Transocean

ANNUAL REPORT - 2009

WELL CONTROL EVENTS & STATISTICS

2005 to 2009

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EXECUTIVE SUMMARY

During the period 2005 to 2009, Transocean rigs (both legacy companies) operated on a total of 6,795 wells.

- Drilling and completion operations were conducted on 4,204 development wells
- Drilling operations were conducted on 1,904 exploration wells
- Workover or abandonment operations were carried out on 687 wells

The data set used to generate well control statistics relates only to legacy Transocean rigs between 2005 and 2007, with legacy GlobalSantaFe operations included from 2008 onwards.

Therefore the relevant operations summary relates to a total of 4,966 wells comprised of:

- 3,155 development wells
- 1,386 exploration wells
- 425 workovers or abandonment

While operating on those 4,966 wells, Transocean rigs experienced 556 well control events.

- 329 of those events were kicks
- 142 events were due to ballooning formations[1]
- 306 well control events (including 185 kicks) occurred on exploration wells
- 242 events (128 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 25 development wells will experience a kick

In addition to indicating the likelihood of experiencing a well control event, the data confirms it is most likely to take a kick on an exploration well, and highlights the importance of being able to distinguish between ballooning formations and actual kicks.

[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).

2009 Well Control Performance Summary

A total of 121 well control events were recorded in 2009. Of these 121 events, 71 were categorized as kicks, 25 were categorized as ballooning, 20 were precautionary type events and 5 were pilot hole (shallow gas) events.

When normalized by the *active* rig count in 2009 (assumed to be 119 rigs due to 30 rigs becoming idle or stacked through the year), the frequency of **kick** events was 0.60 per rig.

The key findings of the well control events that occurred in 2009 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.

- 84% (60) of all kicks were detected in under 20bbls. Capturing a kick in less than 20bbls is reasonable, especially on a floating vessel.
- 14% (10) of all kicks exceeded 20bbls and ranged from 20 to 60bbls. Failure to limit a kick to less than 20bbls is less than ideal.
- Although the related kick may have been reported as being less than 20bbls, six rigs (711, DAS, DD1, MGH, 702 and ATN), to varying degrees, all unloaded their drilling risers. It is absolutely essential that any influx taken into the wellbore on floating rigs is not allowed to migrate or be circulated above an open BOP.
- 44% (31) of all kicks were more than 0.5ppg above mud weight.
- 25% (18) of all kicks were more than 1ppg above mud weight.

Time associated with well control events in 2009

- 5,995 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 49.5 hours
- Rigs operating for ONGC had the highest number of well control events (15) and 616 hours was consumed dealing with these events
- Rigs operating for Petrobras reported only 4 well control events, but these events amounted to 797 hours.
- NAM attributed over 1,800 hours to well control events, closely followed by SAM with 1,600 hours.
- 0.61% of the total contracted rig time in 2009 was spent on well control events.

2005 to 2009 Well Control Performance Summary

- A total of 329 kicks have been encountered while operating on 4,966 wells[2].
- When normalized by *active* rig count, the kick events increased from 0.45 in 2008 to 0.60 events per rig in 2009. (This compares with 1.0 in 2005, 0.8 in 2006 & 0.50 in 2007).
- The percentage of total contracted rig time spent on well control increased from 0.40% in 2008 to 0.61% in 2009. *(Section 3.9)*
- Use of the Wait & Weight method continued to increase in 2009 and was almost 1:1 with the Drillers Method (note that the Drillers Method had been almost **6** times more common than Wait & Weight in 2005). *(Section 3.10)*
- NAM is the only Division in which Wait & Weight actually predominates (62%).
- The Circulate Method[3] continued to be applied more than any other in 2009. This is in line with the continued higher frequency of precautionary events.
- As with 2008, 2009 saw kicks over 20bbls (termed red zone events) occur on 10 occasions, up from 6 per year between 2005 and 2007. *(Section 3.3.1)*
- Overall, 80% of red zone events occurred on exploration wells and similarly, oil-based (or synthetic-based) mud was in use during 80% of the red zone events.

Areas for improvement

- The frequency of riser unloading events is the biggest concern with 6 separate instances recorded (between December 2008 and December 2009). These can be avoided through the application of fundamental well control practices such as treating every positive indicator as a kick, shutting in quickly and taking returns through the choke whenever in any doubt whatsoever.
- There have been instances of wells being allowed to flow due to mistakenly assuming the flow was caused by wellbore ballooning (Loss/Gain events). It is essential that rig crews are able to distinguish between ballooning and actual kicks. Until such time that ballooning has been positively identified the well must be shut-in on all positive flow checks or any other positive indications of flow. No exceptions should be made.
- Kicks greater than 20bbls numbered 10 once again in 2009 and must be reduced.
- Kicks greater than 1ppg over mud weight continued to increase from 2008 highlighting that pore pressure prediction can also be improved. Note that exploration drilling did not increase in 2009 making this statistic less acceptable.
- The instances of shallow gas in 2009 continue to demonstrate the importance of obtaining and reviewing shallow hazard surveys and of having thorough shallow gas plans in place.
  (Refer to Advisory HQS-OPS-ADV-008, December 2nd 2009)
- Compliance, i.e. completion and posting of WCE Reports by the rigs involved, was only 54% in 2009 and must improve. The remaining events were identified and monitored via IADC code searches within GRS and GMS.

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[2] Only includes LGSF wells from 2008 onwards.
[3] 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.

1. INTRODUCTION

This report contains a statistical analysis of all well control events which occurred during 2009 in comparison with and in addition to a historical review of all well control events which have occurred during the last 5 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 2009
- Compare and understand the trends of well control events in 2009 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 GRS/GMS.

Please note that the GRS/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

The reporting of well control events needs to continue improving and 100% compliance remains a challenge.

During 2009 a well control event report was submitted for only 54% of well control events.

Roll-out of GMS is continuing through the first quarter of 2010 and all rigs should have migrated to that system by the end of the second quarter. GMS will automatically prompt each rig for a Well Control Event Report whenever related IADC codes are selected.

1.1 Background Well and Rig Data

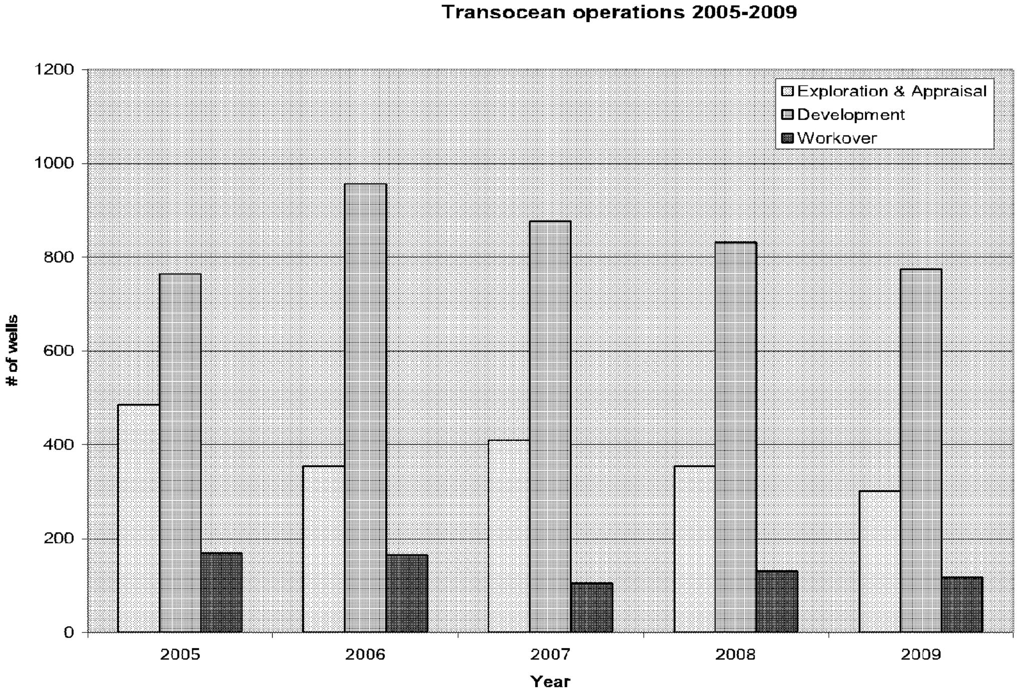

Chart 1: Annual well count

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
Total type	1,904	4,204	687	6,795

Table 1: Annual well count

NOTE

- This data includes legacy GlobalSantaFe (LGSF) for '05-'07.

