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Operator:

Good morning, ladies and gentlemen, and welcome to your Plains Exploration & Company 2003 earnings conference call. At this time, all lines have been placed on a listen-only mode and the floor will be opened for questions following the presentation. It is now my pleasure to turn the floor over to your host, Mr. Jim Flores, Chairman, President, and CEO.

Jim Flores:

Thank you, operator. Good morning, everyone, and welcome to our call. This morning, as usual, we have Steve Thorington, our Chief Financial Officer, Tom Gladney, our Head of our E&P Group, as well as John Wombwell, our General Counsel with us. I would like to take you through all the results of our 2003 operations and also some of the updates we ve had that we announced in the press release this morning. Forward-looking statement, we have it on the website as well as on all our SEC filings. We plan to avail ourselves to all the rights under that and all the protections. So please be aware of that. This morning I would like to make a couple comments about the Company. We are two years old as a stand-alone Company, PXP, so please bear in mind that every result that we have this year that is better than last year is a new record, but it s not really that important from a record standpoint. But it does mark the improvement of the Company from an efficiency standpoint of producing more oil and gas volumes at a lower cost and delivering more value to the shareholders. And of course, when you put against the backdrop of such strong commodity prices, the Company has continued to make spectacular improvement toward being a very efficient leader in our industry as far as producing oil and gas with the highest margins possible. During the 2003 fourth quarter, our net income reflected those results of $12 million, or 30 cents a share. That s compared to the net income of $4.7 million, or 20 cents a share, for the fourth quarter of 2002. When you roll all that up into a full year, the Company reported net income of $59.4 million, or $1.78 a share, compared to the net income of $26.2 million shares (ph) or $1.08 a share in 2002. So great earnings growth from that standpoint. Fourth-quarter 2003 production averaged 39,000 barrels of oil equivalent per day, and we ended the year with 281 million barrels of oil equivalent. Both Steve Thorington and Tom Gladney will take us through a lot more details on the financial side, as well as the operating side, later in the presentation. At this point in time, I want to turn the attention toward the operating success the Company has just announced at our three major operating areas. Inglewood Deep, which we have kind of renamed at this point Deep Inglewood, and in short DI you will hear it referred to as DI has been a tremendous success for the Company. As you recall, we entered into a seismic agreement out there to get 3-D seismic across that big field and then the drilling process, we ve had a rig working out there for about a month and a half now. The first well we turned to sales about ten days ago and it is producing about 800 BOE equivalents, broken down, about 300 barrels of oil a day and 3 (indiscernible) cubic feet of gas. It has been a very consistent producer, with steady flowing tubing pressure about 1100 pounds flowing tubing pressure. And the key about it is 43 gravity oil, which is a lot lighter than our oil that is in our field at 23 gravity oil, where we produce about 7000 barrels a day in the field proper. As we mix the 43 gravity oil with 23 gravity oil, our differential s BOY (ph) will go down. As the production values from this well, as also the sub (indiscernible) wells, increase, you will see our fixed costs, our LOE, materially go down on a BOE basis. And we expect a lot more drilling behind the Deep Inglewood. Presently, we are about halfway down on our second well. We have ten wells that we plan to drill in 04 in the deep section of Inglewood. There are different prospect areas. Each one of these prospect areas sets up multiple development wells upon discovery of the initial well. For instance, this first well, the 800-barrel-a day well we have here set up as many as a dozen direct offsets in its fault block. These are the type of processes that we are going to be putting in our 05 capital budget, where we can run multiple rigs in the Deep Inglewood area, where we will be developing existing discovery areas within a field, as well as looking at another eight or ten new prospect areas in 05 with multiple rigs. PXP owns 100 percent working interest in this project and

