OFFSHORE ENERGY CENTER

ORAL HISTORY PROJECT

Interviewee: BILL PETERSEN

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Interviewer: Joseph Pratt

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Bio

He graduated from California polytechnic in 1959 with a B.S. in mechanical engineering. He joined Shell that same year. He was assigned to the Marine Division in California and went to work developing tools to use in subsea production. He had input in the MO system, RUDAC and MTG systems.

Summary

Short interview that discussed the evolution of undersea production technology. Comments on the MO system, the RUDAC system, MTG System and various other pieces of undersea technology.

Side A

JP: This is an interview with Bill Petersen on October 2, 1999. The interviewer is Joe Pratt. The interview is taking place in Houston, Texas, as part of the OEC ceremonies.

Mr. Petersen, I would like to start by asking you about your own educational background and how you came to work for Shell, and then how you came to work in the offshore.

BP: Well, I am from California. I come from a small town that is inland, central coast of California. So, I really didn't have any origins in the sea with my background, but I was raised in a small town. My father was an operator on a pipeline system for Union Oil Company from the San Joaquin Valley pumping oil to the coast of central California. So, that was my first involvement/interest/contact with the oil industry, was in that pipelining segment.

I was raised in a small town. I graduated from high school there and went to school at California Polytechnic, which is a university in San Luis Obispo, California, and there, I studied mechanical engineering. I had a bachelor's of science degree in mechanical engineering. I really didn't have any strong ambition at first, being a practicing engineer, but I had some skills in math and science. I liked math and science, but I thought maybe I would apply it in agricultural engineering.

It turned out I went to work for Shell Oil Company, and I started to work in 1959, and initially worked in a training program that took me in to several segments of Shell's business on the West Coast. I worked in drilling for a while. I worked in production engineering. I worked in various field operations, jobs, and at that time, it was Shell's method to bring new engineers into their organization to train them in the grassroots parts of the oil industry. So, I felt real fortunate to be able to go through this training program. It also encompassed some training schools here at our research lab in Houston.

After I finished the bulk of the training program, I worked initially in a team that was doing engineering, subsurface engineering, in preparation for steam flooding in Bakersfield. And I worked there just for a short time before I was transferred down to a marine division that was forming in Los Angeles. And this marine division was a new initiative by Shell on the West Coast to develop the technology in order to explore and hopefully produce oil and gas on the West Coast. So, I joined this team called the Pacific Coast Area Marine Division, and I worked . . . initially, I was working with several people. At that time, there were about five or six, maybe seven or eight, come to think of it, engineers in that team, that had already started doing some basic engineering on subsea well systems, on floating drilling systems. And so, I became a junior member of that team, and I was working to evolve equipment, test equipment, take equipment to the field. And so, it was a fast learning curve. At that time, there were very few people. There was lots to do. And the main core effort of this group was to develop this subsea drilling system, and subsea completion system called the MO system, and there were several key people that were working in this Pacific Coast Area Marine Division who were advancing on a steep learning curve this technology that surrounded this new drilling system. So, I felt real fortunate to be able to join that team, and I worked for several months with Ventura Tool Company, which is the forerunner company of Vetco, for Vetco Incorporated, and Shell had basically their own in-house design team that was headed up by a contractor named Glen Johnson. And he was a real clever designer.

JP: This was in California?

BP: In California, in Los Angeles. And so, I was able to work with Glen, and with some other Shell folks. I was working for Howard Shatto at that time. So, they were some real key people in the industry and certainly, they were pioneers in their own right, starting this technology. So, I worked with them developing this equipment, and it was used then to drill several wells in the Santa Barbara Channel, some wells in Cook Inlet in Alaska to discover Middle Ground Shoal field for Shell, drilling from *CUSS 1* and *CUSS 2*. And then, we also had an underwater gas development, gas field development, in what is called the Molino field, where we had four gas wells, initially, that were connected back to a gas plant near Gaviota. So, that was my first experience working, you know, on real live subsea wells. And there, I worked in preparation, preparing equipment, and also, I worked in installing the flow lines. I was involved in the pipelining work. I was involved some in the gas plant. So, it gave me a real good initiation, so to speak, in subsea technology.

