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Integrated Reservoir and Production Management: Solutions and Field Examples

Arild Bøe, Jan-Erik Nordtvedt, Harald S. Schmidt, Roxar Production Management

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Abstract

Reservoir and production monitoring and control devices are critical components for better reservoir management. These devices being important for understanding the state of the reservoir as well as for optimizing its exploitation, their availability and utilization has grown and is still growing. Also, the increasing use of topside/subsea metering systems provides important information on the production characteristics. All these devices can now be logged and controlled remotely in real time. As a consequence, it is now technically possible to manage the reservoir exploitation process fully automatically from a remote location. This paper outlines how logging of data, analysis of data, and control actions, can be implemented remotely and in real time for improving reservoir and production management. Also, we discuss three integrated reservoir and production management field case designs.

Introduction

In the production phase of reservoir exploitation, a large number of opportunities exist for getting best returns on the proven reserves. By implementing technologies leading to increased recovery, more hydrocarbons may be produced than initially estimated.. The NPV may be improved by, e.g., initiating strategies that boost daily production rates. Additional returns can also result from measures implemented to reduce the cost of exploitation.

In the nineties, a series of new technologies emerged to improve recovery. Most notably, the advanced drilling techniques provided for opportunities to locate wells in regions of the reservoir traditionally left unswept. Some oil companies claim that in the beginning of the nineties, advanced drilling alone was contributing to about 70% of the improvement in oil recovery.

Significant cost savings also resulted from a series of other emerging technologies. One such example is the development within permanent downhole gauges for monitoring of pressure and temperature in the well and/or reservoir. Initially, the numbers of such installations were few, as is typical when new technology is introduced into the market. As the reliability of the equipment improved, the oil companies realized that data from such equipment could compete – both with respect to quality as well as price – with traditional methods for obtaining such information. During the nineties, the number of installations of such systems grew significantly. This is illustrated through the number of gauge installations by Roxar per year from 1987 through 1999 – see Fig. 1 (other vendors can probably show similar figures).

Another example of technology for cost reduction is the development within multiphase metering. As this technology evolved during the nineties, the oil companies increasingly regarded it as a cost-effective replacement of test separators. The meters offered multiphase rates and fluid fractions at a comparable quality to the test separators, and at a significantly lower cost. In fact, for onshore and offshore applications a 50% and 75% cost reduction may be expected, respectively, by implementing multiphase metering systems instead of test separators.[1]

In addition to cost reduction, the multiphase metering systems offer a significant increase in functionality over the test separators. The continuous monitoring of all produced fluid flow rates can provide valuable insights into the multiphase flow regimes within the pipelines. In an onshore Middle East field study[1], the metering system was able to detect the oil was slugging while water was not, indicating the water was flowing in the bottom of the pipeline. This highly corrosive environment and potentially dangerous situation was not discovered through the test separator utilized prior to the installation of the multiphase metering system

As a final example on new technology for cost reduction, the development of permanent downhole monitoring of the water saturation is worth mentioning. Whereas saturation logging usually is utilized for obtaining such information, new technology is now available so that saturation logging information may be available virtually continuous and in real-time. Again, this offers significant cost savings over traditional saturation logging operations.

Even though cost reduction was the main purpose for the implementation of these (and other) technologies, the data provided offer a whole series of additional opportunities. As the evolution in the communication technology allows us to acquire these data more or less continuously in real-time, and to transmit the data to any remote locations, we can start to utilize the potential in these data to the fullest. The expectation for this development is large in the oil industry. In fact, the oil companies expect that reservoir and production optimization – through the use of these and other monitoring as well as permanent intervention equipment – will replace drilling when it comes to contribution to increased oil recovery. In many ways, this transition may be regarded as moving the oil extraction process from resembling a mining operation to a process industry plant.

This paper addresses issues connected to how reservoir and production management can benefit from the industry undertaking such a transition. We discuss critical technologies that integrate reservoir and production management, and particularly how the communication and data warehousing technology might be used beneficially in this development. Finally, we present three field cases demonstrating the status and future direction: One sub-sea water saturation monitoring case, one WAG pilot with water injection zone control and continuous water saturation monitoring case, and one well-head platform development case.

