Flow Analysis Activities for the MC252 Well

Report-outs by Government Teams

PREDECISIONAL DRAFT

Friday, July 30

12:00 – 5:00 PM CDT

8635
Exhibit No.
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Introduction and Intent

Tom Hunter

Agenda

Time (CDT)	Speaker	Topic
12:00-12:15	Tom Hunter	Intro/Intent/Chronology
12:15-12:45	Bill Lehr	Flow Visualization Before TopHat-4
12:45-1:15	Dan Maclay	Reservoir – Time of Event with Production
1:15-2:00	George Guthrie	Nodal Analyses – Pre/Post Cut
2:00-2:15	*Break*	
2:15-2:45	Andy Bowen	Doppler Velocities ⟶ Kink and more
2:45-3:15	Paul Hsieh	Reservoir Studies Around Times of Well Integrity Test Shut-in
3:15-4:00	Art Ratzel	Flow prediction around Well Integrity Shut-in
4:00-5:00	Tom Hunter	Discussion and Close-out

Timeline for the Deepwater Horizon Events

Date	Time if available	Events -- Flow Conditions	Collection
20-Apr		Explosion and fire; oil continues to flow to damaged platform at ocean surface	None
22-Apr		Rig sinks; oil and gas flow into ocean from sunken riser	None
5-May		One of three leaks stopped on broken riser	None
8-May		Cofferdam lowered on broken riser; fails due to icing	Attempted
16-May		Riser Insertion Tool (RITT) begins to recover some oil	RITT on-line
25-May		Riser Insertion Tool (RITT) removed	None
26-May		Top kill begins	None
29-May		Top kill ends - unsuccessful	None
1-Jun		First Shear Cut	None
3-Jun		Second Shear Cut	None
3-Jun		Top Hat # 4 Installed (Enterprise recovering)	Enterprise on-line
16-Jun		Top Hat # 4 Operational (Q4000 on line and recovering from BOP manifold line)	Enterprise and Q4000 on-line
29-Jun		2nd set of Pressure Transducers introduced into Top Hat #4 to support flow rate estimation	Enterprise and Q4000 on-line
10-Jul		Top Hat #4 Removed	Q4000 on-line
12-Jul		Flange Removed - Spool Flange Installed	Q4000 on-line
12-Jul		3-Ram Capping Stack Landed/secured	Q4000 on-line
13-Jul		HP1 came on-line; recovering from BOP manifold line	Q4000 online; HP1 coming online
13-Jul	~4:00 PM	Started Well Integrity Test - shut-in operations initiated	None
13-Jul	5:48 PM	Terminated shut-in test due to leak in choke line of stacking cap flow diverted to kill side of stack only	None
15-Jul	12:15 AM	Recovery resumes(during repairs to choke line) with Q4000 and HP1 operational	Q4000 and HP1 brought back on-line
15-Jul	~12:00 PM	Recovery stopped - Well Integrity shut-in begins	None
15-Jul	2:30 PM	Well Integrity test shut-in completed	No flow; shut-in

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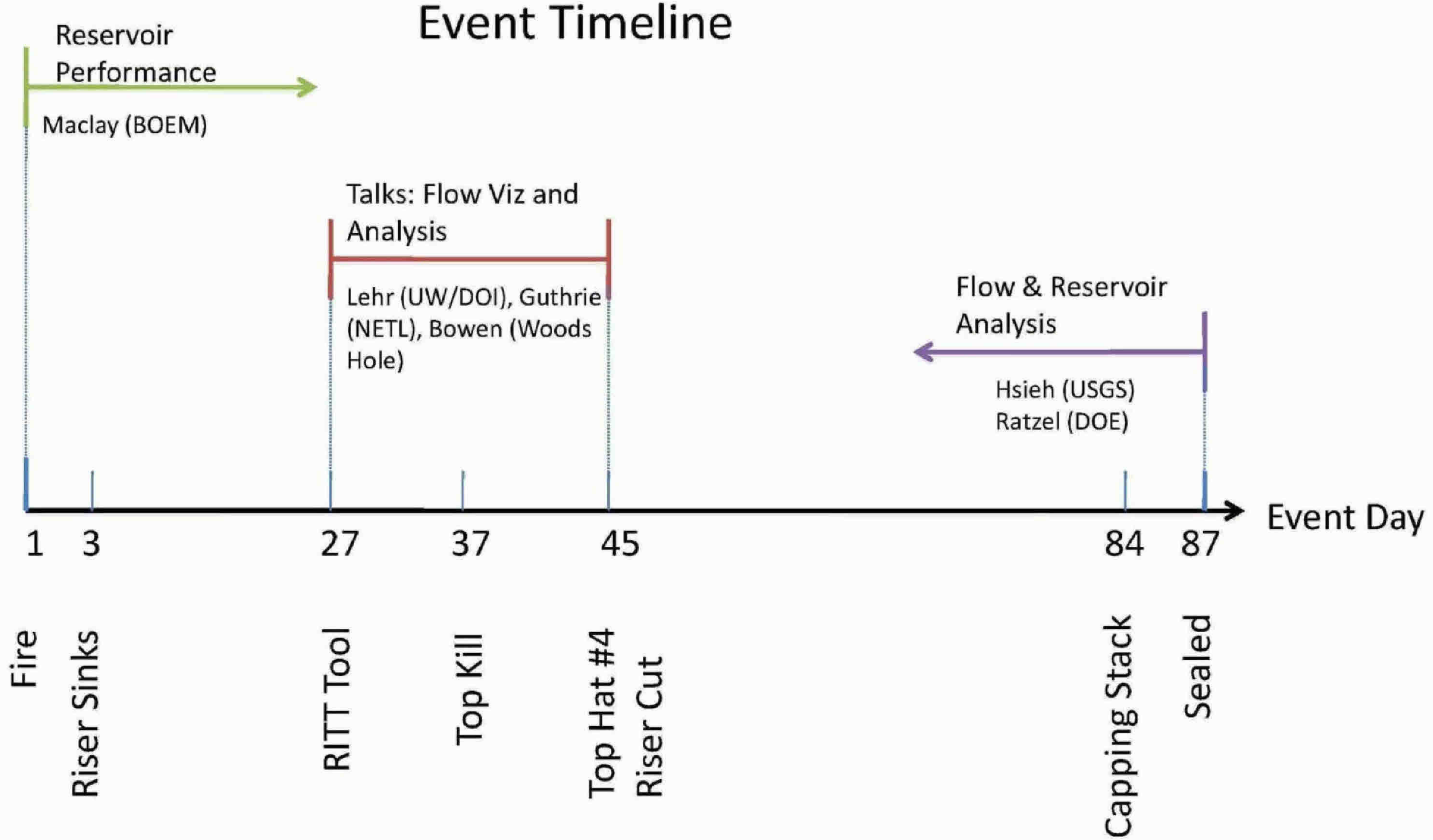
Event Timeline



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Problem Statement

- The intent of this meeting is to review the different methods, evaluate the uncertainties, and to come to consensus on a revised, more informed estimate on flow.

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Flow Visualization Before TopHat-4

Bill Lehr
Alberto Aliseda
Steve Wereley

BOEM

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FLOW RATE TECHNICAL GROUP PLUME TEAM

Aliseda, Alberto	Assistant Professor of Mechanical Engineering, University of Washington
Bommer, Paul	Senior Lecturer, Petroleum and Geosystems Engineering, University of Texas at Austin
Espina, Pedro	National Institute of Standards and Technology
Flores, Oscar	Department of Mechanical Engineering at University of Washington
Lasheras, Juan C.	Penner Distinguished Professor of Engineering and Applied Sciences, University of California at San Diego
Lehr , Bill (Lead)	Senior Scientist, National Oceanic and Atmospheric Administration Office of Response and Restoration
Leifer, Ira	Associate Researcher, Marine Science Institute and Institute for Crustal Studies, University of California, Santa Barbara.
Possolo, Antonio	National Institute of Standards and Technology
Riley, James	PACCAR Professor of Mechanical Engineering, University of Washington
Savas, Omer	Professor of Mechanical Engineering, University of California at Berkeley
Shaffer, Franklin	Department of Energy National Energy Technology Laboratory
Wereley, Steve	Professor of Mechanical Engineering, Purdue University
Yapa, Poojitha	Professor of Civil and Environmental Engineering, Clarkson University

Today's Presenters

Bill Lehr
Alberto Aliseda
Steve Wereley

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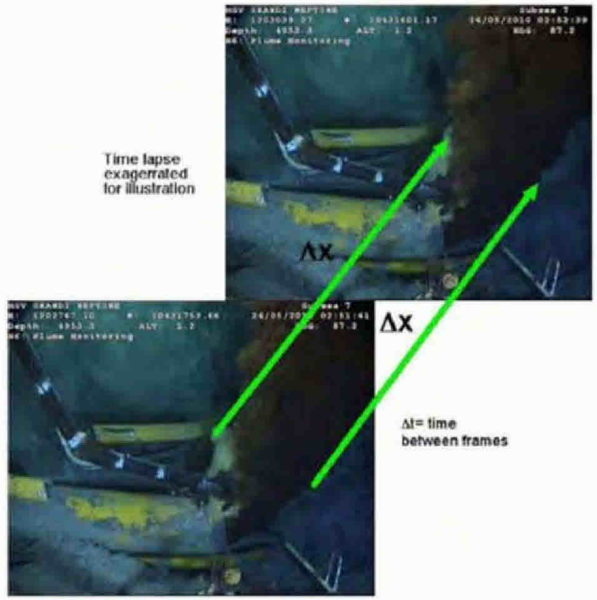
Time/Situation

May 14	ADM Allen requests the National Incident Command (NIC) Interagency Solutions Group (IASG) to provide information on the discharge rate of oil from the well
May 17	NIC IASG assigned leadership of the Flow Rate Technical Group (FRTG) to MMS. The group was initially called the Flow Rate Technical Team. The first task of the team was to determine the flow rate of oil from the well. MMS works with OSTP and NOAA to draft the FRTG Work Plan.
May 26	**FRTG Created.** Flow Rate Technical Group Work Plan approved by the agency members of the NIC IASG. The FRTG Work Plan creates two primary deliverables 1) an ASAP preliminary estimate of the flow rate range from the plume analysis team and 2) on a longer time frame (approximately 1-2 months intended), with extensive peer review and multiple modeling methodologies, a final estimate of the flow rate range and oil spill volume range.
May 27	**Press release on preliminary flow results.** Three independent methods were used by the FRTG to estimate the amount of flow, with the overlap between them being 12,000 to 19,000 barrels per day. One team estimated the flow at 25,000 barrels per day or higher. The methodologies were 1) plume analysis, 2) mass balance analysis using AVRIS surface oil estimates, and 3) flow rate from the RITT with analysis of the plume with the RITT inserted. http://www.deepwaterhorizonresponse.com/go/doc/2931/569235/
June 02	**FRTG preliminary report** was released for broad distribution citing flow rate of 12,000 – 19,000 barrels per day or 25,000 or higher.
June 07	**Plume Team receives new video** of plume after the riser was cut and before Top Hat installed; begin analysis of video.
June 10	**Press Release** of updated flow estimates. From refined analysis by Plume Team of pre-riser cut video: best estimate of 25,000 to 30,000 BPD; could be as low as 20,000 or high as 40,000. Updated Mass Balance Team estimate of 12,600 to 21,500 BPD. Mentioned the WHOI report (see below). No formal report issued in conjunction with Press Release. http://www.deepwaterhorizonresponse.com/go/doc/2931/627011/ Woods Hole Oceanographic Institute submits report on Sonar/Doppler analysis of plume: estimates 0.12m3/s to 0.23m3/s. Under some assumptions, this is consistent with some FRTG range estimates.
June 14	**Meeting of FRTG and DOE teams** with Secretary Energy and Secretary Interior in Washington D.C. Developed consensus for "government estimates" of current flow rate (35,000 – 60,000 BPD)
June 15	**Press Release** on updated flow rates for post-riser period. DOI and DOE jointly release an estimate of 35,000 – 60,000 BPD. Consensus flow rate based on new Plume Team analysis of post-riser cut video and DOE analysis of new pressure gage readings. http://www.deepwaterhorizonresponse.com/go/doc/2931/661583/

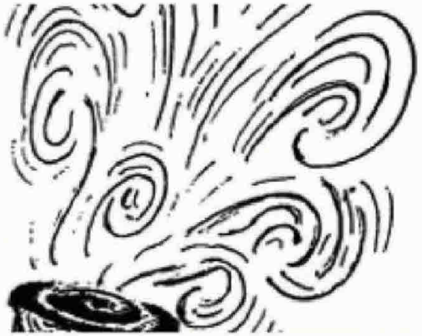
PLUME TEAM

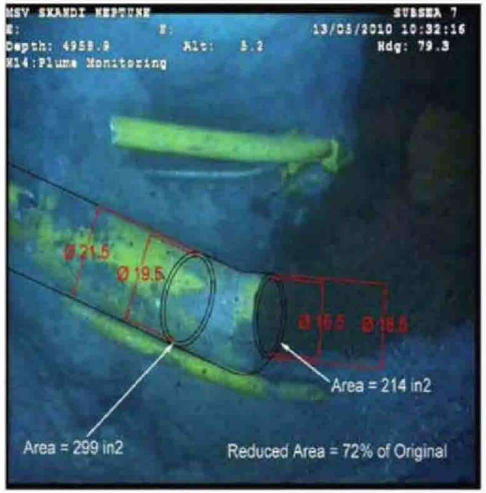


HOW

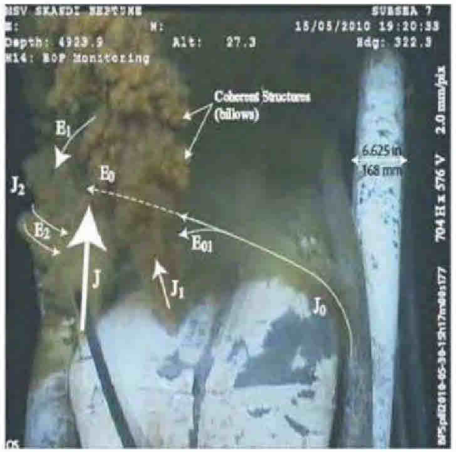
The main method employed to make estimates was a common fluid dynamic technique called particle image velocimetry (PIV). While difficult in practice, it is simple in principle. A flow event, e.g. an eddy or other identifiable item, is observed at two consecutive video frames. Distance moved per time between frames gives a velocity, after adjustment for viewing angle and other factors. Repeated measurement over time and space give an estimated mean flow. Flow multiplied by cross-section area of the plume gives a volume flux

PLUME TEAM
Pre-riser cut

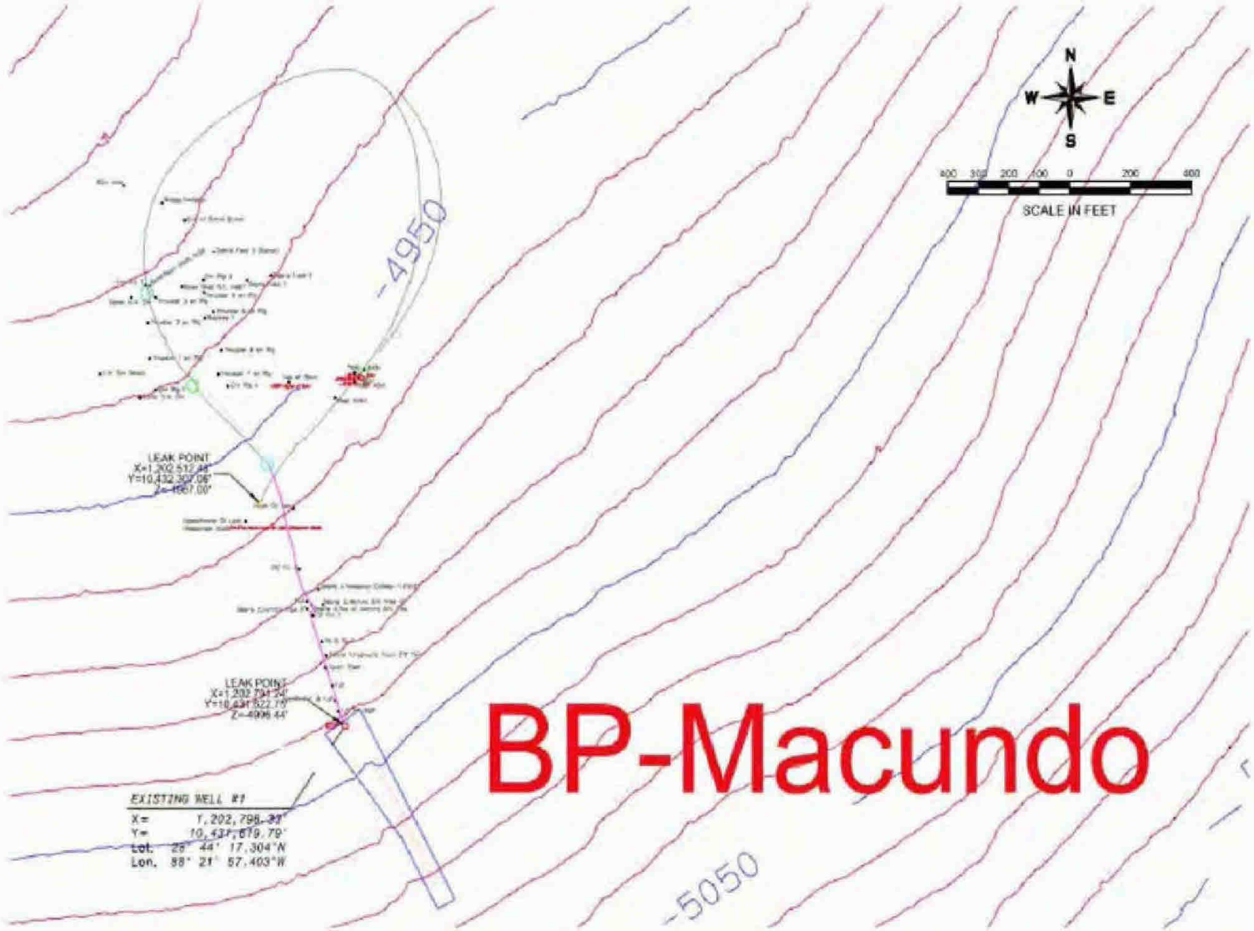




Riser leak
(no excavation,
no dispersant application)



Kink leak (after May 1)



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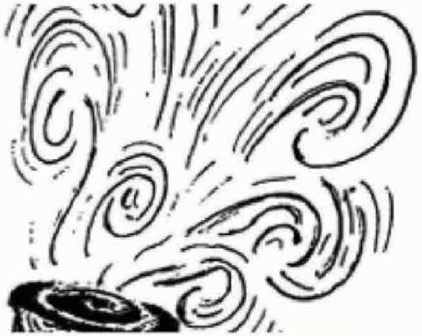
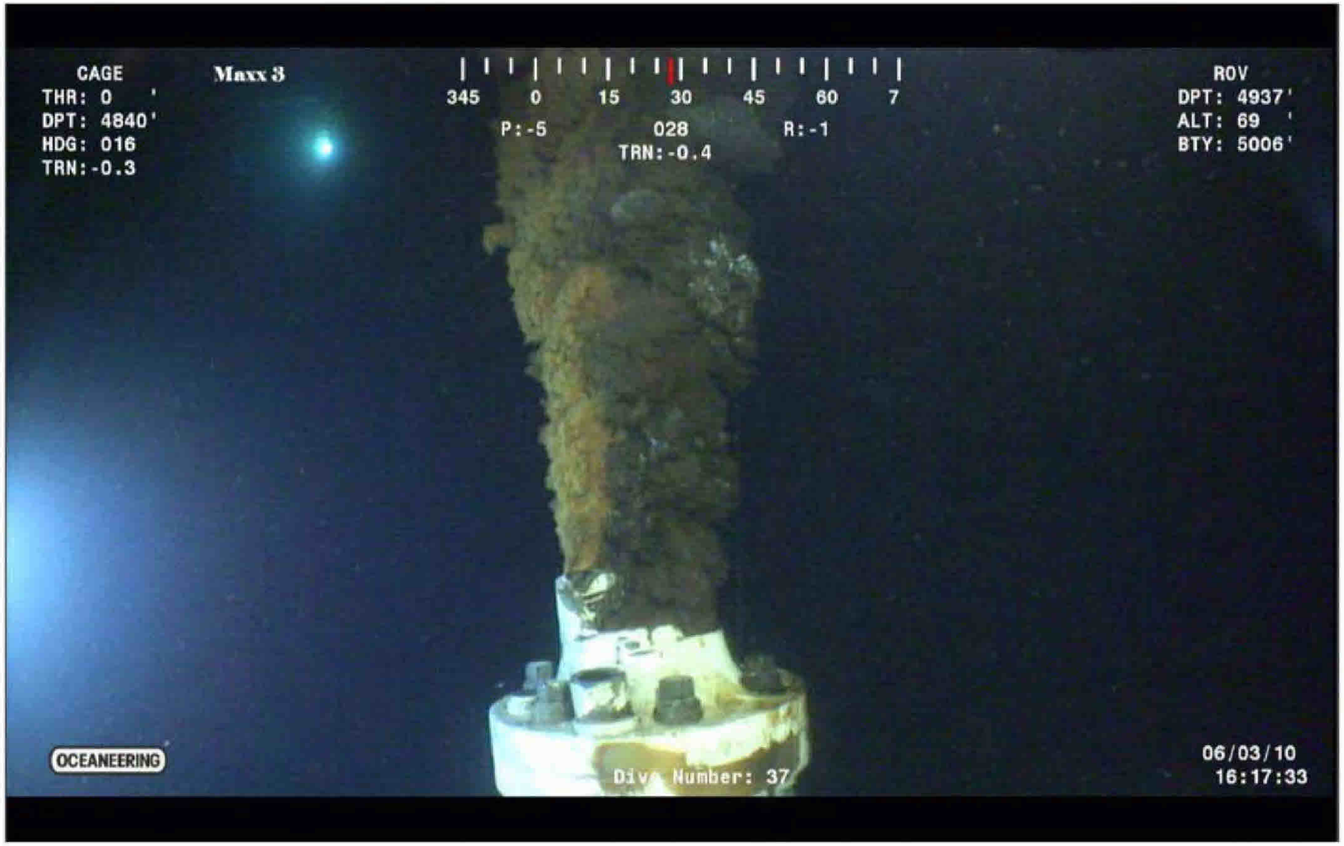


PLUME TEAM
Post-riser cut



Much better quality video

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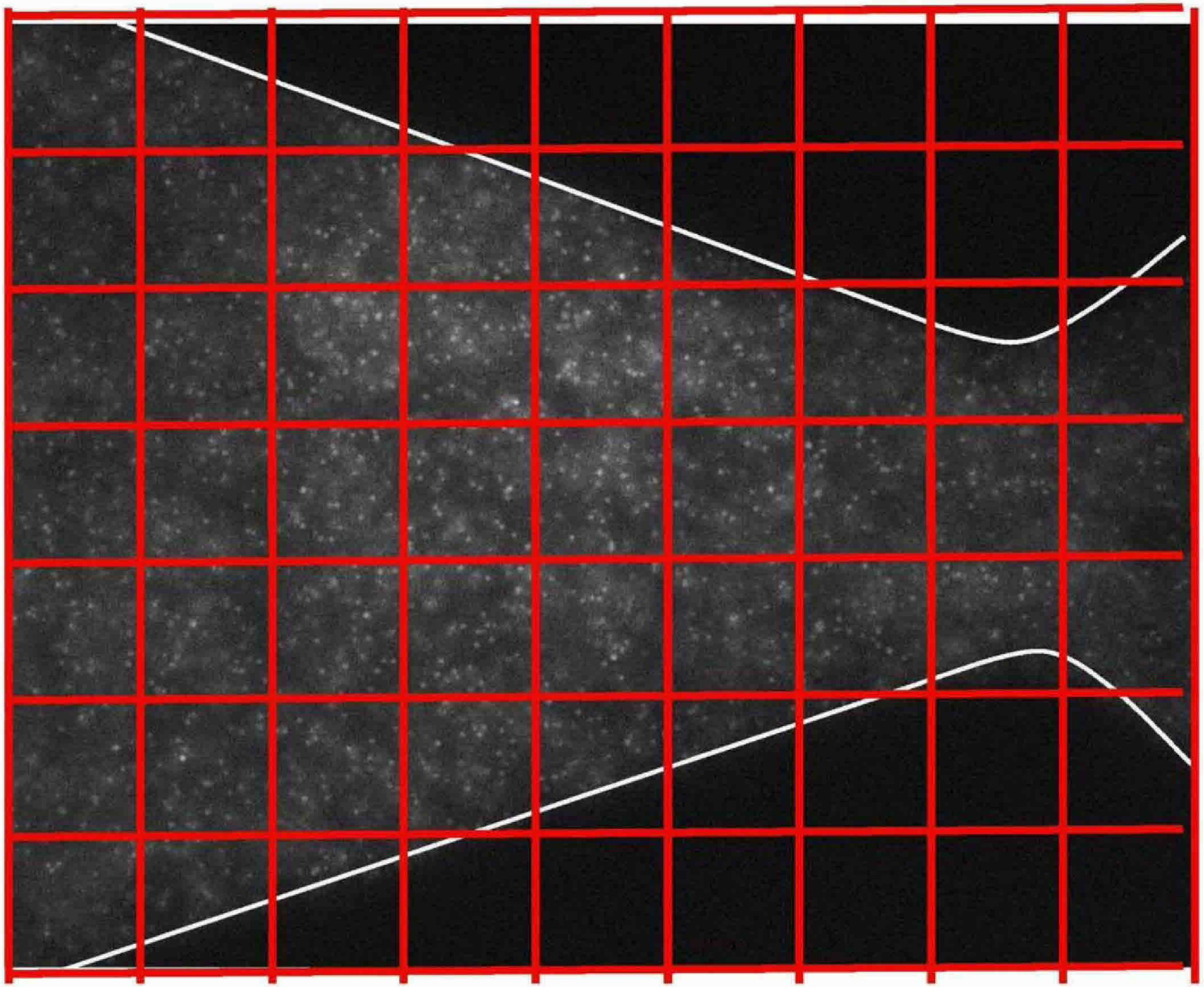
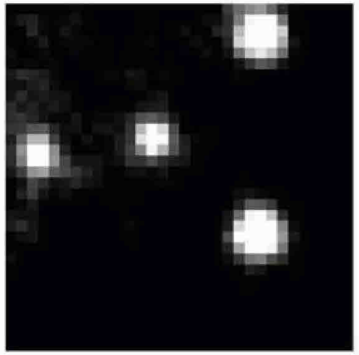
Typical Particle Image Velocimetry Image

Microthruster: Magnification 40x, particle size 700 nm
courtesy of K. Breuer, Brown University