Removing LGSF wells for 2005 through 2007 in order to normalize well control statistics correctly gives the following summary:

	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
Total type	1,386	3,155	425	4,966

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
Floaters *active*	**47**	**55**	**53**	**68**	**68**	**65**
Floaters stacked/idle	9	0	0	0	0	6
Floaters total	56	55	53	68	68	71
Bottom-supported *active*	**29**	**28**	**27**	**70**	**66**	**39**
Bottom-supported stacked/idle	5	4	0	0	1	28
Bottom-supported total	34	32	27	70	67	67
Total *active* fleet	***76***	***83***	***80***	***138***	***134***	***104***

Table 2: Variation in the active rig fleet

NOTE

- The active rig count dropped 30 during 2009 due to stacking of largely Jack-up rigs.
- The assumed rig count whenever normalizing statistics for 2009 was **119**.

Statistics for 2009

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2. 2009 WELL CONTROL EVENTS SUMMARY

The following section contains a statistical analysis of all well control events which occurred during 2009.

2.1 2009 Well control event types

A total of 121 well control events were recorded in 2009. Of these 121 events, 71 were categorized as kicks, 25 were categorized as "Loss / Gain", 20 were precautionary type events and 5 pilot hole (shallow gas) events.

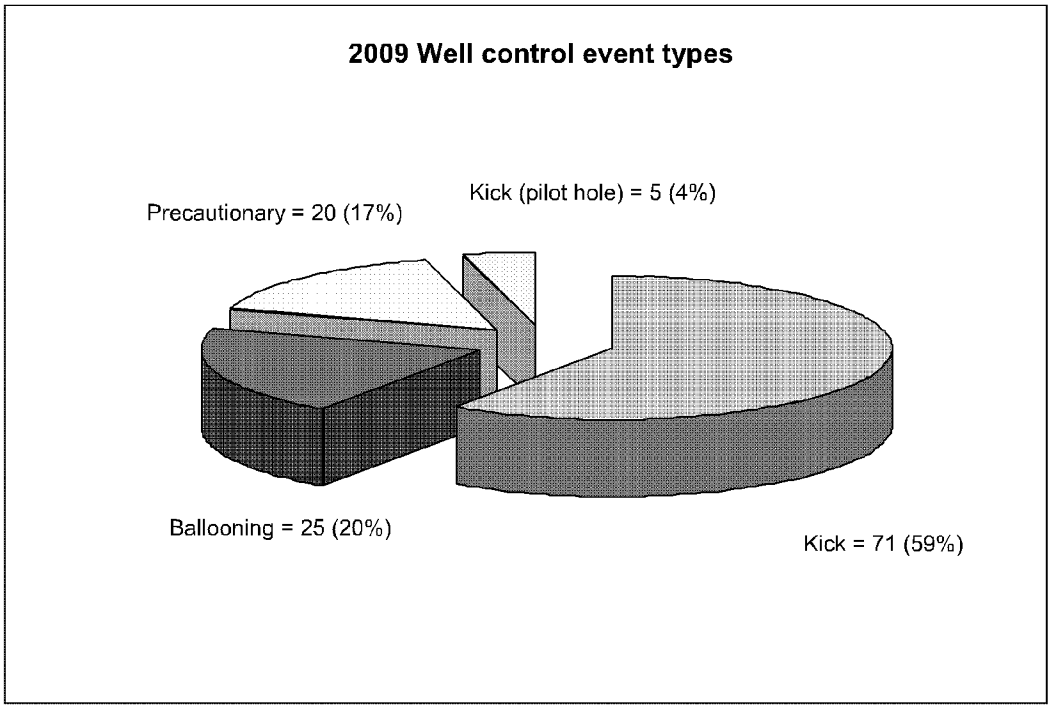


Chart 2: 2009 Well Control Event types, 2009

NOTE

- Ballooning (loss/gain) was responsible for 1 in 5 well control events in 2009.
- Five shallow gas well control events were experienced during 2009.
- On six occasions risers were either partially or completely unloaded as a result of well control events (see overleaf).

2.2 Riser unloading events, 2009

Before reviewing the data related to actual kick events for 2009 in the next section, it is worth briefly mentioning the increasing trend seen in 2009 of drilling risers being either partially or completely evacuated (or unloaded) due to gas being circulated above subsea BOP stacks.

From December 2008 until year-end 2009, this type of event occurred 6 times on Transocean rigs. It is particularly hazardous due to the uncontrolled release of mud and gas through the rotary table and the potential for ignition, either on the rig floor or further down the flow line in the shaker house.

NOTE

- Rigs that experienced riser unloading events include ATN, 702, MGH, DD1, DAS & 711.
- Oil-based or synthetic-based mud was being used in 4 of the 6 events.

Riser unloading events can be avoided through the application of fundamental well control practices such as treating every positive indicator as a kick, shutting in quickly and taking returns through the choke whenever in any doubt whatsoever.

2.2 2009 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	And	< 10 bbls	Minor / Routine	Rig Manager / General Manager
Yellow	> 0.5 ppg	And	< 20 bbls	Major	General Manager
Red	Any Intensity		> 20 bbls	Critical	Managing Director / Operations Director