83 percent revenue interest, and it is going to be a major driver to our value going forward. Our Point Arguello project is moving forward. Nabors should have our rig on location here within the next month, right on schedule to start drilling operations in the second quarter. And we are looking forward to the same type of results, where we will be increasing volumes after we get our wells drilled in the Rocky Point structure to further lower our costs on a per-BOE basis and bring more efficient barrels home for our shareholders. I want to tell our guys at Point Arguello congratulations to getting the 2003 MMS SAFE Award for the second time in four years. They continue to excel out there in the California offshore OCS, and we are very proud of them for doing that. I would actually be remiss if I didn t tell the Deep Inglewood team I am very proud of what they ve done as well. I apologize for overlooking that. It is a heroic effort, really, creating a tremendous value for the Company out of something that had been on the books for a long period of time. Our Breton Sound area that is operated by our eastern business unit continues to deliver solid results to our Company. At the end of the third quarter, we were nine of ten wells. At the end of the fourth quarter or year-to-date, we re 17 out of 21, which is about 81 percent success rate, which is solidly above our 60 percent success rate that we had in our plan. We announced several of the completions and updates. You can see the wells are still at a (ph) high point at 8 to 10 million a day and several hundred barrels of condensate, as well as a couple disappointments in our Hercules and Ursa Major. We are going to be drilling a few dry holes out there, but at the same point in time, the success rates have held up way above are plan. Currently, we re producing about 31 million a day out of the Breton Sound area total, with 6 million today out of our new area in the Breton Sound Extension, with the remaining 25 being in the BSA (ph) area. On the acquisition front, it s been a busy quarter. We announced early in February the Nuevo acquisition, which is a very significant acquisition to the Company and several metrics were achieved with that acquisition. We are planning on filing the S4 documents this week, hopefully, that can allow us to enter the formal registration period with the SEC. And assuming we get a full registration, we will probably be looking sometime in June to consummate that transaction with a shareholder vote. I can t say much about it other than the integration is going very quickly, and being handled professionally by both sides. We are enthusiastic about the upside surprises, not only in the assets but in the people at Nuevo; the Bakersfield people have been very enthusiastic about our approach, and we appreciate all their work on the transition, as well as many of the Houston people. They have been a big surprise for us and we are looking forward to getting all the integration done there. We do believe that all the metrics that we discussed in the acquisition conference call are still intact regarding synergies and some of the production metrics along with that acquisition. We also on a second transaction, we are under contract to dispose of our Illinois asset; that should close this week. It goes along with our rationalization of our inefficient properties and our high LOE properties that don t have much upside for the Company. It s not a significant transaction, but since it will close later this week, we will be making a press release. We want to make everybody aware of that. And we will, of course, use those proceeds to go against our revolving credit facility. That takes care of really the operations and the acquisition of the Company. I do want to make a comment about John Raymond refocusing on Plains Resources and leaving PXP. This was a discussion and a commitment that was made and discussed at the PLX and PXP Board level at the time of the spin (ph) in December 18, 2002, where after a year of running the companies simultaneously, we would see how they are all going and make a decision on management and realignment, and also clarification at that point in time. John ascended to CEO at the time of December 18, 2002. He s done a marvelous job. The stock at Plains Resource is up 70 percent under his direction, as well as the Company is under good footing and as well has a lot of exciting transactions and extraneous things going on, I think of all in there (ph) to the value of the shareholders. John s input and efforts and his direction here at PXP will be missed. He definitely was a driving force in all the restructuring, restaffing, and retooling of this company, and was an invaluable part of it. His ability to put the processes in place and juggle many, many hats was important in the transaction phrase of PXP, and I know it s going to be important, a big value driver for PLX any way how the direction that PLX comes forward. So I m still chairman of PLX with John and partners there with him, and look forward to making a lot more money with him and for all the shareholders there. But we wanted John to know that he will be missed here at PXP. With that, I want to turn it over to Tom Gladney to go over the 2003 operating metrics for the Company, and then we will go back to Steve for the financials and then open it up for questions.

Tom Gladney:

Thank you, Jim. On the reserve side, we ended the year 2003 at 280.9 million barrels, an increase of about 11 percent over where we were end of the previous year, or a gain of 55 million barrels equivalent. 47 million of that 55, of course, by virtue of the 3TEC acquisition. Reserve additions net of revisions were 43.8 million barrels. In addition, there were specifically in the revision side, we were down a net 11.2 million barrels, as well as property sales of noncore marginal properties, 3.6

