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Optimization of Bit Performance for Qatar's Offshore North Field

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Abstract

This paper describes the methodology and the results of a successful partnership between operator and service companies that improved the drilling performance and economics for the development of the North Field in Qatar. Fifteen high rate gas wells were delivered within designated directional targets, ahead of schedule and under budget.

The systematic use of a new methodology for bit selection, linked with an excellent level of communication and confidence between different parties involved in the drilling operations, was a major reason for the drilling success.

The different sections drilled were mainly made up of limestone, marl, and shale, but also anhydrite in the top portions of the well. In the lower sections, hard and soft limestone alternates with highly compacted shales and dolomites. Penetration rates were greatly enhanced and bit performance improved by more than 100% in some instances.

The optimization of the performance took into consideration three aspects:

1. A very tight schedule, where the optimization phase had to be performed within a limited time frame: Four wells were planned to be drilled back to back with two jack up rigs from two production platforms. After this short phase, batch drilling was expected to be performed for more than 20 deviated wells.
2. The formations to be drilled presented a high complexity and heterogeneity where hard stringers alternate with a soft or a very compacted rock, and where in the lower section of the hole, a typical pseudo plastic behavior of the rock has to be anticipated.
3. The well designs, casing depths, and bit types had to be in harmony with the drilling environment, the formation, and provide effective performance. New bit designs, more adapted to the technology available had to be developed or identified.

The use of roller cone bits and motors was planned and used in the top hole sections. The use of PDC bits associated with extended steerable motors and/or turbines was considered as potentially providing the best performance in the intermediate and bottom sections.

The early bit designs were modified based on wear patterns of dull bits. These enhancements and modifications were one of the major reasons in improved drilling performance and helped reduce the total drilling time from 75 days to 56 days per well. The challenges were met successfully, the most economical options selected and carried out ahead of time and under budget.

Introduction

The North Field Development - Phase 2, North Field Bravo (NFB), is the second development of the giant North Field, offshore Qatar (**Fig. 1**). Qatar Liquefied Gas Company (Qatargas) is responsible for this development, and to date, 15 deviated production wells have been drilled from two centrally located wellhead platforms.

Following the field discovery in 1971, 18 vertical exploration/appraisal wells were drilled across the field to provide information on structure/reservoir development. A further 16 deviated production wells were drilled and completed for the first phase of gas production from the North Field Alpha (NFA) Complex. Records from these latter wells were used to benchmark the drilling performance in the NFB series of wells.

The NFB wells are high departure directional wells with an average inclination of ±55 degrees. The well bores can be split into two main sections, the upper section consisting of 24" and 16" phases and the lower section covering the $12^1/_4$" and $8^1/_2$" hole sizes.

The use of tricone bits on steerable motors was planned for the upper section, and PDC bits on turbines or extended motors were considered to provide the best performance potential in the $12^1/_4$" and $8^1/_2$" phases.

From an analysis of the data from Phase 1 (NFA) wells and the delineation well for the NFB block (NFB-1), it was believed that the number of bits used to drill the two main sections could be reduced by at least 50% and the average ROP performance could be improved by between 15 to 20%.

It was decided to attack this challenge using a continuous improvement methodology, both for bit selection and for development of bit design during the drilling phase of the project wells. This was undertaken using a partnership approach involving the engineering and design teams of both the field operator and bit service companies.

The optimization of design and performance was split into three main phases:

1. Initial design study and bit program from the analysis of previously drilled wells.
2. Optimization of performance during drilling of the first four wells.
3. Further improvement and design refinement during the batch drilling of the remaining wells.

Using a systematic approach, bit designs were modified based on the wear patterns of the previous dull bits. Enhancements and modifications were also made to bit programs, motor choices, and drilling parameters. These enhancements made a significant improvement in both bit performance and penetration rates. As a result, the total drilling time per well was reduced from 75 days to 56 days over the two year drilling period **(Fig. 2)**.

General Information

Geology of the Field. The different sections drilled are typically made up of limestone, marl, shale, and anhydrite in the top part of the well. The lower part of the well normally consists of hard and soft limestones alternating with highly compacted shales, dolomites and anhydrite. The formations to be drilled present a high complexity and heterogeneity where hard stringers alternate with a soft or a very compacted rock, and where in the lower section of the hole, a typical pseudo plastic behavior of the rock has to be anticipated **(Fig. 3)**.

Well Plan & Drilling Program. The wells are highly deviated with inclinations ranging from 50° to 55°.

Casing / Hole Size Details. In addition to a 30" conductor, four casing strings were run as follows **(Fig. 3)**.

