SPE 111478

Back to the Future—A Retrospective on 40 Years of Digital Oil Field Experience

Ron Cramer, Shell Global Solutions International B.V.

This paper was prepared for presentation at the 2008 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 25–27 February 2008.

Abstract

Digital Oil Field, Computer Assisted Operations, Smart Fields and iFields are some of the names coined by different E&P Companies for processes that promise to use real time Information Technology to radically change the way the Oil and Gas business is run and is so doing enable significant business benefit.

The Digital Oil Field(DOF) has been the subject of much publicity and further development over recent years. However, there was also much DOF-related activity over prior decades, in which oil companies made their operations' progressively smarter using a combination of IT, instrument engineering, telecommunications and change management.

The intent of this document is to chronicle some of the learning's from DOF's history, initially from a Shell E&P perspective, as this is the author's bias. However, it is hoped that this will spark similar historic learning's from other Shell individuals and other E&P companies and that these thoughts and lessons be used to "grow" towards a more comprehensive view.

Winston Churchill said "Study history, study history. In history lies all the secrets." Looking at DOF through the lens of one person's experience is hardly history, but may give some clues regarding how to do "it" and how not to do "it."

This paper will trace DOF historic developments from the author's personal perspective and tease-out the issues then and now, providing an insight into where we have been, where we are now and what can be practically achieved.

Definition of DOF for Oil/Gas Fields from Reservoir to Point-of-Sale

To provide context for this analysis it is appropriate to define what DOF is aspiring to achieve. DOF is the deployment of people, processes and technology, in pursuit of production, safety and technical integrity improvement, by timely, effective and sustained use of, sufficient, good, production information.

DOF is inherently multi-disciplinary e.g. Production, Instrument, Reservoir Engineer, Petroleum Technologist, Process Engineer, Telecoms, Information Technology

Chronology and Associated Learning's

In the following, the term "Digital Oil Field" is used throughout for consistency, even though the term did not come into use until the millennium. DOF has evolved over the last 40 years as follows:

- Electronic instrumentation on the wells and RTU/SCADA ("devices" to digitize, serialize and modulate telecommunications signals to a remote computer)
- Electronic instrumentation on the surface process (separators, compressors, pumps) acquired by SCADA
- Distributed Control Systems starting to replace/complement SCADA in the mid-eighties
- Subsea Control Systems from the mid-nineties
- Downhole instrumentation from the mid-nineties
- Growing emphasis on management of change issues progressively over the last 30 years

A brief overview of DOF experiences over the last four decades follows, summarizing key learning's for each era.

1.0 The way it was prior to DOF – "charts, paper and people"

It seems appropriate to start with a description of how production data was acquired before the advent of DOF and an indication of how primitive it was, and in some cases still is!

Operators routinely travel in trucks, boats, or helicopters to the remote, unmanned wells.

The wells had no instrumentation. Operators would visit routinely with a portable pressure gauge. The gauge would be attached to a well head sample point and the isolation ball valve opened to expose the gauge to the process fluids. The operator would tap the gauge and take a spot tubing head pressure (THP) reading, which he would duly log into his paper notebook. In many cases the wells would be unstable and slugging with the pressure varying over a wide range, so the spot reading was often misleading. A similar reading would be taken of the flow line pressure downstream of the well. Often the dP between THP and FLP would be negative, because of the pressure variation and asynchronised sampling. The pressure readings would be keyed-into the daily report and reach the remote support staff at the earliest the following day.

The operator would "feel" the flow line – if it felt colder than usual he might surmise that the well had "quit." So, he would look at his watch and note the "detection" time, which in lieu of any better information he assumes was the well quit time. He had no idea of when the well actually quit – it could have been just after the last well test a month before! Also, he is not absolutely sure that the well really has quit, to confirm a well test needs to be performed – this can take up to a day, as other wells may be on test.

