Externality Regulation in Oil and Gas

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Glossary

Common Property: Ownership of an economic asset is joint among several owners, with each having the right to use the asset as they see fit. Common property typically results in either congestion or stock externalities.

Common Carrier: Legislation that requires a pipeline to transport production from all producers at non-discriminatory rates.

Congestion Externality: When the average productivity of a variable input is decreasing in the quantity of the variable input, a negative congestion externality occurs.

Minimum Well-Spacing: Legislation that requires a minimum number of acres per well, a minimum distance between wells, or a minimum distance between wells and the border of a lease.

Monopsony Power: When a purchaser is able to restrict the quantity of inputs that can brought to market in order to lower the price paid for inputs, that purchaser is said to possess monopsony (sole buyer) power. Monopsony power can only be exercised when the supply curve is less than perfectly elastic.

Prorationing: Allocation of production quotas by *pro rata* allocations based on acreage, wells drilled, or some combination. The quota allocations in prorationing were often associated with efforts to restrict output in order to increase the price paid to producers.

Pecuniary Externality: When the price consumers are willing to pay for the good is decreasing in total production and there are multiple producers, an increase in the output by any one producers causes the price to decrease to all producers. This reduction in price is called a pecuniary externality. Economists tend to ignore pecuniary externalities because the loss to other producers is more than compensated by gains to consumers.

Stock Externality: A stock externality occurs when the productivity of a variable input (such as the number of wells drilled) is increasing in the stock of the economic asset, and there are more than one producer extracting from the stock. By appropriating the stock for one's self, producers reduce the future productivity of other producers' inputs. If ownership of the resource stock is common, producers will fail to account for the cost they impose upon others by their extraction from the stock.

Compulsory Unitization: Compulsory unitization legislation enables a majority of producers on an oil or gas field to force the remaining producers on a field to combine their interests into a single producing unit managed by a single unit operator, with allocations of the field production profits made in proportion to lease acreage, number of wells drilled, or productivity of leases.

Key Words

common carrier legislation, common property resource, congestion externality, minimum oil/gas ratio, monopsony power, pipeline transportation, no-flaring rules, pecuniary externality, prorationing, stock externality, unitization, well-spacing.

Synopsis

This chapter examines the evolution of property rights for oil and gas in the United States in the pre-OPEC period, 1859-1972. Private property rights to subsurface mineral rights created a number of problems in the U.S. not faced in countries where the state retained ownership of subsurface rights. First, since oil and gas migrate freely beneath property lines, the courts determined with the "rule of capture" that it was impossible to ascertain to whom the oil belonged until it was brought to the surface. The rule of capture led to over-capacity in wells drilled, storage, and production. Thus producers experienced high costs, rapidly depleted fields, and low output prices. Second, integrated refining/pipeline firms possessed monopsony power over producers. Thus, the low producer prices had two causes, one external and one internal. These two problems were interrelated, however, and attempts at regulation of one led to consequences for the other. This chapter discusses both private and state solutions to these problems, including attempts at consolidating ownership, voluntary and state output restrictions by prorationing, voluntary and compulsory unitization, common carrier legislation, minimum well-spacing requirements, minimum oil/gas and oil/water ratios, and no-flaring and venting rules for natural gas.

1 Introduction

This chapter examines the evolution of property rights for oil and gas in the United States in the pre-OPEC period, 1859-1972. Private property rights to subsurface mineral rights created a number of problems in the U.S. not faced in countries where the state retained ownership of subsurface rights. First, since oil and gas migrate freely beneath property lines, the courts determined with the "rule of capture" that it was impossible to ascertain to whom the oil belonged until it was brought to the surface. The rule of capture led to over-capacity in wells drilled, storage, and production. Thus producers experienced high costs, rapidly depleted fields, and low output prices. Second, integrated refining/pipeline firms possessed monopsony power over producers. Thus, the low producer prices had two causes, one external and one internal. These two problems were interrelated, however, and attempts at regulation of one led to consequences for the other. This chapter discusses both private and state solutions to these problems, including attempts at consolidating ownership, voluntary and state output restrictions by prorationing, voluntary and compulsory unitization, common carrier legislation, minimum well-spacing requirements, minimum oil/gas and oil/water ratios, and no-flaring and venting rules for natural gas.

The remainder of the chapter is organized as follows. Section 2 examines the common property and pecuniary externalities that may arise in the production of oil and gas. Section 3 examines the private solutions to resolving these problems. Section 4 examines state regulatory responses to resolving these problems. Section 5 concludes.

2 Externalities in Oil and Gas Production

2.1 Production of Oil and Gas

Oil and gas is found in pressurized zones lying in porous rock layers trapped between impermeable layers of sedimentary rock. The oil-bearing layer typically lies above a layer saturated with water, and/or below a layer of rock saturated in natural gas. If natural gas is present, some of the gas exists in dissolved solution within the oil, and, if the quantity of gas is sufficiently large, some gas lies in a "gas cap" above the oil. Oil and gas fields are mainly found in three different types of geological traps. Anticlinal traps occur when inverse U-shaped folds in the strata hold oil and gas between impermeable layers. Fault sealed traps occur where a permeable strata is fractured by the two sides of the fault slipping in opposite directions, preventing oil or gas from moving across the fault. Stratigraphic traps occur when a portion of a strata of permeable rock becomes impermeable, so that when tilted, oil, gas and water are trapped below the impermeable strata.

The natural drive mechanism in fields also varies. In "dissolved gas" fields, such as the Oil Creek field in Pennsylvania, oil and gas are mixed under high pressure. When a well is drilled, the resulting low pressure around the well causes oil to flow towards the well as the gas, which is more compressible than oil, expands to equalize the pressure. Between 10-30% of the oil may be recovered before the pressure declines to such an extent that the oil becomes too viscous to flow towards the well. In a "water drive" oil field, such as the 5.4 billion barrel East Texas field, discovered in 1930, the second largest oil field discovered in the U.S.,[1] the oil lies above a layer saturated with water. When a well is drilled, the water expands, pushing the oil towards the well. Ultimate recovery on water driven oil fields can be as high as 75%. In a "gas cap" oil field, such as the 15 billion barrel Prudhoe Bay field in Alaska, discovered in 1967, and the 460 million barrel Kettleman Dome field in California, discovered in 1928, the oil lies below a layer of natural gas. As oil is extracted, the gas expands, pushing the oil towards the well. Natural production in such fields is capable of recovering approximately 50% of the oil in place.

Natural gas is produced either in association with oil as in a dissolved gas oil field or as unassociated gas. When gas is produced in association with oil, it is called "casinghead gas," and can be produced, re-injected, vented or flared. Unassociated gas can be either "dry" or "wet". When wet, unassociated gas contains natural gas liquids (or condensates) such as propane and butane, which are mixed in the gas in a gaseous form when under great pressure underground, but which condenses from the gas when brought to the surface. Primary production of dry natural gas is capable of recovering 90-100% of the gas in place. Production of condensates, however, requires re-injection of the dry gas to maintain sufficient pressure to keep the condensates in gaseous form.

