Transocean

ANNUAL REPORT - 2010

WELL CONTROL EVENTS & STATISTICS

2005 to 2010

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EXECUTIVE SUMMARY

During the period 2005 to 2010, Transocean rigs (both legacy companies) operated on a total of 7,725 wells. (Data from legacy reporting systems)

- Drilling and completion operations were conducted on 4,730 development wells
- Drilling operations were conducted on 2,205 exploration and appraisal wells
- Workover or abandonment operations were carried out on 790 wells

The data set used to generate the well control statistics contained in this report relates only to legacy Transocean rigs between 2005 and 2007, with all operations (post merger) included from 2008 onwards.

Therefore the relevant operations summary relates to a total of 5,896 wells comprised of:

- 3,681 development wells
- 1,687 exploration and appraisal wells
- 528 workovers or abandonment

While operating on those 5,896 wells, Transocean rigs experienced 669 well control events.

- 409 of those events were kicks
- 167 events were due to ballooning formations[1]
- 383 well control events (including 238 kicks) occurred on exploration wells
- 268 events (143 kicks) occurred on development wells

This data indicates historical trends and may suggest future likelihoods as follows:

- 1 in 9 operations will experience a well control event
- 1 in 4 well control events will be a ballooning event
- 1 in 7 exploration wells will experience a kick
- 1 in 26 development wells will experience a kick

In addition to indicating the likelihood of experiencing a well control event, the data confirms:

- The likelihood of taking a kick on an exploration well is significantly higher than that of a development well.
- Being able to distinguish between a ballooning formation and an actual kick is critical to effectively manage well control events.

Note: The data contained in this report does not include the Macondo well incident of April 20th, 2010.

[1] Ballooning formations may also be referred to as fracture charging, wellbore breathing or, as termed within this report, Loss/Gain events (due to such an influx having to have been preceded by a period of losses).

2010 Well Control Performance Summary

A total of 113 well control events were recorded in 2010. Of these 113 events, 74 were categorized as kicks, 25 were categorized as ballooning, and 14 were precautionary type events.

When normalized by the *active rig count*[2] in 2010 (assumed to be 97 rigs) the frequency of **kick** events was 0.76 per rig.

The key findings of the well control events that occurred in 2010 are described below.

Kick Severity

This has two aspects. One is kick volume, which is generally an indicator of rig and crew performance in terms of shutting in the well and the second is kick intensity which is an indicator of the Operator's accuracy in predicting pore pressure.

- 73% (54) of all kicks were detected in under 20bbls.
- 27% (20) of all kicks exceeded 20bbls and ranged from 20 to 100bbls. This is a significant increase over pervious years. All rigs within the fleet must limit the size of any influx by detecting the kick and shutting the well in as soon as possible.
- 28% (21) of all kicks were more than 0.5ppg above mud weight.
- 16% (12) of all kicks were more than 1ppg above mud weight.
- HGR experienced the highest kick intensity (5.31ppg) while drilling for Husky
- DAS experienced the highest kick volume (100bbls) while drilling for Statoil

Time associated with well control events in 2010

- 4094 hours were associated directly with addressing well control events. This time does not include any additional time for remedial activities
- The average time spent dealing with a well control event was 36.2 hours
- Rigs operating for Statoil had the highest number of well control events for any client in 2010. (14 events totalling 645 hours)
    - DAS accounted for 12 of these 14 Events and 598 hrs of time spent on Well Control
- Rigs operating for ONGC spent the most time on well control (8 events and 1077 hours) for any client in 2010
    - FGM accounted for 4 of these 8 events and 912 hrs of time spent on Well Control
- IME attributed the most time at 1,284 hours to well control events, followed by NAM with 996 hours
- 0.48% of the total contracted rig time in 2010 was spent on well control events

[2] *Active rig count* here refers to the average number of working rigs during January 2010 and January 2011.

Areas for Improvement

- 20 kicks (26%) exceeded 20bbls with varying kick intensities in 2010. All attempts must be made to limit kick size. All influxes must be detected as early as possible and the well shut-in as soon as possible.
- More kicks were experienced during tripping, circulating, and cementing operations in 2010 than has been the case in previous years.
  - A suitable margin of overbalance must be in place prior to tripping out of the hole
  - It is essential that primary well control is continually maintained and monitored throughout all operations, during all stages of the well, until the BOP has been removed

1. INTRODUCTION

This report contains a statistical analysis of all well control events which occurred during 2010 in comparison with and in addition to a historical review of all well control events which have occurred during the last 6 years.

Note: Data referenced for 2005 to 2007 considers legacy Transocean rigs only.

The intent of the analysis is to:

- Explore the various trends associated with the well control events for 2010
- Compare and understand the trends of well control events in 2010 with previous years

The data for the well control events is collated from both the well control event reports submitted to the Well Operations Group and from GMS.

Please note that the GMS time for a well control event does not take into account the common subsequent associated complications and remediation involved. This could include stuck pipe incidents, required side tracks, recovery from losses, well abandonment etc. The time required for additional remediation operations is not considered in the analysis.

The analysis presented should be considered indicative and is based solely on the data provided. The events are diagnosed as either a kick or a loss/gain based on the recorded data and inputs from the well control event reports. There are numerous ways one could look at the analysis however only key findings are reported in this document.

The Well Operations Group will be happy to provide customised analysis of the well control events statistics on request.

Observations in reporting

During 2010 a well control event report was submitted for 92% of well control events.

- 100% WCE OER compliance was achieved in Q4 2010. This is excellent and is expected to continue going forward.

1.1 Background well and rig data

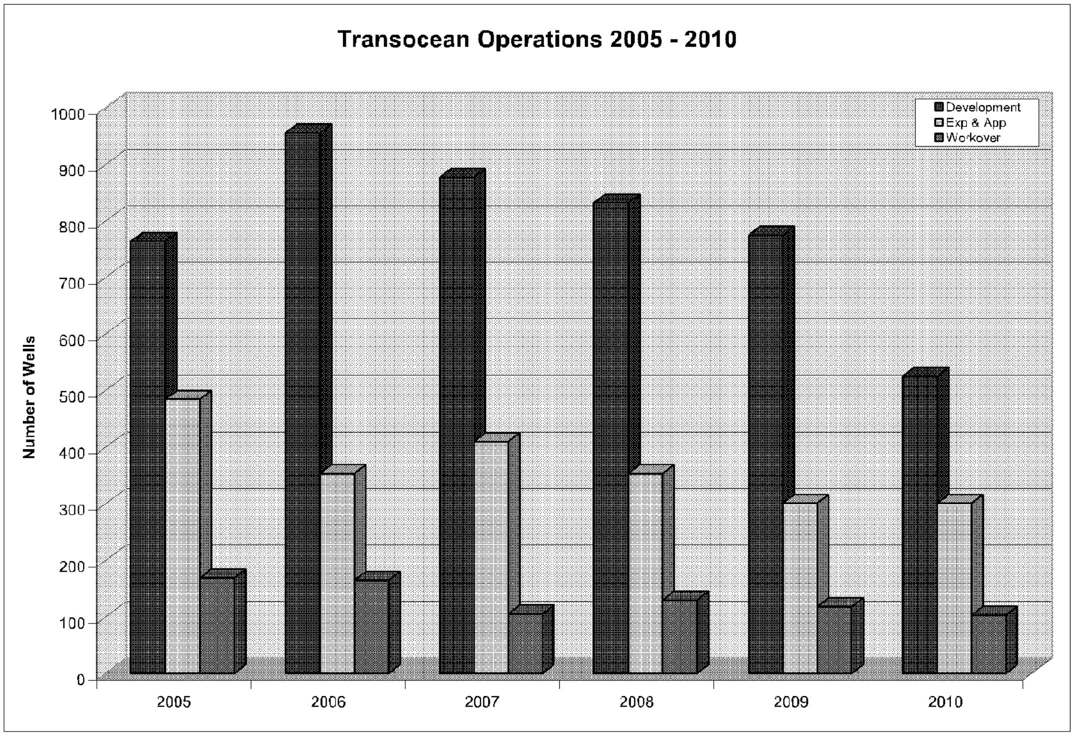

Chart 1: Annual well count

Chart 1 was generated from the following well count summary data.

	Exp & App	Development	Workover	Annual total
2005	485	764	169	1,418
2006	354	956	165	1,475
2007	410	877	105	1,392
2008	354	832	130	1,316
2009	301	775	118	1,194
2010	301	526	103	930
Total type	**2,205**	**4,730**	**790**	**7,725**

Table 1: Annual well count

NOTE:

- This data includes all wells from both legacy companies since 2005.

Removing wells drilled by legacy companies (2005-2006) for which well control event data is not available provides the following baseline data set:

	Exp & App	Development	Workover	Annual total
2005	227	506	78	811
2006	235	540	67	842
2007	269	502	32	803
2008	354	832	130	1,316
2009	301	775	118	1,194
2010	301	526	103	930
Total type	1,687	3,681	528	5,896

In order to normalize well control statistics in terms of rig count, the following fleet information was utilized.

Fleet status	Jan '05	Jan '06	Jan '07	Jan '08	Jan '09	Jan '10	Jan '11
Floaters *active*	**47**	**55**	**53**	**68**	**68**	**65**	**58**
Floaters stacked/idle	9	0	0	0	0	6	14
Floaters total	56	55	53	68	68	71	72
Bottom-supported *active*	**29**	**28**	**27**	**70**	**66**	**39**	**32**
Bottom-supported stacked/idle	5	4	0	0	1	28	34
Bottom-supported total	34	32	27	70	67	67	66
Total *active* fleet	***76***	***83***	***80***	***138***	***134***	***104***	***90***

Table 2: Variation in the active rig fleet

NOTE:

- The active rig count dropped by 15 during 2010.
- The assumed rig count whenever normalizing statistics for 2010 was **97**[3].

[3] The active rig count of 97 is defined as the average of the total active fleet on Jan '10 and Jan '11.

Statistics for 2010

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2. 2010 WELL CONTROL EVENTS SUMMARY

The following section contains a statistical analysis of all well control events which occurred during 2010.

2.1 2010 Well control event types

A total of 113 well control events were recorded in 2010. Of these 113 events, 74 were categorized as kicks, 25 were categorized as "Loss / Gain", and 14 were precautionary type events.

