EFFECTS OF HYDRAULIC FRACTURING IN OKLAHOMA WATERFLOOD WELLS

By John P. Powell and Kenneth H. Johnston
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EFFECTS OF HYDRAULIC FRACTURING IN OKLAHOMA WATERFLOOD WELLS

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INTRODUCTION AND SUMMARY

A comprehensive study of the effects of hydraulically fracturing waterflood wells in Oklahoma has been made by the Federal Bureau of Mines. This report presents results of that study and an analysis of some of the factors governing the results of fracture treatment on waterflood properties.

Originally, hydraulic fracturing was used to stimulate oil production from old wells producing by primary methods, and its application to waterflooding was regarded with skepticism by most producers. However, since 1953 the number of fracture treatments of both oil and input wells in waterfloods has increased steadily. Hydraulic-fracture treatments in waterfloods have generally been successful in stimulating production from oil wells and increasing the rate of injection into input wells. Hydraulic fracturing has enabled several producers to turn probable failures into economically successful projects.

The results of hydraulic fracturing may be affected by many factors, such as the technique used, reservoir fluid and rock characteristics, well-completion practices, and rates of fluid production. The following general conclusions have been drawn:

1. Hydraulic fracturing has resulted in increased rates and increased ultimate recovery of oil from many waterflood projects.

2. Fracturing has been quite effective in improving the performance of partly plugged wells.

3. Most fracturing failures have occurred in edge wells that were fractured with a standard-size treatment, which usually is used in wells having an average thickness of sand.

1/ Work on manuscript completed June 1960.
2/ Former Bureau of Mines petroleum engineer, Bartlesville, Okla.
4. Good results have been obtained in fracturing productive formations above or below water zones by using planned well-completion procedures.

5. Correlating known fracturing techniques with reservoir characteristics, production histories, and well-completion methods is important in selecting the optimum fracture treatments for a particular productive area or field.

Of all the techniques used to increase the productivity of individual wells, hydraulic fracturing probably has had the greatest impact upon the industry. Although the principle of increasing the productivity of wells by hydraulically fracturing the reservoir rock was suggested as early as 1935 by Grebe and Stoesser (3)\(^4\). The practice as now widely applied was first made available to the industry commercially in 1949 under license agreements with the Stanolind Oil & Gas Co. (now Pan American Petroleum Corp.) (2).

The original hydraulic-fracturing process used a gelled hydrocarbon for carrying sand in suspension into fractures artificially created by induced pressure. Later variations in the fluid included the use of residual oils, crude oils, and water. Many changes in fracturing techniques have occurred since 1950 (9). At first, the application of fracturing to waterflood projects was regarded with great skepticism. Now, however, fracturing is used successfully to stimulate production from old wells and for routine completion of new wells in waterflood projects. Fracturing, as well as acidizing and shooting, are used in completing wells in both primary and secondary production operations.

Hydraulic fracturing has been especially effective in Oklahoma (10). Not only has it stimulated oil production when drilling new and proved fields, but it has resulted in the recovery of significant quantities of oil from many shallow sandstones formerly considered uneconomical to produce. This has been especially true in northeastern Oklahoma. The application of fracturing to waterflood wells, which was begun about 1953, also has been a particularly significant development.

Figure 1 shows the total number of hydraulic fracture treatments performed each month in Oklahoma by major licensed companies. Except for seasonal fluctuations, the number of jobs increased steadily from 1949 to May 1954 and reached peaks of 930 jobs in May 1955, and 920 in May 1956. The sharp decrease in the number of treatments from June 1956 to June 1957 was the result of a general slackening of oil activities throughout the State.

Guerrero (4) reports that almost all experimental and theoretical work has shown that properly controlled fracturing is beneficial to waterflooding. Nevertheless, many operators have been reluctant to fracture their producing and input wells, except where other methods of stimulation have failed. How-

\(^4\) Underlined numbers in parentheses refer to items in the bibliography at the end of this report.
ever, service companies report that the number of fracture treatments performed on waterflood projects has increased during the last 2 years.