Primary production occurs as long as the natural drive of the field is sufficient to push the oil or gas to the surface. Once the bottom-hole bore pressure is insufficient to push the oil or gas to the surface, other methods are required. The most common secondary recovery method involves injection of either water or natural gas into a field. In a dissolved gas oil field, this simply involves collecting and re-injecting the natural gas. In water drive and gas cap fields, the process is complicated by an unequal distribution of water-to-oil or gas-to-oil across the field. In these types of fields, it may be efficient to shut down production from wells with a high water-to-oil or gas-to-oil ratio or to use these as injection wells. With heavy oils (oil with low API gravity), such as those found in California, Alaska, and Venezuela, the

[1] Estimates of sizes of fields over 500 million barrels of oil equivalent are from Horn (2003), and estimates of fields between 100 million and 500 million barrels are based on cumulative production through 1995, published in *Oil and Gas Journal* (1996). Data for fields smaller than 100 million barrels of oil is unavailable.

oil is very viscous, making it difficult to extract. In such fields, tertiary recovery methods are required, such as injection of steam, solvents or other miscible fluids into the oil bearing strata, or by heating the oil by burning some of it *in situ*, expelling the oil towards the well by the solvents or by the gases released in burning.

When a well is "completed", it is readied for production by sealing the well-casing from the surrounding strata. Modern completion methods use artificial means to fracture the oil- or gas-bearing strata, by injection of high pressure gases or fluids. Wells are also drilled horizontally ('slant' drilling) along a hydrocarbon bearing strata to increase the surface area of the collection end of the well. This is often used in combination with fracturing and/or injection methods. These methods have become increasingly important in production of shale gas, which started in the Barnett Shale in Texas and, more recently, in production of shale oil, such as in the Bakken field in North Dakota. Finally, mining methods are increasingly being applied to produce crude oil from the bitumen in the Athabasca oil sands in Alberta, where oil sands production presently accounts for more than 25% of Canadian production.

2.2 Production Externalities in Oil and Gas

The most important production externality in oil and gas is due to the 'common pool' problem. A well creates a low-pressure point which causes the fluids and gases to gravitate towards the well. When a field is developed by a single producer, that producer balances the additional cost of drilling another well with the value of additional production that occurs from that well, taking account of the reduction in value of production from other wells. Under the "rule of capture" property rights to oil or gas are acquired only when the oil or gas is brought to the surface. Therefore, under common ownership, the producer balances the additional cost of drilling another well with the value of oil or gas he expects to be produced by that well, ignoring the "congestion externality" cost his well imposes upon other producers' wells.

In addition, there is also potential for producers to impose a "stock externality" cost upon other producers. In water drive fields, for example, if the oil is pumped more quickly than the water inflow to the field, then the water flow becomes relegated to channels with the weakest resistance, and pockets of oil are left behind. A similar effect is found in gas cap fields.

Gas cap, dissolved gas, and wet unassociated gas fields pose an additional type of "reciprocal" externality, which is due to the use of the dry gas as the mechanism for recovering the oil or natural gas liquids. To maximize the recovery of oil in gas cap and dissolved gas fields, the natural gas is reinjected into the field. Thus, production of the natural gas in gas cap and dissolved gas fields reduces the amount of oil that may be recovered. Given relative prices, efficient production first extracts the oil and then the natural gas. Therefore natural gas producers inflict the cost of reduced drive upon oil producers by producing the gas, and oil producers impose waiting costs on natural gas producers if they force them to not produce the gas until the oil has been recovered. Similarly, in wet unassociated natural gas fields, the dry natural gas is the drive which allows recovery of the natural gas liquids. In these fields, given relative prices of condensates and natural gas, a single owner of the field would reinject the dry natural gas to maintain field pressure so as to recover the maximum amount of condensates. Only after the natural gas liquids are exhausted would the dry natural gas be produced. Yet it was the usual practice in the 1930s to flare or vent the the natural gas in both oil and natural gas liquids fields, since the cost of reinjection was borne by the individual producer, but the benefits were spread across all producers on the field.

2.3 Market Structure and Pecuniary Externalities

Primary producers purchase lease rights from the owners of the mineral rights (who can be either the state or private individuals), and then do the exploration and development of oil and gas fields. Output from the primary production sector is transported to refineries and gas plants by trucks, railroad, tanker ships, and pipelines, with the latter dominating in large fields due to economies of scale. Refiners separate the crude oil into gasoline, lubricants, fuel oil, asphalt, and other products. These products are then marketed and sold to final consumers. In natural gas, the refining sector strips the wet gas of the natural gas liquids and then sells the dry gas to power generation, industrial and private consumers.

The North American oil and gas industry is comprised of two important types of firms: "majors" and "independents" (McKie 1960). Majors are vertically integrated firms who have historically owned marketing, refining, pipeline, and primary production. Independents are typically engaged in either refining or primary production but not both, or if vertically integrated, are dependent upon a small number of fields. The economies of scale that allowed pipelines to dominate truck and rail transportation also gave the firms that owned pipelines market power within the industry. Although there are certain levels of economies of scale in refining and marketing, Rostow (1948, p. 68) estimated that a firm could build a refinery for between $2-20 million dollars in the 1940s, which is much less than the cost of building a major trunkline pipeline. As the majors owned most pipelines, they wielded market power. As one independent summarized the situation, "In each field there is usually one predominant buyer and he sets the prices; [w]e are subject to go along with it" (quoted in Rostow, 1948, p. 53). At the time of its dissolution on anti-trust grounds in 1911 (*Standard Oil Co. of New Jersey v. United States*, 221 U.S. 1 (1911)), the Standard Oil Company controlled approximately 80-90% of marketing, refining, and pipelines in the U.S.

3 Private Responses

3.1 The Rule of Capture

The rule of capture evolved out of common law cases where disputes arose on oil and gas fields. In *Jones v. Forest Oil Co.*, 194 Pa. 379 (1900), the Pennsylvania court, citing English common law in *Acton v. Blundell*, 12 Mees. & W. 324, 354, 152 Eng. Rep. 1223, 1235 (Ex. Ch. 1843), found that the rule of capture "accords each well owner with an unlimited right of withdrawal." In *Barnard v. Monongabela Gas Company*, 216 Pa. 362, 65 Atl. 801 (1907), the court explained,

> "An oil or gas well may draw its product from an indefinite distance and in time exhaust a large space. The vagrant character of the mineral and the porous sand rock in which it is found and through which it moves fully justify... 'the right of every land-owner to drill a well on his own land at whatever spot he may see fit.' What, then, can the neighbor do? Nothing; only go and do likewise." (quoted in American Petroleum Institute, 1961, pp. 1120)

One consequence of the rule of capture was that covenants were often placed in leases requiring the working interest owner (the lessee) to protect the interests of the royalty interest owner (the lessor) by drilling wells opposite of wells on adjacent properties. Stocking (1925, p. 171), using data from the 500 million barrel Cushing oil field in Oklahoma, discovered in 1912, showed that the first wells to be drilled were at the corners of a property, followed by other wells drilled along the property line, and that wells drilled on an adjacent property were typically offset by a well drilled on one's own property. Similar patterns were observed on the much smaller Ranger and Burkburnett fields in Texas (Stocking 1925, pp. 151-63) and on the 500 million barrel Leduc and 800 million barrel Redwater fields in Alberta, Canada (Hanson 1958, pp. 71-85).

A second consequence of the rule of capture was the rapidity with which field pressure was exhausted. On the Spindletop field, discovered in Texas in 1901, more than three wells were drilled per acre of land. Production peaked in 1902 at 17.4 million barrels. By 1903 production had declined to 8.6 million barrels; in 1904 production was 3.4 million barrels; and by 1905 production was down to 1.6 million barrels (Zimmermann 1957, p. 284, Table XV). Similar rates of decline were observed in other fields discovered during this time. Thus, both static congestion externalities and dynamic stock externalities were observed in oil and gas production.