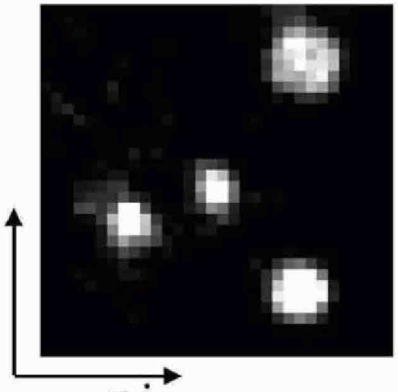


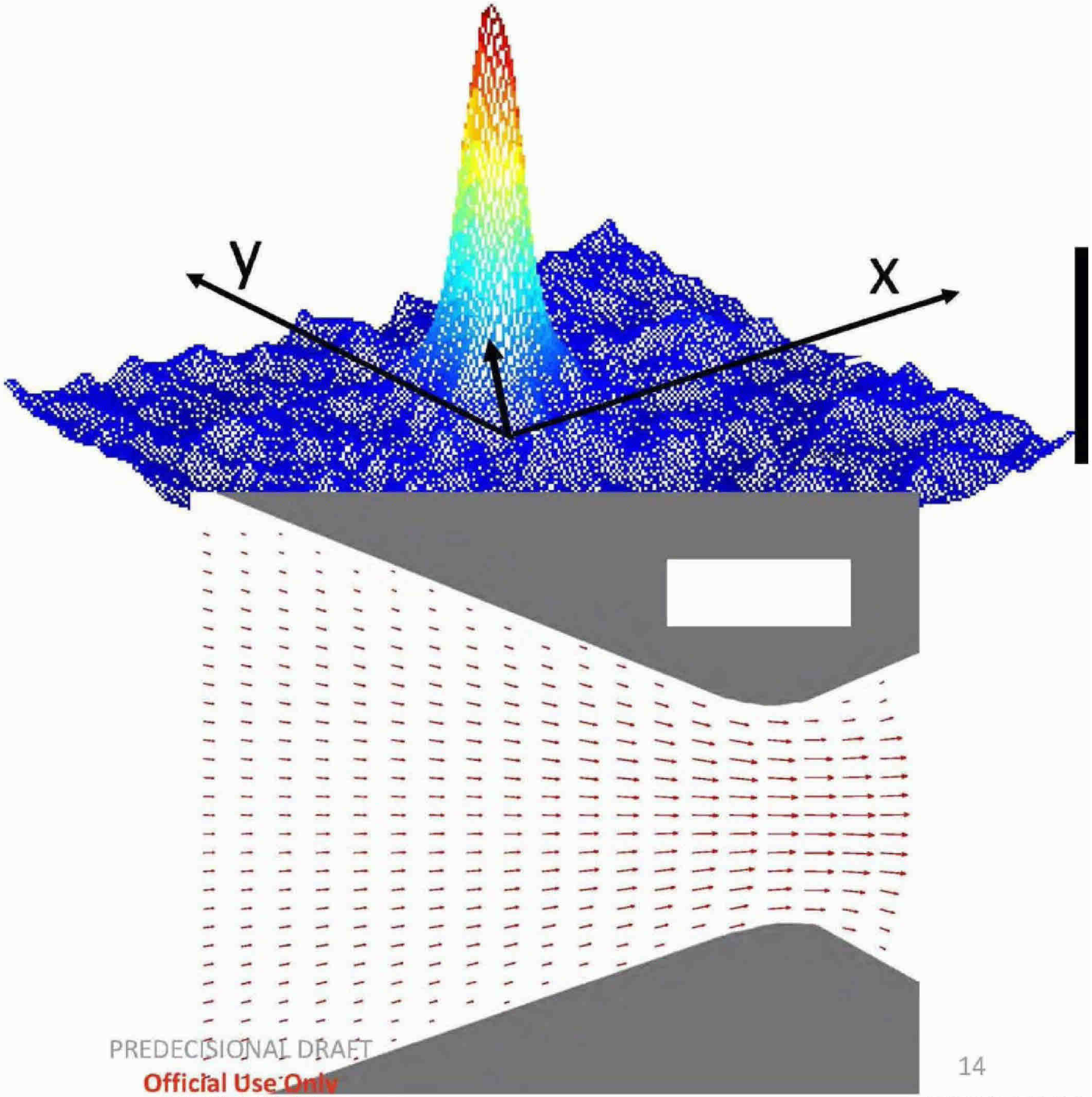
Velocity information extraction

Interrogation Region #1



Interrogation Region #2





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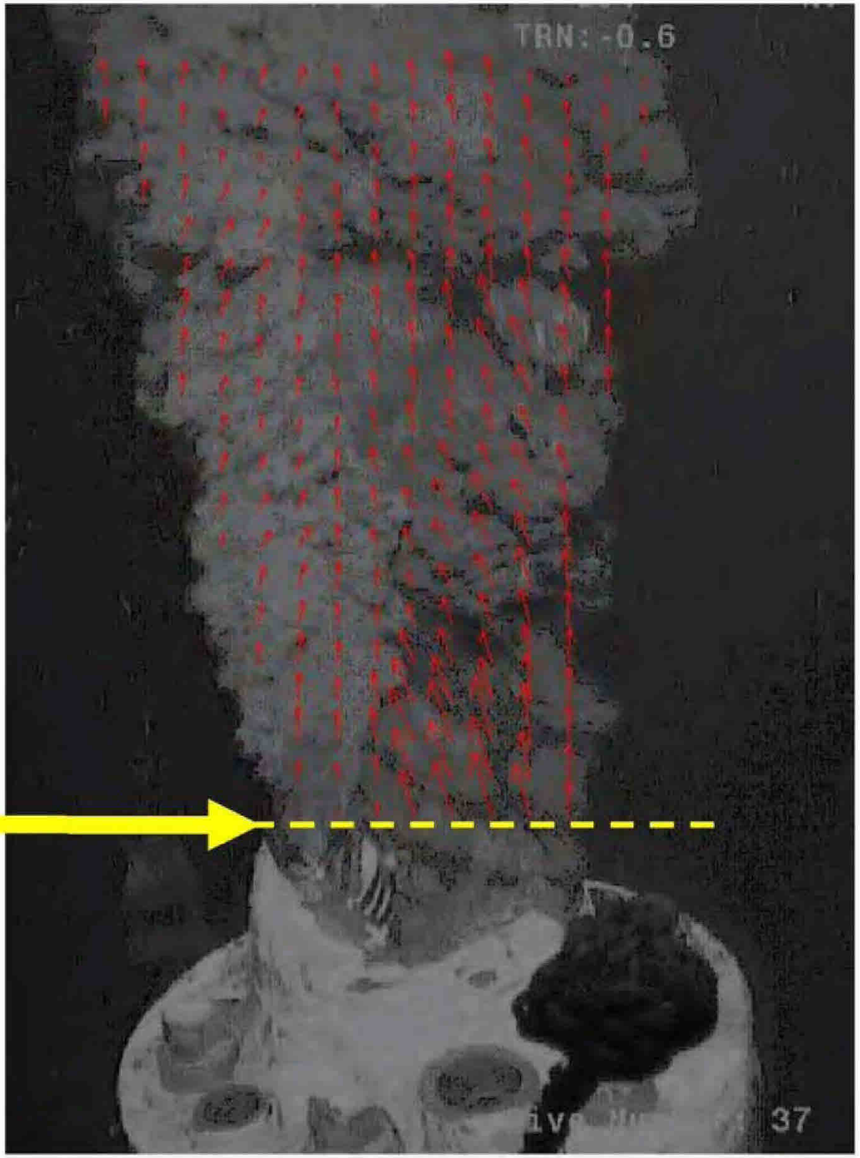
PIV Applied to June 3rd Flow



Velocity calculated here
Avg disp 8.27 pixels

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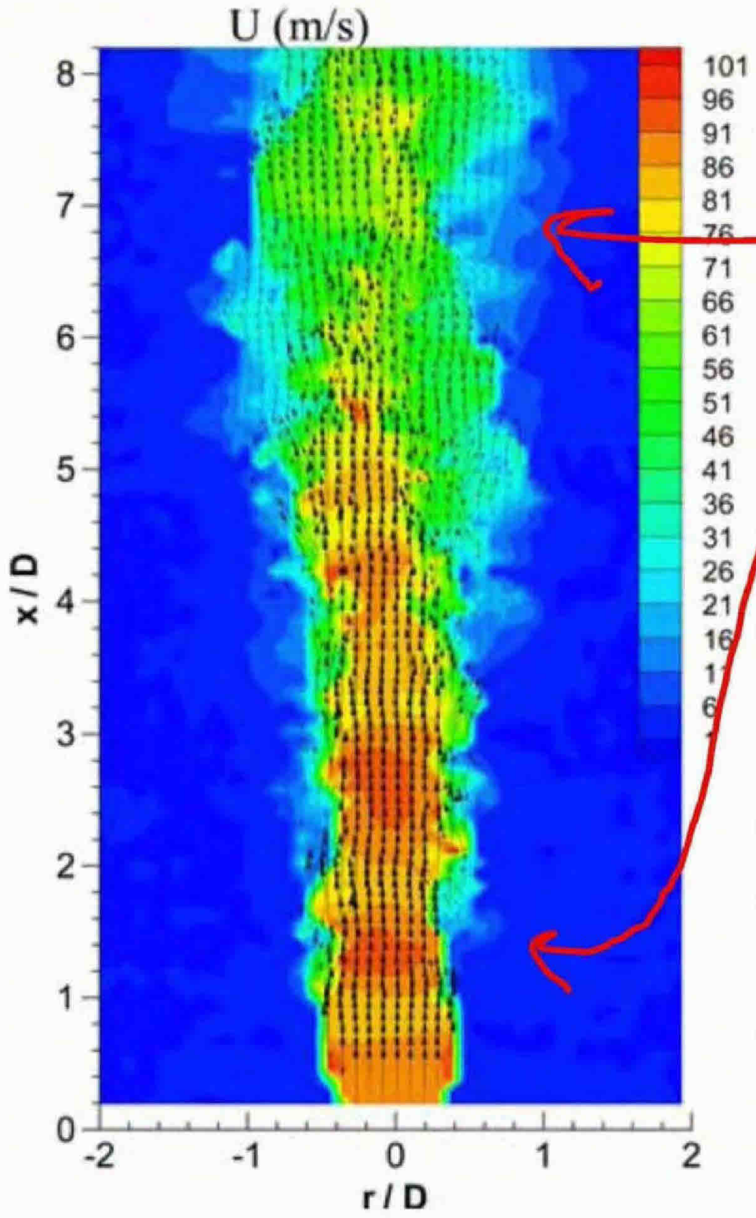
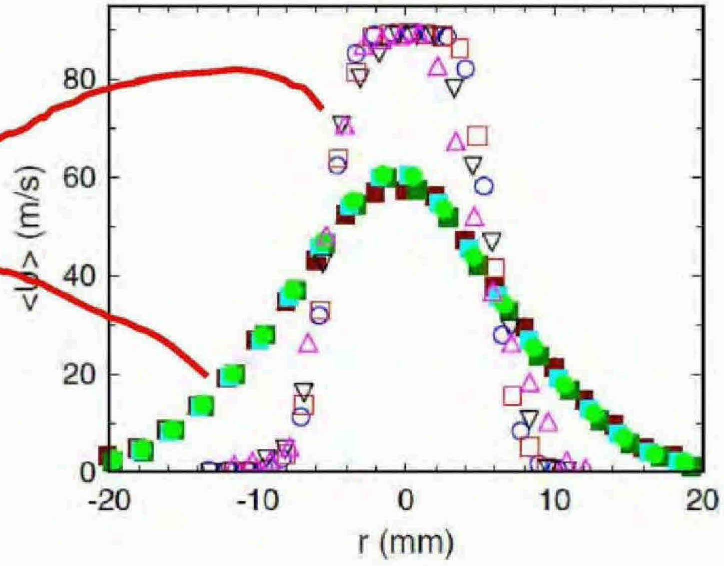
Jet flow physics

Mi, et al., Exp fluids, 2007





- PIV can normally "see through" flow to allow integrating velocity to get flow rate
- Crude oil is opaque
- Can't integrate across cross section to get flow rate
- Need to infer interior flow rate based on speed of outer visible coherent structures

Relationship between outer structure speed and average flow rate of jet

- FRTG deduced factor to range from 1.6 to 2.5 using various sources in the literature (Townsend, 1976; Wygnanski and Fiedler, 1970; Dahm and Dimotakis, 1987)
- Need better evidence of how the speed of visible outer flow structures relates to average jet speed
  - Series of lab experiments on opaque jets to assess this relationship
  - Potentially multiphase
- Crone, et al. (2008) had a good first cu
  - Analyzing these images I get speed ratio (
  - Images too small (~300 pix)
  - Reynolds numbers not matched

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Conclusions

Strengths: PIV provides consistent and accurate velocity measurements across different sequences, algorithms and users.

Main source of uncertainty: lies in the relationship between measured velocity and jet exit velocity (developed vs. developing flow, coherent structures, entrainment with different density, etc.) This introduces a factor of between 1.6 and 3.15

Secondary sources of uncertainty are:

- temporal fluctuations
- use of mean or averaged velocity,
- cross sectional area of the pipe at exit,
- constant vs. inhomogeneous oil volume fraction (0.41)
- ROV velocity
-

Results

Most of the experts, using the limited data available and with a small amount of time to process that data, concluded that the best estimate for the average flow rate for the leakage prior to the insertion of the RITT was between 25 to 30 thousand bbl/day. However, it is possible that the spillage could have been as little as 20,000 bbl/day or as large 40,000 bbl/day. Further analysis of the existing data and of other videos not yet viewed may allow a refinement of these numbers.

The video of the post-cut was of higher quality than earlier video. The best estimate of the PIV experts were for a flow of 35,000 to 45,000 bbl with the possibility that the leak could be as large as 50,000 bbl/day. After consultation with groups from the Department of Energy, a joint estimated range of 35,000 to 60,000 bbl was provided to the NIC.

EXPERT	LOW (BBL/DAY)	HIGH (BBL/DAY)	CONFIDENCE
A	24 000	40 000	Medium-High
B	24 000	40 000	Medium-High
C	24 000	40 000	Medium-High
D	42 000	49 000	Very High
E	30 000	40 000	Medium-High

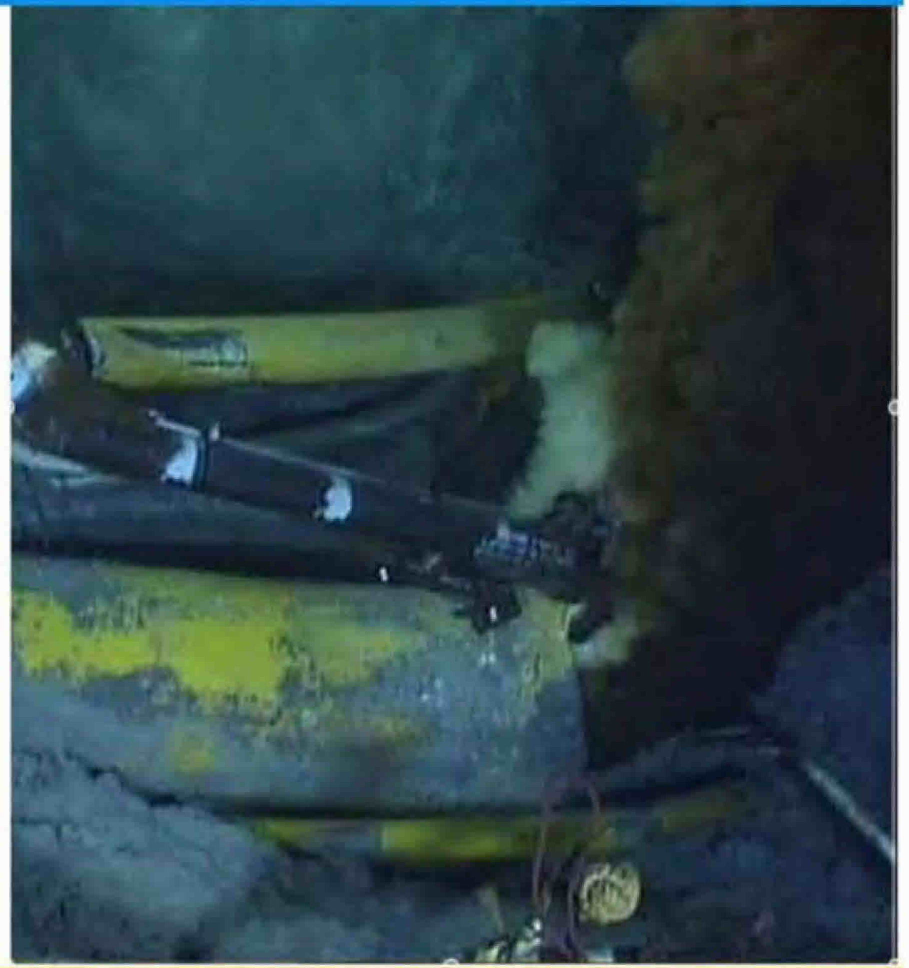
Assessment of the Model Value and Uncertainty Estimate

Contained in report

Deepwater Horizon Release
Estimate of Rate by PIV

July 21, 2010

Plume Team - FRTG



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Reservoir – Time of Event with Production

Dan Maclay
Gerald Crawford

BOEM/USGS

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Reservoir Modeling Team

BOEM/USGS

Presented by:

Don Maclay and Gerald Crawford, BOEM

July 30, 2010

Overview

- The Reservoir Modeling Team was established to develop reservoir inflow as a function of flowing BHP for the Macondo reservoirs and provide results to the Nodal Analysis Team. This team developed outflow curves incorporating changing tubing, casing, BOP and riser configurations.
- The Reservoir ModelingTeam members are Don Maclay and Gerald Crawford, petroleum engineers in the BOEM New Orleans Region Office and Dr. Mahendra K. Verma of the USGS who served as a technical reviewer.
- The Team was tasked to coordinate the independent determination of inflow estimates from experts in the field with minimal input from BOEM.
- BOEM engineers and geoscientists collected proprietary rock, fluid and wellbore data, and generated reservoir maps interpreted from 3D seismic data.
- Federal contracts were developed through academia market research and three teams were awarded:
  - Kelkar & Associates (University of Tulsa Group) headed by Dr. Mohan Kelkar.
  - R.G. Hughes & Associates (LSU Group) headed by Dr. Richard Hughes.
  - Gemini Solutions Group headed by Dr. James Buchwalter.

Time / Situation

- Make use of proprietary BP rock and fluid data, and maps generated from 3-D seismic by BOEM geoscientists.
- Provided detailed pre-rig collapse well design representing initial time period of blowout.
- Focus on most likely and maximum cases; incorporate other scenarios if time permits.
- Generate production rates with associated flowing BHPs and average reservoir pressures.

	Kelkar	Hughes	Gemini
Software	Schlumberger Eclipse	CMG IMAX	GSI Merlin
Cases	Base Case & Max with 5 flow path sensitivities for each case	ML & Max stratigraphic sensitivities (channel, sheet sand)	27 cases, includes sensitivities to strat, k, flow path, aquifer size
Simulation period	116 days	122 days	10 years

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Model Description / Attributes

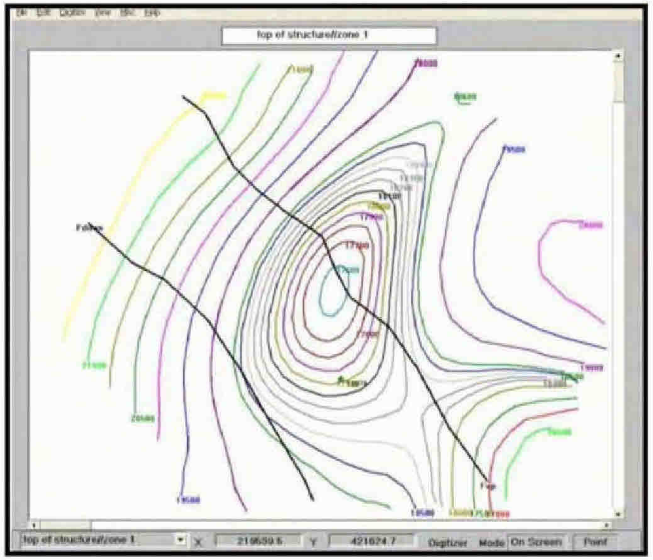
3D Seismic Data Interpretation

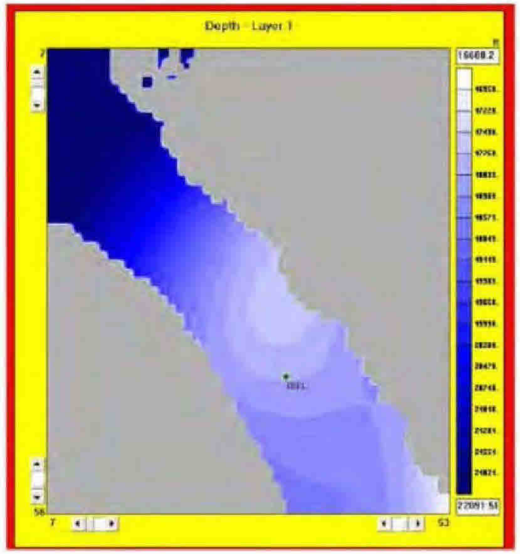
- Analyzed regional pre-stack depth and time migrated 3D seismic surveys.
- Three sands identified by petrophysical review are represented by a single seismic event.
- Depth data shows distinct elongate area of higher amplitude events trending NW to SE across an anticline.
- Amplitude trend interpreted as a sand indicator rather than a pay indicator.
- Time data does not show a distinct high amplitude trend.
- Structure maps developed from depth migrated seismic survey.
- Isochore maps developed using BOEM petrophysical analysis pay counts.

Model Description - continued

Structural/Stratigraphic Interpretation

- North-to-south trending anticline.
- Channel/levee complex trending NW to SE indicated by depth data.
- Time data does not show channel trend; assume a possible sheet sand case.





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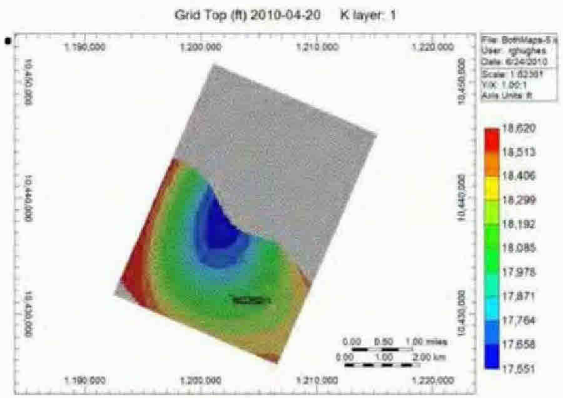
Model Description - continued

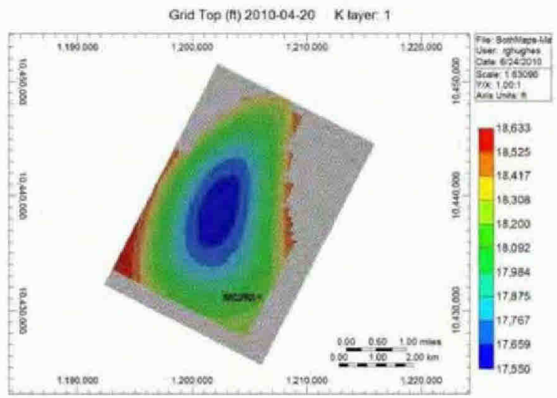
Geologic Input to Simulation

- Assume channel/levee complex interpretation as most-likely case.
- Develop a maximum reservoir extent case using sheet sand model.
- No assumptions developed for aquifer extent; infinitely acting and 6:1 aquifer sizes were used in study.
- OWC location is not indicated by log, well or seismic data; OWC at lowest known oil, spill point and halfway to spill point were simulated.

Channel Model:



Sheet Sand Model:



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Model Assumptions

- Rock/reservoir properties:
  - Porosity: neutron/density log values; Weatherford core analysis report
  - Permeability: Weatherford core analysis report; Corey Functions
  - Rock compressibility: Weatherford core analysis report
  - Pressure: GeoTap Pressure Transient Analysis
  - Connate water saturation: Weatherford core analysis report
- Fluid properties:
  - Core Labs/Pencor report
  - Data fitted to Dindoruk and Christman (FVF, solution gas oil ratio) and Bergman and Sutton (viscosity) correlations
- Multiphase flow model correlations used:
  - Beggs and Brill
  - Duns and Ross
  - Hagedorn and Brown
  - Orkiszewski

Concerns/Potential Issues

Technical Issues

- Any reprocessed seismic data could result in a revised geologic model
- Permeability assumptions significantly impact results
- Unknown aquifer size plays an important role in early time flow estimates.
- Flow path selected has as great an influence on flow rate as any reservoir parameter.

Administrative Issues

- FRTG timeline allowed for only 1 to 2 weeks for data review to final report.
- Proprietary data handled in accordance with federal regulations – Data/Information Security Agreement Form.