million barrels. Total cost incurred, of course, $481 million, the vast majority of that for the 3TEC acquisition. On the revision side specifically and would introduce this by saying 100 percent of our proved reserve reports are generated by our third party engineers, Ryder Scott and Netherland, Sewell. These guys look at our data on the entirety of our fields, and this year we had a gas injection project in one of our satellite fields in the L.A. Basin, plus a waterflood project at two L.A. Basin satellite type fields were either terminated or we recognized performance shortfalls and took negative reserve revisions on those projects. We also, of course, in virtually every field we have we have some minor amount of ups and downs, and we had a number of positive revisions as we went through the rather detailed and meticulous process. The majority of the capital that we will spend and I m not going to quote an exact number, I think that will be in our K that will be filed later this week but the majority of our non-acquisition related capital was put on an emphasis of moving our proved undeveloped reserves into the PDP, or cash flowing category; as well as some get-started costs, if you will, for the 3-D seismic program that led to our Inglewood Deep development this year; and also some land and seismic costs, particularly in South Louisiana. So we had a fair amount of our dollars focused either on proved undeveloped reserves, which of course moved into the producing category, but don t give you a proved add, or contrarily, dollars focused in the growth areas of land and seismic that sets up future opportunities, but did not materialize an approved add in year 2003. With that, we will look forward to questions and discussions at the later end of the conversation. Steve?

Steve Thorington:

As Jim did mention, net income for the fourth quarter was $12 million, or 30 cents a share, compared with net income of $4.7 million, or 20 cents a share, in the fourth quarter of 2002. We consider this to be very strong performances, as it was achieved despite two expense items this year that collectively reduced that income for the quarter by $8.3 million and EPS by 21 cents. The first item was a non-cash, pretax expense of $10.7 million that related to stock appreciation rights, or SARs. As we have discussed in the past, at the end of each quarter, we calculate the in-the-money value of outstanding SARs, and to the extent that this value has increased or decreased since the previous quarter and we recognize that change as a charge or credit to income. Since our stock price increased 23 percent between September 30th and December 31st in 2003, we incurred the expense. The second item, also in the fourth quarter, was we had about $2.2 million of 3TEC merger-related costs that were included in G&A expense, and these costs consist primarily of severance, integration expenses, including accounting system conversion costs, and various non-cash compensation expenses associated with some restricted stock grants that were made as of the merger date. We don t anticipate any material additional merger-related G&A expense for the 3TEC acquisition going forward, but obviously, there will be some merger-related G&A expenses in 2004 for the proposed Nuevo merger. Revenue net of hedging results for the quarter increased 80 percent to 93.1 million, primarily as a result of the 3TEC acquisition and higher commodity prices. Somewhat offsetting this revenue increase was higher production costs associated with the larger volumes and the previously discussed higher period G&A expenses. Our per unit cost structure was very much in line with guidance we provided for the quarter, as total production expenses, which include LOE, production taxes and transportation, were $8.31 per BOE and unit G&A, net of the merger cost and SARs, was $1.56 per BOE. The oil differential, however, of $3.89 was better than the expected range of $4 to $4.25 a barrel. Our total tax rate for the year was 41 percent, again in line with expectations. Our current tax rate for the year was 5 percent, excluding adjustments weighted to the prior year tax returns, which reduced our reported current rate for 2003 to around 2 percent. We have estimated that our current tax rate could be as high as 9 percent, but we were able to reduce the rate with various tax-deductible drilling expenses. We ended the year with approximately $488 million of long-term debt. This represents a $15 million reduction since the end of the third quarter and a $22 million reduction since the end of the second quarter. That results in a debt-to-capital ratio of 58 percent at year-end. Assuming the merger with Nuevo takes place as planned, we would expect the leverage ratio to be below 50 percent at closing. And the financial benefits of the proposed Nuevo merger have been very well recognized in our market, as all three rating agencies, Moody s, S&P, and Fitch, have put the affected debt on credit watch for possible ratings upgrades. Turning very briefly to the full year, we had net income of 59.4 million, or $1.78 a share, compared to $26.2 or $1.08 a share for 2002. Net income in 2003 was reduced by an aggregate $13.6 million, or 41 cents per share, for the SAR and merger-related expenses. For the full year, SAR expense was $18 million and merger-related expenses were G&A were 5.3. Obviously, the SAR expense was the result of the 58 (ph) percent increase in our stock price from $9.75 at the beginning of 2003 to $15.39 per share at the end of 2003. We also mentioned in the press release that we were going to be filing amended second and third quarter 10-Qs to make some adjustments for hedge accounting as it related to the 3TEC acquisition. And basically, we are showing an increase in earnings for the second and third quarter of 1.7 million and 4.2 million respectively. Oil and gas properties and goodwill will also be adjusted on the balance sheet, but these adjustments have no effect on cash flow. By way of background, upon closing the merger, we adopted hedge accounting for the 3TEC derivative contracts and recorded a liability for the negative mark-to-market value as of the merger date. And we had offsetting entries to other comprehensive income, OCI, and deferred taxes. This accounting for the 3TEC hedges is completely consistent with the way in which we account for our own hedges. By further review, however, it was determined that because these hedges were assumed in an acquisition, the treatment in the initial purchase price entries should have been done differently, which is the cause of the adjustments. Basically, the initial purchase entries should have been reflected the fair value as a liability with an increase to oil and gas profits and goodwill. Instead, it was offsetting entries to OCI and deferred taxes. Since as the hedges were settled, the actual cash payments were less than what the liability was recorded at, the difference was reflected as an increase to earnings. And with that, I will turn it back to Jim.