The operator might then put a well on test as follows:

- Consult his notebook to determine the well to be tested and the requisite instrumentation for that well (orifice plate, dP cell range).
- Manipulate the manifold valves to put the well on test
- Adjust the orifice plate and/or dP cell range.
- Annotate the test separator flow charts for gas out, liquid out (and for gas lifted wells, gas in) with the well name, the orifice plate and/or dP cell range.
- Take BS&W samples and send to the lab for analysis
- At the end of the test remove the charts and mail to the office

It could take up to a month to process the samples and charts and present results to the Well Analyst. The results would be compiled in a well book, which was a long term trend of all the well results along with well configuration data, flowing/static pressure surveys etc.

So, if the wells were tested once a month and it could take up to a month to process the results, on average it would be a month before a process change was apparent. In many cases there would be problems – the wrong well was put on test, the wrong orifice plate or dP cell was used, the charts were blurred because of moisture ingress, typographical errors, test separator instrumentation errors/level control problems, planimeter errors etc. This would result in having to repeat the well test.

The well test results, flow line "feeling" and aforementioned pressures would be entered into the hydrocarbon accounting system on a monthly basis and the well test results and "uptime" balanced against fiscal measurements. The difference between fiscal and well test results being "smeared" pro-rata the test results across all the wells – even though the delta may be from only one well!

The erroneous reconciled values/well uptimes and pressures/test results of questionable accuracy entered into the reservoir simulator and used to make strategic decisions like where to drill the next well!

Key Learning's

An underlying issue is, "what is the perception of the value of the data being acquired?" It is gradually being more realized over the years that good data, leads to good information, upon which to make better strategic and tactical decisions regarding field surveillance, optimization and development. Hence, justification for the progressive drive towards DOF as described below.

2.0 Late sixties and early seventies – early DOF successes

2.1 Back in the USA

Back in these days Shell in the USA had many thousands of Beam Pumped wells and one of the issues was finding enough people to operate the widely scattered fields. At just about this time real time optimization was being successfully deployed into downstream refineries and it was perceived that similar technology could be used in the upstream oil and gas business. Electronic instrumentation was installed on numerous unmanned wells and SCADA/Telemetry deployed to bring information back to manned locations on a minute-by-minute basis. It was soon realized that the resulting large data volumes were "indigestible" and had to be processed into more useful information. Whence the first generation of real time software applications were used to refine the data into plots of rod pump strain versus pump displacement – so-called dynagraphs for each well. Limited operational man power could be more efficiently utilized to remotely interpret the dynagraphs and intervene on an exception basis. Hence, pre-emption of pump problems, less OPEX, more production and less need to send operators in hazardous vehicles to hazardous locations. Maintenance of thousands of remote instruments was a formidable and under-estimated task. Lack of timely maintenance affected data quality which jeopardized system credibility.

Key learning's

- Real time data needs to be converted into useful information using software applications – it is one thing to have data, another thing to have useful information
- Bringing the "wells to the operators" is more efficient and safer than sending the operators to the wells, however there were issues convincing operators to stop routine traveling – still a problem 40 years later!
- The beginnings of what later became know as "alarm overload" – still a problem today!
- The beginnings of instrument maintenance and resulting data quality problems – still an issue today!

3.0 Mid-seventies

3.1 Early use of remote control

Operating gas fields in the Southern North Sea with numerous remote unmanned jackets and a few manned offshore platforms. Main gas trunklines landfalling at the onshore terminal, which had a continuously manned control room. It was decided to downman the offshore platforms at night and run the complete field from the onshore control room. To achieve downmanning the offshore wells were fitted with remotely actuated chokes and wet gas flow measurement (orifice runs). SCADA and telemetry was added so that the wells could be adjusted from the remote control room. Gas demand was dynamic and night time supply adjustments, by varying well flows, fairly frequent – the ability to achieve this remotely was appreciated by offshore operations as it saved them unnecessary travel and disturbance to night time activities, such as recreation and sleeping! Hence operations were well motivated and used the system effectively.

This was one of the first successful DOF applications, effectively embedded in the production process. The application was sustained for about 5 years, but new offshore platforms came along with different Operations Philosophies that compromised the nightime downmanning concept.

Key Learning's

- Embedding and sustaining DOF is crucial
- Operator motivation is crucial
- Need to build DOF into Operational Culture
- Emerging new facilities must comply with the overall DOF Operational Philosophy

3.2 Centralized Approach

Based-upon aforementioned successes a DOF department was established in Central Offices to share learning's and experiences on a global basis. A group of experienced instrument engineers routinely visited remote Oil Companies to promote DOF applications and to foster a more standard approach.

