Multiple-Leg Completions Improve Drilling Performance at the San Jacinto Field

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ABSTRACT

Discovering new methodologies and alternative applications of current technology has become essential for continued economic drilling. As new technologies and drilling equipment have continued to evolve together with more efficient drilling practices, increasing optimization has become almost mandatory in the Geothermal drilling industry especially as new project development and financing become even more challenging. The utilization of whipstock methodology and directional drilling technology to create secondary and functional legs from a common wellbore provide a very cost effective means of field development and exploitation.

Introduction

The San Jacinto Field is located in Central Nicaragua approximately 13mi/20km northeast from the city of Leon and centrally located among a series of active volcanoes (Fig. 1). The reservoir is liquid dominant with a temperature range of 260°C – 300°C.

Field development began in 1993 with a Russian company, Intergeoterm, and concluded in 1995 with seven (9) wells drilled. Drilling operations continued from 2007-2008 by Polaris and SKM with six additional wells. Following the acquisition of Polaris by Ram Power in 2009, a drilling program was conducted by Ram Power and SKM from 2010-2011 that included new wells, forks and redrills.

Production has been certified to provide capacity to a power plant rated at 72MW (net). Construction of the plant is ongoing

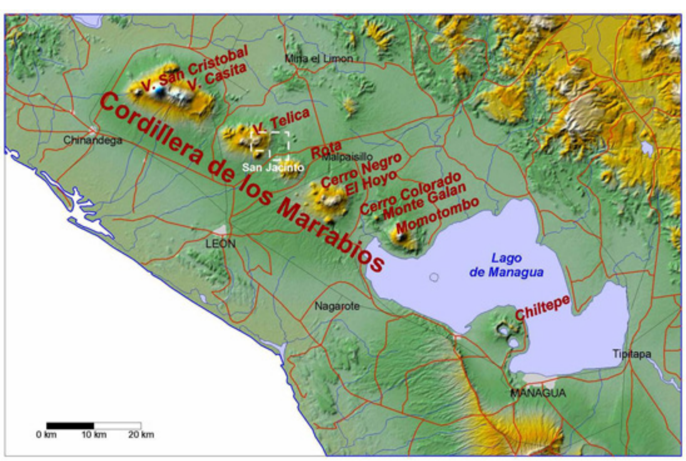


Figure 1. General Map of Nicaragua and Volcanic Structures.

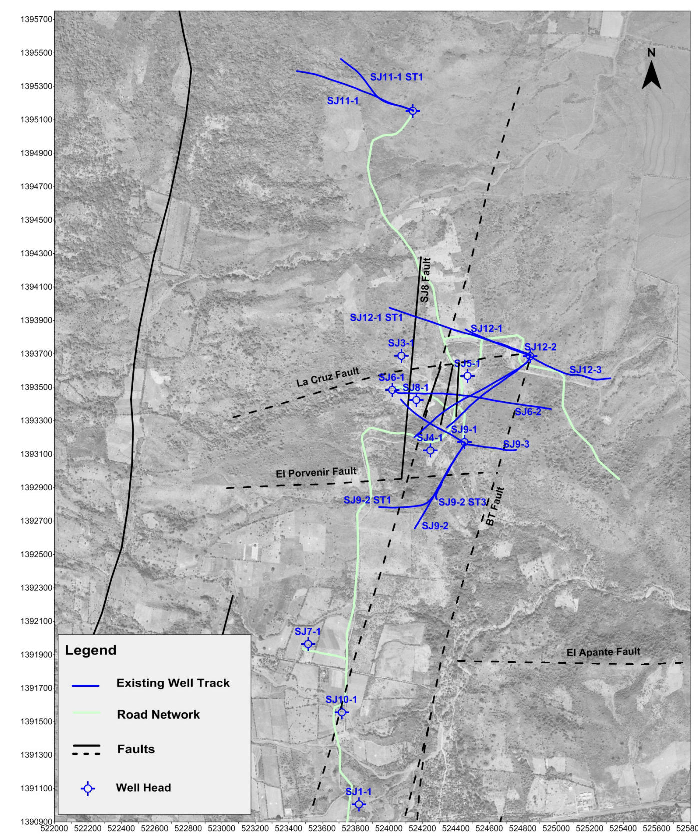


Figure 2. San Jacinto Field Well Locations.

with Phase I (36MW) becoming commercial in January 2012 and Phase II (36MW) scheduled for completion later in the year.

