35th Anniversary of the first land 3D survey by NAM and Shell

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We read, with much interest, the *TLE* article describing the development of 3D surveys by Gulf (Watson, 2009). After a successful ultrasonic test by Gulf R&D of a 3D model immersed in water, the technology was tested in the field in 1974. This resulted in possibly the first 3D offshore survey but the data were not published at the time for proprietary concerns.

The historic record (Schneider, 1998) shows that Geophysical Services Inc (GSI) organized a major research project in 1972 to evaluate 3D seismic. Six oil companies (Chevron, Amoco, Texaco, Mobil, Phillips, and Unocal) participated in this 3D group shoot across an onshore field. This was not in the public domain until 1998.

We would like to complete the historic record with what might be the first onshore operational 3D survey in support of field development and executed by a single company. This survey was carried out in November 1975 for the Nederlandse Aardolie Maatschappij (NAM) in the Netherlands across a gas field some 60 km south of the giant Groningen gas field. A presentation was made at SEG's 1978 Annual Meeting and published by SPE in 1978.

The objective was to assist appraisal drilling by delineating a carbonate within the Zechstein salt where no structural closure could be established even with a 250 × 250-m 2D seismic grid. Acquisition (54%) and processing (46%) costs amounted to 1.6 million guilders.

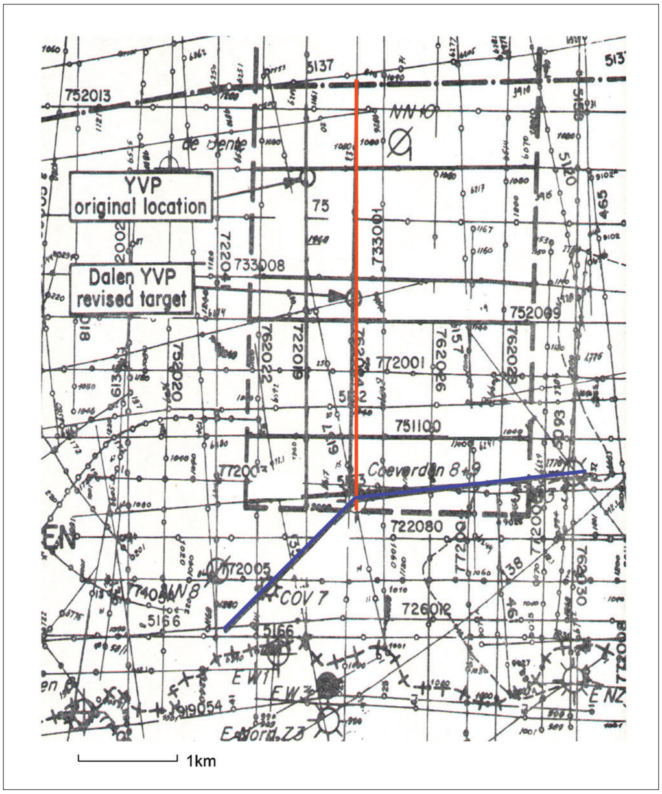

Figure 1. *Red = location of seismic lines shown in Figure 5 and Figure 6. Blue = location of cross section show in Figure 2.*

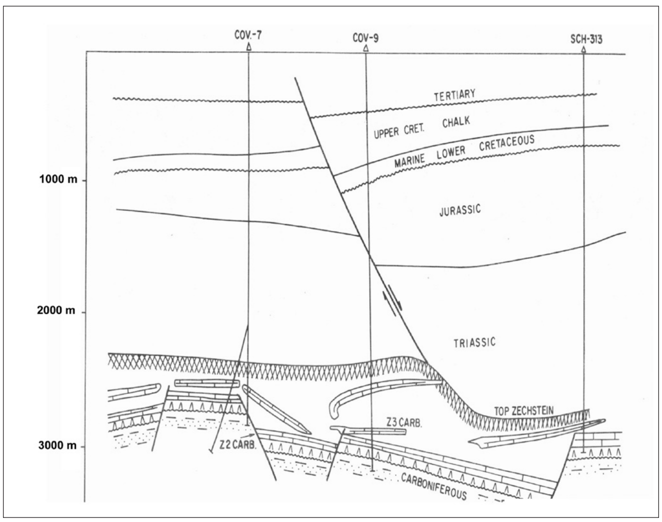

Figure 2. *Schematic geologic section.*

Survey initiative

In early 1975, Jan Endtz and Nick Serck, respectively Shell International Petroleum Mij (SIPM) corporate chief geophysicist and head of acquisition, were contemplating a land 3D test in North Africa for which they had secured 1 million guilders. However, the Netherlands had incentives to search for small volumes of gas to complement Groningen. This made the Netherlands much more attractive to test the 3D concept.