1. $18^5/_8$" surface casing in 24" hole, set in the Laffan Formation at ±2900 ft. MD to cover the upper aquifer loss zones.
2. $13^3/_8$" intermediate casing in 16" hole, set in the Hith Formation at ±6000 ft. MD to case off the Cretaceous hydrocarbon bearing zones.
3. $10^3/_4$" x $9^5/_8$" upper production casing in $12^1/_4$" hole, set in the top of the Sudair Formation at ±10,700 ft to shut off the potentially weak zones in the Qatar and Jubaila Formations.
4. 7" production liner in $8^1/_2$" hole, set in the Median Anhydrite at ±14,400 ft covering the Khuff reservoir zones.

Directional Program. The wells have 'J' profiles and were drilled to targets located at the top of the Khuff K4 reservoir at a horizontal departure of 9100 ft. The kick-off point is at ±650 ft in the 24" hole section, and the build up is completed by the middle of the 16" hole section. The 'Lock up' section continues to T.D. with an average inclination of 55 degrees.

Potential Operational Problems

24" Hole Section. Anticipated problems included complete loss of returns at ±1000 ft, bit free fall due to voids, irregular torque with high surges on rotary, sulfurous waters with H_2S, stickiness in the marl generating swabbing and stuck pipe due to hole pack-off.

16" Hole Section. No special operation problems were anticipated.

12¼" Hole Section. The anticipated problems included; the drilling of the dense Hith Formation, severe lost circulation in the Arab zones and major stuck pipe problems in the Sudair Shales like the NFA wells. Because of the expected stuck pipe problems in these shales, it was initially decided to raise the casing point to the first anhydrite zone below the first shale interval in the Sudair. It was expected that the lower Sudair Shales could be contained by the higher mud weights run in the $8^1/_2$" hole.

8½" Hole Section. The anticipated problems included; control of the Sudair Shales, risk of differential sticking in the Khuff K4 reservoir section, and problems with swab induced kicks while tripping in the reservoir sections.

Lithology & Related Drillability

The initial bit program and technical options were based on a study of the data recorded in Phase 1 of the North Field Development (NFA) and the NFB-1 delineation well.

24" Hole Section. The 24" interval (600 ft - 2900 ft) is one of the most critical sections of the well. The hole is kicked-off below the 30" conductor and hole angle is built at ±2° /100 ft through to casing point. The formations are comprised of shales, marls, limestones, and weak surface aquifers. Complete loss of circulation typically occurs in the Umm Er Radhuma Formation at ±1000 ft.

In this section, some bit gauge losses were expected which could lead to bearing failure. The use of mill tooth bits fit with sealed roller bearings, enhanced cutting structure, and gauge protection was initially recommended. Two IADC 1.3.5 bits run on steerable PDM's were planned for the section. The bits were to be fit with tungsten carbide inserts for gauge protection and reinforcement of the lugs.

16" Hole Section. Previously, this section (2900 ft - 6000 ft) was drilled with a $17^1/_2$" bit. Following the success of running $13^3/_8$" casing in a 16" hole on the NFB-1 well, it was decided to use the same hole size for the remaining NFB wells. Thus, effecting savings in drilling time and mud/cement consumables. The build-up portion of the well is completed in this phase by ±3800 ft MD.

This particular section is mainly made up of chalky limestone with shales in the top portion, and dolomite stringers in the lower part. Pyrite can be encountered intermittently. A key formation in the upper part is the Nahr Umr and the associated Nahr Umr Lower Sand. The Nahr Umr Lower Sand lies within the bottom 33 ft of this section (vertical isochore), and total losses occurred in this layer in the delineation well NFB-1. At the end of the section, the anhydrite of the Hith Formation results in very low rates of penetration. Casing was initially planned to be run 100 ft inside this Hith Formation. Despite the fairly low rates of penetration, the rock bits in this section did not suffer from high levels of wear, but a "Rounded Gauge" wear pattern was observed on dull bits.

The use of an aggressive IADC 4.1.5 insert bit, fit with enhanced gauge protection, was recommended to be run on a steerable motor. A bit with good potential hydraulic behavior was recommended for drilling the softer intervals. Even though the section to be drilled was 3100 ft, it was proposed to drill the entire section with one insert bit. It was recommended that the bit be equipped with enhanced heel gauge protection, diamond gauge trimmers, insert enhancement on the lugs, and a metal face seal feature. If the drilling time exceeded 75 hours then two bits were expected to be used.

$12^1/_4$" Hole Section. The $12^1/_4$" interval (6000 - 10,700 ft), which is the long tangent section, had a good potential for savings in drilling time.

The Hith Formation, encountered in the top of this $12^1/_4$" section, is mainly made up of an amorphous hard anhydrite with dolomite stringers. Low rates of penetration are experienced in this formation. Below the Hith Formation, an intermediate softer section is encountered with alternating limestones and dolomites. The bottom of the $12^1/_4$" section contains the hard drilling formations of the Gulailah (limestone followed by interbedded sequence of limestone and dolomite) and the Khail Anhydrite. Below this is the Sudair Formation which contains a high degree of heterogeneity with shales or claystone alternating with anhydrite, dolomite or limestone.

