BOEM DEEPWATER GULF OF MEXICO HISTORY PROJECT

Interviewee: Depp Cheramie

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Place: Chauvin, Louisiana

Interviewer: Jason Theriot

Ethnographic preface: Depp Cheramie went to work for Texaco in his native Louisiana in 1971, when he was 19 years old. After a decade with the firm, Cheramie moved on to Shell Oil in 1982, working as a senior operator on an offshore platform located in Eugene Island. After focusing on training in electronics, Cheramie was tapped to work on the landmark Auger tension-leg platform (TLP) project in 1992. In 1999, he was transferred to work on Shell's Ursa TLP, sometimes known as "Auger's big sister." By 2005, Cheramie moved to work with Shell's gas pipeline business, and stayed with it after Enbridge acquired the group from Shell. There, his portfolio included overseeing the commissioning of the 120-mile offshore Nautilus pipeline.

JT: This is an interview with Depp Cheramie for the MMS Deepwater History Project. We are in Chauvin, Louisiana, on July 22, 2009. I'm Jason Theriot. I'm talking with Depp about his experience.

Depp, tell me about where you're from, your educational background and then take us into 1971 as you were there when the geography began changing, and something on your experience with Texaco.

DC: I'm originally from Houma, Louisiana. I married a wonderful girl here in Chauvin in 1971. I graduated from South Thibodaux High School here in Houma, Louisiana. I went to Nicholls State University on a music scholarship. I was there for two years, and then I went to work for Texaco.

I went to work for Texaco in 1971. I was nineteen years old. Back then you started out in the kitchen if you weren't twenty-one years old. Texaco had their own kitchen forces, they were Texaco employees. You started out as a galley hand, washing dishes, serving the folks.

The geography was a lot different back then. You had to leave Cocodrie in a crew boat and you had anywhere from a forty-five-minute to an hour boat ride. It was strictly in the canals. If you wavered out of a canal, you went aground, because it was all land-based. The canals had to be dug everywhere to get from Point A to Point B.

Lake Pelto was a very small lake back then, and the camps were actually land-based. Back in 1971, Wine Island Pass was 100 yards wide, with land on both sides. It looked mostly like a large canal. Whiskey Pass was maybe 50 yards wide. The land protruded pretty far out. You had to get to those camps and places where their personnel were housed by boat on Bay St. Elaine, Dog Lake, and places like those, and you had to stay in the canal. Now, in 2009, there aren't that many canals. Everything is wide open to the Gulf of Mexico. Wine Island Pass is history. There's not only no pass, there's no sides either. The Timbalier island group is pretty much diminished, although it's being built up again now.

I started out with Texaco in the kitchen back in 1971. I worked in all of their major fields inshore, which we called shallow water back then; it was ten to twenty feet. All the wells back then were drilled straight down. In other words, wherever you had a well, you had a rig. Today it's a lot different. It's all directional drilled, subsea. You can't really tell where a well is.

I worked for Texaco for ten years, till 1981. Texaco as a company was on their way out instead of on their way in. I was a production operator for Texaco after I made twenty-one, and worked in all the fields and the inland fields for Texaco as an operator, a compressor operator, and a production operator. Back then they called them pumpers. Then in 1982 I went to work for Shell offshore as a senior operator. Texaco was the main oil company in this region and they were low-tech compared to Shell. I left Texaco in 1981 and went into a family crew boat business just before the crash of the oilfields in '82. I hired on with Shell as a senior operator and I went to a platform called Eugene Island 259C, which was back then in about 200-foot water.

JT: I was there not too long ago for the Fourth of July weekend.

DC: Oh, really? So that was my start at Shell. The big difference between Texaco and Shell was that Shell had a large teaching history. What I mean by teaching history is that they wanted employees to learn different crafts, different skills, so they developed their own training schools. Texaco was on-the-job training, learning from somebody else who probably didn't want to show you because they were afraid you were going to take their job. Shell, on the other hand, had classroom studies, correspondence books, et cetera. So it was still up to you to have the motivation to learn, but you could go as far as you wanted to. You could get into the technical ranks and become a certified electrician, become a certified instrumentation specialist, mechanic, of course, production operator, things like that.

JT: So what exactly does a production operator do?

DC: If you were a production operator inshore, which they call them a pumper or an operator, you went from location to location by boat, and your wells were scattered individually in the shallow water lakes. It was your job to take pressure readings, temperature readings, and samples of the liquids, make sure that gas measurement was taking place, and you would change charts for accuracy of gas measurements for all the areas of production.

Then, of course, you maintained all of the safety and environmental requirements. Now, back then, in the seventies, safeties weren't a big thing, neither for employees nor for companies. MMS probably don't want to hear it, but when I first started we brought in a well into the Gulf of Mexico until it made such a bad slick, then we started putting it in the flow line, because these wells, when they first come up, are full of water. So we got rid of the water into the Gulf of Mexico and then put it in the line.

But the difference from inshore to offshore was when I went offshore, everything was contained, sealed on the offshore platforms. You had 32 wells on one platform, instead of 160 wells scattered miles apart. So it was a lot more complex to see the difference for an operator offshore. The reason being was that you not only had to do the production work, take temperatures, pressures, test the wells for their performance, see how much they were making. Then you had the maintenance of the platform, which the operators did themselves; a little chipping, painting, just keeping things clean. They also had to take care of the safeties. There was a lot more safeties like pressure safety highs. Anything for overpressure, they had protection; anything for underpressure, which might be a leak, level safety highs, all sorts of protective equipment to make sure that you not only protected your personnel, but you also protected the environment.

JT: So you were essentially the supervisor or the manager of that particular facility.

DC: No. The operator was the worker bee of that facility.

JT: The foreman.

DC: The foreman was in charge of the overall facility. They either called them an operations foreman or a production foreman, depending on which company you worked for.

But Shell had a lot more training; it was a lot more technical because they had a lot more safety equipment. That's my first work with them and that's because the MMS was governing all of those issues of protection of the environment and protection of personnel.

The best way I could describe when I started with Shell is that it was before computers. We used a lot of carbon paper and adding machines, everything was done by hand. We gradually started incorporating computers in the accounting of oil and gas. Then computers started playing a later role probably in the late eighties, of being able to provide control and protection. Before that, it was all pneumatic; it was all manual, spring-operated. Then we started getting into electronics in the nineties.

I could see the future, so I started spending 90 percent of my time training in electronics and became a senior technician for Shell, and that's how I got to be on Auger. I was part of the original Auger operations personnel. I started on Auger in 1992, during the conception phase.

JT: Here in New Orleans?

DC: Right, in New Orleans. I left the offshore platforms, went to One Shell Square, and started working directly with the engineers in developing the new never-before-seen equipment that Auger was all about. Auger being the first TLP in the Gulf of Mexico.

JT: Were you a part of a team?

DC: Yes, a team.

JT: What was your team?

