Purpose-built land rigs produce step change in drilling time, cost, and opportunities

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RISING NATURAL GAS prices and Wall Street demands have come together to create a new culture of aggressiveness in natural gas development for one operator in the Piceance Basin. Meeting and exceeding growing production targets has had significant challenges. Purpose-built efficiency rigs were specifically designed by the rig contractor and the operator to meet some of those challenges.

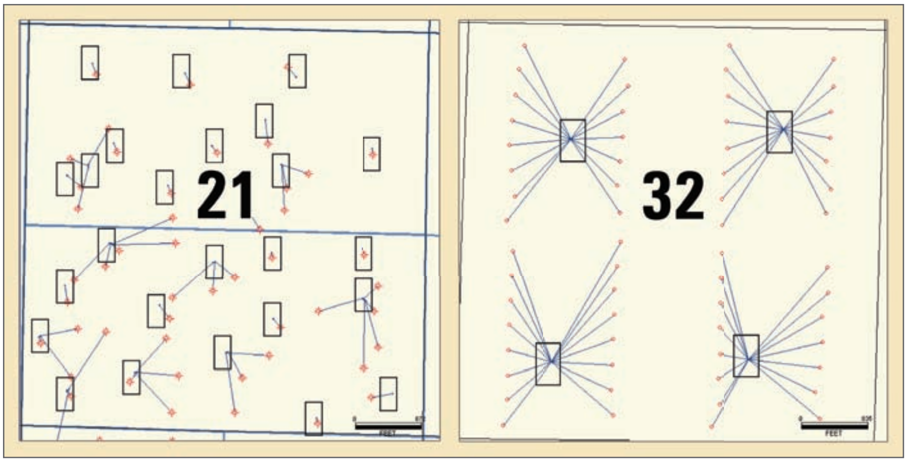
The specific development program described here is a mature field development project with difficult topography and other land-use complications. The operator was faced with the challenge of significantly accelerating development of assets with greater capital efficiency, safety and environmental stewardship. A dramatic change in rig design was the only answer. The rig contractor wanted to establish a new operating area and get more of its newbuild technology to the market. It was the perfect opportunity for collaboration. Ready to take a technological stride, the operator signed a contract for multiple purpose-built efficiency rigs.

Signing the contract involved considerable risk. The operator ordered 10 rigs of a new design, signed three-year contracts with elevated dayrates, and designed budgets and performance goals based on expected but unknown capabilities. Those risks were undertaken with the understanding that purpose-built rigs have higher value in their particular application than any other rigs available. Commitment to the ideal of purpose-built rigs was strengthened by confidence in the possibility of continued successful design collaboration between the operator's drilling team and the rig contractor. The decisive move in the face of a number of risks has led the operator to a competitive advantage with compounding effects.

The competitive advantage has both timing and performance components. Signing early in an environment of rising prices allowed the operator to get the first rigs of their kind at the best day rates so far offered. The performance of the rigs has not only accelerated development but also increased reserves in a variety of ways. In addition to the economic benefits, the rigs offer significant environmental benefits, including less surface disturbance, noise attenuation, reduced truck traffic and rig moves, potentially eliminatation of reserve pits, and lower emissions. The rigs are also safer. Automation and logistical improvements have limited opportunities for dangerous mistakes.

THEORY AND DEFINITIONS

A new combination of rig features was designed to address a specific set of problems and field characteristics. In an area where geology and reservoir characteristics allow for high bottom-



	CONVENTIONAL	EFFICIENCY	IMPROVEMENT
Sample Size (Wells)	51	43	
Spud to TD (Days)	13.1	9.3	29%
Skid Time (Days)	1.2	0.49	59%
Move Time (Days)	3.8	9.5	-150%
Move Time per Well (Days)	1.1	0.7	36%
MD Feet/Hour Spud to Rig Release	25	35.5	42%
Surface Disturbance per Location (Acres)	1.38	3.44	-150%
Estimate Surface Disturbance per Section (Acres)	22.04	13.77	38%
Estimate Surface Disturbance per Well (Acres)	0.34	0.22	38%