Currently, there are thirteen (13) active wells in the field including nine (9) producers and four (4) injectors. These wells are deviated with an average depth of 6500ft/1981.2m and originate from seven sites. There have been two (2) wells completed utilizing multiple-leg methodology and those case histories are discussed in this paper. The steam field and well locations are illustrated in Figures 2 and 3 and their proximity to major fault systems.

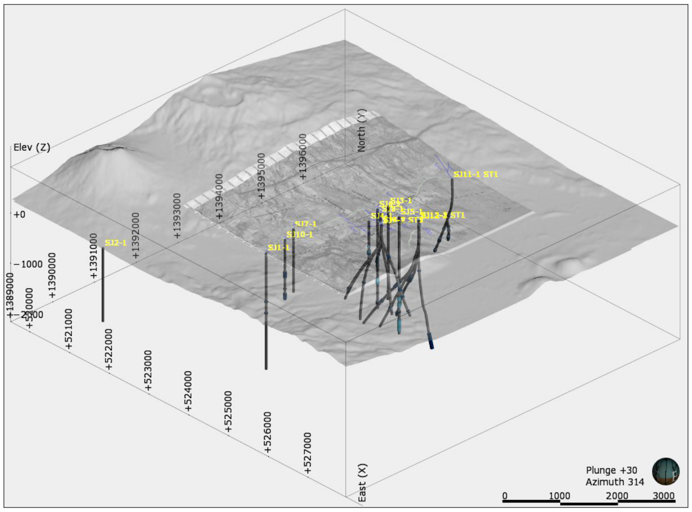


Figure 3. San Jacinto Field 3-D Section of Well Locations.

Application and Design

There are a number of benefits to drilling multiple legs or forks when planning and implementing a drilling program. The major advantages include:

1. There is a significant improvement and impact to the overall project schedule and budget management. Multiple-leg wells are completed sooner and at less cost than an equivalent number of new wells.
2. Drilling and finding costs ($/MW) are minimized resulting in more efficient reservoir exploitation.
3. Fewer surface locations are needed resulting in less wellhead equipment and more efficient use of surface drilling sites.
4. Pipeline and construction costs are reduced with fewer well hook-ups to the production system.
5. Marginal production or injection is preserved and still utilized after drilling a second leg.
6. The knowledge gained from the original leg means resource related risks (e.g. temperature and permeability) in the second leg are significantly reduced with large potential upside.

There are many considerations when implementing a multiple-leg methodology. It begins with a specific job design and then assessing the risks and benefits. As already discussed, the greatest benefit is the positive impact on the overall project schedule and budget. This becomes even more significant at the beginning of a development project where confirming new production should be performed as cost effectively as possible. This is critical to a resource assessment and demonstrating commercial viability. The number of constructed or available drill sites is also an important factor in the decision to drill secondary legs from alternate sites that may not be available. This analysis is balanced against specific reservoir targets and the most optimum means of exploiting those areas and maintaining proper well spacing. The utilization of directional drilling technology is also important to achieving sufficient separation from the original well when drilling a forked leg and avoiding any production communication in the reservoir. Another very key component to the success of any multiple-leg project is the availability of necessary equipment and expertise to implement the plan effectively and minimize downtime. Selection of a contractor with the necessary knowledge, technology and experience is always a major factor when job planning. And, finally, consideration needs to be given to any future remedial work, re-entry, and well monitoring. It is very difficult to re-enter the original leg following the removal of the whipstock assembly. For this reason, a perforated or slotted liner should be installed prior to whipstock removal to preserve the wellbore integrity and avoid any potential obstruction of well flow or injectivity.