ACKNOWLEDGMENTS

The authors gratefully acknowledge the cooperation and assistance of the following oil and service companies that furnished data for the report: Phillips Petroleum Co., Blackwell Oil and Gas Co., Sunray Mid-Continent Oil Co., Sinclair Oil and Gas Co., Kewanee Oil Corp., Keener Oil Co., Pan American Petroleum Corp., The Pure Oil Co., Blackwell Zinc Co., Inc., Dowell Inc., and Halliburton Oil Well Cementing Co. Special thanks are extended to the many members of the Independent Petroleum Association of America and the I.P.A.A. Secondary Recovery and Stripper Well Committee for their encouragement and willingness to cooperate in supplying data included in this report.

EFFECTS OF NATURAL JOINTS AND FRACTURES

Many authorities have indicated that no oil-productive formation is homogeneous. Most formations of marine origin contain natural bedding planes and laminations because of conditions attending their deposition. Compaction, compression, and tension during burial and lithification have formed additional joint-and-fracture systems.
Early recognition of joint-and-fracture systems in a producing formation is helpful, not only during primary development but also in later application of secondary-recovery methods. Systems of joints and fractures effect the results of hydraulic-fracture treatments. In many formations natural joints and fractures may be found at the top of the productive sands. Enlargement of such a fracture may cause serious loss of injected water and impair the efficiency of a water drive. Sometimes, natural joint systems are beneficial in a waterflood. Engineers found in one field that a system of natural joints caused the fractures resulting from hydraulic treatments to be oriented in one direction. Knowledge of this condition caused a change in the flooding pattern, which resulted in better oil recoveries from the project.

Such natural fracture systems also may be harmful. After an unsuccessful fracture treatment of a producing well, a core taken from a new well drilled within a radius of 25 feet showed that the initial horizontal fracture had been diverted by a natural joint into a vertical plane.

Enlargement of this natural joint resulted in the penetration of a water zone and failure of the hydraulic-fracture treatment. In another well, a core taken 50 feet from a fractured well showed the fracture 45 feet below its point of origin. The initial horizontal fracture had been diverted into a vertical plane by a natural joint and had penetrated a bottom water zone. The fracture treatment was unsuccessful.

TIME TO FRACTURE

In waterflooding the question of when to fracture the wells is important and deserves careful consideration. For input wells, the solution is comparatively easy. When a well fails to take water initially or at injection rates necessary for economical recovery, the formation often is "broken down" (fracture treated); however, different practices have been followed for oil-producing wells. Some companies fracture an oil well when the total produced fluid is less than 50 percent of the proportionate volume entering the surrounding input wells. Where oil wells with open-hole completions initially were shot, the best results have been obtained from wells that were hydraulically fractured when the water-oil ratio was 10:1. Other operators believe that wells should be treated when the water-oil ratio is 1:1.

Oil wells that were drilled several months after flooding was commenced and fractured soon after completion have had high initial production rates followed by a sharp decline. This is caused by releasing the built-up reservoir pressure created by a delay in drilling. Figure 2 shows production tests of a Bartlesville-sand well in a delayed flood, fractured when the well was completed. The initial production is not shown, as it was greater than the capacity of the 400-barrel test tank. The sharp decline in the total produced fluid indicates that part of the rapid decline in oil production during 1959 may have resulted from chemical deposits that plugged the sand face.

Figure 3 shows production tests of a Bartlesville-sand well in a delayed flood, fractured 3 months after completion. The first peak rate of oil production resulted from the release of the built-up reservoir pressure through
FIGURE 2. - Production Tests of a Bartlesville-Sand Well in a Delayed Flood, Showing Results Obtained from Fracture Treatment at Time of Well Completion.
FIGURE 3. - Production Tests of a Bartlesville-Sand Well in a Delayed Flood, Showing Results Obtained from Fracture Treatment 3 Months After Well Completion.
fractures resulting from the hydraulic fracture treatment. During the first 5 months after fracture treatment, water-free oil was produced. After pressure was released, oil production declined sharply from approximately 175 to 90 barrels per day. During the next 7 months, production increased to a high of 180 barrels per day in January 1959 and then declined to approximately 30 barrels per day in August 1959. The decline in total produced fluid in May and June 1959 suggests plugging of the sand face.

In any waterflood adequate time should be allowed for the reservoir to fill with liquid and respond to the water drive by forming an oil bank before fracture treatment is tried. Premature fracturing of producing wells could result in water bypassing and trapping large volumes of oil.

