers would bargain for, and frequently receive from purchasers, payment for a minimum quantity of gas, whether or not the purchaser actually took that volume. This became known as a take-or-pay provision (Tr. 1689).

61. In 1978, Congress passed the Natural Gas Policy Act of 1978 ("NGPA") (15 U.S.C. 3301-3432). The NGPA gave the Federal

Energy Regulation Commission ("FERC"), successor to the FPC, jurisdiction over the maximum price producers could charge for gas sold in either the intrastate or interstate markets. But the NGPA mandated the ceiling prices to be used and prescribed a phased decontrol of prices for most gas discovered after February 19, 1977 (so-called "new gas") (15 U.S.C. 3301-3331).

62. Under the NGPA, the price of some categories of gas was decontrolled immediately; the maximum lawful price of other categories of gas was permitted to escalate 10 to 15 percent a year (Tr. 1695). The NGPA deregulated most new gas on January 1, 1985 (Tr. 563). Congress chose to rely upon market forces to bring forth sufficient supplies to satisfy demand (Tr. 560).

63. The enactment of the NGPA was followed in 1979 by the quadrupling of oil prices by OPEC. These events led to a boom in drilling in the United States in 1979, 1980 and 1981. In 1980, for the first time since 1960, the nation found as much gas as it produced (Tr. 1695). A surplus of natural gas first appeared in late 1981-1982 (Tr. 610, 688-89, 1697) and it has continued through the winter of 1986-1987 (Tr. 409, 672). The surplus resulted from increased drilling, increased discoveries, and diminished demand (Tr. 1697). The surplus depressed natural gas prices so that the statutory wellhead price ceiling was no longer the effective constraint on wellhead prices (Tr. 562, 669-70). Contractual provisions reflected this surplus situation. New contracts did not set gas prices at the maximum lawful price (Tr. 691), costs for the construction of laterals were often [16] shifted from the purchaser to the producer (Tr. 672, 866, 925, 940), and some contracts gave purchasers the unilateral right to reduce the price below the contract price if the purchaser determined that the gas was not marketable in end-use markets at the contract price (so-called "market-out clauses") (Tr. 671). Some purchasers have exercised these market-out clauses since at least 1984 (Tr. 691). Some contracts permitted the buyer to deduct increases in third-party transportation costs from prices due the producer (Tr. 921).

64. During the 1970's, the wellhead price was generally the FERC-set maximum lawful price (Tr. 920) and transportation rates did not affect wellhead prices because the end-use market price for natural gas was below the price of competitive fuels (Tr. 859). The elimination of the maximum lawful price as a constraint on wellhead pricing led to wellhead prices being determined by a "netback" process (Tr. 346-859). The value at the wellhead became a function of what natural gas

sold for in end-use markets, less the cost of transportation to the market (Tr. 346, 859). Thus, if the cost of transportation changed, so did the value at the wellhead (Tr. 346, 411, 683-84, 878-79, 920-21; *see* RX 1040B, D; CX's 43A, 63A-B, 82A-B, 99A, 107A-C, 108A-B, 303B, F, 304B, 381A, 1220W, 1268, 1295C).

65. The elimination of binding wellhead price constraints also affected the type of buyer that a producer would seek out. During the period of wellhead controls, a producer received the FPC ceiling price for its gas regardless of who purchased it (Tr. 802). Under these circumstances, wellhead sales to interstate pipeline companies were preferred to sales of gas downstream to local distribution companies or to end-users (Tr. 802). The interstate pipeline companies generally bought gas in the producing area, owned the gas at every point while it was in the pipeline and then sold it to customers at the other end of the pipeline (Tr. 527, 2460-61). Historically, pipelines did not transport for producers (Tr. 674). After wellhead decontrol, wellhead values could vary (Tr. 919), and producers sought to achieve maximum wellhead value (Tr. 674). To achieve this goal, producers have sought to sell gas to firms in addition to interstate pipeline companies, the traditional purchasers. These firms include LDC's and end-users (Tr. 801). To effectuate these sales, producers and their customers sought transportation services from interstate pipelines (Tr. 290-301, 310-28, 677-78, 683, 801-02, 2461).

b. FERC Regulation Of Transportation Services

66. If an interstate pipeline company wishes to construct new facilities, extend existing facilities, provide new services or expand existing services, it must file a proposal with FERC and receive authorization from it (Tr. 564, 594, 2028). Once a particular service or facility is commenced or is in place, the [17] pipeline company must receive FERC authorization to discontinue or abandon the service or facility (Tr. 2026, 2089-90, 2331).

67. The procedures for filing a traditional Section 7(c) certificate for construction of new facilities consist of a pipeline filing a request for a certificate with FERC, FERC publishing a notice in the Federal Register of the proposed certificate, and interested parties filing intervention papers in the certificate proceeding. The FERC staff then makes a recommendation either to grant or not grant the certificate, or to set the case for a hearing. If the case is set for a hearing, all parties with an interest in the proceeding are allowed to appear before

an administrative law judge and argue why the certificate should or should not be granted (Tr. 595). Obtaining a traditional Section 7(c) certificate is obviously a lengthy process (Tr. 104-05, 596, 681, 804).

68. In some circumstances, FERC grants a "blanket certificate" which allows a pipeline company to engage in certain routine activities without the necessity of seeking a FERC certificate prior to each transaction. Transactions undertaken pursuant to a blanket certificate are nevertheless certificated activities. The FERC has merely given advance approval of certain kinds of transactions (Tr. 569-70, 588). This process is authorized by FERC Order 436 (Tr. 605) whose most significant feature is its provision for open access, nondiscriminatory transportation (Tr. 604-05, 2035). This order also has new provisions concerning how transportation rates must be determined (Tr. 606), but does not change the basic method (Tr. 2058). In particular, the Order 436 maximum rate must be "just and reasonable," and must be a fully allocated cost rate (Tr. 2056-57).

69. FERC must approve the abandonment (discontinuance) of a previously certificated transportation service. In making this decision, it would consider whether the reserves underlying the transportation agreement have been depleted and the desire of the shipper having the right to terminate the agreement (Tr. 2159-61). On the other hand, Order 436 transportation rights can be discontinued at the expiration of the contracts underlying the service (CX 1013G, J).

c. FERC Regulation Of Pipeline Construction

70. Where a certificate for pipeline construction is required, three types are available: traditional Section 7(c) certificates, blanket certificates for minor projects, and optional expedited certificates (Tr. 570, 594-95, 641-43).

71. An applicant seeking a traditional certificate must submit an application which is processed in a manner similar to that of a traditional transportation certificate (Tr. 594-95). [18] An applicant for a traditional certificate must show that the project complies with environmental regulations and will be economically viable. HIOS, Stingray and Sea Robin are joint venture pipelines which required FERC approval before construction (RX's 1987A-P, 1989A-C, 1992A-X, 1993A-I, 1994A-B, 1995A-E, 1996A-C, 1997A-C, 1998A-N, 1999A-C).

72. FERC requires that those proposing a new offshore pipeline demonstrate that they have sufficient gas reserves in specific areas

under long-term purchase contracts with producers (Tr. 556, 2072), and that they prepare engineering studies to show how the reserves would be connected, their cost, and the cost of construction to consumers (Tr. 1838).

73. The application to construct Stingray was unusual in that while approximately three trillion cubic feet of reserves served as the basis for the application, only about 1.2 trillion cubic feet were under contract (Tr. 2072-73). Thus, FERC had to evaluate the estimated reserves in the Stingray area and assume that those reserves would be transported via Stingray regardless of who would purchase them (Tr. 2073). The reserves that served as a basis for Stingray were different from the reserves that served as a basis for Sea Robin (Tr. 2073). FERC rejected the idea of duplicative or competing pipelines to provide transportation from the offshore fields served by HIOS, Stingray, and Sea Robin (Tr. 2062-66, 2072-74).

74. FERC avoids inefficient duplication of facilities (Tr. 601, 2074) and would tend not to approve an application for construction of an offshore pipeline based on reserves that had been the basis for an existing offshore pipeline (Tr. 2074). To this end, FERC encouraged cooperation between several parties wishing to construct facilities in the High Island areas. The result of this cooperation was the HIOS joint venture (Tr. 2075). A study of reserves in the High Island area, done in 1975, was relied upon by FERC to justify its construction (Tr. 217). HIOS was based on an estimated five trillion cubic feet of reserves, largely not yet under contract. These reserves were different from the reserves on which the approval of Stingray was based (Tr. 2074-79).

75. FERC has made blanket certificates available for minor projects. Once a blanket certificate is secured, a company can construct, without prior notice to FERC, any facility that does not cost more than \$5,100,000. Any project costing less than \$14,300,000 may be constructed if no protests are filed within 45 days following publication in the Federal Register of a notice of the proposed project. Dollar limits for both automatic authorization and prior notice projects change annually with inflation (Tr. 570, 2108-09; CX 1011A-P). OCS laterals have been constructed under this blanket program (CX's 93C-G, M, 603B, 606B, 1027B, C n. 2). [19]

76. Facilities may also be constructed upon obtaining an Order 436 optional expedited certificate (*see, e.g.*, CX 1014Z-34-Z-43, Z-55-Z-58). Under this certificate, the applicant must bear the financial risk

of the project. Revenues from existing customers may not be used to subsidize the project if it turns out to be unprofitable (Tr. 641-43; CX 1014Z-34). In a proceeding for a certificate under the optional expedited procedures, the applicant does not have to prove economic viability; that burden is shifted to those challenging the issuance of the certificate (Tr. 641-43; CX 1014Z-56 (§ 157.104); CX 1013X).

d. *FERC Regulation Of Pipeline Rates*

77. Pipelines subject to FERC jurisdiction must file their rates with FERC and charge only those rates that are on file. FERC regulates rates charged for sales and transportation services to ensure that they are "just and reasonable" (Natural Gas Act § 4; 15 U.S.C. 717c).

78. FERC regulates the rates for gas sold by interstate pipelines for resale. It does not regulate the price of gas sold by the pipeline directly to end-users, such as industrial customers or electric utilities (Tr. 575). Nor does FERC regulate the price of gas sold by marketing affiliates of interstate pipeline companies (*see* Tr. 1861-63, 2384-85). Gas sold directly to end-users often is sold at a fixed price and not at the pipeline's weighted average cost of purchased gas ("WACOG") (*see* CX's 189A-Z-30, 190A-Z-42, 191A-Z-164, 192A-Z-176).

79. Over the years, FERC has developed a procedure for arriving at "just and reasonable" rates. The first step is the computation of costs which the company is entitled to recover. These include the expenses of operating and maintaining pipeline, storage, and related facilities; sales and administrative expenses; depreciation; and various taxes. Costs also include an allowance for return, which is a return (or profit) on the capital invested. The allowance for return is computed by multiplying the "rate base" (*i.e.*, the dollar amount of the company's assets valued at cost less depreciation) by a reasonable rate of return (Tr. 576-77, 2038-39).

80. FERC then determines the type of customer from which the company will collect certain costs. Costs are allocated between jurisdictional and non-jurisdictional customers, and by function (*i.e.*, gas procurement, transmission and storage). Jurisdictional customers include firms that transport gas and firms that buy gas for resale (*i.e.*, LDC's that supply residential and commercial end-users). Nonjurisdictional customers include firms that buy gas for their own use, *e.g.*, industrial customers. The FERC does not establish a rate for [20] nonjurisdictional customers, but will allocate costs among regulated and nonregulated enterprises when calculating rates (Tr. 577-78, 2038-43).

81. FERC then determines how revenue will be collected. For this purpose, costs are classified as demand costs or commodity costs. Demand costs can be collected through a demand charge, which is a payment for the customer's right to a certain quantity of pipeline capacity regardless of actual service used. Commodity costs must be collected, if at all, through a commodity charge, an amount based upon actual units delivered (Tr. 580-81, 2043).

82. Conceptually, fixed costs are recovered through a demand charge and variable costs through a commodity charge (Tr. 579). However, FERC, at various stages in its history, has adopted various formulas to allocate various elements of fixed costs between the demand charge and the commodity charge (Tr. 579-80). FERC's general current rule is that a pipeline's return on investment and taxes related to income shall be recovered through the commodity charge (Tr. 2046).

83. Finally, FERC computes the appropriate unit rates. Typically, the demand charge is calculated by dividing the demand costs by the total of the contract demands in customer contracts (Tr. 580, 2046). The commodity charge for a particular service (*e.g.*, transportation service) is calculated by dividing the commodity costs by the so-called "representative volume," the estimated total quantity of gas that will be delivered (Tr. 581-82, 2048-49).

84. The rate structure required for Order 436 self-implementing transportation must have both maximum and minimum rates (Tr. 287, 620; CX 1014Z-60). Maximum rates are based upon a pipeline's fully allocated costs (Tr. 621; CX 1014Z-60). Minimum rates are based on the level of variable costs and thus will be well below the maximum rate allowed by FERC (Tr. 288, 621, 2036). Rates actually paid by a shipper are set by negotiations between the shipper and the transporter and may be set at any level between the filed maximum and minimum without prior FERC approval (Tr. 621, 1784; CX 1014Z-60). Transporters may charge different customers different transportation rates (*i.e.*, price discriminate) within the band of allowable rates (Tr. 625-26, 631). This provides the transporter with the ability to meet a competitive situation without lowering its rates across the board to all customers or to all customers within a certain class of service (Tr. 620-26, 2036).

85. The extent to which a transporting pipeline will be able to discriminate between similarly situated shippers with regard to rates under Order 436 is an open question (Tr. 614, 1785). This issue is on

appeal to the United States Circuit Court of Appeals for the District of Columbia in a case challenging Order 436 (Tr. 1786, 2059). Order 436 applies to new [21] shippers and new transportation agreements only. Even if it is upheld, Order 436 will have no effect on the rates applicable under existing transportation contracts that have been approved under the traditional Section 7(c) certificate procedure (Tr. 1795) such as the currently existing long term transportation agreements in effect in the offshore (Tr. 2090-91).

86. Assuming that the selective discounting provisions of Order 436 are upheld, a pipeline that discounts might not earn the permitted rate of return. It could only maintain its rate of return by increasing throughout to a level above that on which the rates were predicated. Where a pipeline elects to discount and undercollects as a result, it cannot transfer those costs to a later rate period in order to recover them (Tr. 600, 622-23, 2059).

87. A pipeline that discounts its rates within the maximum and minimum rates approved by FERC must report such discounts to FERC within 15 days. A customer who believed a pipeline had unduly discriminated among customers in discounting would be able to file a complaint or protest with FERC (Tr. 625-26, 2060-61).

88. Both UGPL and NGPL are operating as open transporters pursuant to interim authority under Order 436 (Tr. 2376-77). They are seeking final settlement of the terms and conditions which will be included in their Order 436 tariff. Sea Robin is fully open now. Although its final tariff has not yet been issued, it is operating under an interim tariff and seeks no waivers of any provisions of Order 436. Although neither HIOS nor Stingray is operating as an Order 436 transporter, MidCon has asked its partners in those pipelines to consider opening the pipelines (Tr. 1750, 1780). Because NGPL and UGPL are shippers on both HIOS and Stingray, and because they are open access transporters, they are operating as open transporters on HIOS and Stingray (Tr. 1750, 1780, 2376-77).

89. FERC regulation is prospective: rates are set for a future time period. FERC rates do not compensate for underrecovery in past time periods or recoup excess revenues earned in past time periods. Thus, a pipeline company's actual revenues may be different from the amounts projected by FERC if the company's level of business varies from FERC projections. For example, if a company's deliveries exceed its representative volume, its total revenue can exceed its revenue requirement. If a company does not deliver its representative volume,

its revenues will fall short of its revenue requirement. During the time period that the particular rates are effective, the company may keep the excess revenue and will not be made whole for shortfalls. This is one of the features of FERC regulation that gives pipelines an incentive to compete for additional business: an increase in deliveries over the representative volume will increase the pipeline's profits (Tr. 582-84). [22]

e. *FERC And Competition*

90. FERC is required to consider competition in carrying out its mandate under the NGA, 15 U.S.C. 717-717W; *Northern Natural Gas Co. v. Federal Power Commission*, 399 F.2d 953 (D.C. Cir. 1968).

91. According to Mr. Malloy, a former employer of FERC, it has displayed a heightened awareness of the role of competition in the regulatory process (Tr. 563, 565). For example, in statements accompanying the issuance of its Order 380, FERC said:

... [A] minimum commodity bill can serve as a barrier to competition. A customer is not likely to purchase gas from an alternate supplier if it is required to pay for gas it does not take from the original supplier. As such, a minimum commodity bill may inhibit natural gas price decreases that could otherwise result from competitive forces.

* * *

The commission therefore finds that utilization of minimum commodity bills to recover costs for gas not taken is fundamentally inconsistent with the increasingly competitive wellhead market mandated by the Congress in 1978. Congress intended that there be an opportunity for gas prices to increase or decrease—whichever the market demands. Implementation of the instant rule will further this Congressional intent by removing one obstacle that inhibits response to market demand (CX 1012B, G).

92. FERC also acted to expand competition by encouraging pipelines to transport for others (Tr. 554, 566). In a series of orders, the Commission permitted pipelines to obtain blanket certificates to transport gas for particular groups of end-users. These orders permitted pipelines to engage in these activities without the need for a certificate for each individual transaction (Tr. 566-68).

93. FERC's Order 436 was adopted to comport with the mandate of NGPA for greater competition (Tr. 611-13). In proposing to adopt Order 436, FERC stated: [23]

The competitive pressures caused by partial wellhead deregulation continue to grow and have become even more evident since January 1, 1985. Demand for transportation services to reflect the growing competition at both wellhead and burner tip can also be expected to increase. Greater customer access to alternate suppliers and/or transporters of gas is giving rise to innovative marketing strategies both by new entrants to the natural gas sales business as well as by traditional suppliers. Alterations in the way risks are shared, more open access to transportation and concomitant changes in service agreements, and new gas purchase policies are reflections of and responses to fundamental changes which have already occurred in the natural gas markets. These new ways of doing business in response to market forces have important implications for the way the industry is regulated, and have made necessary timely regulatory adjustments (CX 1013E (footnote omitted)).

In issuing Order 436, FERC wrote:

The NGPA certainly accomplished its primary goal of increasing competition and gas supplies at the wellhead. But the NGPA also aggravated price distortions between the city-gate and the wellhead. These price distortions have intensified competitive pressures on pipelines for new and lower-priced services. In turn, these competitive pressures require changes in the Commission's regulations if we are to fulfill statutory regulatory obligations over interstate pipelines in turbulent and fast-changing gas commodity markets (CX 1014M).