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Results

Case Name	Max Rate*	28d PI	Description
Kelkar 2	32983	9.84	Base/mean case (channel); Annulus/4" chk/smooth
Kelkar 4	27324	9.60	Base/mean case; Tubing/2" chk/smooth
Kelkar 7	45400	16.56	Max (+perm, +porosity, + c-rock, -GOR, no channel); Annulus/4" chk/smooth
Kelkar 9	36843	16.47	Max (no channel); Tubing/2" chk/smooth
Hughes ML	**63157**	**15.92**	**Channel; Incorporated production ramp up.**
Hughes Max	**64531**	**16.03**	**No channel; Incorporated production ramp up.**
Gemini 1	72725	42.55	Beggs and Brill
Gemini 2	57330	43.03	Duns Ross
Gemini 3	**58352**	**42.97**	**Base Case - channel, inf aquifer, annular, Orkiszewski**
Gemini 4	56152	43.08	Hagedorn & Brown
Gemini 7	58352	43.01	6:1 aquifer: Ork
Gemini 11	42016	44.65	Tubing flow: Ork
Gemini 17	58619	41.46	Sheet sand - no channel
Gemini 18	58050	42.68	Rock C = 5 microsips (base = 10 microsips)
Gemini 19	58704	43.95	Rock C = 20 microsips (base = 10 microsips)
Gemini 20	**51068**	**17.28**	**Perm = 100 md (base = 250 md)**
Gemini 21	**60223**	**87.30**	**Perm = 500 md (base = 250 md)**
Gemini [illegible]	[illegible]	43.78	Max flow case (tubing + annulus)

*** All three research groups conducted nodal analysis.**

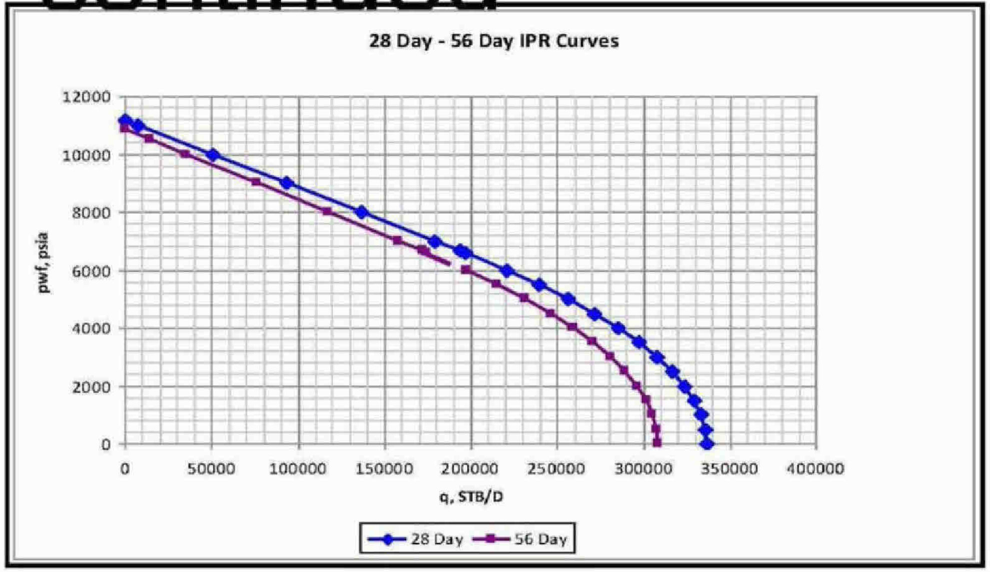
Results - continued

Typical 28-day and 56-day IPR Curves

- Developed 28- and 56-day IPR curves for all cases.
- 250 md base case (Gemini)
- ~ 400 psi pressure depletion
- Not significantly different

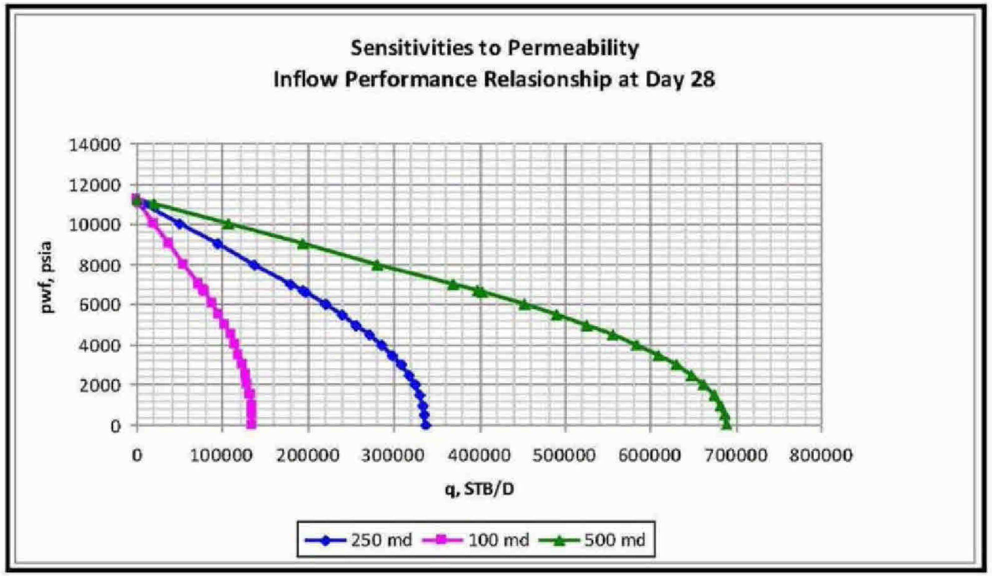
  PI= 42.97 BOPD/psi at 28 days

  PI = 41.01 BOPD/psi at 56 days



Permeability Sensitivity – 28 day IPR

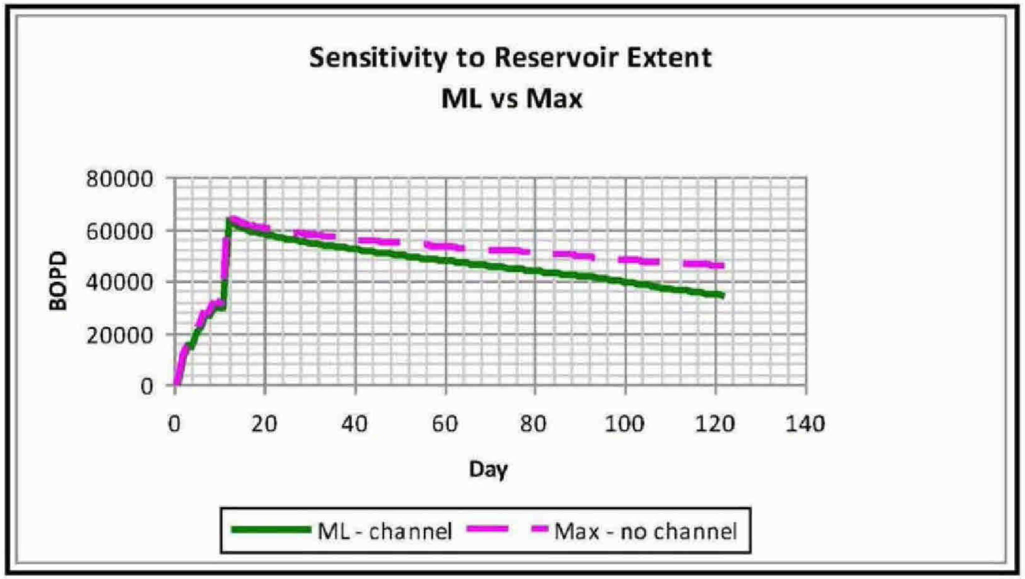
- Perm: 100 md, 250 md, 500 md
- PI: 17.28, 42.97, 87.3 BOPD/psi
- Initial rates, annular flow path: 51,068, 58,352, 60,223 BOPD



Results - continued

Reservoir Extent Sensitivity

- Channel vs. Sheet sand
- Initial rates vary by 2%
- At 122 days:
  - Max rate 32% greater than ML rate
  - ML case pressure drop 2,500 psi
  - Max case pressure drop 1,200 psi



Results - continued

- Inflow Performance Relationship (IPR) curves were developed for 39 cases at day 28 and day 56.
- IPR curves can be used in conjunction with tubing curves to develop production forecasts, and in a comparative review of the researcher's cases.
- Reported rates incorporate Nodal Analysis.
- Hughes and Gemini used the initial wellbore configuration; Kelkar incorporated chokes and pressure drops.
- Reported range of production rates:
  - 27,324 BOPD to 102,607 BOPD;
  - 10th and 90th percentiles: 32,688 and 63,432 BOPD

Percentile	Rate
0.05	29,529
0.10	**32,688**
0.20	40,451
0.30	42,016
0.40	46,534
0.50	**54,130**
0.60	56,664
0.70	57,762
0.80	58,653
0.90	**63,432**
0.95	72,725

Assessment

- Variations in reservoir properties such as rock compressibility and porosity (reported by Kelkar) did not significantly affect initial production rate.
- Permeability uncertainties significantly impact productivity of the reservoir. A low permeability sensitivity resulted in decreasing the reservoir's productivity index by 60 percent; a high permeability case resulted in doubling the reservoir's PI.
- Aquifer size variation had little impact on initial production rate; however, at 3 years, the infinite aquifer case is forecasted to produce at an oil rate 25% higher than the 6:1 size aquifer case.
- Different structural/stratigraphic interpretations impacting reservoir extent did not show a significant difference in initial flow rates. After 6 months of production, however, the two cases (sheet sand versus channel/levee complex) begin to diverge significantly.
- Three muliphase flow models evaluated in this study using Hagedorn & Brown, Duns & Ross and Orkiszewski correlations showed similar results; one method (Beggs and Brill) resulted in a 24 percent higher initial production rate.
- The variable with the greatest impact on flow rate is the flow path. An annular flow path resulted in approximately 16,000 BOPD higher initial production rate (+38 percent) than a tubing/drill pipe flow model. When flow trough all possible paths was considered, initial rate increased by 75 percent over the base case.

Nodal Analyses – Pre/Post Cut

George Guthrie

NETL

Flow Analysis Activities for the MC252 Well

Report-outs by Government Teams

Nodal Analysis Team Summary

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May be exempt from public release under the Freedom of Information Act (5 U.S.C. 552), exemption number and category:

Category 4: Commercial/Proprietary

Department of Energy review required before public release.

Name/Org: NETL Date: 2 June 2010

Guidance (if applicable) ______

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TREX 008635.0036

Nodal Analysis Team Summary

Dr. George Guthrie (US-DOE/NETL)

Nodal Analysis Team Focus:

A peer-reviewed nodal analysis to estimate flow rates from reservoir to release points based on:
(1) calculating flow rates and pressures within the flow-system between the reservoir and Gulf waters,
(2) using data either publically available or provided by MMS (BOEM) as related to reservoir properties; geometries of well, BOP, riser, drill pipe; fluid characteristics; physical conditions; etc.
(3) relying on input from an MMS-led team for detailed factors associated with the reservoir.

Nodal Analysis Team Leads:

LANL: Dr. Rajesh Pawar
LBNL: Dr. Curt Oldenburg
LLNL: Dr. Todd Weisgraber
NETL: Dr. Grant Bromhal
PNNL: Dr. Phil Gauglitz

Statistical Team Lead:

NIST: Dr. Antonio Possolo

Peer-Review Team Lead:

ORNL: Dr. Dave Hetrick

Nodal Analysis Team Members

LANL (Los Alamos National Laboratory): John Bernardin, David Dixon, Rick Kapernick, Bruce Letellier, Brett Okhuysen, Rajesh Pawar, Robert Reid

LBNL (Lawrence Berkeley National Laboratory): Curtis M. Oldenburg, Barry M. Freifeld, Karsten Pruess, Lehua Pan, Stefan Finsterle, George J. Moridis, Matthew T. Reagan

LLNL (Lawrence Livermore National Laboratory): Todd H. Weisgraber, Thomas A. Buscheck, Christopher M. Spadaccini, and Roger D. Aines

NETL (National Energy Technology Laboratory): Brian Anderson, Grant Bromhal, Robert Enick, George Guthrie, Roy Long, Shahab Mohaghegh, Bryan Morreale, Neal Sams, Doug Wyatt

PNNL (Pacific Northwest National Laboratory): P. A. Gauglitz, L. A. Mahoney, J. A. Bamberger, J. Blanchard, J. Bontha, C. W. Enderlin, J. A. Fort, P. A. Meyer, Y. Onishi, D. M. Pfund, D. R. Rector, M. L. Stewart, B. E. Wells, S. T. Yokuda

NIST (National Institute of Standards and Technology): Antonio Possolo, William Guthrie, Pedro Espina

ORNL (Oak Ridge National Laboratory): Charlotte Barbier, David Hetrick, Sreekanth Pannala

Time/Situation/Data

Time point

- Base case for post cutting of riser + drill pipe pre top hat
- Assessment(s) of several time points from explosion to top hat

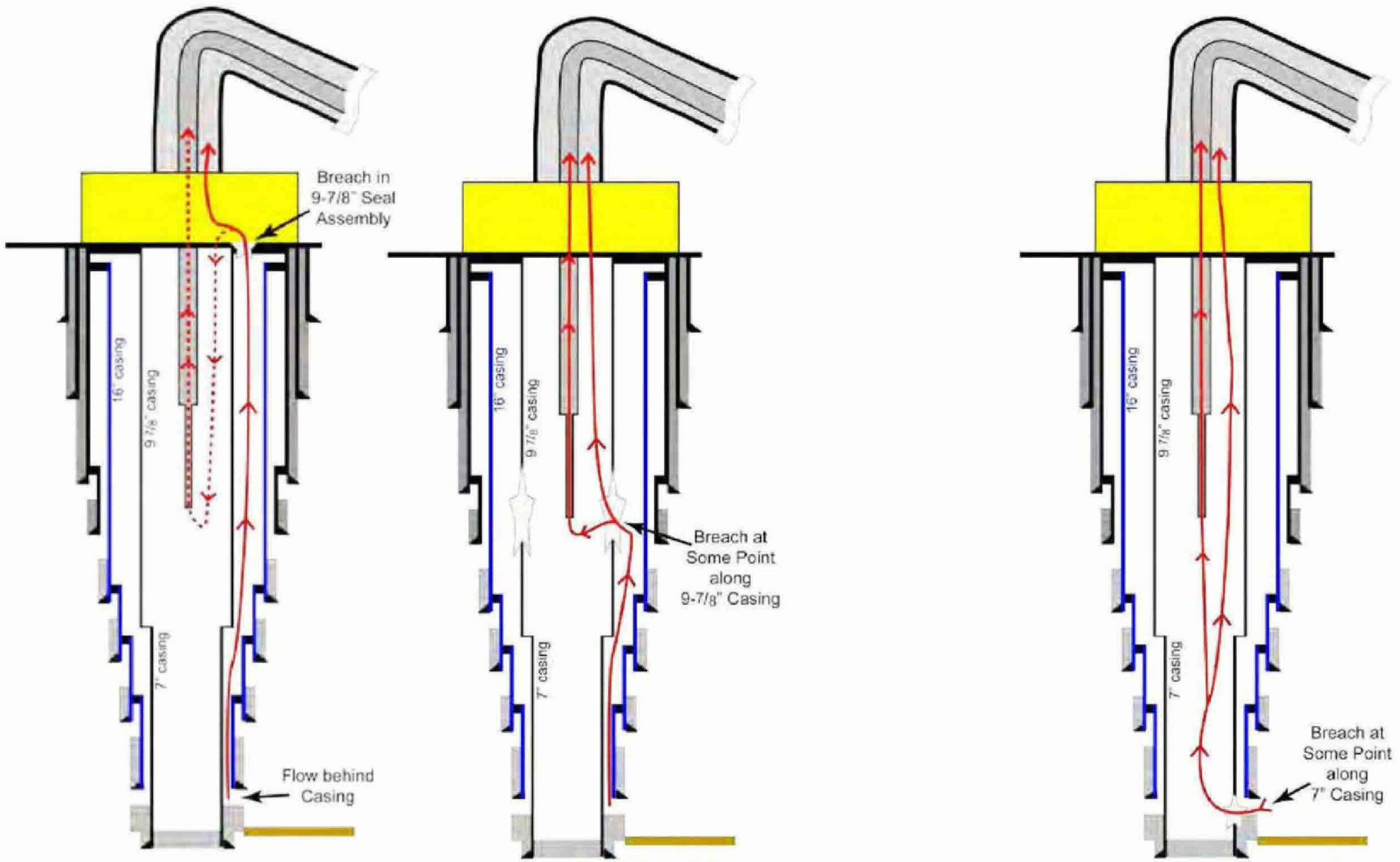
Table 1: Comparison of Simulations Conducted for Different Modeling Periods/Flow Conditions

	Time Period	*Description*	*Dates*	*LANL*	*LBNL*	*LLNL*	*NETL*	*PNNL*
	1	After explosion prior to rig collapse	20 Apr– 22 Apr	X				
	2	Post rig collapse but prior to partial closure of BOP	22 Apr– 25 Apr	X				
	3	Post partial closure of BOP but prior to capping of drill pipe	25 Apr– 05 May	X		X	X	
	4	Post capping of drill pipe but prior to cutting of riser	05 May– 01 Jun	X			X	
base case	5	Post cutting of riser but prior to placing top hat	01 Jun– 03 Jun	X	X	X	X	X
	6	Post cutting of riser with top hat in place	03 Jun–				X	

Time/Situation/Data

Well-Flow Scenarios

- Two end-member and one intermediate flow scenarios



Scenarios 1 & 3

Scenario 2

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Time/Situation/Data

Data

- Reservoir data included pressure (P), temperature (T), depth range, permeability, and porosity. Data sources included a wellbore schematic prepared by BP (now publicly available; listing depths and T), a report prepared for BP by Weatherford Laboratories (listing permeability/porosity at various depths), a report prepared for BP by Schlumberger (listing reservoir pressures and temperatures), and verbal communication from MMS (confirming reservoir pressure and temperature).
- Fluid data included chemical analysis and fluid properties of the produced hydrocarbon (including component hydrocarbon percentages, gas-to-oil ratio, density, viscosity, compressibility, Pressure-Volume-Temperature (PVT) relationships for reservoir fluids, API gravity, properties at reservoir conditions, bubble-point pressure). Data sources included reports prepared for BP by Schlumberger and Pencor. Each team developed its own method to describe fluid properties throughout the system, consistent with the observed properties as reported.
- Well geometry data included the depths and sizes of casings and liners, cement zones, depths and sizes of drill pipe, T as a function of depth, and geometry of the BOP. The primary data source was a schematic prepare by BP (now publicly available).
- BOP data included a report on pressure measurements made at various points in the BOP on 25 May 2010. This information was used to establish potential pressure drops associated with the BOP at one-point-in-time for a given set of conditions.

Approach (Model Description/Attributes)

General Approach

- Engage multi-disciplinary teams at 5 DOE labs to estimate flow ranges based on a variety of models/methods
- Discuss scenarios, data, uncertainties, etc. across teams; develop individual estimates from each team
- Develop an integrated "Nodal-Analysis Team" assessment (using results from individual lab teams and cross-team discussions)
  - for one range, lower bound determined by low estimates for scenarios 1/3 and the higher bound determined by high estimates for scenario 2
  - also assessed two distinct ranges for scenarios 1/3 and scenario 2
  - NIST analysis of expert-elicitation results to develop 95% CI
- Use distinct lab team (ORNL) to provide peer review of detailed reports and summary report

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Approach (Model Description/Attributes)

Team Approaches

Coupled to Reservoir via IPR

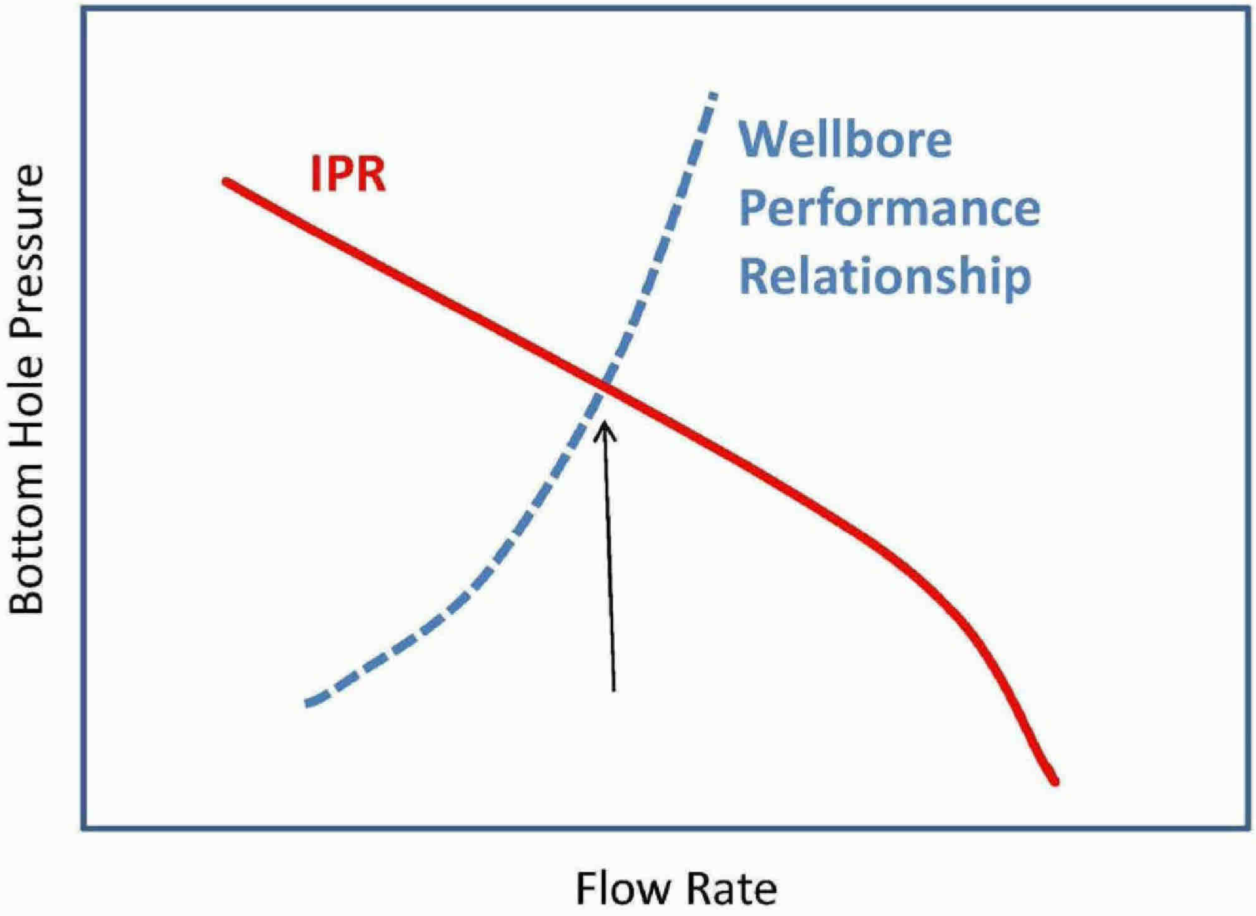
- LANL—a parametric engineering model to predict volumetric two-phase flow rates of oil and gas through both known and postulated restrictions in the wellbore system and associated pressure losses
  - flow estimates were calculated as a function of bottom-hole-pressure; oil properties were described following Dindoruk & Christman (2004) along with data from Schlumberger for the Macondo MC 252 well; gas properties were described following Peng-Robinson (1972) and Jossi et al. (1962)
- LLNL—a two-phase flow model based on BP oil property data for flow within the well system, including the effects of heat transfer to the surrounding rock, and reported pressure drops across the BOP; flow estimates were calculated as a function of bottom-hole pressure
- NETL—a parametric facility model (including well, BOP, riser, and drill pipe) developed using Pipesim™ and tied to the reservoir through an IPR curve to describe the behavior of flow in the reservoir (*i.e.*, flow estimates were calculated as a function of bottom-hole pressure)

Coupled Reservoir—Wellbore Models

- LBNL—a coupled wellbore-reservoir flow model based on the Drift-Flux Model and modified to handle oil-gas systems and to handle uncertainty quantification and sensitivity analysis
- PNNL—a coupled reservoir-well model to estimate the frictional pressure drop(s) within the wellbore system using the revised Beggs and Brill two-phase flow model, given an assumed stock oil production rate
  - oil properties were described following Standing's correlation for bubble point, Glaso for dead oil, Begg-Robinson and Vasquez-Beggs for saturated oil; gas properties were described following Dranchuk and Abu-Kassem for compressibility and density and the Lee-Gonzalez-Eakins method for viscosity

Approach (Model Description/Attributes)

Schematic Inflow Performance Relationship (IPR)



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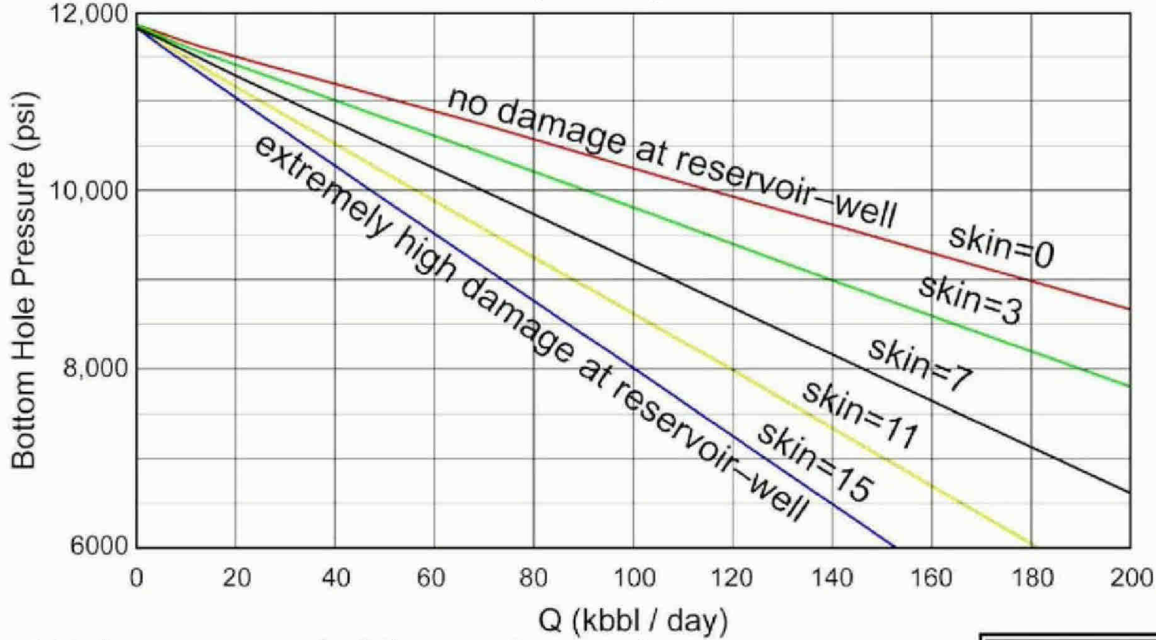
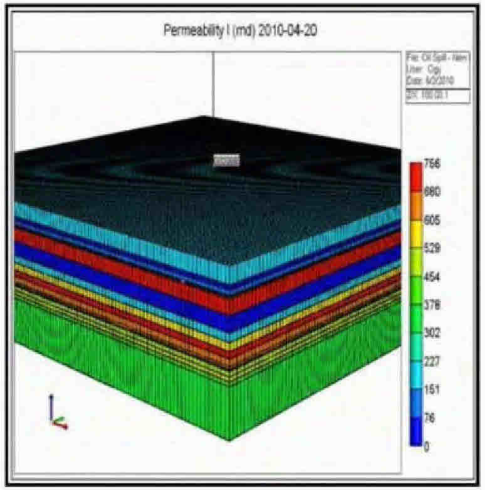
Approach (Model Description/Attributes)

Inflow Performance Relationship (IPR) for day 15 from reservoir model using CMG's IMEX^{TM} black oil simulator (NETL)



Layer	Depth to layer top (ft)	Thickness (ft)	Porosity	Permeability (md)
1	18050.2	20.7	0.224	211
2	18070.9	5.1	0.198	64.1
3	18076	6.4	0.227	78.5
4	18082.4	1.5	0.229	542
5	18083.9	2	0.223	674
6	18085.9	18	0.093	756
7	18103.9	19	0.22	0.0069
8	18122.9	10.1	0.22	159
9	18133	9.9	0.23	577
10	18142.9	8	0.23	756
11	18150.9	8.5	0.23	680
12	18159.4	2.6	0.22	595
13	18162	2.5	0.22	694
14	18164.5	6.2	0.23	471
15	18170.7	5.3	0.21	581
16	18176	5.5	0.21	426
17	18181.5	60.55	0.21	322