Of the 74 kicks:

- 15 kicks occurred on development wells (20%)
- 53 kicks occurred on exploration wells (72%)
- 6 kicks occurred during completions, workover and abandonment (8%)

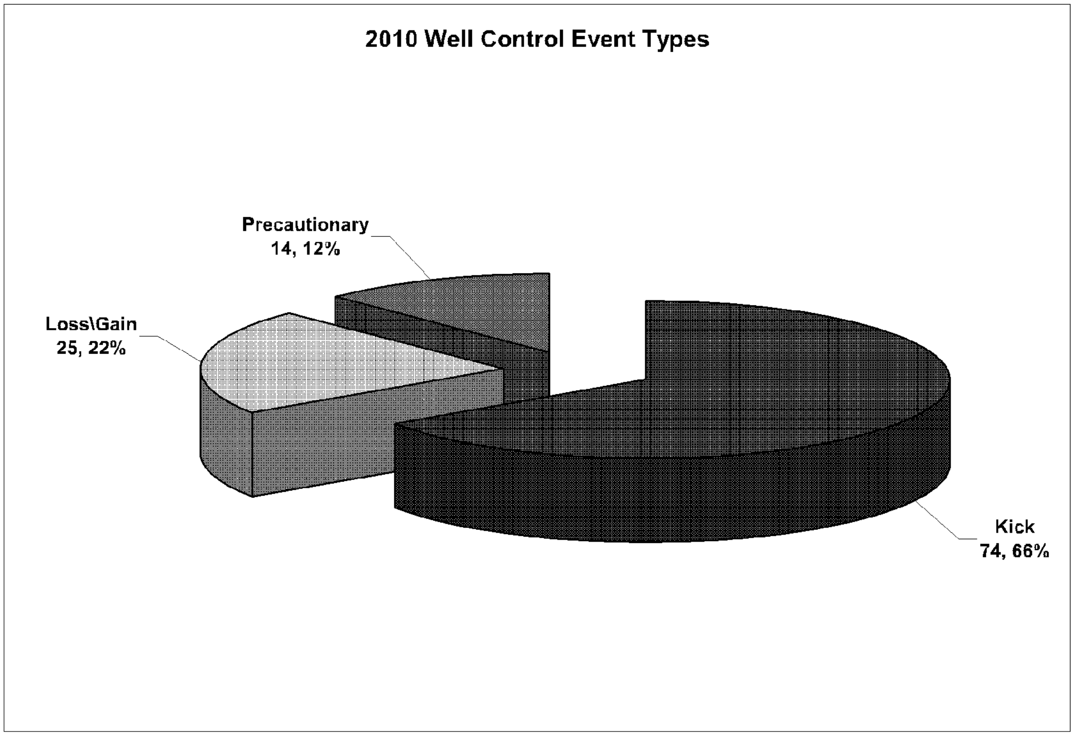


Chart 2: **2009 Well control event types, 2010**

NOTE:

- Ballooning (loss/gain) was responsible for 22% of the total well control events in 2010.

2.2 2010 Kick events

The events have been categorised using a Kick volume vs. Kick intensity matrix. The following 3 categories are used to grade the severity of the events.

Code	Kick Intensity		Kick Volume	Remark	Reporting
Green	< 0.5 ppg	&	< 10 bbls	Minor / Routine	Rig Manager Perf / General Manager
Yellow	≥ 0.5 ppg	or	10 ≤ x < 20 bbls	Major	General Manager
Red	Any Intensity		≥ 20 bbls	Critical	Managing Director / Operations Director

Table 3: Kick Severity matrix

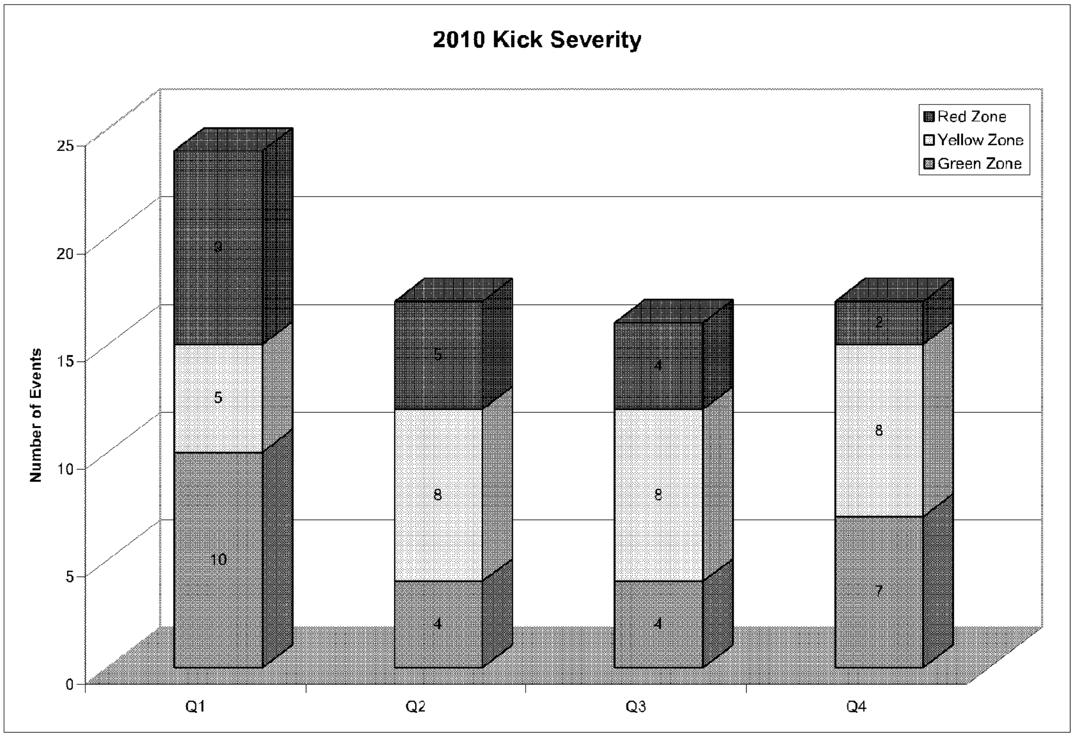


Chart 3: Kick severity for each quarter, 2010

NOTE:

- 20 kicks (26%) exceeded 20bbls with varying kick intensities in 2010.
- The data shows a decreasing trend in red zone events following Q1.

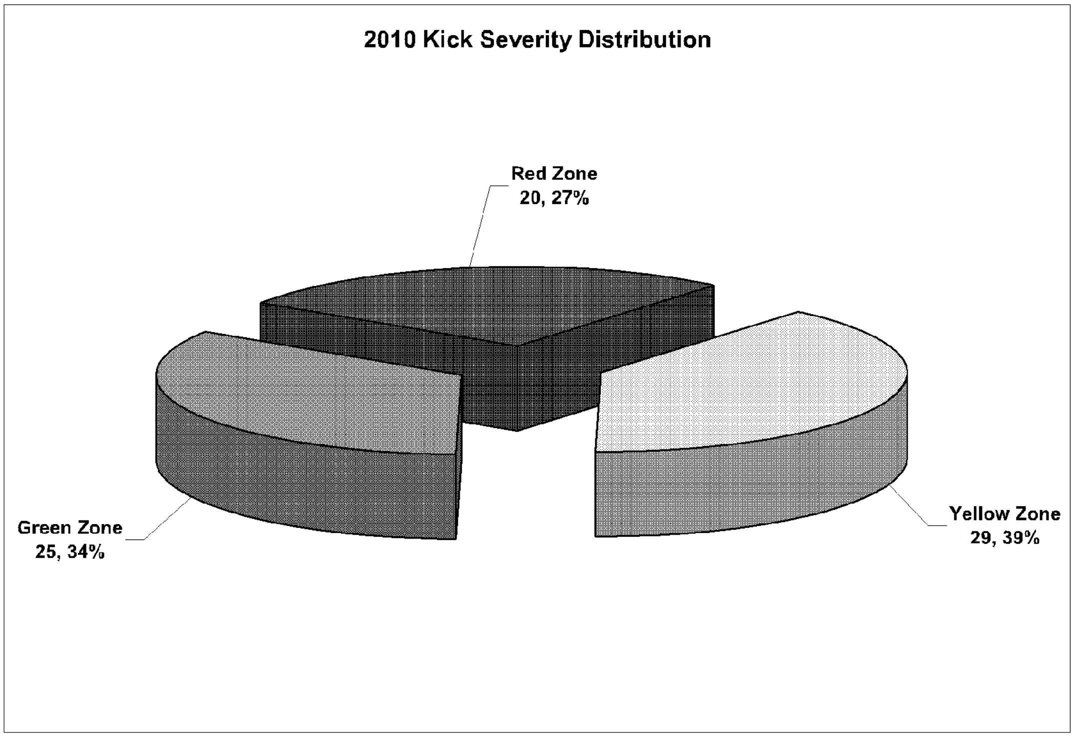
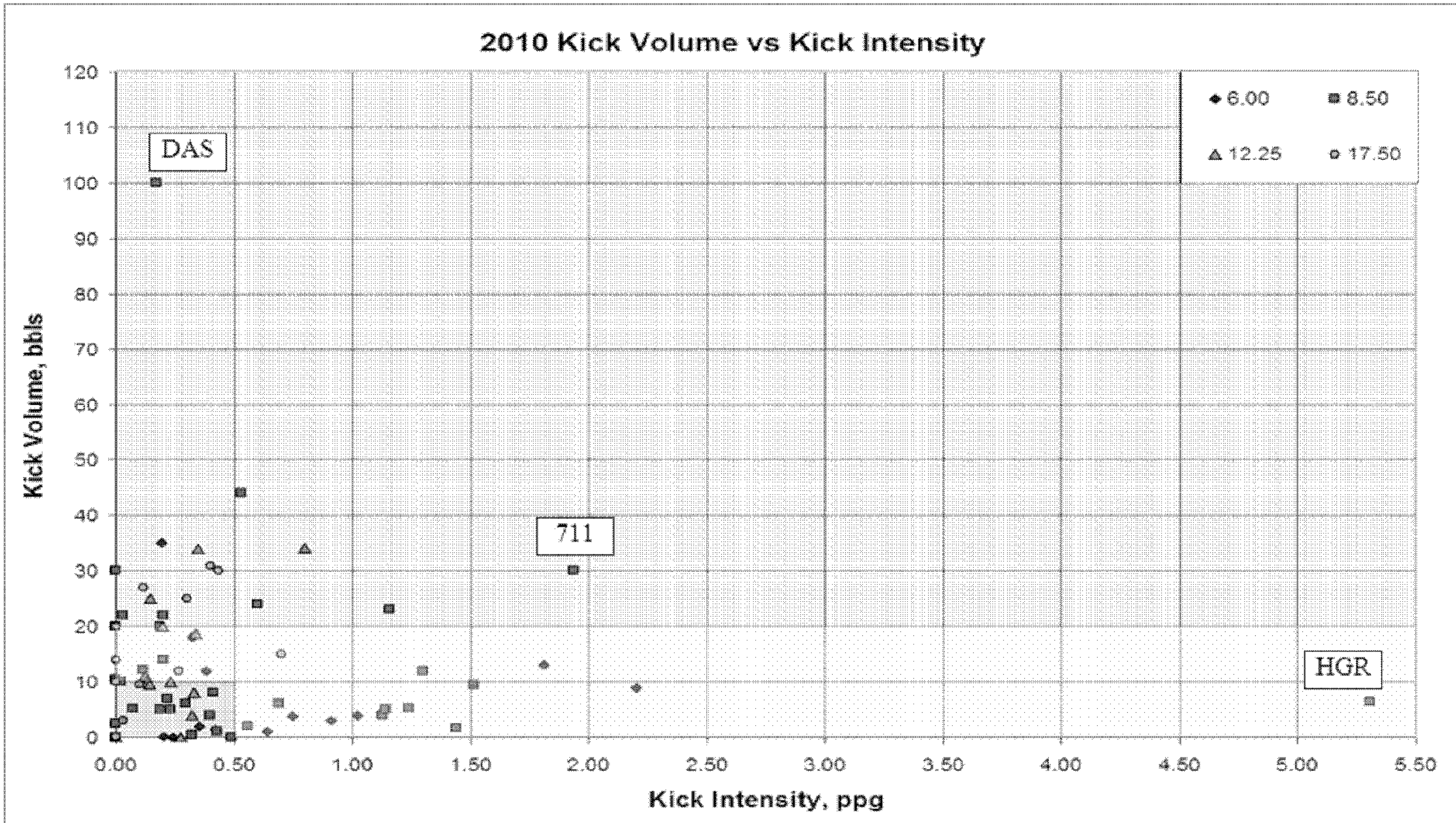


