To: Lott, Jeff M[jeff.lott@bp.com]; Fowler, Mike R[Mike.Fowler@bp.com]; Hupp, Jeffrey L (HOU)[Jeff.Hupp@bp.com]; Quitzau, Robert[robert.quitzau@anadarko.com]; dstrickland@spemail.org[dstrickland@spemail.org]; Bednarz, Michael J[Michael.Bednarz@bp.com]; Boyd, Thomas A[Thomas.Boyd@bp.com]; Powell, Keith (MULLEN ENERGY)[Keith.Powell@bp.com]; Mullen, Mike E (Mullen)[Mike.Mullen@bp.com]; Loya, Darrell (MULLEN ENERGY)[loyad0@bp.com]; Melvan, Joe (Orbis)[Joe.Melvan@bp.com]; Jim Fairbairn[jfairbairn@orbisengr.com]
From: Sharadin, John H
Sent: Fri 5/14/2010 11:09:42 PM
Importance: Normal
Sensitivity: None
Subject: New Plan
Categories: urn:content-classes:message

ExecSumTopKill rev3.ppt
Momentum Kill Risks.doc

<<ExecSumTopKill rev3.ppt>>

Team
We are on Option 1 of slide two. We need a procedure to review amongst ourselves tomorrow afternoon. There will be an outside review on Sunday morning on the diagnostics procedure, and Sunday afternoon with the new Kill procedure.

This slidepack has some good stuff in it, but don't get hung up.

The objective for the night crew is to flesh out more of a plan. Please keep good notes. As you go along:
Identify risks
Identify diagnostic needs that need to be plugged into the diagnostics procedure of mike/Keith.
Keep track of questions and needs
As you put your thoughts together, consider how "option 2" might be employed. Understand, though, that the frac balls or other means for #2 are NOT available for Option 1. Sorry!

We'll hand back over in the morning.
Feel free to go grab some wildwell guys if you need, and others as well if you want to review.

Here is a set of risks I've identified, fyi.
<<Momentum Kill Risks.doc>>
Thanks,
John

9940
Exhibit No. _____
Worldwide Court Reporters, Inc.

Q4000 Operations
Pump-in Diagnostics and
Potential Top Kill Option

Execution Options – Lower to Higher

1. **No Bridge** - Pump 16.4ppg Water Based Mud at as high a rate as possible (40 – 50 BPM) for the first 300 bbls at 8000 psi maximum pressure. Slow down pumps after 300 bbls and maintain highest rate possible at 7200 psi maximum.
   - Regret – Erode orifice and flow increases

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  1. Regret – Complete bridge and exceed allowable shut-in pressure or reduce downhole injectivity – Low Liklihood.

- **Complete Bridge** – Pump either platelets or Junk Shot and follow injection plan per step 1.
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1. **Complete Bridge** - Stop Operation.
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System Review
Reservoir Build Up –Best Case

- Shut-in Pressure at Mudline – 8400 to 8900 psi using 3 Different Models
  - 100 psi / min recovery / 12 min @ 5000 BPD
  - 400 psi / min recovery / 7 min @ 5000 BOPD
- Assuming choke is deep and flow rate is 5000 BOPD build up time is 20 minutes
- Assuming choke is deep and flow rate is 25000 BOPD then build up time is 5 minutes
- Depletion is unknown

System Review
Casing and Ancillary Seals

- At Maximum Wellhead Shut-in Pressure of 8900 psi
  - General System Limitation is 7000 psi with 20% Safety Factor, however;
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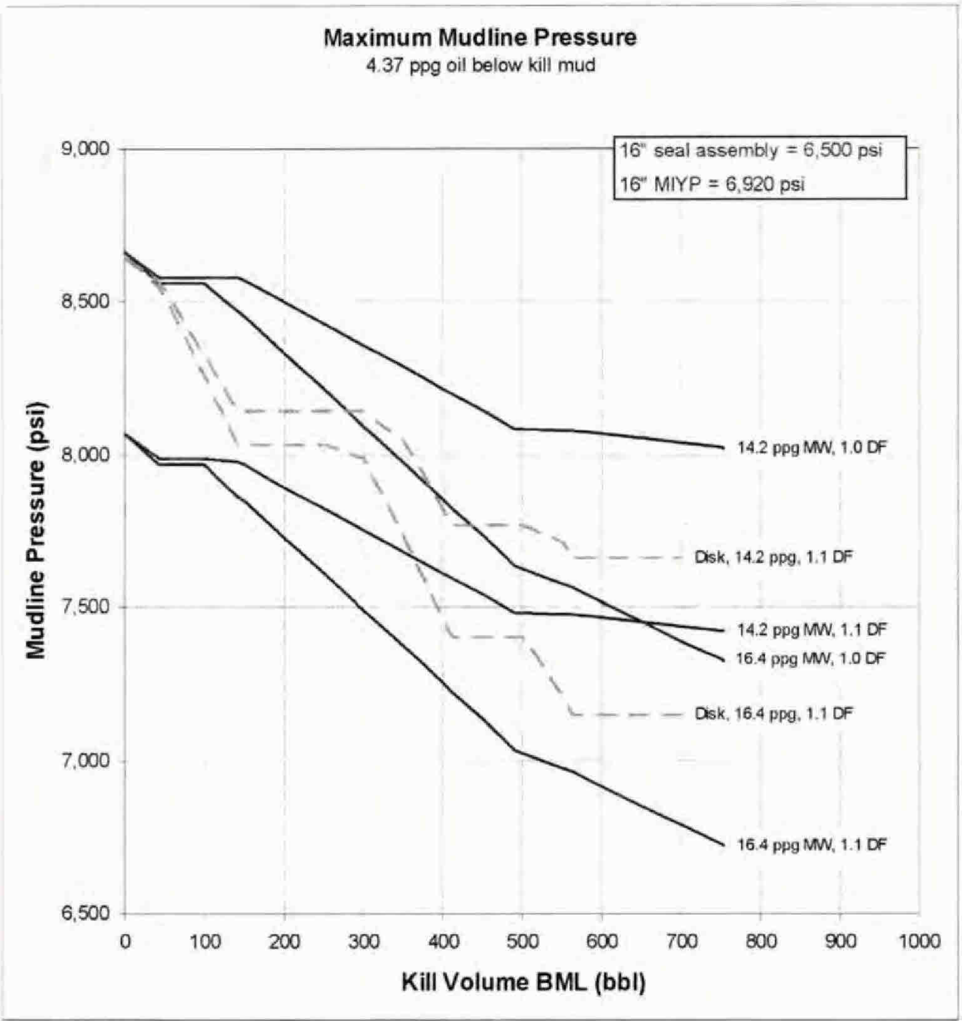
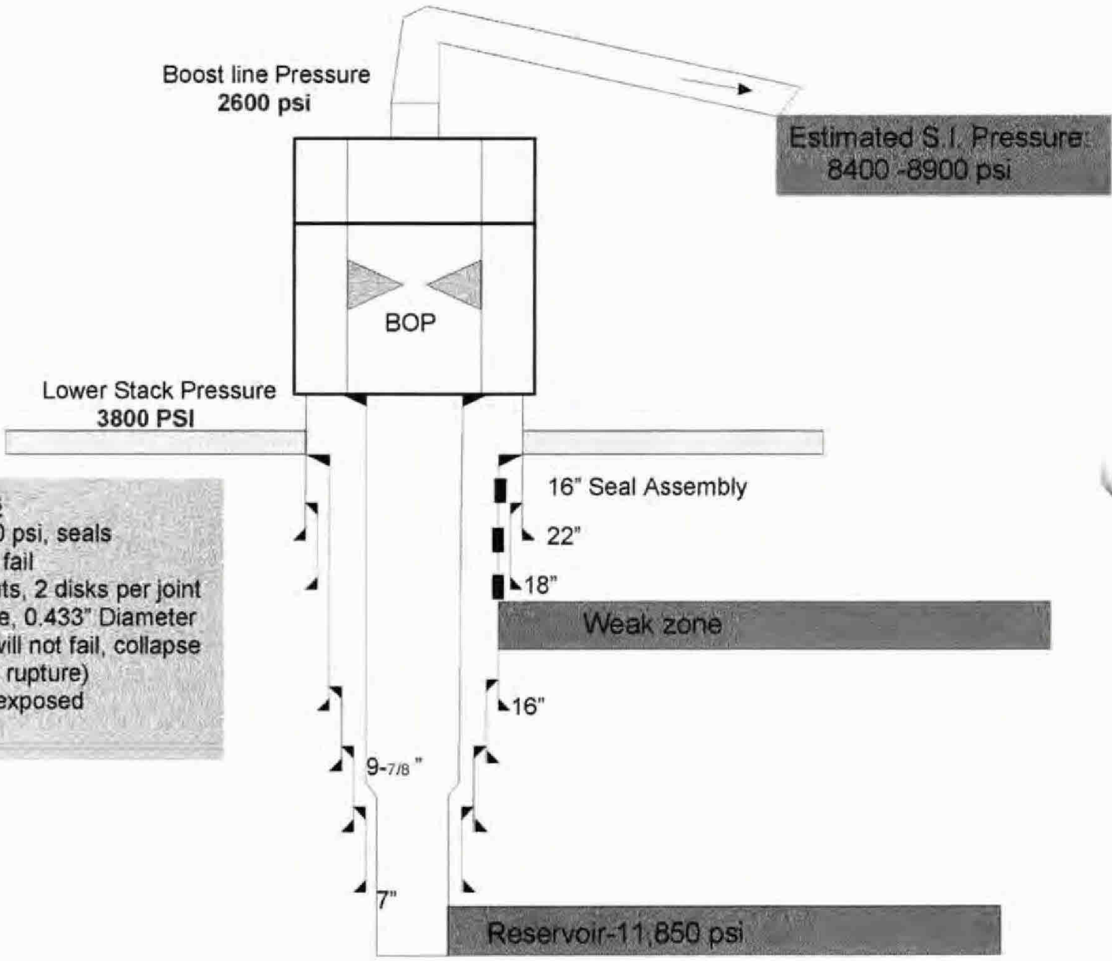
    - Pressure will exceed 16" seal assembly rating but not laboratory tested pressure – protecting 18" shoe
    - 16" will yield but not rupture