94. As justification for adoption of Order 436, FERC stated:

. . . [C]ompetition in the natural gas industry today is proliferating. In these circumstances, it makes little sense to withhold from pipelines the basic weapon other businesses have to wage the competitive battle: the ability to lower prices to beat the competition (CX 1014Z-20). [24]

f. The Outer Continental Shelf Lands Act

95. The Outer Continental Shelf Lands Act ("OCSLA"), 43 U.S.C. 1331-1356, requires that both the purchase and transportation of offshore gas be made on a nondiscriminatory basis (Tr. 2080; 43 U.S.C. 1334(e) and (f)). Pursuant to the OCSLA, the pipeline industry has considered itself obligated to both purchase and transport gas on a nondiscriminatory basis in the offshore (Tr. 2081). A witness from Texaco stated his belief that interstate pipelines have an obligation to move gas for individual companies in the offshore, and that offshore pipelines cannot unreasonably deny access if they have capacity available because of the OCSLA (Tr. 947), and Shell has filed a petition with the FERC alleging that Black Marlin Pipeline is unreasonably denying access to Shell and other producers in violation of the OCSLA (RX 2781, 2782A-U).

96. FERC's actions demonstrate a similar interpretation of the OCSLA. On June 12, 1978, it issued an order amending the original HIOS and UTOS certificates. This order provides: "In order to accommodate volumes attributable to non-affiliated shippers, HIOS and U-T will allocate their certificated capacity on a pro rata basis among all the shippers to be served. Both HIOS' and U-T's existing tariffs provide for the reduction in contract demand on a pro rata basis to accommodate new shippers" (Tr. 2081-82; RX 2760A).

E. Natural Gas Pipeline Systems In The OCS

1. HIOS

97. Five companies participated in the proposal for constructing the HIOS system (Tr. 1858; CX 159Z-1). On June 4, 1976, the FPC issued a Section 7(c) certificate to the partnership (RX 1987A-P), and HIOS was placed in service on March 31, 1978 (Tr. 155, 1859; RX's 1987A-P, 2004).

98. HIOS begins in West Cameron 167, which is 25-28 miles from shore, and extends south into the High Island East Addition Area South Extension A-264 at which point three major legs were built, one going due south and back to the east to A-334 South Extension, the middle leg extending south through the A-573 area, and the west leg extending down to the A-563 area (Tr. 216, 1857; RX 2004).

99. HIOS' termination point in West Cameron 167 is the point at which it interconnects with two separate offshore pipeline systems (Tr. 157, 216, 394, 1746-47). At West Cameron 167, HIOS connects with UTOS and a segment of American Natural Resources' ("ANR") pipeline system [25] (Tr. 170, 217, 1746-47; RX 2004). UTOS delivers gas at Cameron Meadows, Louisiana; ANR's pipeline delivers gas at Grand Chenier, Louisiana (Tr. 170). Shippers send their gas through either UTOS or ANR's pipeline, depending on which system can get the gas back to their onshore systems (Tr. 1746-47).

100. Before the MidCon/United acquisition, HIOS was owned by five partners with equal 20 percent shares: ANR, a subsidiary of Coastal Corp. (and HIOS' operator); Texas Gas Transmission Co. ("Texas"); Transcontinental Gas Pipeline Co. ("Transco"); NGPL, and UGPL. MidCon, through its subsidiaries, NGPL and UGPL now owns 40 percent of HIOS. The other three venture partners own the remaining 60 percent (Tr. 145, 1718, 1743; CX's 159Z, Z-15).

101. The HIOS management committee controls all of its significant business decisions. These include whether to make rate filings or

submit rate proposals to FERC; whether to seek FERC approval to construct new expansions or extensions of the system and, if approved, whether to construct them; and, whether to enter into contracts or amend existing contracts. A majority vote controls decisions of the committee, and three votes constitute a majority. Each owner appoints one member to the committee. MidCon has appointed one person to vote for both NGPL and UGPL (Tr. 184-85, 219, 222-23, 1748; CX's 159Z-13-Z-14, Z-43, Z-46).

102. HIOS has long-term transportation contracts with five owner shippers and eight non-owner shippers (Tr. 206; RX 1059A-B; CX 167K-Z-419). The term of each firm transportation agreement is 15 years from the date of initial delivery, then continuing year-to-year thereafter until the shipper gives a one year notice to terminate the agreement (CX 167P, Z-17, Z-44, Z-69, Z-96 Z-123, Z-148, Z-174, Z-199, Z-224, Z-249, Z-275, Z-301, Z-327, Z-352, Z-377, Z-399; RX 1059A-B). These agreements were executed in 1977 and 1978 (RX 1059A-B). Since initial deliveries began in 1978, the primary term of these agreements will expire in 1993.

103. HIOS' 13 shippers have long term agreements which grant the right to ship specific quantities of gas without interruption (Tr. 172-73, 357-58; CX's 167G, Z-9-Z-12, Z-36-Z-38, Z-63-Z-64, Z-88-Z-90, Z-115-Z-118, Z-143, Z-172-Z-173, Z-194, Z-218, Z-244, Z-269-Z-270, Z-295-Z-296, Z-321-Z-322, Z-347, Z-372, Z-394, Z-419; RX 1059A-B). All of HIOS's certificated capacity that has been approved by FERC is currently contracted to shippers who have firm rights to transport gas on HIOS (Tr. 180, 1747; RX 1059A-B). If a new shipper desires capacity on HIOS, the partnership agreement provides that the existing capacity will be reallocated to include the new shipper (Tr. 1747, 2081-87; CX 159Z-6; RX 2760A-C).

104. Shippers on HIOS have the right to use their firm contract demand to transport gas for third parties (Tr. 219), and there is no significant difference in the transportation contracts between HIOS and its owner and non-owner shippers [26] (Tr. 2082-89; CX 167K-Z-419); these shippers use their capacity to provide interruptible transportation and exchange service to many other parties (Tr. 2353-56; RX 1057D-N). HIOS is a transporter of OCS natural gas; it does not buy and resell that gas (Tr. 219, 698, 1280-82, 1657, 1789, 1858).

105. HIOS is required to file a FERC rate case biannually. The filings are prepared by the HIOS rate committee and submitted for approval of a majority of the HIOS management committee (Tr. 2189;

CX's 39, 159Z-14). Because NGPL and UGPL have one representative on the five-member HIOS management committee, MidCon could not force HIOS to take any action with respect to rates (Tr. 2189-90). ANR, HIOS' operator, represents it in FERC rate proceedings (Tr. 2197).

106. The current unit rate for transportation of natural gas on HIOS is 12.01 cents per Mcf, calculated on a 100 percent load factor basis (Tr. 2194-95; RX 2020A-B). The rate charged by HIOS to its primary shippers is not necessarily the same rate charged by the shippers to third-parties (Tr. 1794-95, 2092).

2. Stingray

107. The first leg of what is now the Stingray pipeline system was built by NGPL in the early seventies (Tr. 1721). In the early seventies, NGPL and Trunkline Gas Company ("Trunkline") proposed a joint venture extension of Stingray (Tr. 1721-22). The proposal was approved by the FPC in 1974. Construction was finished in 1975 and gas began flowing through the system in that year (Tr. 1723; RX 1992A-X).

108. The original 75-mile long Stingray was extended by further additions in 1976 and 1978 (Tr. 1726, 1728; RX's 1993E, 1994A-B). The system now extends from Cameron Parish, onshore Louisiana, to various blocks in the West Cameron area offshore and to High Island A-330 where it connects with HIOS (Tr. 1721-22, 1726-28).

109. Stingray does not build laterals to connect reserves; shippers or other interstate pipeline companies do this (Tr. 1533-35, 1715).

110. Before the MidCon/United acquisition, Stingray was owned equally by Trunkline, which is an affiliate of Panhandle Eastern Corporation, and NGPL. No change has resulted in Stingray's ownership as a result of the MidCon/United acquisition (Tr. 268-70, 1200, 1718; CX 177Z-3).

111. Stingray is controlled by a six-member management committee which consists of three members appointed by NGPL and three members appointed by Trunkline (Tr. 1730-31; CX 177I). Pursuant to the Stingray partnership agreement, all management [27] committee decisions must be carried by a concurrence of a majority of all members appointed by Trunkline and a majority of all members appointed by NGPL. Accordingly, a majority under the Agreement requires the agreement of two out of the three members from each of the companies (CX 177I-J). Therefore, in order for a proposal to be

approved by the management committee four out of the six management committee members must approve it, and as a practical matter, the decision must be unanimous (Tr. 1731).

112. The management committee makes all the major business decisions for Stingray. These decisions include whether to propose a rate change or make a rate filing with FERC, and whether to apply to FERC for permission to construct new facilities (Tr. 1731-32; CX 177I). According to the Stingray Partnership Agreement, neither party can block the construction of a lateral to connect new reserves to Stingray if the proposed construction does not impair the operation and capacity of Stingray (Tr. 1735).

113. Trunkline has operated Stingray continuously since its construction. As operator of the pipeline, Trunkline's responsibilities include the day-to-day running of the pipeline to make sure that gas received at each of the platforms is properly measured, moves through the system, is properly brought to the terminus of the system, dehydrated or separated, remeasured, and then allocated to the receiving pipeline or pipelines. Trunkline is also responsible for the maintenance, ongoing operation, major repairs, and new construction of the system as designated by the management committee. In addition, it is responsible for the accounting, day-to-day cash management, and development of rate filings and rate proceedings (Tr. 1737-38; CX 177N-Q).

114. Three interstate pipeline systems, NGPL, UGPL and Trunkline, have firm transportation agreements which grant shipping rights in the Stingray pipeline system (Tr. 272, 1736, 1743; RX 1059D; CX 180G-Z-52). The initial term of these agreements extends 20 years from the date of initial receipt and delivery and thereafter from year-to-year until a 12-month written notice of intent to cancel is given by one of the parties (CX 180Q, Z-25). Since Stingray began initial delivery of gas in 1975, the initial term of these contracts runs until 1995 (Tr. 1723). Each of the parties has a contractual right to move a specified amount of gas through the system each day without interruption (Tr. 272, 1743; RX 1059D). The parties may lease their contract demand capacity to third parties (Tr. 355, 1743). Stingray transports gas for its shippers; it has never purchased gas (Tr. 1654).

115. The Stingray rate committee reviews the rate filing prepared by Trunkline, subject to the approval of the management committee. NGPL and Trunkline must agree on any action with respect to rates (Tr. 2190; CX 177I-J). [28]

116. Stingray's current unit rate for transportation of natural gas (which is not necessarily the same as that charged by its contracting shippers to other parties), calculated on a 100 percent load factor basis, is 12.72 cents per Mcf. Its profit per Mcf of gas is approximately 2 cents (Tr. 2195-96).

3. Sea Robin

117. The initial Section 7(c) construction application for Sea Robin was filed as a joint venture by UGPL and Southern Natural Gas Company ("Southern Natural"). It was intended to transport gas bought from producers in the East Cameron, South Marsh Island, and Eugene Island areas of the OCS (Tr. 1840-43; RX 1995A-E).

118. In considering the application, the FPC questioned whether Sea Robin would duplicate another offshore system proposed by Texas Eastern, but decided that duplication would not occur (Tr. 1843-44; RX 1995C).

119. Additional construction by Sea Robin of a 26-mile extension from Eugene Island 206 to Ship Shoal 222 was authorized in January 1970 (Tr. 1846; RX 1997A). Extensions of Sea Robin's east and west legs were authorized in February 1977 (Tr. 1847; RX 1998A), the FPC noting that the west leg extension would be in the vicinity of a then recently-authorized extension of the Bluewater System (RX 1998C-D). The FPC determined that connection of the blocks in the area where the two pipelines would cross to the proposed Sea Robin extensions would be quicker and cheaper than connection to Bluewater (RX 1998D).

120. A further 11.3 mile lateral extension of Sea Robin to connect Vermilion 228 to Vermilion 190 was authorized in February 1977 (RX 1999B).

121. Unlike HIOS and Stingray, Sea Robin purchases gas for resale to its two owners, NGPL and Southern Natural. Sea Robin also transports natural gas for its owners and other shippers (Tr. 1752, 2303; CX 178A-Z-634; RX 1059E-F).

122. The Sea Robin joint venture agreement permits either owner to contract for reserves and build laterals to move the reserves without the consent of the other owner (Tr. 1849; CX 179P).

123. Before the MidCon/United acquisition, Sea Robin was owned equally by Southern Natural and United. As a result of the acquisition, MidCon owns half of Sea Robin, as does Southern Natural (Tr. 1663, 1751; CX 179T). [29]

* 124. Sea Robin is controlled by a management committee which is comprised of an equal number of members appointed by each joint venturer. The Sea Robin joint venture agreement requires the concurrence of a majority of all the members appointed by each joint venture to approve decisions (CX 179C-D). In addition, the Sea Robin rules and regulations require an affirmative vote of each of the joint ventures to transact any business (CX 179Z-7). Thus, the agreement of both United and Southern Natural is needed to make any decision regarding Sea Robin (Tr. 1752-53; CX 179D, Z-7). The Sea Robin management committee makes all significant business decisions related to the operation of Sea Robin, including decisions regarding the purchase of gas and gas purchase contracts (Tr. 1753; CX 179C).

125. UGPL, the operator of Sea Robin, has the following duties: (a) representing Sea Robin in FERC rate proceedings; (b) negotiating and administering Sea Robin's transportation contracts; and (c) overseeing Sea Robin's certificate applications (Tr. 2197-98, 2301-02; CX 179I-L). Southern Natural reviews and must approve both the transportation and exchange activities and the certificate activities of Sea Robin (Tr. 2302-03; CX 179L).

126. Sea Robin has firm transportation agreements with ten primary shippers (CX 178B-C, Z-7-Z-8; RX 1059E-F). Generally, these agreements continue in effect from year-to-year after their initial terms unless cancelled by either party by at least six months' written notice (CX 178Z-51, Z-73, Z-105-Z-106, Z-170, Z-263, Z-287, Z-311, Z-387, Z-412, Z-438-Z-439, Z-468, Z-543 (one year notice), Z-555, Z-578). These transportation agreements grant the shipper the right to ship specific quantities of gas in Sea Robin each day without interruption (CX 178Z-61, Z-86, Z-106, Z-170, Z-216, Z-237, Z-258, Z-263, Z-287, Z-311, Z-412, Z-434, Z-467, Z-516, Z-555 Z-578; RX 1059E-F).

127. Sea Robin's rate filings at FERC are prepared by its rates committee, subject to the approval of its management committee. Sea Robin's owners must agree on any action with respect to rates (Tr. 2191-92). Sea Robin's current unit rate for transportation of natural gas is 9.45 cents per Mcf, calculated on a 100 percent load factor basis (Tr. 2194; RX 2020A-B). The rate charged by Sea Robin to its primary shippers is not necessarily the same rate charged by the shippers to third-parties (Tr. 1794-95).

4. Other Natural Gas Pipelines In The OCS

128. Before and after the MidCon/United acquisition, over 20 major

singly-owned and joint venture pipeline systems operated in the OCS, offshore from Texas and Louisiana (RX 2004). These offshore pipeline systems operate as gathering lines or segments of interstate pipeline systems to provide transportation from [30] producing areas in the Gulf of Mexico for ultimate delivery to city-gate and burner tip markets. The offshore pipelines interconnect with other offshore and onshore pipelines to provide a transportation system to move gas from offshore wellhead markets to city-gate and burner tip markets throughout virtually the entire United States. The offshore pipeline systems are owned entirely or partially by interstate pipeline companies with extensive onshore pipeline systems serving various city-gate markets. Many non-owner shippers on offshore pipelines also have extensive onshore pipeline systems serving various city-gate markets. Other non-owner shippers include producers, LDC's and end-users (F.'s 129-142).

129. ANR purchases gas from the offshore Gulf of Mexico and transports it to its city-gate markets in Michigan, Illinois, Minnesota, Wisconsin and Iowa (Tr. 211-12, 1679-80; RX's 2004, 2005). ANR owns several pipeline systems in the offshore, one that starts in West Cameron Blocks 167 and 238 and connects with ANR's main onshore transmission line in Eunice, Louisiana (Tr. 151-52; RX 2004). ANR also owns an offshore pipeline system beginning in the Eugene Island, Vermilion, South Marsh Island and Ship Shoal areas offshore Louisiana which connects with ANR's main line at Patterson, Louisiana (Tr. 151-52; RX 2004). ANR also has a one-fifth ownership interest in HIOS (F. 7). From offshore, ANR's pipeline system extends into the Oklahoma and Texas Panhandle area and extends north into southeastern Illinois, Minnesota, Iowa and Wisconsin (Tr. 212, 1679; RX 2005). The city-gate markets served by ANR are in the upper midwest, primarily Michigan and Wisconsin (Tr. 143-44). ANR transports gas owned by third parties through ANR's offshore lines. ANR also purchases gas in areas where it has no major facilities in the offshore. ANR has entered into transportation and exchange arrangements (F.'s 158-159) with other pipelines to receive the gas and deliver it back to ANR's facilities, onshore and offshore, for ultimate delivery to its city-gate and burner tip markets (Tr. 1679-80; RX 1055A-C, D-H).

130. Columbia Gulf and Columbia Gas are affiliated corporations. Columbia Gulf purchases gas from the offshore and transports it to Mississippi, Tennessee and Kentucky (RX's 2004, 2005). Columbia

Gulf owns offshore pipeline facilities beginning in the East Cameron and Vermilion areas which extend through Louisiana, then run northeasterly through Mississippi, Tennessee, Kentucky, and Ohio where it connects with Columbia Gas' system (RX's 2004, 2005). Columbia Gulf also has an ownership interest in Bluewater joint venture pipeline system (RX 2004). Columbia Gas is a non-owner shipper on HIOS, as well as other pipelines in the offshore (RX 1059A). Columbia Gas has pipelines that start in the Gulf Coast area, and extend through Louisiana, across Mississippi, into Tennessee and Kentucky, and then into Ohio, Pennsylvania and New York (Tr. 212; RX 2005). Columbia Gas has extensive gathering and distribution facilities in Ohio and Pennsylvania; its system ends in New York State and serves the greater New York area as well as lower New England [31] (Tr. 1745; RX 2005). Columbia Gas purchases gas in the offshore, but because it has no offshore facilities it has entered into transportation agreements to have the gas delivered for ultimate delivery to its city-gate and burner tip markets (RX 1055S, Z-8, Z-13, Z-15, Z-39, Z-41, Z-43, Z-47).