JP: When you say MO systems, M-O stands for . . . ?

BP: The MO system . . . MO is an acronym for Mobot, and the Mobot was an underwater vehicle. It was before the name ROV -- remote control vehicle, which is now the acronym for the eyes and the hands of people working on the sea floor. So, at that time, there were no ROVs that you could use for doing robotic work on the sea floor. And so, Shell . . . the heart of this MO system was the Mobot, which was basically a swimming socket wrench in some sense. It had various fixtures and tools that could articulate and screw and grasp. It had television and acoustics so you could sense what you were doing. So, this tool would go down and work on this underwater well-head. And the philosophy behind this MO system was to have a very simple land-type well head, but a rather complex and sophisticated support tool, being the Mobot. And so, it was kind of a . . . it was extremely innovative at that time because, as far as I know, it was the first use of an automatic robot, if you want to call it . . . we call them Mobot, to do underwater work on a subsea well head.

JP: Were you working on the design of the Mobot or its use?

BP: The Mobot was actually designed by Hughes Tool. They were under contract to Shell. And this fellow named Glen Johnson, and Bill Bates . . . Bill Bates was the manager of the Marine Division at that time . . . they had this vision of using this Mobot in this fashion. So, they started the idea, and then, the Mobot went through various evolutionary phases by, initially, Hughes Tool, and then it was later modified by Ventura Tool Company and other contractors to Shell, to take different shapes over the years. But the original Mobot was developed by Hughes Tool. There was also a sister tool that was called UniMo which was another underwater support tool that had five arms, five articulated arms, that looked very spacey, and it was developed, but it really never did mature into an oil field tool, whereas the Mobot did. It was used quite effectively in our drilling program up off of Oregon and Washington and northern California. So, that was my start in design and application of subsea hardware and tools, to drill and produce oil and gas.

JP: Did you work in the Cook Inlet?

BP: I didn't work in the Cook Inlet, but I worked on some of the equipment that went to the Cook Inlet. There was another team that took this equipment to the Cook Inlet, but I worked on the same equipment that went up there. They had some unique conditions up there, and it was mainly the currents. It was they drilled initially with *CUSS 1*, which was one of the real early drilling vessels, shipshape drilling vessel, and they moored it in the Cook Inlet. It was relatively shallow water there. I think it was 120-130 feet of water. But the unique problem was the currents, and there were a lot of problems related to vortex-induced vibrations, where the vibrations of the equipment as you lowered to the water column and high currents . . . we had lots of failures. There were several failures of equipment because of this phenomenon, and there had to be design solutions developed to overcome it.

JP: Did you work it out? That ice flow seems like . . . or even the flow without the ice . . . it seems like it would be really hard on the . . .

BP: Well, you would only drill from floating rigs during the ice freeze seasons. And so, you had a relatively narrow window to drill there. And then, you would have to move the floating rig out during the wintertime. After they made the discovery, then they designed and installed the bottom founded structures, the Middle Ground Shoal structures, that they used to do the remaining drilling and development of that field. But it is interesting, the MO system wellhead system, and drilling system, was used to make the discovery of Middle Ground Shoal.

The other interesting thing is it was used up off of Oregon and Washington and northern California, and that was very, very rough weather. There were large swells, long-period swells. There was a lot of vessel motion. Rather violent storms. We would have winds there, sometimes over 100 miles an hour, which are hurricane-force winds, and a lot of people don't associate that with the Pacific Northwest. But this equipment was used off of various rigs, initially off of the CUSS vessels, which were shipshape vessels, but later off of *Blue Water II*, which was a semi-submersible vessel, a semi-submersible rig. And there, the merits were that it was more stable. So, we could operate more efficiently during heavy weather periods. But because the weather was so difficult, we encountered a lot of problems with our equipment. Mainly having to do with accommodating the vessel motions. In heavy weather, the vessel rolls and heaves up and down. And therefore, when you are connected to the sea floor with the marine risers and different kinds of tools, you have to be able to accommodate this dynamic situation. So, if you are in heavy weather, you need to have some special equipment to do that. And so, that was unique to the Pacific Northwest, as compared to the Gulf of Mexico. In the Gulf of Mexico, there was very little motion during normal conditions. You would have vessel motions during hurricanes but oftentimes, people would disconnect and abandon during hurricanes, whereas, in the Pacific Northwest, the equipment had to be designed to survive during these storms that would arise quickly, unexpectedly.