Jim Flores:

Okay, Steve. Thank you. Thank you, Tom. And operator, we will open it up for questions at this point in time.

Operator:

Thank you. (OPERATOR INSTRUCTIONS) Joe Allman from RBC Capital Markets.

Joe Allman:

I know you didn t replace production with new reserves through the drill bit in 03. What is a reasonable assumption going forward in terms of reserve replacement?

Jim Flores:

Joe, remember we articulated as we did the 3TEC acquisition, we turned our capital spending toward the 3-D seismic at Breton Sound and also the Garden City area, as well as converting a lot of PUDs into PDPs. Reserve gross dictated by the 3TEC acquisition internally, we wanted the productivity up on our fields better. Off the backs of that for 04, we are drilling Deep Inglewood, we re drilling Point A, and we re drilling Breton Sound, and we are also looking at probably drilling a well down at Garden City this year. So after the investment spending in those projects and also the conversion of PUDs to PDPs, this year should be a banner year, depending on how hot the drill bit is in these exploitation projects. But we expect a book a lot of reserves for the drill bit this year.

Joe Allman:

I know maybe this is difficult to answer, but two things. One, can you remind us how much you are going to be spending in 04, and then what would you consider your maintenance CAPEX? How much do you think you need to spend just keep production and reserves flat?

Jim Flores:

We are in the 160 to 170 range on a stand-alone basis, Joe, and we spend about 80, 85 just on a maintenance level basis.

Joe Allman:

Got you. All right, thank you.

Operator:

Jeff Robertson of Lehman Brothers.

Jeff Robertson:

Good afternoon. Can you talk a little bit about the Inglewood Deep well in the context of expected rates and the amount of gas that you got from the well, whether that was a surprise or planned? And also, if these wells do turn out to be somewhat gassy, what in the way of infrastructure is there or might be needed to handle that on a broader development?

Jim Flores:

I will make a couple comments and I will turn it over to Tom. The initial aspects, we engineer these wells for about the average cost is around $1.5 million, and ran our economics about 120 barrel a day type flowrates. The main reason was for the last 20 years, the average flowrate of any completion out in Inglewood has been about 45 barrels a day. We haven t seen a flowrate of 800 barrels a day since World War II out here, with positively charged or virgin pressure type sands and the gas implications and so forth. I m sure we will drill some fault blocks out here that have had more depletion than this fault blocks. The same point in time, it is a welcome surprise and a tremendous boost in the arm to have 800 to 1000 barrel type productivities out here, still in the field proper. The drilling that we re doing, the completion technique that we are doing, I want Tom will go forward a little bit and we are opening up a lot of hole to the surface, so we are getting maximum productivity of not only the Sentous but the Bradner (ph) Zones. We have the Moniet (ph) back (ph) behind pipe. And then we also drilled through our (indiscernible). So we find a lot of reserves for each one of these wells we drill. And it s going to probably take a lot of twinning (ph) just to get the reserves out of the ground on an economic basis. Tom, you want to address the gas situation and make any further comments?

Tom Gladney:

Good question. We certainly knew going into this that as we go deeper in this section, the oil gets lighter and the hydrocarbons get little gassier. This is at virgin pressure, so there s really no depletion here, so these are original conditions, not some sort of secondary gas cap (ph) from depletion. Infrastructure-wise, it is really we have everything we need. We were hooked up and on flow about two days after the rig moved off location. We also operate 100 percent-owned Inglewood Gas Plant. This gas is fairly rich, high BTU, lot of liquids in it we strip that out, sell that, of course. And even from a capacity standpoint, we have sales connections to some of the larger refineries in the L.A. Basin and we can sell high BTU gas without processing. So we pretty much have maximum flexibility here.