The analysis of dull bits from offset wells shows that, on top of the normal worn teeth wear patterns, a fairly high level of chipped or broken cutters occurred indicating that vibration was frequently present. The use of bits with vibration reducing features was recommended.

The use of two or three PDC bits, instead of the four or five in offset wells, was the goal. The recommended bit design was a step type (Schreiner effect) bladed PDC bit fit with spiral blades, and having good cuttings removal capacity. These bits were to be run on turbines fit with diamond bearings for extra durability. This combination of PDC bit and turbine were expected to lead to a 20% improvement in ROP. The recommended bits were fit with vibration reducing features such as asymmetrical positioning of spiraled blades and gauge, speed bumpers and stabilized inner cone. It was recommended to use enhanced diamond content cutters set in the inner cone and nose areas with TSP back ups set behind each cutter.

$8^1/_2$" Hole Section. The $8^1/_2$" interval (10,700 ft - 14,400 ft) was another critical section of the well, with the tangent section being continued through the Khuff reservoir zones. The formations encountered in this phase are the Sudair cap rock (shale alternated with limestones, dolomites and anhydrites) and the Khuff reservoir sequence. The Khuff, containing the main reservoir sections, is a mixture of limestone and dolomite which are separated by bands and stringers of anhydrite. The recommended bit type for these formations was a step type spiral bladed PDC bit with a good hydraulic potential for the evacuation of cuttings. In the NFA offset wells, the $8^1/_2$" section was drilled with an average of two bits. These bits frequently came out with "Cored" and "Chipped Teeth" IADC patterns.

It was attempted to drill the entire section with one bit run on a turbine, but the hard and abrasive Upper Anhydrite between the Khuff K3 and Khuff K4 along with operational problems in the Khuff K4 (differential sticking) required drilling with two bits.

Bit Selection & Data Analysis

A scientific approach was systematically carried out for the bit selection. From the original wells of Phase 1, the data analysis was performed as follows:

1. Each selection was evaluated in terms of lithological characteristic through master logs, sonic logs, gamma ray and neutron density when available.
2. The rock mechanics characteristics such as porosity, abrasiveness, hardness, compressive strength, plasticity, and heterogeneity, were analyzed.
3. The instantaneous ROP, WOB, RPM, torque and other drilling parameters from bit records were analyzed in correlation with the lithology.
4. Dull bit analysis was performed.
5. The mud programs, casing programs and rig systems were all evaluated to improve performance.

The above factors allowed an appropriate selection of bits for each section. Further to this evaluation, the use of the motor and turbine were considered as potential performance improvements for the bits. Based on this analysis, specific bit types and drill systems (motors or turbines) were designated for each hole section. The above analysis technique was effective, because the original bit design was not altered significantly over the remaining wells.

Optimization of Performance

Four wells were drilled from surface to TD back to back with two jack up rigs from two production platforms. After this short phase, batch drilling was performed (in a series of 3 to 4 wells per phase) for the remaining ten wells on Wellhead Platforms 1 and 2 and for four wells on Wellhead Platform 3.

During the batch drilling mode, there was very little time for major engineering changes, but refinements of PDC bit designs were undertaken.

During the drilling of these early wells, trial bit runs were made. The trials resulted in improved bit performance, and these improvements continued through the batch drilling mode.

24" Phase. The first well was drilled with two IADC code 1.1.5 mill tooth bits with an overall ROP of 23.6 ft/hr. Given the wear pattern and bearing conditions, it was decided to try an insert bit IADC code 4.1.5 In the three subsequent wells, this section was drilled with a single bit at an average ROP of 31.3 ft/hr resulting in an increase in ROP of 33%.

One insert bit IADC code 4.1.5 was run per section in the remaining wells. Optimization of the bottom hole assembly resulted in more rotation and less sliding during the directional kick off which increased the overall rate of penetration.

The best performance was on well NFB-18 with an ROP of 55.5 ft/hr resulting in an increase in ROP of 133% over the first well. Cost per foot was 53.87 \$/ft. against 121.41 \$/ft in the first well.

16" Phase. This section was drilled in the first well using an insert bit IADC code 4.4.5 with an ROP of 28.8 ft/hr. While the cutting structure was acceptable, the bearings were graded failed. Total lost circulation occurred in Nahr Umr Lower Sand, with the bit having to be tripped for the setting of a cement plug prior to being re-run. As these losses had also occurred on the delineation well, it was decided to modify the bit program by running a mill tooth bit IADC code 1.1.5 down to the losses and completing the section with the insert bit.