Chart 4: Kick Severity distribution, 2010

2010 Red Zone Kicks						
DIV	**RIG**	**Client**	**Kick Volume (bbls)**	**Kick Intensity (ppg)**	**Hole Size (in)**	**GMS Time (hr)**
NAM	DAS	Statoil	31	0.40	20.00	16.00
NAM	DAS	Statoil	25	0.30	20.00	20.00
NAM	DDS	Petrobras	25	0.15	12.25	25.50
SAM	DWM	Anadarko	30	0.00	8.50	61.00
IME	DWF	Reliance	27	0.11	17.50	11.25
NAM	DWH	BP	30	0.43	16.50	136.50
NRS	JWM	Petro Canada	20	0.20	12.25	14.00
NAM	DAS	Statoil	34	0.35	14.75	64.50
NAM	DWN	BP	22	0.20	8.50	49.00
NAM	DCL	Chevron	22	0.03	7.00	12.50
WAS	RIC	Chevron	20	0.19	9.63	32.00
NAM	CRL	BHP	23	1.16	8.50	36.00
NAM	DAS	Statoil	100	0.17	8.50	13.50
NAM	DAS	Statoil	35	0.19	6.50	64.30
GGA	140	ExxonMobil	24	0.60	8.50	11.00
SAM	CES	Petrobras	34	0.80	12.25	91.00
FEA	JAB	Hess	44	0.53	8.50	13.50
FEA	EPL	Marathon	20	0.00	17.00	32.00
WAS	A09	Afren	20	0.00	8.25	16.00
NRS	711	Shell	30	1.94	8.5	28

Table 4: Kick events greater than 20bbls influx volume, 2010



Graph 1: **Kick volumes vs. kick intensity, 2010**

2.3 2010 Well control events by client

Client	WCE #	Time (hrs)
Statoil	14	645
Shell	10	257
Chevron	10	115
ONGC	8	1077
Petronas	5	404
BP	5	258
British Gas	5	208
TOTAL	5	68
TOI	4	81
BHP	4	58
Marathon	4	48
Petrobras	3	120
Reliance	3	104
Anadarko	3	85
HESS	3	38
ENI	3	30
Afren	3	29
PTTEP-PTT	2	155
Serica Kutei	2	38
BHPliton	2	23
Noble	2	18
ExxonMobil	2	15
Tullow Oil	2	11
Husky	1	122
Esso	1	34
Ocean Energy	1	15
Petro Canada	1	14
Mobil	1	12
Woodside	1	6
Maersk	1	4
ADTI	1	3
Cobalt	1	2
Grand Total	**113**	**4094**

Table 5: Well control events listed by client, 2010

2.4 2010 Well control events by asset type

Well Control by Asset Type	
Floaters	86
Jack-up	27

Table 6: Well control event by asset type, 2010

Fleet status change in '10	**Jan '09**	**Jan '10**	**Jan '11**
***Active* Floaters**	68	65	58
***Active* Jack-ups**	66	39	32
Total	**134**	**104**	**90**

Table 7: Reduction in fleet activity, 2010

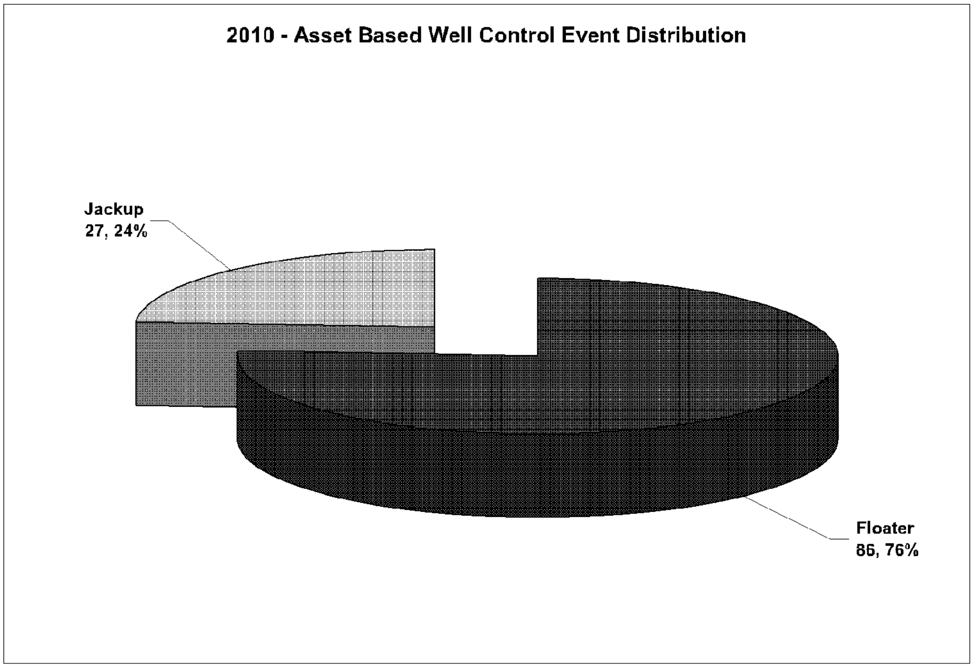


Chart 5: Well control events by asset type, 2010

NOTE:

Three-quarter of events occurred on floaters in 2010. This distribution can be attributed to stacked or idle rigs (14 floaters and 34 bottom supported). The likelihood of encountering a well control event is approximately equal regardless of the asset type.

2.5 2010 Average kick volume by hole size

Hole Size (in)	Average Kick Volume (bbls)
6.00"	7.88
8.50"	13.65
12.25"	14.17
17.50"	15.14

Table 8: Average kick volume by hole size, 2010

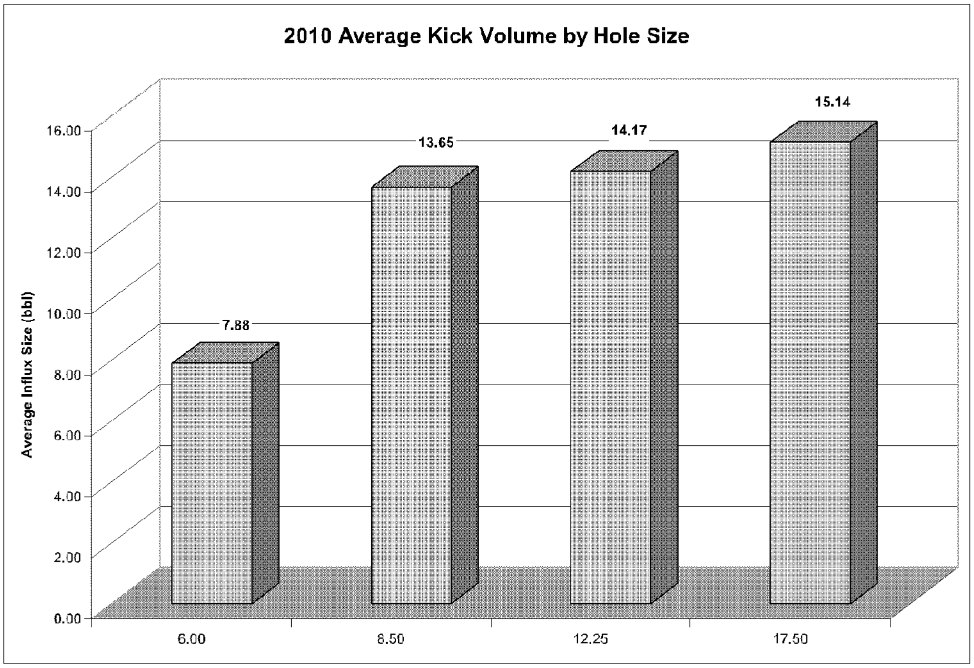


Chart 6: Average kick volume by hole size, 2010

2.6 2010 Well control events and associated time per division

Div	WCE Hours	2010 WCE	Hours / WCE	Kick Hours	2010 Kicks	Hours / Kick
IME	1284	17	76	1255	14	90
NAM	996	31	32	890	21	42
FEA	719	22	33	390	16	24
MED	393	7	56	392	6	65
SAM	383	11	35	326	5	65
NRS	127	9	14	97	5	19
WAS	93	5	19	82	3	27
GGA	59	10	6	27	4	7
NRY	42	1	42	0	0	0
Totals	**4094**	**113**	**36**	**3458**	**74**	**55**

Table 9: Well control event breakdown by division, 2010

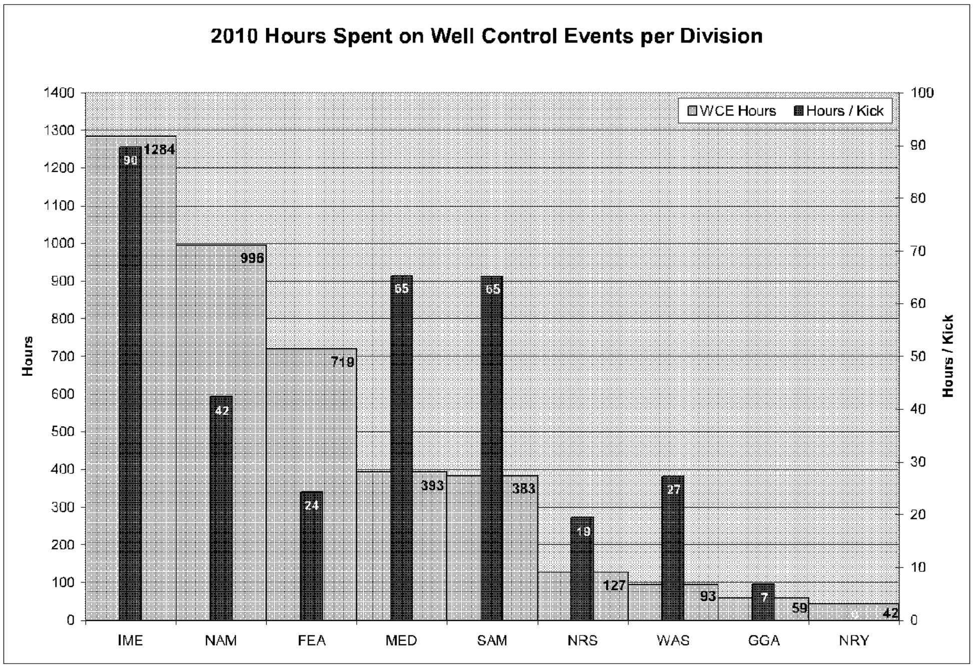


Chart 7: Hours spent on well control events in each division, 2010

NOTE:

- GGA encountered 10 well control events (including 4 kicks) and was able to maintain an average of 6 hours per well control event and 7 hours per kick.
- NRY has continued the trend of previous years having few well control events.

2.7 2010 Well control event kill methods

WCE Kill Method	
Drillers	42
Circulate[4]	26
Wait & Weight	23
Bullheading	8
Bleed off	6
Dynamic	1
Volumetric	1
Other	2
Inject & Bleed	2
Mud Cap	2
Grand Total	**113**

Table 10: Well control event kill methods, 2010

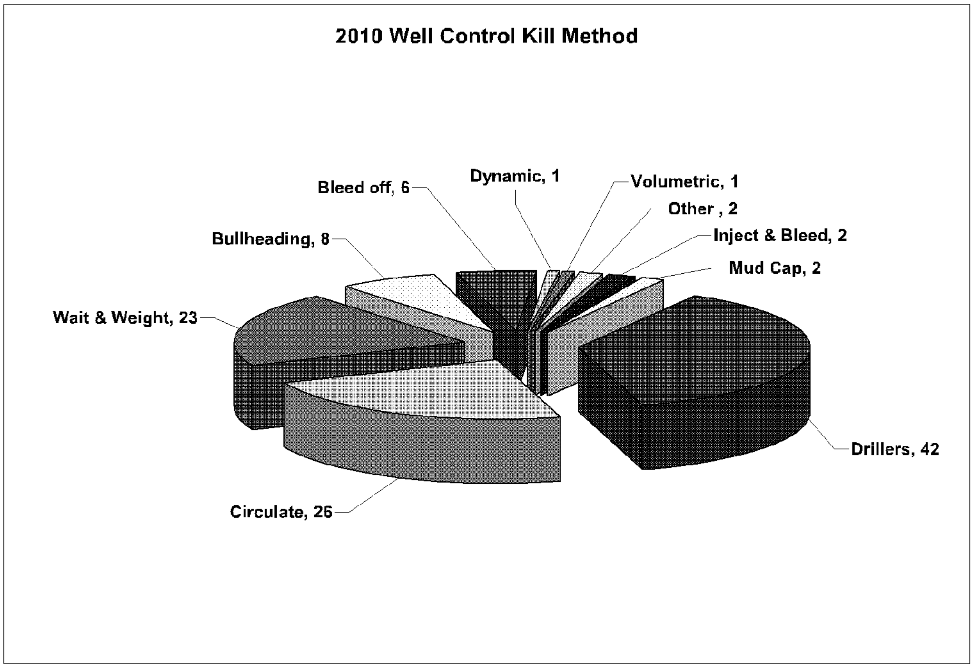


Chart 8: Breakdown of well control event kill methods, 2010

[4] The Circulate Method is not a recognized constant bottom-hole pressure method, but refers to the precautionary step of taking bottoms-up through a fully-open choke – particularly on floating rigs to prevent gas-in-riser.