JP: You talked earlier, before we turned on the tape, about the competing RUDAC system within Shell. Could you explain that competition, or what each was designed to do?

BP: It is interesting. Within Shell, there were actually two programs to develop floating drilling and subsea producing equipment. And the initial effort was in the Gulf of Mexico, and it was called the RUDAC system. And that acronym was for Remote Underwater Drilling and Completion System. And there was a team that was established, actually in Houston . . . some of the members were in New Orleans . . . and they worked in association with selected contractors - Cameron was one of them, Regan Tool was another, WKM - to develop this remote underwater drilling and completion system. And some of the key members in Shell were John Haeber, Ron Geer, Dee de Vries, Bruce Collipp, Jack Allen, and there were probably three or four more that I can't think of right now that worked on that program. And so, they developed an underwater drilling system which consisted of a subsea wellhead and guidance system, and a subsea blowout preventer system, and a marine riser system, and then it was used in association with *Blue Water 1* which was developed by Shell in association with Blue Water Company. And *Blue Water 1* was a converted submersible rig, and it is noted as being the first semisubmersible used in the industry, and it was successful in drilling multiple wells in the Gulf of Mexico before its demise in a hurricane - I think it was Betsy that did the *Blue Water 1* in. But that effort, you know, proved a drilling system, and along with it was a Christmas tree that allowed for producing a system that could be used in water depths off the shelf and, at that time, water depths that were maybe 200 or 300 feet of water were considered deep water. And so, that was going on in the Gulf of Mexico.

At the same time, there was a second team that was on the West Coast, and this was the MO system team, and it was focused on developing the Mobot-supported drilling system that was supposedly designed for a condition where the water was clearer and it was thought that that system also had some advantages to be able to use more basic wellhead equipment, as opposed to more grassroots development, remote systems that would be used in the Gulf of Mexico, where the water was turbid, where you couldn't see, and we thought we needed to use guy lines. So, the RUDAC system used guy lines, and it did have some television that you'd get some information back from the wellhead, but it was primarily designed to be a remotely install system; whereas the system in California, where the visibility was better, was tailored around the use and was designed to be supported by this ROV, this first ROV called Mobot. So, they were functionally doing the same thing, except they ended up looking quite a bit different. So, both of these teams, you know, were successful in developing this equipment, and they were successfully applied, and then, about 1964, it was decided that Shell couldn't continue with the luxury of having two teams each working on their own separate system, so they decided to mesh them, pull them together. So, there was a new group formed on the West Coast called the Marine Technology Group, and it was headed up by Ron Geer. And many of the members of the MO team and the RUDAC team joined this new team called MTG -Marine Technology Group. And the objective of that team was to develop floating drilling and subsea technology that could be used in up to 1000 feet of water, which was maybe 500, 600 feet deeper than what was perceived to be the objective of the MO system and the RUDAC system. So, this team went to work and designed a new system, and it was a system that had some of the elements of both the MO system and the RUDAC system, but I would say it had probably more elements of the RUDAC system in that it was a guy line system. It had a lot of the same wellhead casing hanger, blowout preventer concepts that were used in the RUDAC system. Some of the same marine riser systems that were used in the MO system were used in this MTG system. And so, that effort went on for maybe four years, three or four years, and out of that effort came a system that we could drill wells in deepwater, and we did drill wells up off the Oregon, Washington, northern California -- that program was still underway and in fact, while the drilling campaign up in the Pacific Northwest was underway, we changed out the MO system with the MTG system. And some of my work in that effort was to convert the rig so that it could be used with this new MTG system. And then I worked as a rig engineer to support drilling operations for several years off of the West Coast.