131. Consolidated Gas is a non-owner shipper on HIOS, as well as on other pipelines (RX 1059A). Consolidated Gas is headquartered in Clarksburg, West Virginia and owns pipeline facilities in Ohio, West Virginia, Pennsylvania and New York (Tr. 213, 384; RX 2005). Consolidated Gas has no transmission facilities from the offshore to its facilities in West Virginia, Ohio, Pennsylvania, and New York (Tr. 1745; RX's 2004, 2005). The gas purchased by Consolidated Gas in the Gulf is transported by various offshore pipelines to interconnections with Texas Gas and Texas Eastern for ultimate delivery to Consolidated Gas and its city-gate and burner tip markets (Tr. 393-95, 420, 1745, 2353-54).

132. El Paso is a non-owner shipper on HIOS with firm shipping rights which it utilizes to transport gas it purchases in the offshore (Tr. 214; RX 1059A-B; RPF 178). El Paso serves California and the western parts of the United States (Tr. 1746; RX 2005). Its pipeline system starts in the Permian Basin of Texas, runs west along the Rio Grande River, has an extension that runs through New Mexico and Arizona, and is tied together and terminates at the California border (Tr. 213, 1746; RX 2005).

133. Florida Gas has firm shipping rights on HIOS and numerous other offshore pipelines (RX 1055V, Z-10, Z-13, Z-23, Z-40). Florida Gas owns no offshore transmission facilities (RX's 1347A-I, 2004).

Florida Gas' pipeline system begins in the southeastern portion of Mississippi; traverses into the panhandle of Florida; extends throughout Florida to the cities of Jacksonville, Orlando, Daytona, Tampa, and Sarasota; and runs south along the east coast of Florida to the Florida Keys (RX 2005).

134. National Fuel Gas Supply Corporation is a non-owner shipper on HIOS (CX 167Z-323-Z-347; RX's 1055V, 1059A-B). National Fuel Gas Supply Corporation owns no major transmission facilities in the offshore (RX 2004). National Fuel Gas Supply Corporation owns onshore pipeline facilities starting in the northeastern portion of Pennsylvania and extending into the eastern portions of the State of New York, supplying gas to the cities of Erie, Pennsylvania and Buffalo, New York (RX 2005).

135. Northern Natural has firm shipping rights on HIOS which it uses to transport gas it purchases in the offshore (RX 1057D). Northern Natural's system starts in the Permian Basin and the panhandle of Texas, and brings gas north across Kansas into Nebraska, and then north into the Minneapolis-St. Paul area (Tr. 1682; RX 2005). It also has a leg that runs across into Illinois and southern Wisconsin (Tr. 1682). [32]

136. Southern Natural purchases gas from the offshore Gulf of Mexico and transports it to its market areas in Alabama, Georgia and Mississippi (Tr. 1746; RX's 1059A-B, 2005). Southern Natural owns offshore pipeline facilities which begin in the Eugene Island, Main Pass, West Delta and South Pass areas in the Gulf of Mexico, extend north into Mississippi, and then split into two legs, one going further north then east into northern Alabama and Georgia, and the other going east into central Alabama and Georgia (Tr. 1751-52; RX's 2004, 2005). Southern Natural also has a one-half ownership interest in Sea Robin (Tr. 1751; CX 179T). Southern Natural transports gas owned by third parties through its offshore lines. Southern Natural also purchases gas in areas where it has no major facilities in the offshore (RX's 1347A-I, 2004). Southern Natural has entered into transportation and exchange arrangements with other pipelines to receive the gas and deliver it back to its facilities, onshore and offshore, for ultimate delivery to its city-gate and burner tip markets (RX 1057Z-13, Z-23).

137. Tennessee Gas purchases gas from the offshore Gulf of Mexico and transports it to its markets in Ohio, Pennsylvania and New York (Tr. 213, 1680-81; RX 2005; RPF 251). Tennessee Gas owns offshore

pipeline facilities beginning in the Sabine Pass area, the West Cameron and East Cameron areas, Vermilion area and South Marsh Island area which all connect to a main transmission line onshore in southwest Louisiana (RX 2004). Tennessee Gas also has offshore pipelines in the South Timbalier area, South Pass area, and the West Delta area which connect to main transmission lines onshore in southeast Louisiana (RX 2004). Tennessee's system begins in the offshore and joins with another leg from Texas at the northern border of the State of Tennessee, at which point the system continues north to Ohio, Pennsylvania and New York (Tr. 213, 1680-81; RX 2005). Tennessee Gas has an ownership interest in the Bluewater offshore joint venture pipeline system. Bluewater extends south from Vermilion Parish, offshore Louisiana into the southern border of the Vermilion area, then east through South Marsh Island, Eugene Island and the Ship Shoal areas, then north through the South Pelto area to an onshore connection at Terrebonne Parish, Louisiana (RX 2004). Tennessee Gas also has firm shipping rights on HIOS and Stingray, as well as other pipelines in the offshore (Tr. 2353; RX 1055D-E, S-T, U, W, Z-6, Z-11, Z-30, Z-49). Tennessee Gas transports gas owned by third parties through its offshore lines. Tennessee Gas also purchases gas in areas where it has no major facilities in the offshore (RX's 1347A-I, 2004). Tennessee Gas has entered into transportation and exchange arrangements with other pipelines to receive the gas and deliver it back to Tennessee Gas' facilities, onshore and offshore, for ultimate delivery to Tennessee Gas' city-gate and burner tip markets (RX 1057T).

138. Texas Eastern purchases gas in the offshore Gulf of Mexico and transports it to city-gate markets in New York, Philadelphia and Pittsburgh (Tr. 69). Texas Eastern owns the [33] Cameron offshore pipeline system (Tr. 69-70). The Cameron system begins in the East and West Cameron areas offshore (Tr. 70; RX 2004). The Cameron system extends north and connects with Texas Eastern's main transmission lines in Beauregard Parish, Louisiana (RX 2005). From this point, the main transmission line traverses southwest along the Texas Gulf coast to the Mexican border. The main transmission line also travels in a northeasterly direction through Mississippi, Alabama, Tennessee, Kentucky, Ohio, New Jersey, into New York and Pennsylvania. Texas Eastern also owns offshore pipeline facilities beginning in the Main Pass area, and travelling through the Breton Sound Area into onshore Louisiana and connecting to the main transmission line

near Francisville, Louisiana (Tr. 69; RX 2005). Texas Eastern transports and exchanges gas owned by third parties through its offshore lines (RX 1055Z-28-Z-32). Texas Eastern also purchases gas in areas where it has no major facilities in the offshore (RX's 1347A-I, 2004). Texas Eastern has entered into transportation and exchange arrangements with other pipelines to receive the gas and deliver it back to Texas Eastern's facilities, onshore and offshore, for ultimate delivery to its city-gate and burner tip markets (Tr. 116-18, 127-29; CX 805A-Y; RX's 2064A-Z-14, 2065A-Z-59, 2138A-T).

139. Texas Gas has a one-fifth ownership interest in HIOS (F. 7). Texas Gas' onshore system begins onshore Louisiana, then goes north through Mississippi, Tennessee, and Kentucky; then one leg travels into Indiana and the other leg travels into Ohio (RX 2005). Texas Gas transports its own and other parties' gas through lines on which it has shipping rights, such as HIOS (RX 1057D).

140. Transco purchases gas in the offshore Gulf of Mexico and transports it to its city-gate markets in New Jersey, New York and Pennsylvania (Tr. 211; RX 2005). Transco owns extensive pipeline facilities in the offshore (Tr. 211, 1744; RX 2004). Transco has offshore pipelines beginning at Vermilion Block 215, Vermilion Block 331, Eugene Island Blocks 206 and 208, Ship Shoal area blocks 108, 223, 246, 268, and 239, and South Pelto area blocks 12 and 13, which all connect to its main transmission line in Terrebonne Parish, Louisiana (RX's 2004, 2005). Transco also has offshore pipelines beginning at Mustang Island area blocks 619, Brazos area blocks A-19, A-17, and A-1 which connect to Transco's main transmission line in Texas (RX's 2004, 2005). Transco has an offshore pipeline beginning at Galveston area block 241 and High Island block 179 and another pipeline beginning at West Cameron block 110 which connects to the main transmission line in western Louisiana (RX 2004). Transco also has a one-fifth ownership interest in the HIOS joint venture offshore pipeline system and a one-third ownership interest in UTOS (Tr. 1718; CX's 159Z, 182C, K). Transco's main transmission line extends north from offshore Louisiana and Texas and east to New Jersey, New York and Pennsylvania (Tr. 211; RX 2005). Transco transports gas owned by third parties through its offshore lines (RX's 1055T, Z-33-Z-43, 1057J-L). Transco also [34] purchases gas in areas where it has no major facilities in the offshore (Tr. 817; RX's 1347A-I, 2004). Transco has entered into transportation and exchange arrangements with other pipelines to receive the

gas and deliver it back to Transco's facilities, onshore and offshore, for ultimate delivery to Transco's city-gate and burner tip markets (RX's 1057D, U, Z-3, Z-8).

141. Trunkline and Panhandle Eastern Pipeline Company are both subsidiaries of Panhandle Eastern Corporation (Tr. 268-69). Trunkline purchases gas from the offshore Gulf Coast as well as from South Texas and Louisiana and transports it to its markets in Illinois, Indiana and Michigan (Tr. 269). Trunkline owns the Terrebonne offshore pipeline system (Tr. 271). The legs of Trunkline's Terrebonne system begin in the Eugene Island, South Timbalier and Grand Isle areas and traverse through the South Pelto area, the Ship Shoal area, and South Marsh Island area (RX 2004). Another leg begins in the North Addition of the South Marsh Island area and connects with the main trunk of the Terrebonne offshore system near the shoreline (RX 2004). The Terrebonne system connects with Trunkline's main transmission system in Louisiana (RX 2004). The main line travels north to the city-gate markets it serves in Indiana, Michigan and Illinois (Tr. 269; RX 2005). In addition, Trunkline has a one-half ownership interest in the Stingray joint venture offshore pipeline system (Tr. 268-69; CX 177Z-3). Trunkline interconnects with Panhandle Eastern Pipeline in Tuscola, Illinois (Tr. 269). Trunkline transports gas owned by third parties through its offshore lines (RX 1055Z-44-Z-45). Trunkline also purchases gas in areas where it has no major facilities in the offshore (RX's 1347A-I, 2004). Trunkline has entered into transportation and exchange arrangements with other pipelines to receive the gas and deliver it back to Trunkline's facilities, onshore and offshore, for ultimate delivery to Trunkline's city-gate and burner tip markets (Tr. 350).

142. Panhandle Eastern has an extensive onshore pipeline system (Tr. 1681; RX 2005). It buys gas in the Hugoton and Anadarko Basin field in Kansas and Oklahoma and the West Panhandle field in Texas and parts of Oklahoma (Tr. 268). Panhandle Eastern's system extends from the Panhandle of Texas to the Permian Basin, across Kansas and Missouri into Illinois, and across Indiana into Detroit (Tr. 1681). It serves the Indiana market, the central Illinois market and part of the Missouri market (Tr. 1681; RX 2005). Panhandle Eastern transports gas for resale to customers in five states: Michigan, Indiana, Ohio, Illinois and Missouri (Tr. 268). Panhandle Eastern purchases gas in the offshore, but because it has no offshore facilities it has entered into transportation agreements to have the gas delivered to Panhandle

Eastern for ultimate delivery to its city-gate and burner tip markets (RX's 1055U, 1057E, K, Z-22). [35]

F. Natural Gas Producers In The OCS

143. Natural gas producers operating in the OCS explore for, drill for and produce natural gas throughout this area, as well as onshore (Tr. 2468-69; RX 1341A-Z-50; CX 1212A-V).

144. Some of the more important producers in the OCS are:

145. Amerada Hess, which holds leasehold interests in offshore blocks stretching from the Viosca Knoll area on the far eastern side of the Gulf to the Matagorda Island area on the far western side of the Gulf (RX 1341C).

146. Amoco Production Company, which owns offshore leasehold interests stretching from as far east as Viosca Knoll to as far west as Mustang Island and the Brazos area (RX 1341D).

147. ARCO, which has offshore leasehold interests stretching from as far west as the Matagorda Island area to as far east as the Viosca Knoll area and as far out as the Garden Banks area (RX 1341G).

148. Chevron USA, Inc., which holds offshore leasehold interests throughout the Gulf (RX 1341K).

149. Conoco, Inc., which has offshore leasehold interests stretching from the far eastern side of the Gulf including the Viosca Knoll area, the South Timbalier area and the Mississippi Canyon area to as far west as the Brazos area (RX 1341N).

150. CNG Producing Company, whose offshore operations extend from the South Timbalier area to the High Island area (Tr. 413; RX 1341M).

151. Elf Aquitaine Inc., which has leasehold interests all across the Gulf (RX 1341Q).

152. Exxon Corp., which also holds leasehold interests across the Gulf (RX 1341T).

153. Kerr McGee Corporation, which owns leasehold interests stretching from the far east side to the far west side of the Gulf (RX 1341X).

154. Pennzoil, which has sold gas in virtually every area in the OCS where there is production (Tr. 710-11).

155. Shell, which has extensive leasehold interests in the Gulf (RX 1341Z-18).

156. Standard Oil, which hold leases in Alaska, the continental United States, and in hundreds of thousands of acres from the far west to the far east of the Gulf (Tr. 840; RX 2004). [36]

157. Texaco, USA, which is involved in the domestic exploration and development of oil and natural gas throughout the continental United States, the Gulf and the Atlantic and Pacific oceans. Texaco has interests in approximately 60 leases within the alleged geographic markets (Tr. 916-17; RX 1341Z-43-Z-44).

G. Natural Gas Purchasers In The OCS

1. Transportation And Exchange Agreements

158. Through transportation and exchange agreements, pipeline companies can purchase natural gas in areas where they have no facilities (Tr. 2470, 2478; RX 1348A-Z-97). In transportation agreements, one pipeline company agrees to transport gas for another one, the first company agreeing to receive gas into its system, transport it to an interconnect point between the two systems, and deliver the gas to the second pipeline at the interconnect (Tr. 153, 2235-36; RX 1629A-Z-26).

159. An exchange agreement is a type of transportation agreement. The difference between them is that in a transportation agreement, consideration is received for moving the gas whereas in an exchange agreement, pipeline A which has a gas supply near pipeline B, and B which has a supply near pipeline A, agree to transport gas for each other without charge (Tr. 2237; RX 1742A-V). These agreements, which involve no costs because equal volumes of gas are exchanged, are thought to be more desirable than transportation agreements (Tr. 119, 1675, 2247).

2. Purchases By Interstate Pipeline Companies

160. Transportation and exchange agreements allow pipeline companies to purchase gas throughout the OCS even though their physical facilities are located only in parts of this area (Tr. 246-72, 1674; RX's 1341A-Z-50, 1348A-Z-97).

161. Thus, NGPL, UGPL, Sea Robin, and virtually every other interstate pipeline company purchase gas both near their existing transmission facilities and away from those facilities. Gas purchased by NGPL, UGPL, or Sea Robin which is not directly connected to the wholly-owned facilities of these pipeline companies is moved through transportation or exchange agreements negotiated with other pipeline companies (Tr. 1917-18, 2303, 2309, 2471; RX's 1347A-I, 1348M-N, Z-4-Z-5, Z-19-Z-20, Z-35-Z-36, Z-49-Z-50, Z-64-Z-65, Z-78-Z-79, Z-93, 2001, 2004). [37]

162. Other interstate pipelines operating in the OCS purchase off-system gas and gas located near their systems: ANR (Tr. 1925-26; RX's 1347A-I, 1348B-C, Z-9-Z-10, Z-46, Z-76, 2004); Arkla (RX's 1347C-D, 1348D, Z-11, Z-40, Z-70, 2004); Columbia Gas (RX's 1347A-J, 1348F-G, Z-13-Z-14, Z-41-Z-42, Z-71-Z-72, 2004); Consolidated Gas (RX's 1347, 1348H, Z-15, Z-43, Z-73, 2004); El Paso (RX's 1347, 1348I, Z-16, Z-44, Z-74, 2004); Florida Gas (RX's 1347A-I, 1348J, Z-17, Z-45, Z-75, 2004); Mid-Louisiana Gas Company (RX's 1347A-I, 1348K, Z-18, Z-48, Z-77, 2004); Northern Natural (RX's 1347A-I, 1348"O"-P, Z-21-Z-22, Z-51-Z-52, Z-80-Z-81, 2004); Sea Robin (RX's 1347G, 1348R, Z-24, Z-54, Z-83, 2004); Southern Natural (RX's 1347A-I, 1348S-T, Z-25-Z-26, Z-55-Z-56, Z-84-Z-85, 2004); Tennessee Gas (RX's 1347A-I, 1348U-V, Z-27-Z-28, Z-57-Z-58, Z-86-Z-87, 2004); Texas Eastern (RX's 1347A-I, 1348W-X, Z-29-Z-30, Z-59, Z-88, 2004); Texas Gas (RX's 1347A-I, 1348Y, Z-31, Z-60, Z-89, 2004); Transco (Tr. 817, 870-71; RX's 1347A-I, 1348Z-1-Z-2, Z-32-Z-33, Z-61-Z-62, Z-90-Z-91, 2004); Trunkline (RX's 1347A-I, 1348Z-3, Z-34, Z-63, Z-92, 2004); West Lake Arthur Corporation (1981-1984) (RX's 1348Z-66, 2004).

H. *The Relevant Product Market*

163. There is no record evidence that any method of transportation other than pipelines was considered by producers or is being used to move gas from the producing blocks offshore to the ultimate purchasers. The only practical method of transporting gas from the OCS is through pipelines designed for that purpose (Oil pipelines are not reasonable substitutes, Tr. 400, 695, 817), and Dr. Uri, complaint counsel's expert witness, concluded, therefore, that although natural gas passes through a sequence of markets before it is consumed (Tr. 1011), since market power can be exercised at the origin end of the pipeline (Tr. 996-97), the relevant product market in which to assess the competitive effects of this merger is the transportation of natural gas via pipeline out of the producing areas (Tr. 1010).

