SPE 99949

# Real-Time Field Surveillance and Well Services Management in a Large Mature Onshore Field: Case Study

L. Ormerod, SPE, Weatherford; H. Sardoff, SPE, J. Wilkinson, SPE, and B. Erlendson, Chevron; and B. Cox, SPE, and G. Stephenson, SPE, Weatherford



This paper was prepared for presentation at the 2006 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 11–13 April 2006.



## Abstract

This paper describes the planning for, implementation of and results generated by a real-time field surveillance and well services management system, as it was deployed in an onshore mature field in California USA. The motivation behind the deployment of this system was simultaneously to improve efficiency and reduce operating costs in this large field with over 1,000 wells.

The paper will describe how the business processes and supporting workflows were defined. This is an essential step before any technology can be deployed. The challenges of data management included not only the automatic handling of very large quantities of real-time data, but also the management of inventory, and the integration of field-level data with corporate-level data. Historical data had to be brought into, and made compatible with, the new system. The technologies required for this project included the software systems themselves, but also the integration of these with remote intelligent field sensors and data transmission systems.

The impact of the system has been material to the performance of the asset. Examples will be given of tangible improvements in performance across the disciplines of surveillance, production engineering and well services. What was found was that critical to the successful deployment of this system was the organizational changes needed to support the new working practices it enabled. The paper will discuss the required Change Management programs.

The success of this project has established without doubt that a "smart" solution integrating intelligent remote devices, communications networks and workflow management software can be successfully deployed on large, mature fields. The deployment process to achieve this has been assimilated and is now being reproduced in many other similar fields across North America. The paper will indicate some of the areas where this combination of technology and supporting change management will be expanded in the future.

## Introduction

This paper describes the evolution of an oilfield automation and software system up to an innovative level of surveillance and work planning. The historical automation level was at that of individual wells. (It is estimated that about 10% of the world's wells are automated to this degree.) Next, this data was brought to field offices allowing remote surveillance. (Most automated wells have some similar type of data consolidation.) The next step was to feed this data automatically into engineering models, which is comparatively rarely done (other than with much human intervention).

It was to build upon this relatively high level of historical automation and surveillance that the decision was taken to go a step further and introduce a highly innovative software system which not only further developed the remote surveillance concept, but also managed the well services activities so that full well histories would be electronically managed. What was particularly novel was the concept that the workflow processes themselves would be defined in, and managed by, the software. There are few instances of this level of business process automation being applied in the upstream operations and engineering sectors, and the lessons learned are valuable.

## Prior State of the Business

### Introduction to the Business

Chevron's San Joaquin Valley Business Unit (SJVBU) is located in the southern San Joaquin Valley in central California. The SJVBU is headquartered in Bakersfield, California, which lies in close proximity to the fields operated by the business unit (BU). The SJVBU operations encompass assets in seven individual oilfields which prior to the merger of Chevron and Texaco were operated by those two companies. These fields are Coalinga, Cymric, Kern River, Lost Hills, Midway Sunset, McKittrick, and San Ardo.

The earliest of the oilfields in the San Joaquin Valley was developed from the early 1900's with the majority of the area's development taking place in the 1960's and 1970's as a result of steam flooding technology. Chevron's aggregate operated production from its SJVBU assets is approximately 200,000 bopd. There are approximately 15,000 active producing wells in the BU yielding an average production of approximately 13 bopd per well.

The SJVBU fields largely produce from relatively shallow reservoirs, including the Miocene-Pliocene Kern River, Tulare, Temblor, and Potter formations which typically have porosities ranging from 20% to 30% and permeability in the range of 1 mD to 5 mD. Oil gravity ranges from 13 to 20 API and viscosity approximately 50 cP. The reservoir depth is typically only about 1000 feet making wells extremely rapid to drill. The production revenue from oil is more than 95% of total sales, and virtually all wells are lifted by sucker rod pumps (SRPs).

The key operational focus in the production management of these fields concerns the challenge of maintaining this very large number of wells on optimum production.

This paper is concerned with the introduction of an online system for well surveillance and well services management in SJVBU, and in particular, with the experience of implementing this system in the Cymric field. Cymric is typical of the SJVBU fields and contains approximately 800 SRP wells producing 16,000 bopd. Cymric has another 500 “Huff and Puff” cyclic steam wells that flow after the steam cycle, adding another 24,000 bopd, for a total field production of 40,000 bopd.

**Automation History in San Joaquin Valley Fields**

The deployment of automation technology in SJVBU can trace its roots back to activities in the Lost Hills field in the mid-1980s. This field had been acquired by the operating company as part of the purchase of the previous operator of the field. Under new ownership, a highly successful program was undertaken to increase production. This program was based on finding the best way to fracture the wells. Field production rose from less than 3,000 bopd to over 20,000 bopd (1). Naturally, this success attracted a lot of attention and engendered confidence in the field operating team. Managing this new production became a priority and the team went on to successfully install pump-off controllers (POCs) (2) throughout the field. This was the first form of automation to be introduced in the SJVBU. Members of the Lost Hills operating team subsequently moved to Cymric in the mid-1990s bringing with them their focus on reducing lift costs. This, coupled with their culture of successfully working to deploy new technologies, was to prove extremely valuable.

Between 1995 and 1997, well failures at Cymric, measured by the rate of failures per well per year, had risen from approximately 0.15 (that is, 15% of the population of wells will fail over the period of a year) to approximately 0.3. This may be seen in figure 13. This was causing a significant cost in terms of repair jobs and an additional cost in terms of deferred production. Accordingly, a major effort was initiated with the clear objective of cutting operating costs through improvements in well failure rates. Technology played a significant role in this effort: POCs were deployed using experience gained in Lost Hills; csLift well management software for surveillance and SRP optimization was introduced; and downtime based on production allocation was analyzed and used to prioritize repair jobs.