We convinced them and Huub van Engelshoven, then NAM's managing director, that it would be much more challenging to select a project around a documented subsurface structural problem. They were at first skeptical that we could pull this off in a highly populated area of the Netherlands but agreed to let us take over the project and SIPM would provide 1 million guilders. The upside would be that, if additional gas were found, the risk money would be refunded by NAM, 50% Shell (operator) and 50% Esso. The latter had no technical involvement and preferred to treat it as an SIPM pilot project.

Considering the sampling requirements and the fund available, only a small areal survey could be carried out. Zechstein (Permian) salt throughout our acreage caused many discrepancies between prognosed and actual drilling results. The complex subsurface generated 3D imaging problems while our processing toolkit included only 2D time migration to address them. Thus, if successful, 3D could provide a breakthrough. We found in Henk van Deemter, the production geological interpreter, a strong supporter and the ideal client. He had delayed an appraisal well in the Schoonebeek area for several years, as he could not get closure on a fault block based on a 2D infill grid with 250 × 250-m spacing (Figure 1). He saw the opportunity and grasped it.

Objective

The primary objective in this NAM land concession is the Zechstein Z2 carbonate of late Permian age (Figure 2). The directly underlying Z1 sequence of anhydrite carbonate rests unconformably on a peneplaned surface of the Upper Carboniferous coal, the sandy intervals of which form a secondary objective. The schematic geological section shows an additional gas play in the competent Z3 carbonate "slabs" of unknown size and shape within the massive Zechstein salt sequence. It is known from well data that the Z3 rocks can be independently tectonized: steeply dipping sometimes overturned with duplication or even triplication.

Structural interpretation aims primarily at identifying/mapping the interface between the Z2 salt and the Z2 anhydrite/carbonate sequence. This boundary represents in general the deepest continuous reflector recognizable on seismic sections. The Z2 reflection may be hampered by the overlying Z3 rocks, especially where the separation is small. The Z1 and Z2carbonates and carboniferous formations are dissected by considerable and highly irregular block faulting, sometimes of considerable throw (up to 500 m), which predominantly control the trapping mechanism. A thick package of Mesozoic and Tertiary sediments, often disharmonically deformed due to halokinesis, overlies the Zechstein salt. The seal is in general the overlying rock salt. If the presalt-tilted fault blocks would protrude the gas-water contact and salt is juxtaposed across the faults, the trap would be gas-filled. The natural gas originates from the coal and migration took place from Upper Cretaceous until Recent. The Z3 carbonate floaters and the underlying fault blocks were numerous and the interpreted horizons from the 2D lines were often misplaced due to sideswipe from outside the 2D vertical location and inconsistent with appraisal drilling (well Dalen 3) results.

Business environment

The SIPM E&P operating model (outside North America) was distinctly different from the E&P companies in the US at the time.

Firstly, the priority for exploration in the US was the offshore Gulf of Mexico (GOM). Each OCS sale in the GOM of numerous postage-stamp blocks (typically 3 × 3 miles) had to be evaluated within six months. Large sums were at stake and the auctions were very competitive. So the latest high technology combined with strict confidentiality was key and needed to be shielded from the geophysical community at large.

Gulf of Mexico operations are in reasonable close proximity to an R&D facility. For example, Shell Oil R&D is in Houston and its GOM operation in New Orleans. At that time, Shell Oil had two offshore vessels (and one coastal) and a large processing center to mainly support bidding on GOM leases. GOM prospects at the time were mostly clastics and sometimes salt-flank related. The name of the game was hydrocarbon prediction through "bright spots."

This offshore exploration scene was a geophysicist's dream and in 1975 GOM exploration was a highly skilled and fine-tuned geophysical machine with a few geologists. Shell Oil's R&D geophysical staff in Houston played a key role and provided the technology in Shell Oil's GOM operations. The acquisition, proprietary processing algorithms, and bright-spot analysis were all geared to provide the best signal at loop level. Shell Oil's own staff performed all this.