The objective and procedures for a multi-leg completion include the following steps:

1. The original well is isolated with an inflatable packer followed by a layer of sand and cement. The layer of sand (usually10ft/3m to 15ft/4.6m) is to provide a safety buffer on top of the packer and prevent the cement from interfering with later retrieval. The cement layer provides a base to set the whipstock and anchor assembly.
2. The cement is cleaned out to a correlated depth with respect to the casing collar locations. If available, a casing collar log provides better depth control. This depth control for placement of the whipstock is to facilitate efficient milling and sidetracking operations.
3. A retrievable whipstock assembly (Fig. 4) is ran and oriented to a desired direction with the objective of facilitating immediate directional separation when initiating the new leg. An MWD tool is recommended for this orientation. It is more precise and controllable.
4. The anchor assembly is set on top of the cement. The milling assembly is then disengaged from the whipstock ramp (Fig. 5) and casing milling is initiated. Multiple milling assemblies are

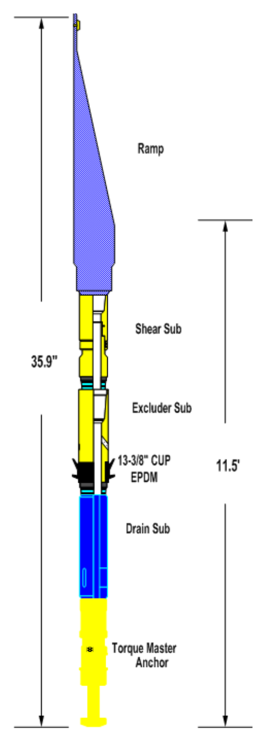


Figure 4. Schematic of Retrievable Whipstock Assembly.

Figure 5. Whipstock Ramp.

used to establish a complete “window” and a new rock formation.

5. A separate leg is directionally drilled form the production casing to a desired reservoir target.
6. A new perforated liner is installed. It is very important during placement that the top of the liner is 15ft/4.6m to 20ft/6.1m below the bottom of the whipstock ramp to allow for any thermal expansion after the whipstock has been removed and the well is exposed to flowing temperatures. However, the liner installation can be problematic if any fill is encountered on bottom. Diligence is necessary when preparing the wellbore prior to running the liner and making sure any hole sloughing is mitigated
7. Injectivity testing and/or production logging are performed to evaluate and assess the new leg.
8. The whipstock assembly is retrieved. A fixed lug retrieving tool (Fig. 6) and stabilized assembly is used. A retrieval slot on the whipstock ramp is located and engaged. Overpull is applied to shear the disconnect and then the whipstock and anchor assembly are recovered.
9. The cement and sand are cleaned out to the top of the packer. The packer is latched, released, and recovered. The original leg is re-opened as an active wellbore.
10. Injection rate or production discharge testing and analysis are conducted for the combined wellbore.

The final objective and desired result are to end up with two separate legs producing or injecting from a common wellbore, both completed with perforated liners, and both drilled to specific targets to facilitate well spacing. There are several challenges, but with the proper job design, equipment, technology, and expertise, the risks are minimal and the rewards very significant.

SJ 12-2 Discussion

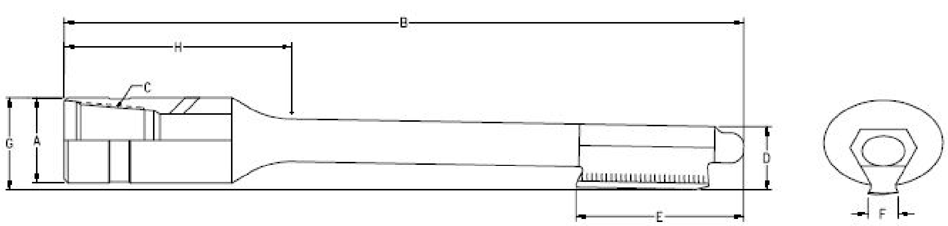
This well was completed in 2011 through separate rig jobs resulting in the first forked well in the field. The original well was drilled to 7501ft/2286.3m (Fig. 7) and a lost drill string prevented the well from reaching its intended target and partially restricted steam flow. The well was tested at 4MW, which was lower than expectations. A decision was made to return the rig with the objective of preserving the existing production and drilling a second leg toward a new reservoir target.