Maximum Mudline Pressure
4.37 ppg oil below kill mud
16" seal assembly = 6,500 psi
16" MIYP = 6,920 psi
Mudline Pressure (psi)
9,000
8,500
8,000
7,500
7,000
6,500
0
100
200
300
400
500
600
700
800
900
1000
Kill Volume BML (bbl)
14.2 ppg MW, 1.0 DF
Disk, 14.2 ppg, 1.1 DF
14.2 ppg MW, 1.1 DF
16.4 ppg MW, 1.0 DF
Disk, 16.4 ppg, 1.1 DF
16.4 ppg MW, 1.1 DF

System Pressure Limitations



System Weak Points
- -16" Seal Assembly -6500 psi, seals will weep, but will NOT fail
- -16" Collapse Disks-3 joints, 2 disks per joint 6800 psi, sudden failure, 0.433" Diameter
- -16" Casing -6600 yield, will not fail, collapse disks fail first (7800 psi rupture)
- -18" Shoe -5520 psi (not exposed unless burst disks fail)

System Review
Description of Well Kill Scenarios

- Best Case Modeled
  - Drill Pipe in BOP Stack across casing shears and flow up annulus
  - 9 7/8" Casing Hanger not choking
  - Choke is Deep near Reservoir
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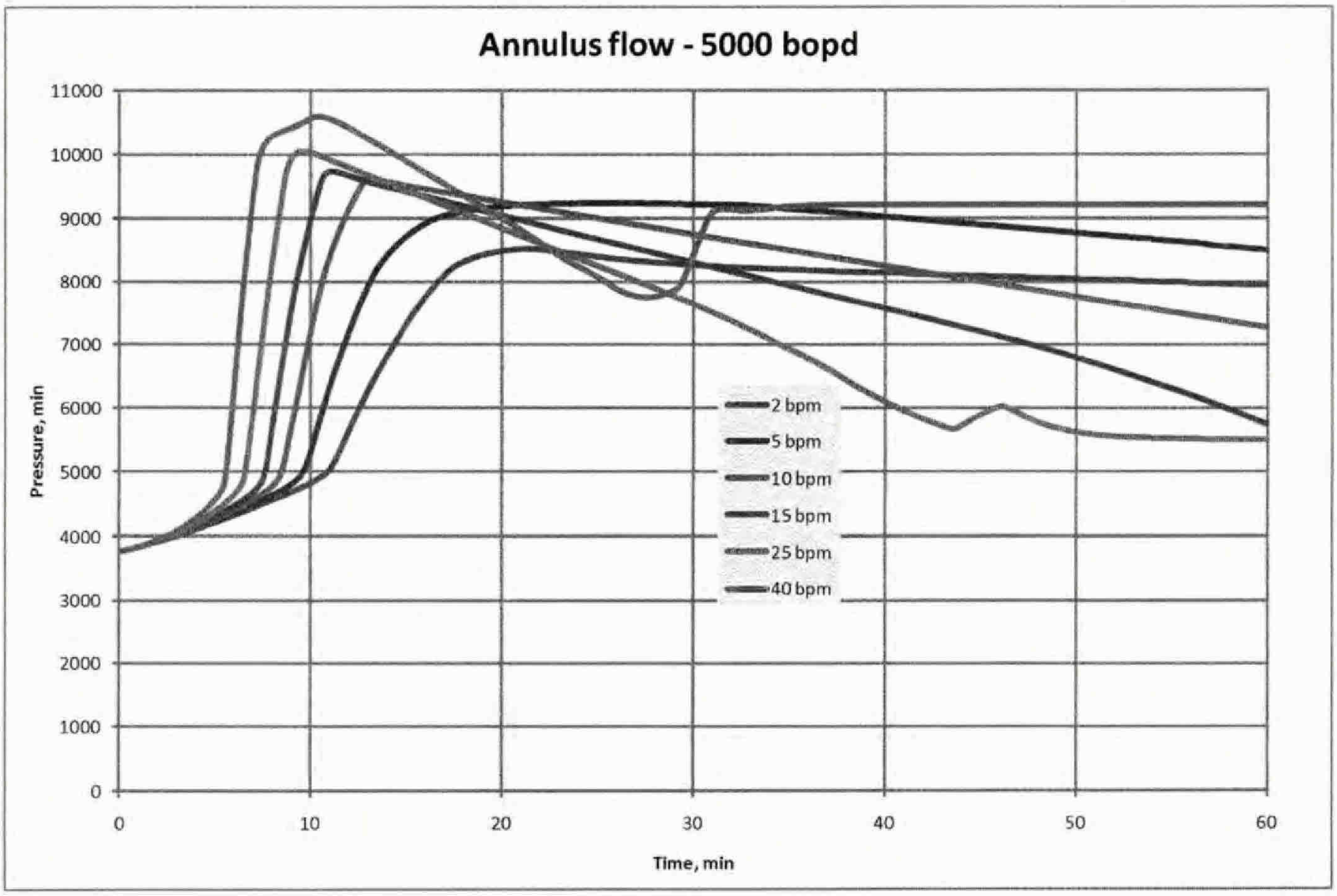
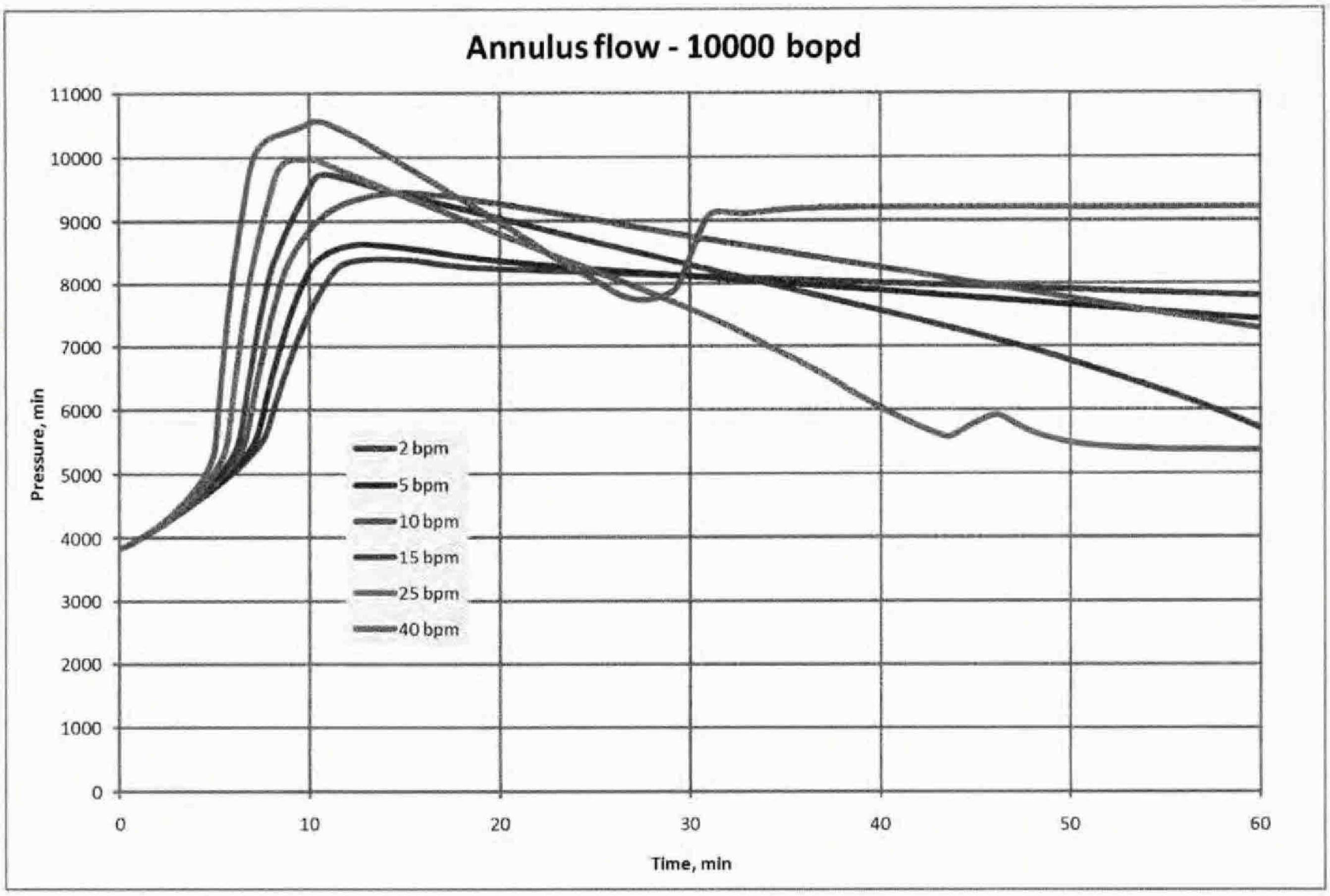
  - No Drill Pipe in BOP Stack
  - Flow up Drill Pipe and Annulus
  - Choke is Shallow at Casing Hanger



Annulus flow - 5000 bopd
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Pressure, min
0
10
20
30
40
50
60
Time, min
2 bpm
5 bpm
10 bpm
15 bpm
25 bpm
40 bpm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10000
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Pressure, min
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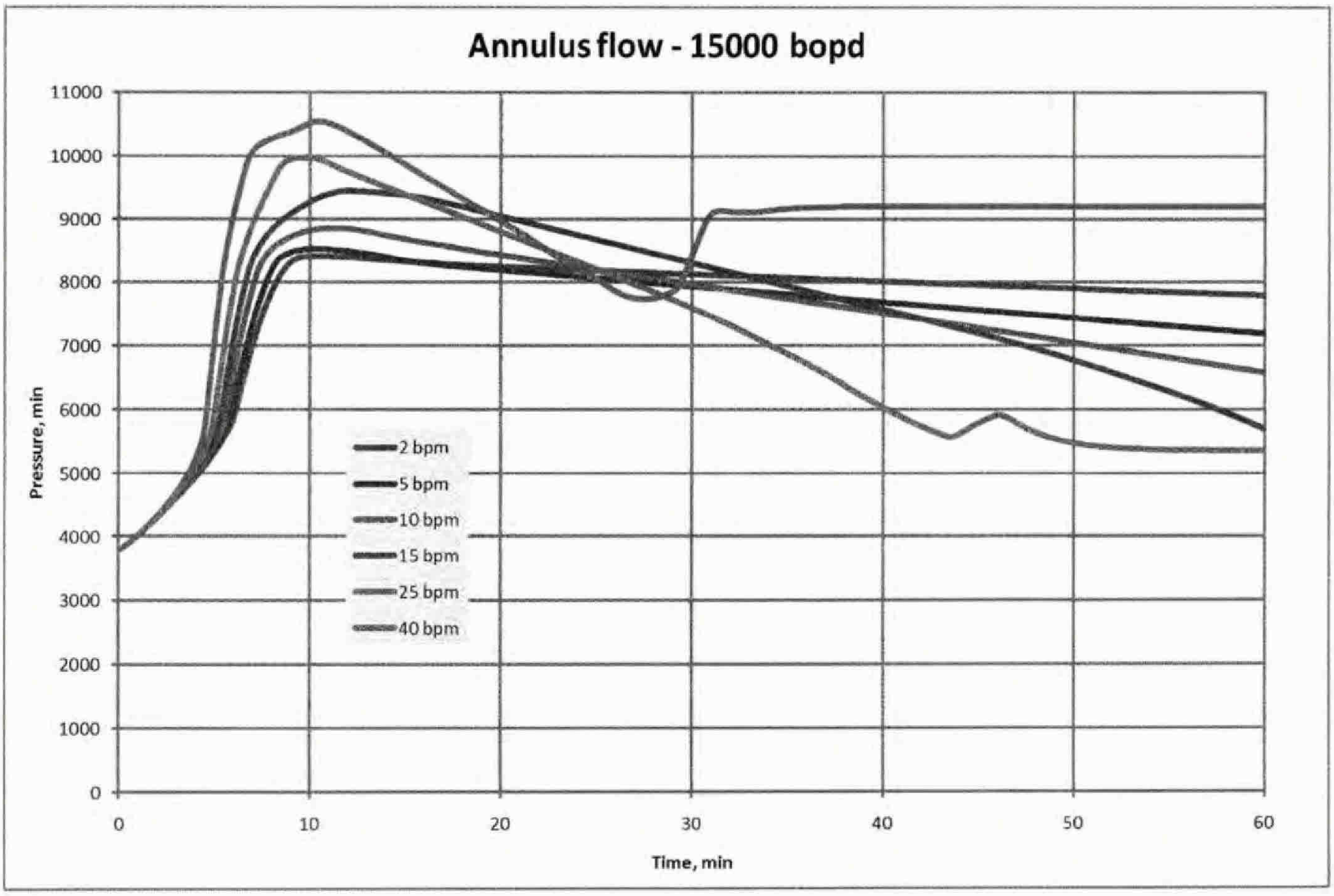
10
20
30
40
50
60
Time, min