2.8 2010 Operations ongoing at time of well control event

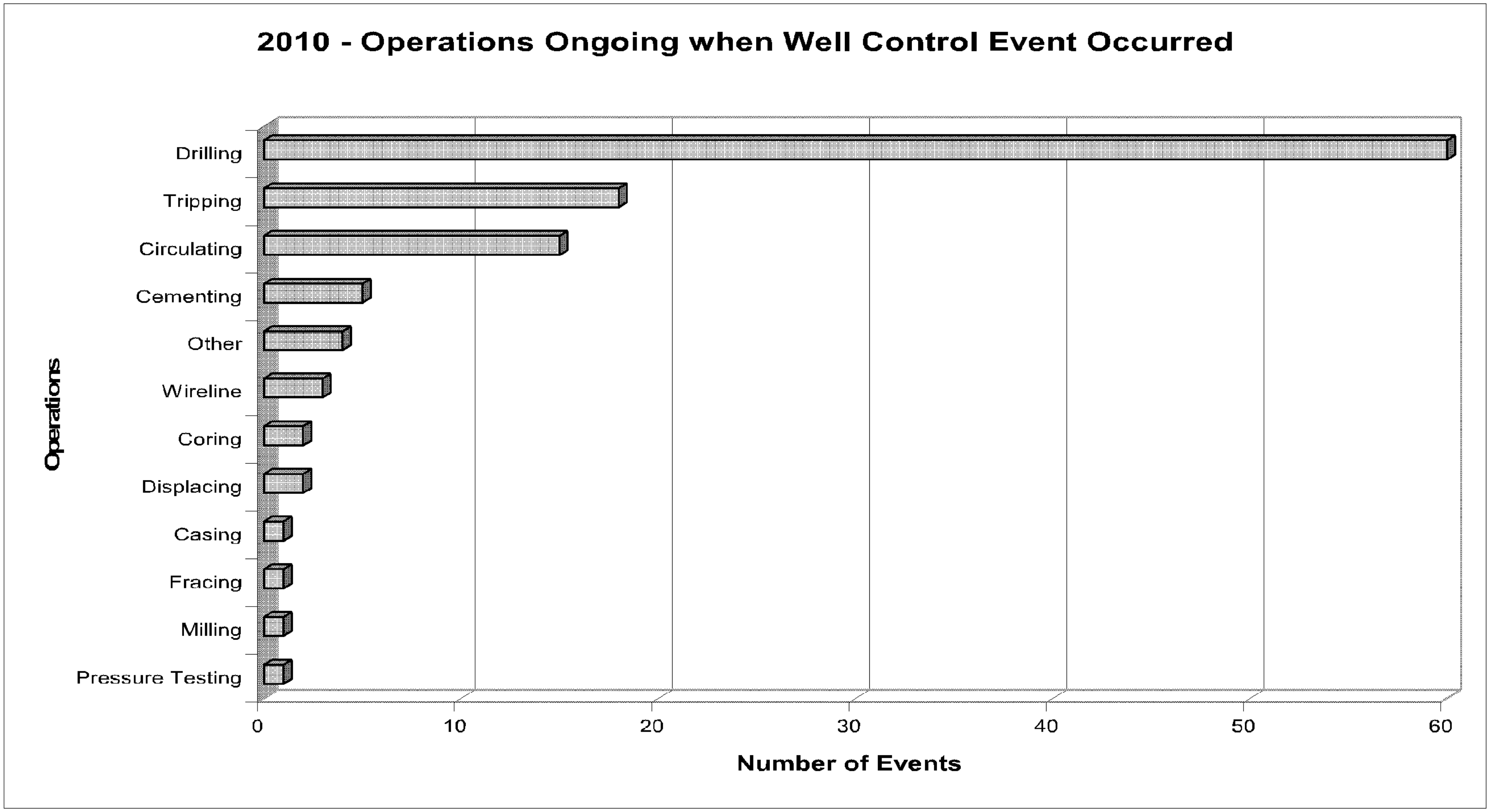


Chart 9: Operations ongoing at time of well control event, 2010.

Statistics for 2005 - 2010

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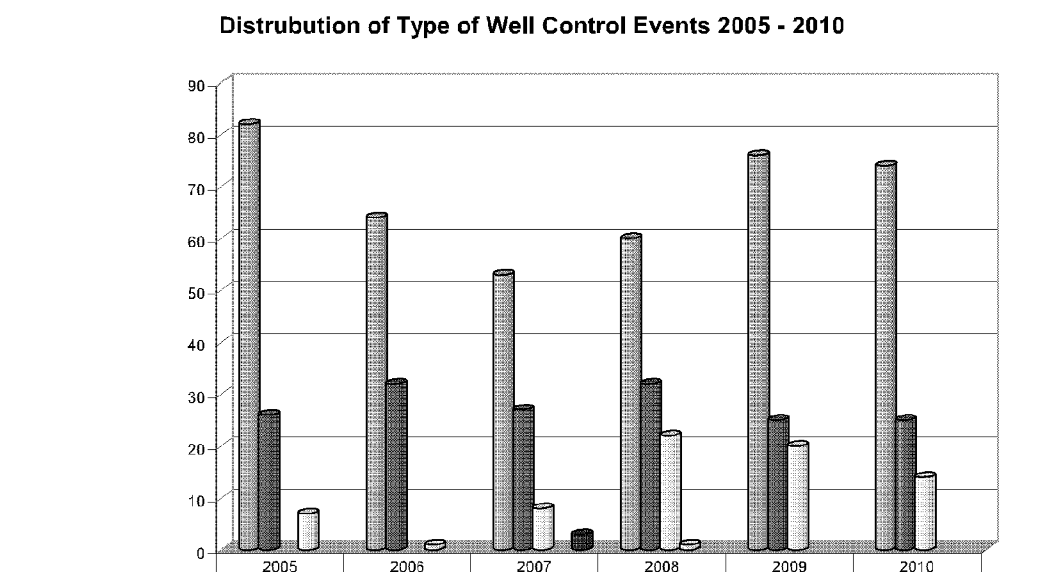
3. WELL CONTROL EVENTS SUMMARY, 2005-2010

The following section contains a statistical analysis of all well control events which occurred during the period from January 2005 until December 2010.

3.1 Well control event types, 2005-2010

A total of 669 well control events were recorded between 2005 and 2010. Of those 669 events, 409 were categorized as kicks, 167 were categorized as “Loss / Gain”, 64 were precautionary type events.



	2005	2006	2007	2008	2009	2010
Kick	82	64	53	60	76	74
Loss\Gain	26	32	27	32	25	25
Precautionary			8	22	20	14
Annulus Pressure	7	1		1		
Pilot Hole			3			

Chart 10: Well control event types, ‘05-‘10

3.2 Ballooning events, 2005-2010

Before reviewing the data related to actual kick events in the next section, it is worth briefly mentioning ballooning events (also referred to as Loss/Gain events). This category represents a significant proportion of all well control events (as can be seen in the table below). Mistaking ballooning for kicks or failing to recognize that ballooning represents a significant hazard in itself, by bringing hydrocarbons, gas or lower density drilling fluid back into the well bore, can lead to complacency or to more complicated and time-consuming recovery operations.

All suspected ballooning events must be assumed to be, and therefore treated as, kicks.

This then leads to a requirement of being able to efficiently distinguish ballooning from kicks once the well is shut-in using pressure build-up data and the correct bleed-off process.

	2005	2006	2007	2008	2009	2010	'05-'10
Loss/gain	26	32	27	32	25	25	167
All WCE	115	97	91	115	121	113	652[5]
Ratio	0.226	0.330	0.297	0.278	0.207	0.221	**0.256**

Table 11: Ratio of ballooning events to total WCE encountered, '05-'10

NOTE:

- Overall, ballooning (loss/gain) was responsible for **1 in 4** well control events since 2005.

	NAM	IME	GGA	FEA	NRS	SAM	MED	WAS	NRY
Loss/gain	41	34	22	21	17	12	10	8	2

Table 12: Distribution of loss/gain events by division, '05-'10

[5] In this instance 652 rather than 669 is used for total well control events to calculate this ratio (those events with insufficient details to allow categorization have been removed.

3.3 Kick events, 2005-2010

Code	Kick Intensity		Kick Volume	Remark	Reporting
Green	< 0.5 ppg	&	< 10 bbls	Minor / Routine	Rig Manager Perf / General Manager
Yellow	≥ 0.5 ppg	or	10 ≤ x < 20 bbls	Major	General Manager
Red	Any Intensity		≥ 20 bbls	Critical	Managing Director / Operations Director

Table 13: Kick severity matrix

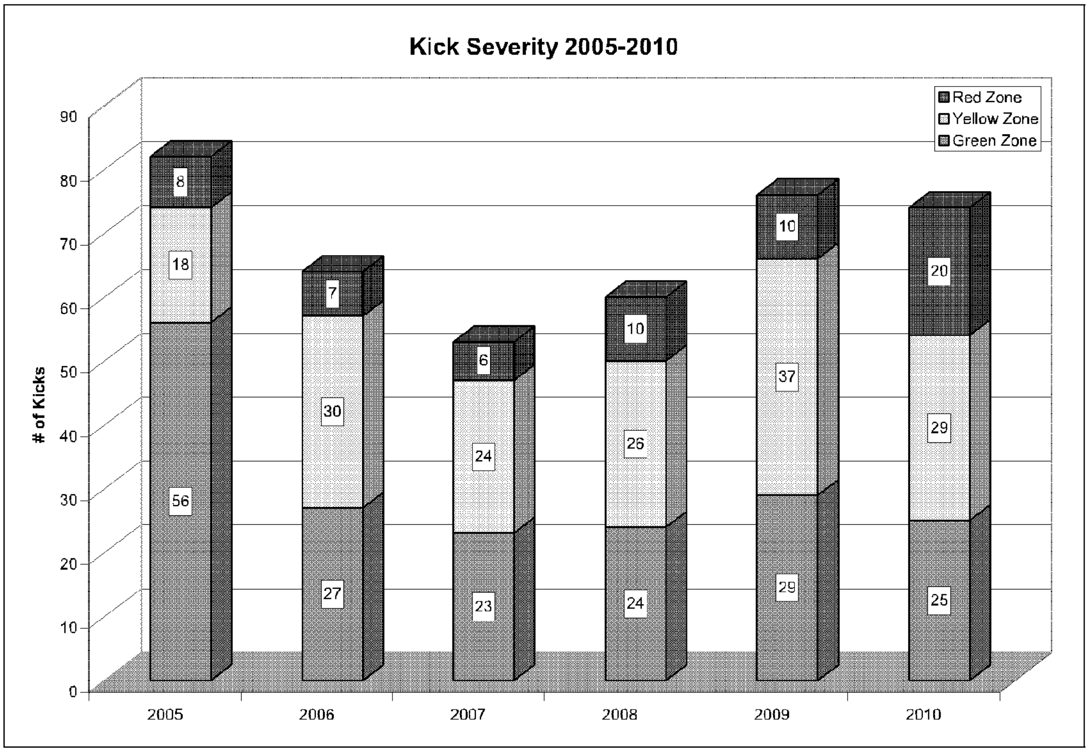


Chart 11: Kick severity for each year, '05-'10

	2005	2006	2007	2008	2009	2010	*'05 - '09*
Green Zone	56	27	23	24	29	*25*	*184*
Yellow Zone	18	30	24	26	37	*29*	*164*
Red Zone	8	7	6	10	10	*20*	*61*
Grand Total	**82**	**64**	**53**	**60**	**76**	**74**	***409***

Table 14: Kick severity distribution summary, '05-'10

- Trending from previous years shows an increase in Red Zone events. 2010 recorded twice as many Red Zone events than any prior year.