Figure 1 (top): Consolidating wells onto fewer locations lessens surface disturbance and requires fewer rig moves. However, drilling multiple wells from a single location requires efficient skidding and has implications for drilling speed and depth capability.
Table 1: Comparison of various criteria for rig moving for "conventional" vs "efficiency" rigs. The efficiency rigs sharply cut critical factors, such as drilling time, skid time, move time per well and surface disturbance.

hole density, surface locations and their optimization become extremely valuable. The productive area, however, is a combination of population centers, protected federal land, extreme topographic relief, and roads crowded with trucks. To complicate matters, many private surface landowners have limited or no mineral ownership. Without significant royalty interest, those land owners have little incentive to allow development on their property. Although current regulations allow for mineral development, it is likely that available surface locations in populated areas will become more restricted over time.

Given such complex land-use challenges, drilling many wells from a single location is attractive. Consolidation of wells onto fewer locations disturbs less surface with pads and roads (Figure 1) and requires fewer rig moves (Table 1) and less truck traffic for a given number of wells. Those effects are compounded in a 4,000-well program, especially where many locations might not be accessible by conventional rigs. On the other hand, drilling many wells from a single location requires a variety of other drilling factors.

First, the rig must be able to skid efficiently from well to well (from 7 ft to 15 ft) without the help of third-party equipment. Second, it must achieve greater vertical sections to reach more bottomhole locations, as mentioned above. Third, greater drilling speed and efficiency are necessary to offset the additional measured-depth footage added by drilling longer vertical sections of 1,000 to 3,000 ft in wells with TDs ranging from 6,000 to 10,000 ft. Throughout the operator's development of the resource, several drilling technologies have been applied to try to meet those challenges.

Conventional, land-based mechanical rigs were designed to move to a location, drill a single well, and leave. Existing rigs were therefore modified to facilitate skidding from one well to the next in a single row and single direction. In the modified skidding process, third-party trucks and bulldozers mobilize to the location after the drill string has been laid down and the production casing has been run and cemented. Then the substructure is pulled forward the appropriate distance to start the drilling of the next well, typically 15 ft. Mud pits, pumps and other equipment all remain in their original locations. This operation is performed only during daylight due to safety concerns. Truck availability, due to weather or activity level, affects the the operation, and the rig may wait several hours before trucks can perform the skid.

The number of bottomhole locations a rig can reach from a single surface location is also limited by that rig's ability to drill wells with longer vertical sections. The vertical section to each bottomhole location must be operationally and economically feasible. Most conventional rigs use a kelly, and top drives either cannot fit in the masts, have limited availability, or are cost prohibitive. Without the top drive, the vertical section required to obtain a particular bottomhole location may force a well's costs beyond the point of economic benefit. To counteract the economic factor, many technologies have been applied to improve drilling speed in conventional rigs. These include PDC bits, mud motors, and wellheads with features to minimize nipple-up time. The combined application of these technologies resulted in significant increases in spud-to-spud efficiency, but cycle-time efficiency was still a limiting factor in determining how many wells could be drilled from a location.

The combined application of technologies increased the number of wells that could be drilled from a single location by addressing those three important factors, but the largest tool, the drilling rig, remained largely unchanged. Even with creative modifications, conventional rigs could not optimize the development program. The number of wells per location was still limited to 2-6 wells, with 4 the most common. Consequently, about 10% of the operator's drillable well inventory was removed when only conventional rigs were available. Only a purpose-built efficiency rig could make the next leap in wells per location, skidding technology, vertical-section achievement, and drilling speed.

When a new rig is created from the ground up, it makes sense to apply the latest technology. Automation and logistical improvements not only help drive efficiency but also improve safety. They can even expand the pool of wellsite personnel in a competitive market. Because of the decreased physical demands on the crew compared with conventional rigs, a more diverse labor pool can potentially fill the crews.