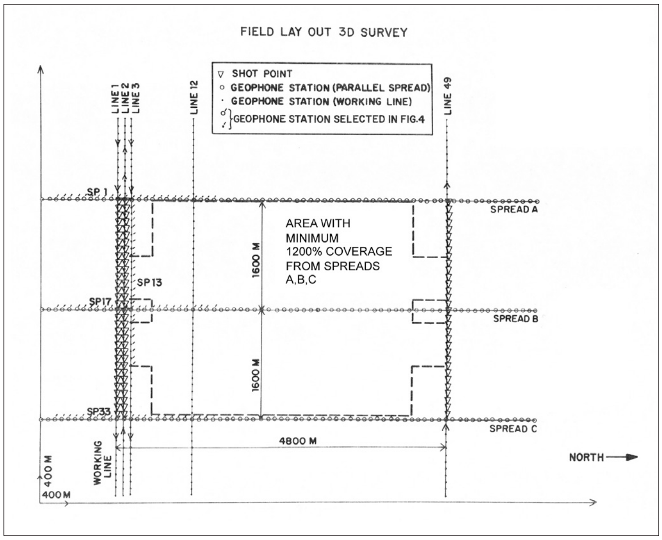

Figure 3. Field layout of 3D survey.

Shell operating companies (outside North America) had a completely different business model. Offices were in the countries of operations around the world and locally staffed, but supplemented by Shell expatriate staff. The companies varied considerably in size and the smallest exploration ventures got support from a core of specialists in The Hague.

Shell R&D in Rijswijk had developed a SIPMAP processing package (Yougo Eskes, Tom Delsing et al.) to embed the research outcome. Rijswijk was involved in longer-term research projects and some service work like processing dedicated 2D lines to provide benchmarks to compare with the contractor's processing. SIPM had no seismic vessels or full production processing centers at the time. For production seismic, the geophysicists in operating companies (like NAM) relied on contractors. Western Geophysical, GSI, Prakla Seismos, and CGG were the top four.

Acquisition of the 3D pilot survey was awarded to Prakla-Seismos and processing to GSI. The authors designed the survey according to the design standards at the time—taking into account the objective level, expected dip range, frequency range, and corresponding stacking and migration operators. We deliberated with the contractors and Shell R&D about acquisition design and planning phase.

Survey design

In 1975, two Prakla-Seismos land crews operated for NAM throughout the year, using 48-channel SERCEL 338 B instruments. We designed a 16 km^2 (six square miles) survey using both crews and their field systems for a full month and exploited all 96 channels. We used a 100 × 100-m surface grid of coinciding shot and receiver locations.

Permitting did not raise serious problems at least with 2D.