In contrast to premature fracturing of oil-producing wells in a waterflood, there also is the possibility of delaying too long. When a well is fractured in a flood that has been operating for several years, the fractures often extend into channels or fracture systems established by water injection at high pressures or into the more permeable zones that have been depleted of oil. This results in an increased rate of water production after hydraulic fracturing.

To illustrate the results of fracture treatments at different stages, two adjacent waterfloods (A, with 4,616 acre-feet, and B, with 3,040 acre-feet) of floodable sand were studied. These tracts were in the same area, and the general characteristics of the producing sand were the same. Figure 4 shows the production history of flood A, which was fractured 18 months after a peak

![Graph showing production history of flood A](image_url)
rate of oil production of 17,200 barrels per month. The rate of production
decline after fracture treatment is at a high level, approximately paralleling
the estimated normal rate of decline. This indicates recovery of additional
oil before the flood production reaches an economic limit. The increase in
ultimate recovery over normal waterflood production was approximately 179,000
barrels. Figure 5 shows the production history of flood B, fractured 36
months after a peak rate of oil production of 30,300 barrels per month. Again,
the decline after fracturing nearly parallels the estimated normal decline,
indicating an increase in the ultimate recovery of approximately 55,000 bar-
rels. Assuming that the wells of flood B had been fractured 18 months after
peak production, a hypothetical curve was drawn on figure 5 to show the addi-
tional oil that possibly could have been recovered by fracturing earlier in
the life of the flood. The hypothetical position of the curve was based upon
the production of flood A (fig. 4) multiplied by the ratio of the productive
sand volumes of the two floods.

From the information in figure 5, researchers estimated that an ultimate
recovery of 118,000 barrels, or 63,000 barrels of additional oil, might have
been recovered from flood B if the wells had been fractured 18 months earlier.
The earlier and additional oil recovery would have hastened the payout for the
project and could have been an important economic factor.

FIGURE 5. - Production History of Flood B, Showing Results Obtained from Fracture
Treatment 36 Months After Peak Rate of Production and Estimated Results
from Fracturing 18 Months Earlier.
Figure 6 illustrates another example of results that may be expected from fracture treatment of a well several years after the peak rate of production. This well was fractured with 3,000 gallons of fluid and 6,000 pounds of sand 2 years after completion. No appreciable increase in the rate of oil production from the treatment was noted, but the normal production decline was retarded and the productive life of the well was extended for several years despite rapid increase in the water-oil ratio beginning in the first part of 1954. As shown in the figure, the rate of water production increased sharply to a peak of 640 barrels per day in August 1954, probably indicating depletion of a high permeability zone.

SIZE OF TREATMENT

Researchers studied the proper size of hydraulic treatment, volume of fluid, and quantity of sand that should be used when fracturing wells. The best results were obtained when engineering data and past experience in a particular area were considered when selecting the size of treatment. Service companies, licensed to sell hydraulic-fracturing services, have followed the practice of fracturing with variations in the use of different fluids, acids,

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5/ The term "fluid" is generally used in hydraulic-fracturing terminology to indicate oil, water, or other liquids, with or without chemical additives.
additives, and propping agents. Then, on the basis of past experience, these companies recommend size of treatments for specific areas.

Often the type and size of fracture treatment used are controlled by the personal likes and desires of the operator purchasing the service. Some operators have copied and used the type and size of treatment used by a neighbor or friend, although better results may have been obtained by modifying the treatment to meet the operator's own conditions. Other operators base the size and type of their treatments on the pumping capacity or service cost of a single truck or unit. Economically this might be a good practice; however, it may not give the best results in recovery of additional oil.

In the Bartlesville-Dewey area and in the adjacent shallow oil-productive area to the east, small initial treatments using 2,000 to 3,000 gallons of fracture fluid and 4,000 to 6,000 pounds of sand have been most effective. When wells were refractured, best results were obtained when the size of the treatment was increased by approximately one-half that of the original.