164. Respondents' expert witness, Dr. Hall, views the product market much more expansively, arguing that since the demand for transportation of gas derives from the demand for gas at the burner tip, the product market extends from the wellhead to the point of consumption (Tr. 2460-61, 2467).

165. Purchasing practices in the industry lend some support to a broad definition of the product market for pipeline companies (Tr.

360, 1754-55), end-users and local distribution companies (RX 1057C, F-L, Z-1, Z-4-Z-6, Z-0) and producers (Tr. 294, 829-30), all arrange for transportation from wellhead to burner tip. They are not concerned simply with transportation [38] from an offshore producing field to the shoreline of Texas or Louisiana because consumers are not located there (Tr. 830, 1486-87, 1826-27).

166. After analyzing the evidence and the testimony of the experts, I conclude that while the overall product market may be viewed as the transportation of natural gas from the wellhead to the city-gate or the burner tip, since market power can be exercised at various stages within this market where separate transactions occur (Tr. 1014), there are product submarkets, including the transportation of natural gas out of the producing areas. In fact, Dr. Hall testified in another case, *Colorado Interstate Gas Co. v. NGPL*, that a relevant market was "the transportation of gas out of Wyoming" (Tr. 2613-17).

I. *The Relevant Geographic Market*

1. Introduction

167. According to Dr. Uri, a geographic market exists if a hypothetical monopolist controlling the producing assets can exercise market power within that area (Tr. 1069-70).

168. A hypothetical price increase postulated by Dr. Uri to define his geographic market could be a uniform price increase or a discriminatory price increase. On a gas pipeline, a uniform price increase would be a rate increase over the entire pipeline for all shippers. A discriminatory price increase would occur over only a portion of the pipeline, such as a single leg, or for connection of an individual block (Tr. 1072-73). In cases where one can define a relevant geographic market based on selective price changes (price discrimination), Dr. Uri testified that there may be more than one geographic market in which to analyze the competitive effects of the merger (Tr. 1073-74). Where price discrimination is possible, the geographic market will be smaller in scope than if price increases are uniform (Tr. 1073).

169. In this case, because of the supposed ability of pipelines to price discriminate, Dr. Uri proposed several geographic markets (Tr. 1073-76): (1) the area identified in paragraph 20 of the complaint as amended; (2) the portions of the paragraph 20 area that are east of the north-south line that runs through the eastern boundary of West Cameron block 596 and that are north of the east-west line that runs

through the northern boundary of Garden Banks block 284; (3) the portions of the paragraph 20 area that are west of the north-south line that runs through the eastern boundary of West Cameron block 596 and that are north of the east-west line that runs through the northern boundary of Garden Banks block 270; and (4) individual blocks within the paragraph 20 geographic area (Tr. 1074-75 (referring to CX's 1125, 1082). Although he could identify additional [39] geographic markets, Dr. Uri concluded that defining additional markets would add little to the inferences that he drew regarding the competitive effects of the acquisition (Tr. 1075-76).

170. Dr. Uri's theory relies, in part, on the fact that pipeline systems in the proposed relevant geographic markets are substitutes for the connection of new blocks in some cases (F.'s 180-195).

171. New blocks have been connected to pipelines that are 10, 20 or more miles from a block (CX 1116A-B). For example, CX 93A-H identifies nine blocks connected to HIOS, Stingray or Sea Robin by laterals more than ten miles long: High Island 480 (12.9 miles); High Island 568 (10.63 miles); High Island 447 (10.76 miles); High Island 414 (14.17 miles); High Island 309 (10.07 miles); West Cameron 630 (12.0 miles); Vermilion 369 (20.45 miles); West Cameron 331 (11.2 miles); Galveston 131 (19.18 miles). CX 94A-Z-13 identifies seven laterals which are longer than ten miles: East Cameron 32 (19.08 miles); Eugene Island 57 (10.34 miles); High Island 171 (26.55 miles); High Island 139 (26.82 miles); Mustang Island (16.7 miles); Vermilion 340 (10.05 miles); West Cameron 436 (13.74 miles).

172. Industry members sometimes consider pipelines that are even further from a block to be viable connection alternatives for that block. Trunkline looked at blocks within a 15 mile radius of Stingray in estimating future reserves and connections available to Stingray (CX 35G). Other pipeline reserve studies assess areas of comparable or further distance from the pipeline (CX 105A-H (Stingray), CX 399A-V (HIOS)). NGPL prepared several gas supply evaluations positing construction of laterals more than 10 miles in length (*see, e.g.*, CX 1400A-D (16.7 miles), CX 1402A-C (25.62 miles). Mr. Hahn of Texaco viewed the Columbia lateral connected to the Bluewater project to be a viable alternative for Texaco blocks West Cameron 654 and 663 (Tr. 936). A review of an OCS map shows that this lateral is over 12 miles from the blocks (West Cameron 654/663 to West Cameron 616) (*see* CX 904). Trunkline proposed to transport gas on Trunkline-owned pipelines from blocks that were substantial distances

from its system. CX 606 is a proposal to connect East Cameron 185 to Stingray, a distance of 23 to 24 miles (CX 606B). A proposal to connect South Timbalier 292 to Trunkline's Terrebonne system involved a distance of 22.5 miles (CX 605B).

173. Analyzing unconnected blocks located within the paragraph 20 market, Dr. Uri found several within 10 or 15 miles of more than one pipeline (Tr. 1047-48, 1249; CX's 1105A-C, 1106A-C) and he concluded that more than one pipeline is likely to be a viable alternative for many blocks (Tr. 1050). In fact, some blocks are connected to more than one pipeline (Tr. 1051-53; CX 1114). [40]

174. Dr. Uri also considers the fact that pipelines cross a confirmation that these pipelines are sufficiently close in some areas to be substitutes for new blocks (Tr. 1042-43). Stingray and Sea Robin cross each other at three points, in East Cameron 265, 278 and 297 (see CX 904). There is an additional point of intersection in East Cameron 264 where a lateral off Sea Robin crosses Stingray (see CX's 807, 904). Similarly, Sea Robin crosses the 601 project once (East Cameron 334) and Texas Eastern three times (East Cameron 248, 263 and 265) (see CX's 807, 904). Stingray crosses the 601 Project in three places (East Cameron 293 and 314, Vermilion 263), and Texas Eastern in 12 (West Cameron 241, 277, 433, 459, 483, 484, 565, East Cameron 263, 280, 281, 286 and Vermilion 263) (see CX's 807, 904). Stingray connects to the West Cameron 616/601 lateral in West Cameron 616 and crosses the lateral in West Cameron 607 (CX's 807, 904).

175. In deepwater areas and other areas far from any pipeline, pipelines even further than 10-20 miles from a block may be alternatives. For example, NGPL extended its pipeline system 53 miles to connect blocks in the Matagorda Island area (CX's 904, 1369A-C, 1370A-C; RX 2004). # [IN CAMERA] # There has been consideration of connection of Garden Banks blocks to pipeline systems in the market. NGPL considered three options for connecting Garden Banks 236, a 18.4 mile lateral to Columbia Gulf, a 15.5 mile lateral to Stingray, and a 19.3 mile lateral to Stingray (CX 1355A-C). HIOS considered extending toward the Garden Banks to compete with Stingray (CX 399Q). Trunkline evaluated a pipeline to connect blocks in the Garden Banks to Stingray (CX 638A-B). Northern Natural has worked with Columbia to connect Garden Banks 236 to Bluewater (CX 502T; see also CX 105A-G (portions of Garden Banks within NGPL study area for expansion of HIOS and Stingray); CX 141E

(HIOS extension to access Garden Banks reserves); CX 149C (17 blocks under exploration in Garden Banks for potential HIOS transport)).

176. Other record evidence convinced Dr. Uri that pipeline companies within the alleged relevant geographic markets are substitutes for one another.

177. Pipelines that interconnect are substitutes, in his opinion, for transporting gas from blocks near the point of interconnection and for gas flowing to the interconnection point (Tr. 1043-44). HIOS and Stingray interconnect at High Island A-330 (Tr. 1043; CX 1125) and gas from the "state line laterals" can flow into either HIOS or Stingray (Tr. 171-72, 2431). Thus, for blocks connected to the state line laterals, both HIOS and Stingray are easily accessible (Tr. 1043). An ANR document noted that if Trunkline would not transport gas from West Cameron 536 [41] and 542 on Stingray, the volumes could be transported on HIOS by displacement even if the blocks were connected to Stingray (CX 385B-C). NGPL has shifted shipments between HIOS and Stingray based on the rates charged by these pipelines (Tr. 2432-33; CX 48A). NGPL shifted volumes from HIOS to Stingray in order to avoid the UTOS commodity change (Tr. 2433; CX's 133A, 143A-B, 202B). This evidence suggests to Dr. Uri that HIOS and Stingray are sufficiently close together to be substitutes for new blocks, particularly those near the state line laterals (Tr. 1045-46).

178. Blocks are often connected to pipelines that are not the closest pipelines, which indicates to Dr. Uri that more than one pipeline can be a substitute for a block and that spatial competition can and does occur among OCS pipelines (Tr. 1034). CX 1117 shows examples of blocks that were connected to pipelines that were not the closest to the block. Where a more distant pipeline connects a block, this indicates that the cost disadvantage created by the longer distance has been outweighed by lower cost of other elements of the transportation charge (*see* Tr. 1034-37).

179. Purchasers of gas at the wellhead often indicate a preference for connecting a block to their own pipeline systems even where other closer pipelines exist (Tr. 1031-34; CX's 371A, 711A). For example, one NGPL evaluation proposed connecting the block to Transco's system via a 1.8 mile lateral, but requiring payment to Transco of 17 cents per Mcf in transportation charges (CX 1403A-C). A second NGPL evaluation proposed building 25.62 miles of lateral to connect

the block to its own system, which could be achieved at a lower overall cost than the Transco option because no transportation charges had to be paid to a third party (*Compare* CX 1402A with CX 1403A; Tr. 2391). NGPL built the 25.62 mile lateral to High Island 139 (CX 902; RX 2004). ANR considered three alternative routes to connect reserves in Eugene Island 284 to its own pipeline (CX 377A-C), while Sea Robin passes directly through the block (CX's 377C, 904). ANR also proposed to connect reserves from West Cameron 169 and 170 to its own system via a 1.1 mile lateral, while noting that Stingray was closer (CX 378).

2. Connections Of Individual Blocks In The Paragraph 20 Area

180. The following analysis of individual blocks located in the paragraph 20 area reveals that in some instances more than one pipeline was considered as an alternative connection.

181. West Cameron 566 and 570: Texas Eastern considered connecting gas it purchased in West Cameron 570 and 566 to HIOS, Stingray or its own Texas Eastern Cameron system (Tr. 82-87) and it connected these blocks to the Texas Eastern system with a 20.1 mile lateral (CX's 314A-B, 1024A-Z23), although HIOS was 11 miles [42] from the block and Stingray was 1.8 miles away (Tr. 82-85; CX's 807, 809A-D). Other potential purchasers and transporters of the West Cameron 566/570 gas also considered alternative connections for this block. For example, Texas Gas evaluated connections to HIOS or Stingray (CX 852). Trunkline proposed to connect the gas on behalf of the producers and transport it through Stingray (Tr. 299-301; CX 601A-D). CNG Producing Company considered HIOS, Stingray and Texas Eastern as viable alternatives for connecting its gas from this block (Tr. 390). # [IN CAMERA] # In evaluating the purchase of these blocks, NGPL concluded that Stingray was the best transportation alternative (Tr. 2402; CX 1381A-D).

182. High Island A-289: Texas Eastern evaluated HIOS and Stingray as substitutes for transporting gas it purchased in High Island A-289 (Tr. 87-91; CX 811A-D). Texas Eastern determined that there would be a lower cost of service for it to connect High Island A-289 to Stingray and utilize a pre-existing transportation and exchange agreement with NGPL on Stingray (Tr. 88; CX 811A). United, the other purchaser of High Island A-289 gas, preferred to connect the gas to HIOS (Tr. 91; CX 309A). HIOS intervened, claiming that the proximity of the block to HIOS indicated connection

to HIOS rather than Stingray (CX 87B, F). Texas Eastern ultimately connected High Island A-289 to Stingray via an NGPL lateral (Tr. 87).

183. West Cameron 556: Tennessee Gas Pipeline considered the Stingray, Texas Eastern and Bluewater systems as substitutes for the connection of gas marketed by Amerada Hess in West Cameron 556 (CX 755). Koch proposed to connect the block "to one of three pipelines in the area: Stingray, Sea Robin or Texas Eastern" (CX 1200A). Trunkline proposed to transport West Cameron 556 reserves through its capacity on Stingray on behalf of the producers (Tr. 310-14; CX 603A-J). Sea Robin evaluated connection of West Cameron 556 reserves to its own system (CX 315A-K). ANR assessed a lateral connection to the Texas Eastern system for West Cameron 556 reserves (CX 379C). Finally, Transco constructed the connecting pipeline from this block to Texas Eastern (Tr. 373; CX 1291B; RX 2004), after also evaluating an alternative connection to the Stingray system (CX 610A-C).

184. East Cameron 299: CNG considered Stingray, Sea Robin, Bluewater and Texas Eastern as viable alternatives to transport gas it planned to market from East Cameron 299. Texas Eastern bought the gas and connected the block to its Cameron system (Tr. 387-88). Sea Robin had evaluated the feasibility of transporting these reserves on its system (CX 329B).

185. West Cameron 597: United evaluated as alternative connections for West Cameron 597 both Stingray and Columbia Gulf's pipeline system (CX 316A-F). [43]

186. West Cameron 494: An NGPL gas supply evaluation proposed to connect reserves in West Cameron 494 to HIOS (Tr. 2403-04; CX 1420A-C). This block has been connected to the Texas Eastern Cameron system (Tr. 2404; CX's 807, 904).

187. West Cameron 464: United conducted two studies for the connection of reserves in West Cameron 464, one with a proposed connection to HIOS (CX 113A), and a second with a proposed connection to Stingray (CX 113B-D). This block has been connected to the Texas Eastern Cameron system (*see* CX's 807, 904).

188. East Cameron 280: Tennessee initially proposed to connect reserves it purchased in East Cameron 280 via a lateral to Texas Eastern in East Cameron 281. Tennessee then proposed to connect the block to Stingray (CX 327). Texas Eastern and Stingray intersect in this block (CX 904).

189. East Cameron 281: United conducted an analysis of connecting reserves in East Cameron 281 to Texas Eastern, Stingray or Sea Robin (CX 324C-F). NGPL and Trunkline preferred to connect this block to Stingray (CX 328). Stingray and Texas Eastern intersect in this block, and the block is connected to Texas Eastern (CX's 328, 904).

190. West Cameron 610 and 615: Columbia proposed to connect reserves from West Cameron 610 and 615 to the Bluewater project, "thus precluding transportation in either Stingray or HIOS" (CX 401).

191. High Island 365 and 375: ANR evaluated a joint lateral project with Trunkline to connect reserves from High Island 365 and 376 to a pre-existing lateral to Stingray (CX 375A). ANR had previously considered connecting these reserves to the east leg of HIOS (CX 375B). The block has been connected to the east leg of HIOS (*see* CX 904).

192. High Island A-350: United sought to connect reserves in High Island A-350 to the HIOS/Stingray interconnect in High Island A-330 which would enable it to transport the gas through its space on either HIOS or Stingray (CX's 18, 26B). Gas delivered to the interconnection can flow in either direction, to HIOS or to Stingray, allowing a shipper to obtain transportation on either of the two pipeline systems (Tr. 170-72, 2431-32; CX 362A).

193. Garden Banks 236: NGPL evaluated connecting reserves from Garden Banks 236 to Stingray or to Columbia Gulf (CX's 71C-D, 72A-C). Northern Natural conducted detailed analyses of a joint project with Columbia to build an 18.5 mile lateral to the Columbia Gulf system for this block (CX's 502A-T, 513A-F). [44] Trunkline investigated opportunities to build a pipeline off of the Stingray system into the Garden Banks area (Tr. 335-37; CX's 624A-B, 638A-B).

194. West Cameron 654 and 663: Mr. Hahn of Texaco identified HIOS, Stingray and Columbia as viable alternatives to transport gas from leases Texaco holds for West Cameron 654 and 663 (Tr. 936).

195. West Cameron 552: Texas Eastern investigated connecting gas reserves in West Cameron 552 to its Cameron system (CX 803A-B), noting that Transco and United had plans to build pipelines from this area to HIOS (CX 802). This block has been connected to the Stingray system (CX 904).

3. Connections Of Individual Blocks In The OCS Outside Of The Paragraph 20 Area

196. The examples described below reveal that pipelines outside of the paragraph 20 areas were sometimes considered as alternative connections to the same block.

197. West Cameron 330: Sonat had a "choice between Stingray and HIOS" for connection of its gas in West Cameron 330 (CX 81A). NGPL planned to take its gas from this block to the Tidal system, seven miles to the east (CX 713C).

198. West Cameron 253: Sea Robin evaluated alternative connections for gas from West Cameron 253 to the Stingray or Texas Eastern systems (CX 321D-E). NGPL also considered a Stingray option and a Texas Eastern option for connecting these reserves (Tr. 2393-94; CX 52A-B). NGPL recommended connection to Stingray (CX 52B); the block has been connected via a lateral to the Texas Eastern Cameron system (CX 807).

199. West Cameron 294: ANR prepared an evaluation comparing connection costs for reserves in West Cameron 294 to HIOS or to ANR's own pipeline system (CX's 382B-C, 392A). NGPL wanted to bring this gas to shore on its own Pelican system (CX 118A-E).

200. West Cameron 169 and 170: ANR prepared a cost analysis for connection of reserves in West Cameron 169 and 170 to ANR's offshore system, noting that Stingray and Natural also had facilities in the area (CX 378). NGPL in fact connected the reserves to Stingray (CX 124D).

201. West Cameron 192: Phillips developed a marketing strategy with other producers of reserves in West Cameron 192 based on the fact that "[b]oth Texas Eastern and Tennessee Gas [45] have lines in the immediate vicinity of our wells" (CX 1292). ANR also developed cost of service estimates for connection of this block to Tennessee or Texas Eastern (CX 397H-M).

202. West Cameron 318: An ANR document proposed connecting reserves from West Cameron 318 to HIOS (CX 387). An NGPL gas supply evaluation recommended connecting this block to the Pelican pipeline (Tr. 2405; CX 1374A-B). HIOS is closer to this gas source than the Pelican system, and in fact HIOS traverses the block (Tr. 2405-06; CX 904).

