Economics of Automated Well Testing

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Until about five years ago the world of an oil producer was a wonderful world. Flowing wells, primary pumping well, and new oil fields kept lifting costs low, kept total production high and, coupled with a good supply of enthusiastic low-priced labor, kept the profits rolling in. Yes, it was wonderful!

Then came the rude awakening! Suddenly it became a hard, cruel world because profits nosedived. Most producers alternated between hysteria, panic, and frenzy in their attempts to keep solvent and stay in business. What had happened? Here's what happened:

(1) Tax burdens jumped.
(2) Labor costs skyrocketed.
(3) Good quality labor became unavailable.
(4) Equipment costs doubled and trebled.
(5) Maintenance and repair costs became frightening.
(6) Fewer new oil fields were discovered.
(7) The normal "depletion" or decline in oil production held to the proven curves.

Faced with these revolting developments, producers did a lot of real soul-searching. As a result, many decided to merge or sell out rather than make the necessary changes for existence in the new cold world. In quite a few instances, one is forced to admit that their decisions were wise. It had been said that "oil producers made money in spite of their operating procedures—never because of them," and this was basically a truism.

Those proudcers who decided to accept the challenges of the present and future all arrived at these same general conclusions:

REQUIREMENTS

1. EFFICIENT MANAGEMENT AND OPERATING STRUCTURES MUST BE DEVELOPED AND INSTALLED.
2. SECONDARY RECOVERY MUST BE LEARNED ABOUT AND INSTITUTED.
3. "FACTS" MUST BE KNOWN EXACTLY AND IMMEDIATELY SO THAT PROPER DECISIONS COULD BE MADE.

The first two conclusions have been given attention and have been covered by many papers and studies, so we will deal only in the area of the third.

"Facts" pertaining to exact oil production from each individual well were not ever available in the past. Each well was checked—sometimes daily, mostly weekly—by these:

"TRIED AND TRUE" TEST METHODS

1. POLISHED ROD "FEEL" - AT WHICH ALL PUMPERS WERE EXPERT, IN THEIR OPINION.
2. BLEEDER FLUID - PROOF OF PRODUCTION.
3. MACHINERY OPERATING NICE AND SMOOTH.
4. CUMULATIVE TANK GAUGES - UNLESS THERE WAS A DISTURBING LOSS FROM YESTERDAY'S, LAST WEEK'S, LAST MONTH'S TOTALS, THEN ALL WAS FINE WITH ALL WELLS CONNECTED TO THE TANK BATTERY.

Facts based on these methods were sufficient for operations up until recently, but today they aren't sufficient to support profitable operations.

BACKGROUND

The above point can best be illustrated by the following case history.

About 15 to 17 years ago, a major oil company drilled-up a field in North Texas. Operations were conducted in accordance with the best procedures and customs of that day. They ended up with 252 good producers at a depth of about 5000 ft from three separate zones. Drilling was completed and production operations proceeded as usual. Other than normal depletion or decline, no great production problems were encountered.

Flow lines, tank batteries, separators, etc., were all installed according to the dictates of the moment. Unit pumpers, powered by gas engines or electric motors, were installed and operated by average employees, supported by usual staff services (engineers, foremen, etc.).

About three years ago, about one-half of the wells had become incapable of producing their allowables. This conclusion was reached in the face of total barrels of oil produced (or rather, not produced) rather than production figures for individual wells. A trailer-mounted production tester was the only means of checking individual wells, so each well was tested on an average of 11 months—theoretically. Actually trouble wells were tested quite often, while most of the "normal" wells never got tested at all.

PLANS AND DECISIONS

The profit crisis was faced and the following actions were taken.

Agreement was reached by management that a waterflood was required to bring total oil production back up to the profitable level. Quotations were taken and a turnkey contract was awarded. This is as far as this needs to be pursued as pertaining to the subject of this paper.

Due to their information and knowledge, field management recommended consolidation of tank batteries and re-laying of most flow lines along with a basic automated testing installation. Home office management disagreed, but after determining that the field people had the courage to back their convictions, they finally agreed to this project. Quotations were taken and a turnkey contract was awarded. This is the project we wish to discuss further.