In this way it was felt that a faster ROP could be obtained with the first mill tooth bit and that the reduced section length for the second insert bit would help the bearing life. For the next three trial wells with this combination of bits, the average ROP was 28.5 ft/hr.

From an examination of the dull bits it was recommended to improve the mill tooth bit with enhanced hard facing, and the insert bit with diamond gauge protection and lug pads.

During the drilling of the four trial wells, the 16" hole TD was deepened to 100 ft into the Hith in order to reduce the amount of Hith drilled by the $12^1/_4$" PDC bits. It was later discovered that the Hith was "hard", but not abrasive. The design of the $12^1/_4$" PDC bits also proved their ability to drill this formation with higher ROP, without suffering damage which might limit their performance in the lower section of the $12^1/_4$" phase. Therefore, given the large difference in penetration rates between the 16" insert and $12^1/_4$" PDC bits, the $13^3/_8$" casing point was moved to the top 50 ft of the Hith Formation.

Further optimization was made on the batch wells with the introduction of a single lobe high speed drilling motor. This high speed motor increased rates of penetration significantly for the insert bit run, which resulted in a lowering of the drilling cost for the interval by ±30%.

The high bearing loads created by the high speed motor reduced the possibility of drilling the entire 16" phase with one bit. To optimize costs a mill tooth bit IADC code 1.1.5 was used down to the lost circulation zone (this bit was usually capable of being re-run on the next well), and an insert bit IADC code 4.1.5 gave the best performance to finish the interval.

The best overall performance was again on well NFB-18 with an ROP of 32.7 ft/ hr for the mill tooth bit, and 49.3 ft/hr for the insert bit. This represents an increase in section ROP over the first well of 55%.

$12^1/_4$" Phase. In the first well, an insert bit was used to drill out the float equipment and continue into the Hith Anhydrite. Due to problems with drilling out the DV, the bit was unable to completely drill the Hith. The remainder of the phase was drilled with two fixed cutter PDC bits IADC codes M6.1.5 and M6.1.6, with an average ROP of 21.5 ft/hr down to the Gulailah and 13.1 ft/hr for the bottom section.

Various bit designs were tried in the next two wells. Performance and wear patterns were studied, and changes were implemented to improve the PDC bit design. This first series of wells used the turbine as the power source. Most of the bits suffered chipped cutters, broken cutters and, in some cases, broken blades, which indicated that a high level of vibration was being experienced throughout the section. More dramatic damage was observed in the bottom part of the $12^1/_4$" section, from the Gulailah down, where the ROP was lower. A very high level of whirling was also experienced.

The most consistent performing bits used 13mm PDC cutters. A 19mm cutter was tried in one well but even though it had a high ROP (48.1 ft/hr) it suffered from excessive cutter wear over a short drilled interval.

The final well, of the four trial wells, gave the cheapest cost per foot of all the turbine drilled $12^1/_4$" sections at 118.33 \$/ft. The first bit, IADC code M6.1.5, drilled a field record footage of 4915 ft at 27.9 ft/hr to the base of the Gulailah. A second PDC bit, IADC code M4.3.3, completed the section at an ROP of 13.1 ft/hr.

The main recommendation after this trial period was to run the bits on extended or dual positive displacement motors (high torque) in the top softer portion of the $12^1/_4$" hole. This was predicted to increase the performance by 30%.

Extended motors provide more power to the bit. This extra power reduces stalling, which smoothes out the drilling, reduces bounce, and makes the bit more stable. In addition, a lower RPM reduces the level of vibration. A balanced bit is intrinsically more stable and less prone to whirl when the RPM is low.

For turbines it was recommended to modify the bit design. The new design had a more parabolic profile and improved bit stability features, thereby reducing vibration.

The use of extended power section motor (for the first time in a Qatar drilling operation) greatly increased the ROP. Bit designs were altered slightly with the addition of vibration reducing features, which increased the bit stability and the bit life.

The fastest $12^1/_4$" phases were drilled with extended power section motors, of which the best was NFB-8 with a cost per foot of 99.92 $/ft. Two bits, IADC code M.6.1.5, were used. The first having a record ROP of 36.4 ft/hr over 4243 ft, and the second finishing the remaining 402 ft of the section at 19.6 ft/hr. This represented an improvement in the overall penetration rate of 85%.

Another important optimization made during this period was moving the $9^5/_8$" casing point to the top 15 ft of the Sudair, thus shortening the phase length by ±200 ft. By moving the casing point up, the mud weight could be increased immediately after drilling out the $9^5/_8$" casing shoe. This provided better control of the over pressured shale and reduced hole problems. Faster penetration rates were also achieved in the Sudair with the smaller hole sizes.

The introduction of extended power section motors and PDC bits with enhanced stability, special enhanced cutters, and anti vibration features allows this hole section to be drilled with one bit, providing directional control is maintained.