Annulus flow - 15000 bopd
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Pressure, min
2 bpm
5 bpm
10 bpm
15 bpm
25 bpm
40 bpm
0
10
20
30
40
50
60
Time, min

System Review
High Level Risks

- Well Integrity Compromised – Increased Flow at MC 252 #1
- Broach to seabed – Potential for Shallow Interval Charging, Jeopardizing Relief Well

Back-up

Kill Models – Worst Case, Deep Choke

- Olga model estimates Shut-in Pressure at Wellhead at 9000 psi for 5 bpm @ 5000 BOPD
- Olga model estimates 8500 psi for 5 bpm at 25000 BOPD

Kill Rates - Best Case, Deep Choke

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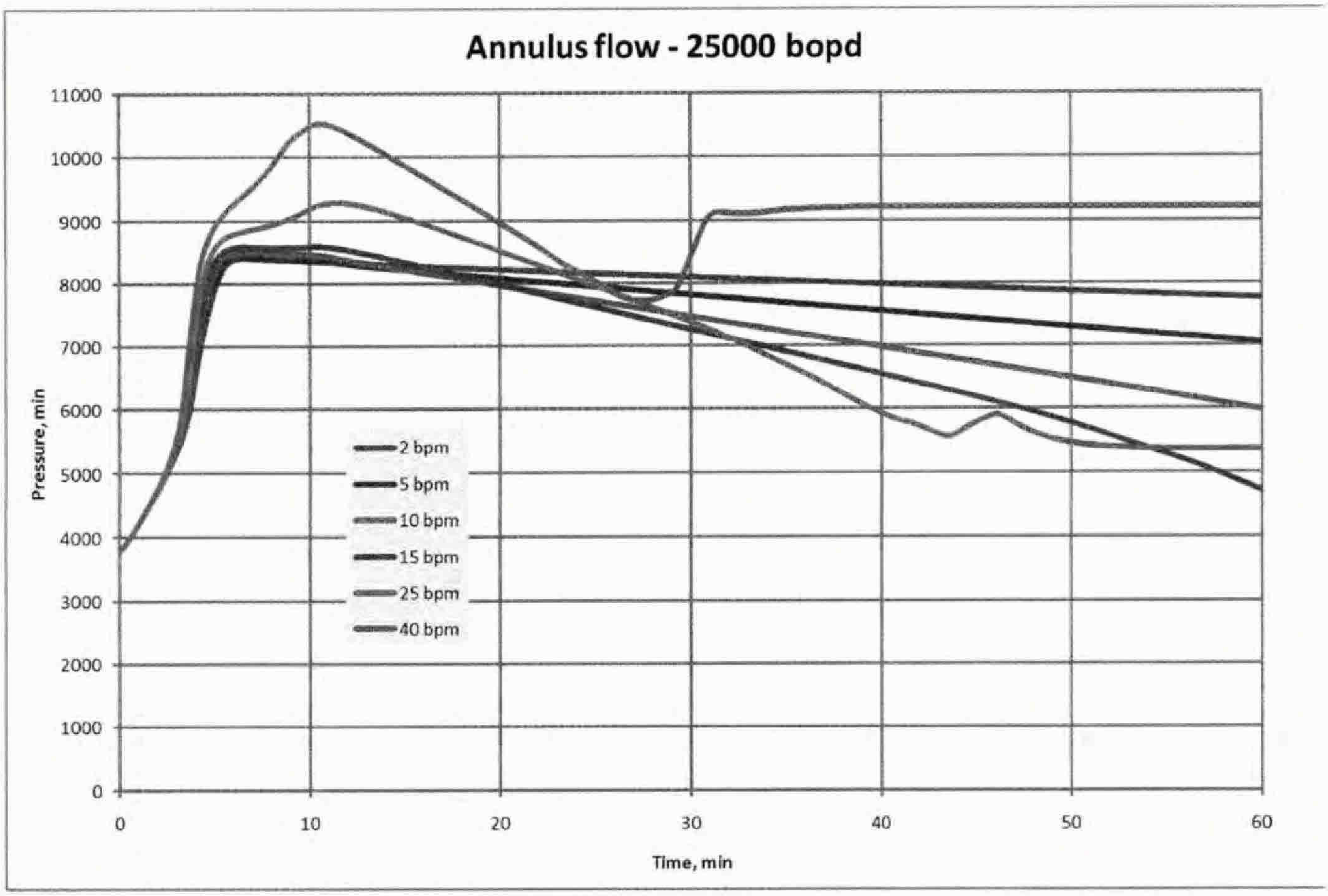
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11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Pressure, min
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10
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30
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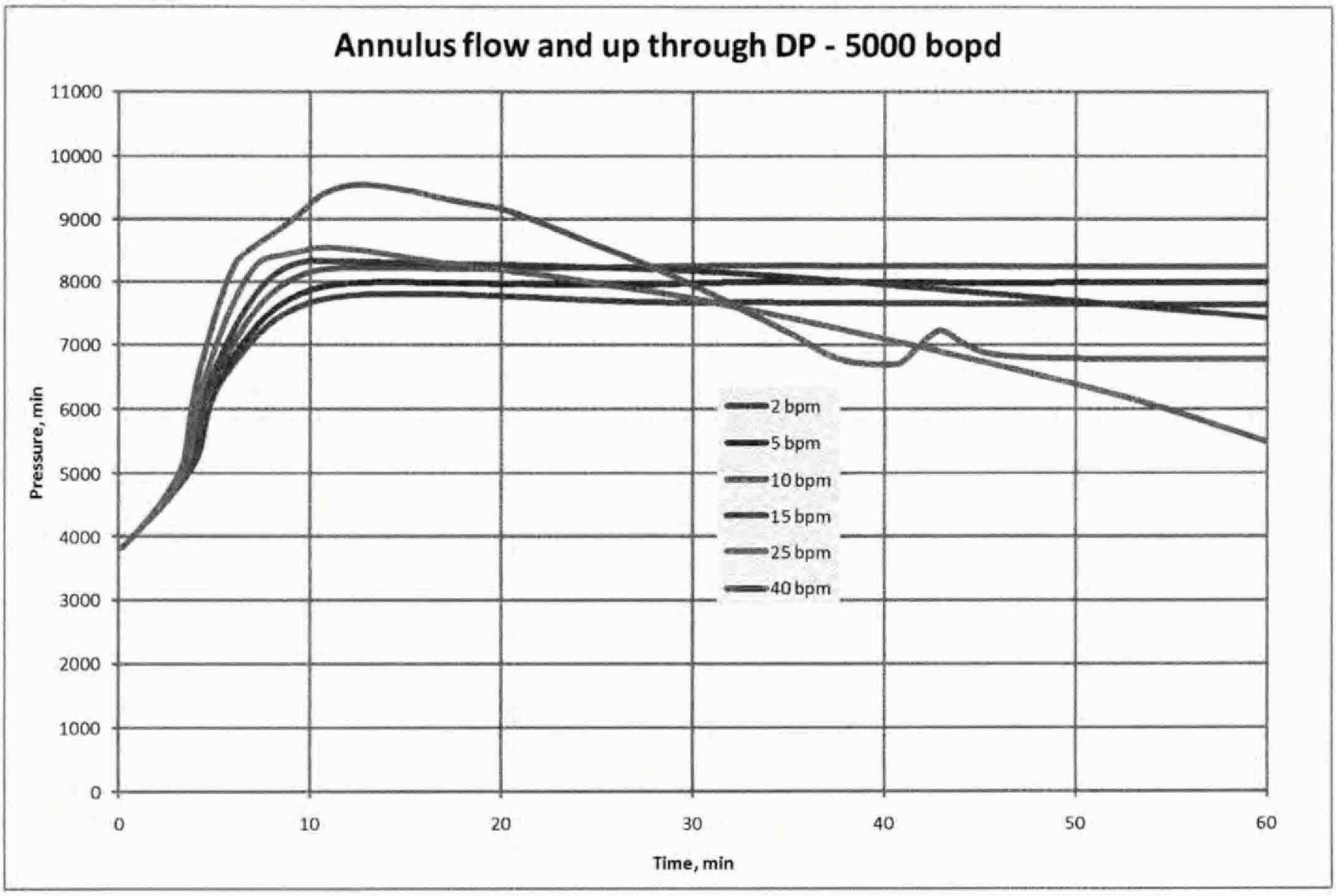
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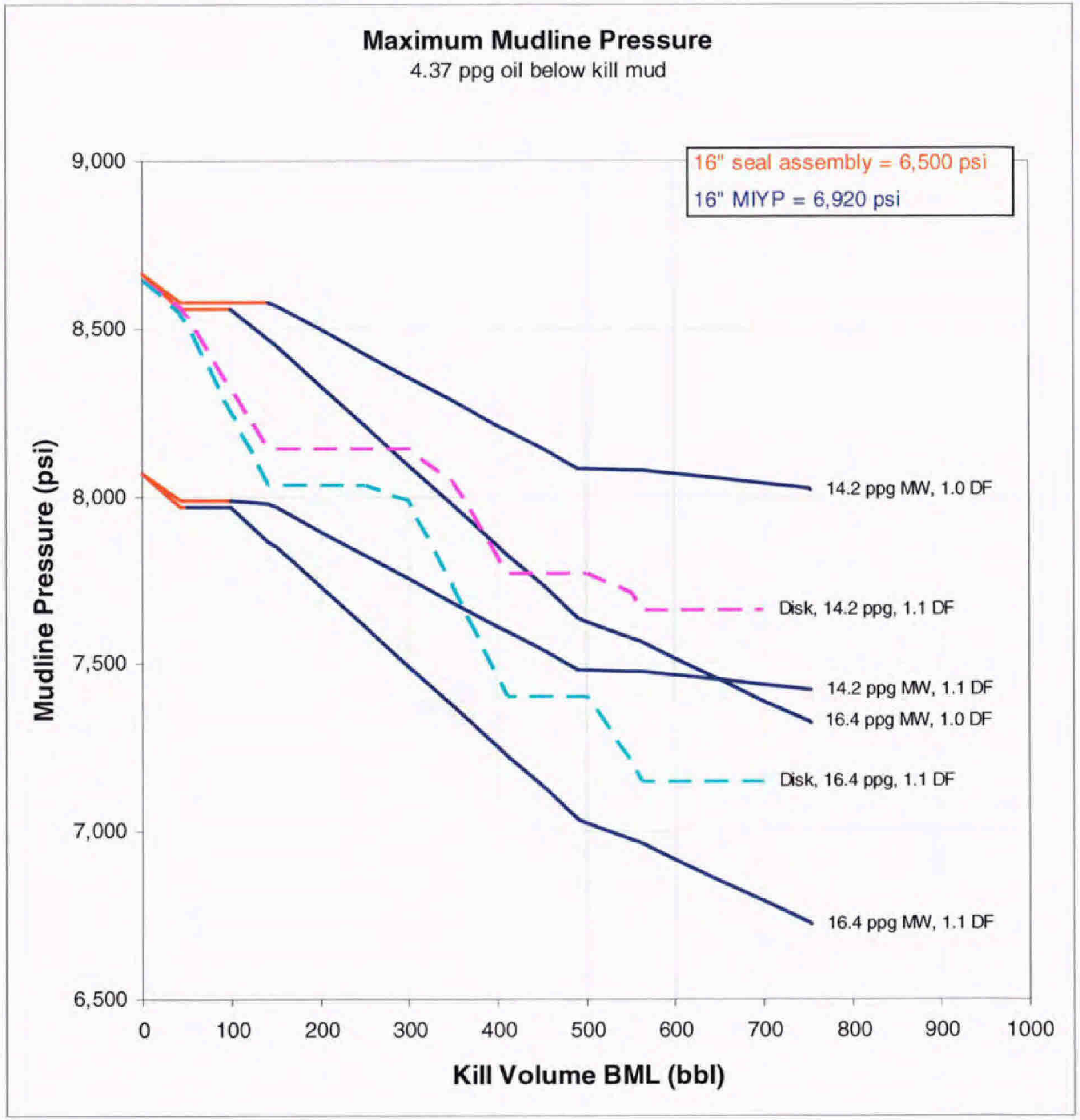
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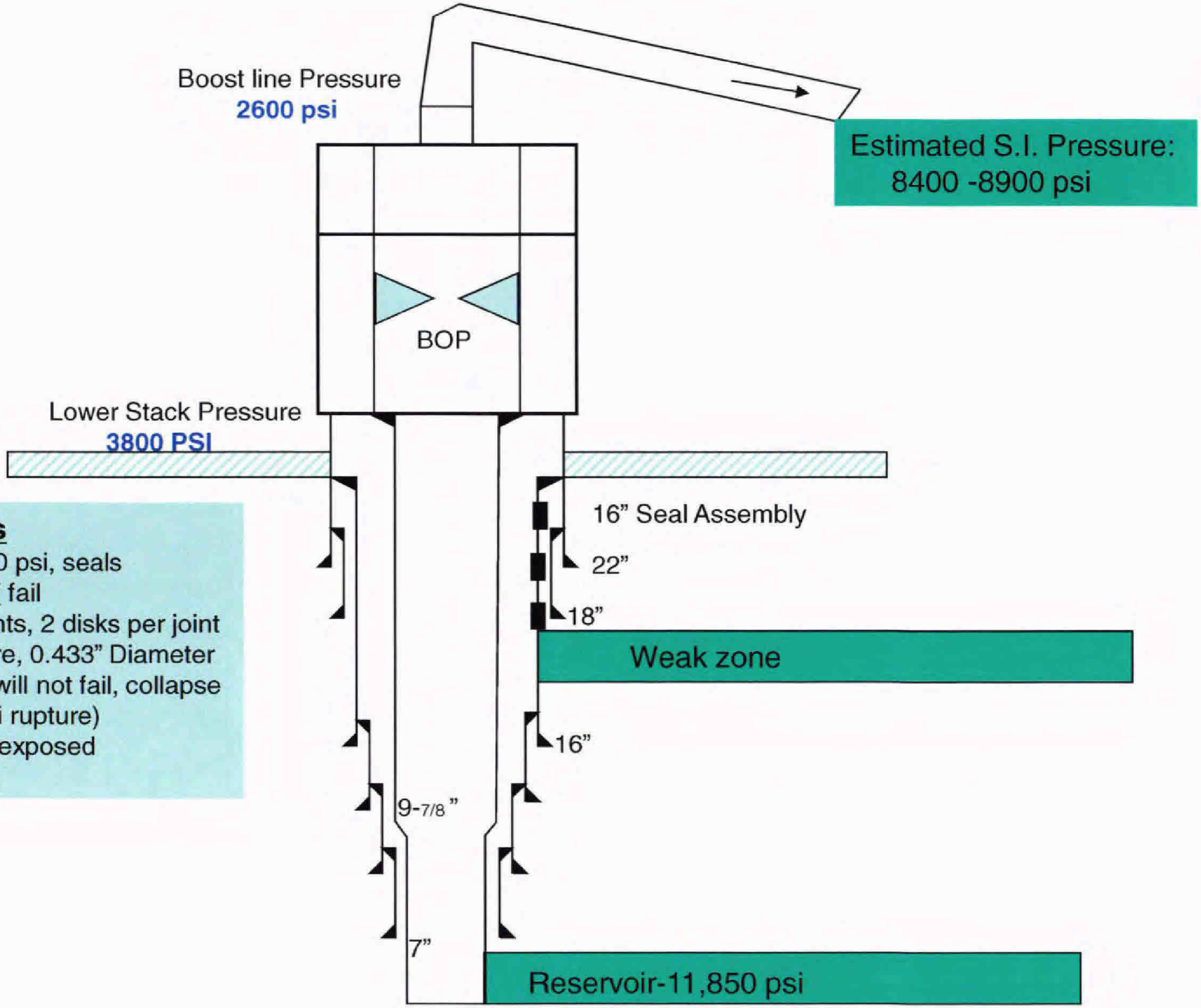
Disk, 16.4 ppg, 1.1 DF
16.4 ppg MW, 1.1 DF