The drilling and completion results of the second leg can be summarized as follows:

1. A casing collar locator was run.
2. The first packer failed. It had been on the site since 2005 and the shear pins were rusted. A second packer was installed at 2799ft/853.1m (above the 9⅝” liner) to isolate the original well followed by 16ft/4.9m of sand and 57ft/17.4m of cement. The cement was cleaned out to 2761ft/842.6m.
3. The whipstock assembly was set at 2761ft/842.6m and directionally oriented.
4. Milling operations to initiate sidetrack took three runs.
5. The forked leg was drilled to 7239ft/2206.4m (Fig. 8) with a 10° azimuth change and 23° increase in deviation. The intended reservoir target was achieved with intersection across a productive fault system and significant permeability encountered.

Fixed Lug Whipstock Retrieving Tool

Dimensional Data Drawing No. 948-774-01P02



Fixed Lug Whipstock Retrieving Tool

Dimensional Data

Refer to Drawing No. 948-774-01P02.

Material No.	Casing Size (in.)	Dim A	B	C	D	E	F	G	H	J	Tensile Load (lb)	Torsional Load Rating (ft-lb)
H150-51-3510	2.625	3.630	57.0	1.500 AM MT	1.750	3.000	0.637	2.630	14.5	4.625	200,000	300
H150-51-4510	4.500 5.000		75.0	2.375 REG	2.250	4.850	0.981	3.630		4.500		1,000
H150-51-5002	5.000	3.125	66.0	2.875 PAC DSI	2.346	6.120	1.071	3.580	11.2	5.875	100,000	
H150-51-5501	5.500		72.0		3.475	7.110	1.171	4.810	10.0	5.125		
H150-51-6610	6.625	5.000	90.0	3.500 IF	3.784	10.010	1.783	5.434	13.4	-	200,000	3,000
H150-51-7001	7.000 7.625				3.967			6.200		6.575		
H150-51-8601	8.625 9.625	6.375		4.500 IF	4.250		1.860	7.40	20.6			7,000
H150-51-9610	8.625 9.625		99.0						30.0			
H150-51-1301	10.750 11.750 13.375	7.750	155.0	6.625 REG	6.188	11.665	2.713	9.31	29.0		250,000	15,000

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Figure 6. Schematic and Dimensions of Whipstock Retrieving Tool.