- 17-layer model based on air permeability data on core
- layer-cake, radial symmetry, infinitely acting (r = ~13 km)
- skin for reservoir-well coupling
- assessed IPRs for several time points
- k*h = ~71,250 md-ft



Approach (Model Description/Attributes)

Reservoir Component of the Coupled Reservoir-Well Models

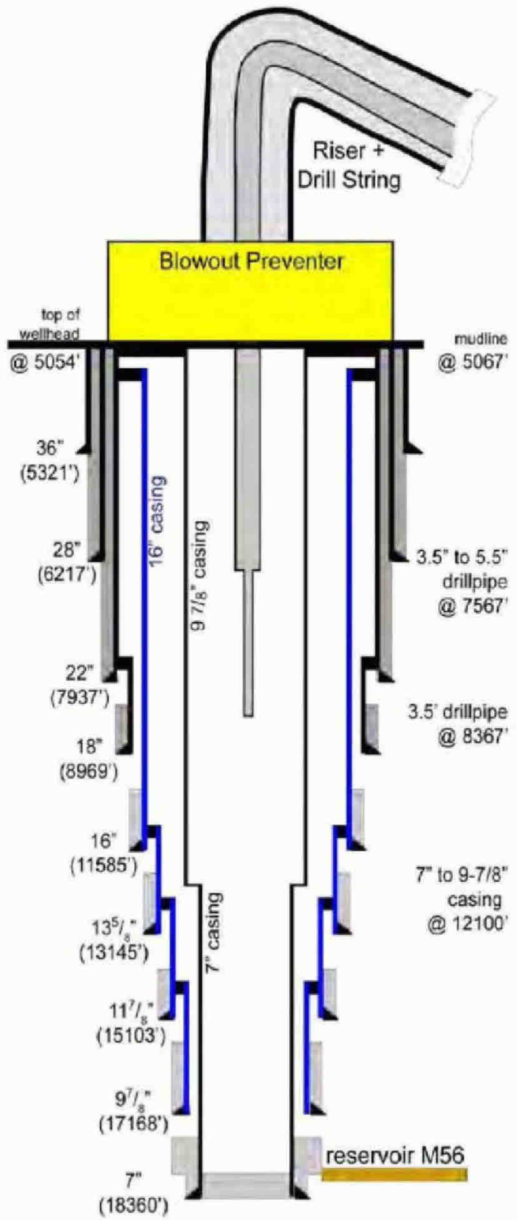
LBNL

- 1-layer model based on average air permeability data on core (465 md)
- layer-cake, radial symmetry, infinitely acting (r = 10 km)
- varied screen interval for reservoir-well coupling
- k*h = ~3,050 md-ft and ~57,200 md-ft

PNNL

- 1-layer model based on 72 md (best estimate) and 465 md (assumed upper bound)
- layer-cake, radial symmetry, infinitely acting (radial wellbore inflow model with r_2 = 1000 ft)
- varied ΔP across reservoir-well interface
- k*h = ~7,200 md-ft and 46,500 md-ft

Approach (Model Description/Attributes)



Facility Component of the Models

- well geometry as detailed in the schematic (and associated documents); roughness varied from smooth pipe to value of commercial steel pipes
- BOP details not considered; however, BOP evaluated by various methods (e.g., pressure drop and choke) over a range of values
- riser + drill pipe assembly considered in some cases by various methods (e.g., mostly flow-in-a-pipe but also w/choke)

Fluid Component of the Models

- EOS or series of correlations (black oil model) used to represent fluid properties (API density, gas density, bubble point, viscosity, etc.) based on (or consistent with) proprietary reports on fluid analyses (Pencor, Schlumberger)
- gas-oil ratio set to typical reported value but sensitivity assessed

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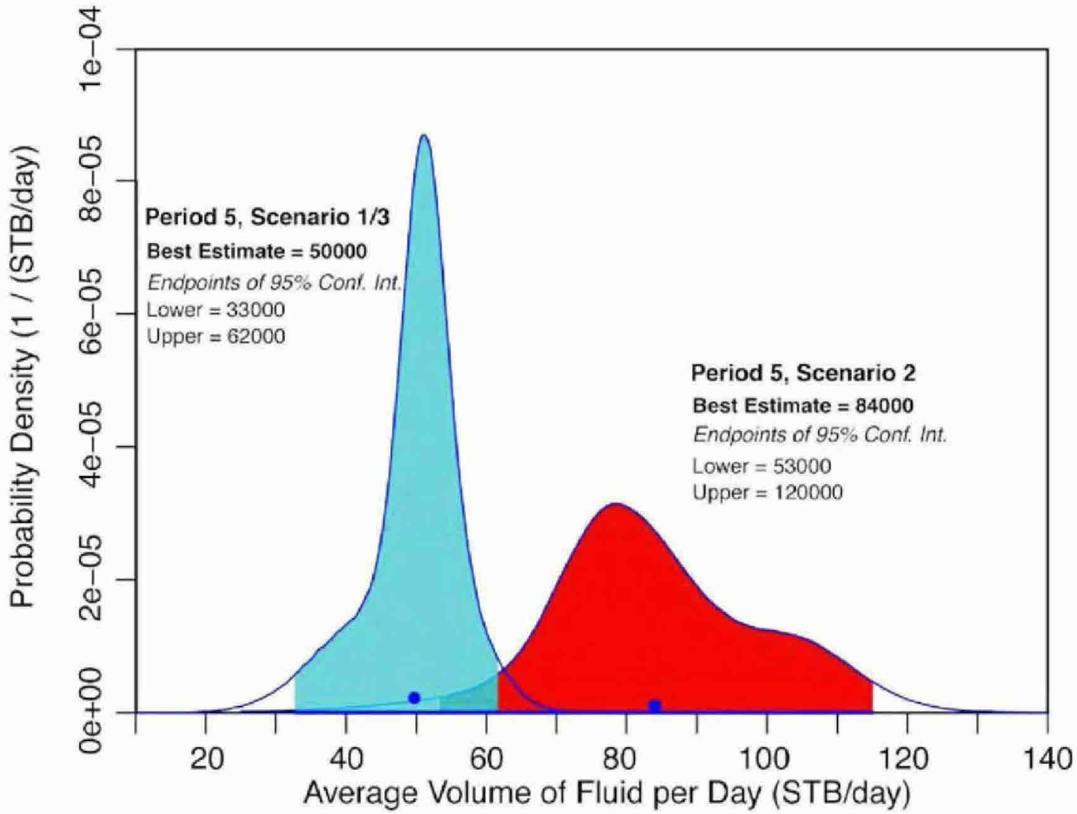
Results

Base Case: Post Cutting of Riser/Drill-Pipe and Pre Top Hat (Time Period 5)

Table 2a: Summary of flow estimates for time period 5.

		Scenarios 1/3 Low Estimate	Scenarios 1/3 High Estimate	Scenario 2 Low Estimate	Scenario 2 High Estimate
Time Period 5	LANL	46,000	56,000	73,000	96,000
	LBNL	(N/A)	(N/A)	90,000	118,000
	LLNL	46,000	56,000	66,000	85,000
	NETL	45,000	64,000	62,000	96,000
	PNNL	30,000	55,000	44,000	110,000



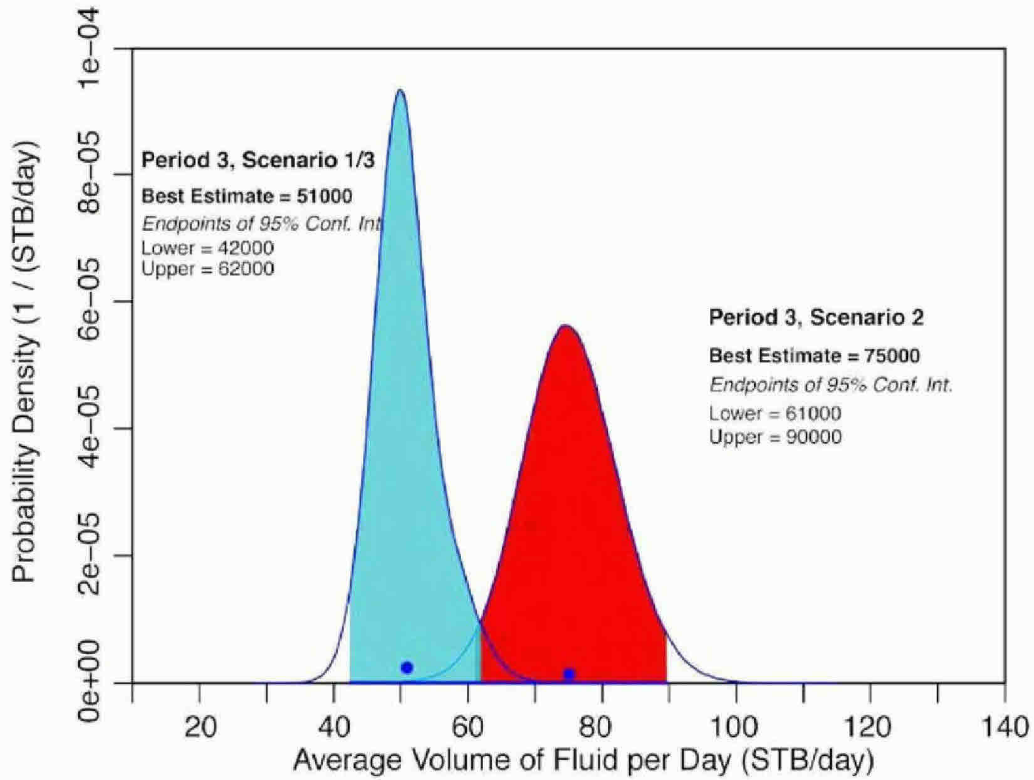
- Monte Carlo and/or expert elicitation to develop 20:1 and 1:20 estimates
- NIST used statistical method to develop combined distributions
- Two distributions relate to well-flow scenario;
  team had no information to select one scenario over the other

Results

Base Case: Pre Cutting of Riser/Drill-Pipe, Post Partial Closing of BOP (Time Period 3)

Table 2a: Summary of flow estimates for time period 3.

		Scenarios 1/3 Low Estimate	*Scenarios 1/3* High Estimate	*Scenario 2* Low Estimate	*Scenario 2* High Estimate
Time Period 3	LANL	42,000	54,000	67,000	90,000
	LLNL	45,000	55,000	64,000	83,000
	NETL	46,000	63,000	61,000	86,000



- Narrower distributions (only three teams, all focused on facility model)

Results

Sensitivity Analysis

Table 5: Percent change for flow rate going from low end of parameter range to high end of range.

Parameter (range)	*LANL*	*LLNL*	*NETL*	*PNNL*
GOR (2300–3150 scf/STBO)	10%	n/a	11%	11%
BOP (1000–2500 ΔP, psi)	17%	17%	19%	20%
BHP (8500–11500, psi)	–77%	–40%	–73%	–103%
Roughness (0.001–0.002 inches)	6%	5%	6%	7%

- Benchmarking around specific conditions showed σ/mean of 6%
- Bottom hole pressure most significant factor impacting flow rate
- Pressure drop across BOP and gas-oil ratio impact flow rate

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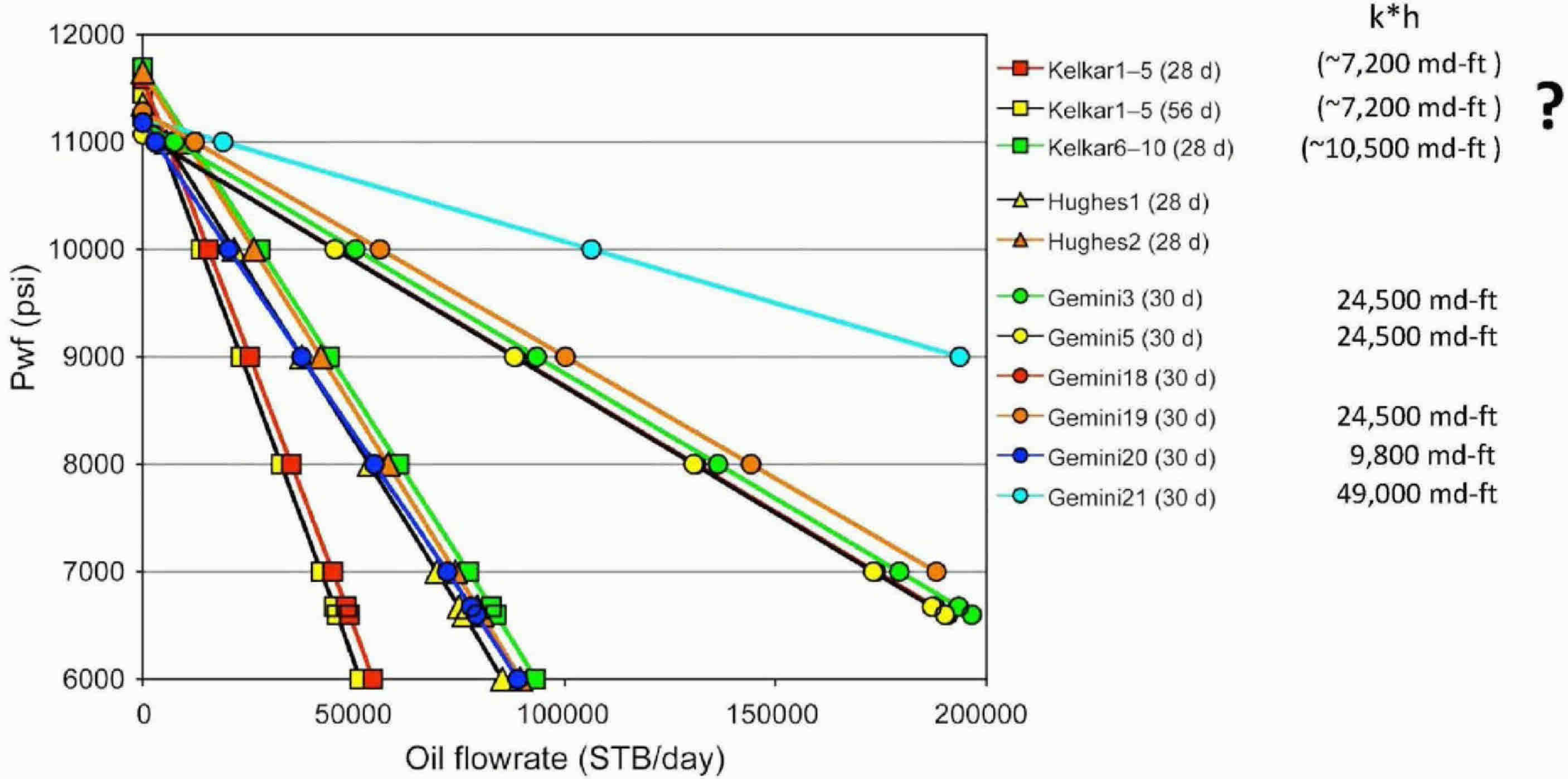
Results

Comparison with Reservoir Team Results



- Gemini-21 case (500 md) roughly equivalent to NETL IPR for skin = 0
  - Nodal team high estimates not impacted by reservoir team results
- Gemini-3, 5, 19 roughly equivalent to NETL IPR for skin = 7

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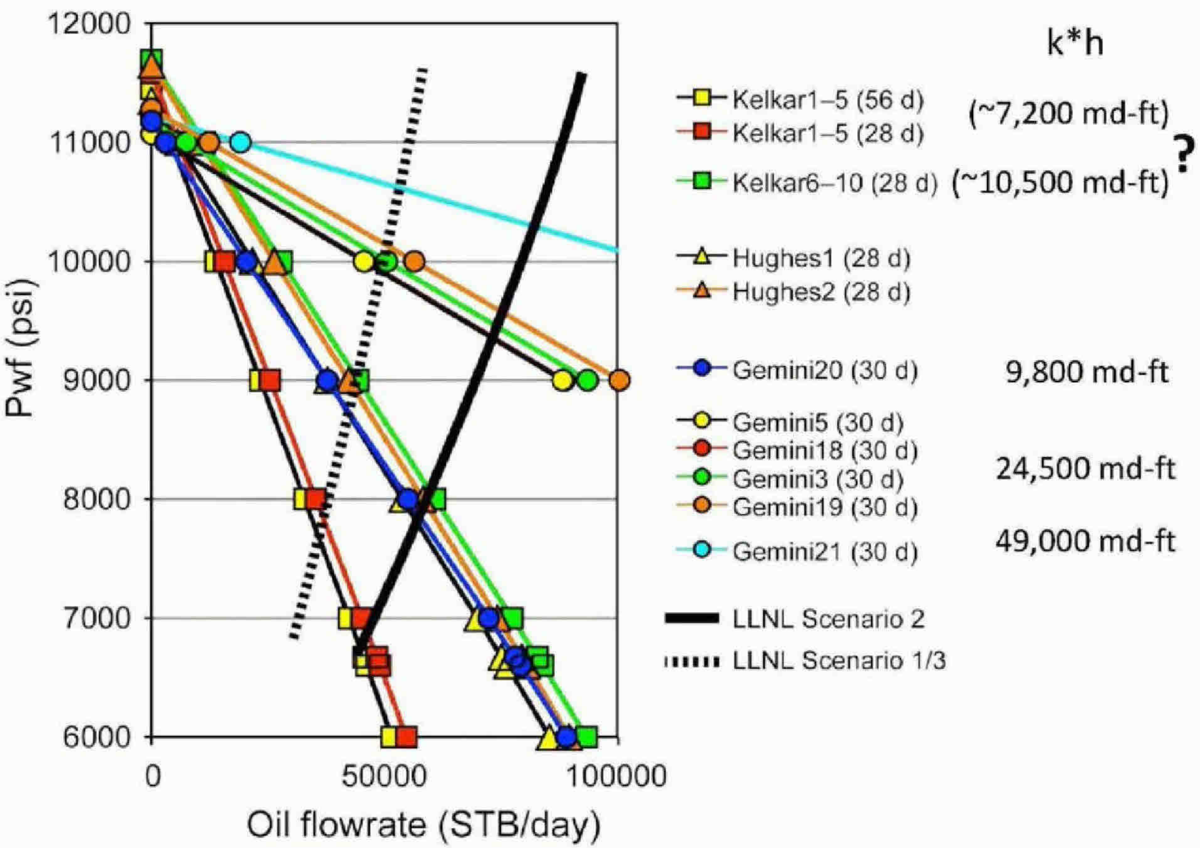
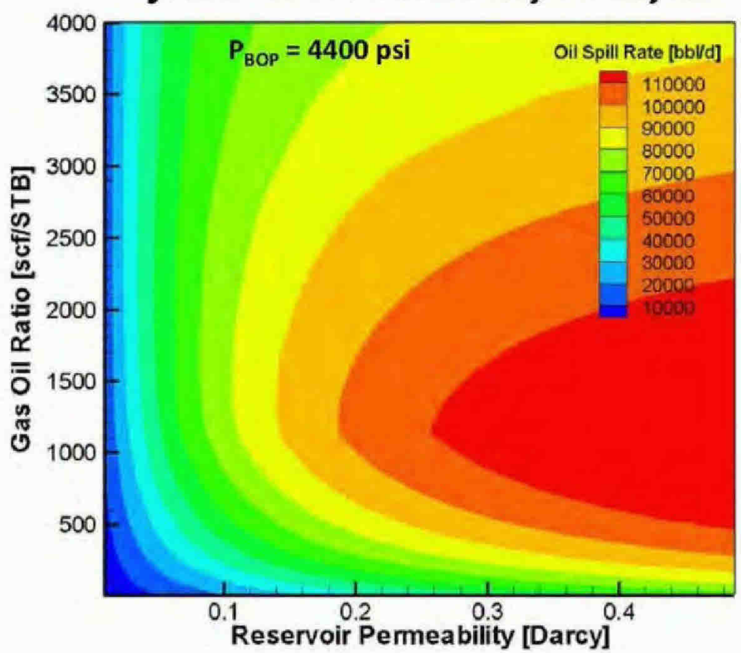
Results

Comparison with Reservoir Team Results



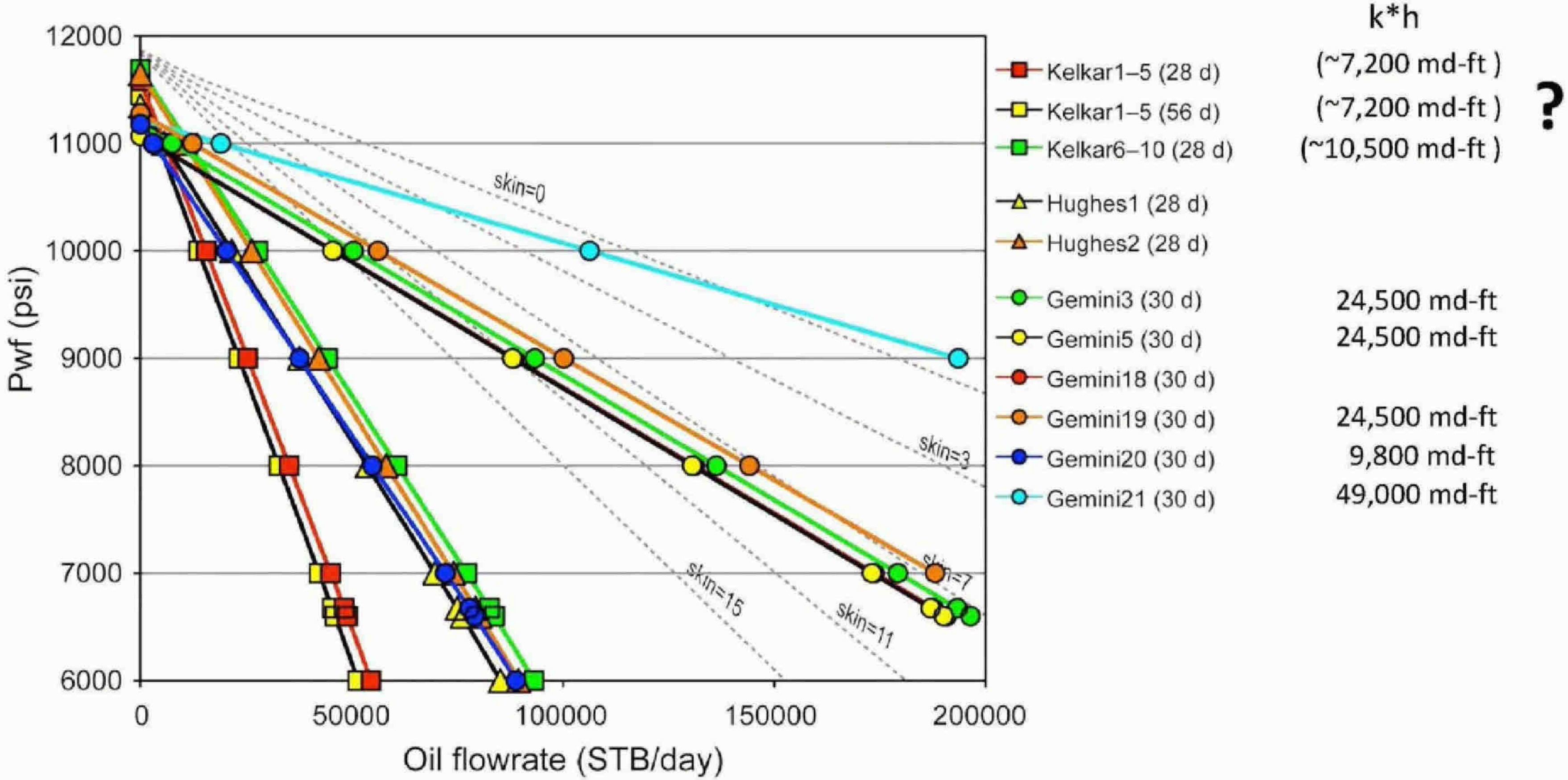
from LBNL Sensitivity Analysis



- Nodal team high estimates not significantly impacted by reservoir team results
- Confirmed nodal team sensitivity analysis that permeability (BHP) is important factor
- Incorporation of full range of reservoir-team properties would decrease lower estimates
- Reservoir team results suggest nodal assumption of infinitely acting reservoir was reasonable and relaxing the assumption would not have big impact on rate

Results

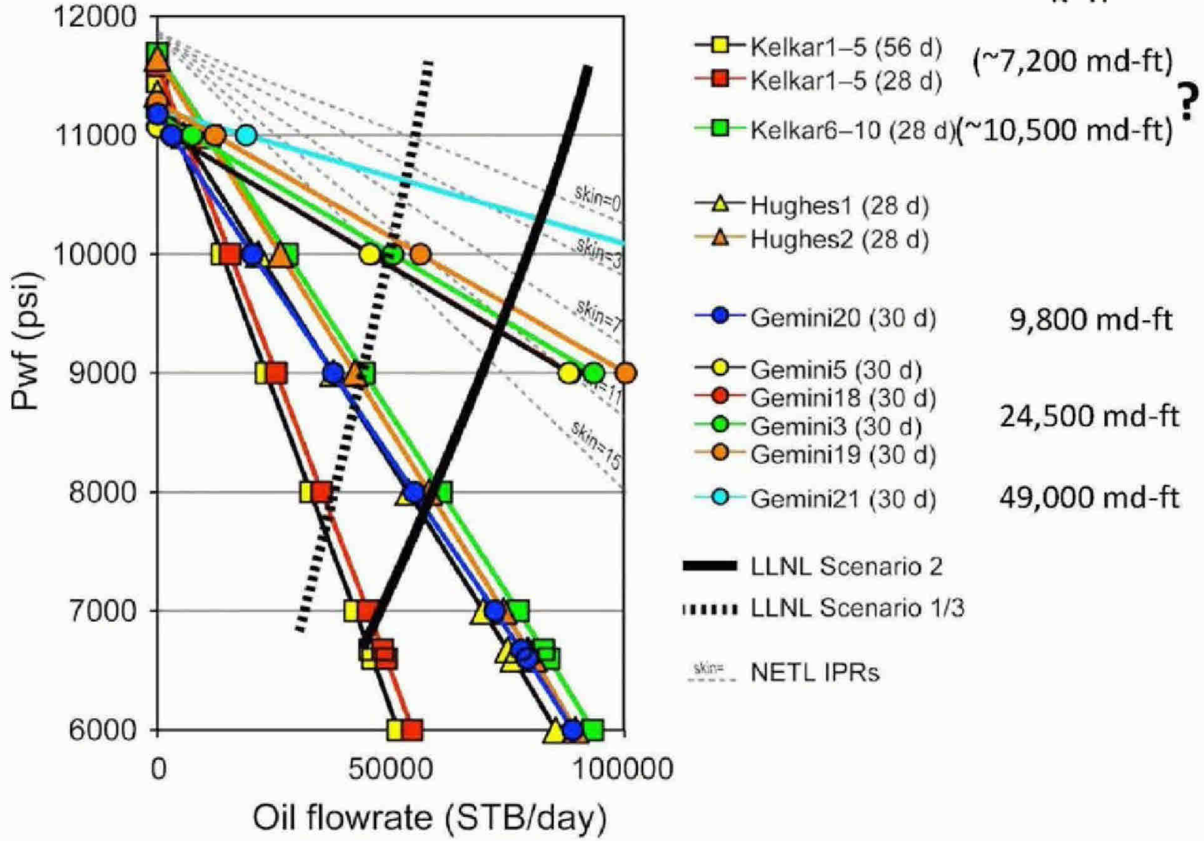
Comparison with Reservoir Team Results



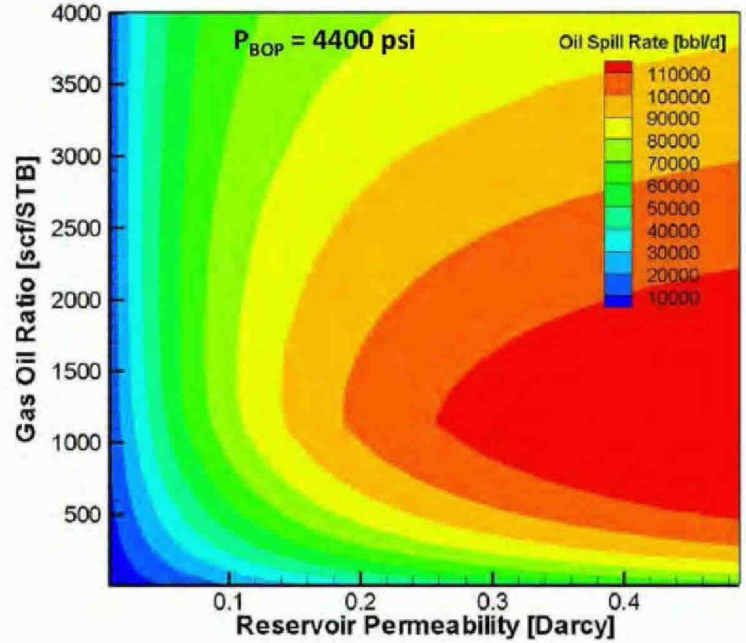
- Gemini-21 case (500 md) roughly equivalent to NETL IPR for skin = 0-3
  - Nodal team high estimates not impacted by reservoir team results
- Gemini-3, 5, 19 roughly equivalent to NETL IPR for skin = 7-15