In addition to technology, significant changes were made to the field management process such as: the development of the Well Manager role, a well review process, and the trending of runtime metrics. Staff development and participation was also increased including actions such as: the frequent communication of the aggressive targets to operators, the sharing of best practices with contractors' staff, and training. Key suppliers were reviewed and in some instances changed.

This all combined to create a major effort which paid off in terms of an improvement in well failure rates. Crucially, the management team did not "drop the ball" once failure rates had been restored to previous levels. Instead, a stance of continuous improvement was adopted which continues to this day. Up to 2001, the penetration of automation was increased and online well surveillance was significantly stepped up.

## Change Drivers

**Business Priorities and Needs**

In a large onshore field with a very high well count, such as any of those in SJVBU, operating costs are likely to be a key governing factor in the business performance of the asset. In the case of SJVBU in 1998, repairs comprised a significant and rising cost element. At a crude oil price of $10 per barrel, well failure direct costs represented over 6% of gross field revenue. This was a significant cost and was why the major effort referred to above was initiated.

When estimating the costs of failures, the two main categories to be considered are: the direct cost of making the repair itself, and the cost of the deferred production. Deferred production equals the well rate multiplied by the total time between failure and production restoration, made up of times between: failure occurrence and detection; between detection and commencement of repair work; and duration of repair work. Figure 1 shows the relative cost contribution between direct cost of repair ($6,000) and the cost of deferred production ($3,000) for a typical well failure in SJVBU. This illustrates that, because the production rates are relatively low, the total cost of the failure cannot be greatly reduced by improving the time taken between failure and repair (i.e. deferral), and instead operators must focus on reducing the overall failure rate.

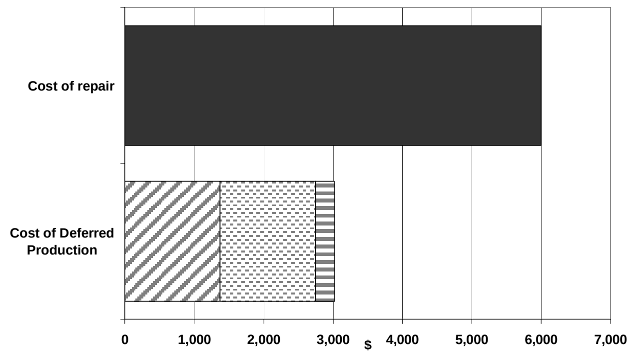


**Figure 1 – Estimated costs of a single failure between direct repair and deferred production, showing deferred production cost split into (left to right) detection time, time to schedule repair, and repair time itself.**

The Cymric situation in 2001 was that, even though failure rates had been reduced from a high of 0.3 in 1997 back to an average of about 0.15 since the end of 1998, they were now beginning to show signs of rising again (see figure 13). New automation equipment had been installed, notably POCs, and software both for well surveillance and for well re-design optimization was being used. Many new processes around well management had been introduced, partially utilizing the data and software which was available. Staff had been thoroughly involved in developing these new work practices. Pumping hardware had been changed as a result of lessons learned. Against this background, it was believed that a new initiative was required in order to make a further impact on the failure rate and thereby on production costs.

Two parallel changes were happening, which further increased the demand for a step change. First, after the recent merger, there was an increasing corporate desire to standardize field management processes. The SJVBU, for example, contains fields which were both previously Chevron- and Texaco- operated. Most fields were developing and utilizing their own well management processes and many of these relied on individual spreadsheets, databases, and custom generated applications. The volume of such applications in use throughout the BU made it impossible to effectively leverage the information they contained or to standardize the business processes. With this in mind, it was desired to consolidate all of these ad-hoc applications into a single software platform, as illustrated in figure 2.

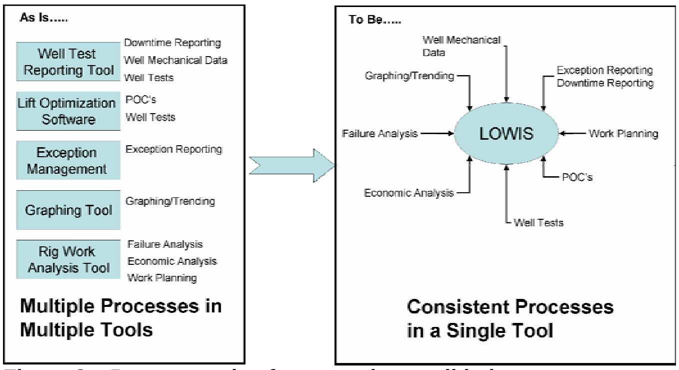


**Figure 2 – Process and software tool consolidation.**

The second independent driver was the fact that manpower reductions led to a need for higher staff productivity.

A vision was therefore developed to uncover the "missing opportunities" required further to reduce Cymric's failure rate. A solution was envisaged that would tie together the aforementioned automation technology, provide real time well surveillance, have the ability to research well histories and develop well service plans. This Well Services Management capability was projected to lead to a reduction in time taken to execute well services as well as a means of driving down the costs of well services through recording and planning the activities. In addition, this system should allow trending of historical data to help evaluate failure causes. This would be a true Life of Well Information System or LOWIS for short.

The Business Case for the required investment in time and software development was made on the basis of projected further improvements in the failure rate. The value of these was quantifiable, and previous initiatives had shown that substantial, measurable improvements in failure rate had been made. A team was in place with a track record of exploiting new processes and technologies to achieve these business results. As a consequence, management was confident that further business performance improvements were achievable.

## Setting The Requirements

The vision for the software was initially set by the field operation team in collaboration with the supplier of the well surveillance software then currently in use. However, it rapidly became apparent that in order to define the requirements for such a complex set of processes that reached outside the field operations team, additional support was going to be required from the SJVBU's central support group. As noted previously, after the merger there was a corporate desire to standardize key work processes. A local work group, Central Operations Services (COS), had been set up in the SJVBU to standardize many processes. Among this process standardization was the subsurface maintenance process. Management support was secured for COS to work with the field operations team and with the software supplier to come up with the specifications and deployment plans for LOWIS. The contribution of all three groups was to prove essential in developing the requirements which were able to be subsequently translated into working software supporting processes that could be implemented across multiple fields. The COS group had eventually evolved into a Corporate Operations Standardization and Improvement (OSI) team working to further standardize business processes across multiple BUs. The OSI team would be instrumental in further expanding the scope of standardization and deployment outside of SJVBU.