There was also a subsea tree that was developed and a flow line connection system that was based on this Marine Technology Group effort, and it was applied in the Gulf of Mexico. There was a test completion made in South Marsh Island, I think it was 73 field, in relatively shallow water -- probably in 120-130 feet of water. And with that system, a well was drilled, a well was completed, a Christmas tree was installed, flow lines were installed, and the well was produced for a period of time. Another facet of the RUDAC system and the MTG system was called TFL system, which is through-the-flow-line maintenance techniques. And what that meant was that things that are normally done with water line on a land well were to be done by pumping tools through the flow lines, from the host facility, to the underwater well, and then down into the tubing string, down to the formation. And it was thought that TFL methods, you know, would greatly reduce the need to vertically access the well with the maintenance vehicle. At that time, the skills in the industry to make good sound gravel packs and reliable completions had not evolved like they are now. The materials weren't as good. Some of the techniques weren't as good. So, wells, especially in the Gulf of Mexico, required a lot of maintenance. Oftentimes, every year or six months, you would have to go into a well and scrape paraffin or perhaps change out gas leak fouls or do work like that. The thought was in the design requirement of these TFL systems was that you could insert these tools in at the flow line, at the host facility, and pump them down in the well, down the flow lines into the well. And they worked. There was a lot of effort put into that. It turns out that it costs a lot to do that. You had to spend extra money for the tree, you had to spend extra money for the flow lines, you had to spend extra money for the completion to put in the tubing string. And so, over time, TFL systems have pretty much disappeared. There are still a few people that still look at them. I think maybe perhaps some people are still doing some work on them. But it has turned out now that subsea wells need less maintenance than was originally thought because of improved completion techniques, plus there are new ways and better ways to do vertical access. Now, there is dynamic positioning equipment and better rigs to vertically access subsea wells.

One of the things I failed to mention, another big part of the MO system that was developed on the West Coast was dynamic positioning. It was the first application of automatic dynamic positioning, where the control system was able to determine where the vessel was and where it needed to be, and send commands to the thrusters to hold the vessel in place. And so, the Marine Division and, in particular, Howard Shatto, did a lot of the pioneering work in automatic positioning system, and it was installed on a vessel called *Eureka*, which was a core vessel, and it was used up and down the West Coast to drill shallow cores for exploration data.

JP: About what years would that have been?

BP: That was in 1962, 1963, 1964, and 1965 - in that range. And that technology now is used around the world. And that was when it was first spawned and applied. So, that was another significant development that came out of the Pacific Coast MO system.

JP: You later moved on to work on well system designs that were TLPs?

BP: Yes, what happened . . . Shell continued to develop their skills and expanded their need for use of floating drilling both in the Gulf of Mexico, but then it started to move out from there around the world. And in the early 1970s, there were efforts by Shell and other oil operators to start exploring in the North Sea and Brazil, off Africa and other places around the world. So, some of the equipment that was developed in these Shell programs, and there were other programs by Exxon and Standard of Cal, which was a forerunner of Chevron, to develop this equipment also. But this equipment was then expanded around the world and, there was a real acceleration in activity including drilling. It really opened up a lot of areas now to exploration and, in particular, the North Sea. And a lot of the rigs and equipment were built and tailored for exploring and drilling in the North Sea. It used a lot of the systems that were then being sold by Cameron and Regan and Hydro and other core manufacturers for use in those programs.

So that really spawned and stimulated a lot of additional development in floating drilling techniques. And that went on through the 1970s. And then, in the early 1980s, there was a move to reach out further, to drill deeper. And in the 1970s, deepwater was thought to be one thousand feet of water. In the latter 1970s-early 1980s, we were talking about one thousand meters or 3000 feet of water. And so, most oil companies and contractors were doing studies to look at floating drilling methods and how they could be applied in deeper water. And so, new riser systems, ROVs -- remote operating vehicles, wellhead equipment, new equipment was evolved and developed to reach further and go to 1000 meters.