Results

Comparison with Reservoir Team Results



from LBNL Sensitivity Analysis



- Nodal team high estimates not significantly impacted by reservoir team results
- Confirmed nodal team sensitivity analysis that permeability (BHP) is important factor
- Incorporation of full range of reservoir-team properties would decrease lower estimates
- Reservoir team results suggest nodal assumption of infinitely acting reservoir was reasonable and relaxing the assumption would not have big impact on rate

Doppler Velocities $\rightarrow$ Kink and more

Andy Bowen
Rich Camilli

WHOI

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US Coast Guard Oil Spill Flow Rate Characterization
Deepwater Horizon well Mississippi Canyon Block 252

(#HSCG3210CR0020)

PI Rich Camilli (WHOI)
Co-PI Andy Bowen (WHOI)

analysis team members

Alex Techet (MIT) | Daniela Di Iorio (UGA)
Louis Whitcomb (JHU) | Dana Yoerger (WHOI)
Chris Reddy (WHOI) | Jeff Seewald (WHOI)

Time/Situation

Acoustic measurement using 1.8 MHz imaging multibeam sonar and 1.2MHz acoustic Doppler velocity profiler (ADCP) mounted to a work class ROV

- Measurements performed at distal riser end and BOP kink
- Data collected 31 May 2010 to 1 June 2010

Analysis of fluids using isobaric gas-tight samplers

- Physical collection of 100ml fluid samples at BOP stub (inside tophat #4)
- Sample collected 21 June 2010

All data collected on a 'non-interference' basis

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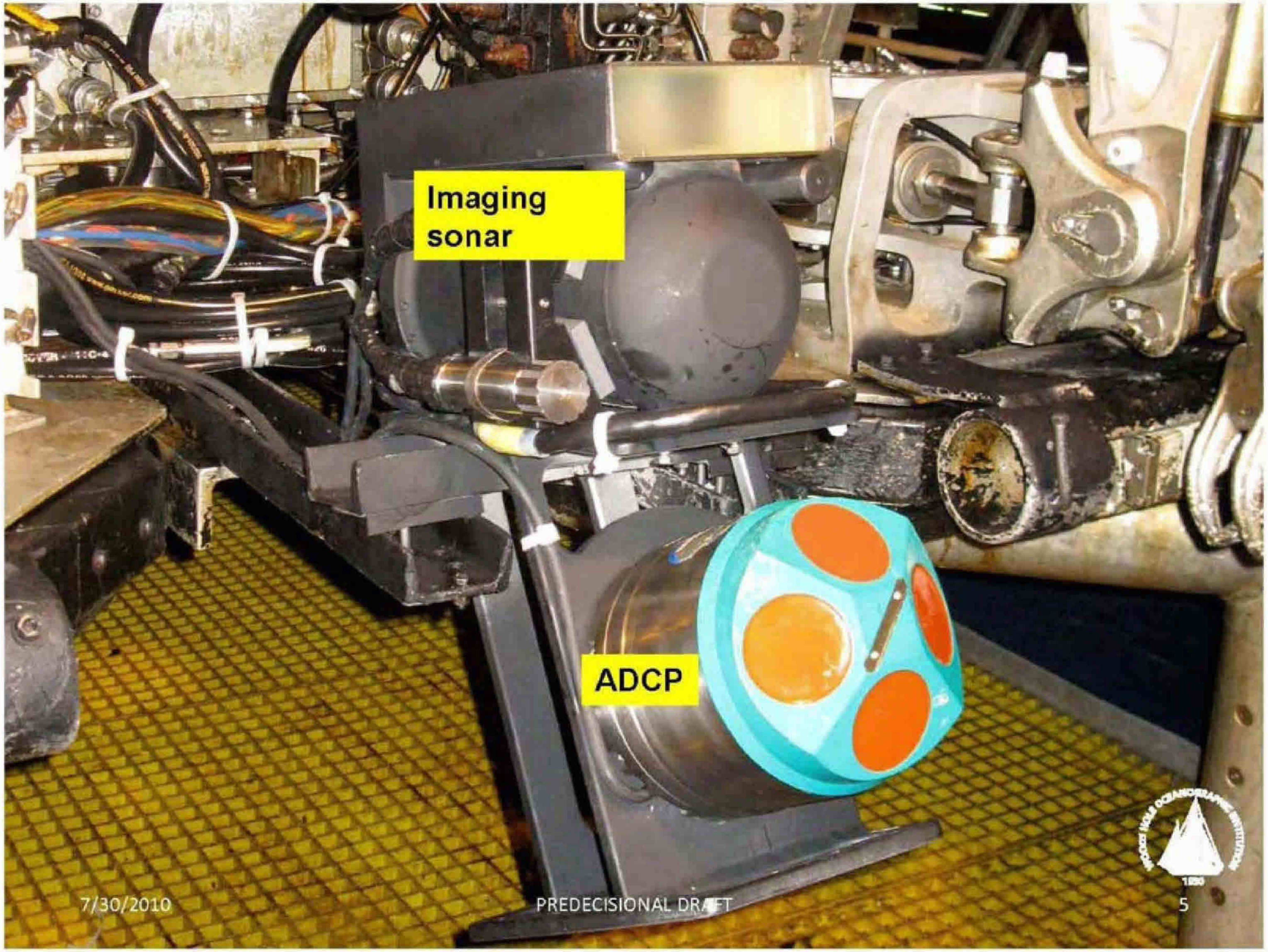
Imaging sonar
ADCP
7/30/2010
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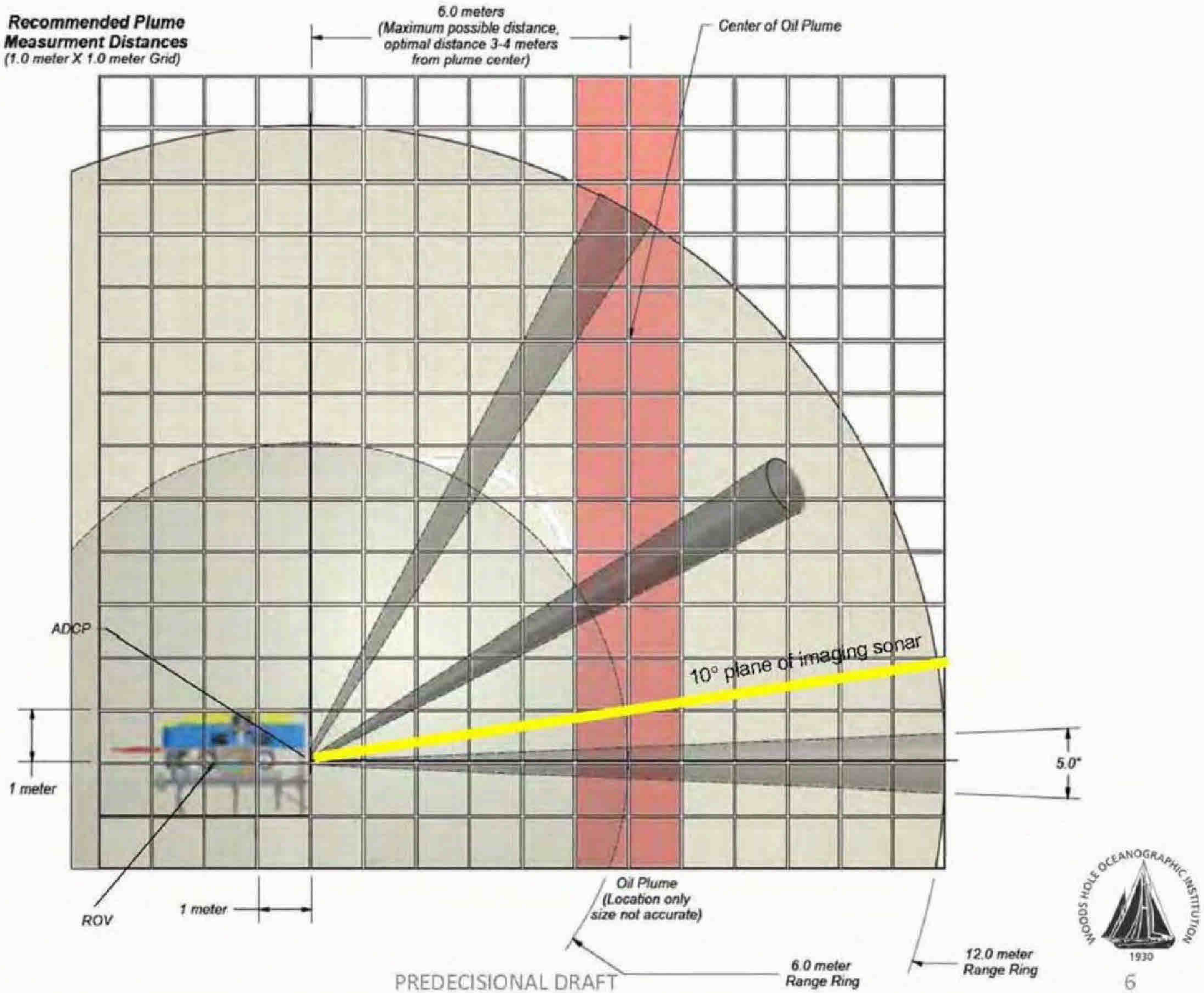

7/30/2010
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Acoustic analysis

Velocity measurements were recorded at two distinct sites, above the riser pipe and at the kink above the BOP. Flow estimates are derived from three different Doppler velocity view angles above the riser pipe and three Doppler velocity view angles above the BOP. Plume cross section measurements were completed using an imaging multibeam sonar operating concurrently with the Doppler system on a ROV.

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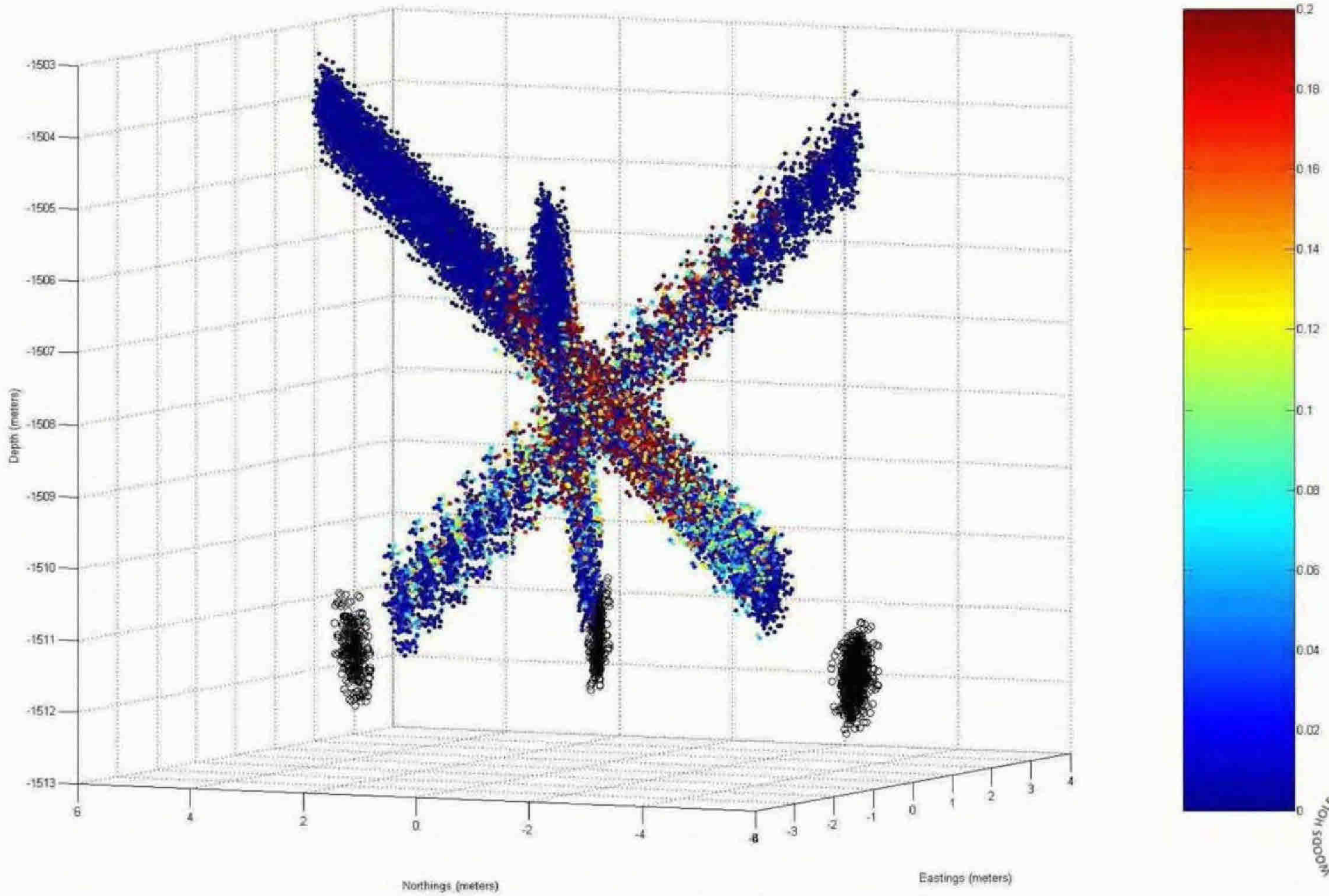
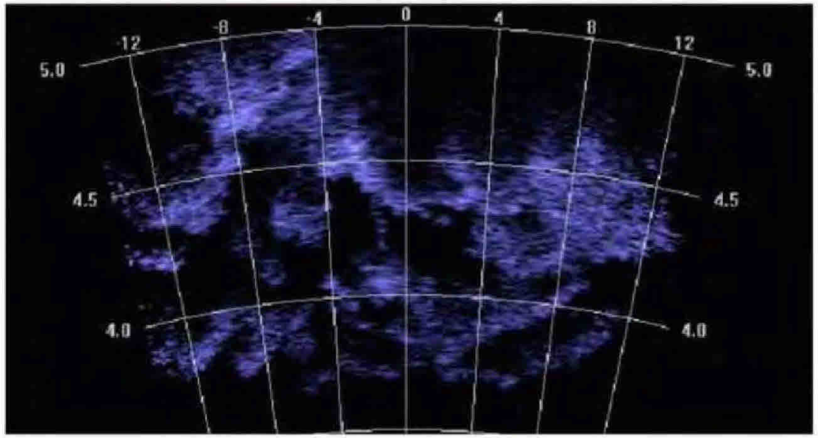
3D reconstruction of plume velocity filed based on ROV navigation and ADCP data

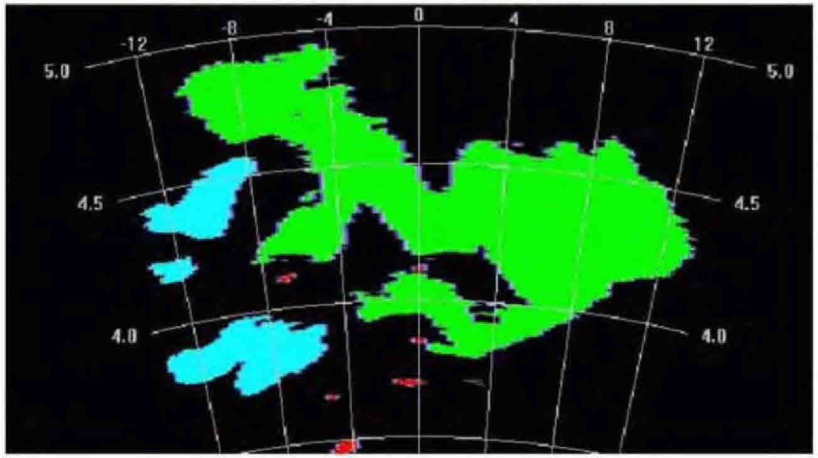


Plume cross section area estimate using 1.8MHz imaging multibeam sonar data

Acoustic image of plume cross section



Plume area calculation using motion tracking with a 6dB threshold



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Analysis of hydrocarbon composition within top hat #4 using Isobaric Gas-Tight sampler

C_1-C_5 hydrocarbon composition

Methane	77.9%
Ethane	7.5%
Propane	4.9%
i-Butane	0.9%
Butane	1.7%
i-Pentane	3.7%
Pentane	3.4%

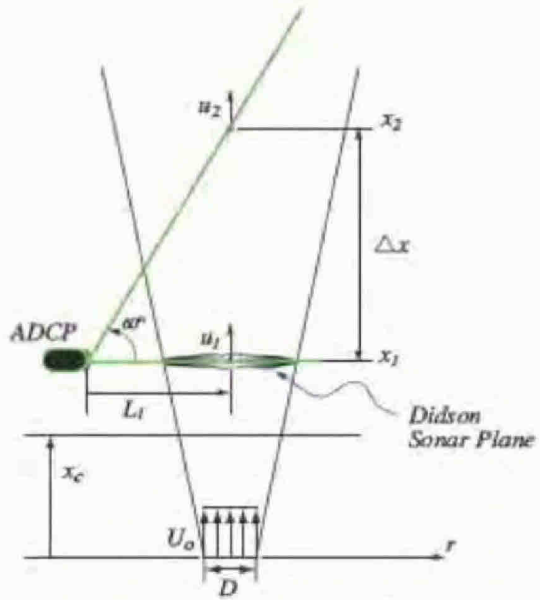
composition @150 atm

43.7% liquid hydrocarbons

56.3% gas hydrocarbons

Model/Experimental Assumptions

- Assumes:
  - Plume radius increases as *f* (vertical distance from source)
  - acoustic backscattering within plume
  - acoustic systems can penetrate plume
  - accurate navigation estimates
  - turbulent axissymmetric jet
  - multiphase flow
  - net vertical velocity
  - 43.7% oil fraction by volume
- Uncertainties (potential systematic biases):
  - complete field of view
  - non-symmetric plume shape
  - acoustic shadowing or distortion
  - actual depth of riser end
  - appropriate detection threshold (dB)



$$u_1 = u_2\,(1 + \Delta x / x_1)$$

back-projecting ADCP velocity
to plume cross-section

Results

- Liquid hydrocarbon fraction 43.7% by volume
- Total ADCP measurements within plume regions : 16,000
- Total multibeam sonar cross sections of plume: 2,600
- Mean riser flow rate: 40,700 bbl/day
- Mean BOP kink flow rate: 18,500 bbl/day
- **Total flow rate 59,200 bbl/day**

Assessment of the Model Value and Uncertainty Estimate

- This work was conducted following top kill attempt and before shearing of the riser. Drill mud, bridging material, and riser shearing are all likely to have altered flow rate over the course of the spill.
- Natural variability due to turbulent flow greatly exceed statistical error bounds.
- Results should be rigorously examined for potential systematic biases, as these acoustic methods are likely to systematically underestimate actual oil flow rate.
- The acoustic methods could be carried out if the cap is removed. Data collection and analysis would be much simpler from a single source and if not subject to operation "non-interference" basis.

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Reservoir Studies Around Times of Well Integrity Test Shut-in

Paul Hsieh

USGS

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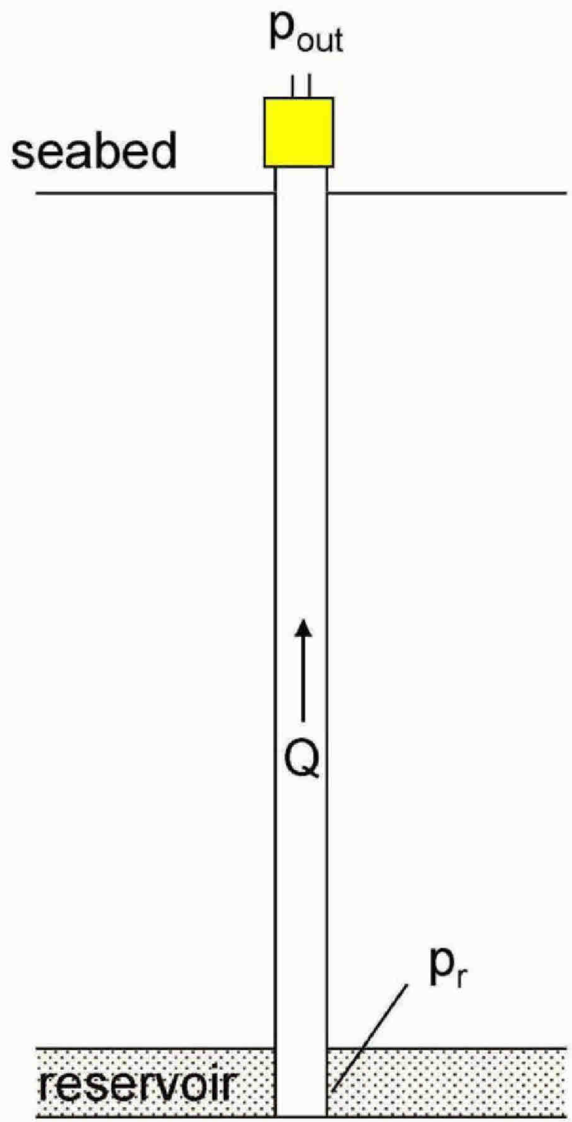
Time/Situation

- Shut-in pressure data from the Well Integrity test can be used to determine:
  - Reservoir geometry
  - Permeability
- Given:
  - Rock compressibility
  - Original Oil in place

The reservoir model can be used to estimate flow rates.

Representation of Well in Model

- The outlet pressure (p_{out}) is specified = 2231 psi (pressure at seabed).
- Pressure drop from the sandface (p_r) to outlet (p_{out}), corrected for elevation difference, is proportional to:
  - Flow rate, Q (linear flow law), or
  - Flow rate squared, Q^2 (quadratic flow law).
- Flow rate is calculated by the model.