Jeff Robertson:

Okay, Steve, a question on the differentials. They were little bit better than what you had been guiding to. Do you foresee any change in that in 2004?

Steve Thorington:

No. We try to be conservative on what we put out there for guidance, especially as relates to differentials. But we are going to stick with what we have out there.

Jim Flores:

Jeff, if you look at the multi-year trend of the differentials on the West Coast, you are really seeing a real reflection of the global oil picture, of a lot less barrels coming across the water and a lot less barrels coming from Alaska, and the value of the California domestic barrels to that domestic refining complex. We are seeing that also on the Nuevo side as well.

Steve Thorington:

Where we did look at a lot more production from future wells at Deep Inglewood, that would obviously have an impact on our overall differential position. So at some point in the future, we may need to change what we have for guidance.

Jeff Robertson:

Steve, that would be dependent then on a change in the overall quality of the crude (indiscernible) you have out there?

Steve Thorington:

Right, the blended quality.

Jeff Robertson:

Okay, thank you.

Operator:

Kent Green (ph) with Boston American (ph).

Kent Green:

On the DI, what is completion time in these wells from the drill start date?

Unidentified Company Representative:

What we budgeted, Ken, there is probably a month from spud date to sales. And the first well, we were under that, but it all just depends. Right now, use that as a metric and you can have a good feel for it.

Kent Green:

With some of this exploration drilling that is going to take place, are you going to switch into production drilling then off of this first well?

Jim Flores:

What we will do, the way our 2004 project is set up, we have ten different prospect areas on our 2000 acre field basically different fault blocks, different kind of geologic settings, a lot of complications going on out there. We plan on drilling each one of those this year and then look at our 05 plan to where we will have a couple rigs developing those discoveries, if you will, of the 04 plan, as well as we re moving forward to developing our 10 to a dozen or so prospect areas for 05. So we will have a multiheaded plan that will drive production and drive the values out there at Inglewood for 05.

Kent Green:

And you re using one rig now? When are you going to switch to two or three?

Jim Flores:

We will probably do that next year. The thing about it, from this field standpoint, we want to drill these ten projects, understand it, put in place. And if we can we are going to plan on 05. We have to do a lot of building up of personnel and things of that nature when you start putting multi rigs out there. So we are tickled to death this thing is working, but we are going to do it in a process that is something our organization can handle, something our organization can execute well. It s something that is done safe and proper. So I think 05, just off the basis of this, we could put one rig around this first well and probably drill all year long just on this one project, just to kind of give you a scale. But we will wait to see how the other eight or nine go this year before we decide to make any proclamations on 05 as far as firm plans.

Kent Green:

Switching to another topic, what is your outlook at oil and gas? Are you surprised by the oil prices staying high in here? Number two, what influence does that have upon your hedges in regard to cost of scouters (ph) or collars or doing floors or whatever?

Jim Flores:

Obviously, we are surprised of it from a standpoint having lived the last 20 years in this oil business in (indiscernible) up-and-down cycles. This has been a much longer, prolonged up cycle and it has a lot of fundamental legs underneath it. There s no question about it. At the same point in time, part of our when we get in a situation where the market is strong and ahead of our hedging program, then we look for an opportunity to physically open up those hedges, and that s one of the constructs of the Nuevo transaction. Much of their oil in 05 was not hedged, and we were able to do a deal with Nuevo and actually put in some pretty nice collars 27 to 30 have them kind of do for the Nuevo side, and have them do some hedging in 05 that, on a blended basis, will increase our hedge number from there and take advantage of these higher prices. Are these prices going to stay and maintain? I think the shareholders are paying us to make sure we have good returns on whatever prices are there, and the thought process of contracting our oil and gas in the future, we are going to try all our efforts to maintain this high a price. But also on the back of the Nuevo transaction, it gives us the balance sheet by which we can take a little more opportunity to preserve some of that commodity price exposure with the use of puts, and some things of that nature where we have a financial capacity to take advantage of those. When you look at it on a blended basis, we re getting pretty good value for our unhedged barrels, even on a percentage basis, to the hedged barrels. And as we continue to grow volumes around here in production, we re going to be pretty proud of our oil price, even if oil prices stay where they are right now.

Kent Green:

Finally, is there any of your debt that is callable that you could refinance at lower rates because of maybe an upgrade?