Shell did some studies to see really how deep in water they wanted to go in to, and they decided that they thought they could go in to 5,000, 6,000, 7,000 feet of water, and the purpose of those studies was to assess whether or not we could compete for some leases off the East Coast. This was in the Wilmington Canyon area off the East Coast, the central East Coast. And so, these studies told the people who were working on it that we had the basic technology to do it. It was more a matter of, did we want to take on the expenditure level it was going to take to do this, and whether or not we were going to take on the risk and apply the resources to do it. And so, Shell has always had a lot of confidence in their technology, and they are managers who supported going forward, and made recommendations that we could compete for these leases. So, we bought these leases off the East Coast, and that initiated a deepwater program using a dynamic positioned vessel, *Discovery Seven Seas*. And that was during the early 1980s. There were several wells drilled in the water depth from 5,000 to 7,000 feet of water. It was a rank wildcat area. Nobody had drilled in that particular region before, in that depth of water, and we didn't find anything to commercially develop at that time, but what happened was that Shell got the confidence that we could drill in that depth of water. And so, the next step then was to apply that confidence in the Gulf of Mexico. In about 1984-1985, there was a large lease sale in the Gulf of Mexico, where Shell acquired a large block of deepwater acreage, several - maybe 100 blocks, in deep water. I don't know really know how many. I would have to check that. But it was bunch. And so, Shell brought the *Seven Seas* down there, and we had also contracted for a new rig called *Zane Barnes* from Reading Bates. We started drilling some of these deepwater prospects. The first one was "Popeye," and it was thought to be one of the better prospects, and it turned out that we found oil and gas, but it wasn't as good as we had hoped. We also discovered "Powell," which was a gas field that ultimately became "Ram Powell." It is being developed now in the Gulf of Mexico. And then, we discovered "Auger" and then "Mars" from this group of deepwater leases we acquired in the mid-1980s.

So, the point I want to make is that even though the deep drilling effort off the East Coast was unsuccessful, it really was a major stepping stone for Shell to go into the deepwater, into the Gulf of Mexico, that led to some of the major developments that Shell has developed that are in operation at this time.

The next challenge was how were we going to develop these fields. We were finding these fields were a long distance from a delivery point in deepwater. So, there was a group set up within Shell during the early 1980s to investigate optional development systems, and when I say a development system, this is the total package -- the drilling, completion and production system that could be installed in deepwater in a remote location. There was a team established in Houston under the direction of Carl Wickizer; we studied floating production systems, tanker-based systems, we studied TLPs, and we studied fully remote subsea systems. And it was decided that Shell should pursue [the] TLP effort. It looked like it was the best choice for us to apply resources onto TLPs at that time. And so, there was a new team established and several people brought in to work on TLPs in, it might have been 1984, 1985, 1986, in that time period. And so, I joined one of those teams working on TLP well systems. And we did different kinds of feasibility studies, and our efforts, it turned out, were very closely aligned to the floating, drilling, and subsea efforts that we had done before. We were only applying them in a little different fashion. So, some of the same techniques for working in deepwater drilling wells were applicable to use on a TLP. So, it was a marriage, so to speak, of floating drilling methods with civil engineering solutions, floating structures and, in particular, this case with TLP. At that time, I look back, and we were really very green in our ideas of what we could do, and what we couldn't do, and we took some significant risks, and our company really had a lot of confidence in the technical people that were working on the project. Fortunately, it all turned out successfully on our first project, which was "Auger." So, we went from a feasibility study into a design phase, and then into a build phase in a fairly rapid fashion. And different from lots of companies, Shell pretty much designed "Auger" in-house. We used lots of contractors but we had our own civil engineering team and we had a lot of folks who worked on the well systems and on the topside facilities. So, rather than going to a general contractor to help us build this deepwater facility, we pretty much did it ourselves. And it was a real challenge for our group, it was a real learning experience, and I think most of us who worked on it really felt lucky to have had the chance to work on such a significant project. I felt extremely lucky to work on it because, having worked in the area that I had in the MO system on the West Coast and working in subsea completions before, I felt that I was able to apply some of my experiences very well on "Auger", and that it was a meaningful project for Shell in order to viably produce our deepwater prospects. From there, our next TLP was "Mars," which was a refinement of "Auger". There were certainly some changes made from the "Auger" system. There were some improvements that saved costs in "Mars". And then we went into . . .

[PAUSE]

JP: This is really useful for me, the technology, but also the Shell stuff. You are really organizing a lot of material. At the time, you don't think of it as talking because it is your life you are talking about . . . Your life organized a lot of material for Shell. And if you start with that MO system and come to TLPs. "Auger" is the one that turns out to be so much better field than you thought it was.

BP: Yes.