A third consequence of the rule of capture was the necessity for storage. Firms without market access would store oil, either in expensive steel tanks, or in open pits. Both were subject to loss by evaporation, seepage or fire. Pogue (1921, p. 344) reports estimates that 20% of the gasoline content was lost to evaporation. In Oklahoma, where in 1914 over 10 million barrels were in storage on the Cushing field on state-wide production of 73 million barrels, it was said that "more oil has run down the creeks of the famous Glenn Pool than was ever produced in Illinois" (American Bar Association, 1938, pp. 112, 123).

3.2 Private Solutions

Three main private solutions to the common property problem arose. The first was to simply buy out one's competitors. On the Oil Creek field, the owner of the Nobel and Delamater well, completed in January 1863, found that its production declined when a nearby Caldwell well was drilled. The owner of the Nobel and Delamater well thus purchased the Caldwell well and shut it down. A similar solution was reached when the owners of the Phillips well purchased the nearby Woodward lease (American Petroleum Institute, 1961, p. 27). Other examples include the Sugarland field in Texas, on which the leases were owned entirely by Humble Oil (Weaver 1986, p. 45), and the 100,000 acre King ranch in Texas, where Exxon held exclusive lease rights (Weaver 1986, p. 316).

The second method was to reach voluntarily agreement to proration output across producers. Table 1 reports efforts to reach voluntary agreements on five Oklahoma and Texas fields between 1926 and 1930. The 1.9 billion barrel Yates field in Texas was organized by voluntary agreement in September 1927. A similar solution was reached on the 800 million barrel Seminole field in Oklahoma in May 1927. But these agreements often could not be reached. Attempts to proration the 250 million barrel Hendrick field in Texas in June 1927 failed, as did attempts to proration the 800 million barrel Oklahoma City field in 1929 and to proration the East Texas field in 1931. These failed for several reasons, but the most important were the large numbers of producers and the heterogeneity of interests. On East Texas and Oklahoma City, large numbers of small producers refused to come to an agreement, even though the large producers were willing to offer considerable concessions. The third method of resolving the common property problem voluntarily was through voluntary unitization. This method was similar to voluntarily prorationing output, except that under prorationing, drilling and injection decisions were left to individual producers, while under unitization, a single producer made drilling and injection decisions.

In addition to the problems of reaching an agreement among many varied interests, voluntary prorationing and unitization faced uncertainty whether such agreements would violate antitrust laws. After the Hendrick field was brought under prorationing by the Texas Railroad Commission (TRC), the regulator of oil and gas in Texas, the operators on the Yates field asked for and received a prorationing order codifying their agreement by the TRC, and the voluntary prorationing agreement on the Seminole field in Oklahoma was also given the consent of the state by being incorporated into a prorationing order by Oklahoma's regulator, the Oklahoma Corporation Commission (OCC).

A second problem faced by the industry was the boom-and-bust cycles that resulted from the rule of capture. Production in 1859 from the first Pennsylvania well was 2,000 barrels of oil, which sold for \$20 per barrel. But the number of wells increased to 202 in 1860 and to 392 in 1861, with production increasing to 500,000 barrels in 1860 and to over 2 million barrels in 1861 as newly discovered fields were subjected to 'flush production' where the wells on the field were operated at full capacity (American Petroleum Institute, 1959). As a result, the price of oil plummeted to \$0.49 per barrel in 1861. Similar declines were observed in Oklahoma with the discovery of the Cushing, Seminole and Oklahoma City fields, and most spectacularly, with East Texas field, when prices plummeted 90% within six months of its discovery in October 1930.

To producers and mineral rights owners, the main problem was the low prices paid to producers. The industry attempted to control production and prices using various means.

Describing an attempt made by producers in the early 1870s to organize production, John D. Rockefeller said, "I could not state how long it was in existence or said to be operative, but the high price for the crude oil resulted, as it had always done before and will always do so long as oil comes out of the ground, in increasing the production, and they got too much oil" (quoted in McGee 1958, p. 160, n. 120).

Rockefeller's Standard Oil Company, which started out as one of many refineries in Cleveland, Ohio in the 1870s, saw that control over transportation and refining was the key to controlling production and prices. By 1900, Standard Oil transported 93% of oil from the Appalachia fields and 92% of the Lima Indiana fields – the major producing areas at the time – and by 1904 Standard Oil refined 84% of the oil in the U.S. (Stocking 1925, p. 51). The 1911 dissolution of the Standard Oil Trust by the U.S. Supreme Court on violations of the Sherman Antitrust Act of 1890 resulted in Standard Oil being broken up into a number of regional companies. However, ownership of the stock in each of the newly created companies was proportional to the ownership of the Standard Oil Trust, so the breakup had little initial effect since the companies competed in separate markets, although some companies, such as Standard Oil of New Jersey, were left with only refining and pipeline properties. The Standard Oil companies' share of refining dropped to 45% by 1921 and their share of major pipelines (trunk lines) declined to 68% by 1918 (Stocking 1925, p. 98). Yet by the late 1930s, ownership in pipelines remained highly concentrated. Rostow (1948) advocated the adoption of compulsory unitization to deal with the common pool problem, and he advocated severing the transportation and refining operations of the major oil companies and enforcing a strict *per se* antitrust rule against combinations to deal with the monopsony problem.

4 State Regulation

Since private solutions either failed or resulted in attempts at monopolization, regulators sought out other mechanisms to regulate production. Thus laws were enacted regulating well spacing, preventing of flaring or venting of natural gas, regulating production from wells with too high of a water-to-oil or gas-to-oil ratio, unitization, and, the preferred mechanism from the 1933-1972, "prorationing," which involved direct limits on field production, with allocation of allowable production *pro rata* across wells. Table 2 presents the major legislative actions and court decisions for the main oil producing states and for the U.S. federal government.

4.1 Common Carrier Laws

The wastes from excessive drilling and the construction of expensive storage were not borne equally across producers. Integrated firms could build pipelines to serve their own needs, and take oil from non-integrated independents only when their own production was insufficient or when the price they could obtain oil from other producers was sufficiently low. Thus, major oil producing states passed "common-carrier" laws (Kansas in 1905, Oklahoma in 1909, Texas in 1917, amended in 1930, Louisiana in 1918, and the U.S. federal government on interstate pipelines, the Hepburn Act in 1906), requiring pipelines to take all oil at the same price without discrimination among producers. See Table 2, column 6.

4.1.1 Effects of Common Carrier Laws

While there appears to be no systematic empirical evidence on this matter, these laws were widely viewed as ineffective. Pipelines would often place minimum shipment requirements which were in excess of many producer's and even some refineries' annual usage levels, or require that shipments be received at only the terminal serving the pipeline's own refinery, which raised transport costs to rivals (Stocking 1925, pp. 97-99). It was also possible for a vertically integrated firm to charge all shippers a common high price for transport, thereby shifting the profit making from its refinery sector to its pipeline sector, but extracting profits from other shippers (Weaver 1986, pp. 41). All of these methods were effective in enhancing the market power of the majors over producers.

4.2 Well-Casing and Abandonment Statutes

Other early regulations in oil and gas governed how wells were to be completed and abandoned. These required wells to be cased to prevent fresh water from mixing with oil or gas and visa-versa, and specified the manner in which an abandoned well was plugged. The validity of these acts was ensured with the U.S. Supreme Court decision in *Ohio Oil Co. v. Indiana*, 177 U.S. 190 (1900), which ruled that the state had a valid interest in regulating the industry because of conservation concerns.