As a guiding priority, it was agreed that the specifications would be set by reference to the desired business processes; and the software would have to support these processes, instead of having process built around the capability of the software. Figure 3 illustrates how the software was architected to reflect the key processes of the organization.

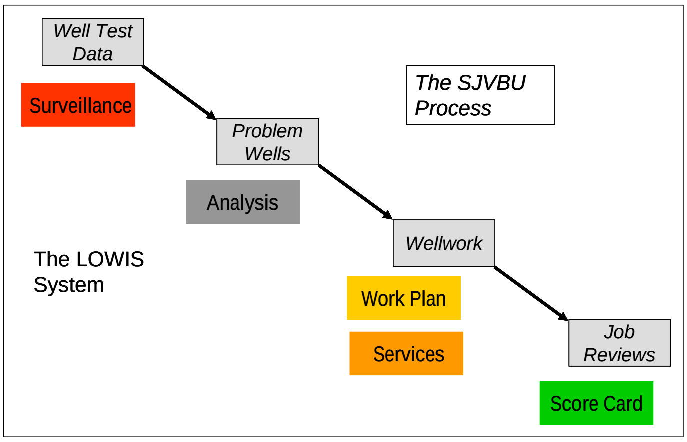


**Figure 3 – The mapping of high-level software functions onto the SJVBU main well management processes.**

The key challenge at this stage was to build the knowledge and understanding necessary to "capture" the business processes in such a way that they could be standardized across multiple fields (and eventually multiple BUs). In order to understand better how these standards might be established, the team developed a high-level mapping of the various roles and responsibilities within the organization against this workflow. This is reflected in Figure 4.

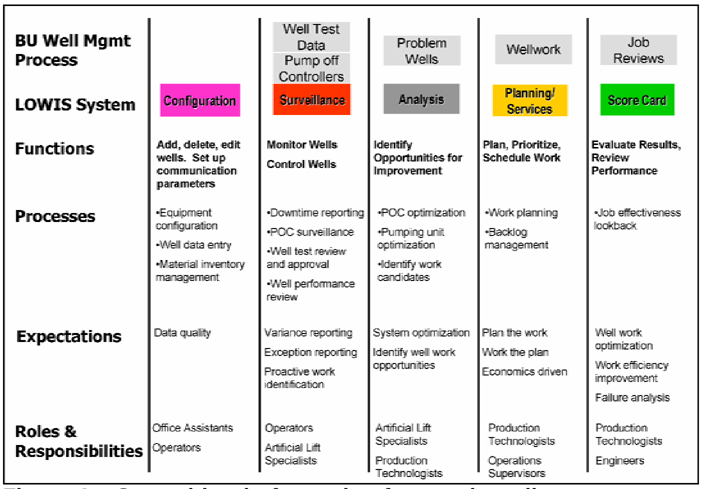


**Figure 4 – Second level of mapping from main well management processes to functions, processes, expectations and roles & responsibilities.**

Once this second level mapping had been established, it was then necessary to work painstakingly at a detailed level. There appears to be no shortcut past this detailed work. However, the task was eased by being taken in two major cycles (as described below). The definition phase lasted for about a year during which time Standard Operating Procedures (SOPs) and process flow diagrams (PFDs) for each of the key business process mapped in figure 4 were documented in detail. One such PFD is illustrated in figure 5.

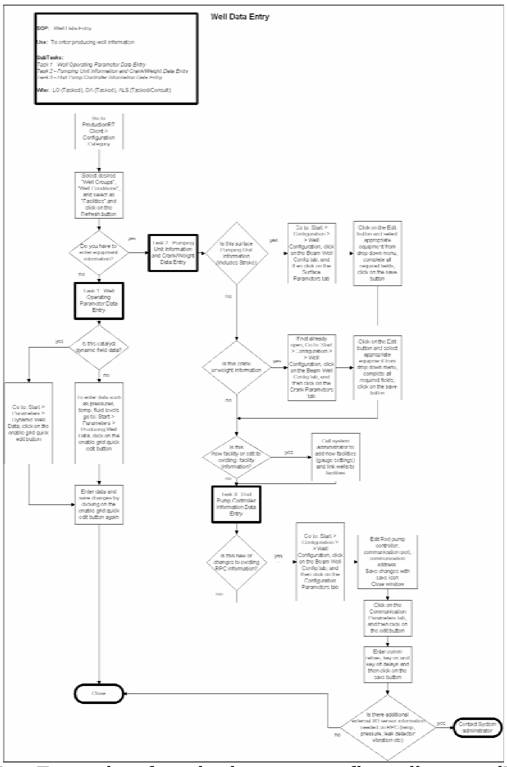

**Figure 5 – Example of a single process flow diagram (PFD) for well data entry: the details on this are less important than the level of detail required which it illustrates.**

Comprehensive roles and responsibilities matrices were created in detail, describing what each user's role was to be within which portion of the software.

In addition to a full-time core team of approximately 3 people doing the documentation, a lot of time was required of field staff to explicitly describe the business processes so that these processes could be replicated within the software. A good deal of input from the software provider was also required to ensure that what was being defined was realistically achievable in software terms.

## Managing the Change

### Technology

The implementation of the solution was able to leverage off some of the existing SCADA (Supervisory Control and Data Acquisition) technologies being used by the operator in this field for the purpose of surveillance of wells and production facilities. Some infrastructure already existed and consisted of the end devices in the field, the communication infrastructure, and a variety of host systems.

A new software interface needed to be developed that allowed the production operation teams to interface with the existing SCADA as well as other data sources in a single environment, as illustrated in figure 6.