Another major factor comes into play when the full development project economics are considered. Bottom-line demands, in the form of NPV or ROI, make timely completions necessary. Drilling many wells in one visit to a single location can take from a few months to over a year. The operator often cannot wait that long to complete. If the rig stays on location, it must have the ability to work safely in concert with logging, completion and production equipment. That concept is called simultaneous operations, or SIMOPS.

Nomenclature

Drilling Days: The number of days it takes to drill a well from spud to rig release, including casing running time.

Move Time: The time associated with moving a rig from one well pad to another well pad. This requires the movement of the rig and all of its components to a new location. The time period runs from rig release on one well to the spud of the next well.

Skid Time: The time associated with moving a rig from one well to another well on the same well pad. This time period runs from rig release on one well to the spud of the next well.

Spud-to-Spud Cycle Time: The benchmark used by the operator to gauge the overall efficiency of the total cycle in a development project. Defined as the time from the spud of one well to the spud of the next well. This cycle time includes drilling days, skidding, or pad to pad moves.

Vertical Section: The horizontal projected distance of a wellbore on a drawing plane.

SIMOPS or Simultaneous Operations: Conducting drilling, completion, production, or workover operations at the same time on the same location.

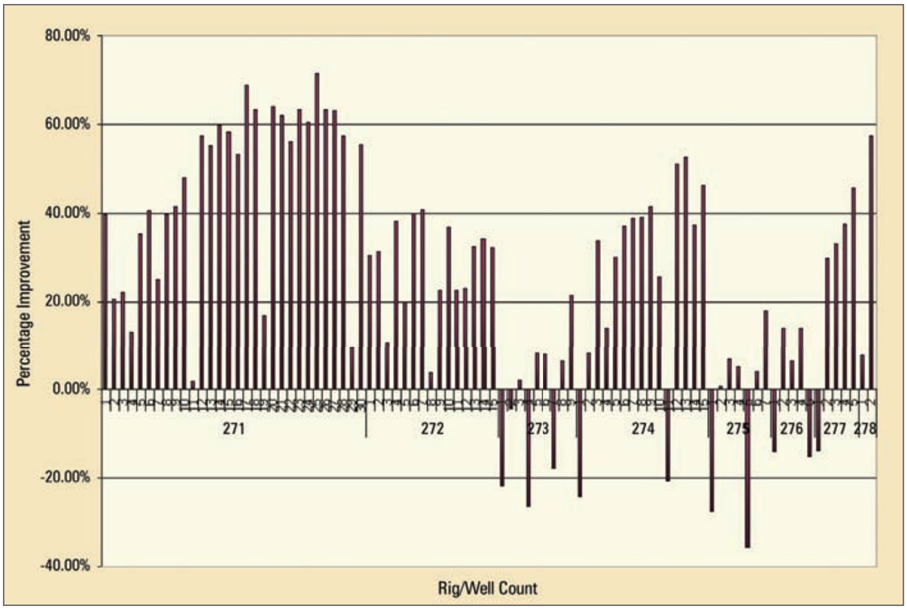


Figure 2: Overall performance improvement of spud-to-spud cycle using the efficiency rigs stood at 25%, compared with a 20% target. Some rigs outperformed that figure. One unit achieved a 72% improvement on one well and averaged a 47% improvement.