Integrated Reservoir and Production Management (IRPM) Solutions

Extraction of hydrocarbons from underground reservoirs is indeed a very complex process. Maybe the most challenging factor is having no *direct* information on any of the quantities really needed when attempting to optimize the production. For example, we do not have any direct measurement of the full state (i.e., the spatial distribution of pressure, temperature, and fluid saturations) of the reservoir at any given time during production, neither do we have any exact information on where hydrocarbons are located or the volume of the reserves. In fact, it is a paradox that we know far more about these issues after the field is abandoned than during production.

Consequently, all data gathering performed during the appraisal and production phase is done to improve on this situation. For example, logging and well-tests are conducted to better understand the well performance and the near well reservoir state, respectively. Based on such information, an improved understanding of the production process may result, and – through some defined work processes (including reservoir modeling and/or well and reservoir fluid flow simulations), decisions regarding new production strategies can be made and implemented.

This traditional approach reflects typical elements in a process control loop: Data are measured and evaluated. Based on the evaluation, some actions are decided upon and subsequently implemented. In the process industry, this chain of events is often conducted in real-time, in a remote location, and also fully automated. This, of course, to optimize process efficiency and minimize the use of raw material, and thus, maximize the economical result.

In the oil industry today, the availability of real-time data from remote locations as well as the level of automation for production optimization purposes, is relatively low. There may be several reasons for this. One is that the time constants associated with the processes characterizing oil production are typically large, so that the value of real-time remote measurement and control is lower than in the process industry. Hence, the need for real-time measurement and control in the oil industry may be questioned. Another reason is that there simply has not been technology available for conducting the operation of the oil field exploitation similar to that of a process industry application. As we also will address later in this paper, the latter is definitely no longer the case – a series of critical components for oilfield measurement and control are now available with capabilities for real-time and remote data delivery. Fig.2 illustrates this situation. Also, real-time control tools – both topside and downhole – are emerging and increasing in popularity and use.

With respect to the desirability of developments leading to better use of real-time information in the oil industry, a series of important applications have been identified. For example, Shell has tested a system for real-time oil surveillance.[2] This system gives remote, real-time information on the well flow rates of oil, gas, and water. Such information has traditionally been obtained through manual operations. The system helps Shell to remotely identify those wells that needs to be tested. This will lower the number of well visits that are necessary, and amount of data needed to be processed. Both these factors lead to better field economy.

Another example is the use of downhole control tools for partial (or fully) zone isolation using remotely operated downhole choke systems. Although in some cases it may be sufficient to change the downhole choke openings on a monthly basis only, optimization of production will often require higher updating frequency. Example of such a case would be when the downhole tool is utilized to tune, e.g., a WAG (Water-Alternating-Gas) process to minimize residual oil saturation. One of the field cases below deals with such a situation.

As a final example, full-field control may be mentioned. One can envision that a field is equipped with downhole monitoring devices (for pressure and temperature), topside multiphase metering opportunities, as well as measurement opportunities for other quantities (such as sand monitoring, wellhead pressures, etc.). Making all these data available remotely in real-time allows the operator to have a full field surveillance capability in real-time. Adding the ability to remotely operate control devices – such as topside chokes, a series of opportunities emerges. One could, e.g., remotely conduct well tests. Through a series of varying topside choke openings, time series of data from the downhole gauges together with the topside multiphase meters can be made available for analyses. This could give productivity indices and well performance indices that can be used in early detection of performance anomalies.

Also, with such data available, one could immediately identify whether the current understanding of the reservoir is correct. This can be achieved by constantly comparing the current reservoir simulations with the data actually measured. If those compared well, one would be more confident with respect to the validity of the reservoir model and its forecasts. The engineers could then concentrate on a series of "What If" scenarios to suggest improved production strategies. Subsequently, these suggestions may be condensed into reservoir and production management decisions, and finally, implemented into practice. Alternatively, if the data and simulation outputs did not compare well, work processes (here: simulation model updating) should be identified and initialized to improve on the situation. Integrating data, work processes for decisions, as well as their implementation in this manner, will lead to better understanding of the reservoir and production processes in a more rapid manner, and thus allow asset teams to better optimize the exploitation process. This will lead to an improved production, higher ultimate recoveries, and thus better field economy. In the final field case discussed below, we illustrate how this will be implemented on a marginal gas/condensate field in the North Sea.