JP: And so, it gets kind of euphoric for a moment!

BP: Well, another thing I didn't bring out was that in the Gulf of Mexico, most of our deepwater effort was focused on wells that only had the capacity of two or three thousand barrels a day. I mean, that was a good well. And so, "Auger", we originally designed it for 40 slots.

JP: That is interesting. It really gets you excited about deepwater if the first one is so successful.

[PAUSE]

We were talking about the design of "Auger", and particularly from the capacity of the wells and your expectations, "Auger" turns out to far exceed your expectations, does it not?

BP: Yes. We originally laid out "Auger" for 40 well slots. At that time, we thought that a two or three thousand barrel a day well in the Gulf of Mexico was a good well. And this was based on production history to that time. Good fields in the Gulf had wells of that capacity. Well, it turned out when we moved out in the deepwater, we were moving into a new province that had turbidite reservoirs. A little different character than some of the other reservoirs that were in shallower water. And there was a lot of concern about the ability to produce those at modest rates, let alone at high rates. So, Shell, in their planning, in terms of economic planning for prospects, was assuming that we were going to have to have lots of wells. For example, "Auger" was designed for a peak oil capacity of 45,000 barrels a day, initially, with 40 well slots. It was later changed to 32 well slots. Well, to do that required lots of drilling, lots of time, a lot of money spent on wells. And it was obvious . . . we were aware of this years ago, it just wasn't thought to be possible that we could actually produce wells at higher rates in the Gulf of Mexico. In the North Sea, you know, wells, 20,000-30,000 barrel-a-day wells, were common. So, I think it was a mindset thing, you know, and there were a lot of technical reasons as well, but it was just trying to refocus on our completion technology and the sizes of our equipment to see if we could produce these turbidite reservoirs harder and get more out of them from fewer drainage points.

It turned out that that was a major factor in the success of these deepwater developments. "Auger", I am not sure what it is producing now, but it produced over 100,000 barrels a day, and 300,000,000 cubic feet of gas from perhaps 14 or 15 wells. So, the wells were a lot more prolific and, therefore, the economics of that particular development were a lot more favorable for Shell. And this also reflected into the future projects like "Mars" and "Ram Powell" and "Ursa." One of the last projects I worked on was "Ursa" and there, you know, they anticipate they are going to have some wells, perhaps 30,000, 40,000, perhaps 50,000 barrel a day wells. And so, it was a major part of the success of the deepwater program in the Gulf of Mexico, was the ability to get more out of each well, increase the capacity per drainage point.

JP: This really changes the whole horizon of thinking, like a Middle Eastern development.

BP: That is right. And, in a lot of ways, you know, the North Sea was showing us the way. I mean, we should have seen it. I actually worked on a project in the North Sea. I went to the UK and worked several years on the UMC project. It was an underwater manifold project there. And it was a joint project with Shell and Exxon. And it was based on wells that were 10,000-15,000 barrels a day. Some of them didn't quite achieve . . . some of them made more. But, you know, they were really leading the way in prolific offshore wells.

JP: Were you working with the group? Transferred? Borrowed?

BP: Well, what happened, in the mid 1970s, the effort in the Gulf of Mexico really went flat. Oil prices were down. There was very little interest to spend more money on technology. We had drilling systems that would satisfy the needs to explore the leases that we had at that time. Shell and other companies decided it wasn't a good time to invest in new technology for the Gulf of Mexico, so several of us who were working on subsea projects there were reassigned to the North Sea. And I was one of them from Shell, and it was fortunate for me because I was able to go work in London for Shell Expro. Shell Expro was the operating company for Shell in the UK, and Expro is Esso and Shell. It is a joint project. So, it was interesting . . . the Exxon people, people who I worked with as competitors in the Gulf of Mexico, we were working on a single team in England on the UMC project.

JP: This was Royal Dutch . . .

<u>End of Side A</u>

<u>Side B</u>

BP: . . . connected to the group company.

JP: Was that much different from a Shell USA perspective?

BP: Yes, it was a lot different.

JP: And how so?