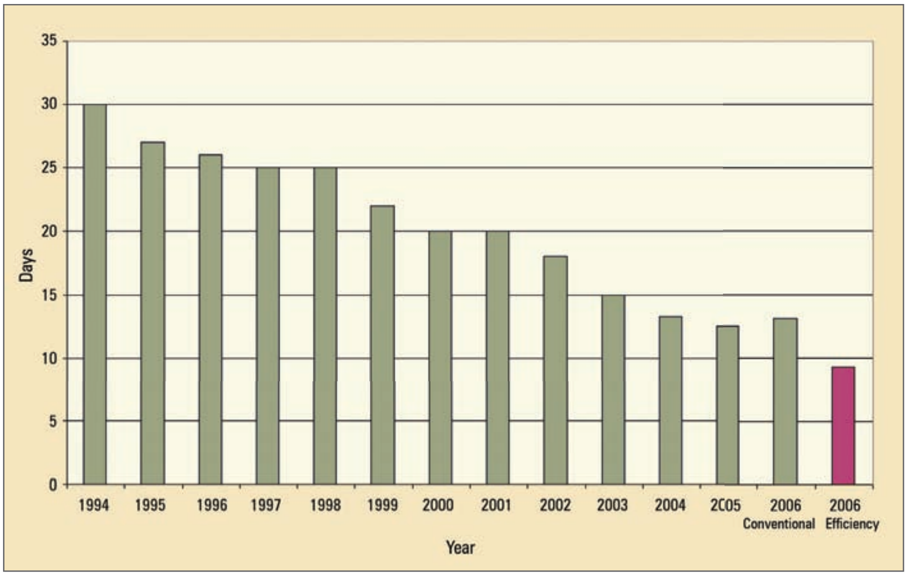
When conventional rigs were modified for skidding, the problem of timely completions was highlighted. While the skidding capability enabled the drilling of more wells on a single location, the previously drilled well was left under the substructure, or was otherwise inaccessible to start completion operations. Although the occasional producing well could remain on line during the new drilling operations, depending on its placement relative to the new wells, both the pipe-handling area and the reclined mast normally got in the way of other equipment and additional wellbores. Consequently, none of the newly drilled wells could be completed until the drilling rig moved off the location. Again, a new rig design was necessary in order to accommodate the possibility of SIMOPS.

The inclusion of that capability in the rig design adds another factor of complexity. Although SIMOPS had previously been used in both onshore and offshore development programs, it had never been attempted onshore on such tight spacing of both surface and bottomhole locations. Some existing protocols and many new techniques had to be employed in order to make it work in this new environment. This and all the other challenges of the operator's development program were considered in the design of the new purpose-built efficiency rigs.

EQUIPMENT, PROCESSES

The operator recognized the limitations of and challenges to the development program using conventional rigs. When market conditions made new rig construction a real economic option, dialogue between the operator and the contractor began. The operator wanted to accelerate and grow its development program, while the rig contractor was seeking entry into a new operating area with newbuild technology. Both parties agreed that existing rigs had many limitations, and it soon became clear that existing designs for other newbuild rigs also presented limitations. As a result, the two entities established a collaborative design team to create a new rig that was built especially for the operator's development program. Based on knowledge of the challenges of the development program, along with the weaknesses that prevented conventional rigs from meeting those challenges, the collaborative team developed a list of criteria for their new design.

- **Maximize safety:** The rig must be safer by design than any existing or other known design-phase rig by rethinking the most dangerous parts of daily operations.
- **Minimize environmental impact:** The rig must incorporate the latest technologies to minimize noise, emissions and other environmental hazards.
- **Minimize surface disturbance:** The rig must minimize surface disturbance by using fewer locations for a given development program, operating on a smaller location with little or no reserve pit, or both.
- **Minimize rig-move effects:** The rig must drill enough wells per location to keep the timing effects of rig moves to a minimum.
- **Maximize possible wells per location:** The rig must be able to drill at least 10 and preferably more wells from a single location in order to minimize surface disturbance and rig moves.
- **Optimize the drilling process:** The rig must optimize performance in as many areas as possible, including rate of penetration, trip times, directional drilling, casing running and bit life.
- **Accommodate existing wells:** The rig must be able to rig up on locations with existing wells without interrupting production on those wells.
- **Skid independently:** The rig must skid quickly and easily in two planes and in both directions both day or night without third-party equipment.
- **Allow for SIMOPS:** The rig must accommodate logging, completion and production activity on its location while it is drilling, through the proper distribution of equipment on the location, flexibility in skidding direction and drilling order, and advanced safety controls.