Steve Thorington:

Well, we could always tender for our debt. I m not sure the economics are compelling for that right now. We can t really call it until, I think, 2007. Now it with Nuevo and again, this is all prospective for closing that acquisition they do have about 150 million of 9 3/8 percent bonds that are callable a year from October. So that is certainly an opportunity, assuming we close that acquisition, to lower the overall cost of debt for the Company.

Kent Green:

Thank you.

Operator:

Philip Putnam with Flagstone Securities.

Philip Putnam:

A couple questions. With respect to the reserves in Breton Sound, could you describe the process of the timing of and what sort of production needs to occur before you can book any kind of significant reserves from there? Or to put it another way, how much of the drilling in the second half of the year, if any, actually made it into that proven reserve number?

Jim Flores:

Phil, let me kind of give you a macro and I ll let Tom kind of fill up some gaps. Breton Sound is a manufacturing process. The key about Breton Sound is it comes out about as fast as it possibly can out of the ground on a reserve basis. If you talk about wells making 10 million a day, and they will make half of their reserves in the first year or first 18 months, excuse me, out of their five to eight Bcf type reservoirs. So as far as booking a tremendous amount of reserves additionally to what s the PDP, it s a limited area. We are enjoying the returns and the cash flow there, but the reserve growth really is going to come out of the California area.

Tom Gladney:

Yes, Phil, in response to your question, and entire Breton Sound area is stratographic trapped play (ph) one-well reservoirs. 3-D seismic and amplitude analysis of that enables this play to be successful such that every well is a one-well field, one well reservoir. And if that well is successful, we move directly into completion and you can see from our release pretty short cycle times on getting these things turned into sales volumes. So any successful well in a given year would have that particular well s reserves assigned to it. Particularly to us in Breton Sound Extension, we started that program in November. By year end, I believe we had three wells down, one well on sales. And so we would have assigned reserves for only three of our thus-far five successful wells at year-end 03. A couple of the Breton Sound area deeper, higher pressure wells were also drilling across the year-end magic December 31 date, so they would be 2004 events. Our entire eastern business unit that is dominated by Breton Sound has a reserve of production ratio following Jim s comment of about 2.2 years, so these things are extremely productive.

Philip Putnam:

Fair enough. One other question. With respect to Deep Inglewood well drilled, am I correct that you stated earlier in the call that or implied anyway that several producing zones were found, at least one of which remains behind pipe?

Jim Flores:

Actually it s multiple, Phil. We drilled through our shallow zone at Vickers/Rindge, the waterflood zone. We found some nice pay there. We found nice pay in the Moniet. And then we set pipe across all those zones and then we have on completion in the Bradman (ph) and the Sentous down in the deeper zones. So there s a lot more reserves in the well than just the reserves we quoted in the Sentous earlier.

Philip Putnam:

And then just a following question to that, relating to the seismic, as you were interpreting it, did what you find correspond with what you were looking for?

Jim Flores:

Yes, that is kind of an easy question to answer. There s so much well control out there yes, the geophysicist did a great job they were right on the money. The question out there was going to the productivity. Once the seismic gave us the picture on the faulting, which was different than what we had looked at before before we had the seismic, the areas stayed the same; the tops were there. The productivity and porosity and the sand thickness turned out to be larger than we expected.

Philip Putnam:

That sounds really good. Thank you very much.

Operator:

Arthur Hulf (ph) with Valeri (ph) and Associates.

Arthur Hulf:

Could you give us a rough idea of the cash-on-cash payback on the DI wells, if they perform like the first one and prices are roughly in the $30 range?

Jim Flores:

We probably could do it in days, Arthur, but I m going to say two months.

Arthur Hulf:

Okay. And the western business unit, the oil, what is the cost of converting the PUDs to the PDP, roughly?

Unidentified Company Representative:

It will vary field to field, but a 3 dollarish range on our conventional on short (ph) California assets.

Arthur Hulf:

Okay, thanks. One more question on the SARs. You say it s non-cash, but ultimately it s cash, isn t it, and when does the cash outlay occur?

Steve Thorington:

That s a good point. It ends up being a cash outflow as they get exercised, and we had around $2 million worth of cash exercises in 2003, which ends up being reflected on our cash-flow statement. We also reflect on our balance sheet a current liability probably at the end of the year it was about $16 million related to the vested and deemed vested, meaning they will vest over the next 12 months, SARs. So we do reflect what the exposure is and we also obviously report what the cash impact is every quarter.