The key for further increase in performance is more efficient drilling of the Gulailah and Khail Formations, which are hard plastic elastic behavior type rock.

The formations below the Gulailah are slightly softer, but have very hard stringers or tight intervals where the ROP slows down considerably to ±5 ft/hr. Bits have been pulled and replaced in this slow ROP section to obtain ROP improvement. This has resulted in very limited improvement in ROP.

These slow drilling sections have now been correlated across the NFB area so that in future wells this can be taken into account when deciding to pull the bit at the end of a long run.

$8^1/_2$" Phase. The $8^1/_2$" phase trial runs were somewhat limited due to coring being carried out in two of the first four wells. None of the wells achieved the target of one bit down to the Upper Anhydrite and a second bit to drill the Khuff K4. However, good performance was recorded in the section and bit modifications were made. The best result was recorded in the last well of the four wells where three bits were used. The systematic use of turbines was anticipated and utilized on all wells.

A recurring problem at the end of the first bit run in the Khuff K3 or in the Upper Anhydrite was the occurrence of a cored or ring out wear pattern. This was similar to the wear patterns seen in the offset NFA wells.

It was recommended to modify the existing long parabolic profiled PDC bits by using the latest features for reducing vibrations. A trial run of a 19mm 'step effect' bit fit with anti-vibration features was proposed.

PDC bits with 19mm cutters were successfully used throughout the interval with the 'step type' bit proving to have the most stable design. This bit, run on a high torque extended motor, should improve performance on future wells.

During the batch drilling phase, six wells accomplished the goal of using two PDC bits to drill the entire interval. Turbines were used on the majority of the wells with extended power section motors being limited to short intervals on two wells.

Once again, NFB-18 had the lowest cost per foot for the interval, at 167.13 $/ft. The first bit, a 19mm step type IADC code M6.1.5, drilled 2326 ft at 20.3 ft/hr. The second bit, a 13mm step type IADC code M6.1.5, completed the interval at 12.9 ft/hr.

However, the bit type which gave the best performance overall in this interval was a short parabolic profile PDC bit IADC code M4.3.3 with strong inner cone, spiral blades, and vibration reducing features. This bit achieved a maximum ROP of 21.8 ft/hr when run on an extended power motor.

The improvements in the $8^1/_2$" phase created a 20% increase in section ROP over the first four wells.

Conclusion

The initial bit program was based on offset records from Phase 1 (NFA) and NFB-1. During the drilling of the first four wells, bit designs were modified based on wear patterns of dull bits. Enhancements and modifications were made to the first generation of bits to improve their life and penetration rates. Improvements of these bits continued during batch drilling and finally throughout the project. These enhancements along with adjusting the $13^3/_8$" and $9^5/_8$" casing points, motor choices, drilling parameters, and optimization of the BHA helped reduce the total drilling time per well from 75 days to 56 days.

The number of bits used was reduced by 40%, and the average rate of penetration (ROP) improved between 40% and 50%. These improvements are reflected in the lower cost per foot (**Fig. 4**), and were a major factor in the project finishing ahead of schedule and under budget.

The results were successful thanks to very close collaboration between the engineers of the two major operators involved in the project, and the bit suppliers.