Table 1 shows data on fracture treatment of 74 Bartlesville-sand wells ranging in depth from 630 to 3,132 feet. The size of the fracture treatments ranged from 1,000 gallons of fluid with 1,000 pounds of sand to 10,000 gallons of fluid with 20,000 pounds of sand. In most of the treatments, either 2,000 gallons of fluid with 4,000 pounds of sand or 3,000 gallons of fluid with 6,000 pounds of sand were used. Favorable results were obtained by treating two of the deeper wells with 800 gallons of fluid and 1,500 pounds of sand. The sand-oil ratio for most of the treatments was 2 pounds per gallon of fracturing fluid, but favorable results were obtained with sand-oil ratios of 1 and 1.5. The table also shows well-completion data, injection rates, breakdown and maximum treating pressures, and the rates of oil and water production and water-oil ratios before and 60 to 90 days after treatment. Favorable results were obtained from most of the 74 treatments. It is of special interest that some of the shallow Bartlesville-sand wells required higher breakdown pressures than those at greater depths.

In the Burbank field the first hydraulic-fracture treatments were small; 1,000 gallons of fluid and 1,500 pounds of sand generally were used. In a few treatments, 3,000 gallons of fluid and 6,000 pounds of sand were used. Field tests showed that for the thicker oil-productive sections best results were obtained when the size of the treatment was increased to 10,000 gallons of fluid and 20,000 pounds of sand.

Table 2 shows data on the fracturing and refracturing treatments of 15 Burbank-sand wells in the Burbank field. The size of initial fracture treatments ranged from 1,000 gallons of fluid and 1,500 pounds of sand to 10,000 gallons of fracture fluid and 20,000 pounds of sand. Refracturing treatments ranged from 1,000 gallons of fluid and 20,000 pounds of sand to 20,000 gallons of fluid and 30,000 pounds of sand. The sand-oil ratio ranged from 1.5 to 2.0 pounds of sand per gallon of fluid for initial treatments and 1.5 to 2.5 for most of the refracturing treatments. On one refracture job, the sand-oil ratio was 20 pounds per gallon. The table also shows well-completion data, injection rates, breakdown and maximum treating pressures, the rates of oil
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1/ Pressure at sand face (4.33 x depth + pump pressure). 2/ Difference between break-down and bottom-hole treating pressure.
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1/ Pressure at surface (3/4 x depth + pump pressure).
2/ Difference between break-down and bottom-hole treating pressures.
and water production, and water-oil ratios before and 60 to 90 days after treatment. In most refracturing treatments, an appreciable increase in the rate of oil production was obtained by using several times the size of the initial treatment. The results obtained by fracture treatment of the Burbank sand are described by Kaufman (5).

Table 3 shows data on fracture treatment of wells producing from 10 formations other than the Bartlesville and Burbank sands. The formations range in depth from 1,000 to 6,800 feet. The size of treatments ranged from 1,000 gallons of fluid and 2,000 pounds of sand to 8,000 gallons of fluid and 16,000 pounds of sand. The sand-oil ratio ranged from 1 to 2 pounds of sand per gallon of fracturing fluid. More favorable results generally were obtained from treatments using the higher ratio. The table also shows well-completion data, injection rates, breakdown and maximum treating pressures, and the rates of oil and water production and water-oil ratios before and 60 to 90 days after treatment. Kaufman (5) also discusses the size of treatment and results obtained from fracture treatment of several formations other than the Burbank and Bartlesville sands.

In the last 3 years the trend in industry has been toward larger sizes of fracture treatment. A technical report published by the Oil and Gas Journal (6) in 1957 shows that treatment sizes increased continuously from the advent of hydraulic fracturing in 1949 to 1957. Average volume increased from 3,000 to 4,000 gallons per treatment in the early 1950's to 7,500 to 8,500 gallons per treatment in 1956.

Larger treatments generally result in larger increases in the rate of production. When a formation is known to respond to fracturing, a big treatment is more economical than several successive smaller treatments. However, 14 fracture treatments by the Carter Oil Co. (1) in the Earlsboro sand in the Keokuk pool, Seminole and Lincoln Counties, Okla., indicate that there is an optimum size of treatment for that area. In all treatments the sand-oil ratio was 2 pounds per gallon, and the pumping rate during injection was about 5 barrels per minute. All wells were in an advanced stage of depletion. The average ultimate increased recovery of oil for four jobs using less than 225 gallons of fluid per foot of sand was estimated at 8,700 barrels, and the average gain for six jobs using more than 350 gallons per foot of sand was about 7,600 barrels. In comparison, the estimated average ultimate increased oil recovery for four treatments using 225 to 350 gallons per foot of sand was about 25,600 barrels per job. Because well conditions vary for fracture treatments in different areas, this evaluation indicates an optimum-size job of 225 to 350 gallons per foot of sand for the Earlsboro sand in the Keokuk pool only.