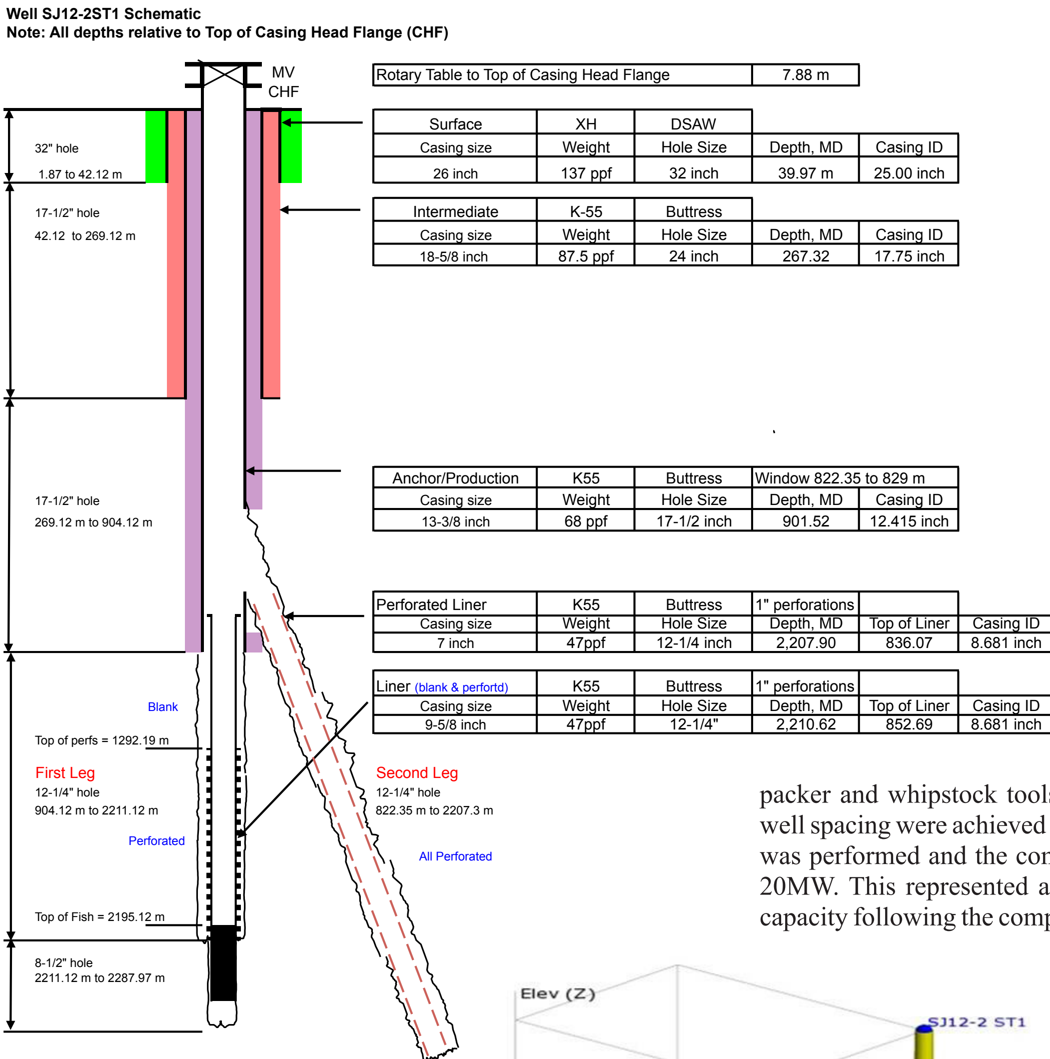

Figure 7. Schematic of Well SJ 12-2.

6. A maximum spacing of 1200ft/365.8m from the original leg was achieved (Fig. 8).
7. A 9⅝" liner was installed and stopped with the liner top 3ft/.9m below the bottom of the whipstock. Some difficulty was initially encountered re-entering the liner. A drill pipe assembly was run inside the liner and the bottom of the wellbore was cleaned out allowing the liner to settle to the bottom. This placed the top of the liner approximately 24ft/7.3m below the bottom of the casing window.
8. Production logging was performed to evaluate and characterize the reservoir parameters.
9. During retrieval of the whipstock, the anchor assembly became separated and was left in the hole. Fishing tools were run to recover the anchor tool. It was discovered after examining the tool that a part of the assembly was packed with metal cuttings preventing any pull on the anchor and resulting in the safety sub shearing. The lesson learned was that more attention should be given to proper hole cleaning when milling operations are being performed. This can be accomplished with proper drilling mud maintenance and pumping high-viscosity sweeps following the casing milling.
10. The sand and cement were cleaned out and the packer recovered.

A successful forked completion was achieved using Baker packer and whipstock tools. The directional target and desired well spacing were achieved as planned. A long term discharge test was performed and the combined flow of both legs was almost 20MW. This represented almost a 400% improvement in flow capacity following the completion of the original well. Compared to drilling a separate new well on this same site, the total benefit of drilling a secoimately $2.3mm and a schedule reduction of almost four weeks. SJ 12-2 has not produced and is still waiting final completion of our Phase II power plant construction, expected in the fourth quarter of 2012.