System Pressure Limitations



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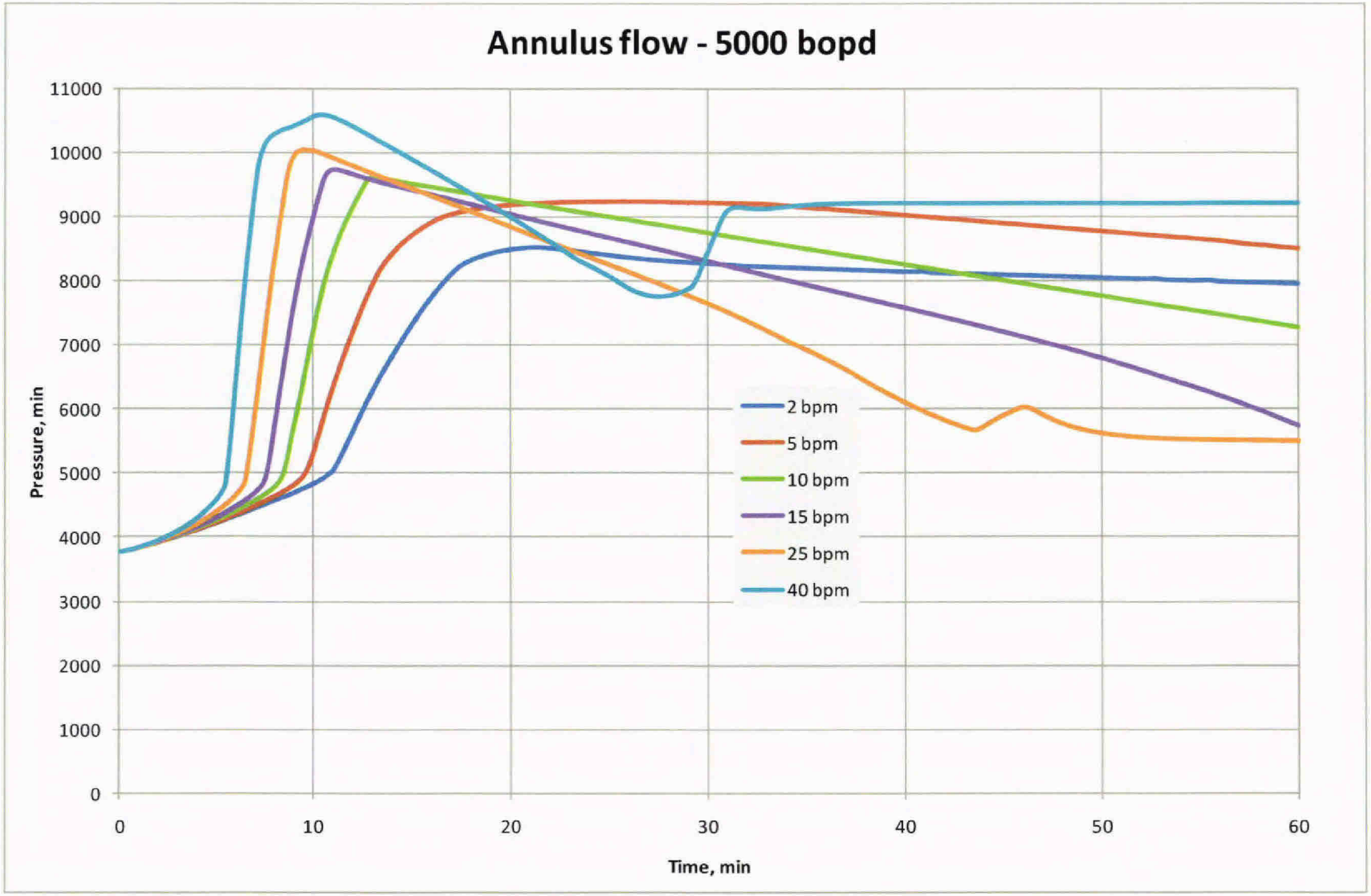
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Pressure, min
Time, min
11000
10000
9000
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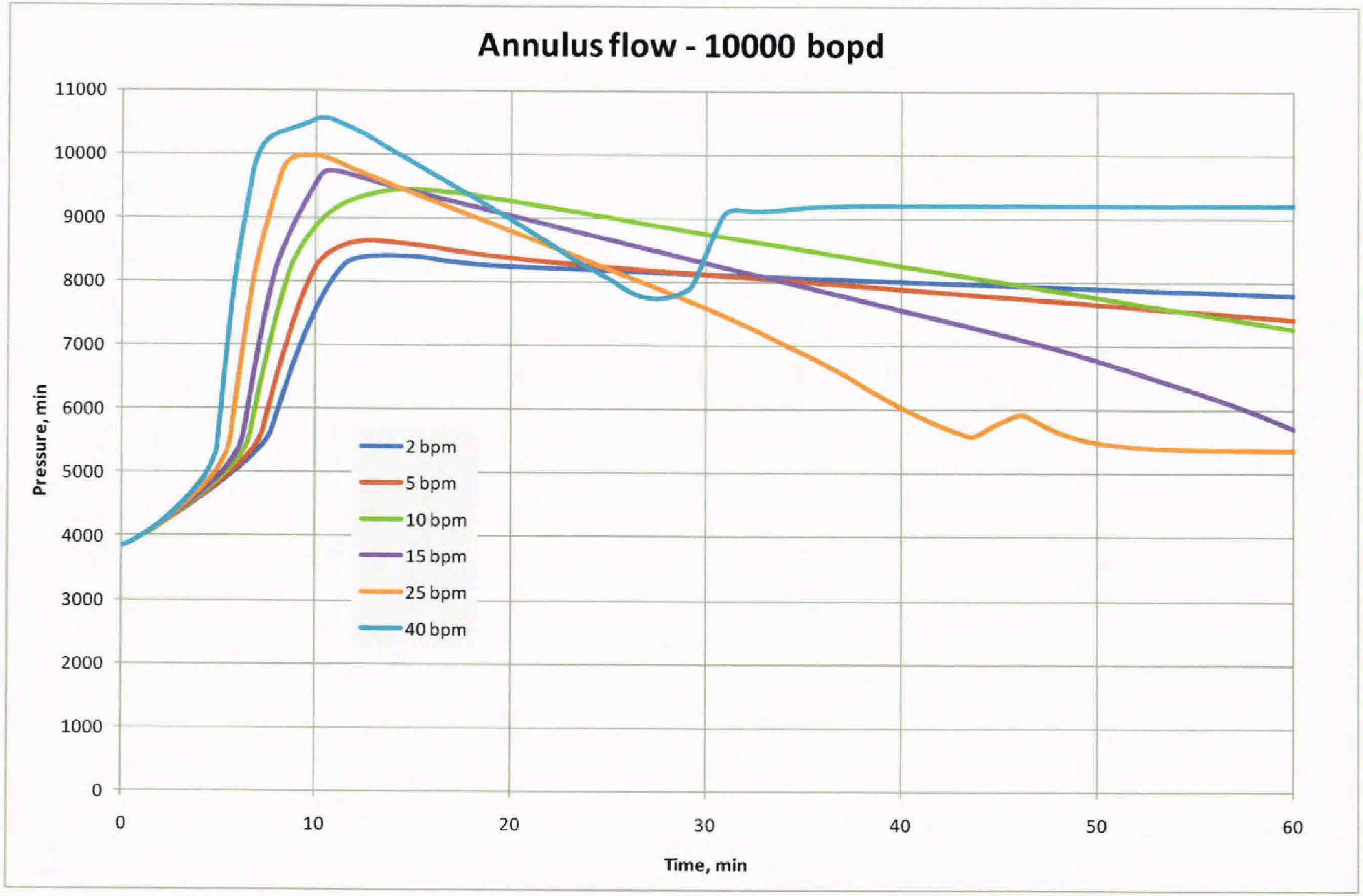
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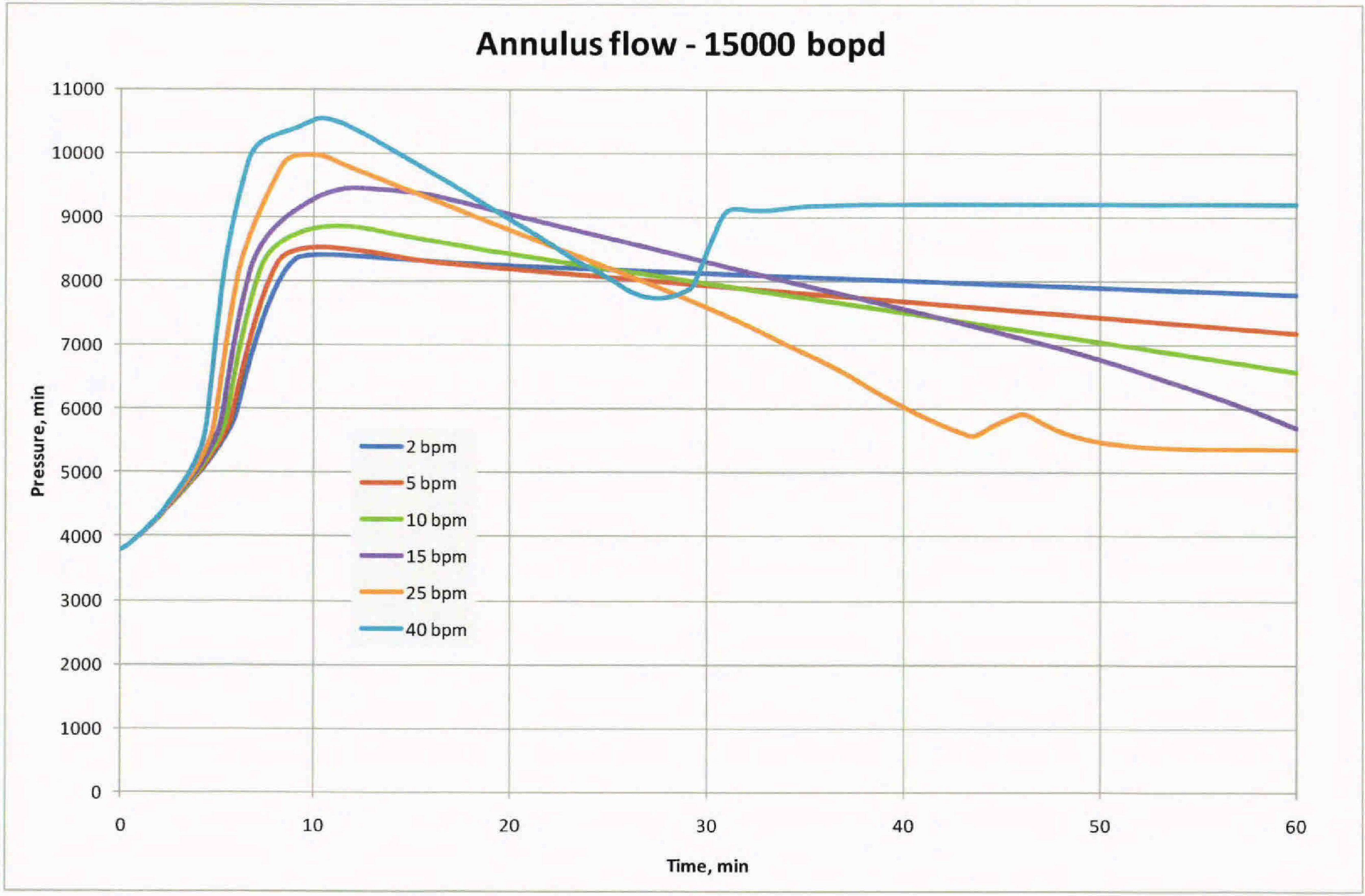