203. West Cameron 115 and 116: NGPL's System Design department prepared "an economic comparison of two possible methods of

connecting West Cameron Blocks 115/116," namely a connection to UTOS versus a connection to the Tidal system (Tr. 2395-96; CX 92A).

204. West Cameron 211 and 212: Northern Natural proposed to connect reserves in West Cameron 211 and 212 to its own system or to UTOS in negotiating with Arco for the purchase of these reserves (CX 1217A-B). NGPL prepared a gas supply evaluation for this gas based on proposed connections to Stingray or to the Pelican system (Tr. 2398-99; CX 1371A-B).

205. West Cameron 64 and 192: ANR considered connections to Tennessee or its own system for reserves in West Cameron 64 and West Cameron 192 (CX 397B-G). ANR chose its own system for West Cameron 64 and Tennessee for West Cameron 192.

206. High Island 116: ANR considered three pipeline system alternatives for transporting gas from High Island 116: NGPL, Transco and Tennessee (CX 390A-B).

207. High Island 139: NGPL prepared three separate gas supply evaluations to evaluate the attachment of reserves from High Island 139 (Tr. 2391-93). Two of these gas supply evaluations proposed a connection to the Transco system (CX's 1402A-C, 1416A-C), while the third recommended connecting the block to NGPL's system (CX 1403A-C).

208. High Island 68: Arco evaluated connection of High Island 68 to Transco, NGPL and UTTCO (CX 1210A-D).

209. Matagorda Island 652, 681 and 682: ANR assessed the costs to connect reserves in Matagorda Island 652, 681 and 682 to both the Matagorda Offshore Pipeline System and a Transco pipeline (CX 391T-W).

210. Eugene Island 336: ANR considered alternative pipeline connections to its own system and to Sea Robin in evaluating a potential purchase of reserves in Eugene Island 336 (CX 374A-C).

[46]

211. Eugene Island 284: ANR prepared cost estimates comparing "three alternatives for the potential connection" of Eugene Island 284 reserves to its own system some three to five miles away (CX 377A-B). Sea Robin traverses this block (CX 377C; *see* CX 904).

212. Eugene Island 182: In assessing "the prospect for obtaining a market for Exxon gas to be produced from a new platform to be installed at Eugene Island 182," Exxon noted that "four pipeline companies have pipeline capacity within seven miles or less of the new platform's location" (CX 1261A). The four pipelines were ANR (two

miles), Sea Robin (3.5 miles), and two Transco pipelines, both seven miles away (CX 1267A).

213. Eugene Island 172: ANR reviewed a competing proposal to connect reserves from Eugene Island 172 to Sea Robin in preparing its own proposal to connect this block to its own system (CX's 389A-D, 1331B-C). Tenneco considered five pipeline systems as alternatives to connect this block: Transco, TGP, Bluewater, Sea Robin and ANR (CX 1331R-T). Tenneco chose the Transco option after comparing costs for each alternative: "The economics shown reflect only expenses (transportation charges), capital requirements for this project and deliverability projections. This was done to highlight the economic differences among the options" (CX 1331J).

214. South Marsh Island 144, 160, 161 and 174: In its assessment of reserves in the South Marsh Island area including blocks 144, 160, 161 and 174, ANR prepared an "economic evaluation [that] compares gathering and transporting 110 MMcf/d from subject area to onshore Louisiana by Michigan, Wisconsin in competition with United Gas Pipeline" (CX's 350A, 367A-E). ANR determined that connection to its own system, via a 19.4 mile lateral, was more economical than a 11.7 mile lateral to United (CX 367C).

215. Natural also prepared a gas supply evaluation for connection of these reserves to the ANR pipeline (CX 1377A-F). Sea Robin proposed to connect these reserves as "[t]he area . . . holds the greatest potential at this time for justifying an expansion of the Sea Robin system" (CX 334C).

216. Ship Shoal 322 and 323: # [IN CAMERA] [47] [IN CAMERA] #

217. Vermilion 220 and 221: NGPL conducted an economic evaluation comparing costs to connect gas from Vermilion 220 and 221 to the Stingray, Texas Eastern or Bluewater systems (CX 65A-B). NGPL connected these reserves to the Stingray system via a 13.3 mile lateral, even though Texas Eastern and Bluewater were closer (CX 65A-B). NGPL rejected the Texas Eastern option because Texas Eastern was competing with NGPL for gas reserves, and rejected the Bluewater option because of higher transportation fees (CX 65B).

218. Vermilion 315: ANR used three alternative potential pipeline connections in its negotiations with Amoco for the purchase of reserves in Vermilion 315: Gulf Oil pipeline, Transco or Trunkline/NGPL (Stingray) (CX 386A-I). The Stingray connection, which required the longest lateral of the three options, would have the

"lowest rate to shore if Amoco [the producer] agrees to absorb the cost of the connection" (CX 386B).

219. Vermilion 318: CNG's first choice was the Gulf Oil pipeline and Stingray for the connection of reserves in Vermilion 318; once Gulf Oil refused to provide transportation for third parties, CNG connected the block to Stingray (Tr. 391-93). NGPL also conducted a project evaluation for a connection of this block to Stingray (Tr. 2400; CX 1353A-B).

220. Vermilion 372: NGPL prepared an economic evaluation for the connection of Vermilion 372 reserves to Stingray (Tr. 2401; CX 1417A-C). This block has been connected to ANR's pipeline system (CX 904).

221. South Timbalier 205, 206, 292 and 295: Trunkline presented a proposal for transportation on its Terrebonne system to Transco for Transco's reserves in South Timbalier 205, 206, 292 and 295 (Tr. 318-19; CX 605A-F). Transco, a "competitor" of the Terrebonne system, was also considering an alternative connection to its own system (Tr. 324). Transco requested in writing a reduction in Trunkline's 100-mile haul rate (CX 604A), and after Trunkline refused the request, Transco rejected the Trunkline option (Tr. 329-30).

222. Ship Shoal 188, 189, 210 and 211: Trunkline negotiated with Shell for the connection of Ship Shoal blocks 188, 189, 210 and 211 to the Terrebonne system while Shell was [48] "considering alternatives which would result in extension of a pipeline to a competitor in the area that was further away than the Terrebonne system" (Tr. 332-34; CX's 645A-H, 646, 647A-B).

4. Individual Blocks As Relevant Geographic Markets

223. Dr. Uri testified that if pipelines can engage in price discrimination, areas smaller than the total area served by a pipeline may be a relevant geographic market—in this case, areas as small as individual blocks (Tr. 1073-75) and that price discrimination is possible if a pipeline can offer a discount from a transportation charge without needing to lower rates on existing or future contracts (Tr. 1057-58, 1067).

224. According to a FERC document:

In a workably competitive market, because of consumer mobility and the inability of firms to prevent resale, the ability of the firm to selectively discount is limited except where [sic] the transaction cost of discovering prices is relatively high. Once the

workably competitive firm posts a price discount, this discount is available to all in that market. However, this firm may not choose to lower its price in all the markets in which it competes. Thus, a price inelastic customer gains the benefits of price discounting only in the market in which prices have been lowered. Natural gas transmission companies possess market power over some customers in some of their geographical markets. These captive customers are not mobile and they are not generally capable of benefiting from resale. The pipeline, unlike many workably competitive firms, can more easily price discriminate among customers . . . (CX 1014Z-20).

225. FERC Order 436 increases the flexibility to offer selective discounts and reduces FERC procedural obstacles to discounting (Tr. 621-22). FERC has, in fact, determined that selective discounting under Order 436 does not violate the undue discrimination prohibitions of the Natural Gas Act (CX's 1014Z-18-Z-21, 1016Z-3-Z-4). The purpose of the selective discounting provisions of Order 436 is to permit pipelines to compete: [49]

. . . [C]ompetition in the natural gas industry today is proliferating. In these circumstances, it makes little sense to withhold from pipelines the basic weapon other businesses have to wage the competitive battle: the ability to lower prices to beat the competition (CX 1014Z-20).

226. It is unlikely that FERC will reject this policy, for it is consistent with FERC's encouragement of competition in the industry (F.'s 90-94).

227. Considering the above, Dr. Uri concluded that individual blocks within the paragraph 20 geographic market are relevant geographic markets (Tr. 1073).

5. Larger Areas As Relevant Geographic Markets

a. *The Paragraph 20 Area*

228. Complaint counsel argue that complaint paragraph 20 defines a relevant geographic market because other pipeline systems are not close enough to this area to prevent the exercise of market power by the five systems which transport gas produced in the area (HIOS, Stingray, Sea Robin, Texaco Eastern, Bluewater) (Tr. 1083, 1088). The following evidence is cited in support of this argument:

1. No blocks in the area have ever been connected to pipelines other than HIOS, Stingray, Sea Robin, Texas Eastern, or Bluewater or laterals connected to those systems (*see* CX's 123, 1118).

2. Documents assessing connection of blocks in the area do not discuss connections with systems outside of the area (F.'s 181-195).

3. A gap between the pipelines serving the paragraph 20 area and the closest ones outside the market which, they claim, is greater than the gaps among pipelines in the area (Tr. 1083-86, 1088, 1090-91, 1595; CX's 902, 1118A-B; RX 2004).

4. Some of the closer pipelines outside the area have diameters that are substantially smaller than pipelines in the area (TR. 1086-88; CX's 904, 1118A, 1681C). [50]

b. The Eastern And Western Regions

230. Two submarkets—the eastern and western regions—within the paragraph 20 area, are also proposed for the following reasons:

1. Gas produced in the eastern region is transported through Stingray, Sea Robin, Texas Eastern or Bluewater, and other pipeline systems are too far away to prevent these systems from exercising market power (Tr. 1094). The northern and eastern boundaries of the eastern region are the same as those of the paragraph 20 market (CX 1125). The southern boundary of the eastern region is further north than the southern boundary of the paragraph 20 market because, as one moves further south, the pipeline systems in the eastern region lose their comparative advantage over the systems in the western region (*see* Tr. 1095-96). In either case, there are no pipelines south of the southern boundary (*see* CX 903). To the west, the closest pipeline system is HIOS (Tr. 1093; *see* CX 904). HIOS is approximately 18 miles from the boundary of the eastern region at its closest point and further from points inside the eastern region and is not close enough to prevent the exercise of market power (*see* CX 904).

2. Gas produced in the western area is transported through one of four pipeline systems: HIOS, Stingray, Texas Eastern or the Bluewater project (Tr. 1095; CX 1109E-G). Other pipeline systems are too far away to prevent these pipeline systems from exercising market power (*see* Tr. 1091-94). The northern and western boundaries of the western region are the same as those of the paragraph 20 market (CX 1125). The southern boundary of the western region is further north than the southern boundary of the paragraph 20 market because, as one moves further south, the pipeline systems in the western region lose their comparative advantage over the systems in the eastern region (Tr. 1095-96). In either case, there are no pipelines south of the southern boundary (*see* CX 903). To the east, the closest pipeline

system is Sea Robin (*see* CX's 904, 1125). Sea Robin is approximately 16 miles from the boundary of the eastern region at its closest point and further from points inside the western region and it is not close enough to prevent the exercise of market power (Tr. 1094-95; CX's 904, 1125). [51]

3. Evidence that pipelines outside the paragraph 20 market have not transported gas from any blocks inside that area shows that such pipelines have not transported gas from any blocks in the eastern region and western region, and the fact that no blocks in the eastern region have been connected to HIOS or any blocks in the western region have been connected to Sea Robin (*see* CX's 325, 363, 904, 1008, 1113B-G).

c. The Gulf of Mexico

231. Although respondents agree that individual blocks in the OCS may be viewed as relevant geographic markets, they argue that complaint counsel have not established any areas broader than those blocks but smaller than the entire Gulf as relevant markets.

232. Supportive of respondents' claim is the fact that the industry does not view the alleged markets as having any significance for business purposes (Tr. 1471-73, 1915, 2378).

233. For example, gas sales representatives employed by natural gas producers often operate without regard to particular geographic sales areas (Tr. 1914-15). Pennzoil has one gas sales representative whose responsibility is the sale of gas throughout the entire Gulf (Tr. 700-01). Pennzoil has never divided the Gulf for purposes of gas sales into any areas smaller than all of offshore Texas or all of offshore Louisiana (Tr. 701). Shell's Natural Gas Department, is organized into three marketing groups according to geographic regions of the country (Tr. 823). These groups are the Eastern Marketing Group, the Western Marketing Group and the Central Marketing Group (Tr. 823). Each regional group sells gas to pipelines serving the corresponding geographic areas (Tr. 823). Each regional group is responsible for selling gas produced both offshore and onshore to the pipelines in its region (Tr. 823-24).

234. Gas buyers for natural gas pipeline companies frequently work on a project-by-project basis without regard to the geographic location of the gas (Tr. 1912-15). No gas supply representative at either Florida Gas or Mid-Louisiana Gas Company was responsible solely for purchases of offshore gas (Tr. 1914).

235. Other evidence which suggests, as Dr. Hall claims, that areas smaller than the entire Gulf of Mexico might not capture all the supply and demand forces affecting the transportation of natural gas (Tr. 2472-73) includes: [52]

1. Producers operate throughout the Gulf of Mexico and do not confine their exploration and production activities to any particular areas (F.'s 144-157).

2. Pipeline companies purchase gas throughout the Gulf (F.'s 129-142).

3. Gas purchase contracts entered into with producers by NGPL and UGPL that relate to gas fields in the alleged geographic markets have purchase price provisions pegged to prices paid for gas throughout the offshore and even nationwide (Tr. 1897-98; RX 2700A-Z-377).

4. Pipeline companies buy gas in the Gulf far from pipeline facilities that they own, and they rely on a web of transportation and exchange agreements between them to transport gas from the Gulf to delivery points and without regard to whether the gas is produced in or outside of the alleged geographic markets (F.'s 158-162).

236. Dr. Hall's theory would be acceptable if the issue in this case were the effect of the challenged acquisition on consumers of gas, but complaint counsel's injury scenario is much more modest. They claim only that the effect of the acquisition will increase transportation rates with respect to the connection of new blocks, and restrict access to pipelines, in the alleged relevant geographic markets, thus injuring producers by transferring wealth from them to the pipelines (CPF 9.62-9.63). Confining the issue to this narrow injury scenario, one does not need to consider all of the supply and demand forces in the transportation of natural gas from the wellhead to the end users. The real issue is: to which pipelines, as a practical matter, can producers of natural gas turn as alternatives for transportation of their gas?

6. Conclusion

237. After considering all of the evidence and the testimony of Drs. Uri and Hall, I agree with respondents that complaint counsel have not established that the paragraph 20 area, or its eastern and western divisions, are relevant geographic markets. [53]

238. All of the evidence leads to the conclusion, instead, that individual producing blocks are the areas where decisions affecting producers' shipments of natural gas will be made. Complaint counsel's pretrial brief, at 40, recognizes this fact:

[T]he potential for competition occurs in determining which pipeline will connect to a new block and transport the gas from the block under a relatively long term contract This case focuses on competition to obtain connections of new blocks.

Dr. Uri also testified to this effect:

We have talked previously about the nature of competition. The competition is not for existing blocks that are currently hooked up to a pipeline. Rather, competition occurs for new hookups (Tr. 1294-95).

239. It is true that in several blocks in the alleged geographic markets, and in the OCS in general, producers may turn to more than one pipeline for connections. It is equally true, however, that for many blocks in the alleged markets, only one pipeline affords a connection. In fact, CX 1105, on which complaint counsel rely, proves this point beyond dispute.

JUDGE PARKER: But out of these seven randomly selected blocks, five of them indicate that only HIOS was ever a potential competitor or a competitor, a possible outlet. So, in competing with nobody, it didn't merge with a competitor?

THE WITNESS (Dr. Uri): That's right

JUDGE PARKER: . . . So, if you multiply it to the universe, or something like 75 percent of the blocks, HIOS never competed with Stingray.

THE WITNESS: If you want to expand it out (Tr. 1257; *see also* Tr. 1431-35).

Dr. Uri had previously testified that CX 1105 was a representative sample of the unconnected blocks in the alleged markets (Tr. 1257).

[54]

240. Dr. Uri also identified some circumstances in which only one viable connection would exist:

Q: Do you agree with the statement in complaint counsel's pretrial brief, I believe found at page 48, to the effect that if a block has a relatively small quantity of reserves and is much closer to one pipeline than another, the closest pipeline may, in those circumstances, be the only viable option for connection?

A. I would agree with that, certainly (Tr. 1431).

241. Blocks that have no viable connection alternatives are obviously not areas of effective competition under complaint counsel's theory. The MidCon/United acquisition could have no impact in these blocks, as Dr. Uri conceded (Tr. 1256-57).

242. There are many instances in which blocks have no viable connection alternatives. For example, from 1978 through 1986, NGPL

prepared 75 gas supply evaluations that evaluated potential gas supplies in the offshore Gulf of Mexico (Tr. 2393, 2395, 2435; CX 52A-B; RX 2710). Six of the seventy-five offshore gas supply evaluations evaluated the same gas supply as another gas supply evaluation pertaining to the same field (Tr. 2389-93). Of the 69 substantially different gas supply evaluations performed by Natural for offshore gas supply sources from 1978 through 1986, 13 of the gas supplies evaluated were within the alleged geographic markets (Tr. 2273, 2436-37; CX 52A-B; RX 2710). Of these 69 substantially different gas supply evaluations, only eight considered more than one possible pipeline connection (Tr. 2435-37; CX 52A-B; RX 2710). Three of the eight evaluations which considered more than one pipeline connection involved different means of connection to the same major transmission system (Tr. 2273-74; CX's 1350A-C, 1378A-C, 1411; RX 2710).

243. None of NGPL's gas supply evaluations considered HIOS and Stingray and Sea Robin, or HIOS and Sea Robin as connection alternatives for any offshore block either inside or outside the alleged geographic markets (Tr. 2275, 2445-46; CX 52A-B; RX 2710).

244. Complaint counsel criticize the methodology of these evaluations and the inferences which can be drawn from them, as do respondents with respect to complaint counsel's analysis which reveals that in some cases, blocks in the alleged relevant geographic markets were or could be connected to different pipeline systems (F.'s 181-195). [55]

245. These analyses may have some problems but there can be no doubt that they confirm that which is evident: If two or more pipelines are equally near a producing or a potentially producing block, or if some other factor such as different transportation rates overcomes a difference in distance, they can compete for hookup to the block. The opposite is equally clear: In many cases, because only one pipeline is near enough to a block, only that pipeline is a viable connection to a particular block.