As a result of developments in this direction, reservoir exploitation will more and more resemble a process industry application – with real-time, remote, and control as three important key words. Fig. 3 illustrates how the measurement process, the work processes leading to decisions, as well as the implementation of these decisions into refined production strategies, may be regarded as a repetitive chain of events. The vision for this development is a "control room" view of reservoir and production management, where all data, work processes, and control actions are integrated in real-time.

For this to become more than a vision, critical components as well as integration technology must be available and tested on real field case applications. Below we describe some critical components and integration technology, and later discuss the planned implementation into field cases and its benefits.

Some Critical Components for IRPM

Below we briefly describe the critical components for reservoir and production management utilized in the field cases.

PROMAC inflow control system. The PROMAC system provides remote control of downhole chokes in production or injection wells – see Fig. 4. The inflow control system provides pressure and temperature monitoring as well as flow control in real-time. Hydraulic control of downhole sleeves enables adjustment of in/out flow, from fully closed to fully open. PROMAC represents an integral part of the production tubing, where individual zones are isolated from each other by use of special production packers.

The PROMAC is rated for HPHT conditions up to 180 °C and 20.000 psig, and up to 6 individual reservoir zones can be controlled in one well using 1 electrical cable and 2 hydraulic control lines. The formations, the well and the PROMAC systems are all monitored and controlled by DACQUS and a fully automated surface pump skid.

Water Monitoring Radar. The Water Monitoring Radar (WMR) measures the conductivity of the formation. An electromagnetic field is generated between a transmitter and two receivers, as illustrated in Fig. 5. Through measurements of amplitude ratios and phase shifts of the signal in the two receivers, the average conductivity can be generated for the actual part of the reservoir. By use of several detector systems, the depth of penetration can be substantial. Continuous measurement of the formation conductivity at various levels may reveal changes in the fluid saturations as result of a water injection program. As this may be conducted on an individual zone basis, and not only by well, valuable and detailed input is achieved for modeling purposes as well as for immediate actions on PROMAC valve positions. The WMR is typically used to observe changes in the fluid saturation in the reservoir or to monitor a dynamic oil/water contact .

Up to 32 fluid detectors can be placed in one well for monitoring of dynamic saturation parameters. The tools are rated for up to 150 °C and will withstand differential pressure up to 15.000 psig. The WMR will work under all salinity conditions, both on injected and formation water. Monitoring is performed by DACQUS and special software for addressing each level and interpretation of conductivity measurements in the formation.

The DACQUS system. DACQUS (see Fig 6) is a system for real-time data acquisition and management of oilfield data and instrumentation. It is designed to run anywhere in a PC network. DACQUS provides direct access to current and historical data from any field equipped with monitoring and/or control system, or subsea/topside metering systems. DACQUS can also incorporate other real-time data, such as choke setting, sand monitoring, etc., whenever that is desirable for a given application. All measurements are constantly updated, building a historical databank, which can be reviewed for any time span. A series of preventive maintenance routines provides for continuous "health check" of measurement devices and data quality.

Some of the features in DACQUS include real-time online mode with a 1-second update rate, remote maintenance and updating, standard protocols for interfacing process equipment, links to SCADA systems, and real-time operation client-server system.

The Metering system. The MFI Multiphase Meter is a compact, straight spool piece with no moving parts and no pressure drop. The MFI Meter utilize a microwave technology for determination of the mixture's dielectric properties. Instantaneous oil, water, and gas fractions are obtained by utilizing the microwave technology along with a commercial ^{137}Cs gamma densitometer for measuring the mixture's density. To determine the flow velocity, the cross correlation between two microwave sensors is utilized. All calculations are performed within the field mounted electronics. Consequently, only final results are transmitted from the field using analog or digital output. An interface to the DACQUS data acquisition software exists, allowing real-time meter information in remote locations.