DC: It was the Auger Production Team. The Auger team actually was made up of three teams. I was part of the process team or production team. They had a utilities team, which took care of utilities like water, generation of power, all of the compressors, the heavy mechanical, the heavy electrical. Then they had the logistics group, which took care of all the logistics support like transportation, drilling operations and work over operations and, of course, the catering and that kind of stuff.

JT: Were you in the process team?

DC: I was on the process team, which is the production team. The production team took care of everything to do with well production, of both oil and gas and pipelines leaving there. Auger was the first of its kind in that there was not a go-by thing in the Gulf of Mexico. The exciting part for me was that I was getting to work on something that had never been done before, including the equipment. They had stuff like riser tensioners that were used to put tension on the production risers coming up individually. The Shell engineering group had to figure out how to do all that. I, as a part of this team, had to help engineering develop how we were going to operate them. It was very interesting going from theory to reality. We got a chance to get in on some one-of-a-kind things, getting a signoff on patents, and things like that.

Before that, operation was done differently. It was never done in a team setting; it was always in a hierarchical setting, you had a supervisor and he told you what to do. It was different now with this team setting. The supervisor was still one major part of the team, but he wasn't in a telling mode; he was in a supporting mode. They assembled experts in their areas—whether it be a production operator, myself, electronic technician—to be part of a group, to work as a team on a particular process.

JT: Do you think this was the first time that that kind of team concept was used?

DC: In offshore production, yeah. Shell was the first one to utilize this much of a team-based system. It was so new that Shell had to develop a new pay system to accommodate that.

JT: I wasn't aware that Auger was really the first of that team kind of concept. I knew Shell was kind of a pioneer in that, but it would be interesting to know the fellow or the group of people who came up with this team concept.

DC: Well, I was part of that design team.

JT: Really?

DC: Yeah. A manager had the vision of this team concept. He's no longer with Shell, he's retired. His name is Rich Pattarozzi. They also hired a high-dollar consultant to help him develop that team concept.

At the time we were paid conventionally. In other words, there were two pay levels for a certain type of work, but there was no incentive for performance. Longevity could give you top pay, not necessarily performance. At that time, Mr.

Pattarozzi was looking for something different; he was looking to pay for performance, he was looking to give some incentive. What would be an incentive for somebody to do more, just besides money?

JT: This is going beyond.

DC: Oh yeah. And then it was a whole new concept. Shell put 1.7 billion dollars into Auger to build it. Everybody thought they were crazy. The unique thing about Auger was this: it was designed for 50,000 barrels of oil a day and 165 million cubic feet of gas. That's what it was designed for. If it would have come in at only that, it would have been a tremendous failure. But it eventually became the biggest producing giant of its time. When I left Auger in 1998, '99, it was producing 165,000 barrels a day and close to 400 million cubic feet of gas. So it was an exciting change.

There are so many things I could talk about the excitement of it, but it was unique in the fact that it was floating, that it was constantly moving. It's still unique today in that it's the only TLP in Shell's inventory that has a lateral mooring system. What that means is that there are eight sets of anchors that are set up miles away from Auger, and there's a system of winches inside there, and instead of the rig on the platform moving on top of the deck like every other TLP, the rig is permanently stationary, welded to the deck, and the whole platform moves over the well. It moves in a 280-foot oval.

Now, what that means when you're looking at the physicals of it, let's say this is a riser and this is a riser, and I want to go this way. Well, when I go this way, these things bend and they have to stretch a little bit to go this way. If I come this way, if I come this way, they're always moving. The engineering feat to me is that they never touch. They've never had a riser strike each other, and they're very close, very close. But those are some of the unique things. There's a 150-foot moon pool, a big hole in the middle of Auger that you can see. These are the iterations of Shell.

JT: Tell me about the first time that you heard about this project and then, lo and behold, you're going to be a part of it.

DC: Well, I heard about it in 1990 for the first time. The way I heard about it was my production foreman whom I was working for at the time had been picked to go on it as a process team leader.

JT: What was his name?

DC: His name was James Burt; [phonetic] he was one of the older production foremans in Shell's onshore-offshore inventory. He was brought in for his experience and he was one of them that picked the process team, that's how I got involved. I had to interview, though. You had a ten-man panel that I had to interview for that position, so he couldn't just say, "I want him," and it happened.

JT: Was that was part of Pattarozzi's team process?

DC: Yes, that was part of the new team process. Before that, a production foreman would say, "Man, I want him," and that's it. Nobody else said anything. If you pleased him, that's where the terms came, "sucking up," all of those things. Well, in this environment, it didn't work that way. The team concept was awesome. I'd always been told my whole career that, "You will never change anything. Just shut up and do your work." Well, the team concept was completely different. They wanted to hear what you thought, what you had to say was important, and the team made decision on what was going to happen, not the supervisor.

JT: Really. How many team members, and do you remember their names, if there wasn't too many?

DC: It was a lot.

JT: For your process.

DC: The process group was a lot. You've got to understand; it was four crews of a dozen people, so the process team might have been seventy people. The process team was made up of four different fourteen-and-fourteen crews. That was another change for us. We had always worked seven-and-seven. Now we were going to work fourteen-and-fourteen. There's a big difference between seven-and-seven and fourteen-and-fourteen. The fourteen days off are wonderful. The fourteen days on are a lot harder. Back then it wasn't unusual for us to put in eighteen-, twenty-hour days. You do that for eleven days straight, you're worn out.

JT: You don't have that seventh and eighth day to sleep in.

DC: Yeah. Every seven days you get a break and you get a chance to take care of family stuff and things like that, but now when you got to seven days, you had to tell your wife, "You've got another seven days to stay without that air conditioner," or whatever, "until I get home." So, yeah, it's a big difference there.

But the team concept was great for me, because you've got to understand where I came from. I came from Texaco, who would not let personnel talk to each other during the work hours about anything other than work, "Hand me this wrench. We're going to turn the L this way." If you talked about something else, you was chastised, even docked. It was a different time.

[interruption]

DC: The culture was so drastically different. When I first went to Shell, before the team concept, it was similar. The supervisor ruled the roost and it was similar to Texaco, but not to the degree that you couldn't talk to each other. Then when they came up with the team concept, that's probably more than anything else that prompted me to want to get involved with them, because they were talking about stuff like input, participation, stand up, be accountable, be responsible. Those are all terms that I was hot and heavy about, because before that, like I said, there were no performance issues. If you were the best performer in there, what they did was that they gave you more to do. The least performer, they took care of him because it was more trouble to deal with a bad performer than it was the guy giving 110 percent.

So this concept really intrigued me. I got involved early on, I was fortunate enough to be picked. Then I immediately went from coveralls to a white shirt and a tie, and that was a big difference. It also was a big difference going from the fields to working in downtown New Orleans, a big city.

JT: Did you have to move the family, or did you all stayed here?

DC: No. The family stayed here; they put you up in an apartment. It was a forty-five-minute drive, but I didn't have to commute. I could stay there, I had an apartment. It was very, very exciting.