Table 3: Kick Severity matrix

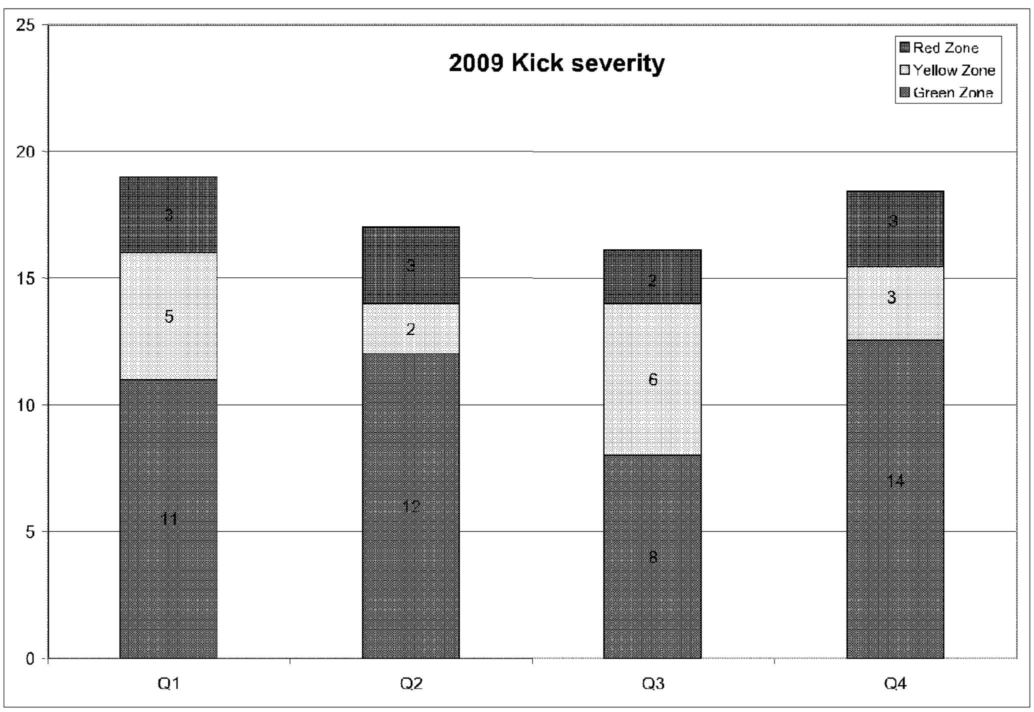


Chart 3: Kick severity for each quarter, 2009

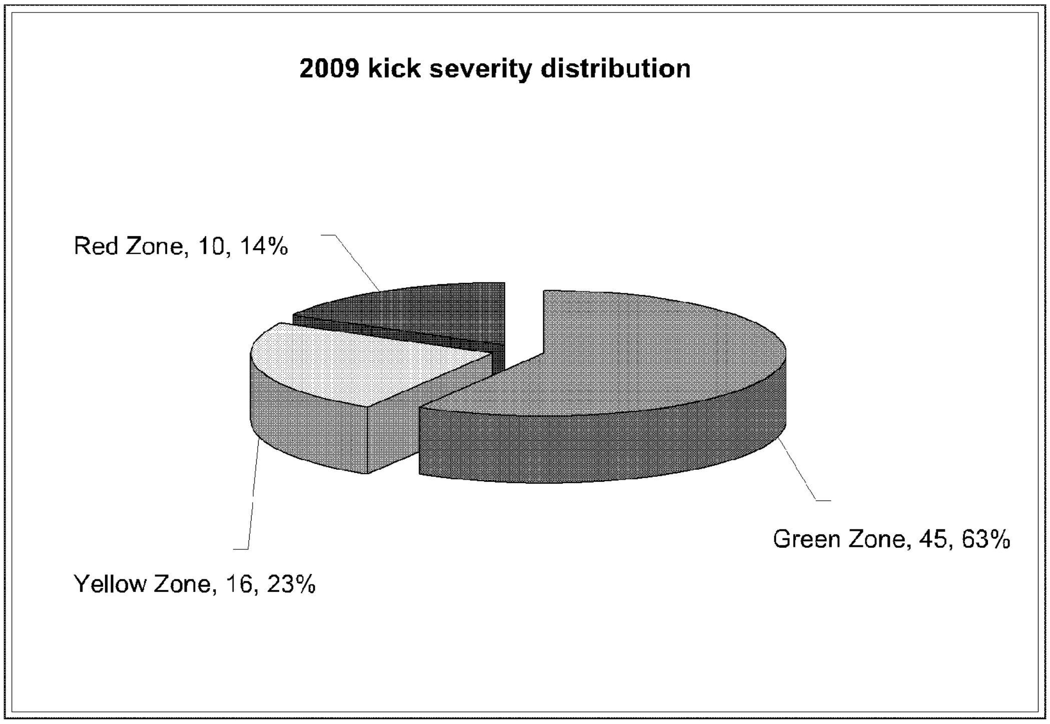


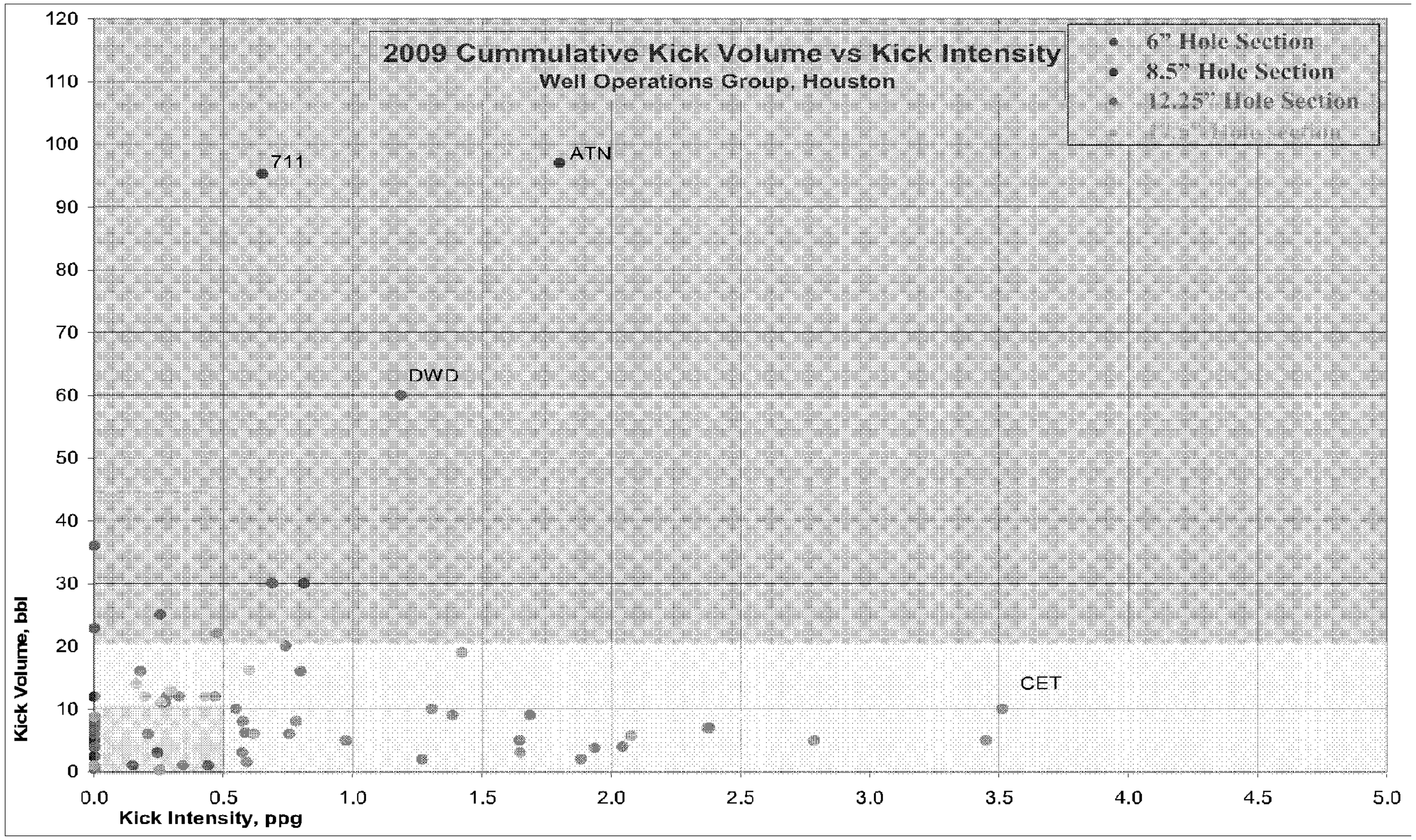
Chart 4: Kick Severity distribution, 2009

Division	Rig	Client	Kick size, bbl	Hole size, in	KI, ppg	Time (hrs)
FEA	ATN[4]	CNOOC	97.0	8.5	1.80	82.50
NRS	711	Shell	95.3	6	0.65	20
SAM	DWD	Petrobras	60.0	12.25	1.18	165.50
GGA	702	BG	36.0	12.25	0.15	29.25
SAM	DWM	Petrobras	30.0	12.25	0.69	383
FEA	PSW	Total	30.0	6	0.81	8.00
NAM	DD1	Cobalt	25.0	12.25	0.26	96.00
NAM	DWN	Shell	22.9	12.25	0.00	45.50
NAM	DD1	Cobalt	22.0	17.5	0.48	192.00
NAM	DD1	Cobalt	20.0	8.5	0.74	20.00

Table 4: Kick events greater than 20bbls influx volume, 2009
NOTE:

- 45 kicks (63%) with a kick intensity less than 0.5ppg were detected and the well shut in resulting in a gain of less than 10bbls
- 16 kicks (23%) with a kick intensity greater than 0.5ppg were detected and the well shut in resulting in a gain of less than 20bbls
- 10 kicks exceeded 20bbls with varying kick intensities
- Refer to Graph 1 '2009 kick intensity versus kick volume'
- Graph 1 below shows that kick severity was more scattered than in previous years.

[4] ATN and 711 reported influx volumes as per the above table. However these were riser unloading events and the actual influx would have been considerably less.



Graph 1: **Kick volumes vs. kick intensity, 2009**

2.3 2009 Well control events by client

Client	WCE #	Time (hrs)
ONGC	15	616
Chevron	11	351
BG	9	197
Eni	9	595
BP	8	140
Shell	7	95
Cobalt	6	703
Reliance	5	136
ConocoPhillips	4	120
ExxonMobil	4	66
Maersk	4	767
Petrobras	4	797
Petrofrac	4	138
Petronas	4	29
Nexen	3	13
Statoil	3	275
Total	3	89
Repsol	2	39
Addax	1	24
Afren	1	5
Anadarko	1	19
Centrica	1	9
CNOOC	1	82
Gulf of Suez	1	86
Petrobel	1	21
PetroCanada	1	314
PetroGulf	1	52
Saudi Aramco	1	1
Silverstone Energy Ltd.	1	63
Talisman	1	6
Vanco Ghana Ltd.	1	52
Vietsovpetro	1	11
Totals	**121**	**5,995**