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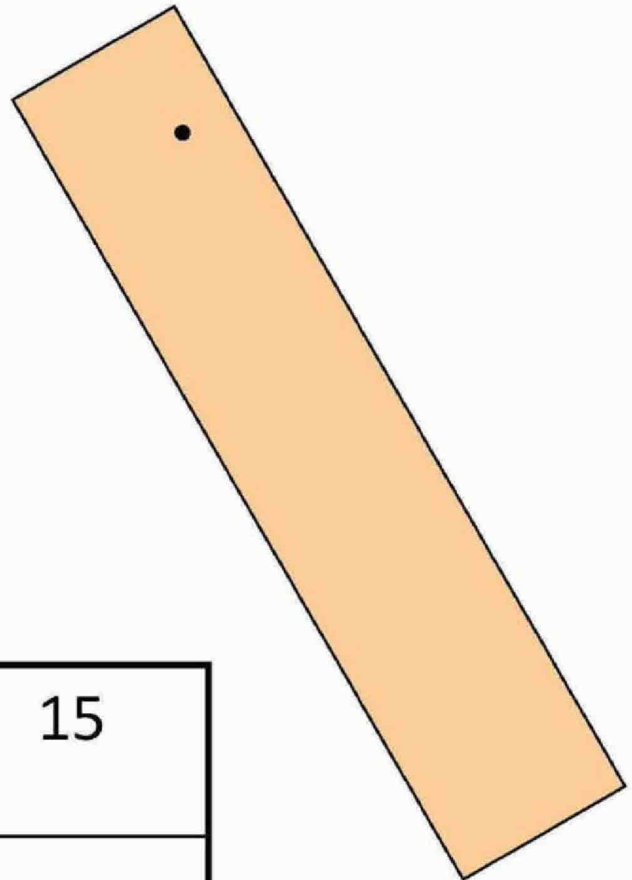
Reservoir Properties

- Volume of Original Oil in Place = 110 million stb
- Formation Volume Factor = 2.35 rb/stb
- Porosity = 21%
- Water Saturation = 10%
- Thickness = 90 ft
- Rectangular Shape

  4,200 ft x 20,300 ft
- No aquifer support



Rock compressibility (10^{-6} psi^{-1})	6	12	15
Permeability (md)	300 - 500		

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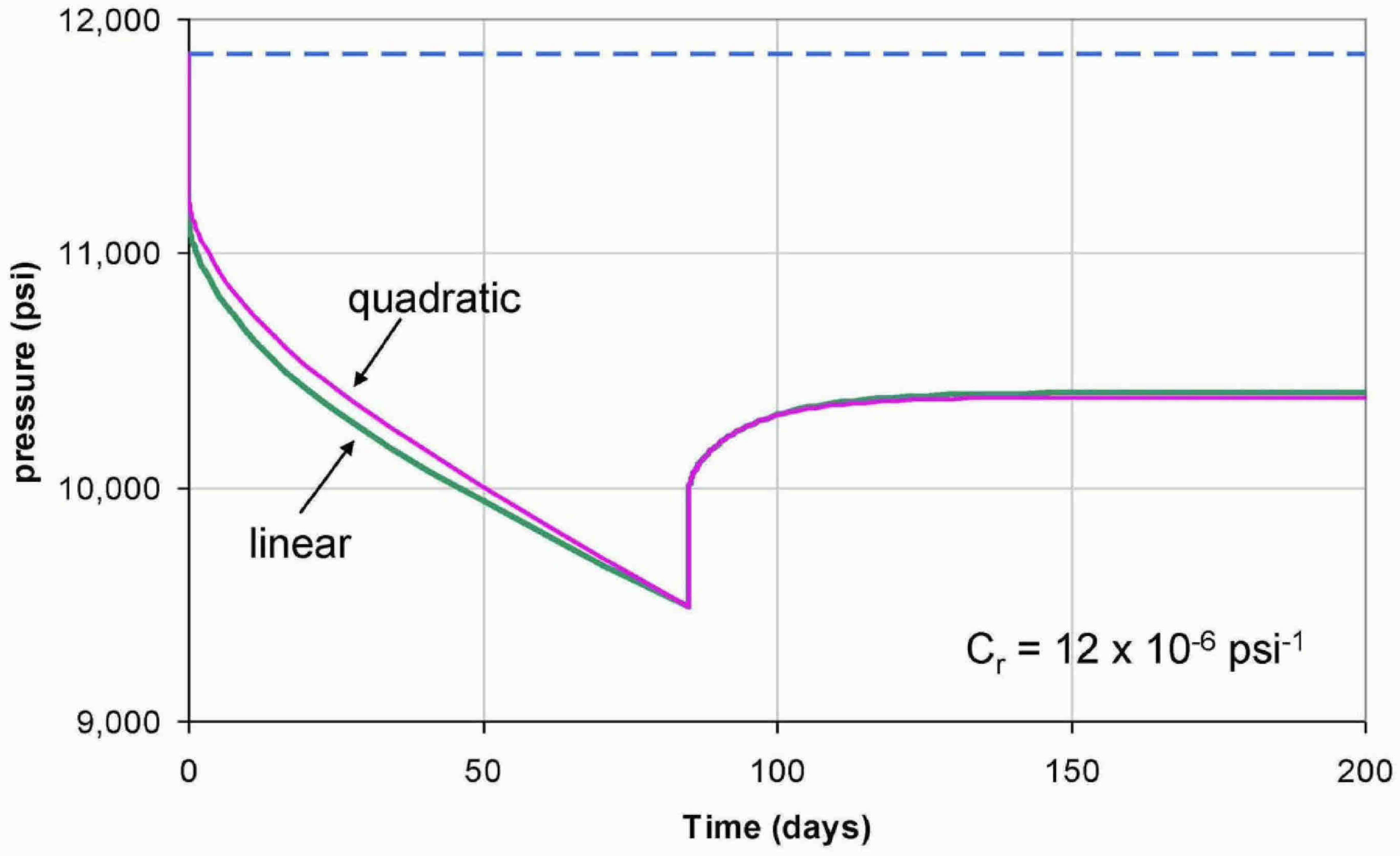
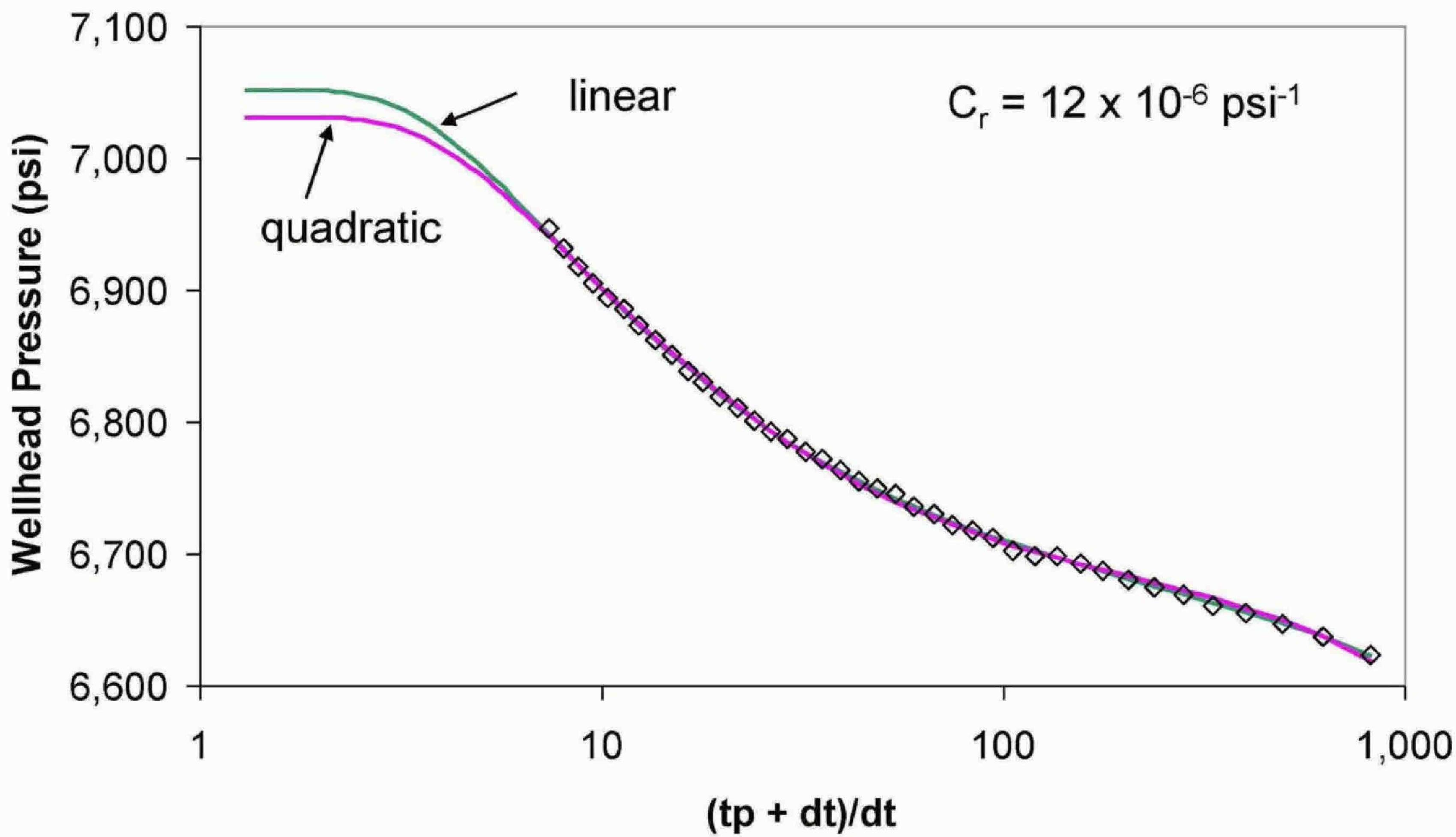
Simulated Sandface Pressure

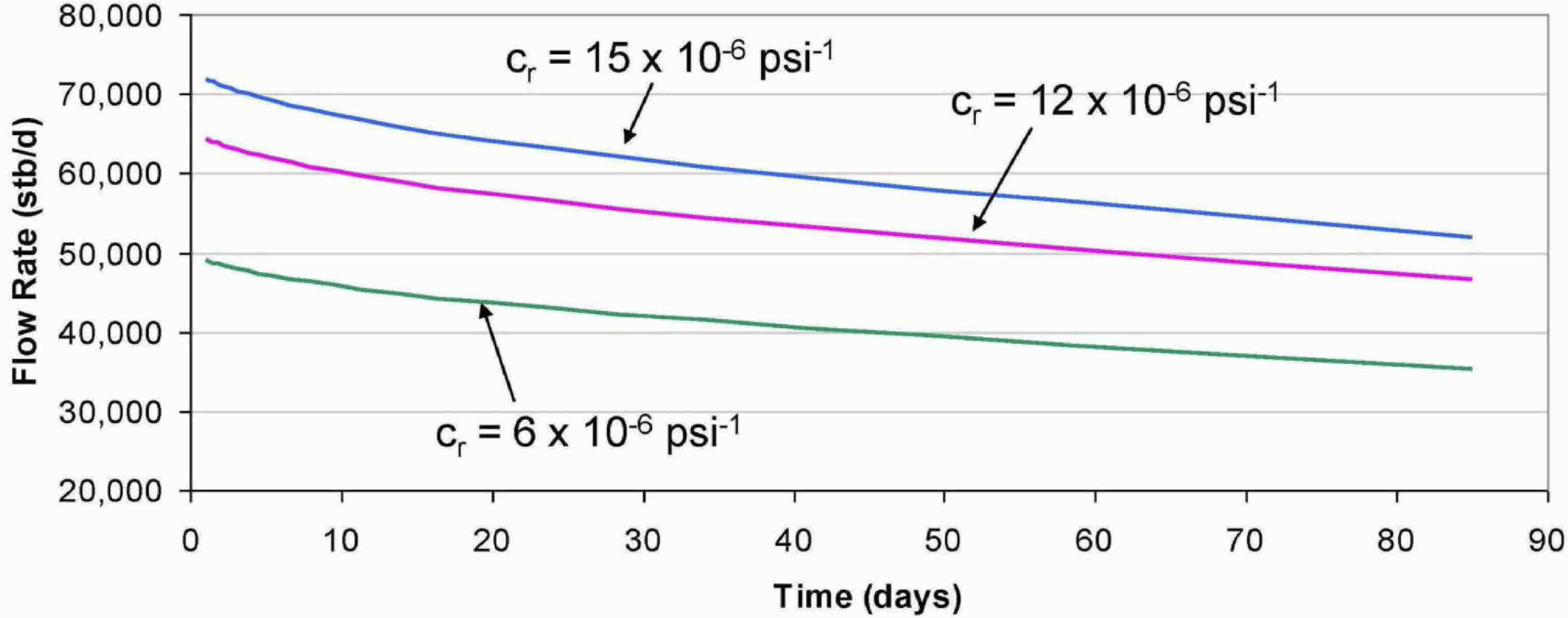


Horner Plot



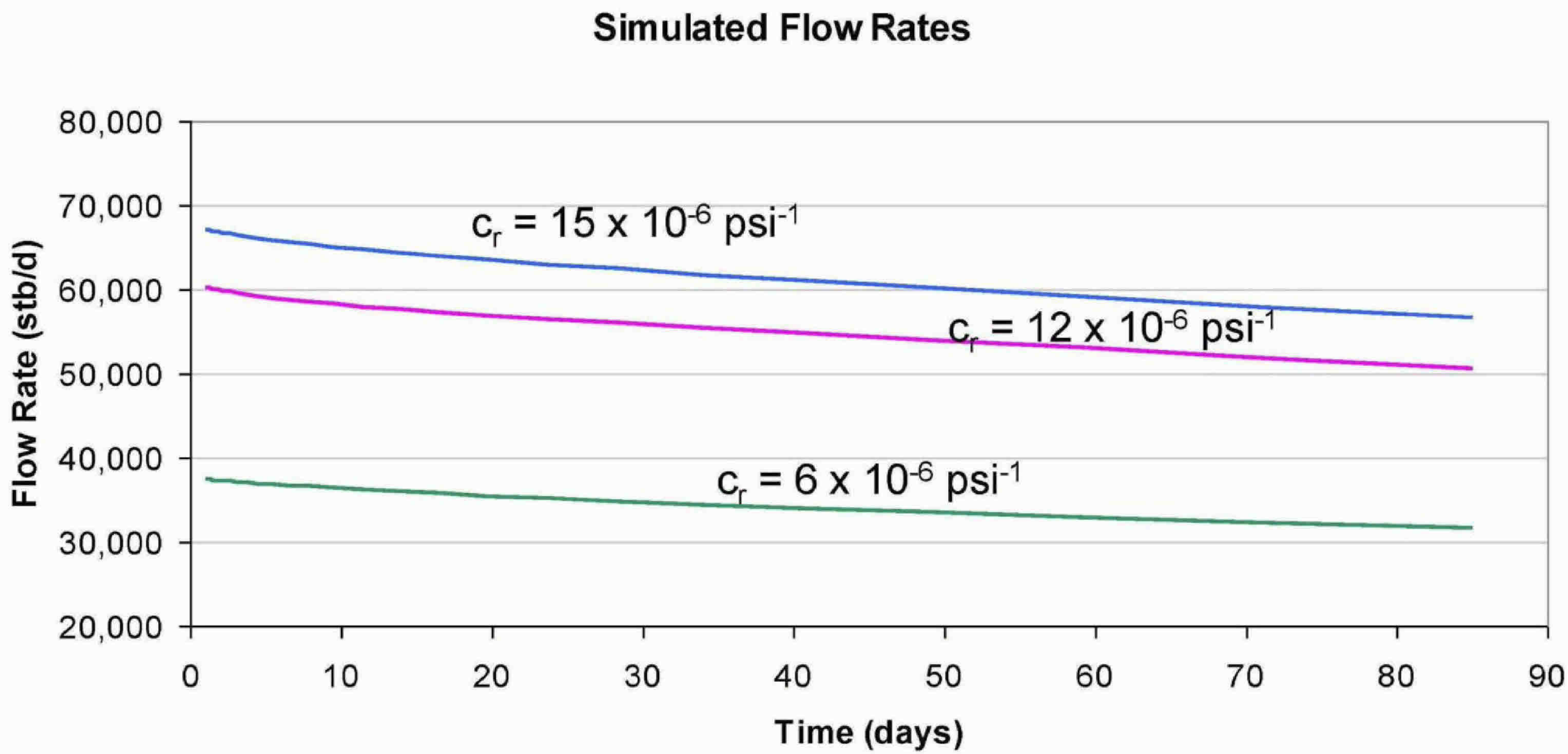
7,100
7,000
6,900
6,800
6,700
6,600
Wellhead Pressure (psi)
1
10
100
1,000
(tp + dt)/dt
linear
quadratic
$C_r = 12 \times 10^{-6}\ psi^{-1}$

Linear flow law
Simulated Flow Rates



c_r (10^{-6} psi^{-1})	6	12	15
Start Rate (stb/d)	49,000	64,000	72,000
End Rate (stb/d)	35,000	46,000	52,000
Average Rate (stb/d)	40,000	53,000	59,000
Total Volumw (stb)	3,400,000	4,500,000	5,000,000

Quadratic flow law



c_r (10^{-6} psi $^{-1}$)	6	12	15
Start Rate (stb/d)	38,000	60,000	67,000
End Rate (stb/d)	32,000	51,000	56,000
Average Rate (stb/d)	34,000	54,000	61,000
Total Volumw (stb)	2, 900,000	4,600,000	5,200,000

Flow prediction around Well Integrity Shut-in

Art Ratzel

DOE Team

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Flow Modeling Activities

Art Ratzel,
Sandia National Laboratories

Representing the work of the DOE Tri-Lab Flow Modeling Team

USGS
science for a changing world

Los Alamos
NATIONAL LABORATORY

Sandia National Laboratories

Lawrence Livermore National Laboratory

IGS075-016351

TREX 008635.0076

Time & Situation
Problem Statement

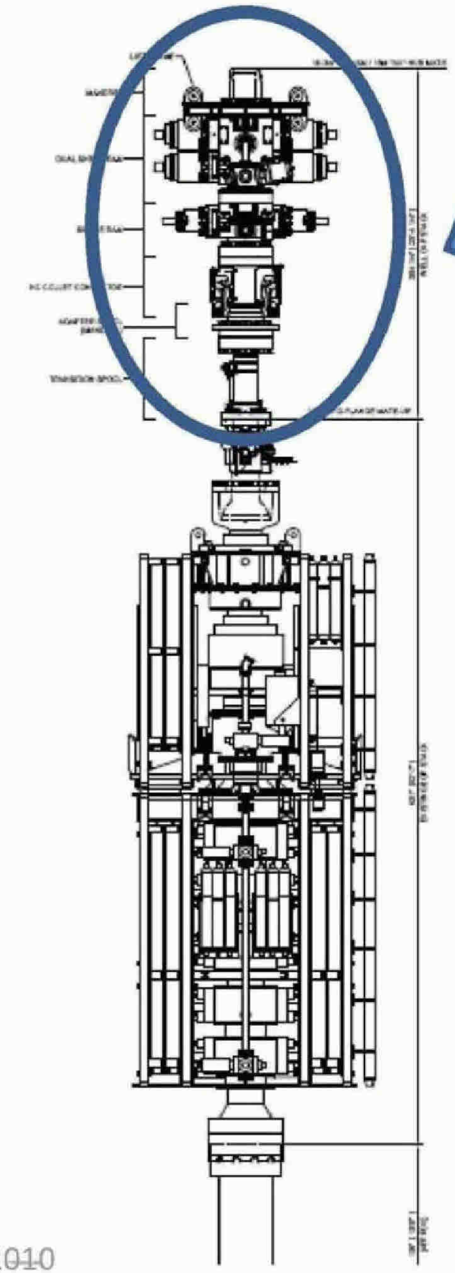
As part of preparations for the Well Integrity Test, analyses were performed to predict key attributes for a contained and leaking well.

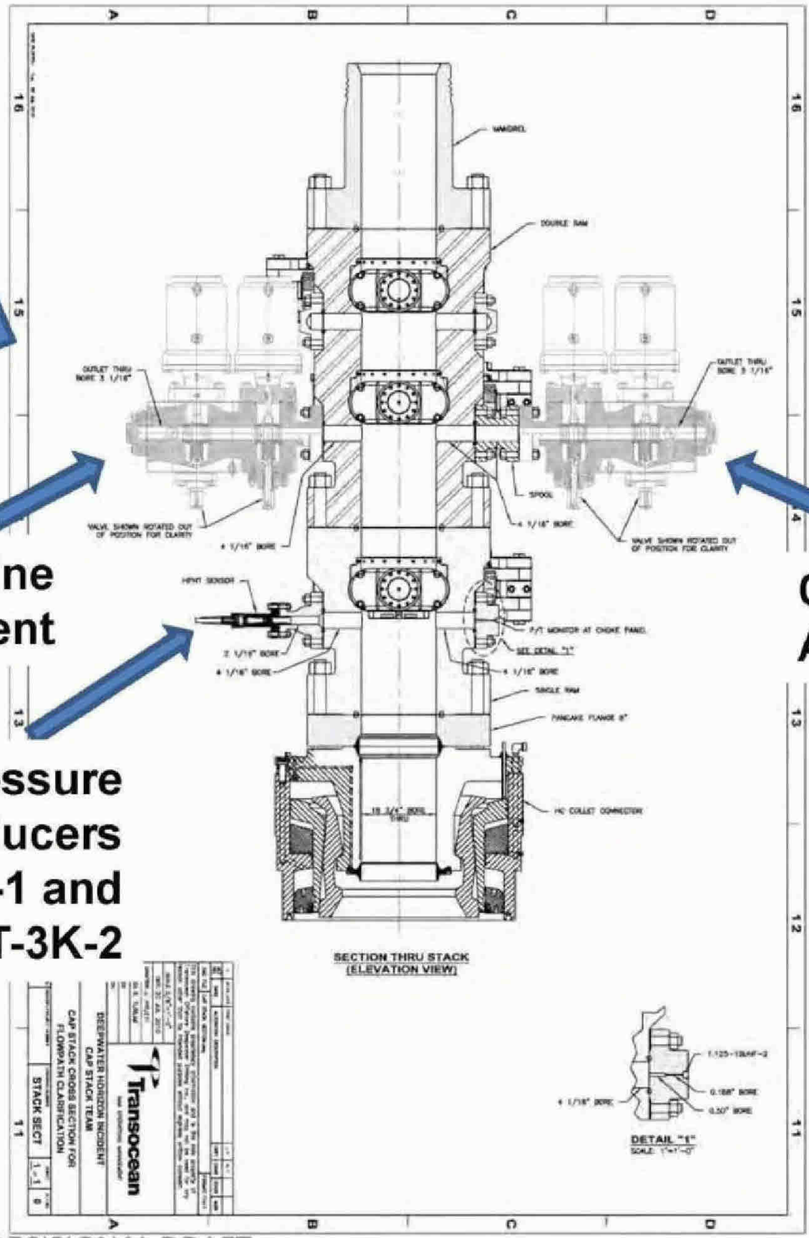
In support of the Well-Integrity studies related to shut-in, the flow modeling team was tasked with predicting the liquid volume "flow" rate (stock-tank barrels of oil per day)

Related questions

- Can the results from the WIT Shut-in test be used to predict the flow rate for other times/events after the accident?
- What is the flow path inside the well – central, annular, or both?
- Is the well leaking?
- What is the pressure in the well below the BOP?

Shut-in of the 3-Ram Capping Stack provided opportunities for estimating flow





Kill Line Attachment

Choke Line Attachment

Pressure Transducers PT-3K-1 and PT-3K-2

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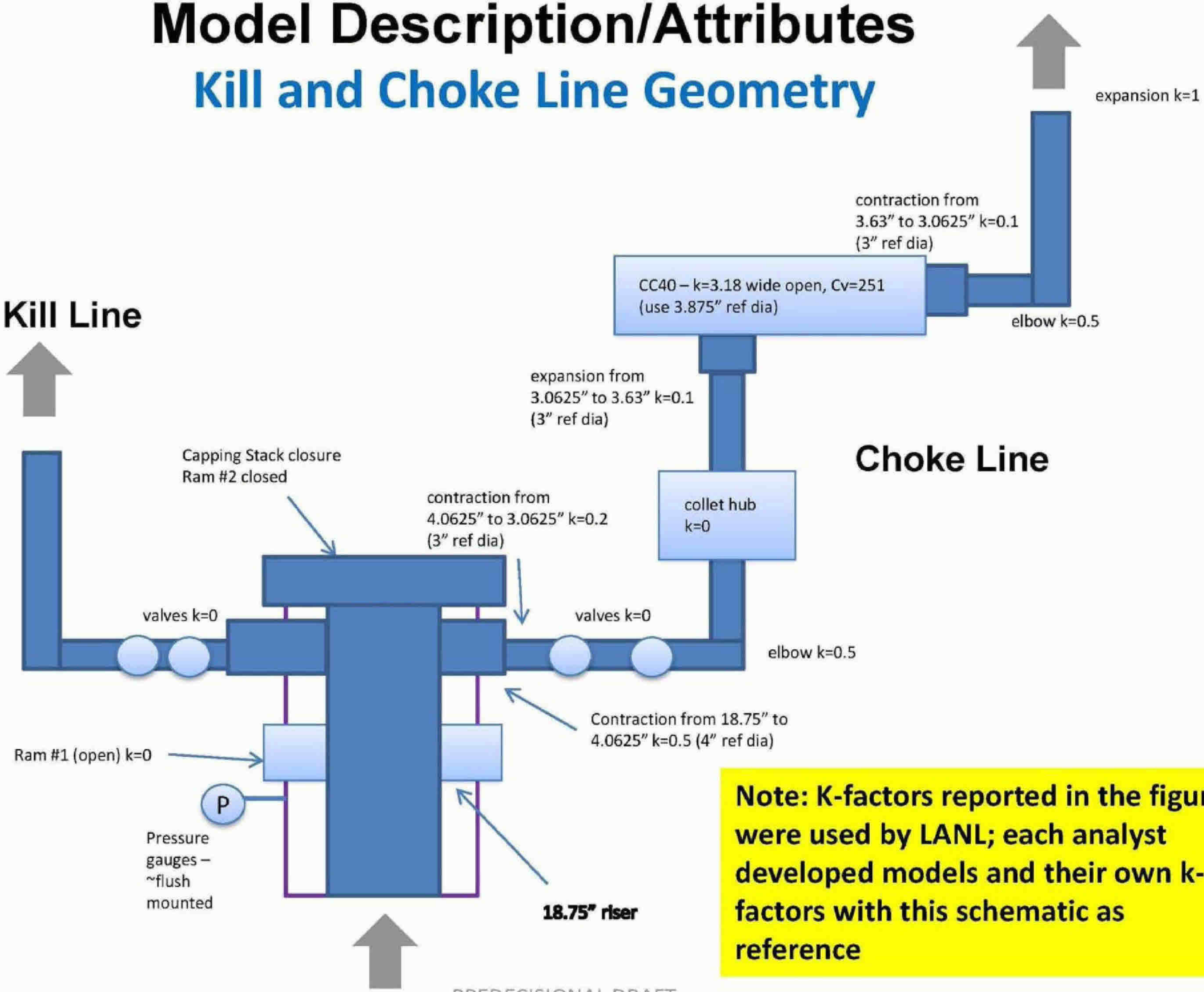
Model Description/Attributes

Kill and Choke Line Geometry



Note: K-factors reported in the figure were used by LANL; each analyst developed models and their own k-factors with this schematic as reference

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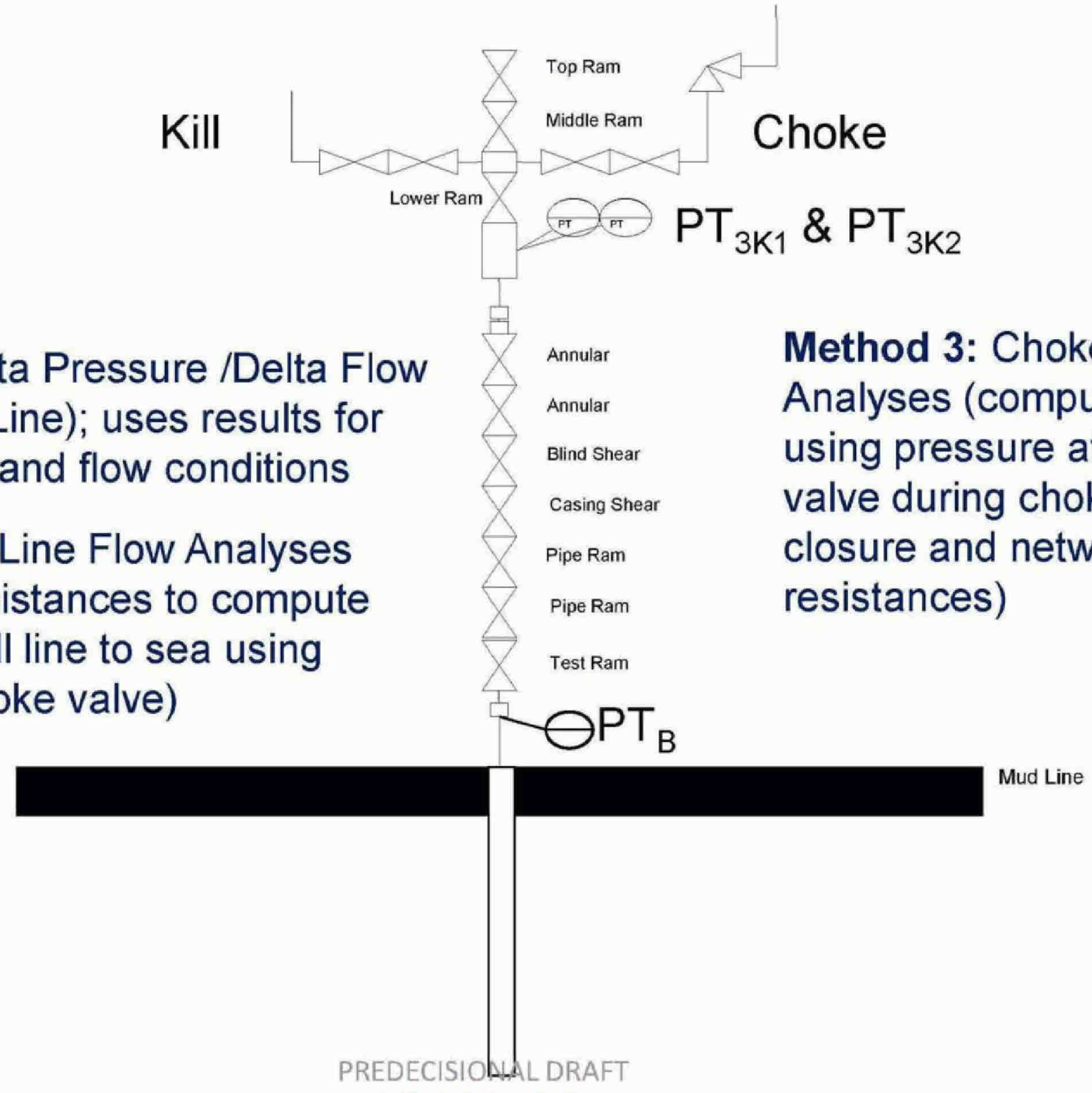
Summary of Three Computational Methods Pertaining to Well Integrity Test Configuration