The unique thing about Auger is that it was modular by design. What I mean is that everything that went on the decks was built across the country, not in one location. That was a big difference. They put it all together in one location, which was the McDermott's yard in Amelia, but the parts were built all over the place. We had the opportunity to travel the country to be involved in the building of the modules that I was assigned; I got a chance to work with different engineering groups, which is something we never did before. Back then I was what they called an automatic control repairman, which is the technician who takes care of all the safety equipment for the MMS. I did all MMS testing.

JT: Is that what you did on Auger?

DC: That's what I did on Shell, at the end, before I went to Auger. I was required and responsible for doing all the MMS testing for the process team on Auger. That was too much for one man; there were over 4,000 individual elements that needed to be tested. This wasn't for one team, this was overall. Of the 4,000, the process team probably had 2,800 of those types of things to check; levels, pressures, temperatures, whatever the case may be.

This should be interesting to MMS. As part of a group, I led the development of a team called the Regulatory Compliance Workgroup, which consisted of people interested and was also responsible to do all the testing for MMS. What it did was that it took the burden off of one or two or three people and spread it over a larger group. We were trained, we all became T2-qualified, and we did the testing.

JT: I'm sure it was more intense during the early phase of it, but then it was probably jut regular maintenance testing over the years.

DC: Well, it was overwhelming in the beginning because there was a lot of stuff we hadn't seen in that particular use.

JT: Can you give me one or two examples?

DC: There was the abundance of electronic over pneumatic. Usually either you had all pneumatic and a little bit electronic, or all electronic and a little bit pneumatic, but this was unbelievable. And every different had different products. You not only had a Rosemount pressure transmitter; you had a Yokogawa pressure transmitter, you had a Ruco pneumatic pilot. MMS would be familiar with all these terms, but these are common manufacturers of overpressure, over-temp, underpressure, under-temp, high-level, low-level. I mean, you had every kind of component that you could think of.

And then all of this was computer-driven. To give you an overwhelming idea of the enormity of it; normally on a platform you have one or two programmable logic controllers called PLCs. Well, Auger had forty-one, and each one is a tremendous programming problem. It was a lot of new stuff for me to learn, so I was on the job training, going to school training, working with engineers, learning new concepts, learning new theories, and all of this in a performance setting. And you could work all you wanted, you could make all the overtime you wanted.

JT: Sounds like you had a lot of manuals.

DC: Oh, man, I wrote some. That's the other thing, too. You had a chance to write operational procedures, because there were none. I was talking to you about these riser tensioners. Well, we had to have some maintenance strategy on how to maintain them the riser tensioners and then on how to operate them. There was no book to go to, there was no manufacturer to go to; it was the engineer's concept of this particular tensioner and operators like myself had to come up with a way to do it.

JT: Can you give me a visual of it?

DC: Let me see if I can give you a picture of one. Let's say you had a riser. This is a production riser. Here's the ground, here's the water, here's the TLP.

[interruption]

JT: So the riser tensioner is what attaches to the platform.

DC: Yeah, I'm going to show you. This is fixed. There was a clamp that fits around this thing that was supported by this cylinder. This was made up of rubber and high-pressure nitrogen, so it had some cavities. Let's say this was a cavity and this was a cavity [drawing schematic on paper]. You would pressure-up in this cavity, along with this rubber, to help put tension. Now, this is anchored at the sea floor. This is not the bottom of the well. This is just the sea floor. The bottom of the well is another 20,000 feet below this. This is about 4,000 feet, 3,000 feet for Auger. So this riser tensioner would support this well. Then on top of this is where you had your safety valve and what they called a Christmas tree, your different valves like that. Then your flow line came off of here and went into the production separators here.

So we had to write how much pressure to put on that based on engineering's theory, to figure out what we needed and come up with a procedure not only to operate—and it had three of these per well.

JT: Three per well and it had thirty-some-odd wells? How big was this cylinder?

DC: Just a little bit smaller than this table. Everything was humongous, it's just enormous.

JT: What was the purpose of that piece of equipment?

DC: The purpose of this is that if they didn't keep tension on this pipe, then it would flex and move a lot. It looks worse than what you can possibly conceive and then you're going to say, how in the hell did they never hit? The next one was right next to it.

JT: It's to keep them from hitting?

DC: Well, it's part of the stabilization system. They had each one of these. There are four columns; they're 180 foot in diameter. Each column is 180 foot in diameter; each one is independent of the other. In other words, they have all the same equipment. If this one goes out, this one can pump this one out. If that one goes out, this one can pump this one out. They're connected below the surface approximately 60 feet by a square walkway. Now, this is 300 by 300 by 300 by 300. The scariest thing you have to do is to go into this walkway here and walk all the way across here, because you have to secure this watertight door.

JT: Go under the sea floor? I mean, when it's under water? You can walk from here to here under water?

DC: Not under water. You're inside of a cylinder. It's approximately, maybe 15-foot circle. But on the outside, when you look at it, it's square. So there's a circle inside of a square.

JT: And it has compartments where you can walk through that circle?

DC: There's a door here, and you can walk from here to here, from here to here and from here to here, sixty feet below the surface.

JT: Did you ever have to do that?

DC: Oh yeah. It gets worse.

JT: Offshore?

DC: That's what I'm saying. Actually, that was just part of the deal. We had to make an inspection. So part of the security is that you have to close this watertight door when you got in, so now you got two watertight doors closed. You no longer have any communication, so if something happens between there and there, you're out of luck. Then you get into here, you get communications again. These things are like 100, 120 feet tall. They're big enough inside that you have a half a basketball court. We put half a basketball court in one side of these columns. Now it sounds like, man those guys have it made. Well, these things rock so much that you shoot the basketball here and the goal ends up over there, but the ball's still right there. It would sway that much. The water would splash in the tall ends in rough seas. I spent two hurricanes out there.

JT: Which ones?

DC: I'm trying to think.

JT: You had Andrew that came through in '93.

DC: No, we were not out there yet for Andrew. That's right. We got out in '94.

JT: How would you get out there, helicopter?

DC: A big helicopter. It took an hour-and-a-half helicopter ride. You would ride fifteen people on board. We called it a Sweet Sixteen. Eventually we got the helicopters to handle sixteen personnel plus two pilots, so it was eighteen. During a hurricane in the Gulf of Mexico, they'd evacuate all non-essential personnel and we could operate that platform with sixteen people. Now, that's main. That's not maintenance; that's just keeping everything flowing. As long as the downstream pipelines were open, so we cut down the criticality. If the hurricane got too close, we'd shut in—

JT: And fly back.

DC: We could put everybody on one helicopter and the helicopter stayed on the deck, so that was pretty neat.

JT: I interviewed Elmo Hubble from the MMS, who was district superintendent of that region. He was telling me that one of the big challenges was to be able to get a helicopter big enough, with enough fuel to get out there. You didn't have a need to go that far.

DC: Exactly. When you start talking about an hour-and-a-half helicopter ride, you had to stop halfway and fuel. Shell was really stringent, really safety-conscious about the helicopters, so you had to have two pilots, two sets of controls, two engines, so if one pilot gave out, the other one could still fly. It was pretty safe.