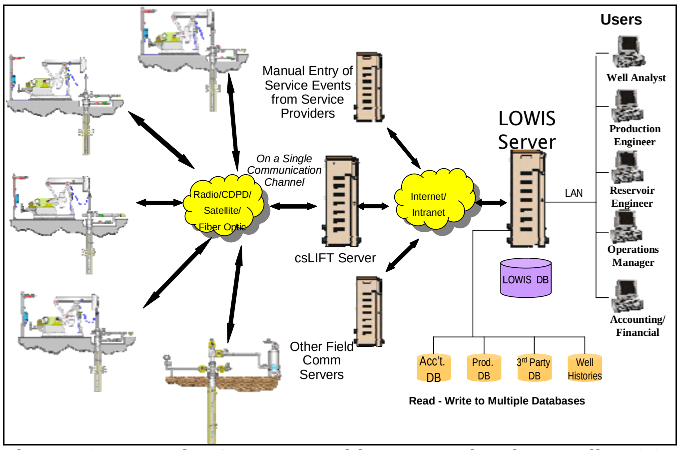


**Figure 6 – Basic System Architecture, showing well POCs connected to data consolidation server, which then connects, together with other data servers, to LOWIS server. This serves web clients and various asset databases.**

This field location has a multitude of end devices in the field for real time surveillance. POCs from various manufacturers are used for controlling a portion of the rod lift systems. Through the continuous monitoring of polished rod load and displacement, POCs are able to detect and prevent adverse conditions such as fluid pound, gas compression in the pump and excessive rod loading. The POC takes appropriate action based on embedded instructions that are provided by the field operator. By controlling fluid pound, POCs reduce rod buckling. This reduces wear and tear on the rod string, tubing string and pumping unit. POCs can also reduce rod failure due to stuck or sanded pumps. A typical POC set up is shown in figure 7.

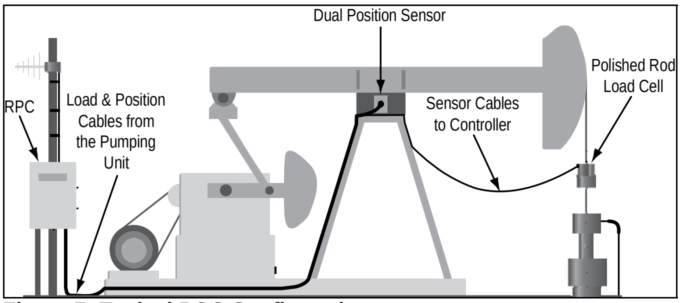


**Figure 7: Typical POC Configuration.**

In certain wells throughout the BU, additional instrumentation is used in conjunction with the POC. One such form of instrumentation is a stuffing box leak detector. If a leak is detected, a signal is sent to the POC, which shuts the well off and generates alarms locally and through the software. This alerts the operator to the problem and mitigates an environmental incident.

Similarly, tank level sensors are used throughout the field. When a high level exists in a tank, the host software generates an alarm and shuts in the wells that feed into the tank battery, again mitigating an environmental incident.

Flow line temperature sensors also play an important role in the field, enabling effective management of the steam flood. Low and high alarms alert operators to lack of steam or steam breakthrough in certain cases.

Casing pressure sensors allow operators to identify problems either down-hole or at the surface which may lead to additional back-pressure on the formation, and which in turn could cause production deferrals.

Automatic well test stations were linked into the host software, eliminating the need for manual entry into the system.

Reliable communications are critical to the successful implementation of any data gathering system. In the absence of a local network, simple radios are used. These field devices communicate back to the host system through licensed radio frequencies and IP radio devices.

The software client interface is an easy to use web-based program. It has a built in workflow process which supports the various operation team members' roles and responsibilities. A variety of tools in the software provide for customization of the interface to tailor it to the needs of the individual user.

The software is divided into four basic sections; Configuration, Surveillance/Analysis, Work Plan/Services and Scorecard. The interface allows a user to work in one particular portion of the system at any given time. The Configuration section provides for easy access managing the addition and definition of wells, facilities, and equipment, and is illustrated in Figure 8.

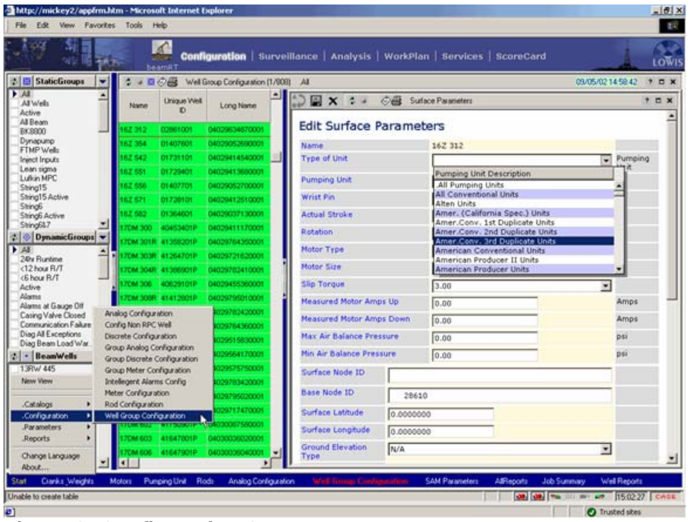

**Figure 8: Configuration Screen.**

Surveillance/Analysis allows the users to monitor and control wells, review production data, and identify opportunities for improvement using engineering models. This section of the software is illustrated in figure 9.