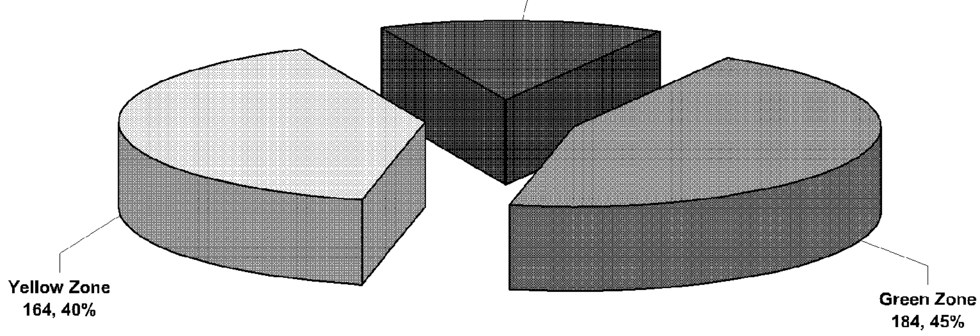


Chart 12: Kick severity distribution, '05-'10

3.3.1 Kick events in the Red Zone, 2005-2010

Year	Division	Rig	Client	Hole size, (in)	Volume, (bbl)	Intensity, (ppg)	Time, (hrs)
2010	NAM	DAS	Statoil	20.00	31	0.40	16.00
2010	NAM	DAS	Statoil	20.00	25	0.30	20.00
2010	NAM	DDS	Petrobras	12.25	25	0.15	25.50
2010	SAM	DWM	Anadarko	8.50	30	0	61.00
2010	IME	DWF	Reliance	17.50	27	0.11	11.25
2010	NAM	DWH	BP	16.50	30	0.43	136.50
2010	NRS	JWM	Petro Canada	12.25	20	0.20	14.00
2010	NAM	DAS	Statoil	14.75	34	0.35	64.50
2010	NAM	DWN	BP	8.50	22	0.20	49.00
2010	NAM	DCL	Chevron	7.00	22	0.03	12.50
2010	WAS	RIC	Chevron	9.63	20	0.19	32.00
2010	NAM	CRL	BHP	8.50	23	1.16	36.00
2010	NAM	DAS	Statoil	8.50	100	0.17	13.50
2010	NAM	DAS	Statoil	6.50	35	0.19	64.30
2010	GGA	140	ExxonMobil	8.50	24	0.60	11.00
2010	SAM	CES	Petrobras	12.25	34	0.80	91.00
2010	FEA	JAB	Hess	8.50	44	0.53	13.50
2010	FEA	EPL	Marathon	17.00	20	0	32.00

2010	WAS	A09	Afren	8.25	20	0.00	16.00
2010	NRS	711	Shell	9.00	30	1.94	28.00
2009	FEA	ATN	CNOOC	8.5	97.0	1.80	82.50
2009	NRS	711	Shell	6	95.3	0.65	20
2009	SAM	DWD	Petrobras	12.25	60.0	1.18	165.50
2009	GGA	702	BG	12.25	36.0	0.15	29.25
2009	SAM	DWM	Petrobras	12.25	30.0	0.69	383
2009	FEA	PSW	Total	6	30.0	0.81	8.00
2009	NAM	DD1	Cobalt	12.25	25.0	0.26	96.00
2009	NAM	DWN	Shell	12.25	22.9	0.00	45.50
2009	NAM	DD1	Cobalt	17.5	22.0	0.48	192.00
2009	NAM	DD1	Cobalt	8.5	20.0	0.74	20.00
2008	MED	T20	Petronas	6	200	1.68	8.5
2008	FEA	KGB	PTT	6	93	0.51	137.5
2008	WAS	AKY	Sonangol	8.5	78	1.8	31.5
2008	IME	534	RIL	12.25	53.6	1.11	27.75
2008	WAS	HI7	Total	17.5	37	0.37	9
2008	MED	KMN	BG	8.5	30	1.16	16.75
2008	FEA	T15	Chevron	6	28	0	24
2008	NAM	DDS	Chevron	12.25	27	0.06	2
2008	NRS	704	ADTI	8.5	26	2.5	26.5
2008	NAM	DSP	Anadarko	12.25	21	0.3	44
2007	FEA	T09	Hoang Long JOC	8.5	60	1.58	15
2007	GGA	T04	Chevron	8.5	45	0.38	252.5
2007	GGA	T04	Chevron	6	34	0.89	14
2007	NAM	DWM	Anadarko	12.25	30	0.75	75
2007	NAM	DDS	Chevron	8.5	29.5	1.2	16.5
2007	IME	CKR	RIL	17.5	21	0.52	78.75
2006	IME	DSS	ONGC	17.5	102	0.7	37.5
2006	NAM	DDS	Chevron	17.5	33	0.15	27
2006	IME	ATN	RIL	12.25	30	0.69	14.5
2006	GGA	T04	Chevron	8.5	24	2.27	22.5
2006	FEA	714	TOTAL	8.5	23.4	0.76	8.75
2006	IME	DWF	RIL	8.5	23	2	35
2005	NAM	DWH	BP	8.5	20	0.16	22
2005	IME	ATN	RIL	6	140	0.46	41.25
2005	IME	ATN	RIL	8.5	100	1.47	20.25
2005	FEA	T09	JVPC	8.5	80	No data	13.25
2005	FEA	T15	Chevron	6	30	No data	4.5
2005	IME	DSS	ONGC	6	28	0.07	17.5
2005	IME	ATN	RIL	6	25	No data	21.75
2005	GGA	MGH	TFE	8.5	22.7	2.59	56.5

Table 15: Kick events greater than 20bbls influx volume, '05-'10

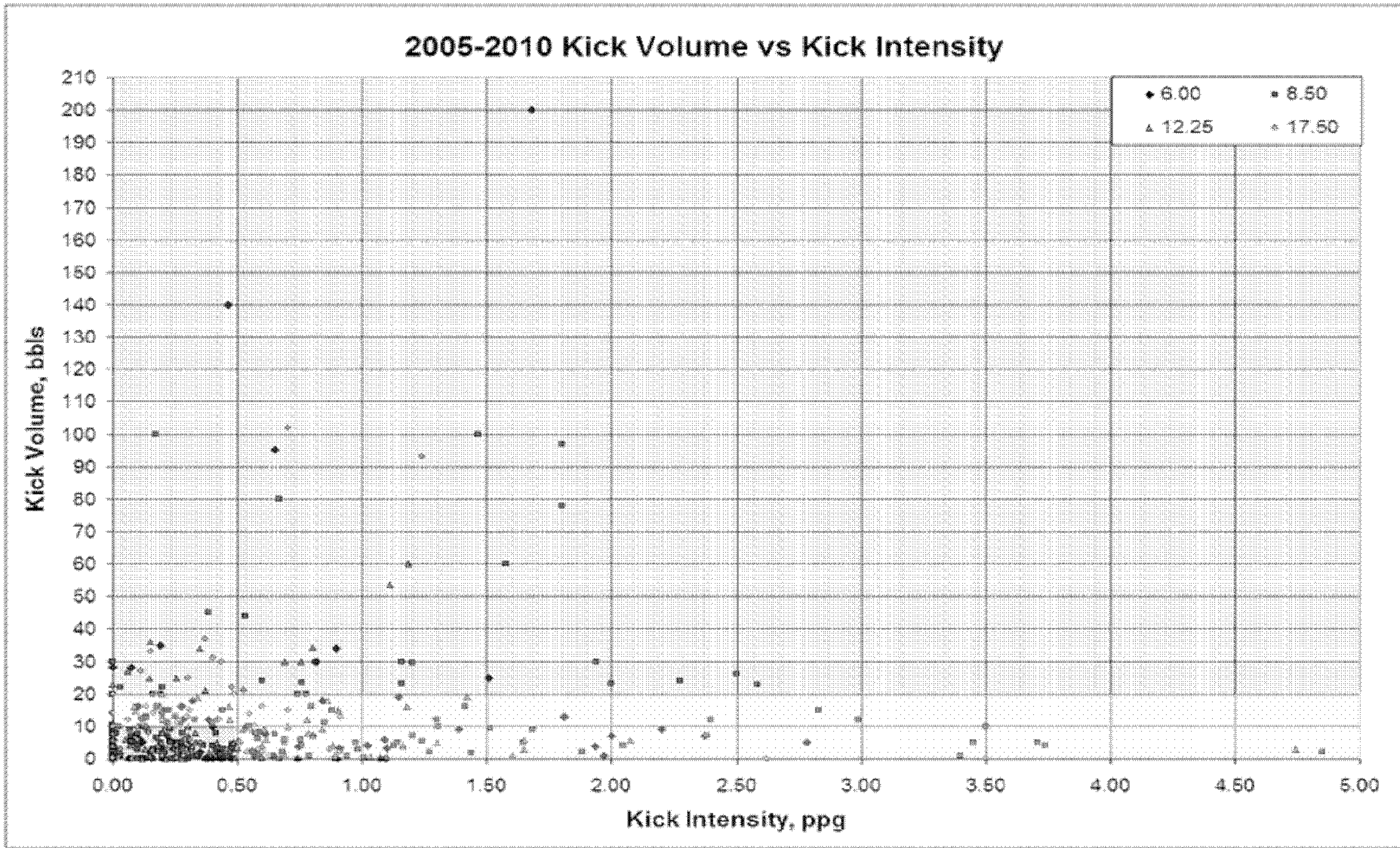
The 61 red zone events recorded on the previous page had the following additional characteristics:

	Mud Type		***Well Type***		***Rig Type***	
	O/SBM	**WBM**	**Exp.**	**Dev.**	**Floater**	**Jack-up**
2010	14	6	14	6	18	2
2009	9	1	7	3	9	1
2008	8	2	8	2	4	6
2007	5	1	5	1	3	3
2006	4	3	6	1	5	2
2005	6	2	7	1	6	2
Totals	**46**	**15**	**47**	**14**	**45**	**16**

Table 16: Summary of Red Zone data, '05-'10

NOTE:

- Red zone events are kick events where the influx volume is greater than 20bbls.
- 74% of all red zone events featured oil-based or synthetic-based mud systems.
- 77% of all red zone events occurred on exploration wells.
- 74% of all red zone events occurred on floating rigs (which is slightly above the general trend showing 62% of all WCE occurring on floating rigs, see Section 3.7).