But again, you're talking about a way out there in the middle. I remember the first time the flare went off. When we began production, you started having a little bit of flare, which is gas that was lit to start off with. Airline pilots were calling in saying they had a platform on fire.

JT: Were you involved in any of the onsite construction sites like in Amelia?

DC: Yes.

JT: Did you have to go there?

DC: Yes.

JT: Tell me about working at that facility with other contractors like McDermott.

DC: You've got to understand, it was a new concept. This had never been done before. You had close to five hundred people working on this project. When we first got there, not everybody knew or understood the unsafeness of working on top of other people. In other words, you might have had ten different deck levels of people working, so you had people underneath you and you had people on top of you. They had one fatality during this project, and it changed the way we worked. A welder on a barge that was working inside the moon pool, underneath 100 foot, away from anything, got struck by a piece of PVC pipe. It killed him. After that nobody could work underneath anybody else without a solid deck. That changed some of our work practices.

It was unbelievable. It looked like ants, they had so many people. It was difficult at times because you had to climb twenty flights of stairs to get up to the first deck and then you had another ten decks you had to deal with.

JT: What about dealing with McDermott employees and McDermott management?

DC: I never dealt with McDermott management, but we never started any day without a safety meeting. Everybody was involved in their workgroups. We never had one giant safety meeting, but everybody was involved in their own workgroups. You had simultaneous operations going on, and what I mean by is that you had things like construction along proactive maintenance.

We were taking things apart, inspecting them. We had sandblasting going on so a lot of the safety components would get full of sand and they wouldn't work. So instead of just waiting, we started cleaning all that stuff ahead of time. There was a lot of testing, like of these riser tensioners, the electronics part, because it was all coming into TLCs. So there was a lot of interface work where you might be doing working on a piece of electrical with a welder alongside of you, from McDermott, who you didn't know, who probably didn't even speak English. Those were some exciting times.

JT: What language would he have spoke?

DC: Spanish.

JT: Were they all Mexicans?

DC: Oh yeah. We had Mexican workers everywhere, for sure. Even way back then, McDermott was employing some Spanish people.

JT: What about other contractors, electricians that might come in? I can just only imagine how different contractors must have come into McDermott's yard every day.

DC: Oh, it was unbelievable. The electrical contractor was MMR. And inspectors, you could have had at least 150 to 200 of them inspecting each one of the disciplines; electrical, mechanical, construction, welding, fitting, whatever. You had so many different people. I'm still amazed at the enormity of it and how it all got put together.

Then we were learning how to work as a team. It was very difficult for supervisors to relinquish the, "Go do that" to, "What are you all thinking about doing today?" That was the thing. We were involved in the planning of the work, something that we never were before. Before that, you were involved in the work. Somebody told you what to do, but now you were part of figuring out what to do and when to do it and how to do it. That was very exciting and self-gratifying.

JT: I'm sure you became good friends with those other team members, but did that friendship extend beyond the planning and the working?

DC: You know, where there's hard work, there's hard play too. We lived in and out of hotels, so there was camaraderie in a sense of a team, and they had some competition between groups, too. There were incentives to complete jobs on time or ahead of time, so you got a chance to make a little bit more money and things like that.

Then they had the other facet of it. They called us Augernauts, and Augernauts were looked down upon by the rest of Shell's operations group for a couple of reasons. We got new clothes, new hats, and more money. We had cappuccino machines. Money was no object. We had the best tools. Where on the shelf, the onshore were skimping, trying to pay for all of us, so when we would go to the training center, to Robert Training Center—

JT: In New Orleans?

DC: No, in Robert, Louisiana. It was a tremendous training center where they had just about every major component that we needed to work on there. You had instructors. It was tremendous. Now, Shell had this before Auger.

JT: This is the first time I hear about this place in Robert.

DC: Oh, really? Yeah, that was a tremendous training center. You had probably fifteen full-time instructors. I mean, they had a full working production facility onshore. It didn't have any actual oil or hydrocarbons, but it had all of the components; tanks, pumps, etcetera. Then we had a full-blown T2 training course, which is the MMS required safety training. We had all the stuff we needed to do it, and it was pretty stringent.

JT: Before I get into pipelines, tell me about the days and moments leading up to that first turn on the valve for the first production at Auger. It must have been intense.

DC: It was hectic. It was intense. There was a lot of pressure for us to meet this date because all of this money had been spent and no money had been made. There was a tremendous effort to get the platform ready; safety, safely, everything, to produce that first amount of oil.

When the first well started producing, it was the biggest disappointment. Everybody thought that everything that was said about Auger, how it was going to be a hole in the water to pour money into, was going to happen because the first well came in at 8,000 barrels a day.

JT: Were you on the platform?

DC: Oh yeah. The first three wells came in at around 7,800 barrels. It was like the end of the world.

JT: How long does it take an engineer or geophysicist to realize the rate?

DC: Oh, about twenty-four hours. So within twenty-four hours, he knew he was dead in the water. Now you had this 1.7-billion-dollar facility, you got all of this equipment. It's too big to measure this little bit of production. So we were scrambling as a process team to see what we could modify to be able to accurately measure this small amount of liquids. The head reservoir engineer looked like he was going to be fired.

JT: I bet he wanted to jump overboard.

DC: Nobody would hang around him. It was ugly. But to his credit, he was a very smart guy.

JT: Do you remember who he was?

DC: Yeah, his name is Christopher Smith. He's a big wheel with Shell now, and I'm going to tell you why in a second. To his credit, he came up with a plan to go to pump a certain combination of acids into the well bore to clean out the fraction, fractionation of the pipes where the holes were popped, to allow oil and gas to come in. He felt strongly that the muds that were used to lubricate the drilling process had stopped up those holes in what they call the gravel pack.

He came up with the process and in less than a week those wells turned around from 7,800 barrels to 18,000 barrels a day. So he went from looking for a job to being an asset manager today. He did well. That being said, we had three wells making over 18,000 barrels a day, and 20 million cubic feet of gas. That was unheard of. Up until that time, the biggest well that I have ever been associated with was 5,000 barrels of oil a day and 3 million cubic feet of gas. Now I got 18,000 barrels of oil.

JT: And how much gas again?

DC: Twenty million, 10 million, 13 million, something like that. It was unbelievable. One well, you understand. And now we're dealing with stuff we never had before. To give you an idea, the production tubing, which is the pipe that the actual oil and gas comes through, used to be two and seven-eighths. Well, this was three-inch pipe, four-inch pipe now.

JT: Was that something you had to modify later on?

DC: No, no, that was original, this was all new, nobody had ever done this before. They had spent a million dollars for each well to put a bottom-hole pressure assembly that would constantly test and send the information of the bottom-hole pressure, which was critical to understanding how well a well was doing. Before that, they would have to use wire line, and every time you stick something in a well, you take a chance on junking it up. Well, they spent a million dollars per well just for that one device and none of them lasted more than a year. Then they had to go back with conventional wire-line operations to do bottom-hole pressure testing. Of course they lost quite a few wells. But now you're used to talking about a well that might cost 50 million dollars, where before a well might cost 10 million, 5 million.