The MFI Multiphase Meter function over the full 0-100% water cut range. Due to the high sensitivity of the microwave sensor, the meter becomes flow regime independent, and, particularly, high gas volume fractions can be accurately accommodated for. This is of particular importance in Field Case C. To date, more than 80 MFI Multiphase Meters have been installed, with a combined operation time of more than 500 000 hours. The experienced accuracy is in the range of 5-7%. See Wee and Haddeland for further details on meters and on field cases.

IRPM Field Cases

Field Case A: The Norne Field. Located in deep water on Haltenbanken, off the Northern coast of Norway, the Statoil operated Norne Field is produced through an extensive subsea production system to a Floating Production Unit (FPU). The reservoir is heavily faulted into major compartments, and a significant number of wells are used for oil production as well as pressure maintenance with water and gas injection.

The majority of the oil producers are equipped with permanent pressure gauges, monitoring the development in the various compartments. As the water is injected into the aquifer, and the gas is pumped into the top section, the reservoir exhibits a free gas zone with an oil column and a dynamically rising oil/water contact. It is the development of this fluid contact which has given the justification for placing the water monitoring radar assembly in one of the water injection wells, see illustration in Fig. 7. Over the lifetime of the field this contact is expected to rise approximately 15 m.

The WMR assembly emulates one permanent gauge through the KOS subsea control system, despite the fact that 15 fluid detector units will be evenly spread over a length of 75 meters. The tubing string is cemented in the openhole section, thereby exposing the WMRs directly to the formation, where the average conductivity is measured at the various addressable levels.

Data acquisition and control is conducted with DACQUS from the Norne FPU as well as from any onshore office in real-time. The data will be used to decide future injection strategies and placement of new wells.

Field Case B: The El Furrial Field. Being one of the most important reservoirs for production of light oil in Venezuela, the El Furrial field has been subjected to some intensive pilot projects in order to gain a further understanding of the fluid movements and saturation development resulting from a water-alternate-gas injection program. Located on the plains of Eastern Venezuela, this HPHT field represents a very challenging planning, implementation and operation task in order to achieve the goals for the project, both for Roxar as the supplier and for PDVSA as the operator.

Two wells are involved with vertical reservoir penetration only 60m apart. The first well will have selective injection of water and gas through a total of 4 PROMAC systems separating the 4 formations to be surveyed. The PROMAC units will have 12 gauges to monitor the pressure and temperature in the reservoir, the well, and the PROMAC valves, see Fig. 8.

The second well is an observation well with WMR units to monitor the conductivity in the formations. With the planned downhole configuration, the depth of investigation for the fluid detectors can be as high as 5m, which means that changes in the saturation from the injection well can be detected very early in the project phase. There will also be a permanent gauge placed in each formation for pore pressure monitoring throughout the duration of the pilot project. The tubing string is cemented in the open hole section, leaving the gauges as external "casing" sensors, and the fluid detectors exposed directly to the formation, just as in the Norne case.

DACQUS will ensure real-time data acquisition and control for improved reservoir and production management by PDVSA, and it is expected that significant added reserves can be taken out as a result of this and other parallel pilot projects.

Field Case C: The Huldra Field. Huldra is a gas/condensate field in the Norwegian sector of the North Sea. Statoil will operate the field, and the production is scheduled to commence October 2001. The field is expected to produce for 8 years.[3] Huldra will be developed as a unmanned well-head platform, and the practical implementation of changing operational conditions (e.g., top-side choke openings) will be done at Veslefrikk. The Huldra reservoir is at about 3800m depth and has an initial pressure of 670 bar and a temperature of about 145 °C.

The field will initially be developed with 6 inclined wells. The pre-drilling phase is scheduled to commence in Summer 2000. The production will be controlled to comply with the gas contracts. The gas will be sold via a pipeline to Heimdal and the water and condensate will be routed to Veslefrikk.

Roxar will supply Statoil with 6 multi-phase meters – one for each well - to measure the rates of condensate, gas, and water. On several of the wells, permanent downhole gauges will be utilized to monitor pressure and temperature. Several other parameter will be monitored, such as well-head pressures and temperature, and sand production. All these data will be available through DACQUS in real-time at the reservoir and production control center to be assembled in Bergen.