Acknowledgments

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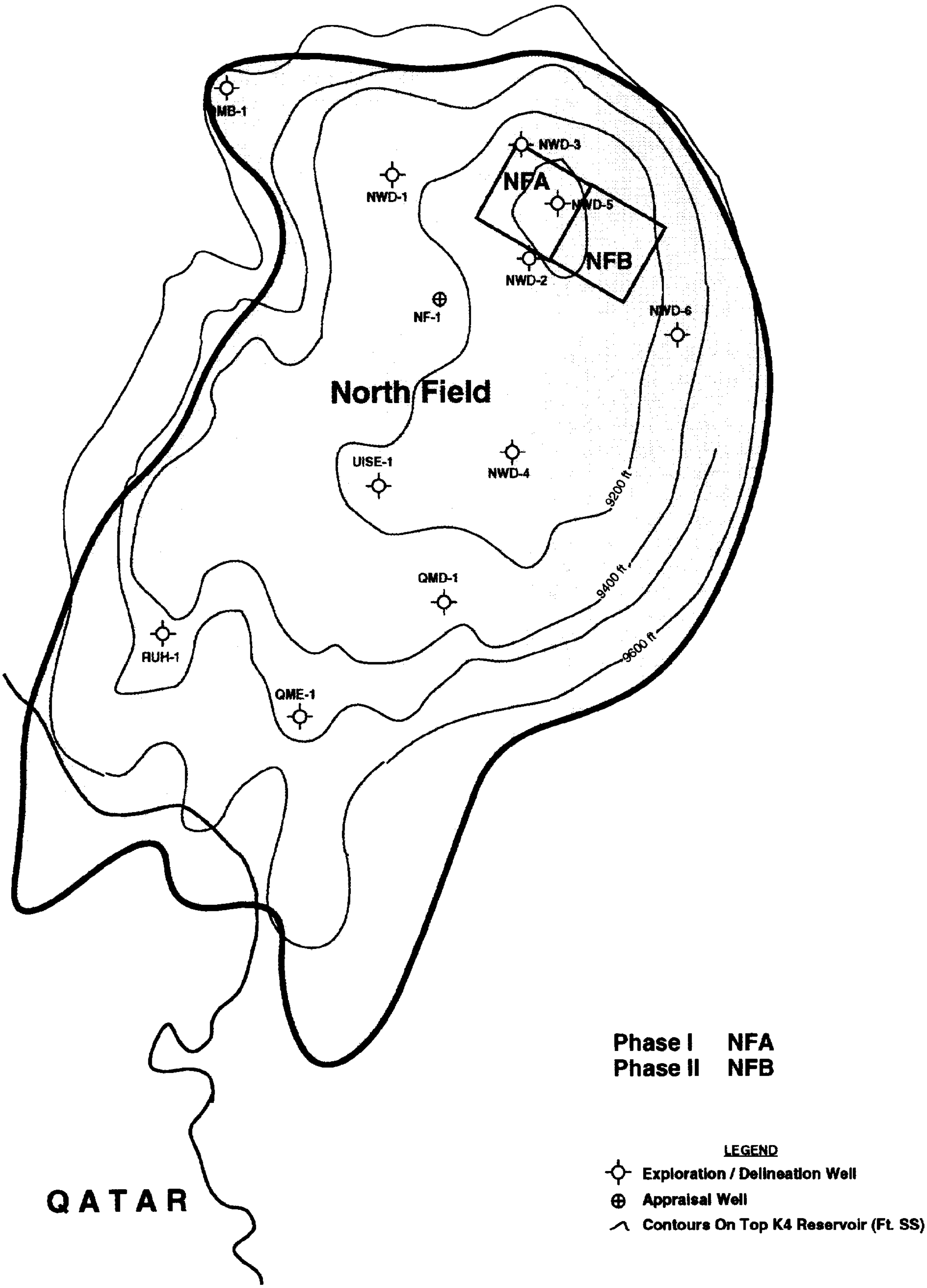