Table 5: Well control events listed by client, 2009

2.4 2009 Well control events by asset type

Well Control by Asset Type	
Floaters	80
Jack-up	41
Total	121

Table 6: Well control event by asset type, 2009

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

Table 7: Reduction in fleet activity, 2009

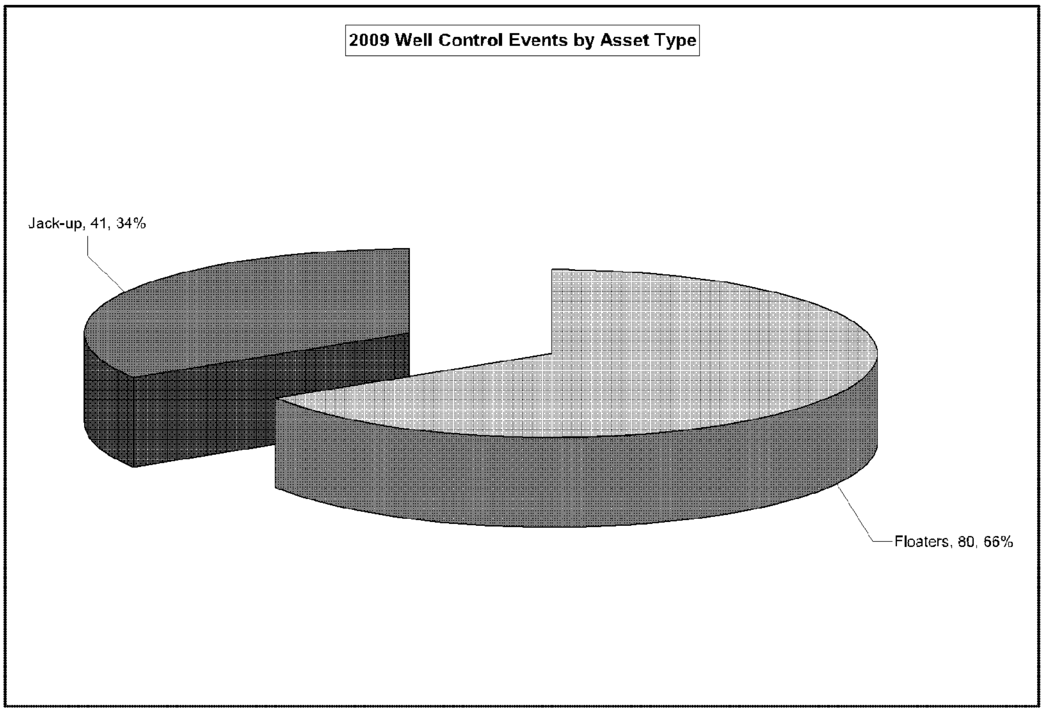


Chart 5: Well control events by asset type, 2009

NOTE

- Two-thirds of events occurred on floaters in 2009. This increase from an approximate ratio of 50:50 in 2008 is likely related to 28 bottom-supported rigs becoming idle or stacked during 2009.

2.5 2009 Average kick volume by hole size

Hole Size (")	Volume (bbl)
6	13
8.5	9
12.25	15
17.5	8
Average	**11**

Table 8: Average kick volume by hole size, 2009

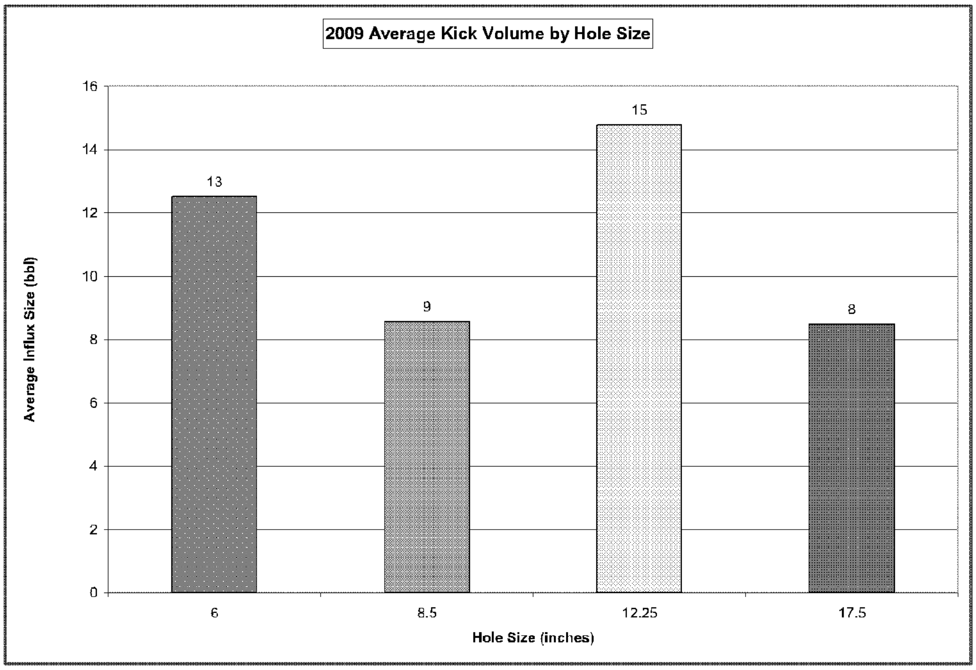


Chart 6: Average kick volume by hole size, 2009

2.6 2009 Well control events and associated time per division

DIVISION	Hours	2009 WCE	2009 Kicks	Hours / WCE
NAM	1,831	25	19	73.2
SAM	1,600	9	5	177.8
IME	777	22	12	35.3
GGA	693	17	6	40.8
FEA	546	18	14	30.3
MED	331	9	6	36.8
NRS	129	12	6	10.8
WAS	72	7	2	10.3
NRY	13	2	1	6.5
Totals	**5,995**	**121**	**71**	**49.5**

Table 9: Well control event breakdown by Division, 2009

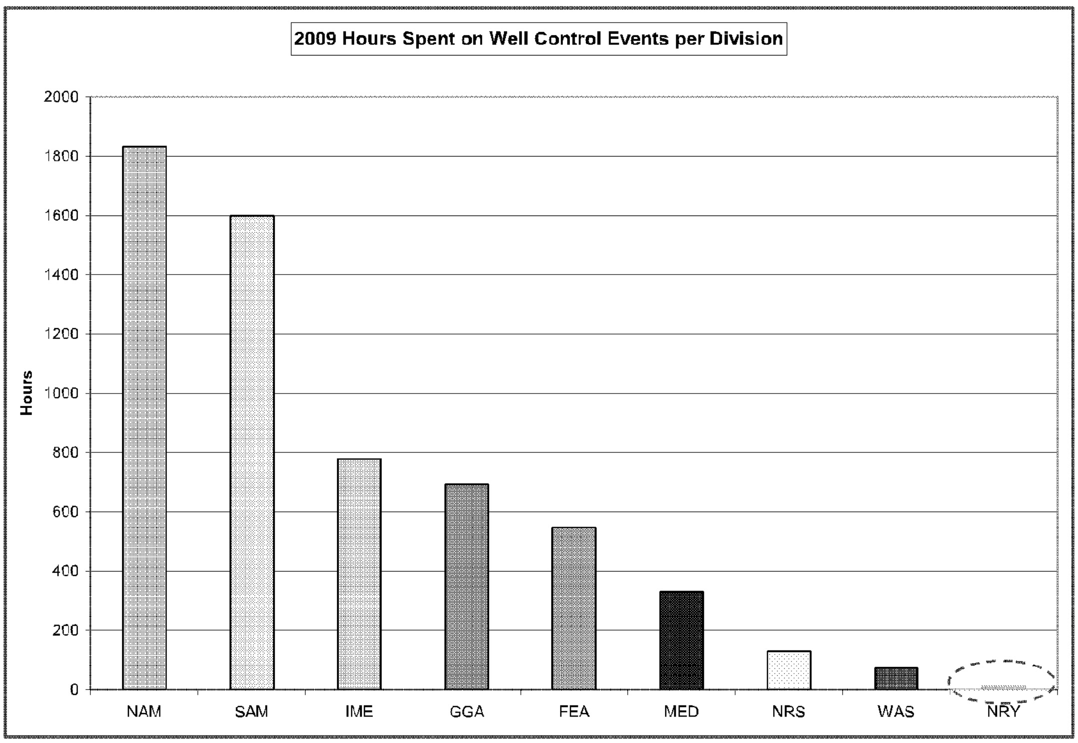


Chart 7: Total hours spent on well control events in each Division, 2009

NOTE

- NRY continues to experience few well control events and spends little time recovering from those that do occur.