Together with Statoil Roxar will implement a system to monitor all relevant information for production management on Huldra. The system is to be used by the production and / or reservoir engineer for everyday surveillance and control; Fig. 9 illustrates this system. The Huldra case is assumed to be one of the first and most comprehensive applications of true integrated reservoir and production management in an offshore field. Through a close working relationship between Roxar, Statoil, and other suppliers, the IRPM concept will be realized for the client in a remote control center where all the essential data is available, and the processing is made in a real-time environment for immediate actions to be taken.

Conclusions

We demonstrate how critical components and integration technology can be utilized for integrated reservoir and production management. Three field cases, all which are planned to being implemented with real-time and remote data acquisition capabilities, show how these technologies can find their way into everyday reservoir and production engineering practices. Through such technologies and projects, the vision of integrating data, work processes for decision making, as well as remote and real-time production may transform to reality.

Acknowledgement

It is certainly the field cases that add value to this paper, as they provide the actual experience of integrated reservoir and production management at various levels. Therefore, the authors gratefully acknowledge Statoil for the contributions to field Cases A (Norne) and C (Huldra), and PDVSA for their support in field Case B (El Furrial).

References

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2. Cramer, R., Eken, A., Dunham, C., Der Kinderen, W., Rudenko, P., Adaji, N., Onoyovwi, C.: “Shell tests low-cost, real-time oil well surveillance,” *Oil and Gas Journal*, Feb. 14, 2000.
3. Data from NPD; see: http://www.npd.no/engelsk/npetrres/ petres99 /index.html.

Figures

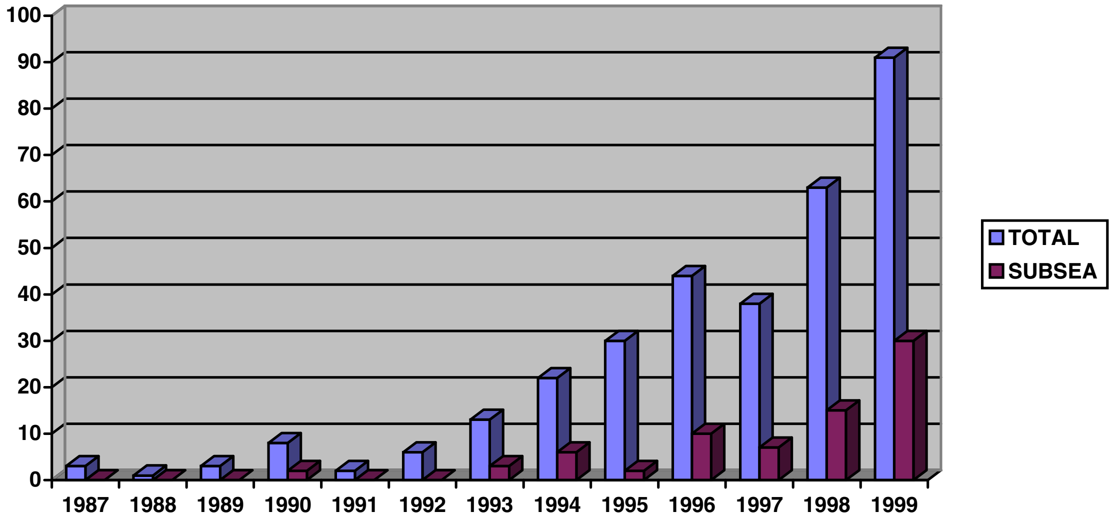

Fig. 1 – Roxar's number of gauge installations per year from 1987 through 1999.