Not To Scale
FOR INFORMATION ONLY

Fig. 1 : Qatar's North Field

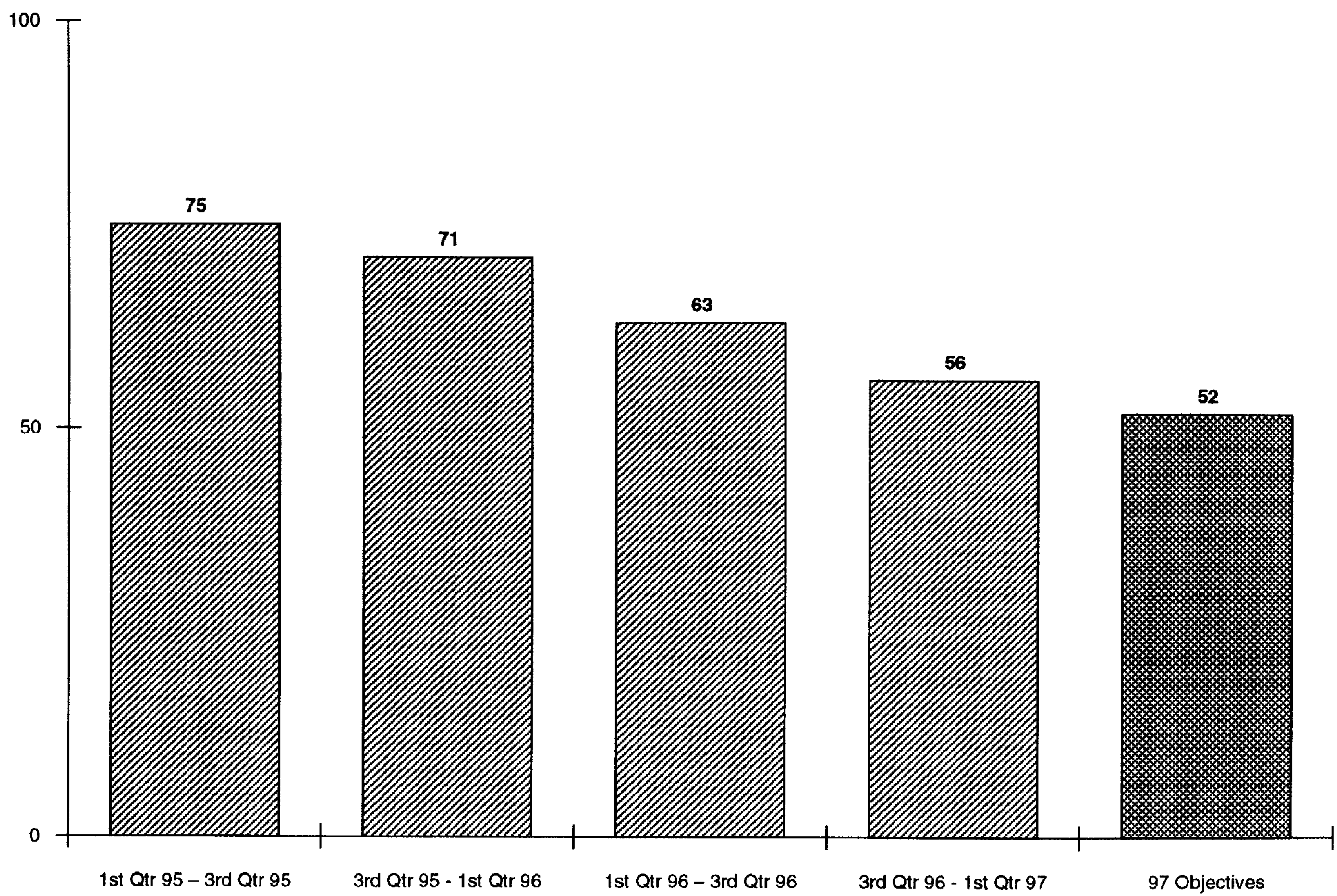

Fig. 2 : Total Drilling Time/Well for NFB Wells • Phase-II