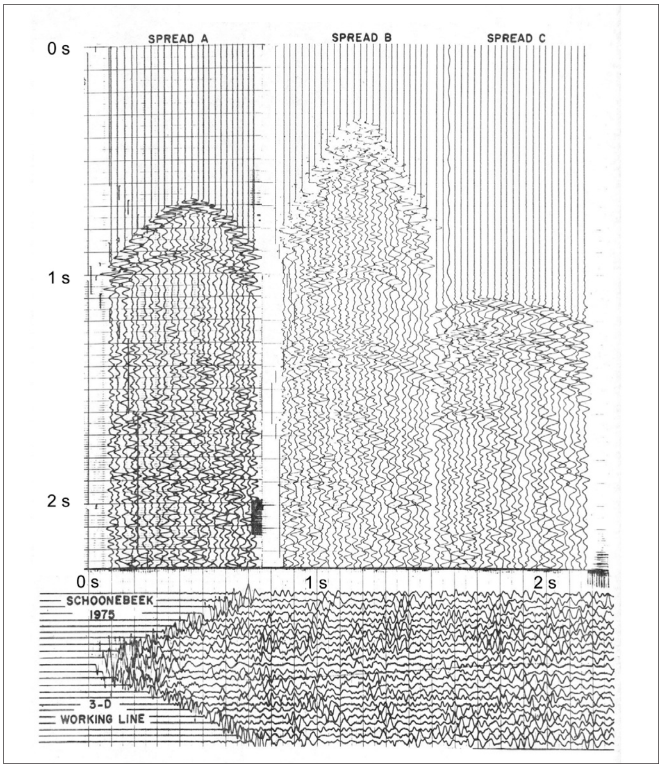

Figure 4. *Four seismic records from one shot.*

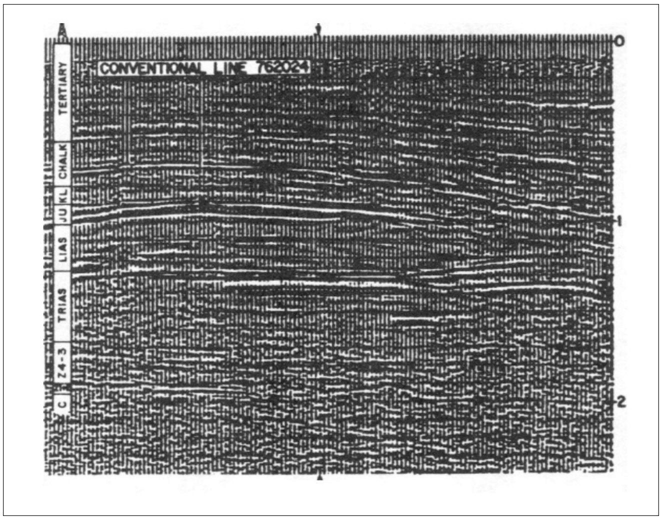

Figure 5. *Conventionally migrated 2D line.*

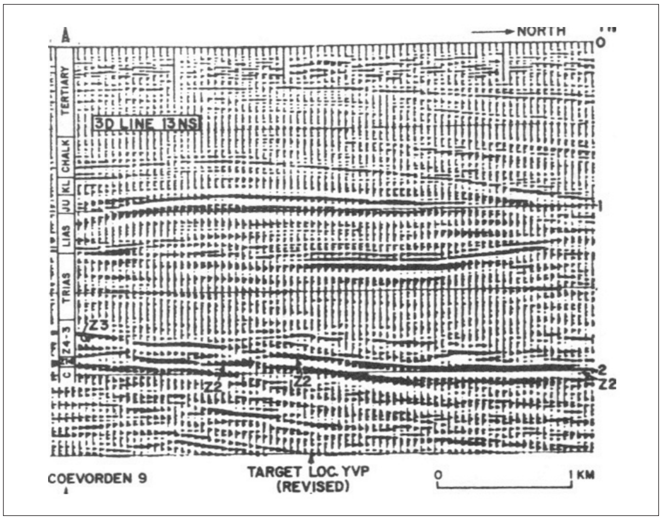

Figure 6. *Reconstructed 3D line from 3D data.*

Rolf Garber, vice president of Prakla-Seismos, was amazed that we wanted to move onshore for our 3D test, as the cost seemed prohibitive. In order to economically justify our project, we used a model that included dry appraisal wells and the risk of ending downdip, leaving updip reservoirs untapped. Depth map migration, developed by Tom Klein, was applied routinely but it was realized that the 2D time input data consisted partly of misplaced sideswipe events. We had two further arguments to select an onshore pilot. There would be no navigation issue with the station positions and each shot would be fired in an areal pattern rather than "semi" 2D.

The drawback was the topography: canals, dikes, roads, railways and high-pressure gas and oil pipes, a recreation center, and a small village in the area. Under supervision of Jacques Pion (head of acquisition) and Nol van Olmen (field supervisor) on the NAM side and Rolf Bading (field supervisor) and Werner Leuschner (party chief) on Prakla's side, all hurdles were carefully taken into account. Deviations of the planned 100 × 100-m grid were necessary (1200 instead of 1600 shot locations); in addition, charges were often reduced from 3 kg to 1–2 kg.

The base Zechstein reflector is around 2 s (two-way time) and far offsets were limited to 3.6 km.

Each shot line (33 shots) generated data on three 24-channel receiver lines (the "parallel" spread A, B, and C) and one 24-channel receiver line coinciding with the shot line (the "working" line). The parallel lines had 36-geophone, 6-arm "mill" arrays; the working line used 24-geophone linear arrays. Shot line spacing was 100 m (Figure 3).

Each shot provided four records, three from the parallel lines and one from the working line (Figure 4). Parallel lines had depth-point spacing of 50 × 50 m and minimum coverage of 1200 fold.