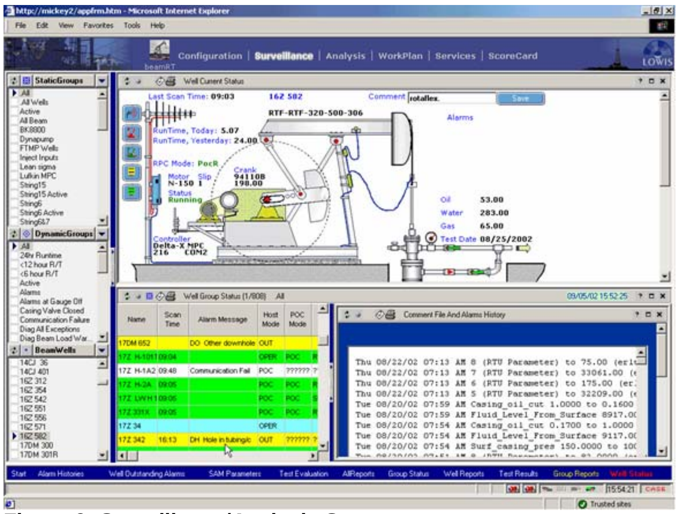

**Figure 9: Surveillance/Analysis Screen.**

Some of those opportunities lead to the need to write a program for subsurface work. The Work Plan/Services section allows a user to easily review the pertinent information and use templates to write a wellwork program. The well services teams can then prioritize these opportunities and issue the work order. This can be accessed by the appropriate service company via an extranet. The end results of what was performed and how the subsurface equipment now appears in the well is then captured. Figure 10 shows a typical view from the Work Plan/Services section.

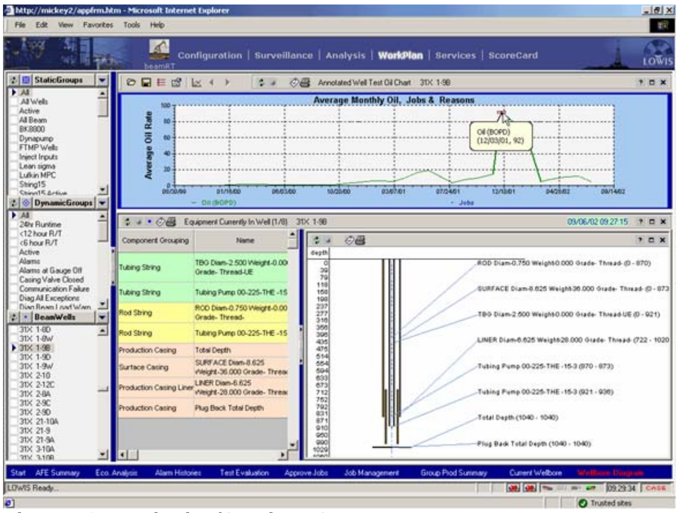

**Figure 10: Work Plan/Services Screen.**

In the Scorecard section, numerous metrics can be reviewed by all levels to help identify any opportunities to reduce failures or improve on job execution. This is illustrated in figure 11.

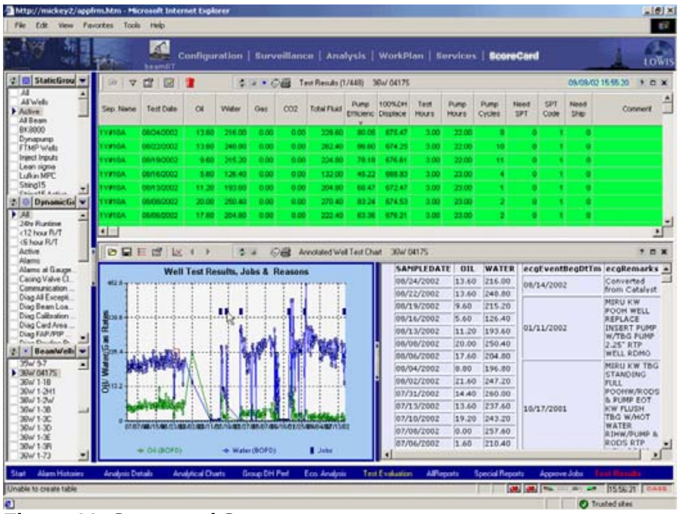

**Figure 11: Scorecard Screen.**

The system is flexible enough to allow users the opportunity to review the entire field, or query down to the subset of the wells that they are interested in.

This Cymric system is supporting more than 1000 wells and over 30 users of the operations team, engineering team, and rig service contractors. Because the server and databases are located in the field location, the system is responsive to the end users. The servers are considered "standard" servers and the client software is easily installed onto the users' desktops.

## Dealing with Data

Data integration, migration, cleanliness, and standardization are always important concerns when migrating between systems or deploying new systems into existing processes. The underlying goal of any data integration project is credible, complete, and timely data. Business critical data needs to be accessible to all business users through standard corporate sources.

As mentioned previously, there were numerous user-developed tools, spreadsheets, and databases supporting well data management processes at the inception of the project. Many of these tools were built only to support a short-term specific need, but were rapidly replicated and became part of the establishment. These tools, although convenient, lacked the data integrity standards described above, although their purpose was in fact to provide operations personnel with the data they needed to perform their jobs. However, the data acquired through such systems cannot be verified as to its accuracy, potentially leading to wrong decisions. Much time is spent hunting down correct data and, within IT, to patching together dissimilar systems to keep these tools operational.

Data requirements were considered for inclusion in the system. The needs were: to facilitate the processes involved in proactive wellwork, to improve reliability analysis, to upgrade decision making, to achieve better resource utilization and to enable consistent economic analysis A boundary condition established upfront dictated that the system would contain complete historical wellwork, wellbore and production history data.

The credibility of the data is an important factor in the adoption of the new system. If suspect data is contained within the system, the users will simply elect to continue to use the systems they are currently comfortable with. Data should be complete, unique, valid, timely, usable, and accurate. Having accurate integrated data reduces errors and data access time, thus eliminating the numerous misaligned data sources and "shadow systems".

For this project, a "system of record" (SOR) was identified for each of the data elements required to be integrated into the new system. The SOR should be well-established and already have the reputation as being a trusted data source. Interviews with customers of the data will assist in identification of these trusted sources. Data that is referenced or loaded into the system should correlate with existing standard data that is contained in the appropriate SOR. All data to be integrated into the system underwent validation tests prior to its being loaded. Any data identified as needing to be changed was updated in the SOR first.