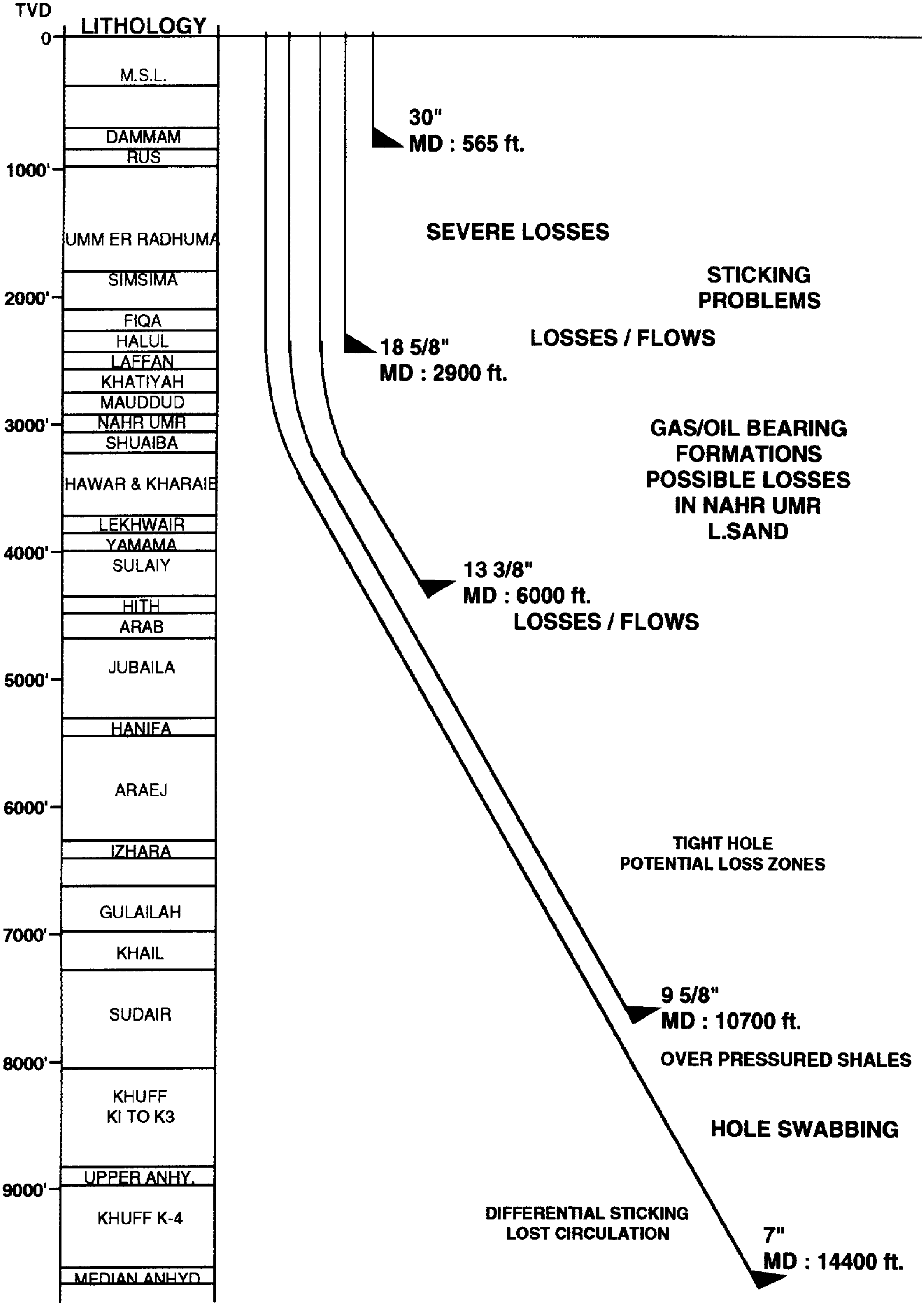

Fig. 3 : History Of Hole Problems (All N.F. Wells)

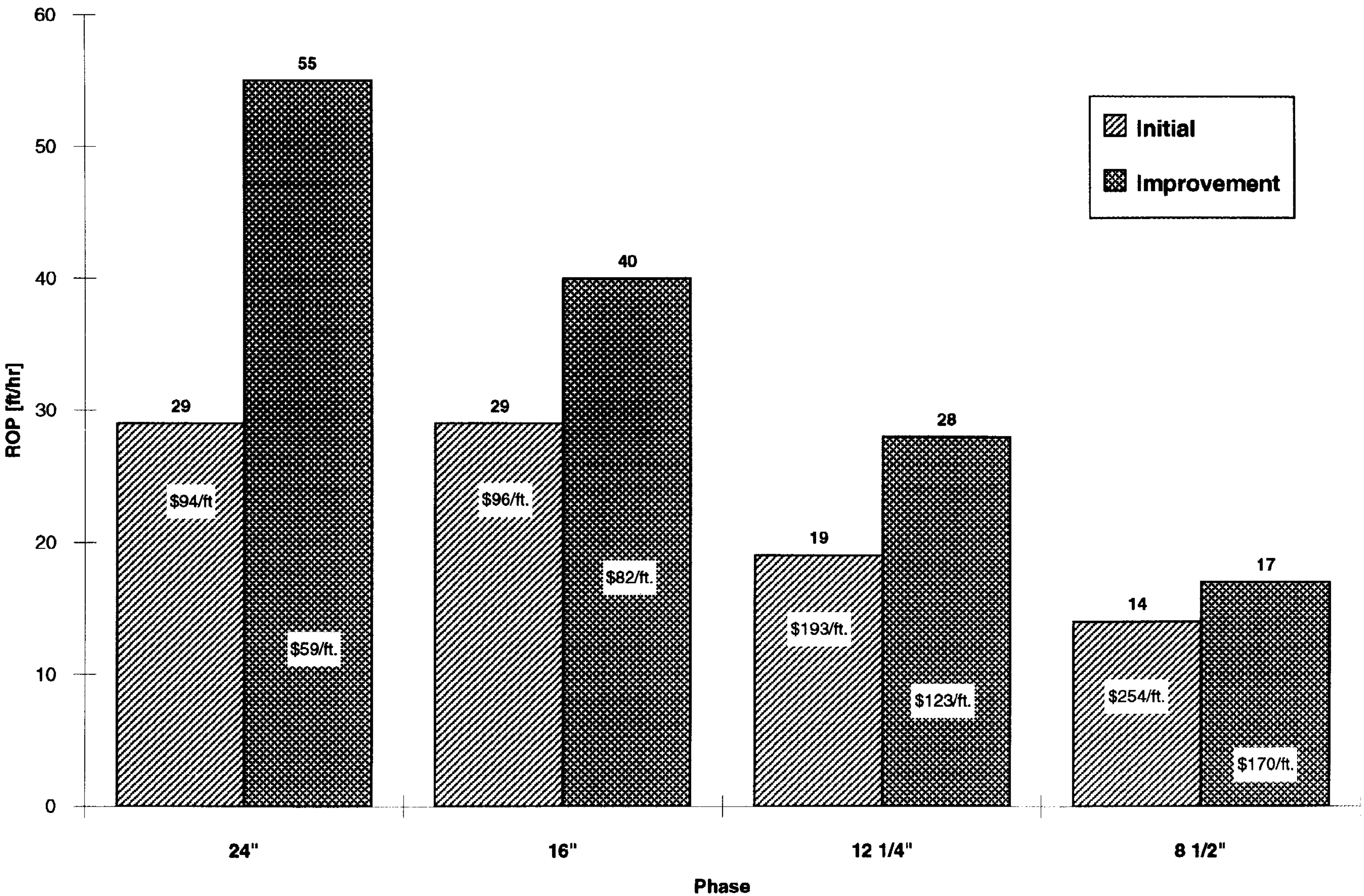

Fig. 4 : Average ROP Cost/Ft. Improvements for NFB Wells • Phase-II