Processing

Processing, by GSI Dallas with participation by Jacques Pion and Khurshid Obaidullah of NAM, took seven months (field and residual automatic statics, deconvolution before stack, 3D stacking at each subsurface point, and D2D Kirchhoff migration) yielded 6300 migrated traces. These were displayed in 97 EW and 65 NS lines. Figure 5 shows a conventional 2D migrated line through well Coevorden 9 and Figure 6 shows a line from the 3D migrated data set at practically the same location. The improvement in signal-to-noise ratio and the vertical and lateral resolution at the target level were considerable.

At the target level (the Z2 carbonate, around 2 s two-way time), structural definition has been improved dramatically and the high block at target location YVP is absent on the 2D section.

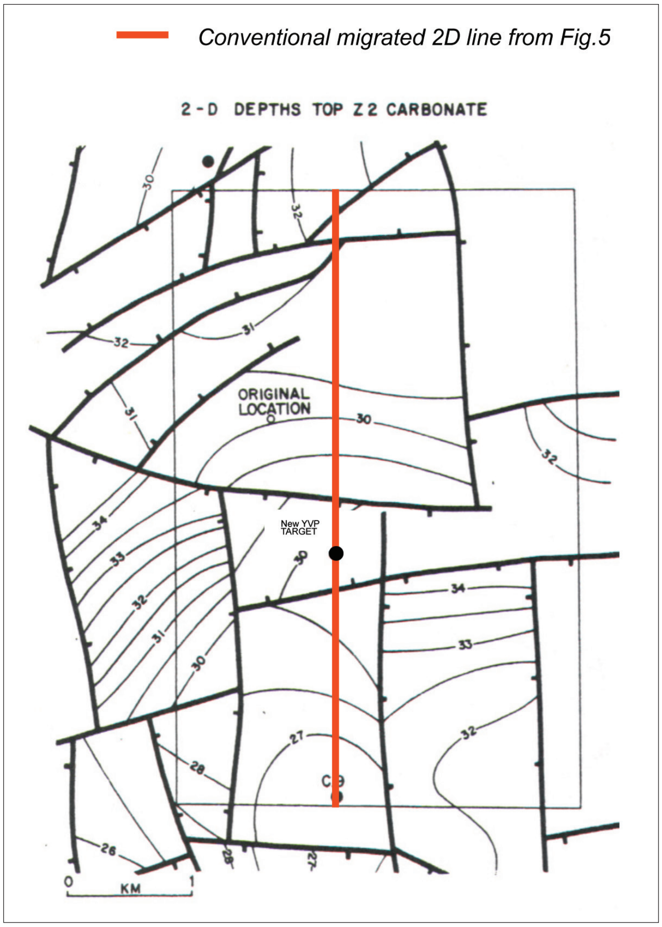

Figure 7. *Top Z2 based on migrated 2D data.*

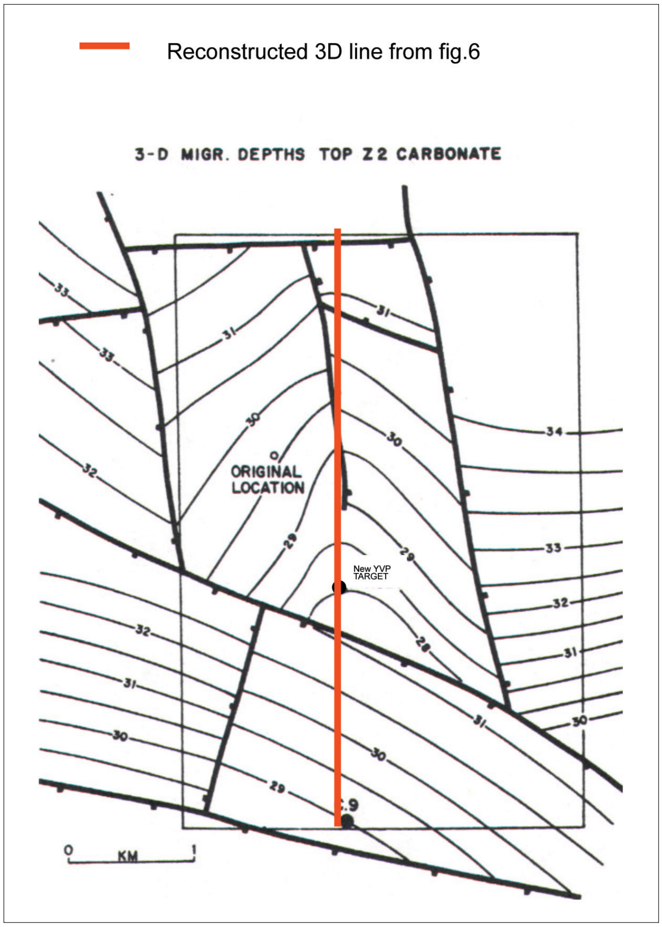

Figure 8. *Top Z2 based on migrated 3D data.*

The 3D data were also presented with GSI seiscrop maps or iso-reflection time surfaces at intervals of 4 ms.