BP: Well, there were several things different for me. One, working there, it was a lot larger structured organization. At that time, the North Sea was at its peak in development . . . building lots of offshore installations, spending a lot of money. And so, it was an execution effort. And a lot of it was to execute in association with established contractors. So, a lot of companies, you know, would have a development, and then they would go out to different contractors and help them build a system to develop the project, field . . .

JP: Project management.

BP: Yes. And, in a way, that is what was done, to some respect, in the UMC project. They had a large team that consisted of Shell and Exxon people working together, and the concept that they used was a large underwater manifold that was very similar to a system that was developed by Exxon and field-tested in the Gulf of Mexico called the SPS. And the SPS was really Exxon's . . . at that time, it was Humble . . . their prototype development system for multiple wells set up on a template. And they spent a lot of money and did a lot of good work on the SPS system, and it was installed in the Grand Isle area in several hundred feet of water. But it never operated very long. It was pretty much a technical success, but it was an economic failure, really, in terms of making money for Exxon. They were able to prove out a lot of technology that was later used on the UMC and is used on a lot of manifolds and templates around the world now.

I felt real fortunate to be able to go work on that team, but it was different for me because we had very small teams here, and we tended to split up the work among fewer people, and it was easier for me to work subsea projects here in the climate that I was . . . I say, the climate, the working climate that I was used to, than it was in the North Sea. It took me almost a couple of years before I really got in the swing of it, of working over there. But I have to say it was very challenging work, and it was very interesting work, and there was a lot of good technology that was developed and successfully applied there.

The UMC project was a success economically. It was in about 500 feet of water. There were five or six wells on a template, and then there were some satellite wells that were linked into this template. And it was designed around use of an underwater manipulator, as well. And this manipulator would land on this template, and it could go to different stations or remove modules and valve inserts and various components and bring them to the surface. So, it was a deepwater system designed to be installed in one thousand feet of water, below diver's limit. And, you know, it was a major milestone for the industry to do that work. It turned out that later, you know, the subsea technology evolved a little bit differently in that most manifolds now do not have the wells on the manifolds. They are more modular. So that the manifold is a module, and then the wells are spaced around the manifold, and linked up to the manifold with pipelines, control cables and umbilicals. So, some of the work that was done at that time using equipment from the UMC, you know, is not used right now. There was a TFL systems well where you pumped TFL tools down through the pipelines, and that is no longer used. So, even though there was a lot of progress made, you know, the technology was moving towards simplification. These simplifications made the equipment more reliable and also helped to reduce the cost.

JP: I am going to let you go to the function, and in conclusion, I want to give you a chance to say anything you want to say, but I am also asking the question, from your point of view, what made Shell USA distinct? With so much coming out of one company . . . why?

BP: Well, I think it was basically the attitude of our management. You know, they always had a lot of confidence in our technical people and, to a large extent, our managers were technical people. And so, from that confidence, they took the lead to obtain the leases which then gave us the opportunity to practice our technology developments. And, you know, right from the very start, from the MO system to the RUDAC system, that attitude prevailed. And it really turned out to be a positive thing for the people like myself who worked on it because we felt that we had the support of our management to move into areas that we felt that we could get an advantage on our competition. And so, if we had some technical leads, most likely, our management would support us to pursue them. We also did a lot of development work, and that is just an attitude of investing in R&D. So, investing in R&D, you know, ultimately paid off in our ability to utilize developments that came from this basic research. It also . . . a company can have the technology, but they also have to have the grassroots confidence that they can use it. And that goes right down to the operators that operate the equipment, to the rig people that install it. And I think that we have always had that in Shell. And we see that in our TLPs, where we have, to a large extent, our own people that are operating these. So, we have a kind of grassroots understanding of what goes into it and what it takes to run it. We have our own civil engineers who, you know, design the equipment, and I think that approach was unique. Not many other companies . . . you had to be a fairly large oil company to be able to do that, you know, especially to carry it through some of the lean years, and Shell was able to do that. And then, I think, you know, they attracted a lot of good people.

There were a lot of good engineers and managers that worked in our deepwater programs, our offshore programs, and you know, having good people, having confidence in them, and then having a management who was willing to take the risk to acquire opportunities to apply it was a pretty powerful combination that Shell was able to capitalize on.

JP: This is a good place to stop unless you have something to add for posterity!

THE END