2.7 2009 Total hours and Contract time spent on well control

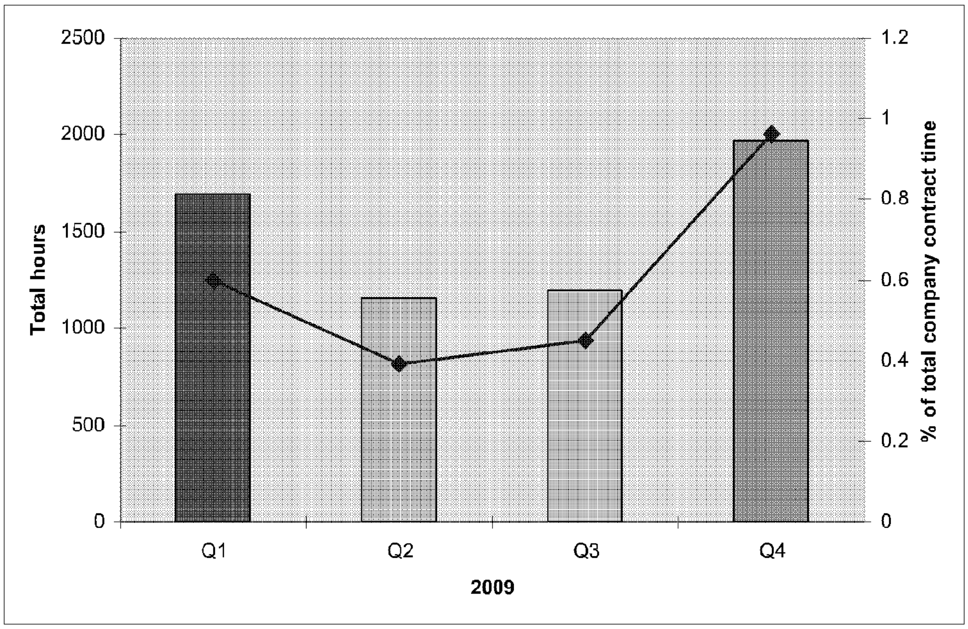


Chart 8: Total hours and percentage of contract time spent on well control, 2009

2.8 2009 Well control event kill methods

WCE Kill Method	
Circulate	39
Drillers	36
Wait & Weight	31
Bullhead	8
Dynamic	2
Volumetric	2
Bleed Off	1
Cement Plug	1
Lubricate	1
Total	**121**

Table 10: Well control event kill methods, 2009

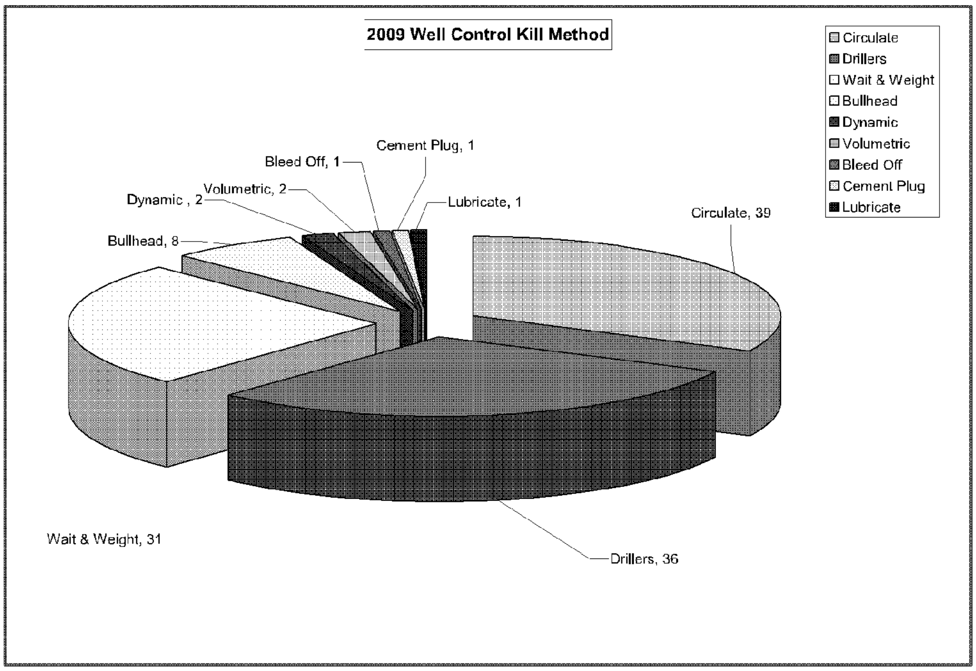


Chart 9: Breakdown of well control event kill methods, 2009

2.9 2009 Operations ongoing at time of well control event

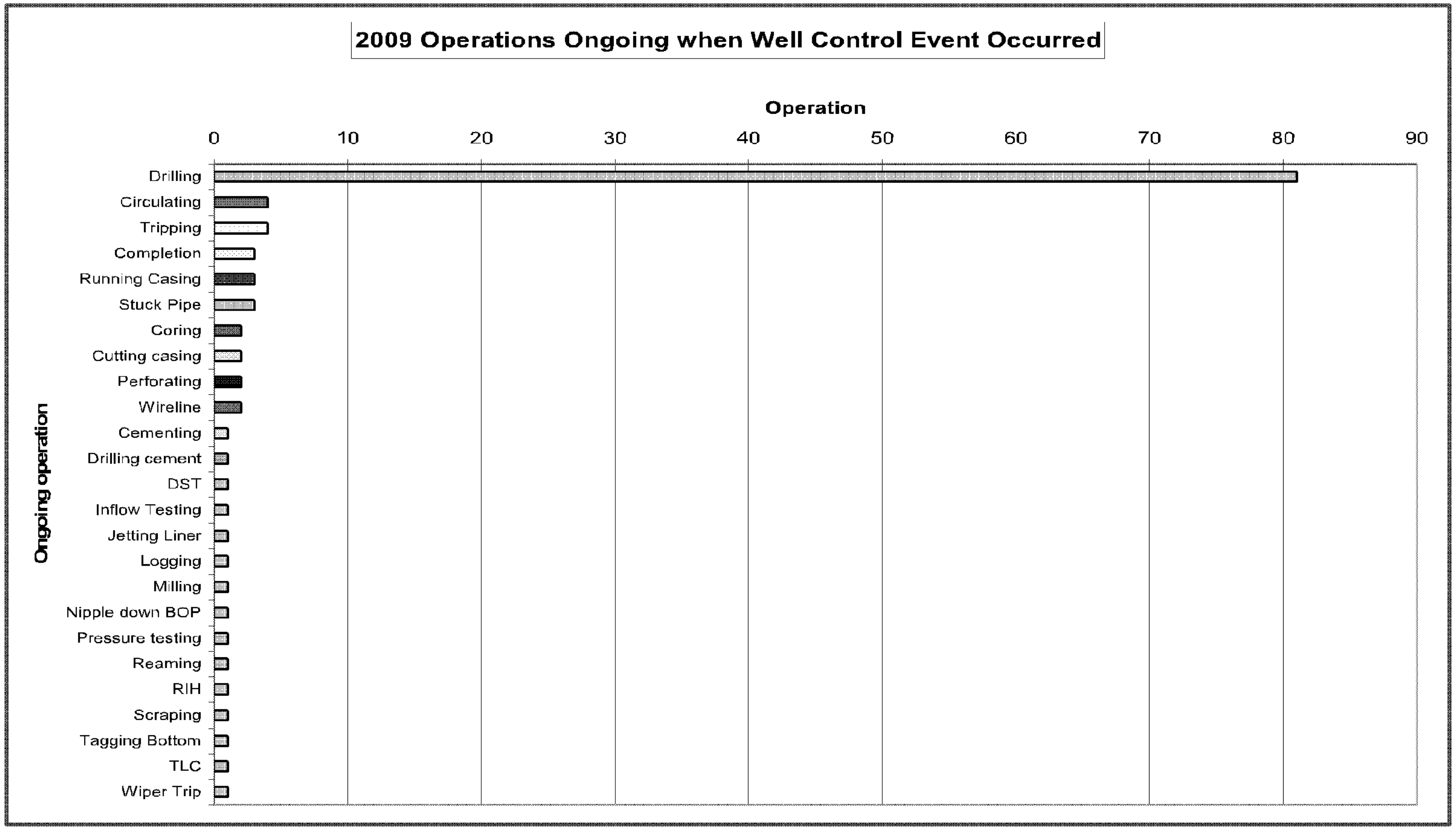


Chart 10: **Operations ongoing at time of well control event, 2009**

NOTE

- With reference to Chart 10 on the previous page, the large occurrence of well control events during drilling operations confirms the majority of events are drilled kicks and ECD-related ballooning events. This is also a positive sign that primary well control is being maintained prior to commencing other well operations.