Further decision was made to install the battery consolidation, flow lines, and automated test manifolds completely, before beginning installation of the waterflood system. Primary reason for this decision was so that control data would be available from the beginning on results and progress from the waterflood, since royalties were to be paid on the basis of GOR tests and of co-mingled oil production, and these could not be determined without the new test installation. This delay also allowed time to perform necessary remedial and work-over actions in order to get the selected injection wells ready for the flood.

BATTERY CONSOLIDATION AND TESTING DECISION

Due to the compactness of the field and the presence of good all-weather roads, it was decided to centralize and finalize the automation at each satellite rather than to bring automation to one central point. In this case the cost of operating from one central point was not justified by distance, type of terrain, poor communications, or personnel shortage.

Layouts of the complete gathering system were studied and examined and it was decided to establish 11 Satellite Stations, each with its LACT unit, testing header manifolds, programmers, and read-outs.

Satellites were to vary from a minimum of 17 wells to a maximum of 36 wells, for an average of 23 wells.

The 11 Satellites were to discharge their oil into 2 Central Batteries—#1 and #2. From these central batteries oil was to be sold to the pipeline.

Cost data for this project included:

COST DATA

(BASED UPON UTILIZING ALL USABLE TANKS, FLOW LINES, SEPARATORS, ETC., ON HAND-MOVING AND RE-INSTALLING.)

1. CENTRAL BATTERY #1 COST $30,052.23.
2. CENTRAL BATTERY #2 COST $29,748.73.
3. ELEVEN SATELLITE STATIONS INCLUDING PROGRAMMERS, PRODUCTION AND TEST MANIFOLDS, LACT UNITS, ETC., COST A TOTAL OF $117,173.94.
4. RE-LAYING AND REPLACING FLOW LINES AS REQUIRED COST $38,526.84.

FOR A TOTAL COST OF $215,501.74.

Resulting in the following cost analysis:

COST ANALYSIS

1. BASED UPON TOTAL COST OF $215,501.74 FOR 252 WELLS, COST WAS $855.00 PER WELL.
2. ESTABLISHMENT OF THE TWO CENTRAL BATTERIES AT TOTAL COST OF $59,800.96. COST PER WELL WAS $237.00.
3. ESTABLISHMENT OF 11 SATELLITE STATIONS. COMPLETE COST WAS $117,173.94, OR $466.00 PER WELL.
4. FLOW LINE SYSTEM COST OF $38,526.84, WAS $152.00 PER WELL.

RESULTS:

(1) **Before** water injection was initiated, oil produced and sold **per day** had increased 447 barrels. This increase can be ascribed only to knowledge gained by daily test and production data. Increase is about six per cent of total, and became effective over the first eight months operation of new test system.

(2) Per barrel lifting costs showed no increase at all, over one year's operation.

(3) Maintenance costs per well per year of production and test system—fuses, switches, lightning damage, electricians time—amounted to $7.00 per well per year, for a total of $1764.

(4) Two wells were abandoned within one month after accurate production tests figures were available, and remedial measures had failed.

(5) One well that had been accepted and recorded as a 16 BPD well was found to be actually producing 168 BPD.

(6) Home office accounting department advised field that the total cost of the new production and test system ($215,501.00) was completely paid out in seven months from incraesed oil sales—**and not one barrel of flood water was injected during this time.**

(7) No additional personnel was hired or required to operate the new production and test system.

SUMMARY

Needless to say, this operator is extremely well pleased with performance and results. When water injection was begun, results from it came on top of the results from the production and test system. They now have a profitable operation.

IF'S

(1) If the tanks could have been set for Satellite Station operations to begin with, then the flow lines could have been laid properly, and this would have saved $77,074.88 total, or $306.00 per well.

(2) If header manifold valves had been installed initially of a type capable of being actuated when required, instead of the conventional gate valve type manifolds generally used, this would have saved $50,600.00 total, or $201.00 per well, without any cost penalty initially.

(3) If foresight had been possible in the original installation, a saving of $127,675.00, or $506.00 per well, would have been achieved.