These statutes and agency rules were relatively uncontroversial, however, because both oil and gas producers and users of fresh water benefited from preventing cross-contamination.

As Table 2, column 1, indicates, these regulations followed the development of the oil industry as it moved across the states.

4.3 Waste Statutes

The next major wave of statutes involved restrictions on 'waste'. These were initially concerned with natural gas. In Louisiana, a statute requiring that gas wells be brought under control was enacted in 1906 after the Caddo gas field blowout, which burned out of control from May to December 1905. Other concerns included the use of natural gas in "flambeau lights", gas lit street lights, which was outlawed in the 1890s in Ohio, Indiana, and Texas, and the use of natural gas to produce "carbon black," used to blacken rubber products, but which had substitutes produced from coal. These were attempts to divert natural gas to what were perceived as higher value uses.

A second phase of waste statutes arose out of efforts in Oklahoma to reduce economic waste. These statutes took several forms. Flaring of natural gas was common both in oil fields with casinghead gas and in natural gas liquids fields. In 1934, the 25,000 trillion cubic feet Panhandle field in Texas was flaring a billion cubic feet of gas per day as producers stripped condensates from the natural gas (Prindle 1981, p. 57-61), and in 1930, the 600 million barrel Santa Fe Springs oil field in California was flaring a half billion cubic feet of natural gas per day (American Bar Association 1938, p. 33). Indiana began regulating gas flaring as early as 1893. Some states, like Texas, allowed flaring of gas on oil wells, but not on gas wells.

Other legislation arose as states recognized the role of natural gas in oil production. Thus, states like California instituted minimum oil/gas ratio requirements at the same time as it instituted no flaring regulations. By the 1930s, with the formation of the Interstate Oil and Gas Compact Commission (IOGCC), a standard set of regulations began to be adopted, which included well-casing and abandonment regulations, no flaring rules, minimum oil/gas ratios and minimum oil/water ratios. Later versions of the IOGCC draft law also explicitly included rules on production limits according to the maximum efficient rate (MER) of production determined for the field. The MER depended upon the source of natural drive as well as other characteristics of the field (McKie and McDonald 1962). Table 2, column 7, lists waste laws.

4.3.1 Effects of Waste Statutes

Energy Information Agency data indicates that flaring and venting accounted for 17% of gross withdrawals of natural gas between 1936-1947, but since 1970, flaring and venting has averaged less than 1% of gross withdrawals. There appear to be no empirical studies assessing the effectiveness of these other types of waste statues.

4.4 Prorationing

In 1913, Oklahoma extended its common carrier law to natural gas pipelines. To meet the pipeline capacity, legislation limited production to 25% of the natural flow and allocated production across producers in proportion to their natural rates of flow. In 1914, in response to the threats of government action using common carrier laws, producers and purchasers on the Cushing field reached an agreement to *pro rata* allocate production across producers as a percentage of potential production. This was codified into an order by the OCC in July, 1914.

The discovery of the Seminole field in 1926 resulted in a 50% increase in Oklahoma production in 1927. A voluntary prorationing scheme was adopted in 1927. As with the Cushing field 1914, the voluntary prorationing agreement was incorporated into a OCC order, which prorated on lease potential. In December 1928, a voluntary agreement to proration output to 40% of potential production on the Oklahoma City field was codified into OCC order 4882 (December 23, 1929). By 1930, however, the field was extended into the city limits. Pressure from town-lot sized production units forced the OCC to issue reduce production to $1/6^{\text{th}}$ of potential production. To enforce the order, Governor William H. Murray declared martial law and shut down production on the Oklahoma City field from August 5-October 10, 1931. The Oklahoma prorationing orders were upheld in federal courts in *Champlin Refining Co. v. OCC*, 51 Fed.(2) 823 (1931), U.S. 210, 76 (1932).

In Texas, the Yates field was prorationed by voluntary agreement of the participants in 1927. But when a voluntary agreement could not be reached on the Hendrick field, the TRC ordered prorationing on the authority of the waste provisions of a 1929 amendment to the 1919 waste act, which stated the waste "shall not be construed to mean economic waste" (quoted in American Bar Associatino 1938, p. 220). In August 1930, the TRC issued its first statewide prorationing order. The TRC state-wide prorationing order was struck down in *Danciger v. TRC*, 49 S.W. (2nd) 837 (1932) because it was limiting economic waste. To enforce prorationing on the East Texas field, Governor Ross Sterling declared martial law on August 17, 1931, again using the waste statute as its legal basis. This was declared invalid in *McMillan v. TRC*, 51 Fed.(2) 400 (1931). In 1932, the Texas legislature rewrote the waste statute to prevent physical waste, and this was upheld in the courts (*Amazon v. TRC*, 5 F. Supp. 633 (1934)).

California never adopted prorationing legislation, but rather accomplished prorationing through private coordination, with the earliest attempts occurring in 1923 (Ise 1928, p. 110). Two attempts to institute prorationing by the state, one in 1931 and one in 1939, were each passed by the legislature, but rescinded by referendum before they could become law. Table 2, column 3 summarizes prorationing in other states. Private coordination was apparently effective: In 1929, California produced 29% of U.S. production; during federal prorationing, 1933-35, California's share of U.S. production was about 20%; and between 1935 and 1970, its share steadily declined to about 10%.

State prorationing, however, suffered from an inability by the states to control interstate shipments of so-called hot oil. Thus, by May 1933, the price on East Texas was down to $0.04 per barrel. In 1933, the National Industrial Recovery Act (NIRA) vested in its "oil code," section 9, the authority to proration oil production throughout the United States to Secretary of Interior. The U.S. Bureau of Mines provided monthly forecasts of demand for this purpose. The federal government ran prorationing from September 1933 until January 1935, when the oil code section of NIRA was declared unconstitutional in *Panama Refining v. Ryan*, 293 U.S. 388 (1935). In response, Texas, Oklahoma, Kansas, New Mexico, Colorado and Illinois formed the Interstate Oil and Gas Compact, with the intention of continuing market demand prorationing. The Connally Hot Oil Act (1935) forbade interstate transport of oil in excess of state prorationed amounts, and the U.S. Bureau of Mines continued to produce monthly forecasts of demand to guide individual state prorationing quotas. Prorationing in this form continued until 1972, when market demand quotas were set at 100%.

4.4.1 Effects of Prorationing

While prorationing was defended in the courts on conservation grounds, it was the price increasing aspects that endeared it to oil producers. When martial law shut down the East Texas field in May 1931, the posted price jumped ten-fold from $0.10 per barrel to $1.00 per barrel in March 1932, but then fell again to $0.04 per barrel in May 1933 after martial law was declared illegal. Similarly, the shut-down of the Oklahoma City field in August

1931 caused the posted price to rise from \$0.38 per barrel on July 24 to \$0.62 per barrel on August 22. Libecap (1989) found there were both fewer nominal price changes between 1934 and 1972 than in the period 1913 to 1933, and that the nominal price changes were smaller in magnitude. Because nominal prices remained relatively constant, however, real prices declined during the proration era.