R&D Rijswijk performed test and benchmark processing, inline stacking along the working line followed by 2D migration and D2D migration. In the case of Schoonebeek, D2D is adequate to estimate 3D migration as the hyperbola behaves not too frantically for its apex which is what is covered by the migration aperture of the small grid. Full 3D Kirchhoff migration could not be done due to the lack of computer capacity at the time.

Comparison of the depth map based on the 3D migrated data (Figure 8) with that of the 2D migrated survey (Figure 7) shows that the objective Zechstein Z2 carbonate block extends much further south: a structural gain of almost 200 m.

The appraisal well (Dalen YVP) was moved some 1250 m south from the originally selected YVP location. This was confirmed by subsequent drilling in 1978 and the Z2 carbonates; all sands penetrated in the Carboniferous were gas-bearing at prognosed depths.

The original 2D interpretation indicated a graben between two high blocks. The project identified a new gas-filled fault block. Esso had agreed to pay its 50% only if the project turned out to be profitable for the NAM; otherwise they considered it to be an SIPM project. It proved profitable indeed and NAM also refunded the risk money to SIPM.

Although our project demonstrated the effectiveness of 3D imaging in an intra- and presalt play, many obstacles still had to be overcome to achieve a technology breakthrough.

Potential technology breakthrough

For an innovation to qualify as a potential technology breakthrough, we suggest that it satisfy three conditions.

- It has to mark a substantial discontinuity in the progress of technology.
- The potential cumulative business impact has to be worth hundreds of millions of dollars (if not billions).
- It has to satisfy extensive "falsity" tests and its technical benefits and current drawbacks need to be thoroughly understood (Popper, 1979).

The second condition took approximately ten years to fulfill. It appeared to many stakeholders that the value created by the Schoonebeek 3D, apart from the dramatic improvement in structural definition so critical to field development, was linked to special fiscal and commercial conditions not applicable at the time to most permits and concessions worldwide. However, when 3D seismic started to considered an essential complement to horizontal drilling, value was created everywhere.

This gave enough time for thoroughly going through the falsity tests to qualify the new technology.

Firstly, Shell R&D Rijswijk started using the data set to develop 3D imaging tools including depth migration. Gordon Phillipson, then head of the Geophysical Department of Shell Oil R&D, acquired the data set to stimulate 3D seismic developments. It would still take years before computer power would allow moving into the prestack domain.

Secondly, 2D stack-array principles developed by Henry Askin and Leo Ongkiehong and his Petroleum Development Oman team in the late 1970s for 2D were generalized for 3D and completely changed design and processing standards (as used for Schoonebeek). This resulted in simpler field layouts by the mid 1980s by Frans Kets, Paul Wood, and Jacques Pion. The main elements included emphasis on bin-offset distribution, not coinciding the shot-receiver location, and zigzag shooting. Predicting and filtering shot-generated noise, providing antialias spatial protection by receiver and shot patterns, and applying migration operators designed for diffractions not poststack reflections were major steps in quality improvement.

Thirdly, the bottleneck for onshore applications was the limited number of channels in the late 1970s. We pushed contractors to request at least 200-channel recorders from the instrument suppliers. Prakla acquired its first 100 telemetric Sercel 348 boxes in 1978 and had 10,000 in 1988.

Finally, the actual Achilles heel in all of this was the numerous paper seismic sections and time slices provided to interpreters. Having observed that they were very uncomfortable with time slices and used only every fifth seismic section, it was clear that we needed a computer-based interpretation system.

Key players

We found a strong supporter in Bob Graebner at GSI, for our 3D seismic project. In retrospect, it is obvious that Bob had his own 3D initiative with the group shoot (unknown to the authors at the time). Bob was a visionary who understood that much seismic market growth could be generated by providing extra information to engineers. They were used to thinking at project scale with substantially larger money commitments and did not focus on seismic unit costs as explorationists tended to do.