JT: And you worked on Auger till '98, '99?

DC: Until 1999, then I went to Ursa. Ursa was Auger's big sister. You've got to understand, with innovation, with highly smart people. On the Auger design team there were four engineers with doctoral degrees. There was a lot of competition between those engineers and the ones who developed Mars and Ram-Powell, so much competition that whatever Auger did, Mars and Ram-Powell was not going to do, no matter what the costs. So of the maybe 200 million dollars of research and development that was done on Auger, none of it was used for Mars or Ram Powell because of the animosity between the engineering groups. Unusual, to say the least. Of course, Mars didn't cost 1.7 billion dollars, either. Well, Ursa was done by the same engineering group as Auger.

JT: So they had improved, they learned from their mistakes.

DC: They learned from that and they that knowledge to make Ursa. Everything on Ursa was one and a half times bigger than Auger but they didn't use the same stuff. We used elastomeric struts; they used a different type of tensioner on Ursa. Auger had a 20,000 barrel a day free-water knockout.

JT: What does that mean?

DC: That means its capacity to handle 20,000 barrels a day; a free-water knockout is a large separator that knocks out free water. In other words, it separates any water that's in the liquids.

JT: Per well?

DC: All the wells go into it at the same time. It's like a bulk separator.

If I was to show you the flow you would see how the wells come out of the ground, through the Christmas tree, and into what they call a high-pressure separator. That's the first separation of liquids and gas. Then it goes to an intermediate-pressure separator, the liquids do. The gas is gone. Now the liquids go in the intermediate-pressure separator. It might be 1,500 pounds on the high-pressure separator. The intermediate-pressure separator might be 800 pounds.

JT: Separating water from the higher—

DC: It's just liquids coming in now, but there's gas entering in the liquids. So when it goes to a lower pressure, poof!, the gas comes out of the liquids. So there's another separation there. That gas goes to a different place because of its lower pressure, it goes to a compressor that pressures it up to pipeline quality or pressure. That liquid from the IP separator goes from there to the free-water knockout. Now, we were just talking about liquids in the other two separators, which is a mixture of water, oil—

JT: Paraffins and all of that.

DC: Whatever, as long as it's a liquid. It gets in the free-water knockout, which is three-phase. The other two are two-phase. The free-water knockout separates water, oil, and gas. The gas goes to another compressor, the water goes to a water purification system, and the liquids go to another vessel called a heater treater, where we put heat along with pressure, but it's substantially less. So you're talking about 1,500 pounds, 800 pounds. Free-water knockout is now 200 pounds. That got a lot of flashing going off. There's a lot of entrained gas in the liquid, so as you drop the pressure, it turns to gas.

Now those 200 pounds go to a vessel that has 30 pounds. That's flashing again, and it's three-phase. If there's any water that's still left in that oil that left the free-water knockout, it gets separated there, and that oil goes to the sales storage tank that's atmospheric. So it goes from 30 pounds to about 15 pounds atmosphere.

JT: Into a pipeline.

DC: Not yet. Gas is still coming out in that storage tank. That gas is sucked out into a vapor recovery unit, which was the biggest vapor recovery unit I've ever seen. It was a DC 1,000-horsepower-driven compressor. Usually we see AC compressors or reciprocal, meaning a gas-driven engine. This was DC, and it could do 5 million a day. That's off of the last part of the oil that went into the tank.

JT: Where was that last part?

DC: Everything is accomplished in here. The problem is that the tank is only 1,000 barrels and you're making 50,000, 65,000. We got up to 165,000 and we only got a 1,000-barrel tank. We're pumping it out of there fast. So if you lose your pumps, you don't have long before your high-level hits and you shut down.

JT: Did you all ever have to upgrade that or do you just had to work with it?

DC: No. You just have to add more pumps and keep them going, do the maintenance, have one down while you're working on the other ones and keep it going; always running. As an operator, your role was to minimize the shutdowns, and the way you did that was by testing and making sure that all the equipment worked properly.

JT: The shutdown was bad news.

DC: Oh, shutdown means no money.

JT: You'd get a phone call, I'm sure.

DC: Not a phone call. Every morning you had a meeting and you either got recognized or you did not get recognized. You got the blame. Every morning, at six o'clock, everybody in the whole platform would get together except for the critical work areas. On the production group, we'd get together and we'd have a morning safety meeting before we went out there and did anything. We talked about production, what we were going to do; if we had shut in, why we were shut in; if we weren't doing as well as we were yesterday. We were always trying to do better, always trying to improve.

It got to a point where we couldn't do any more, but we still had more oil to get out. This was the great part about the team concept. They came to the team and said, "We want you all to think of what you all can do to get more oil out with what we have. What can we do to get more production?" And everybody kind of went on, "There ain't nothing more we can do."

Well, I had a concept in mind, because you have to operate each vessel, as I told you, 1,500, 800, 200, 30. Well, I thought I had a way that I could increase flow through the intermediate pressure separator. One of the things we were doing was maintaining a pressure to get rid of a certain amount of liquid. I said, "Well, what if it doesn't matter how much liquid we get out, as long as we get it all out?"

In other words, we would try and maintain a level and have the valve open and close. I said, "Well, what if we leave it halfway open and we keep enough liquid going in it and enough going out that it doesn't move? So you don't change the levels, so you should be able to run more liquid through it." And it worked. It increased production by 20,000 barrels a day. I was a hero for a day. You don't get anything for that. [laughter]

JT: That's part of what was expected.

DC: Well, you know, you're right. I guess the recognition for me was that I figured it out. But you never were allowed that before Auger, you never had that kind of horses—we call those big wells like that horses. Usually you had maybe 2,000 or

3,000 pounds of bottom-hole pressure. These here had 15,000. I mean, it was unbelievable.

JT: And you did the same thing on Ursa?

DC: When I left Auger, I went to Ursa as an ACR, automatic control repairman and I was able to do the exact same thing I was doing on Auger. I landed on Ursa when it was under tow, so it wasn't on location yet. That was interesting because—you heard me mention Mexicans. Well, Ursa had Dutch. Dutch is a different language, so it was pretty interesting to have to pronounce some of those Dutch names.

JT: Tell me about the pipelines.

DC: Okay. Pipelines had never been done before at 3,000 foot of water, so had to come up with a new strategy on how to support this pipeline that's always going to be moving. You understand that it's coming off of the sea floor, and usually a pipeline is to a fixed structure like a Cognac. Not this time. They had to use what they call a J-lay. It's a special device that supports the pipeline and provides tension on it. It had to have a tensioner too, so that was unique. We had a gas pipeline and an oil pipeline, and they had to add more pipelines to it later on.

JT: Were you in charge of any of the maintenance or the operations of those risers on pipelines?