SAVINGS

THE COST OF INSTALLING THE TWO CENTRAL BATTERIES, AND INSTALLING THE ACTUATORS, PROGRAMMERS, LACT UNITS, ETC., WOULD HAVE BEEN ONLY $87,926.00 TOTAL, OR $349.00 PER WELL - INSTEAD OF THE $855.00 PER WELL ACTUALLY REQUIRED. THE $506.00 PER WELL, OR $127,675.00 TOTAL, WOULD HAVE BEEN A SAVINGS OF 59 PER CENT. WORTHY OF NOTE - YES!

Certainly, no criticism of personnel actions or management decisions made 16 years ago is intended or just. The disturbing knowledge is that generally the same practices are being followed today, and will cause increased capital outlay in the not-so-far-off future. Unfortunately, most producers have not learned from their past mistakes.

Any lease being developed today should be viewed as if it were going to be unitized and automated immediately. This can be done without any penalty in cost or at most with a minimal investment. No one can know with exact certainty just which locations will prove up, but by using the best information available at the time, results will be amazing. When tank batteries and flow lines are located in consideration of future requirements, definite, positive savings will be realized.

Equipment selection during initial stages of development should receive thorough and serious consideration. It has been the custom to build the header manifold one well at a time as required. Screwed fittings and gate valves were used because of supposed economy. This type manifold requires training and familiarity of personnel for even the simplest operation. When programming and automation are considered, they become "write-offs" because they can't be adapted at all.

INITIAL PRODUCTION AND TEST MANIFOLDS SHOULD BE INSTALLED THAT WILL:

A. OFFER EASY, ECONOMICAL, AND SIMPLE MANUAL OPERATION.

B. OFFER EASY, ECONOMICAL, AND SIMPLE ADAPTATION TO PROGRAMMING AND AUTOMATION WHEN, AS, AND IF IT IS EVER DESIRABLE.

C. OFFER QUICK, POSITIVE DETERMINATION OF LEAKAGE-SO AS TO CONFIRM TEST RESULTS.

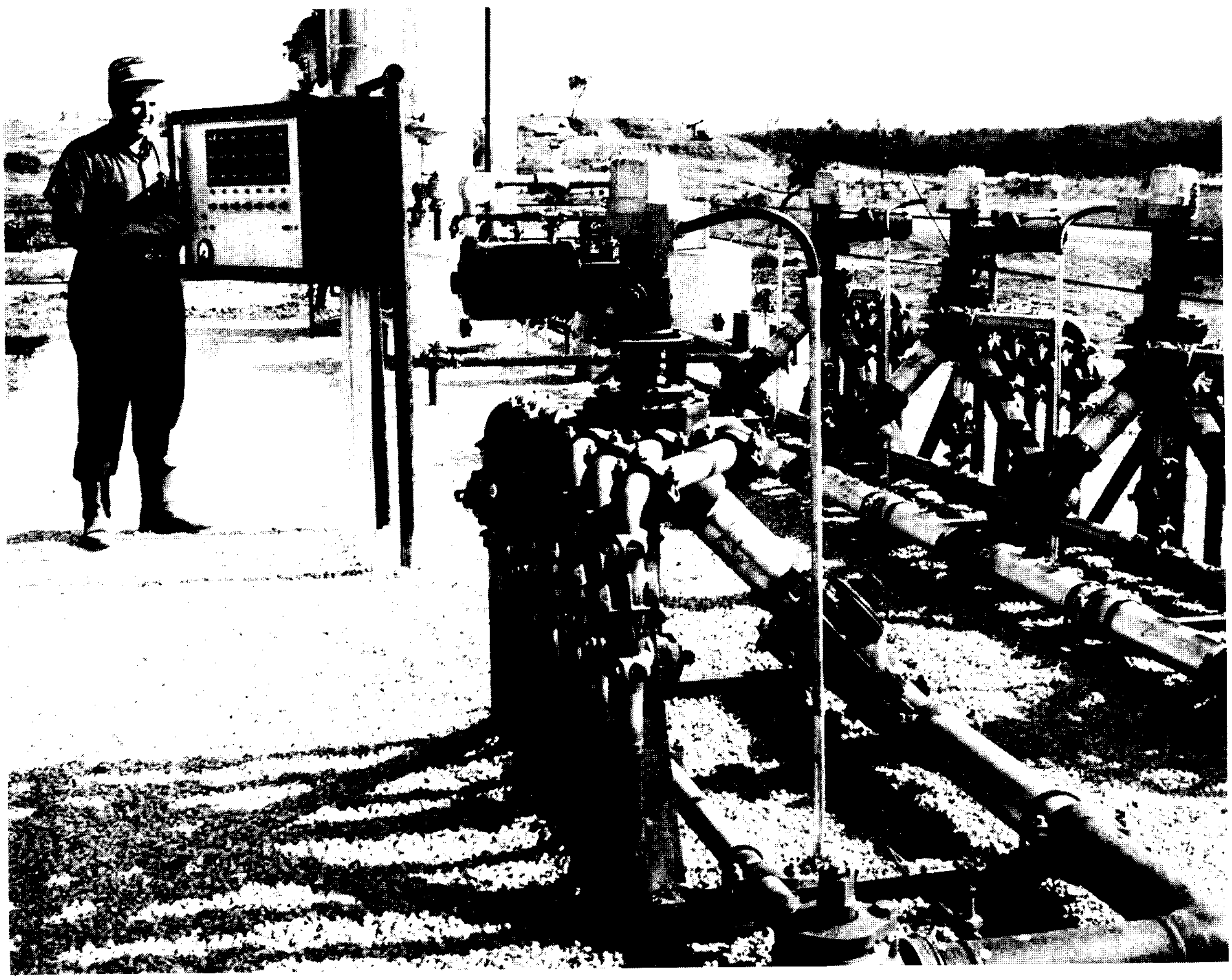
D. ALLOW SIMPLE, LOW-COST REPAIRS WHEN REQUIRED.