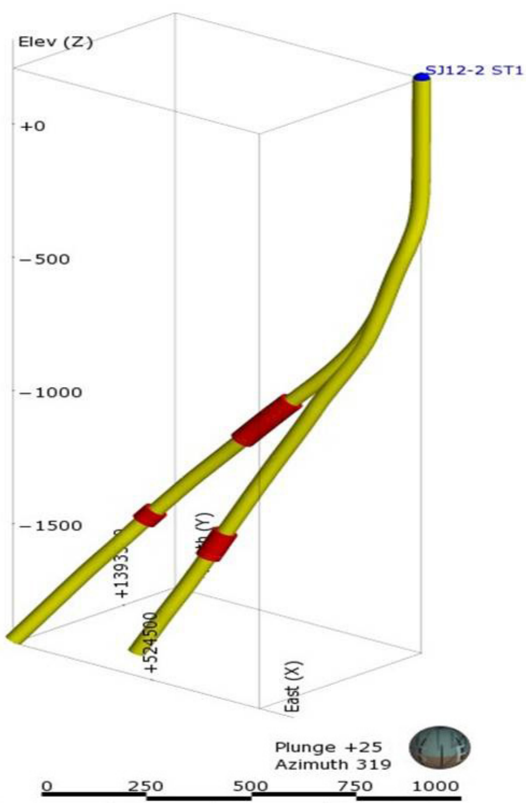

Figure 8. 3-D illustration of Well SJ 12-2.

SJ 11-1 Discussion

This well was planned and successfully completed as a dedicated injection well, also in 2011. A second leg became necessary to achieve the target injection capacity. Very slow drilling rates and significant lost circulation were encountered in the upper section adding many unscheduled days to the completion of the original well. Given this knowledge and experience, the plan to drill a second leg became even more cost effective rather than drilling a second new well from the same site. Also, there was good permeability identified in the initial leg, so it became a strategic opportunity to maximize

Caption

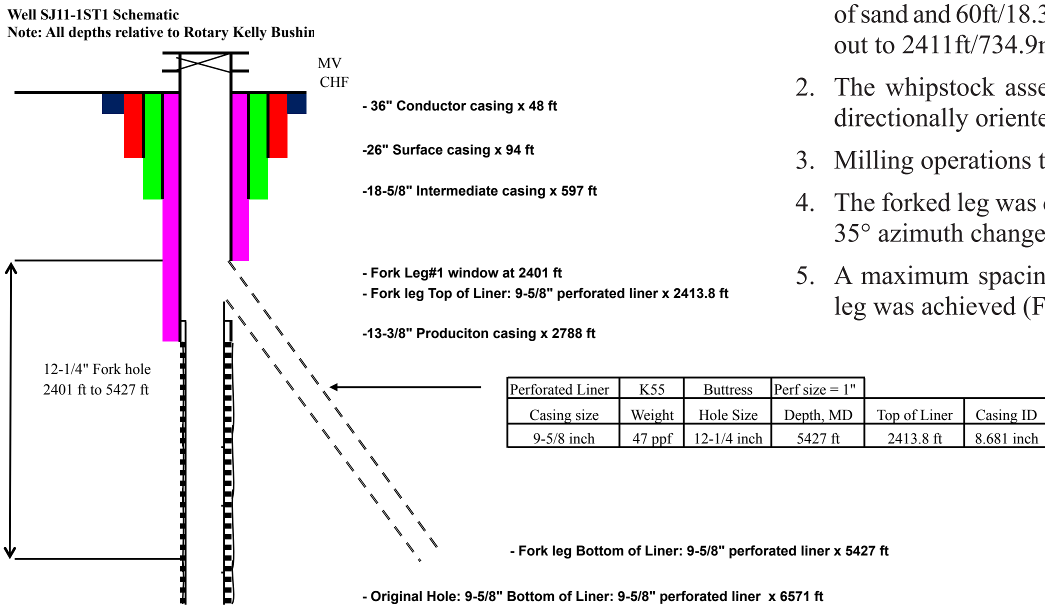

Figure 9. Schematic of Well SJ 11-1.

injection capacity with a second leg and meet target requirements for the project. The first leg was drilled to 6571ft/2002.8m T.D. (Fig. 9) and tested at an injectivity index of 15.5tph/bar, which was below expectations and our field needs.