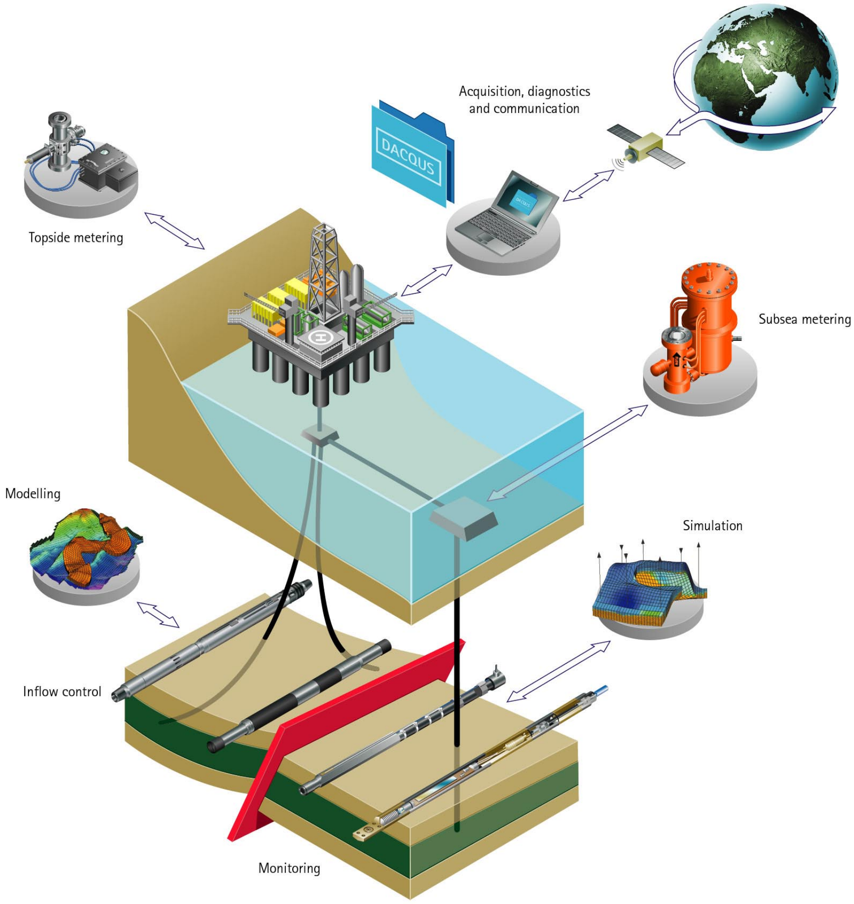

Fig. 2 – Critical components for reservoir and production management.

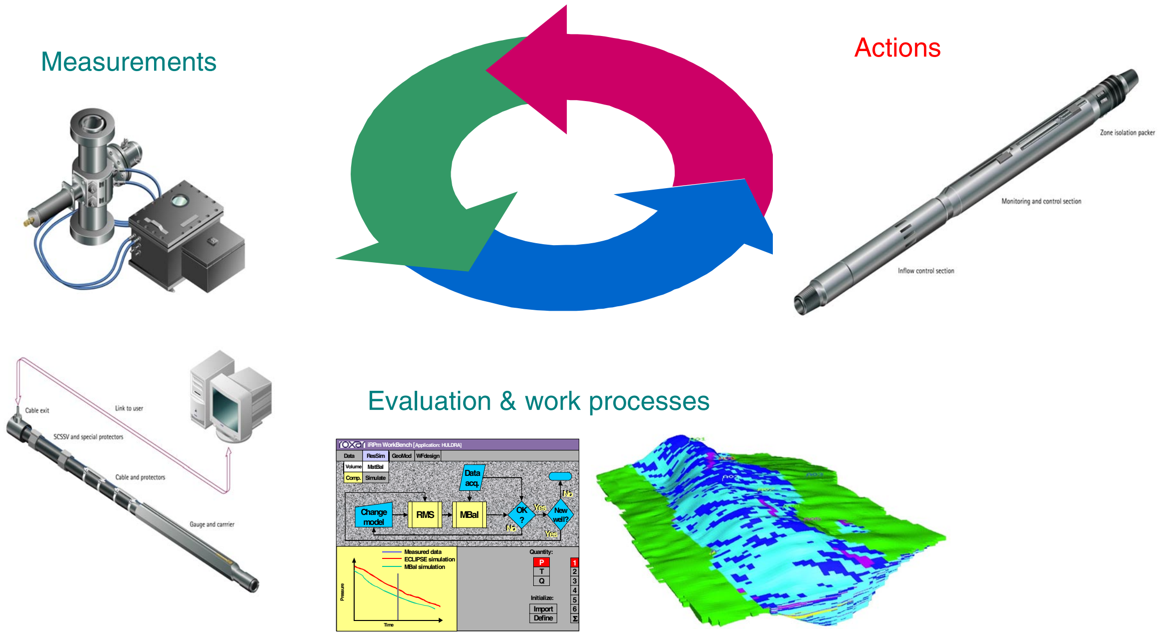

Fig. 3 – The concept for integrated reservoir and production management.