E. LEND ITSELF TO UNITIZATION FOR LOW LABOR COST AND HIGH SALVAGE VALUE.

One item of header manifold equipment seems to fulfill all of these requirements; we mean the "round-house" valve, or as it is properly titled, the rotary selector valve. This item has recorded over 16 years of performance and has proven itself for both manual and automated operation.

One major decision faces producers who are contemplating automation. It is "How far should we go with automation?" There is no general rule on which to base this decision. Type of terrain, extent (or "spread") of the project, labor market, type of produced oil, communications — all of these enter as pertinent facts necessary to making the proper decision. Each project must be studied and evaluated individually before the advantageous extent of automation can be ascertained.

The project discussed in this paper previously is about the simplest form of automated



well testing project; it basically just keeps records on production and assures that wells will be tested frequently because this is programmed. Remember, it cost $855.00 per well. There is another project about 50 miles from this first one, where complete centralization of automation was installed at a cost of over $3000 per well. Both of these projects are economically sound. This illustrates the variation in correct decisions.

Regarding the title of this paper, it should now be obvious that there are no costs that will serve even as a good rule-of-thumb, and no general statements can even be made as to the most advantageous extent of automation, but it should be just as obvious that the following recommendations are valid and sound in all cases:

SUMMARY

1. FREQUENT, ACCURATE TEST DATA ON EACH INDIVIDUAL PRODUCING WELL IS A REQUIREMENT FOR PROFITABLE OPERATIONS TODAY.
2. EACH TANK BATTERY AND FLOW LINE LOCATION MADE TODAY SHOULD BE MADE WITH FULL CONSIDERATION OF FUTURE AUTOMATION POSSIBILITIES.
3. EACH ITEM OF EQUIPMENT PURCHASED AND INSTALLED TODAY SHOULD FIT THE DEMANDS OF THE MOMENT, BUT IN ADDITION SHOULD BE FLEXIBLE AND ADAPTABLE ECONOMICALLY TO FORESEEABLE FUTURE AUTOMATION.
4. DEGREE, OR EXTENT, OF ANY AUTOMATION PROJECT MUST BE DETERMINED IN EACH INDIVIDUAL CASE BY DETAILED INVESTIGATION OF GOALS, ADVANTAGES, AND COSTS.
5. AUTOMATION IS ALWAYS DESIRABLE, BUT MUST BE SOUND ECONOMICALLY.

PLAN AHEAD DON'T **PLAN AHEAD**