The drilling and completion results of the second leg can be summarized as follows:

1. The original well was isolated with an inflatable packer at 2450ft/745.8m (above the 9 ⅝" liner) followed by 7ft/2.1m of sand and 60ft/18.3m of cement. The cement was cleaned out to 2411ft/734.9m.
2. The whipstock assembly was set at 2411ft/734.9m and directionally oriented.
3. Milling operations to initiate the sidetrack took six runs.
4. The forked leg was drilled to 5427ft/1654.1m T.D. with a 35° azimuth change.
5. A maximum spacing of 850ft/259.1m from the original leg was achieved (Fig. 10).
6. A 9⅝" liner was installed and stopped 19ft/5.8m off bottom due to fill. The liner was released and then a drill pipe assembly was run to wash out the bottom of the wellbore. The liner moved down the hole as intended leaving the top approximately 20ft/6.1m below the casing window.
7. Production logging and injectivity testing were performed on the second leg. The test result was an injectivity index of 47.5tph/bar.
8. The whipstock and anchor assembly were recovered with no significant problems. There was some initial difficulty encountered regarding depth control when engaging the slot on the whipstock ramp. It's very important to use the same drill pipe string when retrieving the whipstock as was used during the initial installation. Precise depth control from drill pipe measurements is critical during this retrieval process when locating the whipstock slot.
9. The sand and cement were cleaned out and the packer recovered.

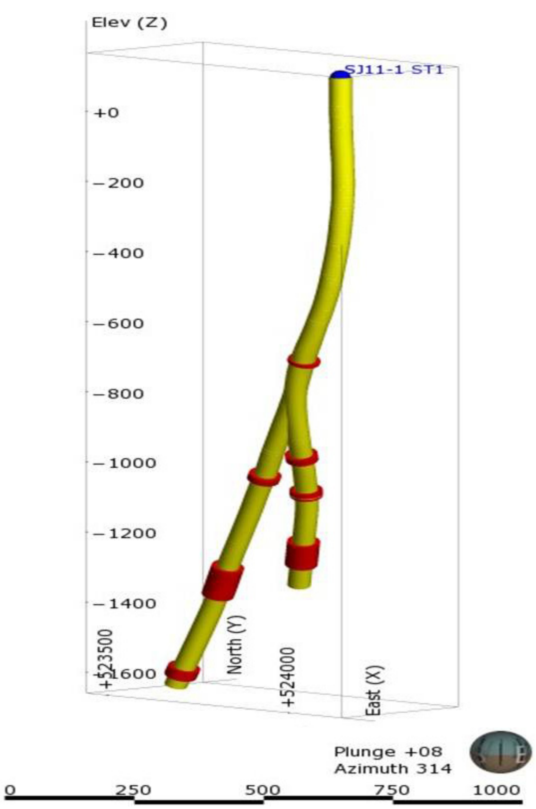

Figure 10. 3-D illustration of Well SJ 11-1.

An injectivity test was performed on the combined legs and resulted in a similar result of 47.5tph/bar. The second leg completion resulted in almost a 300% improvement in injectivity potential. Compared to drilling another new well from this same site and encountering similar problems in the upper section, the total benefit of drilling a secondary leg was a cost savings of approximately $3.7mm and a schedule reduction of almost 6 weeks.

After a 25 day shut-in period, a pressure temperature survey was conducted in the original leg, which showed a down flow of fluids from the forked leg into the original leg. The hot injection capacity for this well was estimated at 825tph for the combined legs at a targeted delivery pressure of 220psi. The well is currently the primary injector for the field and the multiple-leg completion has provided the necessary capacity that would have otherwise required another separate new well.

Conclusions

1. Drilling and completing multiple-leg wells using packers and whipstock systems is a very practical and cost effective technique to optimize performance and field development.

2. The estimated savings in cost and time to the overall project for forking SJ 11-1 and SJ 12-2 totaled almost $6mm and ten weeks. This resulted in a very significant benefit to project budgeting, scheduling, and financial viability.
3. Baker Hughes' equipment, technology, and expertise proved to be very reliable and instrumental to the project success and in minimizing job risks.
4. SKM contributed a vital role in well targeting, advocating drilling with water only, and post-well evaluation and analysis for optimum well performance and reservoir management.
5. Consideration of forked wells should be included in any field development strategy as a cost effective option for enhancing well performance.

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