Key Learning's

- Instrument engineering though a key discipline was insufficient to convince all parties;
- Insufficient attention paid to management of change issues;
- Local Oil Companies have many common DOF system technical requirements, hence opening the door for a more standard, global approach;
- Local Oil Companies may have significantly different DOF "cultural" requirements depending on native language, local customs and local environment.

4.0 Early Eighties

4.1 Northern North Sea

Shell were operating numerous large, complex platforms in the Northern North Sea with export gas and oil pipelines to onshore processing facilities and terminals. These facilities were monitored and controlled using pneumatic instrumentation. However, there was a regulatory requirement for continuous onshore monitoring of all pipelines and key platform parameters. Monitoring was achieved by installing P-I converters, SCADA servers and telemetry to make real time data available in an onshore, continuously manned coordination center. Real time data was also available in the offshore control rooms with a view to operations using these terminals for monitoring and control of the offshore platforms. However, operations continued to use their conventional pneumatic and "old fashioned" control panels.

The systems were reasonably well sustained mainly by dint of management support and effective system KPIs, though instrumentation maintenance was always a problem. DCS systems worked well for on-platform control and monitoring, but were hard to integrate into total DOF system infrastructure

Key Learning's

- Do not provide operations with a new way and an old way to operate the process, if a new facility is deemed necessary, remove the old such that there is no choice!
- Make sure that new systems comply with the overall DOF integrated architecture.
- No feasibility study, or economic justification for DCS systems, which were treated as infrastructure (DCS systems mainly for monitoring and control of the surface production processes i.e. not so much for wells/reservoirs).
- Over the years DOF systems have been regarded as optional extras which have to be economically justified - we gradually realize that DOF also is vital well/reservoir/process infrastructure
- Instrumentation maintenance is crucial
- KPIs for instrument quality were an effective way of flagging problems to management

4.2 Management Support is Crucial

It was decided to apply DOF to 100+ offshore platforms and 1000+ wells in an Oil Company in the Far East. Electronic transmitters were installed on the wells, manifolds, test separators and key parameters of the surface production process. Data was transmitted back to an onshore continuously manned co-ordination center using telemetry/SCADA. The system was fairly-well embedded and sustained in a low-key way, until, during a major incident the system was used to shut-in remote platforms in a controlled manner such that key quantities of gas were available to keep the local power station running. This was sufficient for management to realize the strategic importance of DOF. However, we were unable to trigger Reservoir Engineers' DOF interest – field models at this time were performed monthly, using reconciled hydrocarbon accounting data and/or raw well test results which was considered sufficient!

Key Learning's

- Management support is critical for effective DOF embedding and sustaining
- Hard to achieve support critical mass without Reservoir Engineering "onboard."

4.3 Well Monitoring is Crucial

DOF installed in a large Oil Company with 100+ flow stations, 3,000+ wells in Africa. Because of the sheer number of wells it was decided to instrument the station export flow meters and not the wells. SCADA and telemetry were installed to bring signals to the remote main office. The system was not exploited fully because of the missing well information

Key Learning's

- It is imperative to install monitoring instrumentation on the wells
- Even now we see cases where DCS systems are installed to monitor the production facility, but not the wells!

5.0 Nineties

5.1 Middle East

A Feasibility Study was performed, followed by a successful small Pilot implementation. Management supported a minor extension to the pilot to be followed by another Feasibility Study. A new and supportive manager arrived who believed that one Feasibility Study and one Pilot was sufficient and then drove-through a large project for DOF installation through-out the Oil Company. The installation was completed and excellent benefits were achieved until the supportive manager and key staff were promoted and/or transferred and then the gains declined.