DC: My role on Auger was taking care of the testing all the safety equipment.

JT: On the deck?

DC: On the deck.

JT: Not below.

DC: Well, wherever they were. They had some on the pipeline. I tested all that equipment, but I was what they called the ACR man. I did all the MMS testing. The pipelines had MMS requirements; valves had to shut in less than forty-five seconds, shutdown valves and things like that.

Then after we got Ursa up in production, I got picked to be part of a team developing the subsea wells for the Ursa project, which was called Crosby. I became the liaison between Ursa's process team and the Crosby engineering group, so I went back to One Shell Square for a year. Then I got contacted when

Shell decided to split Shell Pipeline into gas pipelines and oil pipelines. The oil pipelines stayed with the Shell Pipeline group, and then they formed a new company called Shell Gas Transmission for the gas pipelines.

JT: When did they do this?

DC: They did that in 2000.

JT: What was the purpose of that?

DC: Not the purpose, but the theory was that Shell Pipeline personnel had a lot of experience with oil pipelines, but not with gas pipelines. So there was a division within Shell Pipeline, gas against oil, and they decided to separate the two groups. Then it became more performance-driven, and then the gas pipelines ran better, they are run differently. Gas pipelines are different from oil pipelines in the fact that oil inside of a pipeline along with gas are completely different issues.

Then I was offered the position of Shell Gas Transmission Instrumentation Lead, where I was in charge of all the offshore gas pipelines for Shell as far as instrumentation, measurement, all of that. They were getting away from the type of devices that they used on the oil pipeline that really wasn't that popular in the gas measurement business, so there's a difference. I go in on the ground floor of that.

I did that with Shell until 2005, when Shell decided to sell the gas pipelines and they sold it to Enbridge, and I transferred with it. I retired from Shell and went to work for Enbridge. I had a really unique thing. I got a severance package, two weeks' pay for every year of service, I got retired from Shell, I started collecting my pension, I went to work for Enbridge and they gave me all my time that I had with Shell. I started the day one with Enbridge with twenty-three years of seniority.

JT: Wow, man.

DC: Now I got almost thirty with Enbridge.

JT: Where were the operations for the new Shell transmission? Was that at New Orleans?

DC: No, it was in Houston.

JT: Did you have to go to Houston?

DC: Yes.

JT: Did you move to Houston?

DC: Well, no. I didn't have to move to Houston because we had a field office in Thibodaux. I worked out of the field office in Thibodaux, and all of the offshore operations group was out of Thibodaux. The manager, the superintendent, myself as in charge of all SCATA computer systems and all of that, and then all of the clerical as far as the offshore day-to-day business; it was all out of Thibodaux.

JT: So you've been with Enbridge for how long?

DC: Since 2005, but I've been with this pipeline group since 2000, and it's the same group. Very few people stayed with Shell, almost the entire workgroup went to work for Enbridge, so we're still together.

The pipelines haven't grown. In fact, we have less gas than when we started because of the reservoirs going less. But the dynamics have changed since 2000. In 2000 we were a dry gas pipeline, and then some company called BP got involved. The wells that they started drilling; their TLPs, Holstein, Mad Dog, Shenzi, Atlantis, were the highest BTU gas that anybody has ever seen. Consider 1150 was BTU gas before. Now it's 1500, 1600. And what that means is that at certain pressures, retrograde condensate falls out in large quantities. Retrograde condensate is a liquid that's very volatile, very high pressure, and very hard to handle.

JT: Can you reuse that?

DC: It's a high ingredient that people covet, but it's hard to handle because it's under a lot of pressure. So consider that, remember me telling you a number, 1500 pounds? Today it's 3500 pounds. They all operate at 3500 pounds, so that's new to the industry. Pressure transmitters were usually good for 2000 pounds, now we had to have them good for 4000 pounds on measurement. That was another exciting part. Well, to give you an idea, we would maybe get 2000 barrels a year of condensate in the gas pipelines. Today we get over 4000 a day.

JT: Of crude equivalent?

DC: Of retrograde condensate.

JT: Where does that go?

DC: Well, that's something. Of course, we were not prepared for that kind of stuff, so we had to start developing facilities. We're in the process of our second modifications to the facility.

JT: Is it because BP is in a different kind of reservoir environment?

DC: Yes. It's deeper, they're operating at a higher pressure. I'm the supervisor of the Nautilus pipeline.

JT: Which is Mars?

DC: No, the Nautilus pipeline is a thirty-inch pipeline that comes in from Ship Shoal 207, which is an Enbridge hub.

JT: Somebody gave me this the other day. I've been studying it very thoroughly.

DC: This is it. These are all my pipelines. Who gave you this?

JT: His name is Charlie Rhodes.

DC: This is the exact same thing I have in my office. This is the Nautilus pipeline.

JT: Where does it come in at right here?

DC: At Garden City, right off of Highway 90. You see Highway 317 exit to Burns Point? That's where it's at.

JT: And what kind of facility is here?

DC: That facility there has a slug catcher which we have to pave these pipelines, so you get slug or liquids in. It separates liquids from gas, then the gas just turns around and goes to the Neptune plant owned by Enterprise next door. They process it. They've got a little fractionator there and they strip it of some liquids and some good components and then they give us the strict gas back and then we distribute it to other companies. So we have a facility there. I have ten people working there now because of all this liquid. I truck out over twelve trucks a day of retrograde condensate.

JT: Where does it go?

DC: It goes to a railcar in Petal, Mississippi. Then it's transferred into rail cars and it goes to fractionation plants, where they can take this retrograde condensate and do it. The problem with this stuff, it has color. In our country, color is always an issue. Color in retrograde condensates—

JT: What happens when they refine it? What do they use it for?

DC: That's made into high-end products like polyurethanes, specialty components in gas, and things like that. It's very rich—

JT: So this is a thirty-six?

DC: Thirty-inch.

JT: When was this laid?

DC: This was laid about fifteen years ago.

JT: Was this a Shell-laid pipe?

DC: No, this was Marathon.

JT: To get to wherever their fields were?

DC: This was a Shell partner-operated facility. This pipeline was owned by Marathon.

JT: For the record, is this the Nautilus pipeline?

DC: This is the Nautilus pipeline, for the record, which is now owned by the Enbridge partnership.

JT: So thirty-inch, what's that, 150 miles?

DC: A hundred and twenty miles.

JT: What was the Shell facility right here that it tapped into?

DC: That is Ship Shoal 207. It's a hub. But that was a Shell partnership, not a Shell-owned facility. This is called Manta Ray. It starts getting real complicated, because Shell owned a percentage of Manta Ray and they sold that percentage along with—

JT: Destin?

DC: Destin, Mississippi Canyon. I operate these; this is operated by BP. Enbridge owns it, Shell did at the time. Mississippi Canyon is owned by Enbridge, it used to be owned by Shell. This is Nautilus. I supervise this one. This is Sting Ray, this is owned by Enbridge and it's operated by another group.