246. Indeed, as respondents emphasize, of the well over 100 blocks connected to a pipeline within the paragraph 20 area before the acquisition, complaint counsel have identified only 11 blocks for which HIOS, Stingray and Sea Robin, in some combination, were allegedly considered by some party as potential transportation substitutes. *See* CPF's 6.27-6.30, 6.34, 6.36-6.39, 6.41-6.42 (F.'s 181-184, 187, 189-192, 194-195). Thus, for 90 percent or more of the blocks connected

to a pipeline within the paragraph 20 area before the acquisition, complaint counsel do not even contend that HIOS, Stingray or Sea Robin were substitutes for each other. Of the 96 blocks within the alleged market that were actually connected to HIOS, Stingray or Sea Robin before the acquisition, complaint counsel only contend that three involved competition between or among these pipelines. *See* CPF's 6.28, 6.38, 6.42 (F.'s 182, 191, 195). The examples cited by complaint counsel from outside of the paragraph 20 area do not, of course, establish that HIOS, Stingray and Sea Robin actually competed within the paragraph 20 area (F.'s 197-222).

247. Despite this evidence, Dr. Uri's theory assumes that, within his markets, all blocks can be served by all of the pipelines which are included in his concentration charts.

248. This is clearly incorrect and leads to inconsistent conclusions as to the nature of competition in the three alleged relevant geographic markets. In the paragraph 20 area, the concentration charts (CPF 7.31, Tables I and II) conclude that HIOS, Stingray and Sea Robin are competitors. Yet, in the eastern region (which is a subsection of the paragraph 20 area) (CPF 7.32, Table III), HIOS is not treated as a competitor of Stingray and Sea Robin, while in the western region (which is also a subsection of the paragraph 20 area) (CPF 7.33, Tables IV, V, VI), Sea Robin is not treated as a competitor of HIOS and Stingray.

249. Complaint counsel do not explain why HIOS, Stingray and Sea Robin are treated as competitors in the broad paragraph 20 area, while HIOS and Sea Robin are excluded as competitors in, respectively, the eastern and western regions of the broad area.

250. This inconsistency not only destroys the validity of Dr. Uri's conclusions with respect to the paragraph 20 area, but also those with respect to the eastern and western areas, for it [56] is unquestioned that within these areas there are many blocks where all but one pipeline is too far away to be a viable connection possibility.⁴

251. To explain away these problems, Dr. Uri developed a "capacity

⁴ The very reason why HIOS and Sea Robin are excluded, respectively, from the eastern and western regions of the paragraph 20 area:

See CPF 6.99-6.100: "Gas produced in the eastern region geographic market is transported through one of four pipeline systems: Stingray, Sea Robin, Texas Eastern or the Bluewater project. Other pipeline systems are too far away to prevent these systems from exercising market power"

"Gas produced in the western region geographic market is transported through one of four pipeline systems: HIOS, Stingray, Texas Eastern or the Bluewater project. Other pipeline systems are too far away to prevent these pipeline systems from exercising market power"

interaction" theory in support of his claim that the relevant geographic market could be broader than individual blocks. I reject this theory.

Q: So your testimony, then, you begin with an individual field as the area within which competition occurs, and then in some fashion build out from that by use of this capacity interaction notion, perhaps as far as the Gulf?

A: Well, the capacity interaction is not the exclusive consideration. It is one of the considerations.

Q: What other considerations would indicate that one ought to examine something larger than an individual field or block?

A: Well, if we're going to look at collusive behavior, it might be convenient to have a collusive arrangement that covers more than an individual field. So you're asking [57] what other factors might be relevant. Well, the convenience consideration is another factor.

Q: Are there any other factors?

A: None that come to mind right now (Tr. 1464-65).

252. Dr. Uri's theory, which is not supported by any record evidence, is that one pipeline's success or failure in competing against a second pipeline to connect a particular block could affect the first pipeline's competition with a third pipeline to connect some other block (Tr. 1465-66). Taken to its logical conclusion, this theory could support the claim that the entire Gulf of Mexico is the relevant geographic market (Tr. 1464).

253. Dr. Uri could give only one example of "capacity interaction" (Tr. 1595-97) and this involved an onshore interconnection (Tr. 1595-97; CX 808B), well outside the alleged relevant geographic markets.

254. Dr. Uri's theory that it would be more "convenient" to have a conspiracy among pipelines in the alleged markets as opposed to the entire Gulf does not prove that his markets exist.

255. Finally, Dr. Uri includes in the paragraph 20 market, a part of the Garden Banks area in the deep water of the Gulf of Mexico where no pipelines exist (Tr. 1716; RX 2004), and where there is no natural gas production (Tr. 692). Dr. Uri testified:

Q: Wouldn't it therefore be really just a matter of speculation as to when pipelines might be built in that area?

A: Well, it's a matter of speculation to the extent we don't really know what's going to happen in the natural gas market in the future. I've spent a lot of time in the forecasting business when I was at the Department of Energy and, based on my experience there, there's an awful lot of uncertainty.

And so, given the attendant uncertainty with regard to the future of the natural gas market, there will be considerable uncertainty attendant with the development in that area. [58]

Q: Given that uncertainty about the natural gas market, then it's possible that no pipelines will be built in the Garden Banks for five or ten years? Is that possible?

A: It's possible that a sustained period might occur before pipelines are built into that area (Tr. 1469-70).

256. Dr. Uri admitted that in these circumstances the Garden Banks area was not an area in which competition presently exists:

Q: Is it fair to characterize the Garden Banks, then, as a potential future market, but not a present market, for the sort of competition you've analyzed for purposes of this case?

A: With regard to the kind of competition I considered, that's a fair characterization (Tr. 1468).

257. After analyzing all of the evidence relevant to the issue,⁵ I conclude that complaint counsel have not established that the paragraph 20 area or the eastern and western regions of that area are relevant geographic markets. I also reject respondents' claim that the Gulf of Mexico is a relevant geographic market.

258. Complaint counsel, respondents and I agree that individual blocks are relevant geographic markets, but complaint counsel's argument that the acquisition will substantially lessen competition (CPF's 7.01-7.68) does not, except for unsupported claims,⁶ rely on injury to competition as to individual blocks; [59] instead, complaint counsel's concentration charts in their proposed findings relating to the open access (Tables I-VI) and closed access scenarios (Tables VII-XII) rely on the theory that the paragraph 20 area and its eastern and western regions are relevant geographic markets. Since I reject these proposed markets, I necessarily must reject, as irrelevant, all proposed findings relating to concentration and the competitive effects of the acquisition under both scenarios (CPF 7.01-9.68).

III. CONCLUSIONS OF LAW

A. *The Relevant Product Market*

Under Section 7 of the Clayton Act, a product market is defined "by the reasonable interchangeability of use or the cross-elasticity of demand between the product in question and products which are reasonable substitutes for it." *United States v. Continental Can Co.*,

⁵ Including statements of some industry members that pipelines compete which I do not find significant since they do not relate to the alleged relevant geographic markets proposed by complaint counsel. Furthermore, Dr. Uri testified that he was unaware of any instance where HIOS, Stingray or Sea Robin set transportation rates in reaction to each other's rates (Tr. 1531). Ordinarily, one would expect this to occur if these pipelines were competitors (Tr. 1532).

⁶ CPF 7.38 argues that "the acquisition is likely to lead to a merger to monopoly for some blocks" but does not identify those blocks.

378 U.S. 441, 449 (1964). On the supply side one considers whether producers of other products or services can readily switch facilities to the product or service in question. If so, then those producers must be included in the market. See *Brown Shoe Co. v. United States*, 370 U.S. 294 (1962); *Coca-Cola Bottling Co. of New York, Inc.*, 93 FTC 110, 204-05 (1979).

The evidence reveals that, despite some differences in quality or pressure characteristics, pipelines compete with one another in transporting gas from the OCS to the burner tip (F.'s 52-55). Furthermore, since there are no substitutes for pipelines, the only feasible method of transporting gas from the OCS to the end-users is the pipeline. Finally, oil pipelines are not a practical alternative for transporting gas out of the OCS to end-users (F. 163).

The only disputed issue on this point is the extent of the product market: whether, as complaint counsel claim, it is for the transportation of gas from producing fields or, as claimed by respondents, it extends from the OCS to the city-gate or burner tip.

Respondents are correct that the demand for the product—the transportation of natural gas—is derived from the demand for gas at the city-gate or burner tip. No customer of a pipeline or OCS producer is concerned with transportation only from the OCS to onshore, for consumers exist far beyond that point, and it is their demand which the pipelines exist to satisfy (F. 165).

Thus, the overall product market is the transportation of gas from the wellhead to the city-gate or burner tip, but a submarket also exists, *i.e.*, the transportation of gas from [60] producing blocks in the OCS (F. 166). See Hansen, *U.S. Oil Pipeline Markets*, 39-40 (1983). Referring to the oil pipelines, Hansen states:

Another difficulty lies in the definition of the relevant product. Very little consideration has been given to the definition of the product offered by oil pipeline companies, generally it reflects transportation services of crude oil 'between given producing areas and given refining areas.' It is occasionally noted, for example, that there are at least eighteen possible products pipeline routes between St. James, Louisiana, and Toledo, Ohio, implying that this might be a relevant market (transportation services over this distance being the relevant product). Yet, upon reflection, it seems unlikely that consumers in Toledo would care much about whether they received petroleum products from refineries in Louisiana or in Michigan. With few exceptions the origin of petroleum products is irrelevant to the consumer. We may conclude, therefore, that products shipped by pipeline from the gulf to Toledo compete with products shipped by pipeline from Chicago as well as with products from local

Toledo refineries. Realistically, there are at least two different products in two different markets being offered by a pipeline connecting the gulf coast with Toledo.

First, the pipeline offers a service that might be called 'a means of getting the petroleum out of the gulf coast area.' In this market the pipeline competes with other pipelines that carry the same products from the gulf coast whether they are going to Toledo or to some other market. Second, the pipeline offers a product that might be called 'a means of getting petroleum to Toledo.' In this market the pipeline competes with all other carriers that ship the same product to Toledo whether the shipments originate in the gulf or some other area (including products refined in Toledo).

Thus, in both crude oil and petroleum products pipelines there are four different types of markets: the markets where crude pipelines gather oil from producers, the markets where crude pipelines distribute oil [61] to refineries, the markets where products pipelines gather petroleum products from refiners, and the markets where products pipelines deliver products to distributors.

In any event, the dispute between the parties is of little practical significance, for the issue of controlling importance is the relevant geographic market, for if complaint counsel's claimed geographic markets do not exist, then whatever the product market may be, they cannot argue that the acquisition will lessen competition.

B. The Relevant Geographic Market

The purpose of defining a geographic market in a Section 7 proceeding is:

... [T]o establish a geographic boundary that roughly separates firms that are important factors in the competitive analysis of a merger from those that are not.

DOJ Merger Guidelines, § 2.31, 2 CCH Trade Reg. Rep. ¶ 4,492 at 6,879-10 to 11.

Respondents correctly point out that before one can define the relevant geographic market, one must determine what competitive activity might be suppressed by the challenged acquisition (Respondents' Post Trial Brief, at 32). Respondents argue that the competitive activity in this case which might be suppressed is the transportation of gas from points of production to points of consumption. If this is true, then Dr. Hall's theory that the relevant geographic market extends at least throughout the Gulf is correct, for competitive activity of this kind exists throughout the Gulf (F. 128).

However, complaint counsel take a much narrower view of the nature of competition in this case, and since they have the burden of establishing the relevant market, their claim as to the validity of that

market (or markets) must be tested in light of their definition of competition—the substitutability of pipelines to connect new reserves.

The test which should be applied to determine the commercial reality of complaint counsel's geographic market is simple: "Where, as a practical matter, can the purchaser turn for alternatives." *FTC v. Food Town Stores, Inc.*, 539 F.2d 1339, 1344 (4th Cir. 1976). [62]

In this case, the purchasers are future producers of natural gas in individual blocks within the alleged relevant geographic markets (F. 238). According to complaint counsel, the five pipelines in the paragraph 20 area or, alternatively, the four pipelines in the eastern and western regions are the suppliers of services to which the producers may turn for transportation from individual blocks.

Although some reference to individual blocks as relevant geographic markets is made in their proposed findings, complaint counsel's theory of competitive injury relies on their charts depicting concentration increases in the paragraph 20 area and its eastern and western regions (F. 258), and it is the validity of their choice of these areas as relevant geographic markets which must be tested.

The basic assumption of the concentration charts is that extrapolating from the few instances where there was competition for hookups, competition for new hookups will occur among all of the pipelines throughout the selected areas and that undeveloped blocks in the selected areas are potentially commercially productive. Complaint counsel have not satisfied me that this is true; in fact, their claim is refuted by the construction history of HIOS, Stingray, and Sea Robin. Given the enormous construction costs of these pipelines, it would have been folly to place them so that they would serve the same blocks, and FERC avoided inefficient duplication of pipeline services when it authorized their construction (F.'s 73-74, 118). Thus, there is little doubt that if these pipelines are extended into the Garden Banks area (F.'s 255-256), FERC will not authorize them to serve the same blocks and they will not be competitors.

Despite FERC's philosophy, in some cases within the alleged geographic markets, producers have been able to choose among different pipelines for connection (F.'s 181-195) but there were many instances where only one pipeline was a feasible connection possibility (F.'s 242-243, 246) and Dr. Uri conceded that in these cases these blocks were not areas of effective competition (F.'s 239-241).

In fact, analysis reveals that in the vast majority of cases involving connections made in the paragraph 20 area, HIOS, Stingray and Sea Robin were not considered as alternatives (F. 246).

Furthermore, complaint counsel's claim that five pipelines, including HIOS, Stingray and Sea Robin, compete within the paragraph 20 area is belied by their contradictory claims that in the eastern region of this area, HIOS is not a competitor, while in the western region, Sea Robin is not a competitor (F. 248).

The reason given by complaint counsel for their exclusion of HIOS and Sea Robin is that they are too far away to prevent pipelines which are competitors from exercising market power [63] (F. 250), but this is precisely the reason why I find that the markets selected by complaint counsel do not reflect commercial reality, and that, given complaint counsel's theory of competition, only the individual OCS blocks are relevant geographic markets.

Complaint counsel also point to the fact that blocks in the paragraph 20 area are not connected to pipelines outside the area (F. 228), but this is true with respect to pipelines in the area, as complaint counsel concede when they argue that HIOS and Sea Robin do not compete in the eastern and western regions.

Dr. Uri's "capacity interaction" theory was apparently designed to avoid problems presented by the fact that many OCS blocks have only one connection possibility, but if I were to accept it, there is no reason why it could not justify the inclusion of all blocks in the OCS as the relevant geographic market (F.'s 251-252). In fact, this theory seems to be similar to respondents' which posits a Gulf-wide relevant geographic market because of the web of commercial relationships between producers and pipelines in that area (F.'s 128-161).

Other indications that the geographic markets proposed by complaint counsel are artificial are the lack of industry recognition of them as relevant markets (F.'s 232-234), see *Brown Shoe Co. v. United States*, 370 U.S. 294, 326 (1962), and the absence of any evidence of significant price competition between Stingray, HIOS and Sea Robin within the alleged markets (F. 257, n. 5). Generalized statements by FERC (F.'s 90-94) and industry members about pipeline competition do not establish the validity of complaint counsel's proposed markets, for those statements refer to overall competition for the consumer's business from the producing fields to the burner tip.

While the DOJ Merger Guidelines require only that the proponent of a relevant geographic market establish that it "roughly" separates competing firms from non-competing ones, the market must be measurable in other than hypothetical terms. *Consul, Ltd. v. Transco*

Energy Co., 1986-2 CCH Trade Cas. ¶ 67,347 (4th Cir. 1985), and it must "correspond to the commercial realities of the industry and be economically significant." *Brown Shoe Co. v. United States*, 370 U.S. 294, 336-37 (1962). Complaint counsel's proof does not satisfy these standards.

Since complaint counsel have failed to meet the burden of proving that the relevant geographic markets which support their claim of probable injury to producers of natural gas exist, I reject their proposed findings relating to the effects of the acquisition, and find that they have failed to establish that the acquisition may substantially lessen competition for the transportation of natural gas out of the producing basins and fields in certain areas of the OCS off the coasts of Texas and Louisiana. Therefore, [64]

IV. ORDER

It is ordered, That the complaint be, and it hereby is, dismissed.

OPINION OF THE COMMISSION

BY CALVANI, *Commissioner*:

I. INTRODUCTION

A. *Procedural History*

MidCon Corp. ("MidCon") acquired United Energy Resources, Inc. ("United") through a cash tender offer in 1985. The Commission's complaint, issued September 19, 1985, charges that this acquisition may substantially reduce competition in the transportation of natural gas out of producing fields and basins in certain areas of the Gulf of Mexico Outer Continental Shelf ("OCS"),¹ in violation of Section 7 of the Clayton Act and Section 5 of the Federal Trade Commission Act. The administrative trial began November 4, 1986 and concluded February 26, 1987.² The record was closed on November 27, 1987, and after briefing, Administrative Law Judge Lewis Parker issued an initial decision February 2, 1988, dismissing the complaint. Complaint counsel has appealed. For the reasons described below, the complaint is dismissed.

¹ The second count of the complaint, charging that the acquisition also produced anticompetitive effects in onshore natural gas transportation and sale, was settled by a consent order at the same time the complaint was issued. *Midcon Corp.*, 107 FTC 48 (1986).

² After MidCon sold United LaSalle Energy Corporation on June 30, 1987, MidCon moved to dismiss the complaint. The Commission denied that motion on November 16, 1987.

B. Summary of Facts

MidCon and United transport and sell natural gas. Each, through subsidiaries, has interests in pipelines that transport gas from producing platforms in the OCS to the shore. The OCS pipelines at issue here are High Island Offshore System ("HIOS"), U-T Offshore System ("UTOS"), Stingray Pipeline Co., and Sea Robin Pipeline Co. These pipelines are highlighted on the map attached to this [2] opinion.³ The interests in these lines of MidCon, United, and their other owners are summarized in the following table, which shows the owners' percent shares and identifies the pipeline's operator.