The software architecture allows for multiple data stores to serve the data to the end users. The existing SCADA system data was expanded to house definitional data for all the wells in the field.

Once deployed, the LOWIS system was able to feed other data systems which required access to this data. Routines were put in place to export the production data, the wellbore data, and the well downtime information. This provides for a single point of entry by the production operations team that feeds other data systems used throughout the operating company's organization.

Having in one place the complete, accurate data required to analyze a well and to make appropriate recommendations on a course of action reduces the time and resources required to develop that recommendation. This improves response times to potential production problems.

## Deployment

Two system architecture designs were considered as deployment models. One option considered was a locally deployed architecture in the field. The second option considered was a remotely deployed architecture with servers located in a centralized data center. Due to the complexity of the field radio communications, the proven nature of the current system to perform in that environment, and to uncertainties of remote system operations, the team agreed on the field-deployed system.

Two methods for system deployment were considered. A full system deployment on a field by field basis was weighed against a deployment on a functionality by functionality basis to all fields. The decision was made to roll out the system in phases. The first phase would be to roll out well surveillance and downtime reporting functionalities to all field locations (phase 1), then follow that up with roll out of well service management functionalities (phase 2) to all field locations. The benefits of this deployment included getting people's early exposure to the system interface in advance of the system itself being rolled out. This deployment method also created early consistency in several key operational processes amongst the field areas.

**People Issues**

It was clear from the outset that a critical factor determining success or failure would be managing the issues around people's abilities and willingness to adopt the new system. The concept of the software is closer to that of an "ERP-like" all-pervasive system, rather than a traditional upstream technical application confined to one specific area of operation or engineering. However, unlike other Enterprise Resource Planning tool (ERP) deployments, there was no upstream equivalent precedent for the software. The system did not exist prior to the project being initiated, and so it was not possible to see it in action prior to its being deployed.

Upstream IT projects have a tendency to be highly technically focused. However, many sources, see for example (3, 4) have highlighted the importance of "soft" or people issues in achieving success.

In terms of organizational culture, key members of the operating team had worked together in other assets as well as in Cymric, and had a track record of successfully introducing new technologies and new practices. There had been a movement to empower decision making to the field operator level rather than restricting it to petroleum engineering levels. Working closely with key suppliers was the norm.

Leadership was another factor in favor of the project's potential for success. A key business objective for the asset was to continue to cut operating costs. The project was clearly aligned to that objective. It was initiated at the field level and supported at the corporate level. Senior management at the BU and corporate levels strongly supported the project in terms of setting out the vision, making resources available and actively pushing for the necessary changes.

A key aspect of the deployment process involved employing "sponsors" within the organization to assist in the cultural challenges anticipated in the transition. These were key stakeholders who have the power and/or influence to impact the success of project implementation. Sponsors were chosen from people in the field area who had gained the respect of their peers. The sponsor would actively support the process and serve as the "eyes and ears" on the ground in advance of and following the deployment. Key roles in advance of deployment included communication of project status, demonstration of system functionalities, and creating alignment between the project team and the operations area. During and following deployment, the sponsor would serve to reinforce behavior, arrange necessary resources, assist with training and development, and sustain the change momentum.

One important task for the organization was the extensive amount of pre-preparation, such as the development of documented SOPs and PFDs prior to system deployment, and the involvement of staff in defining these. In addition, deployment was preceded by communications about the aims of the system. For example, presentations and posters were produced on how current practice would map to the processes in the software. As noted above, the current processes needed to be defined in a high level of detail. However because each field had its own processes, there had to be a "cut-off" on the amount of detailed individual processes that could be supported. The concept was that if a process was 80% fit for purpose across assets, then it would be adopted as a standard and the assets would have to adapt to the remaining 20% "gap" to current manual processes. This sometimes required a push from management.

Training was provided for all affected staff in a classroom setting. Training material in terms of SOPs, PFDs, written manuals and a web site was all made available to coincide with the rollout.

Post-implementation support generally lasted about one month at each field before the deployment team moved onto the next field. A full-time team of about four people, with a further two or three part-time, provided this training and post-implementation support. By the end of deployment, over 500 people in the BU had been trained to be regular users of the system. These include rig crew chiefs and other vendor users as well as operating company personnel.

During the early stages of deployment in particular, requests for enhancements were handled through a dedicated group which included the software provider. Weekly user forums were initiated for training and for managing requests. This helped engender a spirit of joint ownership and co-operation between all the stakeholders involved in the project.

Following the training, a competence assessment was made of all the staff covering skills and motivation for changing to the new system, and gaps in system or staff performance. The results of this assessment helped the team to identify which areas required further attention. In many cases, follow-up training was provided to fill the gaps that were identified by this survey. Figure 12 depicts a scorecard that was developed based on the results of one such assessment, showing key action areas (the low scores).

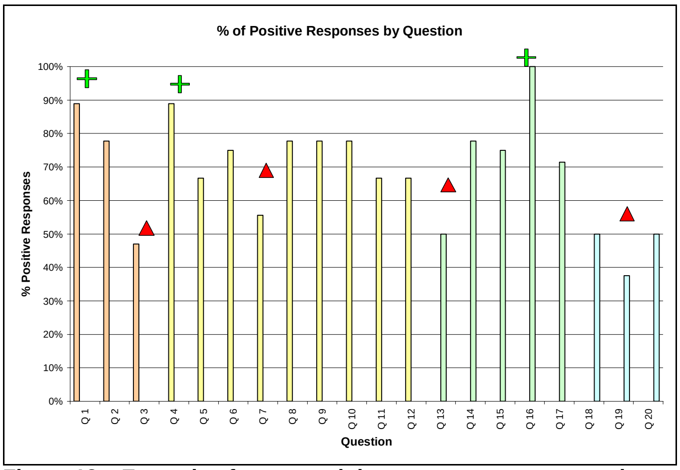

**Figure 12 – Example of a post-training assessment scorecard.**

## Results

### Benefits Realized

The key business driver to which the project was aligned was operating cost reduction. The most tangible evidence of success in this was in the reduction in well failure rate which followed the deployment of the software system. Referring to figure 13, the Cymric field failure rate, the downward shift at the start of 2002 can be seen. This shift also corresponds to a number of other initiatives – as noted above, such as: a new pump supplier, changes to hardware and further POC work. The software system contributed to these gains along with other changes, and it is confidently expected that the software system will continue to deliver further changes as its use is fully consolidated across the BU and is further expanded in future. The improvement in failure rate over the time of deployment of the software was from 0.15 to 0.1 in the Cymric field. This corresponds to a direct cost saving for repairing failures of approximately \$0.5 million per year in this one field. Scaling this performance improvement up to the whole BU represents an annual saving of \$6 million.