Zimmermann has presented evidence on the effectiveness of prorationing in preventing loss in field pressure. Table 3 compares ten fields discovered previous to prorationing with ten fields discovered after state-wide prorationing. While the earlier fields are smaller both in surface acreage and in total potential oil reserves, they experienced greater drilling (1600 wells per field vs. 1000 wells per field) and more rapid depletion, as is indicated by the magnitude of year 15 production relative to peak production, which averaged 8.6% of peak production in the fields discovered before prorationing and 73.9% of peak production in the fields discovered after prorationing. Thus, prorationing was successful in preventing premature depletion of fields due to the stock externality.

Prorationing, however, had two problems. The first was its failure to sufficiently alter incentives for drilling a well. On the one hand, the prorationing quota reduced the quantity any well could produce, which would reduce the number of wells drilled. On the other hand, prorationing raised the price received, reduced the loss in pressure from over-production, and allocated quotas in part on a per well basis, all which would increase the number of wells drilled. Adelman (1964) estimated that \$4 billion per year was lost to excessive drilling and to the mis-allocation of production due to exemptions to marginal wells and pooling requirements (discussed below). Table 4 presents evidence of the over-capacity during the prorationing era compiled by McDonald (1971). Between 1954 and 1967, the three main market demand prorationing states of Texas, Louisiana, and Oklahoma averaged 36.8%, 37.8%, and 40.5% market demand shares, respectively. Due to a large number of exemptions to minimum-well spacing rules and for old fields, these corresponded to average production shares relative to capacity of 65.2% for Texas, 70.3% for Louisiana, and 84.6% for Oklahoma. In contrast, among Colorado, Kansas, Mississippi, Montana, New Mexico, and Utah, the shares of capacity ranged between 90.2% and 100% over this period. Thus, the market demand prorationing states had much greater excess capacity than those states which did not adopt market demand prorationing.

The second problem with prorationing was that for it to be successful in maintaining prices, it had to control entry. Although it was one of the original signatories to the IOGCC, Illinois failed to enforce production quotas. As a result, Illinois' share of U.S. production jumped from 2% in 1938 to nearly 10% by 1940. But because its fields were developed under flush production, rapid depletion caused production in 1943 to drop to 83 million barrels, down from its peak of 147 million barrels in 1940. Because its prorationing was run by industry, California was much more erratic in its control of quotas. But the California market was geographically isolated from the mid-continent market and with the rapid growth in population in the post-WW II era, California had little effect upon prorationing pricing by the other states. States like Oklahoma and Texas recognized the problem new discoveries posed for prorationing, and as a result Oklahoma prohibited production for 65 days after discovery on new wells, while in Texas, fields would come under prorationing restrictions as soon as 6 wells were drilled.

4.5 Well-Spacing, Pooling Requirements, and Marginal Wells

Texas implemented minimum acreage requirements for oil wells in 1919, requiring 300 feet between wells, or about 2.25 acres per well. In 1929 the city of Oxford, Kansas restricted wells to one per city block. Oklahoma and and California wrote similar minimum acreage requirements for fields in urban areas.

Inevitably, minimum well-spacing laws forced "pooling" of small tracts. In pooling, several owners whose individual tracts were each not large enough to satisfy a minimum well-spacing requirement were forced to pool their interests into a single well that satisfied the minimum well-spacing requirement. On the East Texas field, where the TRC implemented a 10-acre minimum spacing rule, producers requested and were granted exemptions from the pooling requirement on the basis that such a requirement resulted in confiscation of their property. Ely (1938) estimated that of the 24,269 wells drilled on the field by January 1, 1938, 17,000 had been drilled as exemptions to the pooling requirements. Weaver (1986, pp. 367-68) found an average of 1661 successful exemption requests per year between 1940 and 1981, with 98% of applicants being successful.

Texas passed a Marginal Well Act in 1931, which exempted from prorationing restrictions those wells whose unconstrained production was less than 20 barrels per day. The daily Texas allowable on January 1, 1938 was 1.389 million barrels per day; of this 1.083 million barrels (78%) came from wells exempt by the marginal well act (Ely 1938). On the East Texas field, where 98% of the 491,852 barrels per day field quota were produced by marginal wells, this meant that the remaining 2% was allocated across the 25% of wells not so exempted.

During World War II, prorationing reverted to the federal Petroleum Administration for War (PAW). Because the war imposed great demands on steel and iron, the PAW required that new fields be managed by a 40-acre per well minimum spacing on oil fields and a 640-acre per well minimum spacing on natural gas fields. After the war, the success of these spacing requirements caused many states to adopt similar requirements. Prorationing allocation formulas (based on depth and well-spacing) were altered to give firms an incentive to adopt greater spacing distances between wells. Well-spacing and pooling laws are reported in Table 2, columns 2 and 7, respectively.

4.5.1 Effects of Well-Spacing Rules

Table 5 reports evidence from McDonald (1971) on the number of fields choosing various well-spacing rules between 1950 and 1965. In 1950, 43% of new oil fields in 9 states studied were on well-spacing of 20 acres per well or less and only 6% were on 80 acre per well or larger, but by 1965, only 15% of new oil fields were on a well-spacing of 20 acres per well or less, while 48% now used an 80 acre per well minimum or larger.

4.6 Unitization

Unitization was advocated in the 1920's by independent Texas oil producer Henry L. Doherty, who argued that the field, not the well nor the surface property boundaries, was the obvious economic unit of an oil or gas field (Hardwicke 1961, p. 13). Doherty advocated "unitization" of production as the solution to preventing the boom-and-bust cycle, noting that "the location of an oil pool means under the [rule of capture] that it must be immediately forced upon the market whether the market can take it or not" and claiming that "if the unit plan is adopted, we can recover at least double as much oil as we now do and can conserve at least $66\frac{2}{3}$ percent of our gas" (quoted in American Petroleum Institute 1961, p. 1174-75).

Compulsory unitization legislation is summarized in Table 2, column 4. Under compulsory unitization, when a majority (or supermajority) of producers agree to unitize a field, the remaining producers are required to join the agreement. The Humble Oil Company, at the time the largest oil producer in Texas, was responsible for organizing a voluntary unitization of the Yates field in 1926. Estimates by Humble engineers stated that oil could be produced at \$0.04 per barrel, which was considerably less than the price of \$0.10 per barrel reached in May 1931 (Weaver 1986, p. 47). Humble's method of obtaining unanimous agreement, however, was to threaten to build a pipeline only if the producers agreed to proration output. As Humble was the only pipeline in West Texas, this was a credible threat.

Humble, which leased 16% of the East Texas field, attempted to unitize that field in the same way as it had done on Yates. But unlike Yates, with its small number of producers, East Texas had over nearly 150 potential producers at the time of discovery (see Table 1) and over 600 producers by July, 1931. Furthermore, while the largest 19 producers held 57% of the leases, they only produced 36% of output, while the smallest 586 operators controlled 12% of acreage, but produced 49% of output (Weaver 1986, p. 49). Thus, the East Texas field suffered from large numbers of producers as well as a striking heterogeneity among producers. In contrast, on the Yates field, the largest producer in 1927 owned 12 of 17 wells, but, though still the largest producer a year later, only owned 35 of 204 wells (Libecap and Wiggins 1984). Thus, firms on Yates were both less numerous and more homogeneous in size.