Fig. 4 – The PROMAC inflow control system.

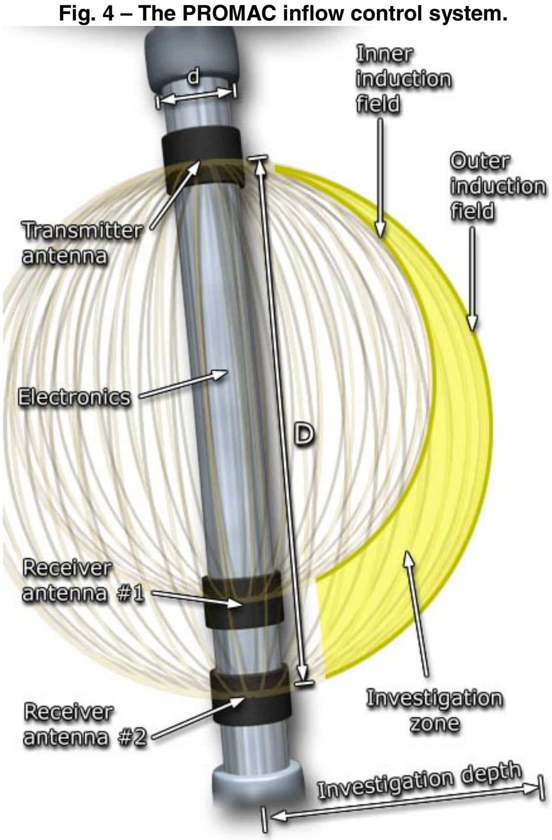

Fig. 5 – The Water Monitoring Radar (WMR) system.

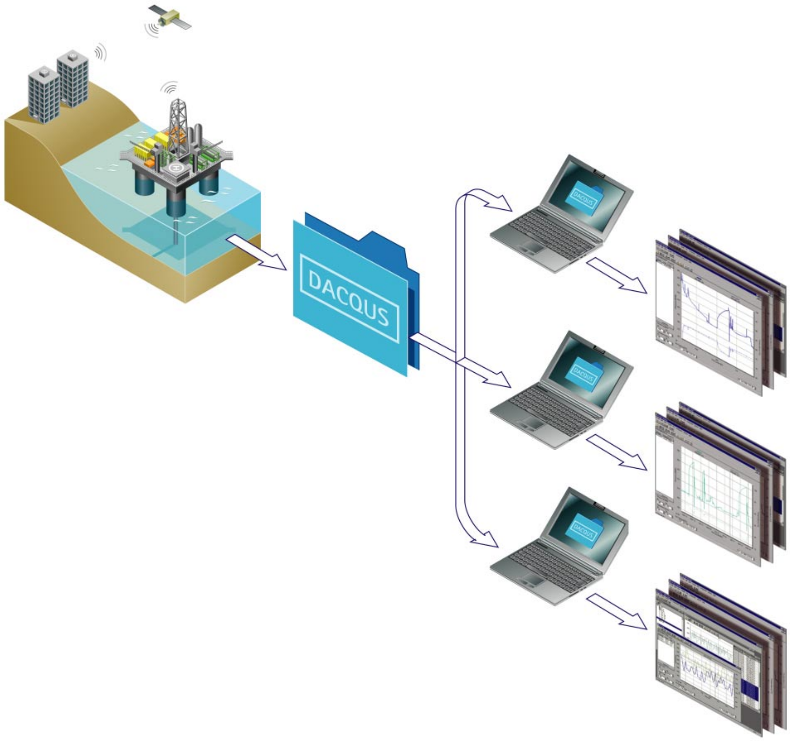

Fig. 6 – The DACQUS data acquisition set-up

Fig. 7 – The Norne field case.