From the fracture treatment of 20 producing wells and 4 input wells in North Texas, some of the parameters Riley (8) has suggested for use in selecting job size, injection rates, maximum injection pressures, and type of fracture job follow: (1) Based on sand thickness and 10 to 20 acres per well density, a maximum fluid volume of 50 gallons per foot of pay zone treated should not be exceeded; (2) multiple fracture treatments can be obtained more easily by using high fluid-loss fracturing fluids and/or selective plugging
agents; (3) a formula derived from the Darcy equation for flow relating fracture length to injection rate, fracturing fluid viscosity, formation permeability, and fracture time can be used in job planning; (4) injection rates apparently are critical to fracture length; injection of 0.5 to 1.0 barrel per minute per foot of net pay has been relatively successful in most instances provided volumes are maintained at the level stated above, permeabilities average 30 to 100 millidarcys, and a true fracturing fluid is used; (5) low injection rates and medium volumes or high injection rates and very low injection volumes give desired results; and (6) the injection pressure necessary to create formation fracturing normally does not exceed 1 pound per foot of depth.

As an aid in selecting the optimum size of treatment, accumulated data on fracture treatments in a local area or field should be tabulated and analyzed. The tabulated data should include well-completion practices, shot size or number of perforations, size of treatment (fluid and sand), pumping rates and treating pressures, and rates of oil and water production before and after treatment. Where possible, these data should be correlated with porosity, permeability, and saturation data.

EFFECTS OF HYDRAULIC FRACTURING IN BARTLESVILLE-SAND WELLS

Hydraulic fracturing to stimulate oil production in waterfloods was first used in the shallow sands of northeastern Oklahoma. One of the first full-scale uses was in the Weber pool in Washington County, where the treatment of 24 producing wells, 21 successful, resulted in the recovery of 112,000 barrels of oil in 11 months in addition to that expected by waterflooding (7). Most of the wells originally were treated with 6,000 pounds of sand and 3,000 gallons of oil. Some of the wells were refractured with 10,000 pounds of sand and 5,000 gallons of oil. Two of the unsuccessful fracture treatments were caused by fractures extending into a depleted gas sand on top of an oil sand. This gas sand had relatively low oil saturation from migration and a high water saturation. The third failure was in a shaly section on the edge of a flood that had been watered out.

The following conclusions were drawn from the results obtained on the 24 fracture treatments:

1. A fracture treatment probably is more successful when the well has been shot originally. The shot creates many small fractures in the sand face, which are multiplied and lengthened by the fracture treatment.

2. Accurate records of quantities of water injected and fluid produced are important to indicate the efficiency of the flood sweep and to show the oil wells that need treatment.

3. Newly drilled wells should be cored.

4. In both primary and waterflood production, shaly sections and those of low permeability seem to react better to fracturing than cleaner sections of sand.
5. Even in clean sections of sand, fracturing may increase ultimate recovery.

6. Where a depleted gas sand lies atop or very near the oil sand, fractures may extend into the gas zone and provide a channel for injected water to move directly to producing wells.

Figure 7 shows the results obtained from the fracture treatment of 43 oil wells in a Bartlesville-sand waterflood in Nowata County, Okla. Early fracture treatments were small; 1,000 to 3,000 gallons of fracture fluid and a sand-oil ratio of 1 pound per gallon of fluid were used. In later treatments, 3,000 gallons of fluid and a sand-oil ratio of 2 pounds per gallon were used. A substantial increase in the rate of oil and water production was obtained by increasing the size of the treatments. An estimated 145,000 barrels of oil, equivalent to 3,372 barrels per well, was recovered in 1958 as a result of fracture treatments.