As shown in Table 2, unitization statutes occurred later than prorationing and waste statutes in most jurisdictions. An important exception, however, is the U.S. federal government, which in 1930 amended the 1920 Minerals Leasing Act to require unitization on federal leases, with the Kettleman Hills field in California the first to be unitized under this law. Unlike most state unitization statutes, the federal unitization statute required unitization agreements to be reached prior to exploration. While voluntary unitization was allowed in California and New Mexico as early as 1929, and in Texas as early as 1935 for natural gas, Louisiana introduced a compulsory unitization statute in 1940, when it allowed unitization on gas cycling fields if 75% of the producers agreed to unitizing the field. The first state compulsory unitization statute for oil fields was passed in Oklahoma in 1945. By the 1970s, with the important exception of Texas, most states had passed compulsory unitization laws, although the terms under which compulsion could enforced varied greatly across states.

4.6.1 Effects of Unitization

Bain (1947, p. 29), in an often cited study, reported that of 3,000 fields in the U.S. in 1947, only 12 had been fully unitized. American Bar Association (1948, p. 49), however, reported that between 1929 and 1942, 18 unit agreements had been reached in California, mostly as a result of the federal Minerals Leasing Act, and Williams (1952, p. 1173, n. 74) reported that in 1951 there were 181 federal unitization agreements covering 2,623,261 acres and that in 1949, 53% of oil and 75% of gas on federal lands came from unitized leases. In addition, there were 40 private unitization agreements on natural gas fields in Texas by 1948 (Weaver 1986, p. 78). An IOGCC report in 1964 found that production on unitized fields in the U.S. had risen from 50 million barrels per year in 1948 (2.5% of U.S. production) to 400 million barrels per year in 1962 (15% of U.S. production) (Weaver 1986, p. 418). Surprisingly, the literature contains no systematic empirical analysis of productivity differences between unitized and non-unitized fields.

Table 6 reports the effect on shares of production from unitized fields based on differences in compulsory unitization requirements. Oklahoma, which required 63% agreement to trigger unitization, had 38% of its production by unitized fields in 1975. In contrast, in Texas, where unitization was voluntary, only 20% of production was from unitized fields, although this statistic is skewed somewhat by the fact that the East Texas field, which has never been unitized, accounted for over 20% of cumulative production in Texas by 1979. Table 6 also reports estimates on the number of unitization agreements reached annually in Texas. Between 1948 and 1978, over 1000 unitization agreements were formed in Texas oil fields, accounting for over 50% of production (Weaver 1986, p. 317). Unitization, however, was a lengthy process, with the average time to reach a unitization agreement equal to 18 years in Texas (Weaver 1986, p. 318). Thus, much of the common property rent dissipation had already occurred by the time a unitization agreement was reached. Unitization agreements were also often only partial, since it was too costly to get agreement on all of a field (Weaver 1986, p. 319). On the Slaughter field in west Texas, 28 separate units were created, and 427 offset wells drilled at a cost of $156 million dollars to prevent oil from moving across subunit boundaries (Libecap and Wiggins 1985). However, Boyce and Nostbakken (2011) estimate that the drilling of these offset wells dissipated only about 3% of the rents.

Table 7 reports the results of a study by Libecap and Smith (1999) of 60 unitization agreements. In an efficient agreement, firms share profits, typically by acreage or by some potential production formula. Nearly half (27 of 60) of the agreements they studied allocated the same shares of production and costs to each producer. In addition, another third (19 of 60) of the agreements involved a multiphase plan, in which criteria were specified in advance under which the switch from primary to secondary production would begin. While these agreements had strong self-enforcing mechanisms, oil fields which had gas caps, like Prudhoe Bay, had agreements which were subject to conflict, since the shares held by participants in the gas cap and in the oil rim were unequal. On these fields, much litigation occurred, as different participants' interests were not always aligned.

5 Conclusions

This chapter considered the evolution of property rights for oil and gas in the U.S. over the period 1859-1972. The laissez-faire equilibrium faced two problems: over-drilling due to the rule of capture and a natural boom-and-bust cycle which leads to repeated attempts to control the market. Private solutions were generally either ineffective, because of high bargaining costs among different actors with different interests, or so effective that they resulted in antitrust violations. This opened the door to state solutions. The first major innovation in state solutions was prorationing, which tamed the boom-and-bust cycle, but failed to reduce the incentives for over drilling. This led to calls for either direct regulatory responses such as minimum well-spacing requirements or minimum oil/gas and oil/water requirements, and for appeals to let the industry manage costs through unitization. By the time most of the U.S. states adopted compulsory unitization, however, most of the common property rent dissipation had likely already occurred.

Nevertheless, the history of regulation in oil and gas remains important. Since the oil price shocks in the 1970s, the issue of market power has dominated economists' thinking. But new technological developments in fracturing are now being applied to shale gas and oil fields, causing a new wave of exploration and development in North America with similar common property externality problems. In addition, new developments in dealing with carbon dioxide, including using oil and gas fields for underground storage, are bringing back to the forefront new demands for the regulation of externalities. As regulators seek methods for dealing with these issues, many of the issues that were historically important will reappear.

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6 Web References

U.S. Energy Information Agency:
http:www.eia.gov

Canadian Association of Petroleum Producers:
http:www.capp.ca

Table 1: Private Contracting and State Regulation in Five Oklahoma and Texas Fields

Field	Date	Number of Producers	Time to Private Contract	Time to State Regulation	Output Controls Effectiveness	Output Allocation Rule
Yates	July 1927	6	2 Months		Full Compliance	Acreage
Oklahoma City	December 1928	18	1 Month	1 Year	Small Lot Deviations	Per Well
Seminole	July 1926	27	None Completed	1 Year	Full only with State	Per Well
Hendrick	June 1927	18	None Completed	10 Months	Full only with State	50% Acreage, 50% Per Well
East Texas	October 1930	147	None Completed	7 Months	Full only with State	Per Well

Notes: Adapted from Libecap and Wiggins (1984), Table 3, p. 92, with permission.

Table 2: U.S. Federal and State Oil and Gas Regulations and Court Decisions, 1859-1967

State	1. Casing Abandon	2. Spacing (ac./well)	3. Prorationing	4. Unitization (% Agree)	5. Pooling	6. Common Carrier	7. Waste
Alabama	1911[c]	1911 gas[c] 1935 Waste-O[c]	1945[c]	1951 Gas[e] 1957, 1969 (75)[g] 1956 Big Units[f]	1951[e]		1911 Waste-G[c] 1945 GOR[c]
Alaska				1955 (62.5)[g]			1955 IOGCC[f]
Arizona	1927[b]		1951[f] 1962[f]	1939 (100)[c] 1962 (63)[g]	1951[e]	1962[f]	1927 Waste[c] 1951 IOGCC[f]
Arkansas		1923[a] 1939[c]		1943 (100)[c] 1950 *Dobson v OCC* (compuls.)[f] 1951 (75)[e] 1965 (75)[g]	1943[c]		1939 IOGCC[c] 1957 Water[f] 1959 Water[f]
California	1915[b]	1931 (1)[b]	1931 (defeated)[b]	1929 (100)[b], 1958, 1965 (65)[g]	1950[e]		1929 Flare[b] 1941 MER[c] 1955 MER[f] 1961 Sec.[f]
Colorado	1915[b]	1921[a]		1965[f] 1969 (80)[g]	1951[e]		1915 Vent[b] 1927 Waste-G[b] 1951 IOGCC[f] 1955 *Union Pac. v O&GCC* (Flare)[f]
Florida	1945[c]			1945-G (100)[g]	1945[c]		1945 Offsets[c]
Illinois	1905[b]	1925[a] 1941 (20)[c] 1959[f]			1951[e] 1959[f]		1951 IOGCC[f]
Indiana	1893, 1903[b] 1909[b]	1947 (20)[c] 1965[f]		1947 (100)[g]			1891 Flamb.[b] 1893 Flare[b] 1947 IOGCC[f] 1957 Inject.[f]
Kansas	1981, 1935[b] 1917 Poll.[b] 1949 Plug.[f] 1953 Poll.[f]	1923[a]	1931[b] 1957 old fields[f] 1957 Min. Allow.[f] 1958 *Cit.Serv. v SCCK*	1967 (75)[g]	1929 (Oxford)[e]	1905[b]	1901 MER[b] 1935 IOGCC[b] 1933 Econ.[b]