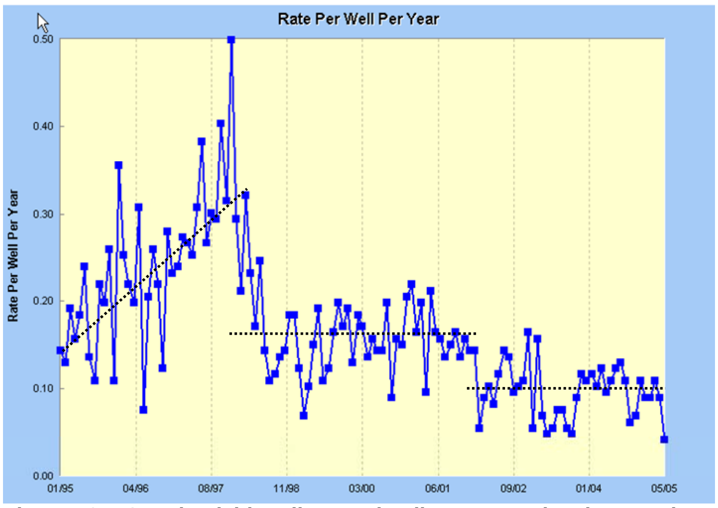

**Figure 13 – Cymric Field Well Annual Failure Rates showing trend rising to 0.3 in 1995-1997 before action was first taken, rate of 0.15 through 2001, and improvement to 0.1 after current project was initiated.**

Since the software system enables online surveillance as well as automated standardized well service management planning and execution, production deferment on failures (due to the time delays shown in figure 1) should substantially reduce. The time taken to diagnose a problem and schedule the right job to address it is much faster with the new system. An additional means of speeding the repair process is that contractors have access to the system and so can see the appropriate scheduled jobs as soon as they are approved for action. An estimate of the annual saving in deferred production for the BU is \$3 million.

A key benefit of the system is that it is possible to rank jobs by economic priority in a consistent way across all wells requiring repair. As a result wells will be repaired in line with their business impact. Prior to the deployment of this system there was no way to know if, at the field (and still less at the BU) level, the right wells were being fixed in the right order.

A further category of benefit obtained from the use of the system has been experienced where new processes have been enabled. Frequently, these were not envisaged at the start of the project but have emerged as additional value through use of the system. One example is how previously, well managers would be responsible for a group of wells and would write the jobs required to repair these wells in a manual process. There were not resources available to review these jobs prior to their execution. However, now that the jobs are prepared electronically it is possible for a co-worker or supervisor to “run a second pair of eyes” over the plans before execution. This yields improved quality and reduced costs.

A further example of a new process relates to the ability to allocate pumping units to wells where they will be properly utilized. Prior to the online system, operators had no idea about gearbox loading. Now that they can monitor this, it has the benefit of not just reducing failures (the initial purpose), but, by looking across the field, it enables pumping units to be moved to wells where they are neither over- nor under-utilized. Getting this allocation of pumping units right has saved further material sums. A data mining approach is possible because all well data across all the assets is now visible to all users. The field operating teams are confident that many more such improvements will be made in the future.

In general, the use of this electronic system drives better performance through areas such as data validation and quality (because data is visible and is used, bad data gets weeded out and fixed); the ability to look at quality and performance across all fields through electronic score carding; the ability to compare actual job costs to estimated costs; and indeed the ability to compare jobs and costs performed by one rig or crew to those performed by another. In a large BU incremental savings of a small percentage have a very material impact; and the tool is now in place to enable the field operating teams to uncover and execute such savings.

### Extensions to Other Business Units

Cymric’s success quickly led to recognition that there was potential for similar applications in the other areas within the SJVBU. This was an easy projection since these fields all have very comparable characteristics with respect to well depth, producing method, etc. and, perhaps more importantly, these field areas all have similar processes for managing surveillance, production optimization, well intervention, etc. Benefits recognized in Cymric were used to develop a business case for a SJVBU wide deployment and SJVBU received management's commitment to a BU-wide deployment, supporting over 15,000 wells and more than 200 users per day across the BU.

Optimism quickly spread that the software system might be deployed across all of the operating company's North American operations with similar gains in efficiency and cost reduction expected. This led to management forming a project team that was tasked with developing processes and deploying the software in the remaining two BUs in North America. Without the inherent similarities in processes and production that were found in the expansion in SJVBU, there were numerous new hurdles and issues that would need to be resolved in order to roll out across North America.

The Mid Continent BU is traditionally thought of to consist primarily of pumping wells in large West Texas water flood fields. However there also is a wide variety of other production methods being employed in this BU, i.e. plunger lift, submersible pumps, gas lift and even free flowing wells. The Gulf of Mexico BU consists of mainly two producing methods, gas lift and free flowing wells. Well intervention processes also varied significantly, from simple pump changes and sand clean outs to the multi million dollar major rig workovers found offshore in the Gulf of Mexico.