JT: So the supervising operation occurs here?

DC: It occurs wherever I'm at. [laughter]

JT: So you've got one of the phones that keeps you in contact with everybody?

DC: Oh, yeah. I have a Blackberry, and that's the lifeblood. I spend time at both places. As you well know, if you travel through Louisiana, you're looking at three and a half hours of road travel time. This area is very susceptible to hurricanes. This one is not.

JT: What's the hub here? I mean what's the facility here?

DC: This here is called the Venice facility, but it's inside of the Targa plant.

JT: That's the Mississippi Canyon one. Where does Destin come in at?

DC: Destin comes in at Pascagoula, but that's all ran by BP, on BP's hub.

JT: Interesting. I could spend an hour talking to you about this stuff.

DC: I'm not opposed to us meeting again if you feel a need. I feel like we barely scratched the surface, we're not even talking about pipelines. The interesting thing to me is that the MMS now is dealing with us on a situation where they're not on familiar ground.

JT: Which is?

DC: Which is trucking operations. Trucking of retrograde condensate is different than putting retrograde condensate in a pipeline. The MMS is very knowledgeable in transportation of liquids and gas through a pipeline, either through a Daniel orifice meter or through a LACT unit because they know everything that there ever was to know about. Trucking? That's new to them.

Trucking is different. We don't use a meter; we use a scale and weigh it. We've been dealing with them for quite some time to get them a good feeling about security and measurement and allocation and those things there. You have to understand, what the MMS has been doing its whole life, the trucking industry has been doing the same thing with scales. Just like it would be weird for trucks to use a meter, it's weird for the MMS to use a scale, but we're working with them on getting a better knowledge of that.

But the pipeline business has changed because of this stuff that they're finding out here in this deepwater. It's higher BTU gas, it's at a higher pressure. Eventually you've got to drop down to a lower pressure anyway, and when you do that, that gas is coming out. Like I was telling you before, the gas was coming out of the liquids, now the liquids are coming out of the gas. The liquids are entrained in the gas, and as soon as the pressure drop, it falls out. Then guess what? The liquids go to atmosphere, they evaporate; it's like they were never there.

JT: The liquids?

DC: I can these 5000 barrels a day of liquids, and 50 percent of it will evaporate into thin air like it was never there.

JT: Wow.

DC: At atmospheric pressure. It's a battle for us to keep it under pressure so these trucks are all pressurized at 150 pounds.

JT: How big are the trucks?

DC: The trucks are like your larger eighteen-wheelers. Next time you're on the road and you see a truck with the name Dufour on it, that's probably one of my trucks. Like I said, we do twelve trucks a day. They carry about 180 barrels of retrograde condensate. They go anywhere from Petal, Mississippi, to Longview, Texas.

JT: Fascinating.

DC: This whole thing is fascinating to me. I think that's why, being fifty-seven years old, I'm still enthusiastic by the overall excitement of it. I'm excited that I've been able to work on most of the major TLPs, not only from my company, which was Shell, but I got to go on Gunnison, which was, I think, BP, and then I went on Conoco Phillips' Magnolia. I went on Gunnison to set up equipment. It was interesting to see the different concept of a TLP. They use a spar, so you've got a single leg, and that was unique.

JT: There's a few of those coming out.

DC: Compared to four. But it's all about money. It's all about cost. Auger was so expensive.

JT: The first of its kind. Since we've probably only got a couple of minutes, let me throw a question out there for another project that I'm working on personally. You being a native of Houma, living here in Chauvin, you are quite aware of the contradictory nature of all of this here. What is your opinion on the long-term impact of oilfield canals, pipeline canals, and their relationship to transformation of the marsh?

DC: Well, to me personally, being there from the early beginning, all these pipeline canals and the navigational canals that the oil companies built were the death knell to our barrier islands and our coastal marshes. I've been flying over this area since 1981, and I've been on a boat since 1971. I went to work for Shell in 1981, and I started flying over these areas. You could see all the canals where you started, you had plenty of land in between them, and now it's nothing but water.

So what I'm saying is that when a hurricane hits, if there wouldn't have been none of those canals there, it would have done some damage, but it couldn't have cut into a pipeline. You know what I'm saying? Let's say you had a barrier island here and you had a canal right fifty feet behind it. You ate up that fifty feet. Now that's gone. Now you've got just the canal against the other bank. Now that becomes the barrier. So the last time I flew over this area where I'm living at now, Chauvin, I was in shock because the barrier islands today are Chauvin, Montague, Houma. That's your barrier islands. It ain't Timablier.

What a lot of people don't understand is that they had to dig a canal to get to every well, and that was the difference. Today they wouldn't have to dig probably 80 percent of the canals they did, because of directional drilling, but before it was poke a hole, poke a hole, poke a hole, poke a hole, because you couldn't get to it; it was on land. It only makes sense that, to me, that oilfields should be paying part of that.

JT: This right here is basically stating that you are agreeing to participate in this project and that you give authority to our team over the intellectual property that is on that little recorder right here. That is to allow us to archive this data and to use it in publications for this MMS project.

DC: It says "The interview recorded on—." It's blank right there.

JT: I need to put in that date.

DC: Oh, okay. That would be today's date.

JT: The twenty-second of July.

DC: The project that I'm working on is a Ph.D. dissertation, but it will eventually be a book. It's entitled "Building America's Energy Corridor." I'm studying the first major natural gas gathering system built by Tennessee Gas in 1956. It was called the Muskrat line. It ran from Bayou Salé, parallel to the coast, across Atchafalaya, crosses at Cocodrie, at Cocodrie Island, crosses Lake Barre. It crosses right behind but over Grand Isle, into Barataria and the Bastion Bay and connects into the Port Sulphur facility here. That was the first. Before that, there was no natural gas industry in Louisiana. It might have been pipelined by United into New Orleans to run the lights. They didn't have a market for the amount of natural gas that was available out here, nor did they have interstate transmission companies until the mid fifties to go ahead and gather this gas, eliminate the flaring, and begin sending that gas on to the northeast consumers.

DC: You're absolutely right. By the time I came into the pipeline those types of companies were well established, now they're gone. They're owned by other companies. Enterprise, for example.

[interruption]

JT: That was the first one. Twenty-four-inch, 1956, it was called the Muskrat line. It had numerous feeder lines that connected to Shell, Continental, Superior, and then to two kind of small independent oil companies. They had all these fields that were producing oil but they were flaring the gas. That's when Conoco came in.

DC: That was a bad product. Do you want to keep any of this?

JT: I appreciate it, but I've got more pictures than I know what to do with. We interviewed the project managers of all three, Auger, Mars, and Ram Powell. Dan Godfrey, I guess he was on Mars, he had a table with all kind of pictures and graphs and charts.

DC: So you got everything you need.

JT: He has all this stuff and said, "Look, just take it, take what you want."

