From: Corser, Kent
Sent: Fri Jun 25 19:15:28 2010
To: Morten Haug Emilsen
Subject: RE: ACTION - Dynamic Simulation Report
Importance: Normal
Attachments: MC252-1 Sand Description v2.xls

This sand is new. They did a new study and have classified it a gas bearing and capable of flow. See attached chart. This is NOT the brine sand.

Would this change the best fit for flow (shoe vs annulus).?

You working across the street?

Kent Corser
Drilling Engineering Manager NAG
BP America Inc
510 Westlake Park Blvd Room - 2.332A
Houston Texas 77079
Office- 281-366-2142
Cell - 281-433-0093
Home - 281-578-3224

From: Morten Haug Emilsen [mailto:Morten.Haug.Emilsen@addenergy.no]
Sent: Friday, June 25, 2010 1:37 PM
To: Corser, Kent
Subject: Re: ACTION - Dynamic Simulation Report

Kent,

Remember some initial discussions we had on this stringer. The reservoir engineer claimbed it could not flow. If it can, it is possible that an influx could be taken from this zone also before the negative test as it is above or at balance with the 14 ppg mud in the hole. Do not really think this will change the picture much with respect to the circulation and unloading sequence as the productivity of this zone is very poor compared to the oil sand. Including this sand will most likely have a very minor effect to the simulation results. We know that oil was flowing initially and we know that we were underbalanced, also to the 12.6 ppg sand during the negative test without taking any gains.

Best regards,
Morten

Sent from my iPad

On 25. juni 2010, at 19.03, "Corser, Kent" < Kent.Corser@bp.com> wrote:

Morten,

We need some help with an update on the dynamic model. Are you available now or is there someone else who could run the model? We have a sand at 17,467' MD that is 2' thick 14.1 ppg and classified as GAS and would flow. Want to see how that fits to at least start the kick.

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From: Morten Haug Emilsen [mailto:Morten.Haug.Emilsen@addenergy.no]
Sent: Thursday, June 10, 2010 7:40 AM
To: Corser, Kent
Subject: RE: Dynamic Simulation Report

Got ya,

5.5 times higher volume at 1100 psi than downhole.

Regards
Morten

From: Corser, Kent [mailto:Kent.Corser@bp.com]
Sent: 10. juni 2010 14:34
To: Morten Haug Emilsen
Subject: RE: Dynamic Simulation Report

The actual N2 is 53 bbls at 1100 psi. This was injected at surface. Per CSI it is around 8-10 bbls down hole.

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From: Morten Haug Emilsen [mailto:Morten.Haug.Emilsen@addenergy.no]
Sent: Thursday, June 10, 2010 7:31 AM
To: Corser, Kent
Subject: RE: Dynamic Simulation Report

Kent,

Just to clarify, 60 bbl at surface (1 atm) would be approximately 400 times less in volume down hole.
Hence 60 bbl at surface would only be 0.15 bbl at downhole conditions.

Best regards

<image001.jpg>

Morten Haug Emilsen
Senior Petroleum Engineer

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mail Morten Haug Emilsen

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is strictly prohibited.

From: Corser, Kent [mailto:Kent.Corser@bp.com]
Sent: 10. juni 2010 00:16
To: Corser, Kent; Morten Haug Emilsen
Subject: RE: Dynamic Simulation Report

Morton - Also would like to model N2 breakout at TD. If I had 60 bbls at surface the down hole volume would be about 10 bbls. Given this can you create chart that would show pressure increase as N2 rises vs time?

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From: Corser, Kent
Sent: Wednesday, June 09, 2010 1:08 PM
To: 'Morten Haug Emilsen'
Subject: RE: Dynamic Simulation Report

Morten - hope the vacation is going well. A few questions. Based on your model. When would (time) expect the hydrocarbons to reach the well head/BOP. We are trying to get an idea of when it was too late to recover from a shut in.

Are you sure the bled down from 21:36 to 21:38 is at the surface? If we had gas at the BOP and annular leaked would you not see that drop?

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From: Morten Haug Emilsen [mailto:Morten.Haug.Emilsen@addenergy.no]
Sent: Wednesday, June 02, 2010 5:11 PM
To: Corser, Kent
Subject: Dynamic Simulation Report

Kent,

It has been a pleasure working for you, your team and the rest of the Investigation Group.
Keep up with the good work, but do not forget to tell some jokes in-between ;-)
I like your sense of humor, and I'm confident that the other guys here do agree.