Key Learning

- Feasibility studies and pilots – once is enough
- One key manager can make it happen, but is insufficient to sustain

5.2 Bolstering Centralized Approach

A global UNIX-based DOF software platform was developed and implemented in the USA. Key US managers were transferred to Central Offices with a view to deploying the UNIX-based DOF platform globally. A workshop was held to determine if it was necessary to repeat the aforementioned feasibility study/pilot – it was concluded that repetition was unnecessary because of functional commonality across Local Oil Companies. The systems were successfully rolled-out to multiple Local Oil Companies. However, Central Offices was reorganized and the centralized approach was scaled-back and the Local Oil Companies were more left to their own devices.

Key learning's

- Centralized approach can bring concentration of expertise, standard approach and economies of scale, but it also must be sustained

5.3 Introduction of Downhole Instrumentation

Downhole pressure gauges installed in a number of wells. Even though instrument reliability was (and is to a lesser degree) an issue, this was sufficient to trigger Reservoir Engineering (RE) interest.

Key Learning

- Need to involve RE's to achieve critical mass

5.4 Online Optimization - some early experiences

For a North Sea gas lifted field, online optimization was performed by interfacing validated real time data with a surface process model and "curve-fitted" approximate well models with an optimizer running "on top." The following resulted:

- The optimizer needed periodic, manual (Petroleum Technologist) gas lift curve entry;
- The PT workload in generating and entering the curves was load intensive and was not consistently performed;
- There was a "competing" system within the asset where the same curves were loaded into a "home grown" spreadsheet with some optimization capability;
- The optimizer results were different from the spreadsheet version.

The optimizer was eventually switched-off.

In an African Gas Lifted field a dedicated multi-discipline team was formed and initiated various projects - improved data management, improved speed of reaction in the field, automated well head chokes, DOF upgrade, downhole chokes, selective zone completions, rapid response Gas Lift optimizations, and some facility debottlenecking. A production system model was added to automate complex Excel spreadsheets and macros. This automation facilitated working from up-to-date data - previously the data was updated monthly. The main successes all resulted from getting the multidiscipline team working together with good data and turning around fast actions in the field and initiating projects to solve problems.

Key Learning's

- If it is not embedded in day to day operations it dies.
- DOF requires smart, motivated, well trained teams of multi-disciplinary people
- Good timely data is essential for effective optimization

6.0 Late Nineties to the present

6.1 Far East partial success

DOF installed in one field on-time, below budget. Tantalizing signs of successful impact were evident in the early days of the implementation - production increased, unscheduled deferments were reduced and reconciliation factors improved. However these improvements were not sustained, because DOF was not effectively embedded/integrated-into production operations. Instrumentation was not effectively maintained, leading to a lack of confidence in system capability, also insufficient training was provided for onshore/offshore staff. Operations continued to run the business the old way - as if early successes had never happened!

Key Learning's

- Operations not effectively prepared to utilize real time data
- System not effectively maintained

6.2 Progressive broadening of Smart Field Capability

With the advent of reliable downhole gauges, Distributed Temperature Sensing (DTS) and control valves, DOF was extended from the well head down to the reservoir sand face. Initially downhole gauge life span was far short of expectation.

Rel time downhole signals, along with surface measurements and well tests were used to build online, data-driven models to continuously estimate well and zonal flows.

Key Learning's

- Downhole gauges along with virtual measurements facilitates zonal surveillance, allocation and optimization
- Downhole harsh environment necessitates special considerations for gauges and gauge connections

6.3 Far East Success

Infrastructure described in 3.2 above was extended to include downhole gauges, DTS and remotely actuated control valves. Virtual well measurement software applications added to continuously estimate well and zonal flows and to perform real time optimization. Remote collaboration center in-place bringing together all DOF-related disciplines in frequent audio/visual contact with offshore staff. A round-the-clock co-ordination center fully operational using real time data to track KPIs and ensuring that contractual obligations are effectively managed.

The overall system has been effectively embedded and sustained over the last three years

Key Learning's

- Combination/collaboration of onshore support staff and offshore staff both looking at the same "good" online data enables better process surveillance and optimization
- Well virtual measurement is key - quickly indicates well low/off and hence reduces deferments and provides key inputs for online optimization, as well as improving hydrocarbon accounting and reservoir modeling

6.4 DOF - becoming Standard for Green Fields

DOF facilities inclusive of downhole gauges/control valves, integrated data flows inbuilt as a standard for all new green field E&P projects.