As part of the operating company's vision for success, a high degree of standardization was desired that would facilitate comparison and sharing of operational data across the North American operations. However, with the variations referred to above it was realized that the SJVBU work could not be a direct "copy and paste" application, but that it could be a good starting point. Leveraging off the development in SJVBU, modification and changes were made to both the work processes and to the software. Standard processes were developed at a level that would allow for these variations in production methods and work type. Features were added and enhanced in the software to meet the needs of these other areas in North America. The "80/20" approach was taken and the majority of the North American operations are included in the new processes and program. Staff from SJVBU have been seconded into the roll out program, leveraging their experience and skills. Rollout is currently underway across North America and there have already been early indications of success in areas outside of SJVBU. Plans are also in place to help develop additional functionality within the software to accommodate even more of the operating company's operations.

**Areas for Improvements and Future Development**

Despite the undoubted success of this automation/software system project, there are a number of areas where, in retrospect, improvements could have been made. In addition, there are areas of functionality which could usefully be further developed in future.

One issue which must be faced when replacing one system by a new and improved one is that it is often hard to cover each and every piece of functionality that the old system had. This may not matter to new users, but can create a migration barrier to experienced users of the old system. In this project it resulted in "maverick users" continuing with useful pieces of the older system since these were not so well supported in the new one; and with hindsight, more effort should have been allocated to covering these areas, removing one point of resistance.

End users have commented that, once the deployment reached a certain size, it stopped being something they had any influence over. The roll out across other fields in SJVBU and across other BUs meant that the development and deployment teams were focused on these challenges, and some further incremental improvements have been delayed for early-adopters such as Cymric. It is worth considering how to keep developing the early adopters' systems at the same time as deploying across mass areas. Otherwise there is a risk of stagnation at the first sites.

In a very large onshore asset such as SJVBU, there is continuous activity to develop further the field infrastructure. Wells are being drilled in the BU at a high rate. Although field configuration is one of the principal workflows within the software, the scale of this task has proved difficult to manage. It can be seen that even more effort should have been put into the apparently "background" tasks of changing configuration whilst continuing operations on a 24/7 basis.

Today, despite some minor growing pains, the field teams consider that they could not operate so effectively without the system. Improving business performance is a matter of continuous improvement and there are many possible areas in which the existing system can be extended.

One such area is to introduce artificial intelligence methods for steam flood monitoring. This is an extension of manual data mining exercises and could well be found to be applicable to other areas.

## Conclusions

This was a successful project in many ways. Material tangible business benefits were generated. Further gains that were previously unidentifiable are being discovered, and future gains and developments are projected. The technology and methodology have been proven to be sufficiently scalable and configurable to enable deployment across large regional business units, enabling the savings and efficiency gains from standard well management processes across a whole enterprise.

The project offers a number of useful insights into the development and deployment of such upstream "transformational" IT projects. These are as follows:

1. It proved possible successfully to introduce the innovative degree of work process management fully integrated with the daily activities of a large operation. Combining the management of real time data, the engineering modeling for monitoring and diagnosis and the management and assessment of the required remedial work in such a manner is believed to be quite novel.
2. The project contributed materially to the improved performance in the SJVBU fields. However, unlike many upstream investments such as drilling or workover, it is difficult to attribute the gains directly to an IT system since it is likely to be part of a whole process of improvement. It should be seen rather as an essential "enabling platform" for business improvements.

3. The business case was easier to make because of a proven history of improvements of a key metric (failure rate) which relates to a business driver. This meant that the system had a context in which its impact could be projected. A "Blue Sky" business case for an IT investment is harder to make.
4. The business case was supplemented by additional "soft issue" improvements the system would enable. In practice, there were further improvements made to work practices, which were not originally envisaged.
5. The field teams' track record of successful assimilation of new technologies and work practices in a continuous improvement culture was an important foundation for the project, in which staff willingness and ability to change was essential.
6. It was vital to "think big" about the scope (and duration) of tasks that were additional to the software development itself. Primarily these were: definition and specification before development, and training and support after deployment. The tendency to focus on the software as "the product" must be resisted. The budget needs to cover the whole scope, which is likely to be many times the cost of the software itself. Otherwise the project will run out of resources.
7. Without the detailed definition of work flows and their documentation as SOPs and PFDs, it would not have been possible to develop the software to support these, nor to migrate the staff onto the defined processes using the new software.
8. Involvement of the whole workforce had a big beneficial impact. This includes involvement in setting the common processes to be adopted; finding the "champion users" to start use first and then train others; involving management as sponsors and advocates; and gathering and communicating feedback during roll-out.
9. The technology aspects remain crucial – they are not diminished by the need for all the complementary activities described in this paper. Key technology requirements for the success of this project included the ability to handle large volumes of real time data and to process these into useful information; the capability to view and "data mine" raw and processed data using either built-in or ad hoc views; flexibility in allowing work processes to be established and enforced; the importing of legacy data; and the ability to consolidate data upwards from fields to BUs and the Corporation. System performance as hundreds of users are added needs to be considered. A web interface is highly useful to allow not just internal users but suppliers' users to access the system.

## Acknowledgements

The authors would like to thank their respective employers, Chevron North America Exploration and Production Company Inc, and Weatherford International and its affiliates, for permission to publish this paper. The authors would also like to thank their many co-workers for their contributions to the project development.

## Nomenclature

*Bopd – Barrels of Oil Produced per Day*
*BU – Business Unit*
*ERP – Enterprise Resource Planning tool*
*PFD – Process Flow Diagram*
*PLC – Programmable Logic Controller*
*POC – Pump-Off Controller*
*RTU – Remote Terminal Unit*
*SCADA – Supervisory Control and Data Acquisition*
*SOP -Standard Operating Practice*
*SOR – System of Record*

## References

1 Klins, M.A. et. al: *"Fracturing Alliance Allows Economical Production of Massive Diatomite Oil Reserves: A Case Study"* SPE 29662
2. Eckel, A. et. al: "*Testing and Practically Applying Pump-Off Controllers in a Waterflood*" SPE 29636
3. Lewis, K: "*Eight Reasons Why Software Implementation Projects Fail*", Power & Gas, Spring 2003
4. Murray R. et al: "*Making Our Mature Fields Smarter – An Industry Wide Position Paper From The 2005 SPE Forum*" SPE 100024