Annulus flow - 15000 bopd
11000
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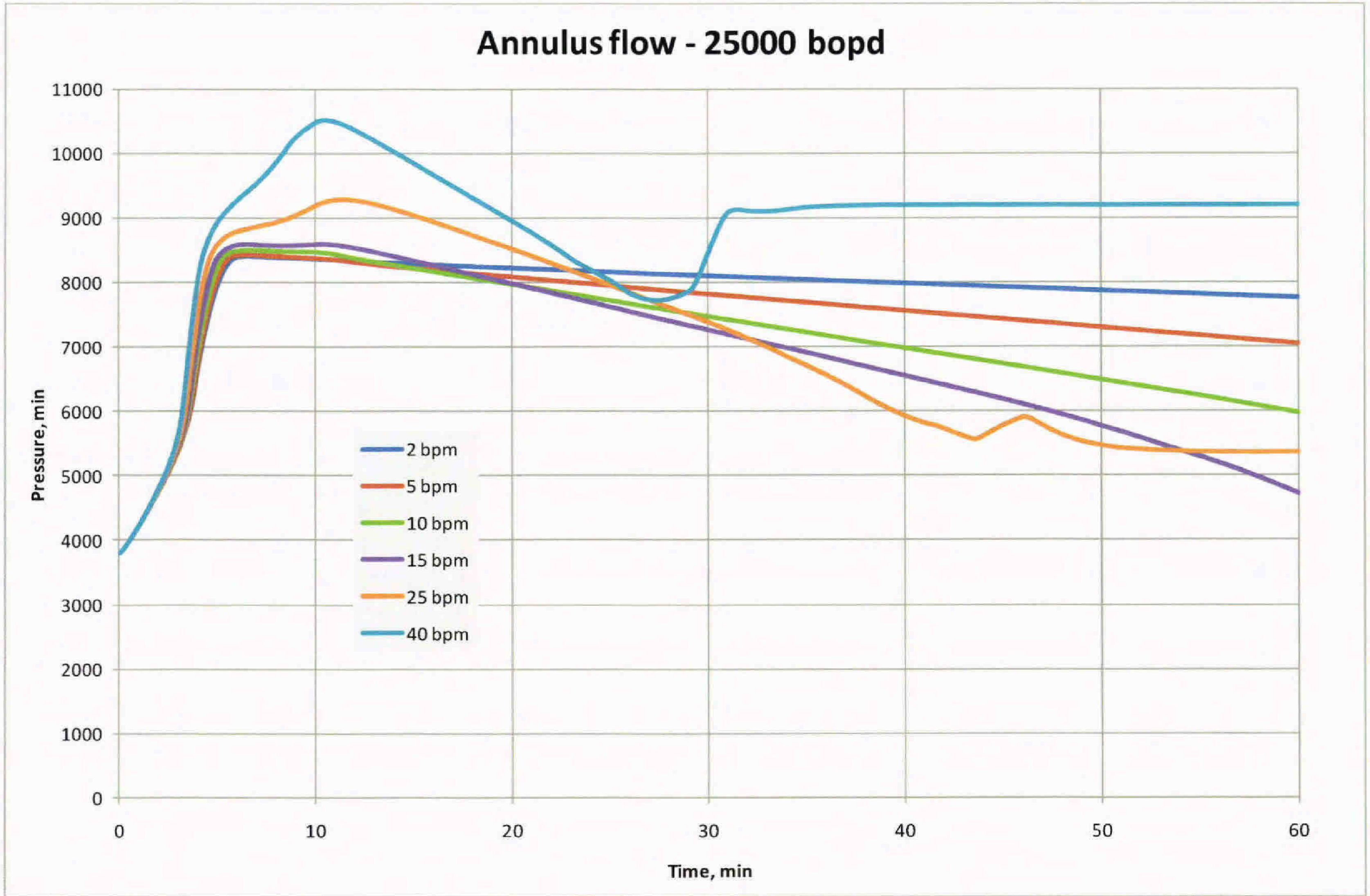