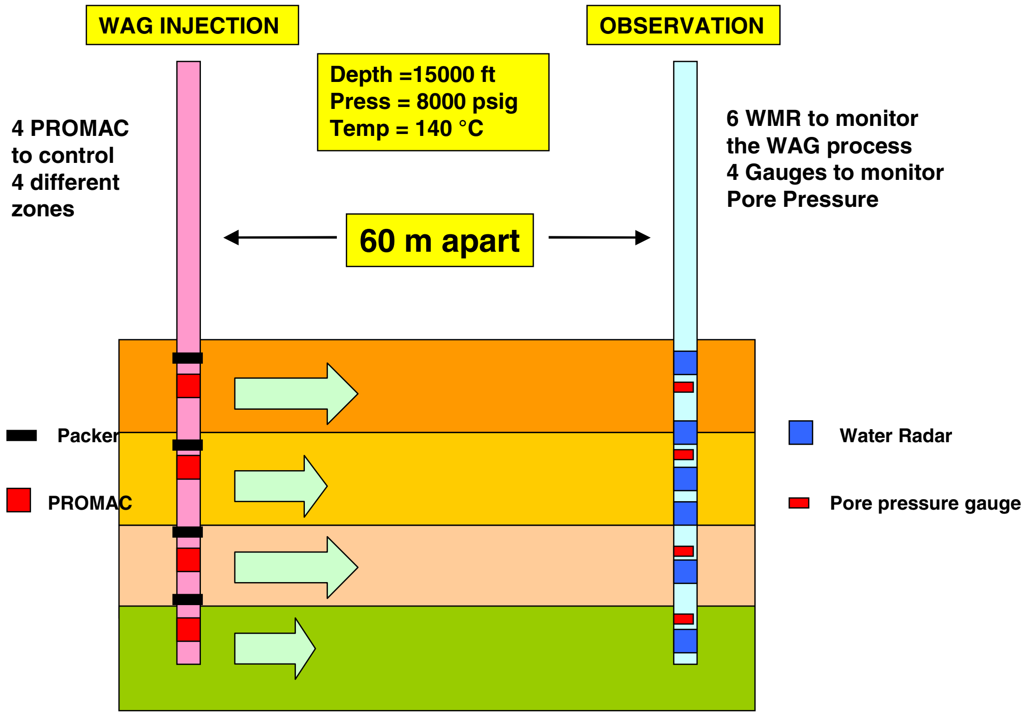

Fig. 8 – The El Furrial fied case.

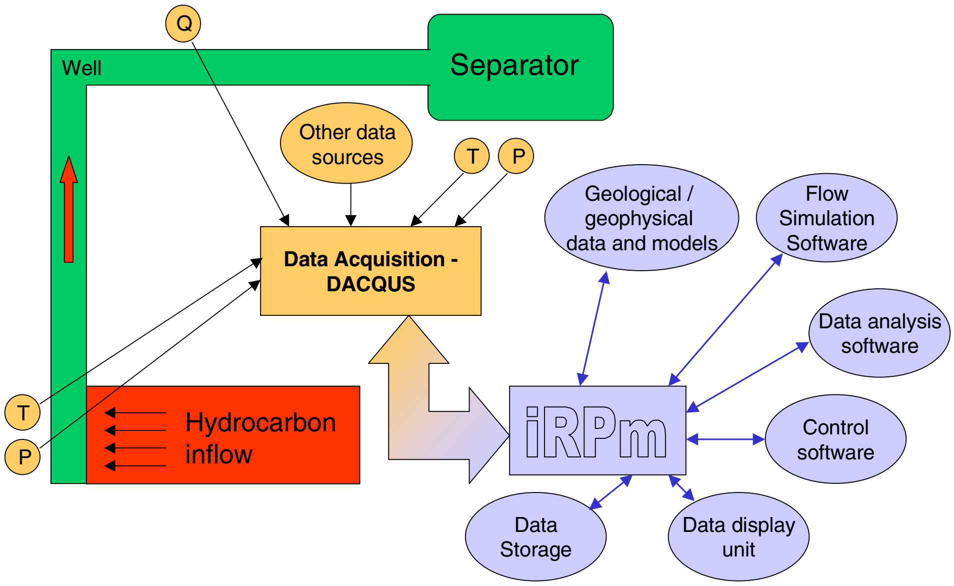

Fig. 9 – The Huldra field case.