Should there be any questions, do not hesitate to send me an email or give me a ring
(be aware of the time difference, Cannes is 7 hours ahead ;-)

I believe I'll be back during the summer as we also are involved in the Relief Well Kill team.
See you then.

Talk to you later,
Morten
Best regards,

<image001.jpg>

Morten Haug Emilsen
Senior Petroleum Engineer

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mail Morten Haug Emilsen

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	Top of Sand MD Depth	Bottom of Sand MD Depth	Top of Sand TVDSS Depth	Bottom of Sand TVDSS Depth	Fluid Content	Expected to flow (Used in Modeling)	Sand Name	Gross Sand	Net Sand	Pay Sand	Average Gross Porosity	Average Net Porosity	Average Pay Porosity	Average Net Sw	Average Pay Sw	Arithmetic Air Perm	Geometric Air Perm	Geometric Perm converted to Oil (85%)	Temperature	Pressure	Pressure Depth Datum
	Feet	Feet	Feet	Feet				Feet	Feet	Feet	%	%	%	%	%	MD	MD	MD	Degrees F	psia	Feet TVDSS
	12030.0	12246.0	11945.0	12161.0	Gas	Yes if Liner Leak	S023	2	2	2			35		10			1000	162	7081 psia (based on 11.3 ppg pore pressure)	12053
	13227.2	13230.2	13141.6	13144.6	Gas	Yes if Liner Leak	S026	3	3	3			35		10			1000	178	8405 psia (based on 12.3 ppg pore pressure)	13143
LINER	17168.0		17157.0																		
14.2	17467.0	17469.0	17381.1	17383.1	Gas	Yes	M57B	2	2	2	17.95	17.95	17.95	51.58	51.58	15.08	7.5	7.50	234	12847 psia (based on post well 14.2 ppg pore pressure)	17382
14.1	17700.0	17708.5	17614.1	17622.6	Uncertain	No	M57C	8.5	0	0	8.95								237	13017 psia (14.1 ppg) (Geo tap @ 17713' tvdss) (MDT 3 attemp	17713
13.07	17804.0	17806.5	17718.1	17720.6	Oil or Gas	Yes	M56A	2.5	2.5	2.5	22.48	22.48	22.48	24	24	1702.07	467.39	397.28	239	12038 psia (13.07 ppg)(one MDT pressure at 17721' tvdss)	17721
	17975.5	17989.5	17889.6	17903.6	Brine	No	M56B	5	3	0	14.18	16.99		57.65		7.43	3.12		241		
	18030.0	18032.0	17944.1	17946.1	Brine	No	M56C	2	2	0	17.28	17.28		64.2		4.73	4.05		241		
12.6	18067.0	18089.0	17981.1	18003.1	Oil	Yes	M56D	22	22	22	20.67	20.67	20.67	17.17	17.17	257.67	101.8	86.53	242	11838 psia (12.67 ppg) (MDT & Geotap)	17993
12.6	18120.0	18191.0	18034.1	18105.0	Oil	Yes	M56E	69.5	64.5	64.5	21.42	22.08	22.08	9.7	9.7	514.04	323.79	275.22	243	11856 psia (MDT) (12.64 ppg)	18065
12.6	18217.5	18238.5	18131.5	18152.5	Oil	Yes	M56F	6.5	6.5	6.5	21.08	21.08	21.08	21.85	21.85	1440.59	129.87	110.39	244	11875 psia (12.6 ppg) (based on fluid gradient 0.568 gm/cc)	18142
								Vsh<0.4	Poro>0.14	Sw<0.5	Vsh<0.4	Poro>0.14	Sw<0.5								
If Density log is not corrected to match core porosity																					
	18067.0	18089.0	17981.1	18003.1	Oil	No Use Other	M56D	22	22	22	18.32	18.32	18.32	18.55	18.55	26.96	10.46	26.96			

1. From core in M56D and M56E: K (klinkenberg air core at net confining stress = 2000 psi) is a function of core porosity at net confining stress
2. Log porosity is calibrated to core porosity at net confining stress in M56D & M56E
3. Log perm is calculated from core derived equation (from #1)

Gross has Vshale cut off Vsh<0.4
Net has a Porosity cut off Poro>0.14
Pay has a Sw cut off Sw<0.5

Water Depth = 4992 feet