Graph 2: Kick volume versus kick intensity, ‘05-‘10

3.4 Well control events by well type 2005-2010

	Exp & App	Development	Workover	Completion	Abandonment
2005	70	56	2		
2006	55	41	4		
2007	71	21			
2008	51	63	1		
2009	59	61	1		
2010	77	26	3	5	2
Grand Total	**364**	**268**	**11**	**5**	**2**

Table 17: Well control event by well type, '05-'10

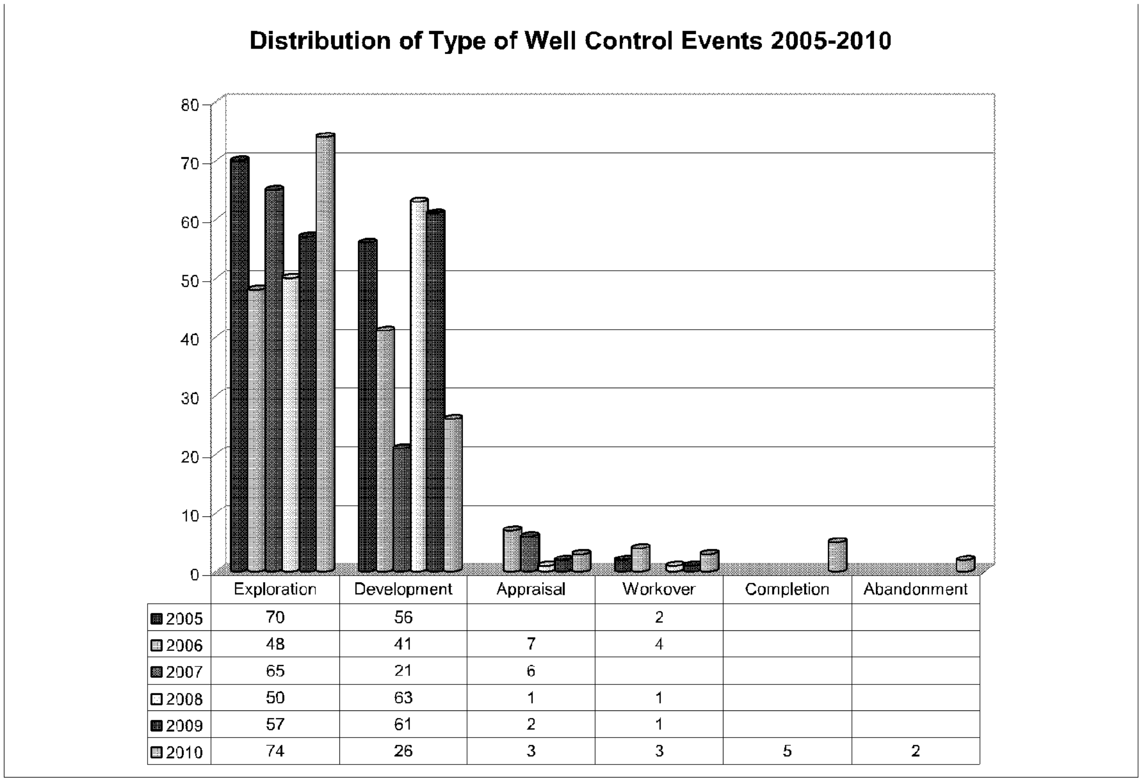


Chart 13: Well control event by well type, '05-'10

3.5 Well control events by client, 2005-2010

Client	2005	2006	2007	2008	2009	2010	Client Totals
ONGC	28	17	11	7	15	8	**86**
Chevron	22	23	10	9	11	10	**85**
Shell	6	4	12	10	7	10	**49**
RIL	14	12	7	11	0	0	**44**
BP	6	4	4	11	8	5	**38**
Petrobras	6	8	6	1	4	3	**28**
TOTAL	5	3	8	4	3	5	**28**
ENI	3	1	3	7	8	3	**25**
Petronas	2	5	2	6	4	5	**24**
British Gas	1	1	0	7	9	5	**23**
Statoil	5	0	1	0	3	14	**23**
Nexen	1	1	6	2	3	0	**13**
Anadarko	2	0	5	1	1	3	**12**
JVPC	3	3	0	2	0	0	**8**
Reliance	0	0	0	0	5	3	**8**
Cobalt	0	0	0	0	6	1	**7**
Esso	2	0	0	4	0	1	**7**
HESS	3	0	0	1	0	3	**7**
PETROBEL	3	1	1	1	1	0	**7**
AGIP	1	3	2	0	0	0	**6**
BHP	0	0	0	2	0	4	**6**
ExxonMobil	0	0	0	0	4	2	**6**
Afren	0	0	0	2	1	2	**5**
ConocoPhillips	1	0	0	0	4	0	**5**
Maersk	0	0	0	1	3	1	**5**
Marathon	0	0	0	1	0	4	**5**
PCVL	0	5	0	0	0	0	**5**
Saudi Aramco	0	0	0	4	1	0	**5**
Apache	0	0	4	0	0	0	**4**
Petrofrac	0	0	0	0	4	0	**4**
Repsol	0	0	1	1	2	0	**4**
TFE	3	1	0	0	0	0	**4**
TOI	0	0	0	0	0	4	**4**

Table 18: Well control events listed by client, '05-'10

NOTE:

- Only those clients totaling 4 or more kicks have been listed in the table above.

3.6 Summary of well control events *by type and client*, 2005-2010

WCE			Client	Kicks			Loss/Gain			Precautionary		
#	Hours	hrs/#		#	Hours	hrs/#	#	Hours	hrs/#	#	Hours	hrs/#
86	4,648	54.0	ONGC	57	3,867	67.8	19	504	26.5	4	5	1.3
85	2,169	25.5	Chevron	57	1,738	30.5	21	378	18.0	3	6	1.8
49	1,468	30.0	Shell	23	977	42.5	16	403	25.2	5	9	1.8
44	1,490	33.9	RIL	35	1,273	36.4	6	163	27.1	2	29	14.5
38	1,271	33.4	BP	20	781	39.0	12	452	37.7	6	38	6.3
28	2,904	103.7	Petrobras	16	2,267	141.7	10	631	63.1	2	6	2.8
28	697	24.9	TOTAL	21	522	24.8	4	165	41.2	3	11	3.6
25	1,106	44.2	ENI	14	883	63.1	7	196	28.0	2	8	4.0
24	920	38.3	Petronas	16	430	26.9	3	437	145.6	4	19	4.8
23	996	43.3	British Gas	9	699	77.7	10	252	25.2	4	45	11.2
23	1,232	53.5	Statoil	19	1,111	58.5	1	42	41.5	1	6	6.0
13	530	40.8	Nexen	6	489	81.5	4	29	7.3	3	12	4.0
12	529	44.1	Anadarko	7	325	46.4	3	176	58.5	2	29	14.5
8	124	15.5	BHP	4	100	25.0	3	16	5.3	1	8	8.0
8	79	9.9	JVPC	3	30	10.1	3	47	15.6	2	2	1.1
8	240	30.0	Reliance	6	166	27.7	2	74	37.0	0	0	0.0
7	705	100.7	Cobalt	4	488	122.0	2	215	107.5	1	2	2.0
7	165	23.6	Esso	1	34	33.5	2	20	10.0	2	17	8.3
7	272	38.8	HESS	3	51	16.9	4	221	55.3	0	0	0.0
7	107	15.3	PETROBEL	5	99	19.8	1	6	6.0	0	0	0.0
6	78	13.0	Afren	4	65	16.2	1	6	6.0	1	7	7.0
6	328	54.7	AGIP	3	127	42.3	1	186	186.0	0	0	0.0
6	82	13.6	ExxonMobil	2	73	36.5	2	6	3.0	2	3	1.3
5	128	25.5	ConocoPhillips	3	71	23.5	2	57	28.5	0	0	0.0
5	755	150.9	Maersk	3	747	249.1	0	0	0.0	2	7	3.6
5	69	13.7	Marathon	3	47	15.5	1	21	20.5	1	2	1.5
5	13	2.7	PCVL	5	13	2.7	0	0	0.0	0	0	0.0
5	27	5.4	Saudi Aramco	1	1	1.0	2	5	2.3	1	21	20.5
4	80	19.9	Apache	3	71	23.7	1	9	8.8	0	0	0.0
4	139	34.6	Petrofrac	3	137	45.5	0	0	0.0	1	2	2.0
4	1,007	251.8	PTTEP-PTT	4	1,007	251.8	0	0	0.0	0	0	0.0
4	113	28.1	Repsol	2	73	36.5	1	28	28.0	1	12	11.5
4	189	47.3	TFE	2	77	38.3	1	112	111.5	0	0	0.0
4	81	20.3	TOI	3	64	21.3	0	0	0.0	1	18	17.5
597	**24,738**	**43.7**	**Totals**	**367**	**18,899**	**52.8**	**145**	**4,854**	**34.6**	**57**	**320**	**4.7**

Table 19: Well control events listed by type and client, '05-'10

NOTE:

- The data listed above only includes those clients with 4 or more well control events.

3.7 Well control events by asset type, 2005-2010

Asset	2005	2006	2007	2008	2009	2010	Grand Total
Floaters	70	52	72	55	81	86	416
Bottom Supported	58	48	20	60	40	27	253
Grand Total	**128**	**100**	**92**	**115**	**121**	**113**	**669**

Table 20: Well control event count by rig-type, '05-'10

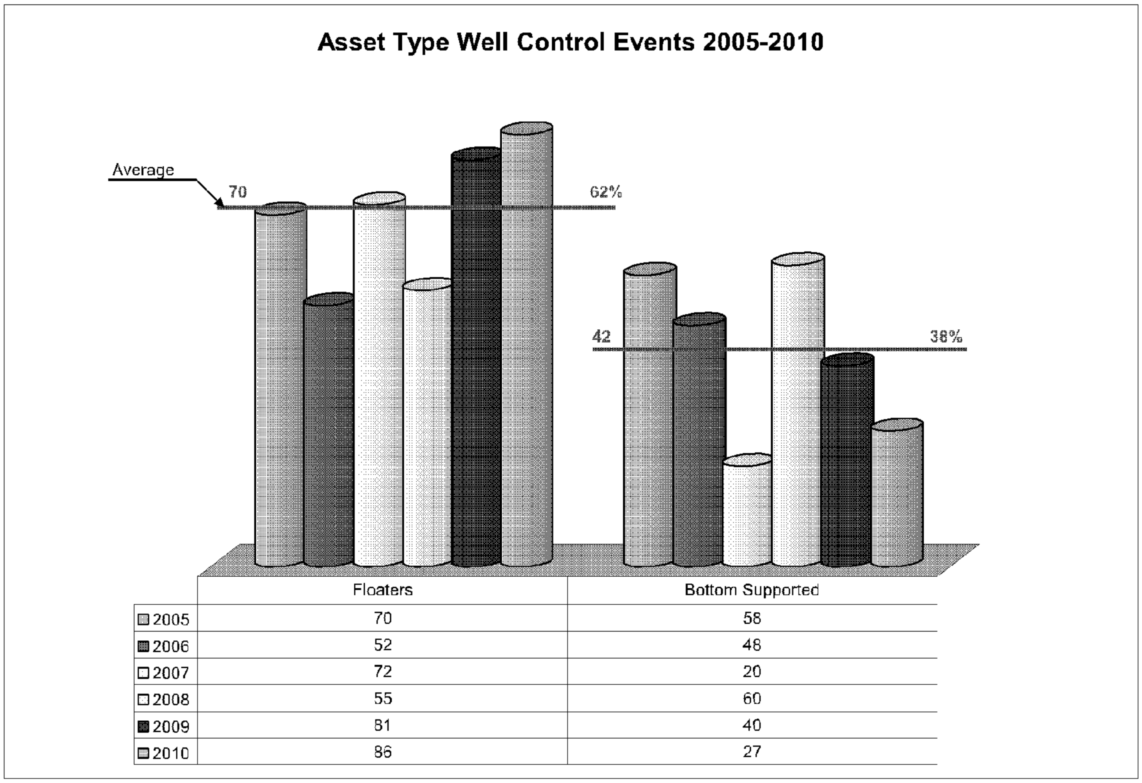


Chart 14: Well control event count based on asset-type, '05-'10

3.8 Well control events by hole size, 2005-2010

	2005	2006	2007	2008	2009	2010	Grand Total
6.00" Hole	39	24	12	9	17	16	117
8.50" Hole	36	34	39	53	48	48	258
12.25" Hole	27	22	21	38	36	31	175
17.50" Hole	13	16	20	15	20	18	102
Grand Total	**115**	**96**	**92**	**115**	**121**	**113**	**652**

Table 21: Number of well control events versus hole section, '05-'10

NOTE:
- This data set does not include those events from 2005 and 2006 that could not be classified due to inadequate data.