Figure 8 gives the results obtained from fracture treatment 3 months after completion of a Bartlesville-sand well that initially produced oil and water. The well was fractured in March 1958 with 3,000 gallons of fracture fluid and 6,000 pounds of sand. The fluid was injected at a rate of 16 barrels per minute and a maximum pressure of 1,300 p.s.i. The fracture sharply increased oil production to a peak rate of approximately 250 barrels per day with only a slight increase in the rate of water production. From this amount, oil production decreased gradually to approximately 80 barrels per day in August 1959. Water production increased gradually for about 8 months and then increased sharply to approximately 350 barrels per day in May 1959.

Figure 9 shows production tests of a Bartlesville-sand well in a regular flood, fractured 3 months after completion and shot with nitroglycerin 2 years later. The well was fractured in March 1958 with 2,000 gallons of fracture fluid and 4,000 pounds of sand. The rate of injection was 65 barrels per minute, and the maximum pressure 1,263 p.s.i. This treatment resulted in a gradual increase in the rate of oil production to approximately 60 barrels per day in July 1958. From this, the oil production decreased gradually to approximately 20 barrels per day in April 1959. The rate of water production increased sharply at the time of treatment to a peak of approximately 120 barrels per day but decreased to 60 barrels per day in June 1958. Shooting the well with 22 quarts of nitroglycerin in April 1959 resulted in a small increase in the rate of oil production and a large increase in the rate of water production.

Figure 10 shows production tests of a Bartlesville-sand well shot with nitroglycerin 2 years after completion and fractured 2 years later. In August 1954 the rate of oil production was approximately 2 barrels per day, but after shooting with 30 quarts of nitroglycerin it increased to approximately 40 barrels per day. From this peak, the rate decreased to approximately 2 barrels per day in May 1956. The fracture treatment with 3,000 gallons of fluid and 6,000 pounds of sand increased oil production to approximately 40 barrels per day. From this peak the rate decreased gradually to approximately 3 barrels per day in December 1956. The rate of water production
FIGURE 7. - Production History of a Bartlesville-Sand Waterflood, Showing Results Obtained from Fracture Treatment of 43 Wells.
FIGURE 8. - Production Tests of a Bartlesville-Sand Well That Initially Produced Oil and Water, Showing Results Obtained from Fracture Treatment 3 Months After Completion.
FIGURE 9. - Production Tests of a Bartlesville-Sand Well in a Regular Flood, Showing Results Obtained from Fracture Treatment 3 Months After Completion and Fracture Treatment 2 Years Later.
remained nearly uniform after the nitroglycerin shot but increased sharply following the fracture treatment. Both the nitroglycerin shot and the fracture treatment retarded the normal rate of decline and extended the economic life of the well for several years.

Figure 11 shows production tests and the results of fracture and refracture treatments of a Bartlesville-sand well in a delayed flood. The well was fractured with a small treatment immediately after completion, but failed to respond with a sharp increase in the rate of oil production typical of wells in a delayed flood. The well was refractured 9 months later, and a sharp increase in water production resulted, with little change in the rate of oil production.

Figure 12 indicates the results of refracture treatment through perforations of an upper zone. The well was completed in open hole, except that an upper gas sand was cemented behind the casing. The well was fractured with 2,000 gallons of fluid and 4,000 pounds of sand. The rate of injection was 12 barrels per minute at a pressure of 1,889 p.s.i. The initial rate of oil
FIGURE 11. - Production Tests of a Bartlesville-Sand Well in a Delayed Flood, Showing Results Obtained from Fracture and Refracture Treatments.
FIGURE 12. - Production Tests of a Bartlesville-Sand Well in a Delayed Flood, Showing Results Obtained from Fracture Treatment and Refracture Treatment Through Perforations in an Upper Section.
production was low, but the well responded to fracture treatment with a marked increase in both oil and water production. This was typical of wells fractured in a delayed flood. The sudden decrease in the rate of oil and water production in November 1958 was caused by pump difficulty. In May 1959 the casing opposite an upper sand was perforated, and the well was refractured through the perforations. Production data and well tests indicated that fractures from the second treatment entered and enlarged the fractures formed by the original treatment. A rapid decrease in total fluid produced in July and August 1959 was believed to be the result of chemical plugging in the fractures and at the sand face.
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