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11000
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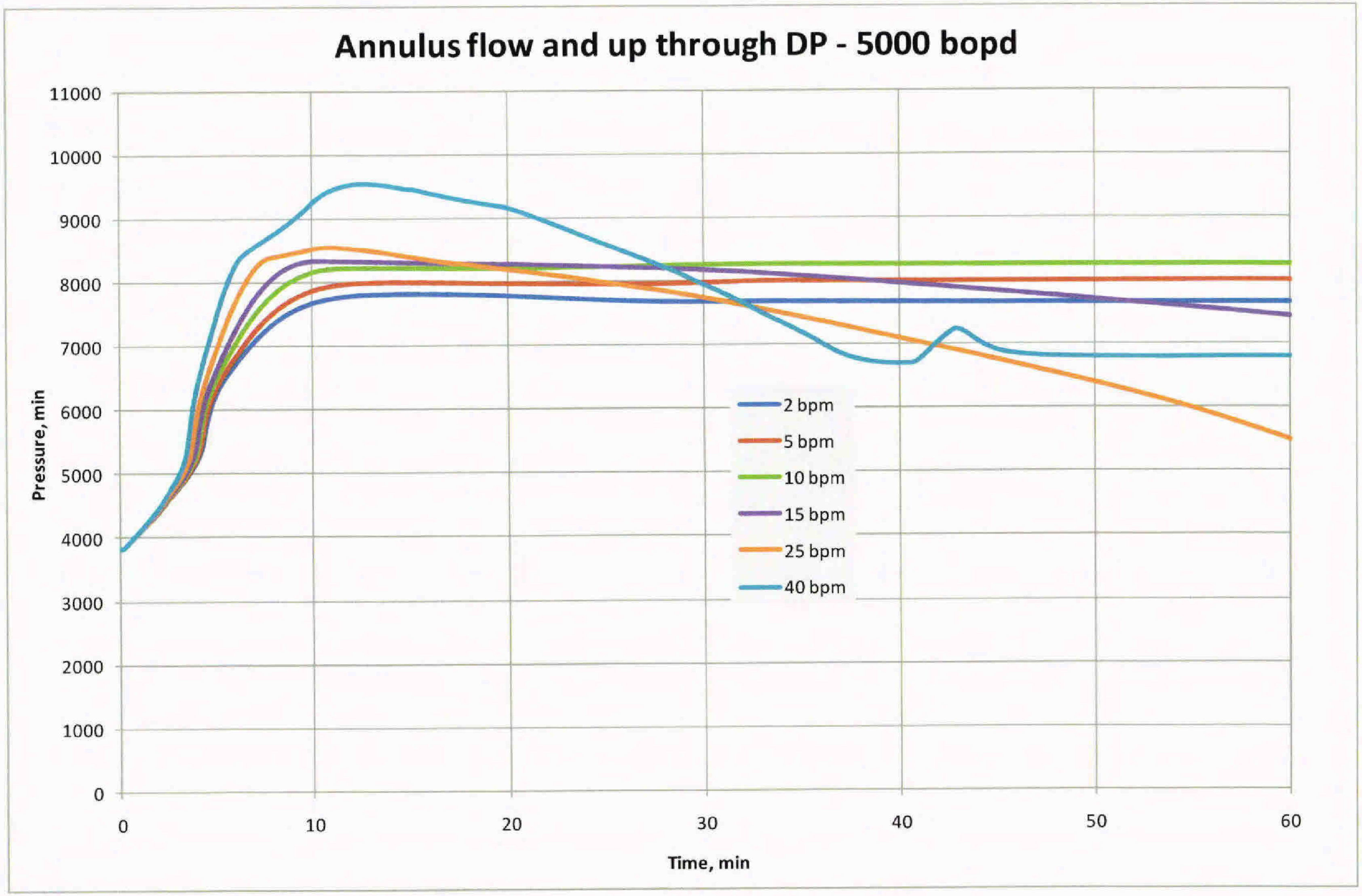
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Pressure, min
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11000
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60
2 bpm
5 bpm
10 bpm
15 bpm
25 bpm
40 bpm

14 May, 2010

<u>Risks associated with this operation:</u>

Risks associated with high rate:

- Overrun if fast lockup - Pressures will climb as order given to shut down - may have only a few hundred psi of room. Exposes weak elements to failure.
- Erosion over the long job - the orifice will likely enlarge; the pumping assumptions change and the ability to pump to a pressure schedule is compromised. Perhaps we can model this? Also, if well reverts to current, the flow area will increase and will produce some incremental surface flow - perhaps small.

Other risks

- Low injectivity of the formation: In the 5000 bopd case, flow is 3.5 bpm. If injection is 10% (generous) of that, we would inject 0.35 bpm with the same pressure differential, which will be several hundred pounds (in addition to "shut-in). This will take a long time to get mud past the weak points and further down the hole to where we can raise the pressure to frac. Until we get fluid far down the well, we can not frac - only inject. As a consequence, we'll be pumping mud for a long time - erosion and exhaustion of supply.
- Don't really know how much fluid in well. If putting more fluid in the hole than thought, will be exerting more pressure on the weak components than expected.
- Curve families may not track. Do a test kill to mitigate this and some other bullets here?
- Counting on liner packoff to hold 7500 psi differential based on lab tests. Haven't seen documentation, but the liner was tested only to a substantially lower pressure ~3500 psi.
- There may be unidentified zones other than the gas and brine stringers - low probability, I'd guess.

John Sharadin