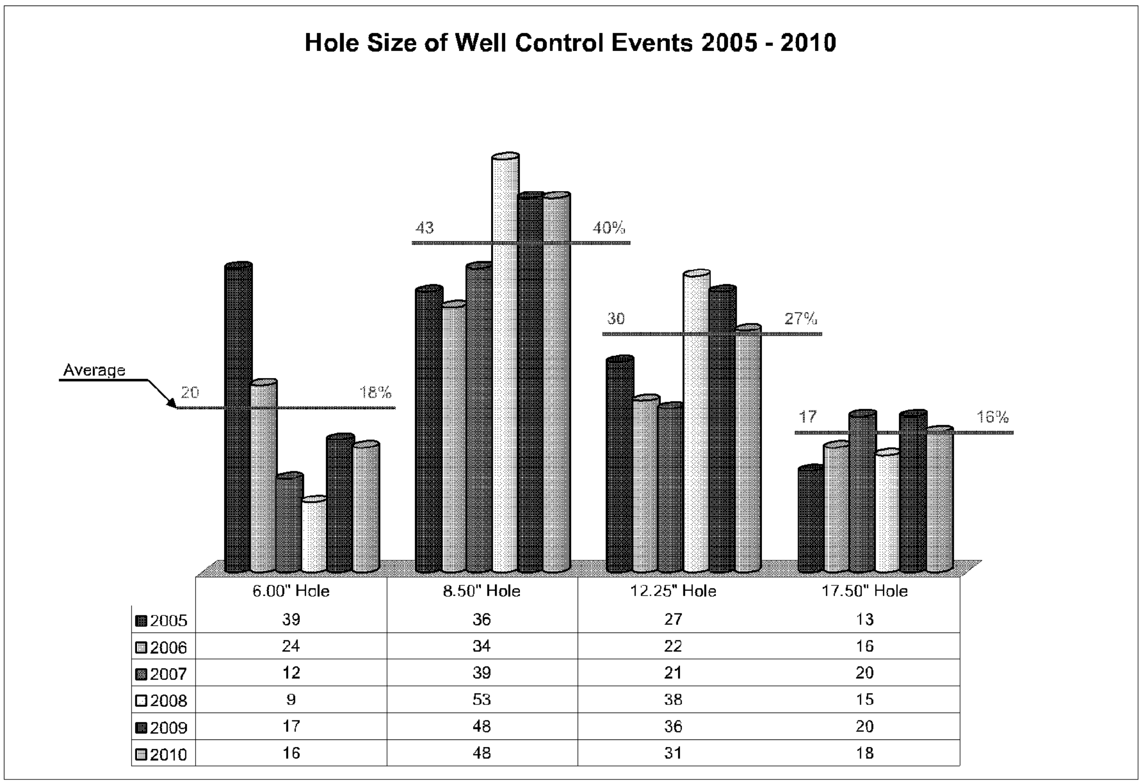
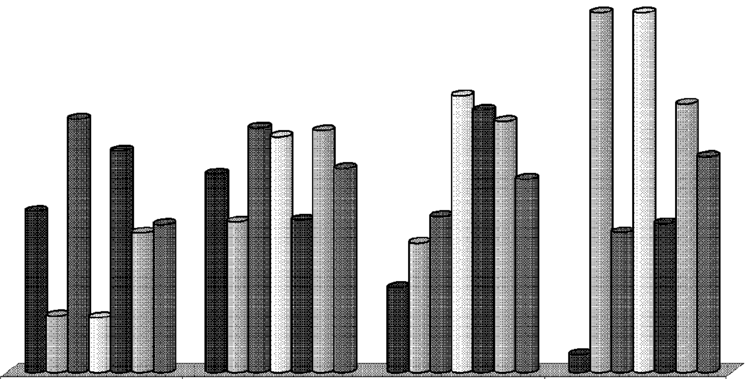


Chart 15: Average number of well control events by hole size, '05-'10

NOTE:
- Since conventional well design still aims to drill target reservoirs in 8-1/2" hole size, it is not surprising that almost 40% of all well control events occur in the 8-1/2" section.

Average Kick Size, bbl 2005 - 2010 for Each Hole Section



	6.00" Hole	8.50" Hole	12.25" Hole	17.50" Hole
2005	9.1	11.2	4.8	1.0
2006	3.2	8.5	7.3	20.3
2007	14.3	13.8	8.8	7.9
2008	3.1	13.3	15.6	20.3
2009	12.5	8.6	14.8	8.4
2010	7.9	13.6	14.2	15.1
Average	8.3	11.5	10.9	12.2

Chart 16: Average kick volume by hole size, '05-'10

NOTE:

- There is a wide variation in kick volume from year-to-year for each hole section.
- The most common kick section (8-1/2 inch) has the most consistent results and averages 11.5 bbls.

3.9 Well control events and statistics by division, 2005-2010

Division	WC HOURS	Events	Kicks	HOURS / WCE
IME	6,736	158	105	42.6
NAM	5,634	134	80	42.0
SAM	4,069	40	22	101.7
FEA	3,501	116	84	30.2
GGA	3,442	78	42	44.1
MED	1,732	52	30	33.3
NRS	1,557	55	27	28.3
WAS	537	27	12	19.9
NRY	168	9	7	18.7
Totals	**27,374**	**669**	**409**	**40.9**

Table 22: Well control event summary by division, '05-'10

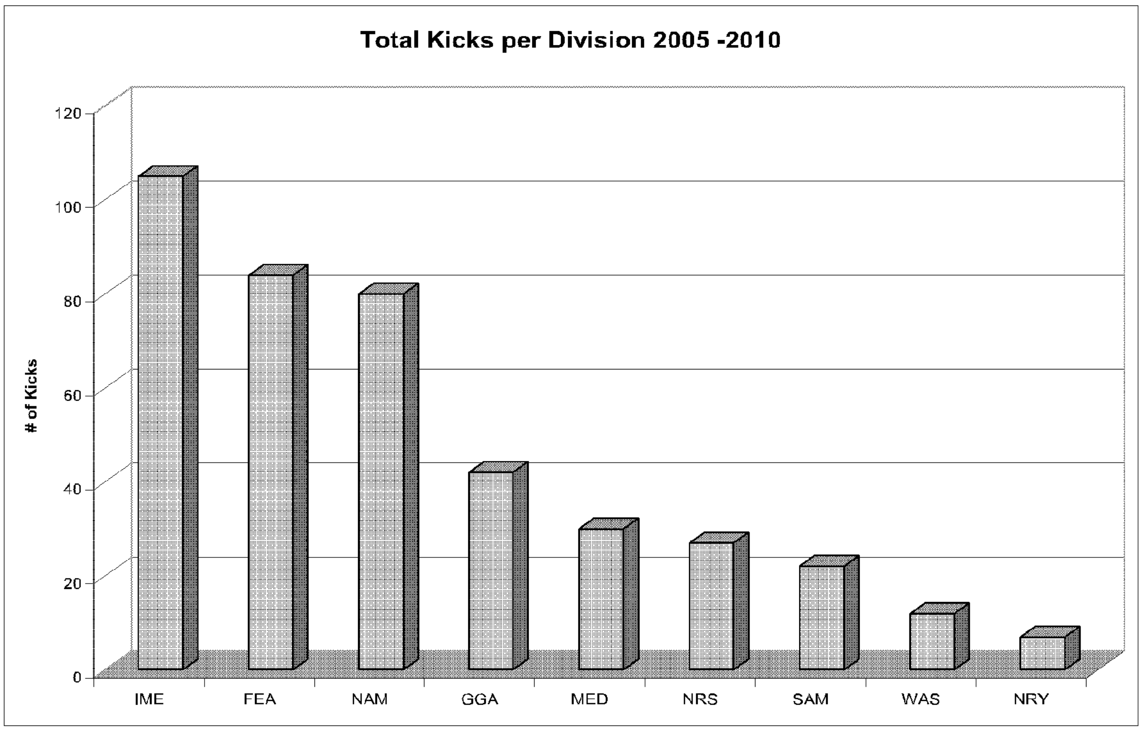


Chart 17: Total kicks taken in each division, '05-'10

WCE			Division	Kicks			Loss/Gain			Precautionary		
#	Hrs	Hrs/#		#	Hrs	Hrs/#	#	Hrs	Hrs/#	#	Hrs	Hrs/#
158	6736	42.6	**IME**	105	5400	51.4	34	946	27.8	11	92	8.4
116	3501	30.2	**FEA**	84	2623	31.2	21	827	39.4	9	25	2.8
134	5634	42.0	**NAM**	80	4255	53.2	41	1225	29.9	8	67	8.3
78	3442	44.1	**GGA**	42	2130	50.7	22	1096	49.8	6	51	8.4
55	1557	28.3	**NRS**	27	1049	38.9	17	420	24.7	10	37	3.7
52	1732	33.3	**MED**	30	1451	48.4	10	195	19.5	8	52	6.5
40	4069	101.7	**SAM**	22	3351	152.3	12	636	53.0	5	10	2.0
27	537	19.9	**WAS**	12	411	34.3	8	95	11.8	7	31	4.4
9	168	18.7	**NRY**	7	104	14.8	2	65	32.3	0	0	0.0
669	**27374**	**40.9**	Totals	**409**	**20773**	**50.8**	**167**	**5505**	**33.0**	**64**	**364**	**5.7**

Table 23: Well control event breakdown by type and division, '05-'10

Div	2005	2006	2007	2008	2009	2010	Grand Total
IME	42	29	23	25	22	17	158
NAM	22	18	24	14	25	31	134
FEA	23	26	10	17	18	22	116
GGA	16	10	10	15	17	10	78
NRS	5	6	8	15	12	9	55
MED	8	7	8	13	9	7	52
SAM	8	4	6	2	9	11	40
WAS	1	0	2	12	7	5	27
NRY	3	0	1	2	2	1	9
Year Total	**128**	**100**	**92**	**115**	**121**	**113**	**669**