Statistics for 2005 - 2009

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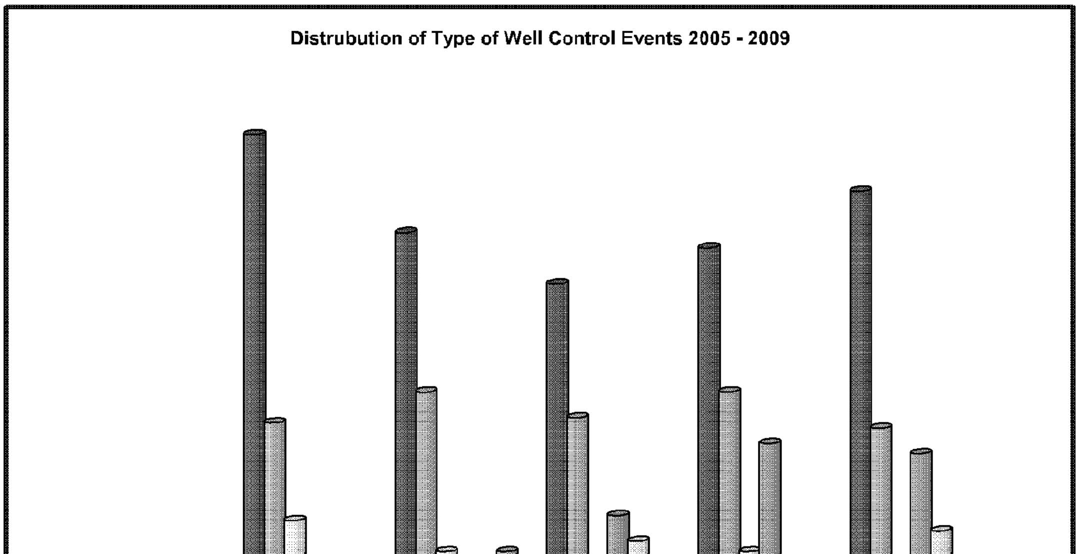
3. WELL CONTROL EVENTS SUMMARY, 2005-2009

The following section contains a statistical analysis of all well control events which occurred during the period from January 2005 until December 2009.

3.1 Well control event types, 2005-2009

A total of 556 well control events were recorded between 2005 and 2009. Of those 556 events, 329 were categorized as kicks, 142 were categorized as "Loss / Gain", 20 were precautionary type events.



	2005	2006	2007	2008	2009
Kick	82	63	53	60	71
Loss / Gain	26	32	27	32	25
Annulus Pressure	7	1		1	
Precautionary			8	22	20
Kick- Pilot hole			3		5
Shallow gas		1			

Chart 11: Well Control event types, '05-'09

3.2 Ballooning Events, 2005-2009

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.

Type	2005	2006	2007	2008	2009	*'05 - '09*
Loss/gain	26	32	27	32	25	*142*
All WCE	115	97	91	115	121	*539*[5]
Ratio	0.226	0.330	0.297	0.278	0.207	***0.263***

Table 11: Ratio of ballooning events to total WCE encountered, '05-'09

NOTE

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

3.2.1 Ballooning versus Kicks, 2005-2009

	2005	2006	2007	2008	2009	*'05-'09*
Loss/Gain events	26	32	27	32	25	*142*
Hours spent on L/G	800	904	856	1,210	1,180	*4,950*
Ave. hours per L/G event	30.8	28.3	31.7	37.8	47.2	***34.9***
Kick events	82	63	53	60	71	*329*
Hours spent on kicks	4,244	2,534	2,750	3,042	4,700	*17,270*
Ave. hrs per kick event	51.8	40.2	51.9	50.7	66.2	***52.5***
L/G time as % of kick time	59%	70%	61%	75%	71%	***66%***

Table 12: Relative impact of Loss/Gain events, '05-'09

	NAM	IME	GGA	FEA	NRS	MED	WAS	SAM	NRY
Loss/Gain events	35	33	18	18	14	9	7	7	1

Table 13: Distribution of Loss/Gain events by Division, '05-'09

NOTE

- Overall, encountering and dealing with a Loss/Gain event has consumed two-thirds of the time taken to handle a kick event.
- NAM & IME encountered most Loss/Gain events. As a proportion of their respective WC events both NRS & MED feature prominently (Refer to Section 3.8 for more details).

[5] In this instance 539 rather than 556 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, 2005-2009

Code	Kick Intensity		Kick Volume	Remark	Reporting
Green	< 0.5 ppg	And	< 10 bbls	Minor / Routine	Rig Manager / General Manager
Yellow	> 0.5 ppg	And	< 20 bbls	Major	General Manager
Red	Any Intensity		> 20 bbls	Critical	Managing Director / Operations Director

Table 14: Kick Severity Matrix

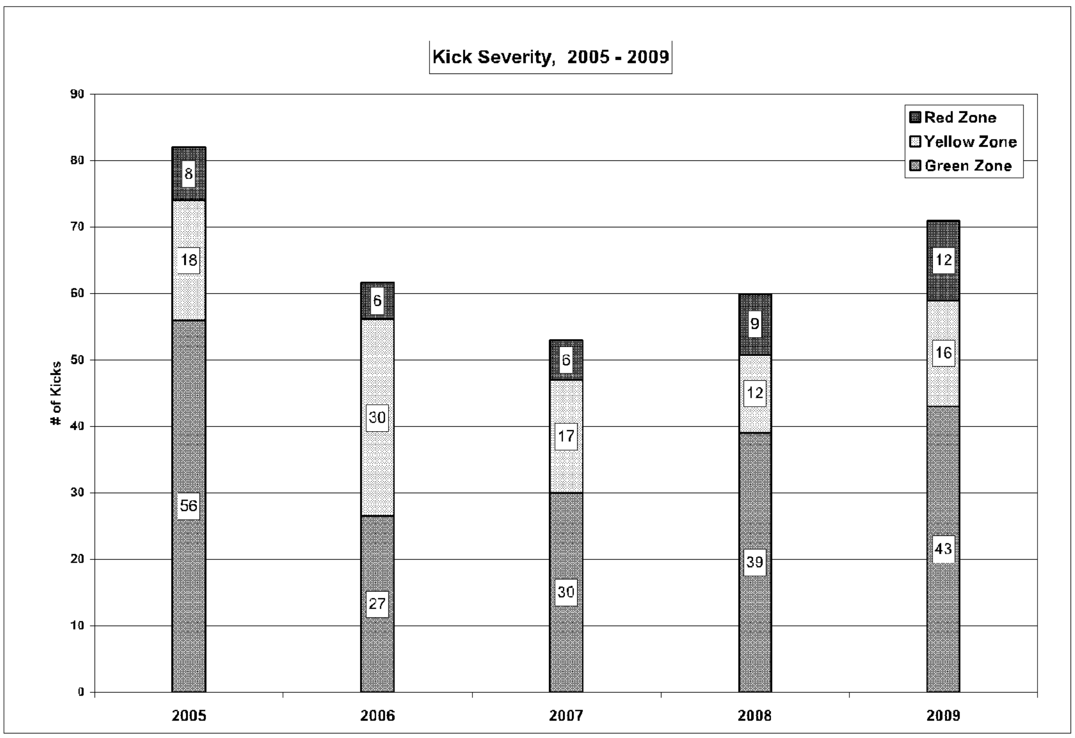


Chart 12: Kick severity for each year, '05-'09

Code	2005	2006	2007	2008	2009	'05 - '09
Green	56	27	30	39	43	*195*
Yellow	18	30	17	12	16	*93*
Red	8	6	6	9	12	*41*
Totals	*82*	*63*	*53*	*60*	*71*	***329***