Table Continues

Table 2 – continued from previous page

State	1. Casing Abandon	2. Spacing (ac./well)	3. Prorationing	4. Unitization (% Agree)	5. Pooling	6. Common Carrier	7. Waste
	1957 Casing[f]		(Gas Price)[f] 1959 Min. Allow.[f] 1959 Purch. Nomin.[f] 1963 *NNG v SCCK* (Interstate gas)[f] 1965 Discoveries[f]				
Kentucky	1892[b] 1966[f]	1960[f]		1948 (100 gas)[c]			1936 Waste-G[b] 1938 Inject.[b]
Louisiana	1906 Poll.[b] 1924[b]	1924[b] 1926[a]	1935[b]	1940-G (75)[g] 1949 *US v Cotton Valley* (Antitrust) 1960[f]	1936[a] 1940[c]	1918[b]	1924 MER-G[b] 1935 GOR[b]
Michigan	1929[b], 1938[b] 1951 Plug.[f]	1935[a]	1938 Gas[b]	1959 (75)[g]	1938[b]	1929[b]	1929 Waste-G[b] 1939 MER, GOR[c]
Mississippi	1932[b]	1933[a]	1932-G (by acre)[b] 1936-G[b] 1948-O[c]	1964 (narrow)[i] 1972 (85)[g]	1948[c]		1948 GOR[b] 1948 IOGCC[f]
Montana	1917[c]	1927[a]		1969 (80)[g]			1953 IOGCC[f]
Nebraska	1941[c]			1959, 1967 (75)[g] 1965[f]			1959 IOGCC[f]
Nevada				1953 (62.5)[g]			1953 IOGCC[f]
New Mexico	1912[b] 1967[f]	1935 (40)[b]	1935[b], 1941 oil[c]	1929 (100)[b] 1941 (100)[c]	1935[a]		1935 MER-O[c] 1944 Disc. Bonus[c] 1949 MER-G, Sec.[f] 1961 Water[f] 1965 Potash[f]
New York	1879[c]			1963, 1972 (60)[g]			1919 Inject.[c] 1963 IOGCC[f]
North Carolina	1945[c]						1945 Waste[c]
North Dakota	1911 gas[c] 1937[c] 1937[c]	1941 (10)[c]		1965, 1971 (80)[g]			1929-37 Logs[c] 1941 MER, GORs, & Inject.[c] 1953 IOGCC[f]
Ohio	1883, 1889[c]	1936[a]		1965[g]			1893, 1896 Flamb.[c]

Table Continues

Table 2 – continued from previous page

State	1. Casing Abandon	2. Spacing (ac./well)	3. Prorationing	4. Unitization (% Agree)	5. Pooling	6. Common Carrier	7. Waste
	1957 Plug.[f] 1963[f]			1967 (65)[g]			1939 Inject.[c] 1964 Water[f] 1965 IOGCC[f]
Oklahoma	1905[b] 1965 Plug.[f]	1935 (40)[b]	1913-G[b] 1914 Oil[b] 1915 gas[b] 1927 statewide[b] 1932 *Champl. v OCC* (upheld proration)[i] 1950 *CitServ. v Peer.* (gas price)[f] 1955 *NGPL v OCC* (gas prices)[f] 1961 *Gulf v Okla.* (compuls. purch.)[f]	1945 (85)[e] 1951 (63)[e] 1951 *Palmer v Phillips* (compuls.)[f]	1935[b] 1959[f]	1909[b]	1915 Econ.[b] 1935 MER[b] 1955 Water[f] 1965 Water[f]
Pennsylvania	1863 Poll[c] 1878 Plug.[c]						1900 *Jones v For. Oil* (rule / capture)[i] 1961 IOGCC[f]
South Dakota	1925[c]		1943 Proration (for waste)[c]	1939 (100)[c] 1961 (75)[g]	1953[f] 1953[f]		1929-G[c] 1929 Gas[c] 1961 IOGCC[f]
Tennessee	1895[c]		1943[c]	1971 (50)[g]			1905 Gas [c] 1943 GOR, Inject.[c] 1947 IOGCC[c]
Texas	1899[b] 1967[f]	1919 (300')[b] 1931 Mrg. Well 1934 Confisc.[d] *Humble v TRC* (upheld 1931) 1958 (40)[h]	1928 Yates Order[b] 1930 statewide (overturned)[i] 1931 statewide (overturned)[h] 1932 pro rata (overturned)[h] 1933 50:50 (well/pressure)[h]	1935 Gas (100)[i] 1949 Oil (100)[i] 1953 Gas[f]	1961 *ARCO v TRC* 1965[f]	1917[b] 1930[i] 1958 *Perm. Bas. v TRC*	1899 Flamb.[b] 1931[h] 1925 Flare-O[h] 1934 Flare-G[i] 1949 *TRC v Sterling* (Flare)[f]

Table Continues

Table 2 – continued from previous page

State	1. Casing Abandon	2. Spacing (ac./well)	3. Prorationing	4. Unitization (% Agree)	5. Pooling	6. Common Carrier	7. Waste
			1935[h] 1941 *TRC v Rowan & Nichols* (St. Crts.)[i] 1953 *TRC v Rowan* (correlative rights)[i] 1961 *ARCO v TRC* (small tracts)[f] 1962 *Halbouty v TRC* (small tracts)[f]				1953 *TRC v Rowan* (Flare)[f] 1961 Inject.[f] 1961 Poll.[f]
Utah		1965[f]		1969 (80)[g]			1955 IOGCC[f]
Virginia							1950 Coal Seams[f]
West Virginia				1972 (75)[g]			1932 Conserv.[a]
Wyoming				1931[a] 1971 (80)[g]	1951[e]		1950 Flare[f] 1951 IOGCC[f] 1951 Coal Seams[f]
U.S. Federal			1933 NIRA[h] 1935 *Panama v Ryan* (NIRA)[h] 1935 Hot Oil Act[h] 1938 Nat. Gas Act[f] 1954 *Phillips v Wisc.* (Gas Price)[f] 1961 *FPC v TCG* (Pipeline)[f]	1930[a] 1954 (Unit Extensions)[f]		1906 (Hepburn Act) 1953 Exempt[f]	

Notes:
Well Casing and Abandonment: "Casing" – Regulates casing of wells. "Poll." – Regulates pollution from oil or gas wells. "Plug." – Regulates plugging of abandoned wells. *Prorationing:* "Defeated" – Passed by legislature, but defeated by referendum (California). *Waste:* "IOGCC" – Interstate Oil and Gas Commission Model Waste Statute (gas/oil ratio, MER, economic waste, no-flaring or venting of natural gas, injection and water disposal regulations). "Flamb." – Prohibits 'flambeau' natural gas lights. "GOR" – Gas/Oil Ratio regulation. "MER" – Maximum Efficient Rate of Production Regulation. "Waste" – Prevents 'physical' waste. "Econ." – Prevents 'economic' waste. "Flare" – Prevents flaring of natural gas. "Vent" – Prevents venting of natural gas. "-G"/"-O" – Previous Regulation applies only to Gas or Oil fields (otherwise to both). "Inject." – Regulates injection wells. "Water" – Regulates water disposal. "Sec." – Regulates secondary production methods. "Offsets" – Regulates drilling of offset wells.
Sources:
[a] Ely (1938), [b] American Bar Association (1938), [c] American Bar Association (1948), [d] Hardwicke (1951-52), [e] Williams (1952), [f] McDonald (1971), [g] Eckman (1972), [h] Prindle (1981), [i] Weaver (1986).