Table 24: Well control event breakdown by division, '05-'10

Well Control Events per Division 2005 - 2010

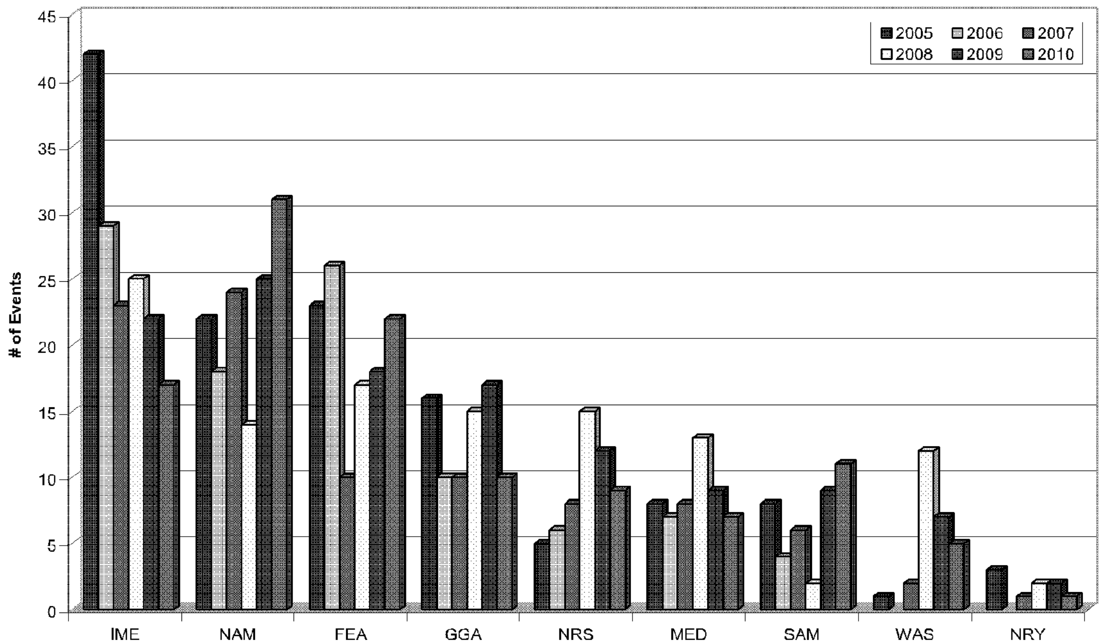


Chart 18: Annual well control events by division, '05-'10

NOTE:

- Although NRY has a relatively small sample group of rigs and wells, they continue to have a low incidence of events from year-to-year.

Div	2005	2006	2007	2008	2009	2010	Div Total
IME	33	20	13	13	12	14	105
FEA	21	16	6	11	14	16	84
NAM	7	7	16	10	19	21	80
GGA	6	7	8	7	10	4	42
MED	4	7	2	5	6	6	30
NRS	1	4	5	6	6	5	27
SAM	7	3	1	1	5	5	22
WAS			1	6	2	3	12
NRY	3		1	1	2		7
Year Total	**82**	**64**	**53**	**60**	**76**	**74**	**409**

Table 25: Kick events breakdown by division, '05-'10

Div	2005	2006	2007	2008	2009	2010	Grand Total
IME	5	7	8	5	8	1	34
FEA	1	9	3	4	1	3	21
NAM	12	11	4	4	4	6	41
GGA	4	2	1	6	5	4	22
MED	0	0	4	4	1	1	10
NRS	3	2	2	5	2	3	17
SAM	0	1	4	0	2	5	12
WAS	1	0	1	3	2	1	8
NRY	0	0	0	1	0	1	2
Year Total	**26**	**32**	**27**	**32**	**25**	**25**	**167**

Table 26: Loss/Gain events breakdown by division, ’05-‘10

	NAM	IME	GGA	FEA	NRS	MED	WAS	SAM	NRY
Loss/Gain events	41	34	22	21	17	10	8	12	2
All WC events	134	158	78	116	55	52	27	40	9
L/G as % of WC events	31%	22%	28%	18%	31%	19%	30%	30%	22%

Table 27: Ratio of loss/gain to WC events by division, ’05-‘10

NOTE:

- A larger proportion of WCE in NAM, NRS, WAS and SAM are Loss/Gain events in comparison with other areas.

3.10 Total hours and contract time spent on well control, 2005-2010

	2005	2006	2007	2008	2009	2010	*5 - '10*
Contract hours (from GRS/GMS)	661,606	668,405	655,360	1,092,440	989,539	859,311	*4,926,661*
Number of Well Control Events	128	100	92	115	121	113	*669*
Number of Kicks	82	64	53	60	76	74	*409*
Hours spent on WC Events	5,707	3,485	3,679	4,413	5,995	4,094	*27,373*
Average time per WCE	45	35	40	38	50	36	41
Percentage of contract time spent on WC Events	0.86%	0.52%	0.56%	0.40%	0.61%	0.48%	0.56%

Table 28: Well control data based on operating hours, '05-'10

3.11 Well control event kill methods, 2005-2010

W C Method	2005	2006	2007	2008	2009	2010	Grand Total
Drillers	57	33	35	33	35	42	235
Circulate	23	23	24	41	40	26	177
Wait & Weight	10	19	17	25	31	23	125
Bullheading	14	15	6	12	8	8	63
Bleed off	13	3	6		1	6	29
Inadequate Info	5	4					8
Dynamic			4	1	2	1	6
Stripping	5			1			6
Volumetric	1	1		1	2	1	3
Inject & Bleed					1	2	3
Other		2		1		2	2
Mud Cap						2	2
Cement Plug					1		1
Grand Total	**128**	**100**	**92**	**115**	**121**	**113**	**660**

Table 29: Well control event kill methods, '05-'10

NOTE:

- The Drillers Method has historically been most commonly used. 35% of all Well Control Events from 2005 to 2010 have used the Drillers Method.
- The Wait and Weight Method has been used less in 2010 than previous years. 19% of all Well Control Events for 2005 to 2010 have used the Wait and Weight Method.
- "Circulate" has been used less in 2010 than previous years. This is inline with the decline in precautionary events.

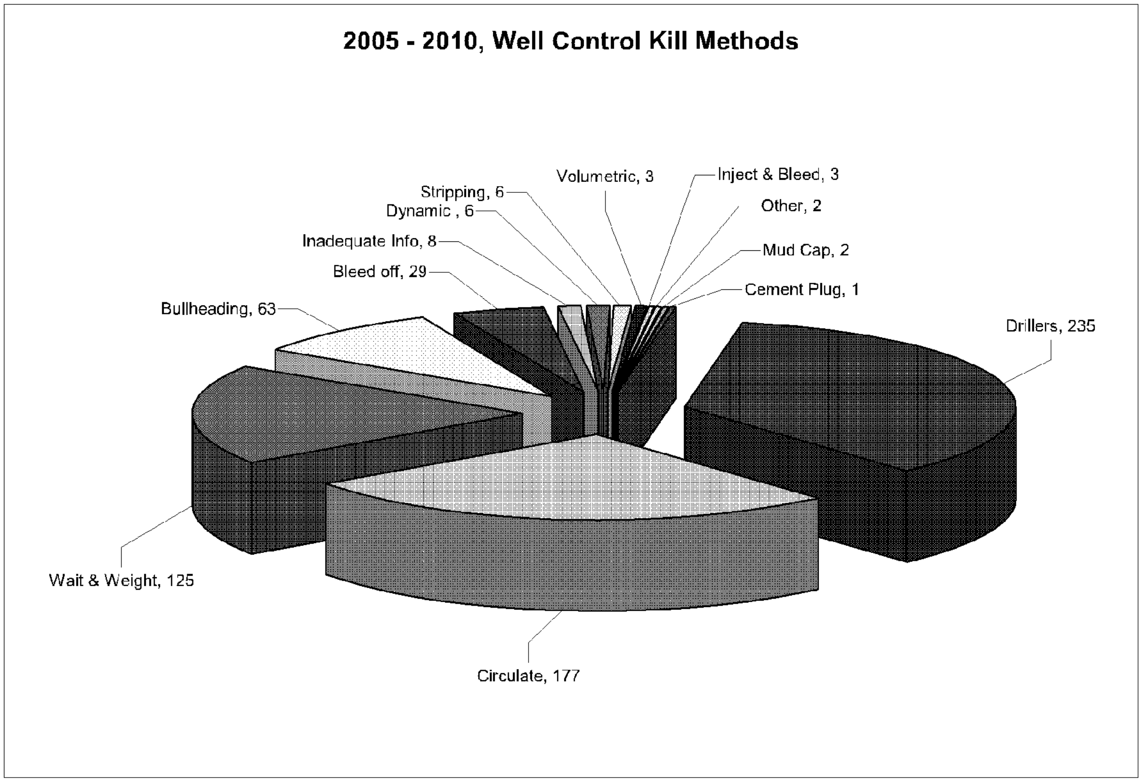


Chart 19: Breakdown of well control event kill methods, '05-'10

3.12 Operations ongoing at time of well control events, 2005-2010

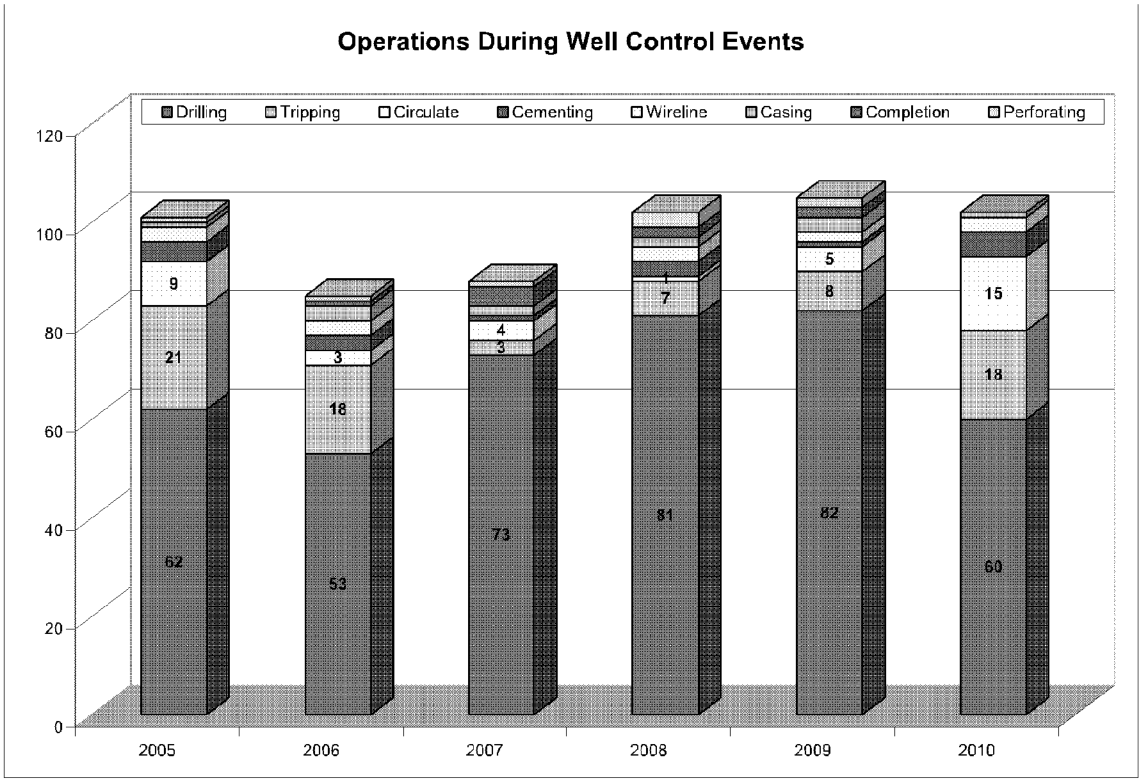


Chart 20: Operations ongoing at time of well control event, '05-'10

More kicks were experienced during tripping and cementing operations than has been the case in previous years.

- A suitable margin of overbalance must be in place prior to tripping out of the hole.
- It is essential that primary well control is continually maintained and monitored throughout all operations, during all stages of the well, until such point when the BOP is removed.

CONCLUSIONS AND RECOMMENDATIONS

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4. CONCLUSIONS AND RECOMMENDATIONS

Please refer to the Executive Summary at the front of this document for a summary of conclusions and recommendations to be made from the analysis of well control data for 2010 and from years 2005 to 2010.