DC: Well, I didn't know if you wanted anything like this about the detailed information about exactly what the Auger TLP is. This kind of tells you about the different things: fixed platform, compliant tower, floating production system, and their differences. Then, of course, this is the original news release information. It gets into the construction. "The Auger superstructure was designed and engineered by Shell Oil Company. More than 740 companies in thirty states—." That's what I'm thinking, that kind of information might be interesting for your research. It really gets into the details of it. It said 1.2 billion dollars, so I was off.

JT: Can I make copies of this and mail it back to you?

DC: Yes, you can. Also look at this. That really gets to the heart of it. I knew this was going to come in handy someday.

JT: Can I write your name on here so I know who it belongs to.

DC: Sure. I hope it wasn't a waste of your time.

JT: Oh, no, man, this is great. You answered a lot of questions that only someone with that exact expertise could handle.

DC: I've been involved with the oil industry since 1971, but I'm going to tell you, looking back on the industry, if I were to pick one thing that destroyed our barrier islands, that would have been the oil industry, because I fished them all. I've been places that I fished twenty years ago, and they're no longer there. It's been the saltwater intrusion more than anything, and the only way you got saltwater intrusion was between hurricanes and the canals being built. The pipelines were one of the big killers too, because they dug a canal and put the pipeline in.

JT: A flotation canal. Nowhere has that been more pronounced to me, for someone who lives in Houston. I'm an academic; I'm in a different kind of field. The things that we mostly look at are documents, maps, images. But as a kid, coming to the Cocodrie camp, looking directly across the bayou at that huge ridge line that it looked like you were driving through ___________ [unclear] right there. It was just a big; it looked like oak and just a huge tree line right there, a huge ridge. This morning when I woke up, I walked out, because I got there yesterday evening, and it's just a few twigs, man.

DC: I know. Isn't that amazing?

JT: You can see right through it. You can see the sun coming up, but right behind that is a lake which was a pond fifteen years ago when I used to come out as a kid.

DC: How old are you now?

JT: I'm thirty-four.

And attached to that pond was an eight-inch feeder line built by Tennessee Gas in a push-pull, and those canals were dredged at anywhere from 10- to 12-foot wide, but now it's 150-foot wide. The bulkheads that they built in the fifties and sixties were designed using 1950s, 1960s engineering mentality to limit saltwater intrusion, but they're blown out. The bulkheads are still there, but they're blown out, and every tide twice a day that comes in delivers a little bit more.

DC: To me, it was because of the political corruption of Louisiana politics back then. I say that not from an observation, but from intimate knowledge because I had relatives that were involved in that corruption. Being a Cheramie, originally all my family was from Golden Meadow and Galliano, but we moved to Houma when I was a young kid.

You got to understand that I grew up with Texaco as the preeminent company. My grandfather had the original Texaco distributorship in Lafourche Parish. It was called the Golden Meadow Oil Company. His name was Nativale Collins [phonetic]. He started selling Texaco products with a Baden pump, out of a fifty-five-gallon drum. He increased that from several drums of diesel and kerosene to an empire of twenty-five Texaco service stations at the height in the seventies. At one time, when I'd go to my grandpa's house, the office building was in the front of his house and he had his house and he built a pool, and behind the pool there was a million-and-a-half-gallon diesel tank. That was the bulk plant, behind the pool.

So I grew up playing with Texaco trucks and everything. Out of my graduating high school class in 1970, seventeen of us went to work for Texaco. It's amazing. But when I got to work for Texaco, that's not where I wanted to stay. I had five lost-time accidents in ten years, four back injuries and then this souvenir, fifty-six stitches where I almost lost my arm.

JT: From what? Don't tell me an industrial grinder.

DC: No. I don't know how familiar you are with shallow-water drilling barges. They have a keyway and they would slide it around the well and then they would sink the barge down to the bedrock, to the shells, and then they would drop something called a pollution gate. And that keyway, which was half-inch steel—

JT: Got your hand caught on there.

DC: Well, picture this. This was a worst-case scenario. I'm holding it; it's half-inch steel, now, it's about ten foot wide, and I got another guy on the other side of the key weigh, holding. We're holding it steady so it can go in the slot. My gang pushes on the other side. There's a winch pulling this weight, it's called a BB winch. It's a term you don't hear much, but it was a common term back then. It had a giant metal wheel on it, to give you leverage, so you could handle the weight, and it had a dog with a big gear on it. The dog kept it from going away, so you'd pull the dog and use your strength to pull on the wheel. He couldn't control it, so he let it go. When he let it go, the guy on that side let his end go, and when he let his end go, and it started to come towards me like that.

I'm holding it here. I went to move my arm out this way. There was a post right there. So it got caught in between there, and it was sliding down my arm and the post. I pulled so hard that I peeled this all the way to my wrist. Never bled. It looked like a filet of speckled trout. [laughs] Now, no pain, no pain. This is all adrenaline now, so I grabbed it and I took off running. And, man, I was pissed off. Nobody wanted to come around me. I was cursing quite a bit at that time.

Back then I used to smoke. Well, it was a forty-five-minute boat ride—they didn't come and get you in the helicopter.

JT: Where was this at?

DC: This was at Lake Barre. Okay. It was a forty-five-minute crew-boat ride.

JT: Did you think you were going to die?

DC: I smoked a pack of cigarettes in that forty-five-minute boat ride. They had wrapped a bunch of stuff on it. It was pretty good. To cut a long story short, I get to the hospital, and I had to wait for the Texaco doctor. Nobody else could see me except the Texaco doctor. I don't have any money. I'm in my work clothes. I don't want to call my wife and tell her to come pick me up in the emergency room, you know, and freak her out. So I get in there and the doctor is sewing me up and telling the nurse that 99 percent of the accidents caused offshore is by the stupidity of the worker. I ain't feeling no pain right now, so I come off on him, and told him where to get off. It wasn't my fault, you know.

Then I call Texaco office in Houma, it used to be where T. Baker Smith's office is. I said, "I'm Depp Cheramie, and I need a ride home."

"What you calling us for?"

"Well, I just had an accident offshore," and I said, "I'm over here at the emergency room, and I ain't got no frickin' car."

"Well, why don't you call your wife? You can't call somebody?"

And I said, "No, I don't want to call them and tell them to come pick me up at the emergency room. Are you crazy?"

"Well, call a cab."

I said, "Dude, I ain't got no money. Just come over here."

"Just charge it to Texaco."

So I got my arm in a sling. A cab pulls up, drops me off. I used to live further down the bayou by Ward Seven, by ______ [unclear] Bridge. I come out. My wife and I had been trying to get pregnant for about six years and we weren't having no luck, and she thought I was coming home with a baby. [laughs]

I stayed off three months from that accident, and when I went back to work. This is how Texaco was ran. I went back offshore to the location I'd been working for five years, and the production foreman told me to go back on the rig where I'd hurt myself. "I don't work on the rig. I work in production. I'm one of the roustabouts over here, you know?"

"Oh, okay." They didn't care. They didn't have a good handle on shit. It was either become an alcoholic or do drugs. I mean, it was a different oil field back in the seventies.

[End of interview]