Table 15: Kick severity distribution summary, '05-'09

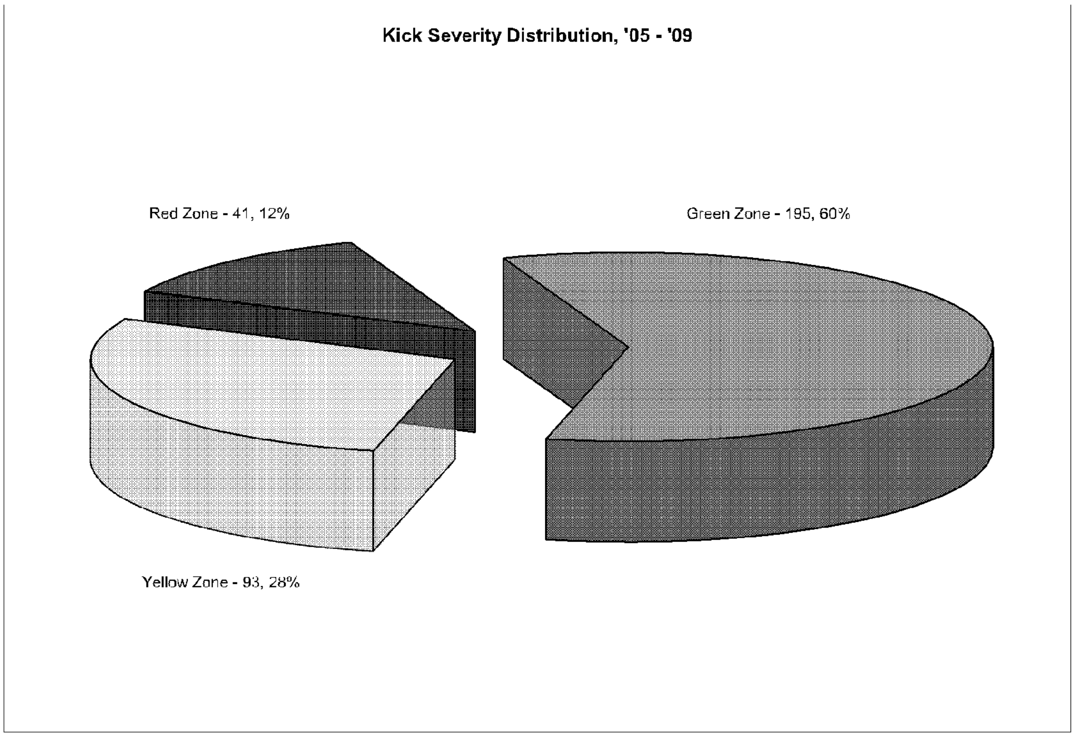


Chart 13: Kick severity distribution, ‘05-‘09

3.3.1 Kick events in the Red Zone, 2005-2009

Year	Division	Rig	Client	Hole size, in	Volume, bbl	Intensity, ppg	Time, hrs
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	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

Table 16: Kick events greater than 20bbls influx volume, ’05-‘09

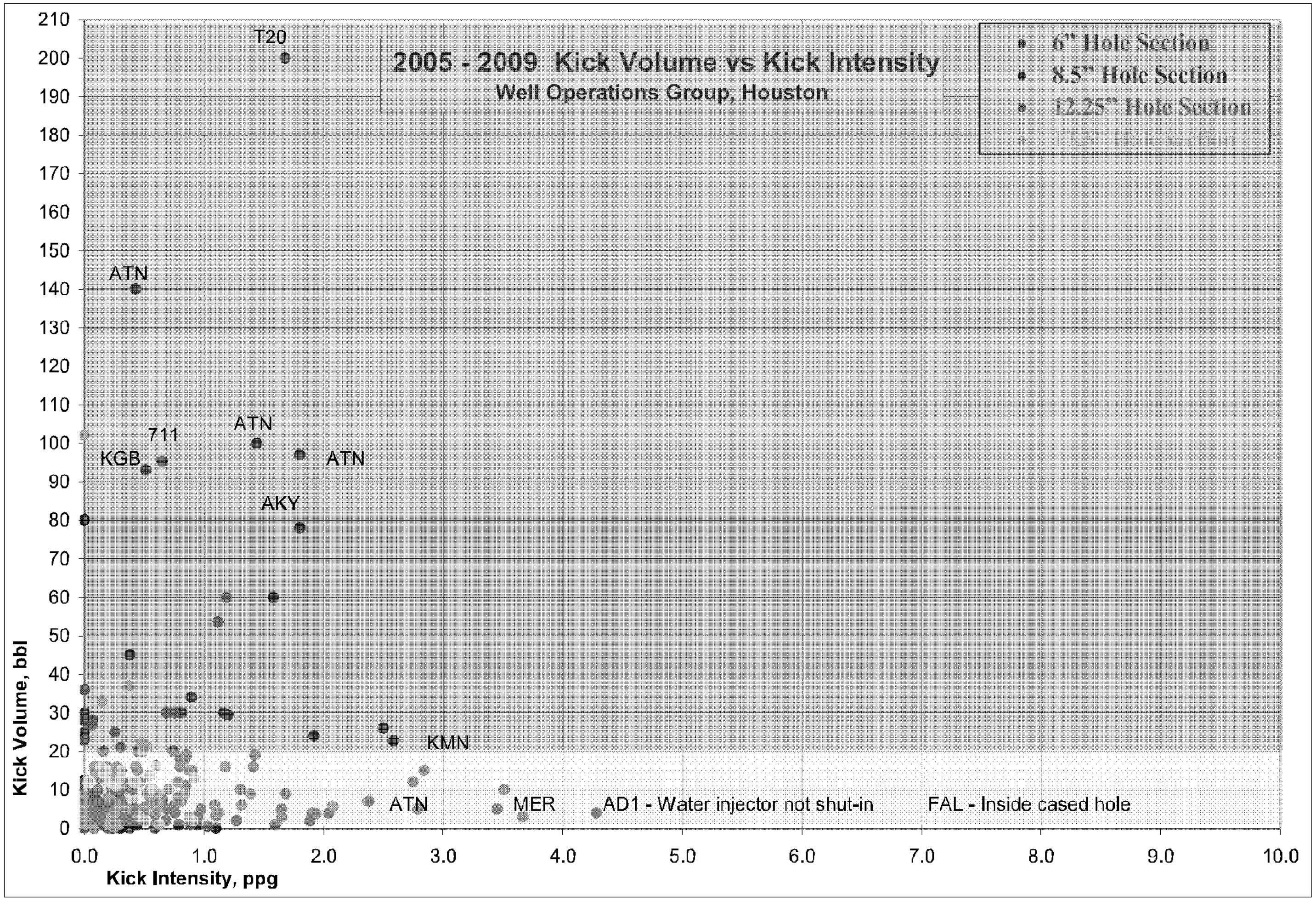
The 38 red zone events recorded on the previous page had the following additional characteristics:

	Mud Type		*Well Type*		*Rig Type*	
	O/SBM	**WBM**	**Exp.**	**Dev.**	**Floater**	**Jack-up**
2009	9	1	7	3	9	1
2008	8	2	8	2	4	6
2007	5	1	5	1	3	3
2006	4	2	5	1	5	1
2005	4	2	5	1	4	2
Totals	**30**	**8**	**30**	**8**	**25**	**13**

Table 17: Summary of Red Zone data, '05-'09

NOTE

- Red zone events are kick events where the influx volume is greater than 20bbls.
- 80% of all red zone events featured oil-based or synthetic-based mud systems.
- 80% of all red zone events occurred on exploration wells.
- 66% of all red zone events occurred on floating rigs (which is slightly above the general trend showing 60% of all WCE occurring on floating rigs, see Section 3.6).

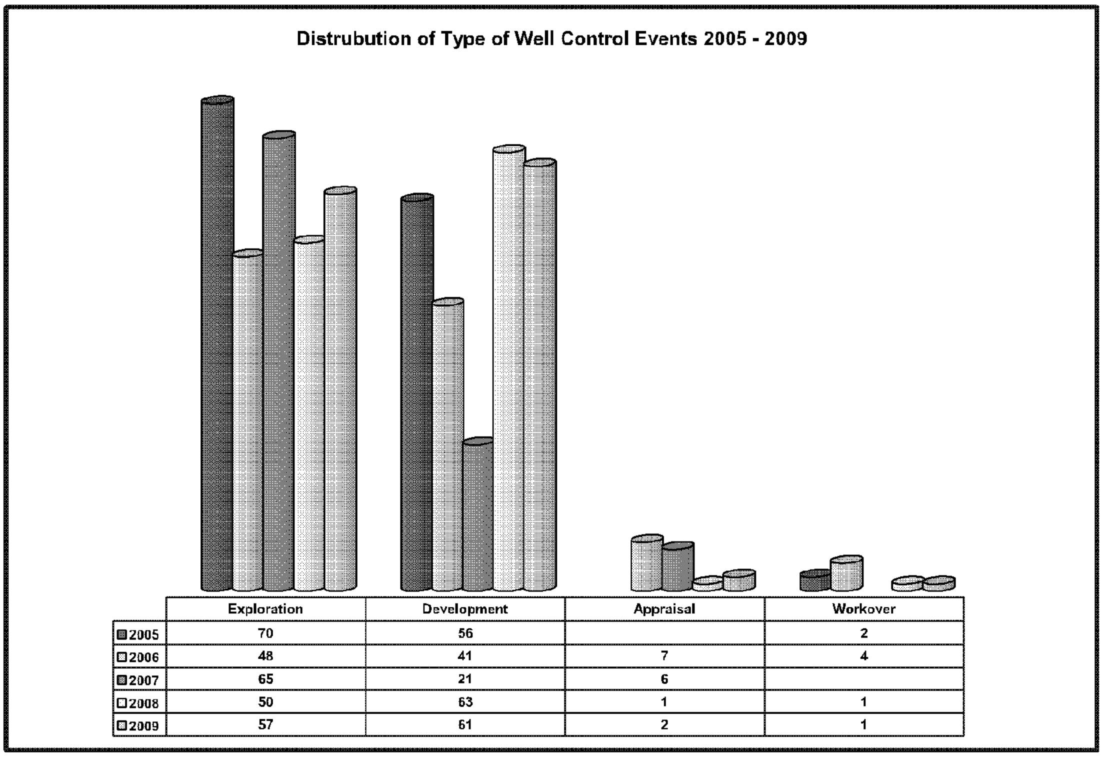


Graph 2: Kick volume versus Kick intensity, '05-'09

3.4 Well control events by well type 2005-2009

	Exp & App	Development	Workover
2005	70	56	2
2006	55	41	4
2007	71	21	
2008	51	63	1
2009	59	61	1
Totals	306	242	8