Sometimes one gets information presented that really knocks you off your feet and in a list of the top ten, apart from this pilot, comes to mind the slide Bob Graebner and Alistair Brown showed from the 3D Gulf of Thailand offshore survey at SEG's 1978 Annual Meeting. It was a very shallow time slice (196 ms) well above the producing gas reservoirs and showed a spectacular meandering river system as if we were flying over it. If we would just be able to reconstruct our seismic data sets at target level deposition times or track the reservoir bodies, we would be in business for many decennia to come.

In the early 1980s, we approached Graebner again. We were both intrigued by the potential of the seismic 3D cube for structural definition and potentially for stratigraphic reservoir and fluid characteristics, already an important production issue with the extensive appraisal programs.

Bob agreed we needed an automated interpretation workstation. We realized this was a risky venture as building an interactive system from scratch was new to the geophysical processing industry.

Gijs Vermeer got the project to specify the requirements for an interactive horizon and fault interpretation system SIDIS. If you know Gijs, as many do from his lectures and publications, he took the job very seriously and provided detailed specifications. We spent days with Bob and Mike Golding and their staff in Dallas to prioritize and analyze the requirements. Bob stayed optimistic on the progress and made a preannouncement at an SEG meeting.

However, a start-up company, Landmark Graphics, picked up the challenge in 1982. Landmark released workstations and 3D interpretation software ahead of GSI and the others. The interpretation community immediately appreciated their product.

Another approach relied on imaging, developing quickly for medical applications, rather than signal-processing techniques. Shell R&D Rijswijk staff (Dick Dalley et al.) developed 3D proprietary software for visualization, attribute processing, and auto voxel tracking. Under favorable circumstances, it became possible to define the limits of hydrocarbons themselves and, in rare cases, show the retreat of hydrocarbon-water contacts in response to sustained oil and gas production.

As an end user, we were very pleased that workstations appeared on the market and the 3D train started really moving.

We met Anders Farestveit for the first time in the mid 1970s in a small booth at an EAEG exhibition. He had no seismic equipment but he had air compressors with a capacity to supply a 2600 cubic inch array, twice as much as available at the time. R&D Rijswijk experts Leo Onkiehong, Wim Huizer, and Joost Nooteboom designed the array and we shot test lines for NAM. Andres set up a geophysical company (GECO) and became a leader in 3D offshore surveys. He amazed us, together with other major contractors, in developing extensive multiple source arrays and later the multiple cable-towing capabilities pushing down the cost of offshore 3D and improving the imaging.

In 1987 we used double sources and double streamers (50 km^2/month) and in 1995 this capability had grown to 2 sources and 16 streamers (600 km^2/month) while the unit price dropped from US $20,000/km^2 to $5000/km^2. A key parallel development in positioning techniques based on differential GPS provided the necessary accuracy, which was not available before.

Woody Nestvold, chief geophysicist of SIPM, became a very strong champion of a worldwide Shell 3D campaign in the mid 1980s. At the end of that decade, he began to publish papers and make presentations on successful 3D projects at professional meetings, including SEG and EAEG; this continued until his retirement in 1992. By then, Shell had acquired 65,000 km^2 in some 300 surveys. The 1992 SEG expanded abstract by Nestvold and Oosterbaan lists 35 3D papers/presentations in 1987–1992 by Shell International E&P staff.

Shell and partners (outside North America) spent, in Shell-operated acreage, in 1992 a staggering US $430,000,000 (in one year!) on seismic; 90% was related to 3D.

Conclusions

The 1975 3D onshore seismic survey, acquired by NAM, and originally cofunded by Shell International was a striking success. It was to our knowledge the first 3D onshore survey (including full D2D migration) by one company to assist production-related objectives and an appraisal drilling campaign. There may have been earlier single-company onshore 3D surveys under the veil of company secrecy of which the authors are not aware. The vertical and lateral resolution, especially at the objective level, permitted a new approach to field development, hitherto believed unattainable with routine 2D seismic. The survey resulted in the discovery of a new high block with a 200-m gas column in place.

Since the early 1990s, all onshore and offshore concessions in NAM's portfolio have been covered with 3D. The onset of 3D helped the geophysical industry survive the 1980s and 1990s as the oil industry was getting saturated with 2D data and needed a major technology breakthrough.

We have tried to extend the historic record and give recognition to the many players in this project because the Schoonebeek 3D project was a decisive event in seismic subsurface exploration and production. TLE

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