Table 3: Effects of Prorationing on Field Pressure and Drilling Density

(*A*) Fields Discovered Prior to Prorationing

Field	State	Year Discovered	15th Yr. Prod. (% of peak)	Acres	Wells Drilled	Acres / Well	1952 Reserves	1952 Cum. Production	Reserves / Well	(Reserves + Cum. Prod.)/Wells
Smackover	AR	1922	9.1	29,500	3,919	7.5	465	430	0.12	0.23
El Dorado	AR	1920	8.1	10,650	1,125	9.5	65	60	0.06	0.11
Cushing	OK	1912	15.8	27,800	3,731	7.5	410	358	0.11	0.21
Healdton	OK	1913	27.6	7,200	2,511	2.9	230	206	0.09	0.17
Haynesville	LA	1921	6.1	13,650	978	14.0	125	106	0.13	0.24
Homer	LA	1919	4.6	3,020	651	4.6	85	132	0.13	0.33
Hendricks	TX	1926	4.8	9,800	621	15.8	230	224	0.37	0.73
Baston	TX	1903	5.8	650	1,136	0.6	50	42	0.04	0.08
Spindletop	TX	1901	1.9	500	1,461	0.3	130	131	0.09	0.18
Mexica	TX	1921	2.3	3,980	600	6.6	107	103	0.18	0.35
Average		1916	8.6	10,675	1,673	6.9	189	179	0.13	0.26

(*B*) Fields Discovered After Prorationing

Field	State	Year Discovered	15th Yr. Prod. (% of peak)	Acres	Wells Drilled	Acres / Well	1952 Reserves	1952 Cum. Production	Reserves / Well	(Reserves + Cum. Prod.)/Wells
Wasson	TX	1936	76.8	62,025	1,757	35.3	650	276	0.37	0.53
Slaughter	TX	1936	63.0	83,490	2,169	38.5	475	199	0.22	0.31
Tom O'Connor	TX	1934	64.8	12,000	680	17.6	499	196	0.73	1.02
Thompson	TX	1931	69.2	6,500	417	15.6	225	153	0.54	0.91
Webster	TX	1937	65.2	4,000	217	18.4	350	192	1.61	2.50
Goldsmith	TX	1934	82.5	62,200	2,083	29.9	440	170	0.21	0.29
Hawkins	TX	1940	100.0	9,200	663	13.9	480	166	0.72	0.98
Anahuac	TX	1935	57.1	7,000	367	19.1	250	122	0.68	1.01
Keystone	TX	1930	71.0	32,300	999	32.3	450	122	0.45	0.57
Conroe	TX	1931	89.5	17,660	1,014	17.4	525	331	0.52	0.84
Average		1934	73.9	29,638	1,037	23.8	434	193	0.61	0.90

Notes: Adapted from Zimmermann (1957), Tables XV-XVIII, pp. 284-89, with permission. Reserves and Cumulative Production in millions of barrels. 15th year production is percentage of peak production.

Table 4: Overcapacity from Prorationing

	Prorationing Market Demand Factors (%)				Ratio of Output to Productive Capacity (%)									
					Market Demand States					Non-Market Demand States				
Year	Texas	Louisiana	New Mexico	Oklahoma	Texas	Louisiana	New Mexico	Oklahoma	Kansas	Mississippi	Colorado	Wyoming	Montana	Utah
1954	53	61	57		71	85	91	82	92	97	115	85	78	119
1955	53	48	57	60	72	87	99	83	88	106	93	83	73	85
1956	52	42	56	53	72	80	93	84	88	98	92	88	96	96
1957	47	43	56	52	70	69	93	83	88	93	89	92	100	80
1958	33	33	49	45	60	59	89	79	88	100	86	97	85	136
1959	34	34	50	41	63	63	92	79	90	119	90	100	97	110
1960	28	34	49	35	60	67	90	77	87	104	100	105	97	102
1961	28	32	49	31	60	65	88	79	88	104	100	102	107	82
1962	27	32	50	35	59	68	83	82	90	104	91	94	110	94
1963	28	32	54	31	62	69	84	84	89	104	95	100	97	108
1964	28	32	54	28	63	68	89	86	89	98	95	98	100	87
1965	29	33	56	27	64	66	92	87	91	103	97	96	106	92
1966	34	35	65	38	67	69	96	98	95	89	101	94	104	100
1967	41	38	74	50	70	69	98	101	97	88	100	90	96	98
Average	36.8	37.8	55.4	40.5	65.2	70.3	91.2	84.6	90.0	100.5	96.0	94.6	96.1	99.2

Notes: Adapted from McDonald (1971), Tables 15-17, pp. 164-67, with permission.

Table 5: Well Spacing on New Fields

State	Year	≤ 20 Acres	40 Acres	80 Acres	≥ 160 Acres	TOTAL
Louisiana	1950	2	20	7	0	29
	1955	4	10	6	0	20
	1960	10	23	12	3	48
	1965	8	17	40	5	70
Oklahoma	1950	21	18	0	0	39
	1955	115	37	2	0	154
	1960	42	53	41	0	136
	1965	57	90	104	3	254
Texas	1950	30	24	0	0	54
	1955	31	44	19	0	94
	1960	14	69	22	0	105
	1965	5	55	38	6	104
All States	1950	53	63	8	0	124
	1955	152	123	45	3	323
	1960	70	176	100	10	356
	1965	75	201	218	23	517

Notes: Adapted from McDonald (1971), Table 18, p. 169, with permission. All States includes Colorado, Kansas, Montana, North Dakota, and Wyoming in addition to the states listed.

Table 6: Percentage of Oil Production from Unitized Fields and Number of Oil Fields Unitized.

	Percent of Production from Unitized Fields			Annual Number of Oil Fields Unitized in Texas
	Wyoming	Oklahoma	Texas	
1950	51	10	1	11
1955	55	25	4	19
1960	64	24	7	64
1965	70	30	16	74
1970	67	35	14	38
1975	82	38	20	12

Notes: Percent of production from unitized fields adapted from Libecap and Wiggins (1985), Table 1, p. 92, with permission; number of fields unitized adapted from Weaver (1986), Appendix III, with permission.

Table 7: Characteristics of Unitization Agreements.

		Multi-phase Partition	No Multi-phase Partition
	Number of Agreements	3	11
Dual Participating Partition	(%) Equal Profit Shares	0%	9%
	(%) Phase Trigger	100%	–
	Number of Agreements	19	27
No Dual Participating Partition	(%) Equal Profit Shares	100%	100%
	(%) Phase Trigger	95%	–

Notes: Adapted from Libecap and Smith (1999), Table 1, p. 540, with permission. A total of 60 Unit Operating Agreements are studied.