Owner	Share of Ownership or Control			
	HIOS	UTOS	Stingray	Sea Robin
MidCon	20	33⅓	50	
United	20	33⅓		50*
Transco	20	33⅓		
Texas Gas	20			
ANR	20*			
Trunkline			50*	
Southern Natural				50

*Operator of pipeline

Thus, the acquisition gave MidCon a 40 percent interest in HIOS, 50 percent in Stingray, 50 percent in Sea Robin, and 66⅔ percent in UTOS, which is functionally an extension of HIOS.

These OCS pipelines transport gas from producing fields in the Gulf to onshore points of connection with other pipelines. The OCS pipelines are "trunklines", connected to the gas production platforms by smaller diameter pipes called "laterals". The producing platforms are located in "blocks" of the OCS, areas usually three miles square defined by the Department of the Interior for assigning mineral leases. Gas producers bid for these leases, which convey the right to explore for gas and, if exploration is successful, to produce the gas and sell it. During the five- to ten-year period during which the winning bidder has the right to explore, before actual production begins, the lease is said to be in its "primary term". A lease will be extended indefinitely once production starts.

HIOS, Stingray, UTOS, and Sea Robin are joint ventures (although some OCS pipelines are not). For each, the management, operation,

³ Derived from CAB, Appendix A, Map 3.

and owners' rights are controlled by the terms of a joint venture agreement. On some joint venture pipelines, although not any of these four, each owner has the right to use its share of the capacity independently, so that, to the extent of that share, each owner acts as an independent competitor. On others, the pipeline is run as a single venture, with the owners acting together to manage it. For each of the joint venture pipelines at issue here, there is a management committee whose members are nominated by the owners in proportion to ownership shares. Although substantial management authority is delegated to the pipeline's operator, a majority vote of the managing committee is required for decisions concerning expansion and rate changes. Thus, for HIOS, with no owner controlling a share over 40 percent, no single owner can control or veto decisions. For Stingray and Sea Robin, each of the 50-percent owners has an effective veto over those decisions that require majority votes.

The theory of complaint counsel's case is that this acquisition, by adding veto power over decisions by Sea Robin to MidCon's existing veto power over decisions by Stingray and by increasing MidCon's influence in HIOS (and UTOS), may substantially lessen competition among these pipelines [3] and others for connecting new gas supplies. Complaint counsel's analysis presumes that the acquisition amounted to a merger of these lines.⁴

The principal issue on appeal is the proof of the relevant geographic market. The complaint alleges that four areas of the Gulf of Mexico, defined by terms used in describing lease blocks, and "any relevant submarket" of any of these four areas are relevant "sections of the country". Complaint counsel elected to focus the case on the area described in Paragraph 20 of the complaint (slightly modified) and smaller areas within it called the "western" and "eastern" regions.⁵ The Paragraph 20 region, which covers several thousand square miles of the Gulf, begins about 60 miles offshore and extends out over the continental shelf and beyond, south of the Louisiana-Texas state line. The western region and eastern region are, roughly, the Paragraph 20 region's northwestern and northeastern quadrants. These regions are highlighted on the map attached to this opinion. Stingray extends into the center of the Paragraph 20 region, HIOS enters it from the west, and Sea Robin enters it from the east. UTOS does not itself reach this

⁴ See CAB p. 19, CRB pp. 35-44.

⁵ The areas defined in Paragraphs 17-19 of the complaint were abandoned and dismissed with prejudice. See record, p. 1385. The Paragraph 20 market is essentially the same as that described in Paragraph 17 plus two areas to the south of it.

region, but it connects HIOS to the shore. In addition to these large regions, complaint counsel also contends (and MidCon agrees, in principle) that individual blocks could be relevant geographic markets.

Judge Parker found that complaint counsel had failed to prove that the Paragraph 20 regions were relevant geographic markets, and that, although individual blocks could in principle be relevant markets, complaint counsel had not carried its burden of proving those markets.⁶ We agree with [4] Judge Parker that complaint counsel failed to show that there was a substantial likelihood of anticompetitive effects in a section of the country.

II. PRODUCT MARKET

A. *Natural Gas Transportation*

Traditionally, interstate pipelines bought gas from producers at or near the wellhead, transported it across the country, and then resold it to local distribution companies ("LDCs") or large industrial consumers. Natural gas transportation was thus only one of a pipeline company's internal operations. Since the onset of deregulation, it is increasingly common for LDCs, industrial consumers, and companies that simply market gas to purchase gas directly from producers and then arrange for pipelines to transport it for them. Thus the transportation function is becoming identifiably separate from the business of buying and selling gas. Judge Parker found, and we agree, that transportation of natural gas from wellhead to the burner tip is a market.⁷

A relevant product market, within the broadly conceived market for natural gas transportation, is transportation from producing areas. The complaint alleges that a relevant line of commerce is the

⁶ On appeal, complaint counsel alleges that Judge Parker made the following errors:

1. Finding that complaint counsel had failed to show how concentration would increase and competition decline in individual block markets.
2. Finding that a region (such as the Paragraph 20 region and the western and eastern regions within it) could not be a geographic market unless each competitor in it could compete with each other competitor in every part of the region.
3. Misunderstanding the extent of interpipeline competition and ignoring changing conditions favoring increased competition in the future.
4. Failing to make findings on concentration and other factors.

Rather than address the issues in the particular order of complaint counsel's stated issues on appeal, we set out here our own views on the geographic market questions, the nature of industry competition and the need for specific findings about concentration and other factors affecting competition.

⁷ ID p. 59.

transportation of natural gas from producing fields and basins.⁸ Judge Parker found that this term described a separate stage or transaction at which market power might be exercised.⁹ That finding is supported in the record. Even MidCon's economic expert, although arguing in this case for a broad market, previously testified in another case that this separate stage of transportation was itself a relevant market.¹⁰ For the purpose of this appeal, neither complaint counsel nor respondents dispute Judge Parker's finding that transportation from producing areas is a relevant product market.

B. Regulation and Competition

Natural gas transportation has historically been highly regulated, first by the Federal Power Commission and now by its successor, the Federal Energy Regulatory Commission ("FERC"). FERC approval is required to construct new interstate pipeline facilities and again to abandon them. FERC regulates the prices pipelines charge for gas sold to LDCs (but not for direct sales to industrial users or sales by pipeline marketing affiliates), and regulates transportation rates pipelines may charge other shippers. For many years, FERC regulated wellhead natural gas prices.

But the industry's record of close regulation does not portend a future without meaningful competition. Over the last ten years, the industry has been evolving toward greater reliance on the forces of competition, led by initiatives from Congress and FERC. The Natural Gas Policy Act of [5] 1978¹¹ started decontrolling prices. FERC in 1985 adopted Order 436,¹² permitting pipelines to become "open access" transporters, free to engage in many transactions without specific prior FERC approval. Order 436 permits rate structures with maximum and minimum rate levels within which the pipeline may set prices to individual customers. FERC has announced that Order 436 is intended to encourage price discounts in response to competition.¹³ After the court's ruling on appeal of Order 436,¹⁴ FERC modified

⁸ Complaint, 16.

⁹ ID p. 38, 166, and p. 59-61.

¹⁰ ID 166, citing Tr. 2613-17.

¹¹ 15 U.S.C. 3301-3432.

¹² FERC Order No. 436, Docket No. RM85-1-000, 50 Fed. Reg. 42,408; see CX 1013, CX 1014, CX 1016, CX 1017.

¹³ Under Order 436, a pipeline's maximum rate is based on total costs, and the minimum rate is based on variable costs. One witness gave an example of the range of an Order 436 pipeline transportation rate, from \$.15 to \$1.00 Tr. 620-21.

¹⁴ *Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1987).

some of the Order's details, but reaffirmed its basic purpose.¹⁵ The industry is recognizing and adapting to these new competitive realities. Sea Robin has already become an open access pipeline under Order 436, as have two of the respondents' major pipeline subsidiaries, Natural Gas Pipeline Company of America and United Gas Pipe Line Company. FERC has now decided that all OCS pipelines should be open access pipelines subject to Orders 436 and 500, and has ordered HIOS, Stingray and UTOS (as well as others) to take necessary steps to do so.¹⁶

In examining this market's likely future, we assume that the changes in regulatory attitude at FERC, as reflected in Order 436, will persist. The initial decision recognizes,¹⁷ and we agree, that FERC is unlikely to reverse its pro-competitive direction. Basing analysis on the new environment, rather than the environment in which many of the events described on the record took place, would be consistent with the Commission's general approach to post-acquisition evidence. For one thing, the changes in regulatory climate are not post-acquisition events. The move toward greater reliance on market forces in the transportation of natural gas began many years before this acquisition, and one of FERC's most significant changes in transportation regulation, Order 436, coincided with it. The Order 436 rulemaking process began in December, 1984, the detailed proposal was put out for comment in May, 1985, and the order, issued on October 9, 1985, became effective in October and November, 1985.¹⁸ Meanwhile, the premerger filing for this acquisition was made August 13, 1985, and MidCon acquired a majority of United's shares by the end of September, but MidCon did not complete the acquisition until December, after Order 436 had become effective.¹⁹ In addition, even if the regulatory changes had post-dated the acquisition, post-acquisition changes [6] in competitive conditions brought about by changes in law can be considered in analyzing an acquisition's likely effects. *American Medical International*, 104 FTC 1, 212 (1984). The government's announcement of new laws and regulations, and the market's response, are not the kinds of exculpatory self-help by respondents under investigation of which the Commission and the courts have long been skeptical. See *United States v. General*

¹⁵ FERC Order No. 500, 52 Fed. Reg. 30,334.

¹⁶ FERC Order No. 509, 53 Fed. Reg. 50,925 (December 19, 1988). The Commission grants MidCon's January 6, 1989 motion, which complaint counsel does not oppose, to take official notice of this FERC decision.

¹⁷ ID 226; see also ID 90-94.

¹⁸ CX 1013, CX 1014.

¹⁹ RPF 41.

Dynamics Corp., 415 U.S. 486, 504-05 (1974); *Hospital Corp. of America*, 106 FTC 361, 473 n. 10 (1985), *aff'd*, 807 F.2d 1381 (7th Cir. 1986), *cert. denied*,—U.S.—(1987).

C. Focus of Competition: Transporting New Supplies

In the market for transportation from producing areas, the competition is to connect new sources of production rather than to divert existing production away from current transportation outlets. Transportation contracts in the OCS are usually long-term and the physical facilities that transport natural gas are expensive and immobile. FERC policy would discourage building a new pipeline to transport gas already being transported by another pipeline, at least if that gas had been part of the basis for granting the old pipeline's original certificate.²⁰ There is no evidence of a producer cutting off a block's connection to one pipeline in order to connect it to another pipeline. This is not to say that it could never happen. Supply contracts for these pipelines, entered during the era of tight regulation, are still in their initial term; what will happen when they expire in a new, more competitive environment is unknown. But even if past trends continue, so that a producer will not change a block's connection from one pipeline to another, there is substantial evidence that producers already can and do choose between different pipelines in deciding how to connect a block that is beginning production.

Respondents are wrong in asserting that there is little inter-pipeline competition for new supplies. Instead, there is ample evidence that developers of new sources can and do choose among alternative pipelines.²¹ That a producer ultimately chose one of the alternatives as best does not necessarily mean that the others were "noncompetitive". In addition to the basic transportation rate, criteria for deciding which pipeline to choose include factors such as the cost of building a lateral (which is usually proportional to distance), and contract terms such as contract demand requirements, receipt points, and others. A customer may prefer to connect to a pipeline that can deliver most directly to the customer's ultimate consuming location. Choices are different at different locations, and for some locations realistic possibilities may be limited, perhaps to only one. But there are enough opportunities for competition to reject the argument that competition

²⁰ See *Id* 72-76. The FERC decisions described in this record were made ten or fifteen years ago, when these pipelines were originally approved. The record is silent about how FERC would now treat such an application, especially if the construction costs of the existing pipeline had already been recovered.

²¹ *Id* 180-222.

is an aberration, a geographic accident that misrepresents the true nature of the marketplace. Moreover, there is likely to be additional new production in the future for which there will be competition for transportation service. Exploration and development of potential new gas supplies in the Gulf of Mexico continues. [7] The pipelines expect that new supplies will be developed in the future²² and that they will be competitors for connecting new supplies.

III. GEOGRAPHIC MARKET

Geographic market definition identifies the suppliers to consider in predicting competitive effects. The goal is to "roughly separate [] the firms that are important factors in the competitive analysis" from those that are not.²³ But where it is difficult to distinguish or identify who is in and who is out of the market, it will be difficult to predict competitive effects confidently.²⁴

A. Range of Service

A threshold issue in defining a geographic market is how close a trunkline must be to a production platform to provide it with transportation service. The question in geographic market analysis is, "Where, as a practical matter, can the purchaser turn for alternatives?" *FTC v. Food Town Stores*, 539 F.2d 1339, 1344 (4th Cir. 1976). Here that question implies another: How far is practical? How long a lateral can be depends on how the cost of building and operating it compares to the expected revenues and profits from selling the gas it will carry. In general, the larger the reserves under a block, the longer and more expensive the lateral to it can be. There is evidence roughly quantifying the relationship between reserve size and lateral length. The estimates vary, from 4 Bcf (billion cubic feet)

²² See ID 26-33.

²³ Department of Justice, Merger Guidelines, 2.31 (June 14, 1984) ("DOJ Guidelines"). The DOJ Guidelines characterize an area as a market if firms in the area could impose a "small but significant and nontransitory" price increase without losing significant sales to firms in other areas.

²⁴ The discussion assumes that "blocks" in the OCS are "customers", an assumption that is not strictly correct. Producing wells are located at places conveniently designated by their block "addresses". But the customer looking for transportation service may not be the lessee producer. MidCon argues that a customer—a production company, an interstate pipeline, an LDC, or an end user—may have interests (of different kinds) in production from several different locations, so that focusing on individual blocks misses competitively important relationships. Complaint Counsel simplifies its case by treating each OCS lease block as a distinct customer, thus assuming that, no matter what the other commercial interests of the firm with rights to that block's gas, the demand for transportation at that block is independent of transactions at or affecting fields under other blocks. This simplification is consistent with complaint counsel's theory of anticompetitive effect, which is concerned about anticompetitive reductions in wellhead prices (and thus reductions in the incentive to discover more gas). See ID 236.

of gas reserves per mile of lateral up to 10 Bcf per mile, with most around the middle of this range, at 7-8 Bcf per mile.²⁵ At that 7-8 Bcf per mile rate, a producing field containing about 75 Bcf of gas reserves (typical of those already discovered and connected in [8] the OCS) could justify building a lateral about ten miles long. Using the higher and lower rates would imply feasible laterals for such a field from 7 to nearly 20 miles long. A larger field could justify a longer lateral. These rough approximations are consistent with observed practice; there are a number of laterals from 10 to 15 miles long, and some even longer.²⁶ The assumption used by complaint counsel's expert, that pipelines within a range of 10 to 15 miles from a location could be competitive (all other things being equal), is supported in this record.

MidCon's argument that the feasible lateral length is so short that for any producing well or block there is usually only a single feasible trunkline connection—that, therefore, competition is essentially impossible—is rejected. MidCon's claim is a generalization from the lengths of existing laterals. These include the laterals to the blocks connected when the trunklines were first built, which may be “unusually” short because the trunklines were located in part to serve these blocks and presumably to minimize the costs of connecting them. Thus the lengths of all existing laterals may imply little about the feasible length of laterals connecting new producing wells or blocks to an existing pipeline. The most useful estimate of relevant lateral length might have been the “average” length of laterals constructed to connect new supplies to existing lines. A systematic estimate of this average was apparently not done, but the record cites many examples of laterals to newly connected blocks that are 10 to over 20 miles long.²⁷ The existence of these longer laterals supports the conclusion that a large enough new supply of gas might have many possible pipeline options—depending on just where it is.

B. *The Entire Gulf As a Market*

If we assume that geographic price discrimination is not possible, the entire Gulf of Mexico appears to be the smallest relevant geographic market. This conclusion follows from an analysis of supply

²⁵ See CPF 6.09. Judge Parker evidently rejected this proposed finding, without explanation. See ID p. 3. But it is supported by the exhibits in the record, respondents did not object to it, and Judge Parker's findings that there are laterals ten and even twenty miles long, ID 171, are consistent with it.

²⁶ ID 171-72.

²⁷ ID 171 identifies laterals to new blocks ranging from 10 to 27 miles long.

elasticity similar to that set out in the DOJ Guidelines. Begin where the respondents' pipelines can supply transportation service. Those locations would include each point along the pipelines' length at which gas supplies could be connected, plus the area on either side of the pipeline swept out by the length of a feasible lateral. Because of the pipelines' extension across the Gulf, and because of their owners' interests in other lines, the initial region identified is likely to extend through a large part of the Gulf.²⁸ Next hypothesize a monopolist trying to impose a non-transitory, [9] uniform price increase along the length of each of its pipelines.²⁹ Can the customer turn to suppliers elsewhere in response to that increase? The pipelines and the producing platforms are stationary; they cannot literally move themselves. But, can existing pipelines build laterals, or can new pipelines be built, into the region from elsewhere?³⁰ If so, expand the region to include the additional locations and repeat the process, ending only when no feasible outside source is found.

A customer seeking to connect a new well located equidistant from the hypothetical monopolist's location(s) and another pipeline at a different location could presumably choose either.³¹ An equidistant, or crossing, pipeline, by not going along with the monopolist's price increase, could prevent the monopolist from raising the price. If the monopolist does not price discriminate and therefore the increase must be uniform for the entire pipeline, blocking the increase at one point means blocking it for the entire pipeline. The entire length of both pipelines must then be included in the market. Because the interlock-

²⁸ Lines in which Midcon had an interest before the acquisition (HIOS, UTOS and Stingray) reach regions extending from High Island South Addition in the west to the Vermilion region in the east, and from a point on the shore in the West Cameron region to the Garden Banks—roughly, a triangle 90 miles on a side. Lines in which United had an interest before the acquisition (HIOS, UTOS and Sea Robin, and UGPL itself) stretch even farther, over a trapezoidal area from High Island South Addition in the west to the Ship Shoal and Eugene Island South Addition regions on the east, a distance of roughly 130 miles, and from the Garden Banks to a 90 mile stretch of the shore extending from the West Cameron region to the Eugene Island region. Lines owned by the other partners in the lines in which Midcon or United had interests are found in virtually every region of the Gulf from southern Texas (Transco) to the mouth of the Mississippi (Southern Natural).