Arthur Hulf:

Would that impact diminish as the stock goes higher? Is it sort of a diminishing type of function or how does that ?

Steve Thorington:

Actually, it s the other way. The higher the stock goes, the greater the SAR expense is, and (multiple speakers).

Arthur Hulf:

In terms of dollars, but I m thinking of percentages. In other words, if we go up another three points, is that another $18 million or something like that?

Steve Thorington:

What it tends to be through most of 2003, the rule of thumb was it is about $1.50 expense for every dollar increase in stock price. We had some more SARs vest at the end of the year, so we are still trying to fine-tune exactly what that number is. It is going to be a little bit more than 1.5 million, but that s basically the math for what the impact is for every dollar change in stock price.

Arthur Hulf:

Okay, thanks.

Operator:

Larry Busnardo with Petrie Parkman.

Larry Busnardo:

Jim, can you talk a little bit more about the Breton Sound area, number of wells you have planned for this year and maybe a breakdown of how we can see that taking place for each area there?

Jim Flores:

Well, we ve expanded the area with the acquisition of about 250 square miles of 3-D additional seismic. We are building inventory there. We will probably drill 30 gross wells there a year, probably maybe a little more than that, but then net 15. We have about half interest in all of that out there. So we have two rigs running pretty much all year long, and again, as we get these wells on and increase the production out there and be more of a steady state. I don t see us going to more than a couple rigs at this point in time out there; we are just going to go through the inventory over the next two to three years.

Tom Gladney:

Larry, when we announced our joint venture deal expanding that area, we acquired about 32 existing prospects. And of course, as we drill this stuff up, a few of those may fall out; at the same time, a few new ones may get added. And that is the area where we are 5 out of 6 and drilling on the seventh well. So we are chewing through that inventory about a prospect every three to four weeks. Then we ve got about 178 square miles of newly shot (ph) and/or newly purchased 3-D that we re building prospects on. And then we ve also acquired as a further expansion that we just announced in this release about 80 square miles adjacent to our main area that we ll operate with about a 75 percent interest. We are capturing prospects in there, but we don t consider them drill ready. That will probably be part of our 2005 portfolio.

Larry Busnardo:

Can you just remind of the cost to drill the wells there just an average?

Tom Gladney:

We have two types of wells there. The Breton Sound extensions are mainly the normally pressured wells. These are a couple million dollarish type wells. Then in the original area, where we have an extra string of pipes set, and the richer condensate yields and over-pressured wells, these are more in the 5, $6 million drilling completes.

Larry Busnardo:

Okay and then moving back to Deep Inglewood, do you have indication of what the EORs might be there?

Jim Flores:

It s preliminary right now. We want to get a lot more production history before we start quoting those. We used project economics around 4 to 500,000 barrels.

Larry Busnardo:

Okay. And then lastly, just in terms of Point A, you spud the well in May. How soon do you think before we would hear anything just in terms of results?

Jim Flores:

It would be third quarter.

Larry Busnardo:

Okay, thanks.

Operator:

(indiscernible)

Unidentified Speaker:

Thanks, my questions have been answered. Thanks.

Operator:

Joe Allman with RBC Capital Markets.

Joe Allman:

Hi again. Just a quick follow-up. What are you seeing in terms of service cost increases, service availability, and what have you locked in in terms of cost, if any?

Jim Flores:

Let me answer. We haven t locked anything in. We are seeing a little uptick in service costs and we are kind of projecting a 7 to 8 percent increase in service costs over the next year or 18 months in some of the things. Steel costs have gone up; pipe has gone up, like everybody else. But in our California drilling market, we have a contract with Nabors out at Point A as far as locking in price there, and we do yearly contracts out on those fields. So we are not going to see any drilling cost. But the overall services and costs of doing business, probably 7 to 8 percent.

Tom Gladney:

We still have a rather large program of development drilling. For example in East Texas, we will have exposure about 40 gross wells, maybe 20 net wells in East Texas. And we are seeing those costs up about 5 percent from, say, midyear 03 to now, and most of that is pipe and a little bit of that is rig rates basically going to the labor side of the rig costs.

Joe Allman:

Thank you.

Operator:

(OPERATOR INSTRUCTIONS) Gentlemen, it appears we have no further questions.

Jim Flores:

Okay, thank you very much, operator. We will see you at the end the first quarter.

Operator:

Thank you. This does conclude today s presentation. Please disconnect your lines and have a wonderful day.

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