- **Method 1:** Delta Pressure /Delta Flow Analyses (Kill Line); uses results for different times and flow conditions
- **Method 2**: Kill Line Flow Analyses (network of resistances to compute flow through kill line to sea using pressure at choke valve)

Method 3: Choke Line Flow Analyses (computes flow using pressure at choke valve during choke valve closure and network of resistances)

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Well Integrity Test Modeling Efforts: Knowns, Assumptions and Uncertainties

Knowns

- Known geometry for the Capping stack
- Pressure readings from 2 gauges in 3-Ram Capping Stack with pretest calibration at seabed
- Surface vessel recovery rates and volumes during some operations

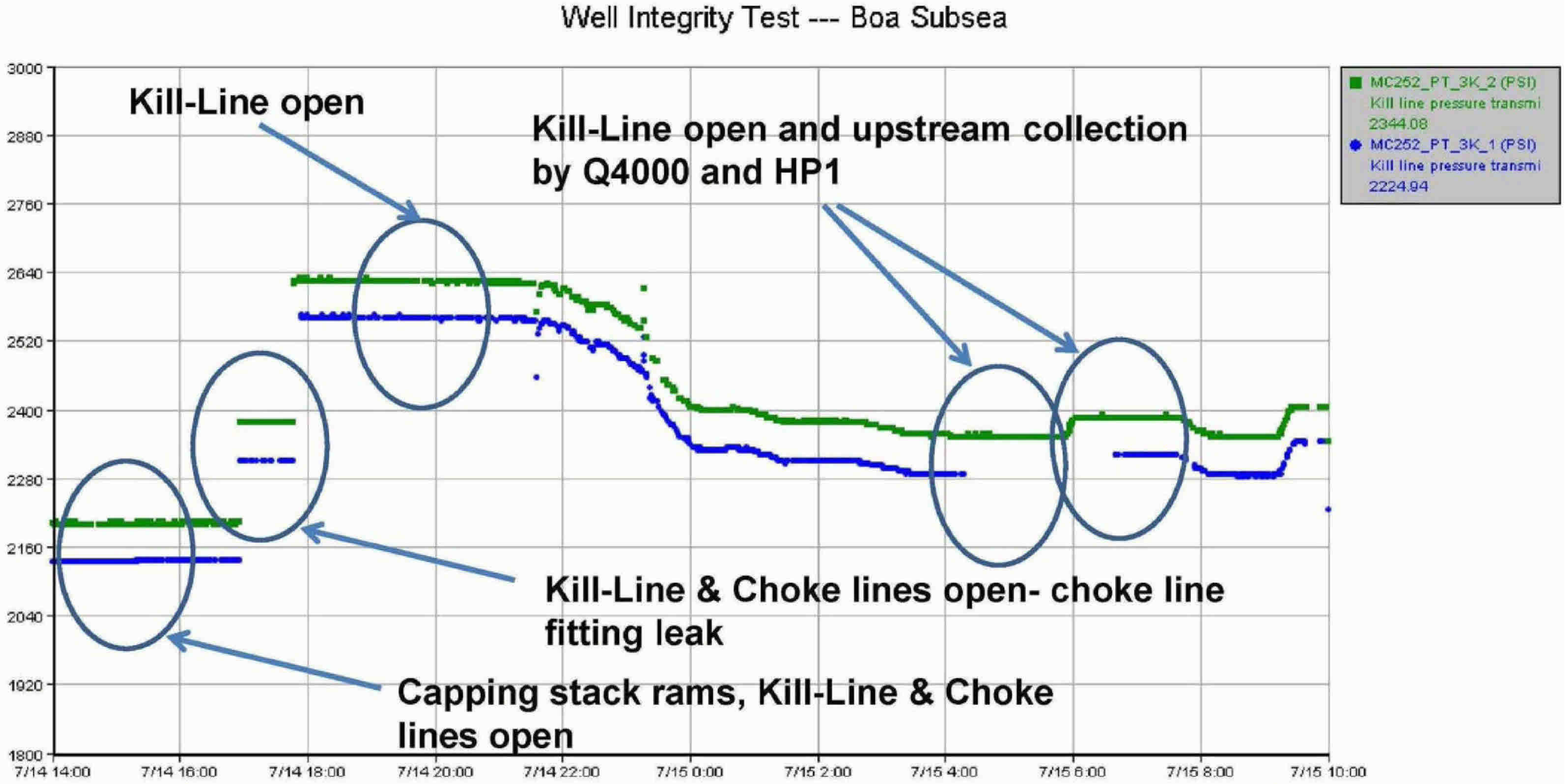
Assumptions

- Reservoir pressure prior to accident and estimates for depletion (~1800 psi)
- Temperature of flowing hydrocarbon at wellhead (before initiation of well integrity test) - estimated at 180-200F
- No well leakage
- Steady state flow
- Productivity Index of the reservoir (PI assumed to be ~50)

Uncertainties

- EOS and multiphase flow models
- K-factors and choke valve vendor data for multiphase flow regimes

Choke Pressures on July 14-15 Under Differing Flow Conditions through Kill Line



"Preferred" transducer is in green – has 10 psi DC offset not corrected in figure; evaluations performed at seabed

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Delta Pressure Analyses – Method 1

- Analysis Method: Use two steady flow conditions
  - Initially all flow through the Kill Line
  - Later flow split through the Kill Line and collection lines (HP1 and Q4000 collection)
  - Back out total flow due to change in Kill Line pressure
- Assumptions
  - Assumes fluid density does not significantly change - 15% change in density may yield a 8% error in flow rate.
  - Assumes resistance does not significantly change (relaxing multiphase effects assumption not yet verified)
  - Requires an estimate of flow decrease from well due to changing back pressure

Flow estimates for step change in flow and pressure measurement

- Flow through a constant resistance when **collection** exists: low choke pressure, late time

$$\Delta P_2 = KQ^2$$

- Modify flow rate due to known collection rate change (w) and less flow up well (g): high choke pressure, early time **(base case)**

- Solve for *Q* and *K* from two equations

$$\Delta P_1 = K(Q + w - g)^2$$

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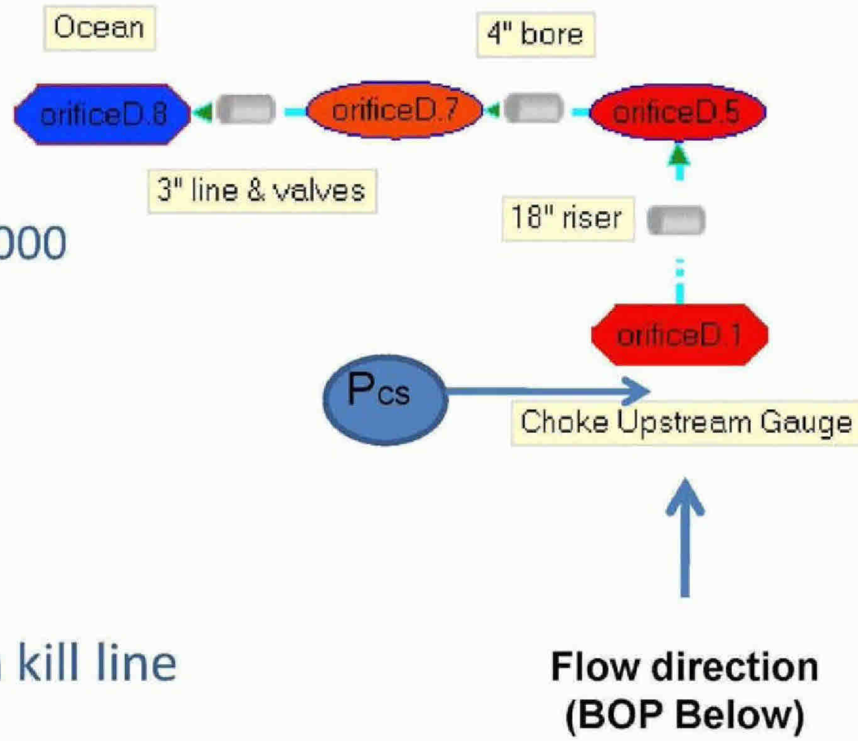
Delta Pressure Analyses – Method 1 (cont'd)

- Model Advantages
  - Geometrical effects minimized – Does not require determining *K* from single phase relations, nor does it require a two phase correction
  - Uses steady flow measurements for comparison to a steady model
- Model unknowns
  - Pressure measurement +/- 10psi
  - Flow decrease due to back pressure increase 1000 +/- 500 bopd
  - Ambient pressure 2189 +/- 2 psi
  - Collection rates +/- 1000 bopd
- Results: total flow out the kill and collected at beginning (Q+w)
  - Total flow range **(collection case)** from **52,600 to 52,900 bopd** (no parameter variation) for various quasi-steady time periods
  - Error bars are difficult to estimate due to use of single phase concepts for a multiphase flow (model inaccuracies).
  - Ignoring model inaccuracies, the flow range is **48,000 to 58,000 bopd** given model unknowns above. Total error may be greater.

Kill Line Analyses – Method 2

- **Analysis Method: Flow through the Kill Line**
  - Model flow restrictions between the choke pressure gage and exit into sea
  - Use measured P_{cs} and known P_{sea}
  - Two cases:
    - Flow only through kill line to exit
    - Some flow through the Kill valve to exit, some diverted upstream to HP1 and Q4000 collection vessels
- **Resulting Model: Network Model**
- **Assumptions**
  - Kill line gate valves are wide open
  - All flow into 3-ram stack exits through kill line
  - No elevation change of kill line



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Kill line Analysis Results Method 2

Kill Line open and no shipboard collection

Lab	P_choke (psia)	P_sea (psia)	Oil from kill line (bopd)	Oil collected on ship (bopd)	Total oil flow (bopd)
Sandia	2615	2192	51000	0	51000
LLNL	2615 +/- 10	2192	47,900 49,200	0	47,900 49,200

Kill Line open and shipboard collection; 04:30-05:30

Lab	P_choke (psia)	P_sea (psia)	Oil from kill line (bopd)	Oil collected on ship (bopd)	Total oil flow (bopd)
Sandia	2343	2192	29700	22100	51800
LLNL	2343 +/- 10	2192	26,500 28,400	22,000 +/- 1100	47,400 51,600

Kill Line open and shipboard collection; 06:30-07:30

Lab	P_choke (psia)	P_sea (psia)	Oil from kill line (bopd)	Oil collected on ship (bopd)	Total oil flow (bopd)
Sandia	2376	2192	32900	18,900	51800
LLNL	2376 +/- 10	2192	29,660 31,450	18,940 +/- 950	47,650 51,340

Range Min	47,430 bopd	Range Max	51,570 bopd

Pressure and collection data uncertainties are being developed by BP – uncertainty analyses to follow

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Kill Line Analyses – Method 2 (cont'd)

- Model Advantages
  - Simple geometry, does not include reservoir or well.
  - Well-defined geometry and boundary conditions-fully prescribed problem
  - Trust in pressure boundary conditions
- Model Limitations/Issues
  - Two-phase flow losses may be inaccurate
  - Head loss at closed ram/angle into kill line (stagnation flow) not fully understood

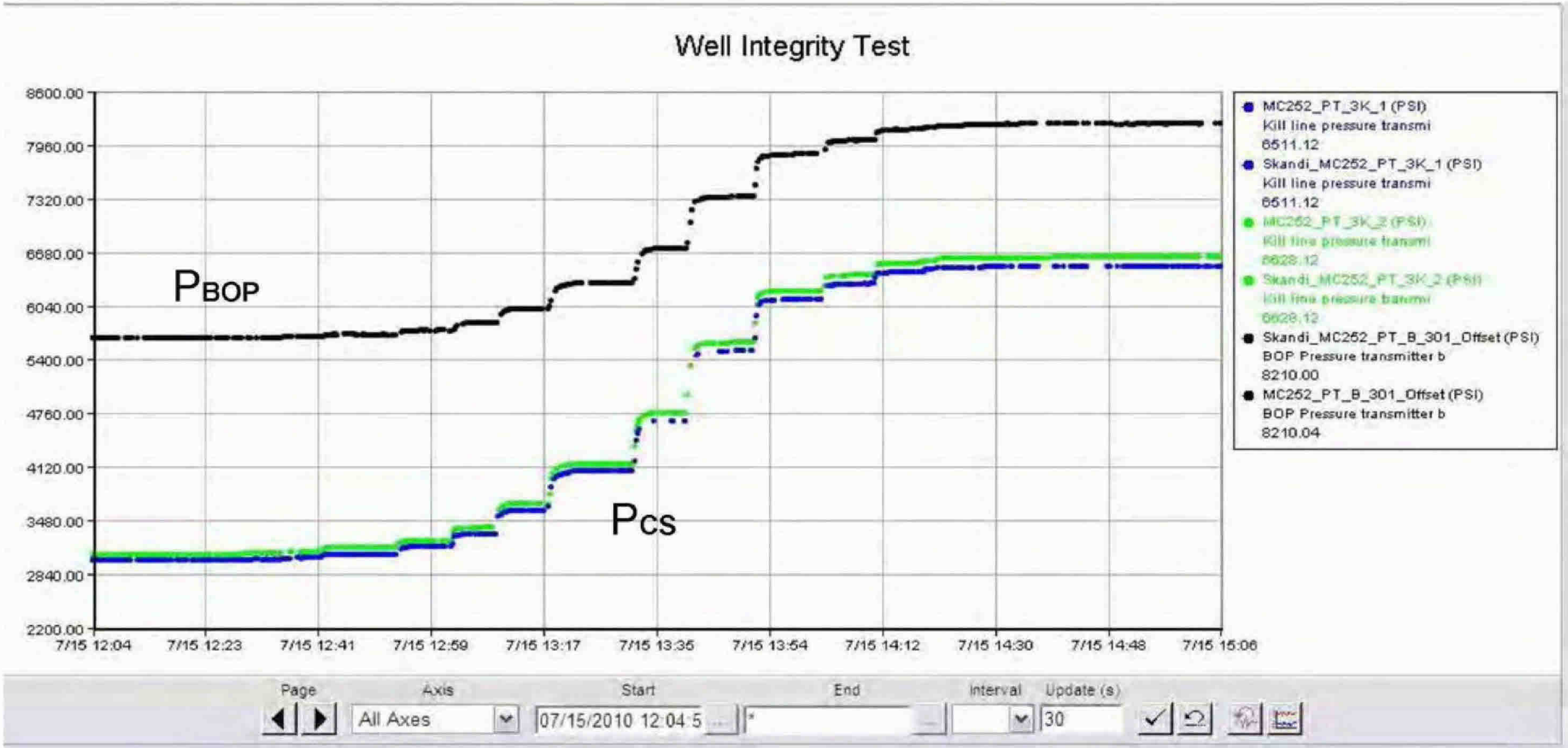
Results Summary

- Flow only through Kill Line: Average Flows of **48-51K bopd**
- Flow through Kill Line with **~19-22K bopd** removed upstream: : Average Flows of **47-52K bopd**

Choke Line Analyses – Method 3

- **Analysis Method: Predict Flow through the Choke Line**
  - Model flow restrictions between the pressure gage and exit
  - Use measured Pcs and known Psea
- **Resulting Model: Network Model**
  - See earlier vg for geometry details
- **Assumptions**:
  - All flows treated as steady state in the analyses
  - All flow into 3-ram stack exits through choke line; choke line gate valves are wide open
  - Choke valve operates as per manufacturer's specs (see data)
  - Multiphase flow effects are tractable in the steady state models being applied

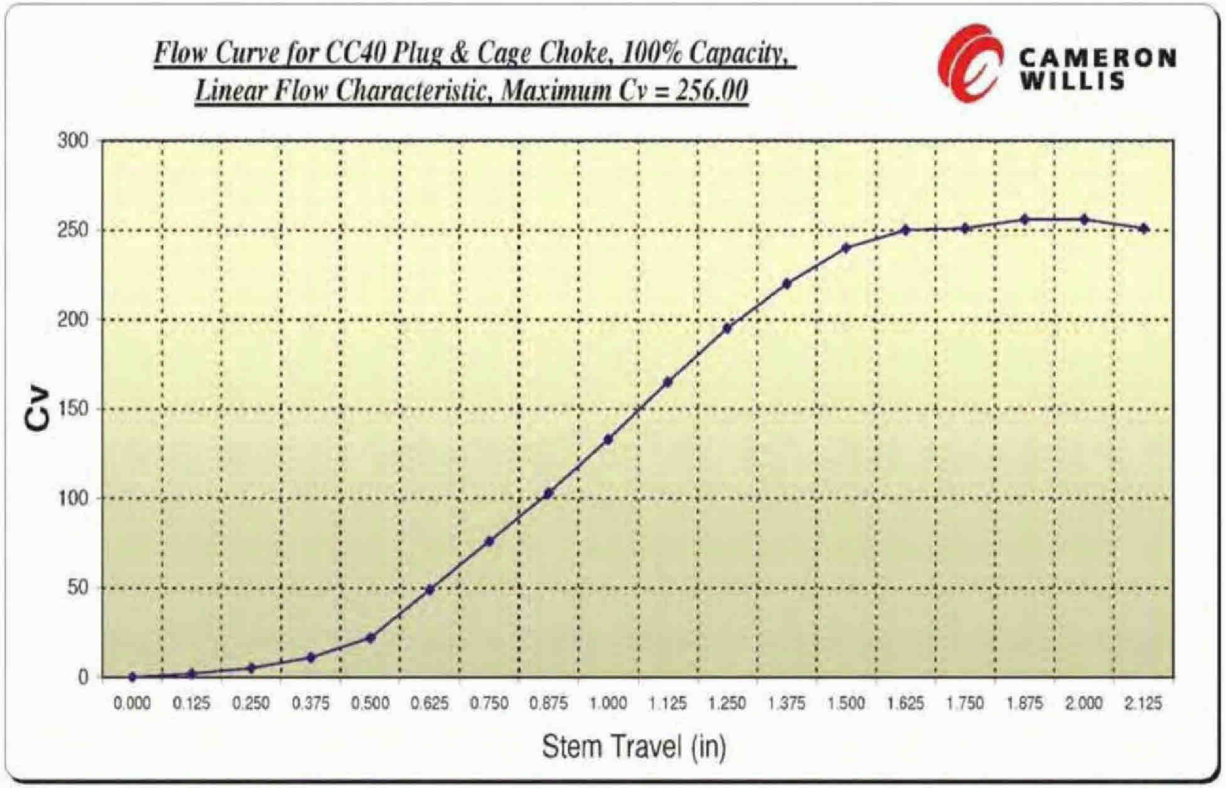
Results from Well Integrity Shut-in Test of July 15, 2010



Pressure gauge below the BOP also shown; correlation of gauge with expectations was poor

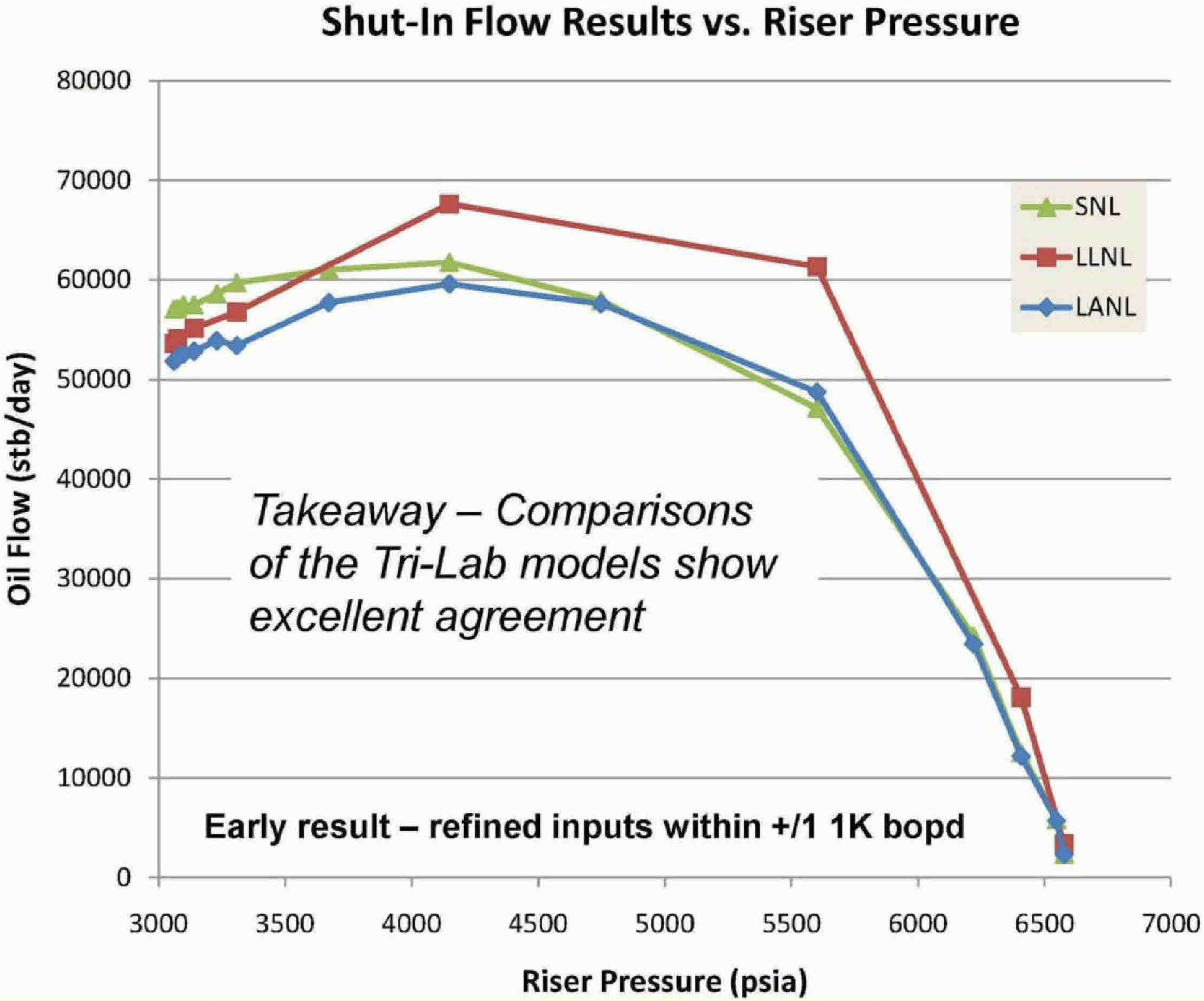
CC40 Choke valve characteristics and choke pressure data for July 15 well integrity shut-in test

# Turns	Pcs**	% Open	Cv
0	3061	100	251
2	3075	86	250
2.5	3099	78	240
3	3140	69	220
3.5	3230	59	195
4	3384	50	165
4.5	3672	41	133
5	4149	32	103
5.5	4748	23	76
6	5602	16	49
6.5	6220	9	22
7	6408	5	11
7.5	6548	2	5
8	6578	1	2
8.5	6605	0	0



Cv	0	2	5	11	22	49	76	103	133	165	195	220	240	250	251	256	256	251
% Travel	0	6	12	18	24	29	35	41	47	53	59	65	71	76	82	88	94	100
% Open	0	1	2	5	9	16	23	32	41	50	59	69	78	86	93	99	100	100
64ths	0	22	33	55	75	100	120	139	158	175	191	206	219	230	240	246	248	248

Choke Line Analyses – Method 3



Computational results obtained across the Tri-Lab compare well and provide for a fully open choke valve a mass flow prediction of 52-57K bopd

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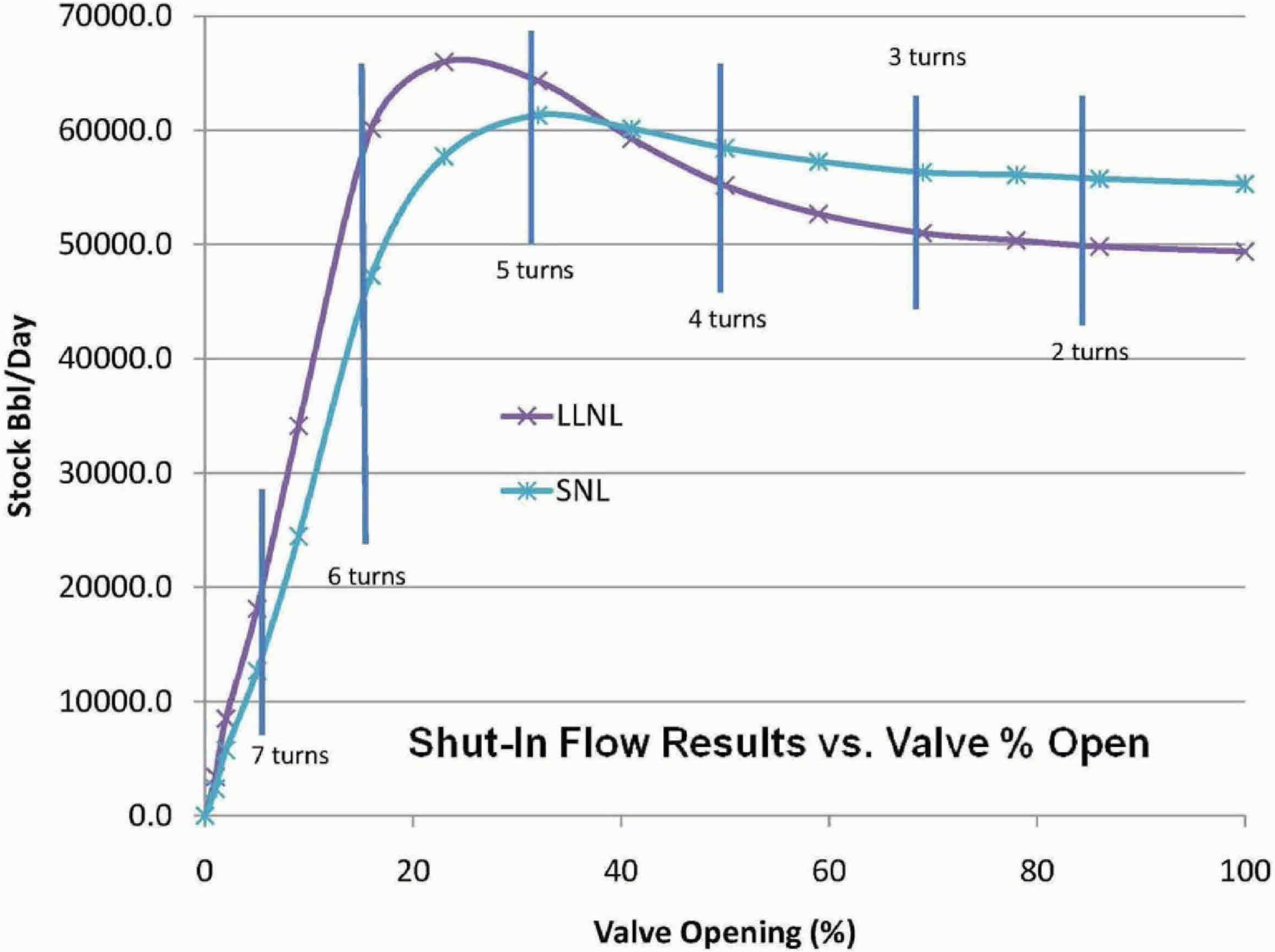
Choke Line Analyses – Method 3



Flow increases during the initial closing of the choke valve. This suggests that the models are not accurate for two phase flow.