Key Learning's

- No need for feasibility study
- No need for pilot project

6.5 Brown Fields – progressing towards DOF

Brown fields progressively fitted with DOF infrastructure, systems, integrated data flows and management of change initiatives. Co-existence of new DOF ways of working with "old" infrastructure and "old" ways of working is inevitable as DOF is progressively rolled-out over time. However, data quality remains a significant issue as older infrastructure may not have been effectively maintained.

Key Learning's

- Preservation of the "old" perpetuates all of the problems described in section 1.0 above and sends a message that the "old" way is acceptable and hence tacitly perpetuates bad practice, making it harder to impose DOF ways of working
- Move Brown Fields to DOF as soon as practical.
- Need to refurbish older infrastructure

Conclusions

The findings are summarized and categorized by People, Change Management, Strategy and Technology issues as shown in the appended matrix. As can be seen technology has never really been a significant issue over the last 40 years, the big problems have been and still are with the softer issues. There have been scattered successes over the years, but sustaining and embedding has always been a problem.

It likely that DOF' ways of working will ultimately prevail as new "green" fields projects are designed to be smart from the "get go." The question is how long will it take to get the brown fields operations up to the same standard.

Prevailing and old issues that continue to be a "thorn in the flesh" are:

- Will the "old" brown fields ways of working contaminate the "new;"
- Do operations really buy into the new ways of working ;
- Do operators really buy-into the equation - better online information today = more oil/gas and safer operations today and tomorrow;
- Alarm overload;
- Instrumentation maintenance;
- Unnecessary travel in hazardous vehicles to hazardous locations;
- Effective multi-disciplinary collaboration

We are making significant progress but only time will tell if we can convert old and new facilities to DOF, effectively embed and then hardest of all sustain over the life cycle.

Appendices

1. Key Learning's Summary

People	Change Management	Process/Strategy	Technology
Operator motivation is crucial	Embedding and sustaining DOF is crucial	Good data, leads to good information, upon which to make better strategic/tactical decisions	The beginnings of what later became know as "alarm overload" – still a problem today!
Instrument engineering though a key discipline was insufficient to convince all parties	Need to build DOF into Operational Culture	Real time data needs to be converted into useful information using software applications	The beginnings of instrument maintenance and resulting data quality problems – still an issue today
Management support is critical for effective DOF embedding and sustaining	Emerging new facilities must comply with the overall DOF Operational Philosophy	Bringing the wells to the operators is more efficient and safer than sending the operators to the wells	Imperative to install monitoring instrumentation on the wells
Hard to achieve support critical mass without Reservoir Engineering "onboard."	Oil Companies may have significantly different DOF "cultural" requirements depending on native language, local customs, local environment	Oil Companies have mainly common system technical requirements, hence opening the door for a more standard, global approach	Good timely data is essential for effective optimization
Need to involve RE's to achieve critical mass	Insufficient attention paid to management of change issues	Over the years DOF systems have been regarded as optional extras which have to be economically justified, only now are we realizing that DOF is vital infrastructure	Systems not effectively maintained
One key manager can make it happen, but is insufficient to sustain	If it is not embedded in day to day operations it dies	KPIs for instrument quality were an effective way of flagging problems to management	Downhole gauge along with virtual measurement facilitates zonal surveillance, allocation and optimization

DOF requires smart, motivated, well trained teams of multi-disciplinary people	Combination/collaboration of remote/local staff both looking at the same “good” online data enables better operations	Do not provide operations with a new way and an old way to operate the process, if a new facility is deemed necessary, remove the old such that there is no choice!	Well virtual measurement is key
	Preservation of the “old” sends a message that the “old” way is acceptable - perpetuates bad practice	Make sure that new systems comply with the overall DOF integrated architecture	
	Operations not effectively prepared to utilize real time data	No feasibility study, or economic justification for DCS systems, which were treated as infrastructure	
	Feasibility studies and pilots – once is enough	Centralized approach can bring concentration of expertise, standard approach and economies of scale, but it also must be sustained	
		Move Brown Fields to DOF as soon as practical	
		Need to refurbish older infrastructure	