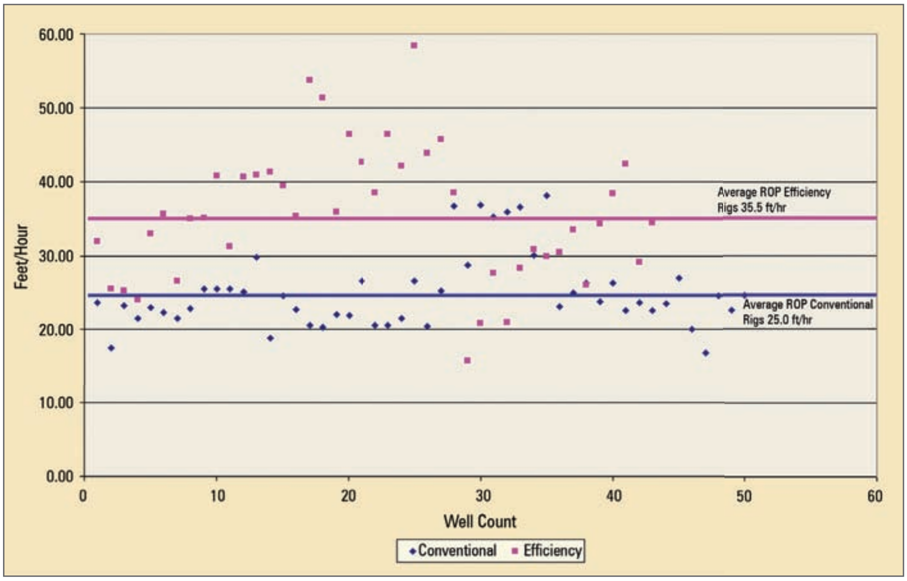


Figure 3 (top): Spud-to-TD drilling days have improved 29% over conventional rigs.
Figure 4: Analysis of drilling time as a function of measured depth demonstrates that the efficiency rigs have performed 42% better than conventional rigs.

Most of the criteria above can be encompassed within the single concept of efficiency. In the simplest terms, the rig must drill a given group of wells in less time for less money and with less surface disturbance, less environmental impact and fewer accidents, while not delaying the revenue stream from those wells. Based on the criteria developed by the design team, the contractor proposed a rig with both new technology and innovative combinations of existing technology.

Because safety and environmental impact were top concerns, the design team analyzed rig operations to identify the most dangerous tasks. Then, the rig contractor sought to change the conduct of those tasks or eliminate them altogether. They incorporated an automated pipe-handling system and an iron roughneck, eliminating the need for manual tongs. The conventional driller's station was replaced with computer controls and placed in a climate-controlled driller's cabin to maximize efficiency while minimizing human error. The new rig design set out to mitigate environmental impact, not only by limiting necessary surface disturbance but also by incorporating other features. AC power throughout the rig created more efficient energy usage while minimizing noise, and spill-proof floors improved the design. The mud system was designed for closed-loop operation, potentially eliminating the need for reserve pits.

The rig contractor also focused on maximizing the number of possible wells per location, along with other features to minimize surface disturbance and rig-move effects. Although the quickest and easiest way to minimize surface disturbance and rig-move effects was to maximize possible wells per location, the contractor found additional ways to improve those metrics. The rig was designed with a smaller footprint than a conventional rig and with the potential to operate without reserve pits, as mentioned above. Rig moves also became more efficient by using process mapping and computer animation.

Maximizing possible wells per location required optimization of other drilling parameters, such as rate of penetration, trip times, directional drilling, casing running, and even bit life. AC-powered drawworks and computer-assisted controls on rotary speed, differential pressure, torque on bit, and weight on bit minimized variability to create consistent and efficient operations. The contractor's patented mast design with integrated top drive and mud pumps with higher horsepower improved drilling rate and directional performance.