Flow at full open agrees well with Method 1 and Method 2

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Choke Line Analyses – Method 3 (cont'd)

- **Model Advantages**
  - Analyses do not require knowledge of conditions in BOP and Well section
  - Choke line geometrical effects known *(but does add complexity)*
- **Model Limitations/Issues**
  - More "plumbing" than for Kill Line analyses – K-factor variation for multiphase analyses (esp through choke valve) critical
  - Flow through the choke valve
    - **are we handling multiphase flow correctly?**
    - **Are the vendor provided Cv data appropriate for the flow conditions**
- **Uncertainties with Choke Calculation**
  - Multiphase Flow effects -- Cv and K values are based on water. Multiphase flow is more complicated and may yield higher K values (which yields a lower predicted flow)
  - Model is a series of steady state conditions, but data never achieves steady state flow in the well.

Summary of results from 3 methods for estimating well flow rate

Date	Synopsis	Wellhead flow rate (bopd)	Major Uncertainties	Other Notes
Method 1: Pressure Differential Analyses	Kill Line Studies – uses two flow conditions	~52K (48-58K all parameters varied)	•Multiphase flow effects •Collection data	• Includes pressure gauge and collection variations • Performed cursory uncertainty analysis
Method 2: Flow through Kill Line valve	Computes flow using Pressure at Choke valve and sea pressure through kill line	47-52K	Multiphase flow effects	Includes pressure gauge variations +/- 30 psi
Method 3: Flow through Choke Line	Computes flow using Pressure at Choke valve and sea pressure through choke line	49-55K	• Multphase flow model • Choke valve characteristics for flows modeled	No pressure variations or other uncertainties considered

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Capping Stack Analyses and Uncertainty

- Insufficient information to perform an uncertainty analysis on flow rate and total flow at time of meeting.
  - Values presented are point estimates only
  - The uncertainty is not bounded by the range of values presented
- Uncertainty sources
  - Model Form
    - Evaluations used 3 approaches for flow before WIT. Agreement may only be fortuitous as each has significant assumptions
      - **Method #1: e.g. K does not change with flow**
      - **Method #2 & 3: e.g. K based on water (instead of two phase flow), K's can be added**
  - Boundary & Initial Conditions
    - Pressure & flow rate uncertainty
  - Other model parameters
    - EOS parameters, friction factors, etc.

Flow Rate Calculation Conclusions

- 3 Methods for flow prediction provided using data from Well Integrity tests
  - Independent calculations for each method were performed by the DOE Tri-Lab team.
  - Good-to-Excellent comparison of results; estimate **53K bopd +/- 5-10K bopd**
  - Results are tightly bunched – but analyst team has significant concerns that the uncertainty remains large
- Greatest uncertainty in multiphase correlation – especially for choke line flow analyses
  - Additional literature searches in-progress
  - Contacted Norweigan SMEs who have worked extensively in the multiphase flow regimes of interest for their support in estimating the uncertainty

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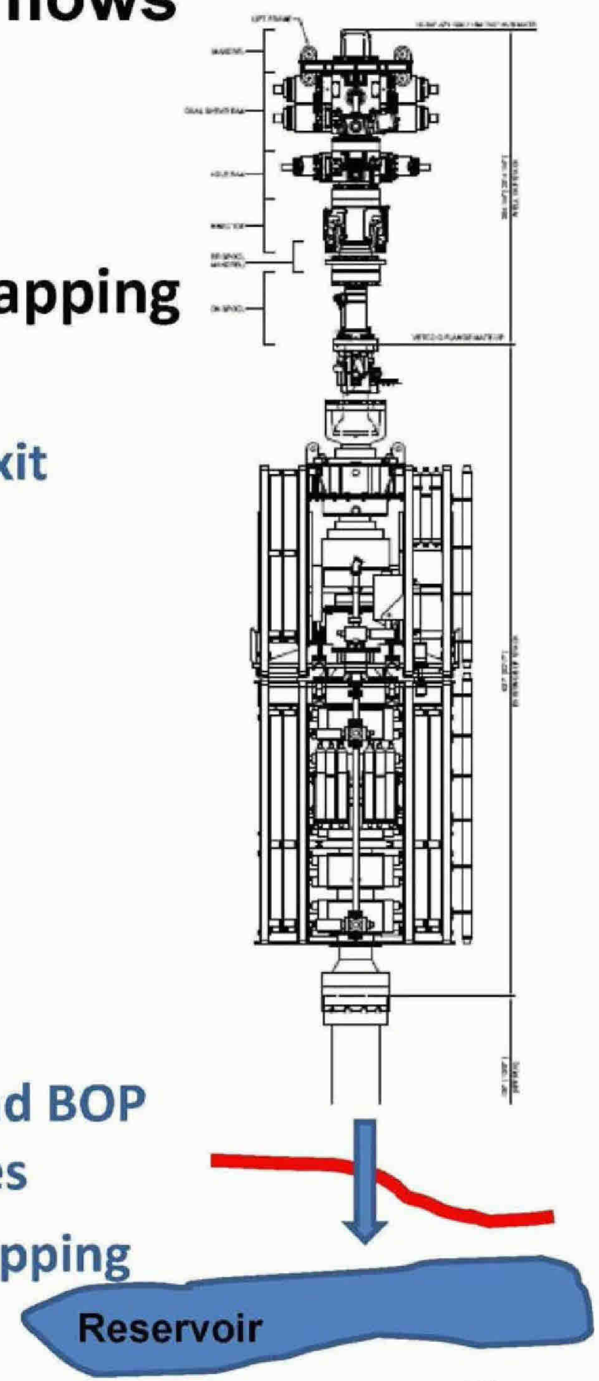
Using the Model and the Insights and Results from the Capping Stack Studies

Using the WIT Flow Results to predict flows in earlier times



Two approaches pursued

- **Full Models: Flow through the Well, BOP and Capping Stack to Sea**
  - **Model flow restrictions between the reservoir and exit**
  - **Use measured Pcs and known Psea**
  - **Model accounts for:**
    - Reservoir-to-well flow
    - Well flow (annulus and pipe)
    - Flow through BOP
    - Flow through stacking-cap to sea
- **Extrapolation Model - for earlier times**
  - **Flows predicted based on frictional losses for well and BOP applying "first principles " estimation of flow regimes**
  - **Based on known pressures and flow rate from the capping stack analyses**

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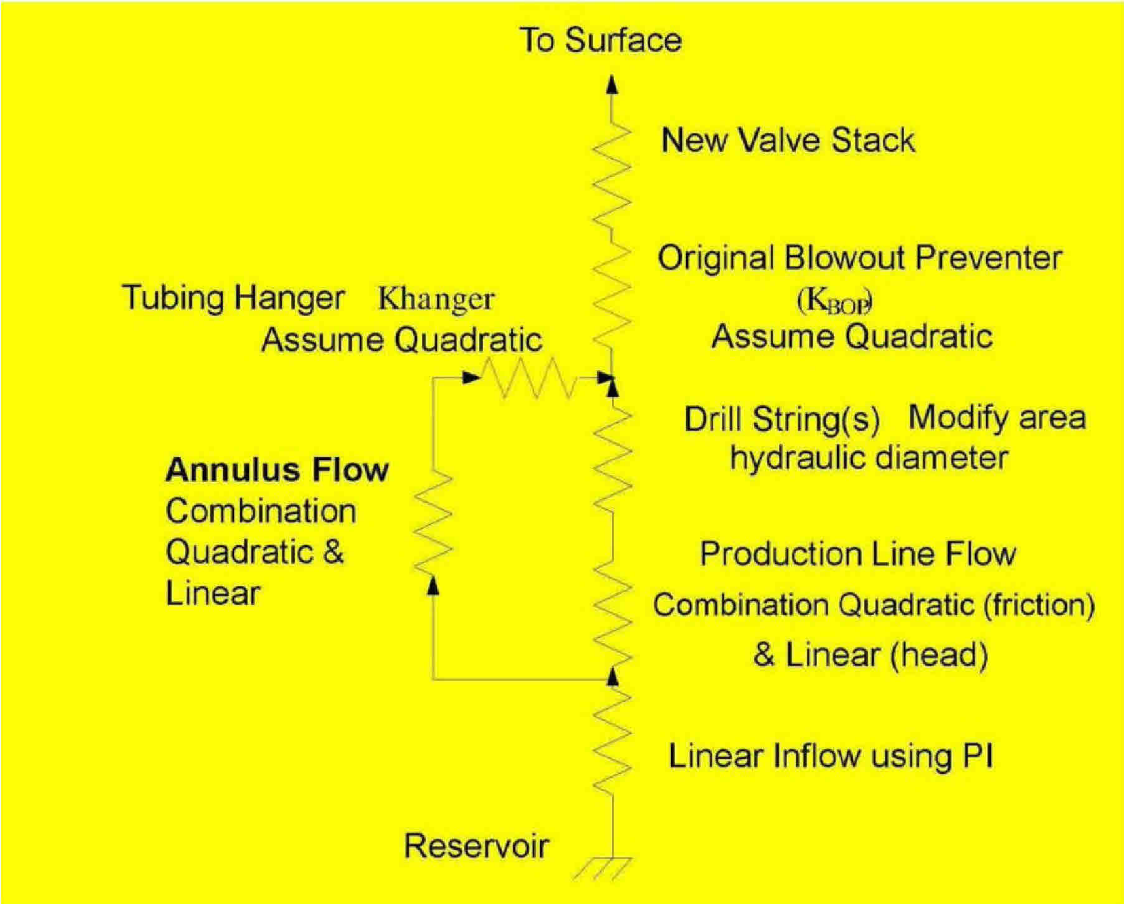
Reservoir-to-Sea Analyses:
Full Well Model Descriptions

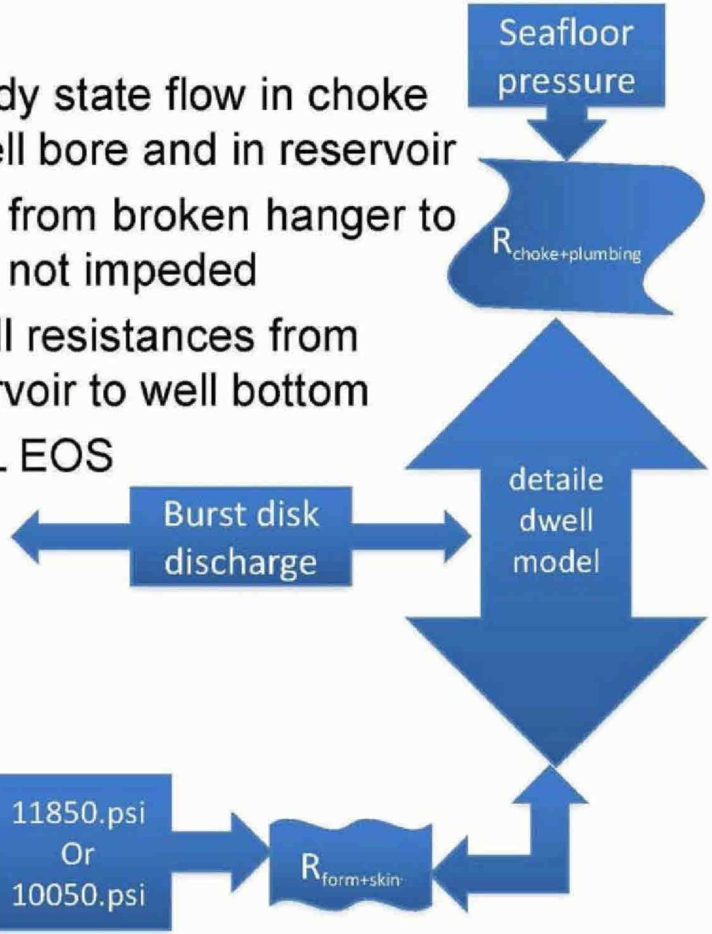


Assumptions

- Multi-phase Constitutive Model: Peng Robinson multi-component 2-phase flow model w/ flash
- PI = 50

Assumptions

- Small hydraulic resistance assumed for unknown BOP path
- Steady state flow in choke in well bore and in reservoir
- Flow from broken hanger to BOP not impeded
- Small resistances from reservoir to well bottom
- LLNL EOS



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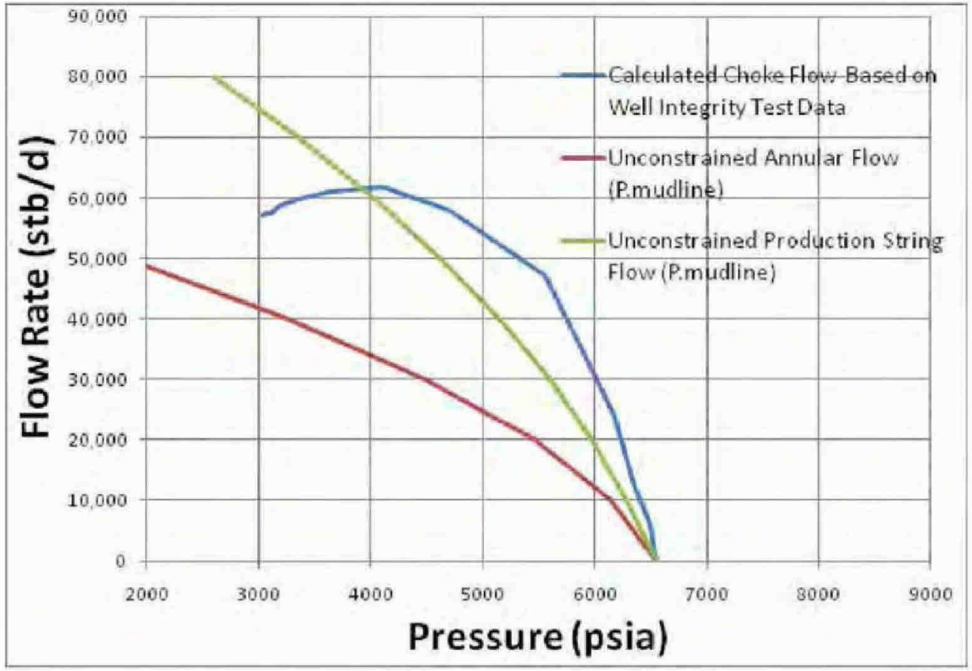
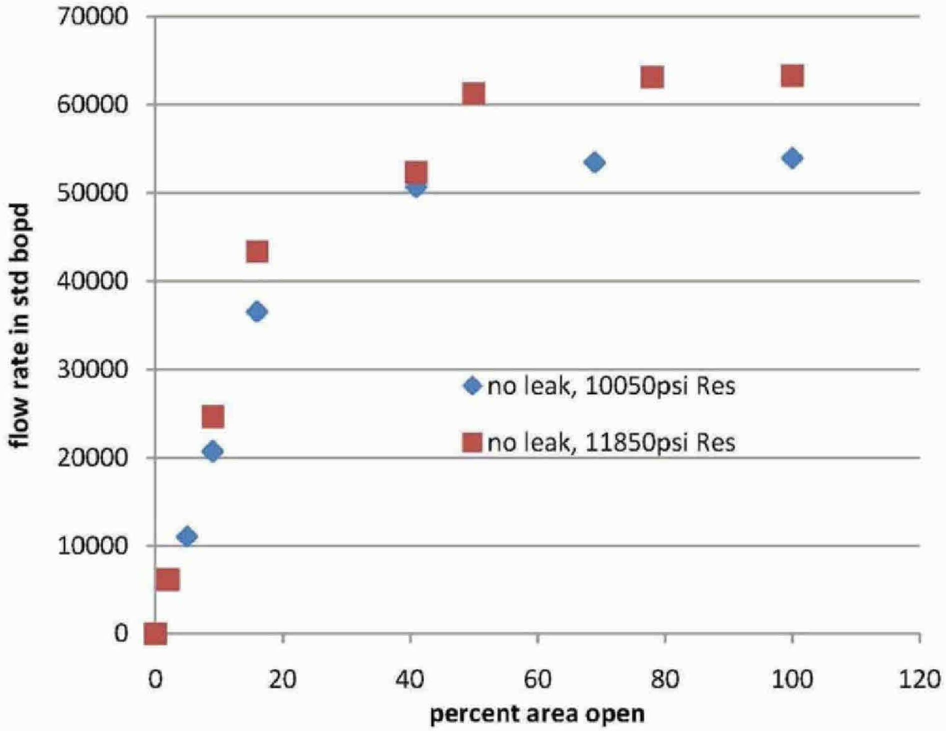
Reservoir-to-Sea Analyses:
Full Well Model 2 Results

- **Full reservoir-to-sea analyses allows for scoping calculations for estimating flow paths within the drill pipe**

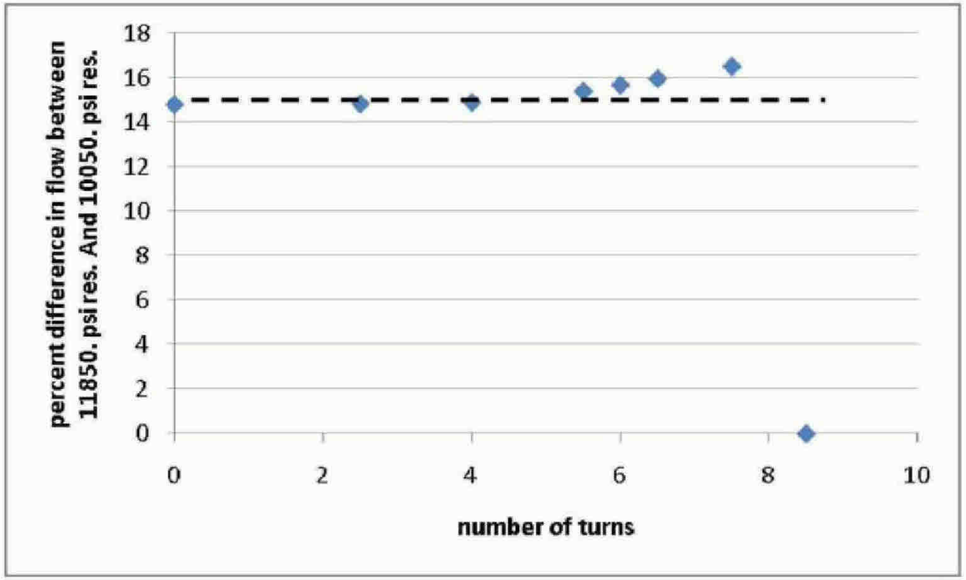


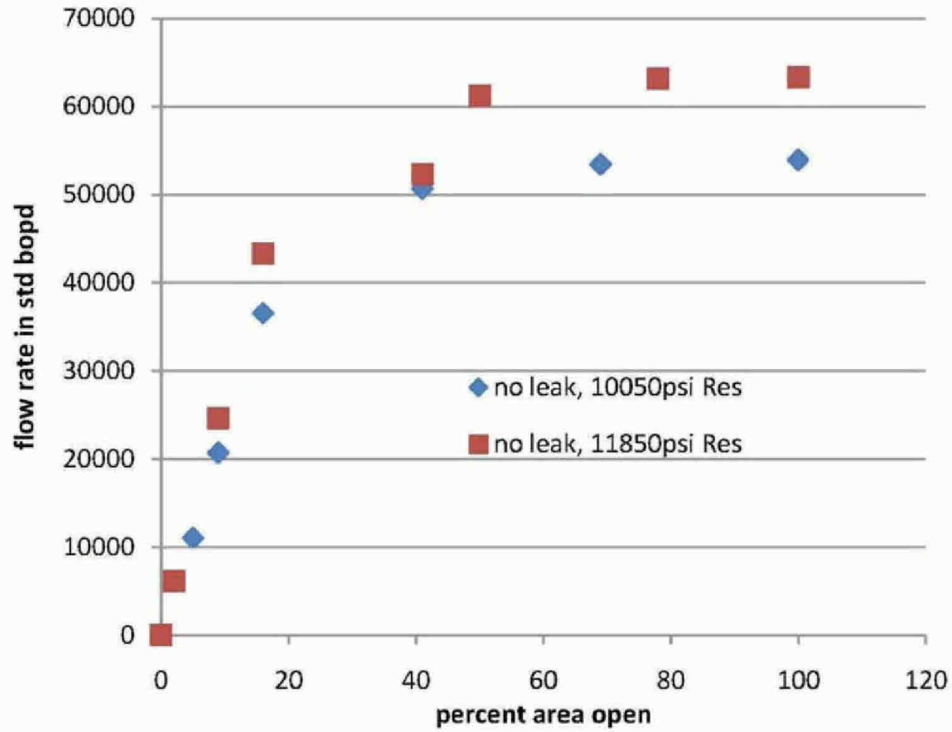


Full well model allows for simulations of well from initial condition to current estimated depleted state

Reservoir-to-Sea Analyses:
Full Well Model 2 Results

"Initial" vs "depleted reservoir results; computations match expectations based on initial and "depleted" reservoir pressures of 11850 and 10050 psi, respectively





Full well model allows for simulations of well from initial condition to current estimated depleted state

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Reservoir-to-Sea Analyses: Observations on Full Well Model

- As used, this method is not an independent prediction of the well flow rate
- Method 1-3 flow predictions provide added constraint to existing well models
- Network models of well still under-constrained *(still need PI and $P_{reservoir}$)*
- Possibly a means of assessing well configuration scenarios
  - Could assume a mass flow rate and check resulting choke pressure vs. observation
  - Could be used to estimate/refine "$K_{effective}$" for BOP

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Reservoir-to-Sea Analyses: Extrapolation Model Attributes

Extrapolation of Well Integrity Test (WIT) flow to earlier times

- **Capable of well geometry changes**
  - capping stack installed
  - riser removal
  - kink leak generation
  - Etc.
- **Model of entire well can be informed by WIT flow rate to allow estimation of flow changes due to well geometry changes.**

Approximate (aka "Extrapolation") Model

Key Assumptions

- Elevation head approximately equal in all cases
- Frictional head scales with flow – consider bounds
  - ✓ Well drawdown scales linearly
  - ✓ Laminar flow scales linearly
  - ✓ Turbulent flow scales as a quadratic
  - ✓ The exact state of the well is unknown

Resulting Form of the Model yields following

- Linear assumption yields the highest perturbations
- Quadratic assumption yields the lowest perturbation
- Realistic assumption is the expected intermediate result
  - Elevation head in well 2750 psi
  - Frictional head 4700 psi (=10050-2600-2750)
  - Well geometry from reservoir to above the original BOP (below the capping stack) remains approximately the same

$$\Delta P_{frict} = \Delta P_{laminar}\frac{Q}{Q_o} + \Delta P_{turbulent}\left(\frac{Q}{Q_o}\right)^2$$

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Extrapolation to earlier times: Approximate Model Results

- **Three time periods to consider**
  - WIT with all flow out kill line (base case)
    - 10050 psi reservoir to 2600 psi at kill line exit
  - Just before WIT without capping stack
    - 10050 psi reservoir to 2175 psi ambient
  - Initial state (maximum flow)*
    - 11850 psi reservoir to 2175 psi ambient;

***Note: This case never existed (i.e. initial state included resistance at kink in riser), but this does allow an estimate of a limiting maximum flow**

	Base case	w/o capping stack	Maximum flow
linear	53000	56950	73300
quadratic	53000	54940	62330
realistic	**53000**	**55170**	**63450**
Full Well Model	**53000**	**56000**	**65900**

The model captures key attributes of the full well model without the added complexity

Closure -- Takeaways

- This work incorporates all major elements necessary to calculate flow rates following the Deep Water transient
- Key takeaways from this study include:
  - **Analysis models for the WIT shut-in provide nominal flow rate estimates of 53K bopd with uncertainties tbd**
  - **Additional analyses based on the results of the Capping Stack work provide early time (post-accident) flow estimates of ~65K bopd assuming a reservoir pressure of 11850 psi**
  - **Reducing uncertainty – we must understand the multiphase aspects much better – this will not be easy or quick**

Estimating the total oil released over the 87 days of the event is critically dependent on getting the flow rate right

Government Modeling Team

- Project POC
  - Art Ratzel - DOE Natl. Labs
- Flow/Uncertainty Analysts
  - Curtt Ammerman – DOE Natl. Labs
  - Barry Charles – DOE Natl. Labs
  - Diane Chen – DOE Natl. Labs
  - Ron Dykhuizen – DOE Natl. Labs
  - Mark Havsted – DOE Natl. Labs
  - Tom Hunter - DOE Natl. Labs
  - Stewart Griffiths – DOE Natl. Labs
  - Paul Hsieh – USGS
  - Wayne Miller – DOE Natl. Labs
  - Charlie Morrow – DOE Natl. Labs
  - Scott Perfect – DOE Natl. Labs
  - Marty Pilch – DOE Natl. Labs
  - Sheldon Tieszen – DOE Natl. Labs

Discussion and Close-out

Tom Hunter

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Problem Statement

- The intent of this meeting is to review the different methods, evaluate the uncertainties, and to come to consensus on a revised, more informed estimate on flow.