²⁹ This could take the form of a change in base price or a uniform change in pricing policy. A pipeline's basic transportation rate may either be uniform at every point along the pipeline ("postage stamp") or vary based on mileage; thus, it is possible to conceive a uniform increase in that rate, affecting every customer. However, other provisions of supply contracts might differ between particular connections, resulting in different effective prices. To avoid complications based on such circumstances, a proxy for a uniform price increase might be a system-wide surcharge or elimination of discounts.

³⁰ A customer might be able to get equivalent value or service elsewhere, but this is not an option if the goal is to transport gas from a specific producing well. But possibility not developed in the initial decision is that a customer could shift production to a different part of the Gulf where the pipeline rates are better, all other things being equal. Complaint counsel did not address this, because its "modest" competitive effects claims were limited to effects on netbacks and drilling incentives; thus, the concern indeed was moving particular physical parcels of gas.

³¹ ID 245.

ing network of pipelines extends across the Gulf, when we posit a uniform price increase, the market could not be limited to any smaller region.

C. Paragraph 20 Regions As Markets

If we assume the possibility of geographic price discrimination, relevant geographic markets smaller than the entire Gulf of Mexico are possible. Regions such as the Paragraph 20 area, the "eastern" and "western" regions within it, or other collections of blocks—even perhaps individual blocks—could be relevant geographic markets. To the extent that a region is geographically isolated from other pipelines, no transportation alternatives would exist to defeat a hypothetical increase in transportation rates within the region. There are some examples in this record of areas so isolated that a single pipeline may be the only feasible transportation available. For example, producing blocks in the southwestern corner of the High Island, South Addition area are more than 50 miles from any pipeline except HIOS.

For the paragraph 20 region (or its eastern or western regions) to be a relevant geographic market under this analysis, the pipelines that serve it must have the power to set prices within the region independently of the prices they set outside it, without fear of competition from other [10] pipelines that do not now serve the region. Because basic transportation rates for these pipelines are uniform for their entire length, outside these regions as well as inside them, differences in pricing would have to be accomplished by differences in discounts or other terms.

The Administrative Law Judge decided that the Paragraph 20 area could not be a relevant geographic market on the theory that the pipelines in the area do not compete.³² In his view, "FERC avoided inefficient duplication of pipeline services when it authorized their construction," and FERC will not authorize the pipelines to compete with respect to any extensions to unconnected reservoirs of gas.³³ We disagree. Although FERC may have authorized the pipelines to serve different gas reserves, in fact the pipelines in the Paragraph 20 area are located so that they are transportation alternatives for some producing blocks. The pipelines are located close to one another, Stingray, Sea Robin, Bluewater and Texas Eastern intersect at

³² I.D. at 61-62.

³³ I.D. at 62.

several points and HIOS and Stingray are connected at one point to facilitate shipments through either of them. The record shows that gas producers and shippers can and do consider pipeline alternatives when they are available. We can infer that adjacent and intersecting pipelines will be available alternatives for transportation out of the area for some producing blocks. The conclusion that the pipelines do not and cannot compete is, therefore, incorrect.

No evidence about price sensitivity between the Paragraph 20 region and other areas was offered. We do not know whether or how prices for transportation in these regions have been, are, or will be affected by or related to prices for transportation elsewhere. To be sure, in the past close regulation may have disguised or even overwhelmed any interregional pricing relationships; moreover, because the separate market for transportation services was nearly nonexistent, there would have been little evidence about separate prices for those services. The market is changing, and there is as yet little experience of actual pricing for transportation services. The briefs only speculate about actual pricing practices under the newly allowed selective discounts under Order 436. Whether prices in the future will demonstrate close relationships, or no relationships, is speculative.

The evidence of actual shipping patterns establishes that gas produced in this region has only been transported on pipelines in this region. Although evidence about shipment patterns can demonstrate the existence of geographic market, it must not be used uncritically, especially when there is little or no evidence about price correlations tending to show that a region is competitively isolated. The fact that producers in this region have always connected to pipelines in this region could be consistent with the existence of a much larger geographic market, in which competitive pressure from pipelines outside this region forces those within it to offer prices so attractive that producers do not choose to go outside. If that were the case, then those other pipelines should be considered to be in the market, not outside it.

Examining the map³⁴ and applying the kinds of benchmarks used by complaint counsel's expert witness discloses some apparently arbitrary inclusions and exclusions. Some blocks within the [11] alleged Paragraph 20 market, at its northwestern edge, are more than 15 miles from any large pipeline, whether inside the region or outside

³⁴ CV 804

it; the same is true of blocks in the Garden Banks to the south. Presumably, these blocks are included in the alleged market on the theory that, if any pipeline could serve them, it would be one that serves the Paragraph 20 region. But any pipeline serving these blocks would be well over 15 miles away, farther than the expert's 10- and 15-mile benchmarks.³⁵ The inclusion of these more distant blocks in the alleged market implies that pipelines more than 15 miles from a producing well could be considered feasible transportation alternatives in some circumstances.

On the southern edge of the eastern and western regions of the alleged market, other blocks are more than 15 miles from any pipeline. Some of these blocks are about the same distance from the pipelines within the alleged market as they are from an ANR pipeline only 14 miles outside it. Complaint counsel would exclude the ANR line because its diameter is only 12 inches,³⁶ but just five miles farther away that 12-inch line connects to a 24-inch line, one that is larger than the nearby legs of Stingray (22 and 16 inches) and Texas Eastern (12 inches and 16 inches) inside the Paragraph 20 region. Complaint counsel would also exclude the two 20-inch diameter Transco legs that come within 20 miles of the eastern edge of the region. But lines that are included in the Paragraph 20 region, or laterals from them, reach to within just three miles of these two Transco lines. Just outside the Paragraph 20 region is a block, Vermilion 369, connected by a 20-mile lateral to a pipeline inside it; that block is 15 miles from ANR and less than 20 miles from Transco.³⁷ Are the Transco lines too small or far away to matter, especially given the evidence that laterals are sometimes as long as 20 miles, or even longer? Complaint counsel has done little more than assert that other lines not physically within the Paragraph 20 region are either too small or too distant.

Even assuming the ability of pipelines to price discriminate on a geographic basis, on balance it is not entirely clear that pipelines outside the Paragraph 20 area are too far away to provide transportation alternatives for producing blocks in the area, so that the Paragraph 20 region as a whole could be considered a relevant geographic market. But the availability of nearby pipelines as

³⁵ Complaint counsel's expert witness used the 10- and 15-mile benchmarks to identify blocks that might be affected by the acquisition. By implication, those benchmarks would, under the expert's analysis, also measure the range of feasible alternative pipeline connections.

³⁶ CPF 6.96.

³⁷ ID 171; CX 904.

transportation alternatives for some producing blocks at the edges of the alleged Paragraph 20 market would not defeat the ability to exercise market power, if any exists, in more distant parts of the area. Judge Parker was incorrect in suggesting that a region cannot be a geographic market unless each firm located in the market competes in every part of it. The fact that HIOS and Sea Robin are too far from each other to compete directly with respect to particular producing blocks does not, by itself, defeat the existence of the larger Paragraph 20 market. HIOS and Sea Robin could be in the same geographic market, even if they are too far apart to compete with each other directly, if each of them competes with Stingray or some other pipeline or pipelines. Stingray in fact intersects with every other pipeline in the alleged market: HIOS, Sea Robin, Texas Eastern, and the Bluewater [12] extension. Thus complaint counsel's delineation of the alleged eastern and western region markets is not necessarily inconsistent³⁸ with a geographic market that encompasses both.

The evidence supporting the Paragraph 20 regions as geographic markets is not strong. Because the argument ultimately depends on the ability to price discriminate, it may be more fruitful to examine the implications of such price discrimination at the level of individual blocks or collections of blocks, rather than attempt to determine whether the theory supports defining the somewhat arbitrary Paragraph 20 regions as "markets".

D. Individual Blocks As Markets

A collection of blocks could also describe a relevant market if price discrimination is possible at particular block locations. As a theoretical proposition, this was found by Judge Parker and is admitted by respondents. If a hypothetical monopolist could impose a discriminatory increase at isolated locations within a larger market, then it is appropriate to collect those locations into a separate market for assessing competitive effects. In considering possible markets defined under this theory, there is a danger of implicitly assuming the conclusion. It is important to consider how significant the price discrimination might be to determine whether Section 7's requirement of "substantial" lessening of competition would be met in such "markets".

Here, the possibility of economic discrimination—differences in price not based on differences in cost—has been established more in

³⁸ See I.D.F. 249 & 250.

theory than in fact. Regulated uniformity of price has been the industry's traditional practice. FERC has announced that it will now permit more price variation to encourage greater price competition. Whether the effect of permitting greater variation will be to increase, or restrict, the range of options available to producers is conjectural. The evidence offered to show past price discrimination shows only price differences. It includes special deals some customers have negotiated allowing them to reduce contract demand, and one example of a flatly different rate for one customer.³⁹ Differences in the contracts' dates and other circumstances make comparison difficult. The record does not clearly demonstrate that the differences between the contracts reflect economic discrimination.

Complaint counsel's chief evidence for the possibility of price discrimination, other than the fact of geographic isolation,⁴⁰ is the wide gap between maximum and minimum prices permitted [13] under Order 436.⁴¹ But permitting pipelines to grant deep discounts on transportation rates to capture new business could expand the range at which they can offer service.⁴² The availability of a lower transportation rate, for example, could make it economical to build a longer lateral, all other things being equal. Thus, although geographic isolation in principle could encourage discriminatory treatment, permitting pipelines to offer non-uniform pricing could reduce the importance of that isolation. The net effect is, at the moment, speculative. The industry is adapting to the new regulatory environment, and FERC, while interested in encouraging selective discounting as a form of competition, still has the statutory obligation to prohibit undue discrimination. Because the experience under Order 436 is limited, predictions of future effects should be made cautiously.

We do not require proof of actual price discrimination in the past to use the possibility of price discrimination to define a market in a Section 7 case. Section 7 addresses likely future effects on competition, so proof of likely future discrimination could support the necessary market definition showing. The ability to price discriminate in the future is an open question in this industry, because prices

³⁹ CPF 6.83.

⁴⁰ Complaint counsel also asserts that arbitrage is difficult: the "same" transportation service cannot be shifted to any other place, because contracts restrict the customers' right to nominate or change delivery points. Such a shift might be made indirectly, by reselling, not the transportation, but gas produced where the favored transportation rate is available, to a customer who wants to avoid paying a higher rate. Whether such indirect arbitrage is a realistic possibility is not developed in the record.

⁴¹ CPF 6.14; see note 12 *supra*.

⁴² *Id.*

historically have been regulated and because some future price regulation is likely. For example, under Order 436, FERC regulates minimum and maximum prices, and unduly discriminatory prices are prohibited. We do not require waiting until market power is established and is being exercised before taking enforcement action. Thus the possibility of price discrimination might in appropriate circumstances be enough to justify concern about anticompetitive effects. But "possibilities" can be a weak foundation for a prediction of "likely", "substantial" competitive effects.

IV. COMPETITIVE EFFECTS

To demonstrate the extent of the acquisition's competitive effects, complaint counsel's expert witness used a simple sampling method, analyzing the transportation choices available at each of a number of blocks selected at random, on the assumption that only pipelines within 10 to 15 miles of a block were feasible. This analysis disclosed some blocks in the Gulf where the number of pipeline alternatives was limited, and where that number would be reduced if this transaction were treated as a merger.⁴³

Other assumptions, in addition to the assumption that price discrimination is possible, are necessary to infer an effect on competition for connecting new supplies at the blocks identified by the expert. Some of these assumptions are plausible and some are not. One plausible assumption is that gas in commercial quantities will probably be found at some unconnected blocks. The fact that a particular block is not leased (and is therefore unexplored) may not demonstrate that no gas will ever be produced there, but the fact that a block has been leased, explored and abandoned may be some evidence that gas is not available in that block in commercial quantities. That the amount of gas below each block is unknown is not critical. It may be plausible to assume that some commercial [14] quantities will be found in some of the identified blocks. This assumption is supported by findings that additional reserves will be connected in the OCS, from blocks now leased in primary term if not from the never-leased or abandoned orphans.⁴⁴ The assumption that pipelines more than 15 miles from a block are not feasible alternatives is a defensible estimate, but not a clearly demonstrated fact. The feasible length of a lateral to a particular block depends on the size of

⁴³ The locations found by the sampling method are not contiguous, but that fact is not fatal: it is conceivable that, in an industry like this one, a "Swiss cheese" pattern could have been shown to be a relevant market.

⁴⁴ ID 26-33.

its reserves, something that is unknown. Longer laterals in the OCS suggest that at least some customers might have transportation options at distances greater than 15 miles. Moreover, there is little experience under the newly permitted deep discounts; it is conceivable that pipelines might offer service at even greater ranges under the new regulatory scheme.

Complaint counsel sets out an "existence" proof, a sample undertaken to determine whether there are potential new gas supplies for which competitive choices could be affected by the acquisition. The concrete showing is limited. For about three-quarters of the 42 blocks in the sample, competition is presumably possible because there are already two or more pipelines within 15 miles. About two-fifths of those 42 blocks have been leased, and two MidCon-affiliated lines are within the benchmark distance. The sample contains two blocks that most clearly fit complaint counsel's scenario of competitive effect, because this acquisition allegedly left those two blocks, High Island 390 and Garden Banks 140 (which are virtually adjacent), with no alternatives other than MidCon-affiliated lines. High Island 390 is unleased. Both blocks are at the southwestern part of the western region, reasonably close to HIOS and some 15-20 miles from Stingray. But the claim that MidCon-affiliated pipelines are the only transportation alternatives within the benchmark distance is belied by the map: these two blocks are about as close to Bluewater as they are to Stingray.⁴⁵

Complaint counsel would extrapolate from this sample to a conclusion that this acquisition would affect competition in hundreds of blocks in the Paragraph 20 region. They do so simply by multiplying the proportions from the sample by 929, the number of unconnected blocks in the region. The detailed extrapolations now urged from the sample are unpersuasive. A large number of the blocks allegedly affected by the acquisition would be in the still-undeveloped Garden Banks, where predictions for gas reserves and transportation alternatives are most uncertain and where only a few blocks are within 15 miles of any pipeline. Few of these blocks are represented in the sample, although it is intended to be representative of all of the blocks. Some of the arguments made here demonstrate how extrapolations from the sample can be unreliable. By Judge Parker's reckoning, based on the lack of transportation alternatives for 5 out of 7 blocks, 75 percent of the blocks in the alleged Paragraph 20 market

⁴⁵ See CX 904.

would not be affected by the acquisition because they already had no transportation alternatives.⁴⁶ To counter that extrapolation, complaint counsel argues that shifting the boundary six miles to change the sample would yield the opposite conclusion: that *all* of the blocks *would* be affected.⁴⁷ Complaint counsel thus demonstrates that the value of projections from its sample is questionable. Thus, although we agree that there are likely to be more blocks affected [15] than the particular ones identified by the sample, we are much less confident that there will be hundreds of them.

We do not demand that each affected block be identified, any more than we would typically require that every affected customer be identified in any other merger case. But the sample here, which turned up only a few examples of blocks where customers might suffer the alleged anticompetitive effects, is insufficient to show substantial anticompetitive effects.⁴⁸

The Commission does not rule out the possibility that mergers among OCS pipelines could violate Section 7 of the Clayton Act. There is evidence that OCS pipelines have been considered competitors with each other in the past and that they are likely to have more opportunities to compete in the future. A merger that is proven to be likely to substantially lessen that competition will be found illegal. But complaint counsel has failed to make that proof here.

V. CONCLUSION

The complaint is dismissed for failure to prove the likelihood of substantial lessening of competition in a section of the country.

⁴⁶ ID 239.

⁴⁷ CCAB p. 53 n. 35.

⁴⁸ Judge Parker apparently found that complaint counsel failed to show anticompetitive effects because no concentration data were presented for "block" markets. I.D.F. 258. But detailed concentration data are not always necessary in a Section 7 case (and the initial decision is in error to the extent it suggests otherwise) if other evidence shows the likelihood of anticompetitive effects. Here, it is not obvious that the changes in ownership from this acquisition would cause a significant change in concentration or competition at alleged "block" markets. The isolated examples of alleged "merger to monopoly" are two blocks where, pre-acquisition, the nearest pipelines were HIOS (20 percent controlled by Midcon), Stingray (50 percent controlled by Midcon), and Bluewater. The increase in Midcon's interest in HIOS to 40 percent does not self-evidently pose a competitive threat to these blocks.

Opinion

APPENDIX A



FINAL ORDER

This matter having been heard on the appeal of complaint counsel from the initial decision and on briefs and oral argument in support of and in opposition to the appeal, for the reasons stated in the accompanying opinion, the Commission has determined to deny the appeal. Accordingly,

It is ordered, That the complaint is dismissed.
Commissioner Machol not participating.

IN THE MATTER OF

SILO, INC.

CONSENT ORDER, ETC., IN REGARD TO ALLEGED VIOLATION OF THE
ENERGY POLICY AND CONSERVATION ACT & THE FEDERAL TRADE
COMMISSION'S APPLIANCE LABELING RULE

Docket C-3263. Complaint, July 20, 1989—Decision, July 20, 1989

This consent order requires, among other things, the Philadelphia, Pa. based corporation, that operates stores that sell major appliances, to pay \$45,000 in civil penalties.

Appearances

For the Commission: *Kathryn Nielsen.*

For the respondent: *Erin Scher, Weil, Gotshal & Manges, New York City.*

COMPLAINT

Pursuant to the provisions of the Energy Policy and Conservation Act ("EPCA"), as amended, and by virtue of the authority vested in it by the aforementioned Act, the Federal Trade Commission, having reason to believe that SILO, Inc., a corporation, hereinafter sometimes referred to as respondent, has violated and is violating said Act, and the Commission's Rule for Using Energy Costs and Consumption Information Used in Labeling and Advertising for Consumer Appliances Under the Energy Policy and Conservation Act ("Appliance Labeling Rule"), and it appearing to the Commission that a proceeding by it in respect thereof would be in the public interest, hereby issues this complaint, stating its charges in that respect as follows:

PARAGRAPH 1. SILO, Inc. ("SILO") is a Pennsylvania corporation, with its office and principal place of business located at 6900 Lindbergh Boulevard, Philadelphia, Pennsylvania.

PAR. 2. Respondent advertises, offers for sale, and sells household appliances and electronic equipment in its retail stores located throughout the United States.

PAR. 3. The Energy Policy and Conservation Act, 42 U.S.C. 6291 et