For many wells to be drilled from a single location, the rig must skid independently, accommodate existing wells and allow for SIMOPS. The contractor altered the design to incorporate more efficient skidding operations. The catwalk and V-Door were repositioned to allow more room for SIMOPS and to move all pipe-handling operations away from existing well heads. The mast was also turned to be raised and lowered away from existing well heads. In order to eliminate the need for third-party equipment in skidding operations, the contractor designed the substructure with a self-contained, integrated bi-directional skid system with a sliding cable tray. The design of this hydraulic skid system allowed the operation to take place over existing wells without interrupting production on those wells.

DATA AND RESULTS

To date, performance has exceeded high expectations. While some individual components or rigs have taken longer than others to outperform conventional rigs, many of the rigs have demonstrated performance and efficiency gains in their first year of operation that exceeded what both companies had hoped to see several years down the road. Target performance improvement vs a conventional rig benchmark of spud-to-spud cycle time was 20% (Figure 2). To date, overall percentage improvement has been 25%. Several rigs have consistently and significantly exceeded the target improvement, with one rig achieving a 72% improvement on one well, with an average improvement of 47%.

The economic benefit of shorter cycle time is monumental. With only a 20% improvement in spud-to-spud cycle time, the lifetime project NPV of activity completed during the contract life increases approximately $12 million per rig. With a 30% improvement, the NPV improves by another $12 million per rig. A 50% improvement in performance versus the conventional rig benchmark provides an incremental $50 million per rig of NPV.

Other indicators have shown similar performance improvements (Table 1). Spud-to-TD drilling days have improved 29% over conventional rigs (Figure 3). Analysis of drilling time as a function of measured depth has demonstrated that the efficiency rigs have performed 42% better than conventional rigs (Figure 4).

The directional capabilities of the rigs have also already been realized. In 2006, the vertical sections achieved by the new rigs exceeded those of the conventional rigs by an average of 49% and had average inclinations 38% higher in the tangent sections. It is important to note that these were achieved along with improvements in the cycle time, as discussed above.

SIMOPS has been a tremendous success. As a result of careful planning, coordination, and communication in the design and execution phases, drilling, completion, production and workover operations have all been executed simultaneously and without incident. The SIMOPS technology used by this rig includes all operations previously mentioned, which is very rare. Onshore operations have never before seen such close spacing of surface and bottomholes with the full integration of SIMOPS. Offshore rigs do their own completions and therefore usually do not drill and complete simultaneously. These purpose built-rigs not only brought the tight spacing of offshore SIMOPS onshore but also allowed for the concept to be implemented to the fullest.

Although some locations were enlarged to accommodate SIMOPS contingencies, the surface disturbance per well is still significantly less than drilling the same number of wells with conventional rigs (Table 1). It is anticipated that individual locations will be smaller as the operator gains SIMOPS experience. Despite larger surface locations, many environmental benefits have been realized. The governing regulatory body recently recognized the operator with an award for Outstanding Oil and Gas Operations, New Technology, for its part in the development and use of the purpose-built rigs.

CONCLUSION

An operator seeking dramatic drilling performance improvement and a rig contractor seeking entry into a new market joined forces to design and put into use a fleet of purpose-built efficiency rigs. The rigs ultimately featured a unique combination of new and existing rig technologies combined to address challenges specific to the development area. The resulting design has had a major impact on drilling performance from both economic and EH&S standpoints. The rigs have drilled more wells in less time for less money and with less surface disturbance, less environmental impact, and fewer accidents, while not delaying the revenue stream from those wells. They have also increased future reserves by allowing access to bottomhole locations that could not be economically reached with conventional rigs. The operator and rig contractor's shared commitment to the ideal of purpose-built efficiency rigs and willingness to take risks have paid off for both parties, as well as for many other stakeholders directly or indirectly involved.

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