Table 18: Well control event by well type, '05-'09



	Exploration	Development	Appraisal	Workover
2005	70	56		2
2006	48	41	7	4
2007	65	21	6	
2008	50	63	1	1
2009	57	61	2	1

Chart 14: Well control event by well type, '05-'09

3.5 Well control events by client, 2005-2009

Client	2005	2006	2007	2008	2009	Client Total
ONGC	28	17	11	7	15	**78**
Chevron	22	23	10	9	11	**75**
RIL	14	12	7	11	0	**44**
Shell	6	4	12	10	7	**39**
BP	6	4	4	11	8	**33**
Petrobras	6	8	6	1	4	**25**
TOTAL	5	3	8	4	3	**23**
ENI	3	1	3	6	8	**21**
Petronas	2	5	2	6	4	**19**
BG	1	1	0	4	9	**15**
Nexen	1	1	6	2	3	**13**
Anadarko	2	0	5	1	1	**9**
Statoil	5	0	1	0	3	**9**
JVPC	3	3	0	2	0	**8**
Petrobel	3	1	1	1	1	**7**
AGIP	1	3	2	0	0	**6**
Cobalt	0	0	0	0	6	**6**
Esso	2	0	0	4	0	**6**
ConocoPhillips	1	0	0	0	4	**5**
PCVL	0	5	0	0	0	**5**
Reliance	0	0	0	0	5	**5**
Saudi Aramco	0	0	0	4	1	**5**
Apache	0	0	4	0	0	**4**
ExxonMobil	0	0	0	0	4	**4**
Hess	3	0	0	1	0	**4**
Petrofrac	0	0	0	0	4	**4**
TFE	3	1	0	0	0	**4**
Yearly Total	**117**	**92**	**82**	**84**	**101**	**476**

Table 19: Well Control Events listed by client, '05-'09

NOTE

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

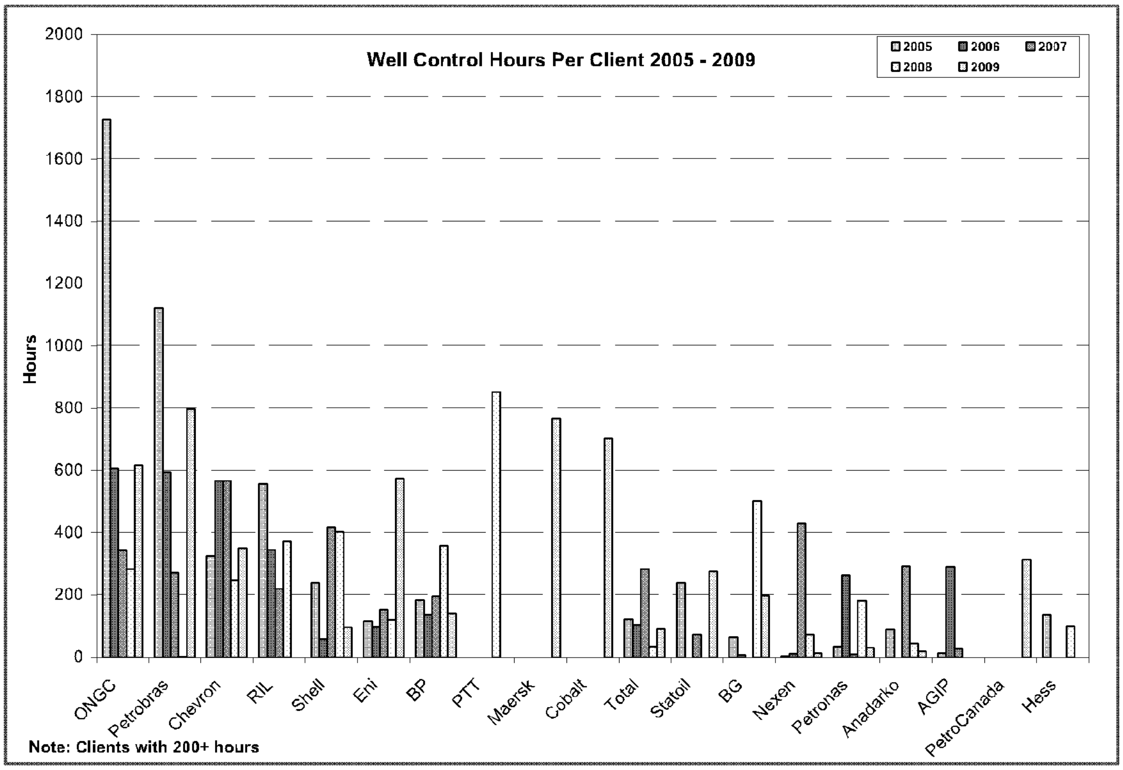
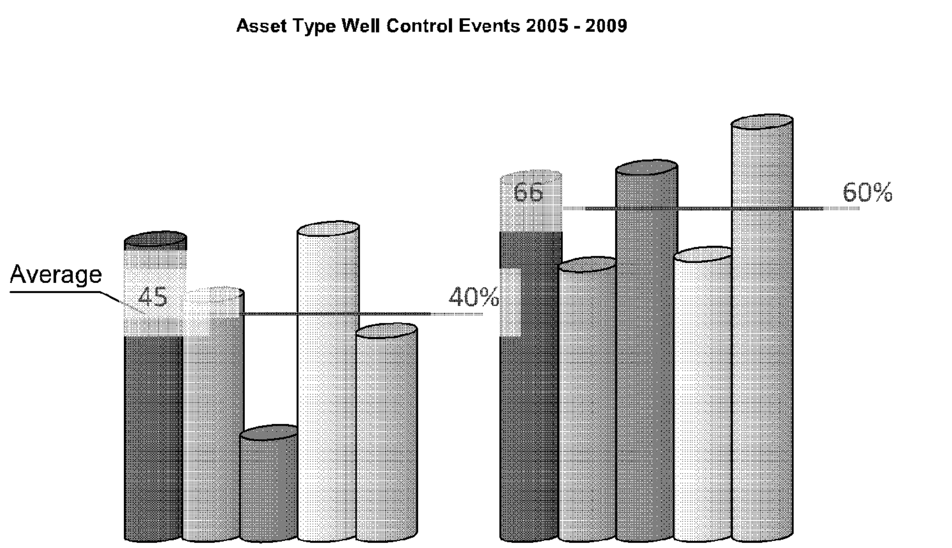


Chart 15: Well Control Event time by Client, '05-'09

3.6 Well control events by asset type, 2005-2009

Asset	2005	2006	2007	2008	2009	Total
Floaters	70	53	72	55	81	331
Jack-ups	58	47	20	60	40	225
Totals	**128**	**100**	**92**	**115**	**121**	**556**

Table 20: Well control event count by rig-type, '05-'09



	Bottom Supported	Floaters
2005	58	70
2006	47	53
2007	20	72
2008	60	55
2009	40	81

Chart 16: Well control event count based on asset-type, '05-'09

3.7 Well control events by hole size, 2005-2009

Hole size	2005	2006	2007	2008	2009	Totals
6"	39	24	12	9	17	101
8.5"	36	34	39	53	48	210
12.25"	27	22	21	38	36	144
17.5"	13	16	20	15	20	84
Totals	**115**	**96**	**92**	**115**	**121**	**539**

Table 21: Number of well control events versus hole section, '05-'09

NOTE

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

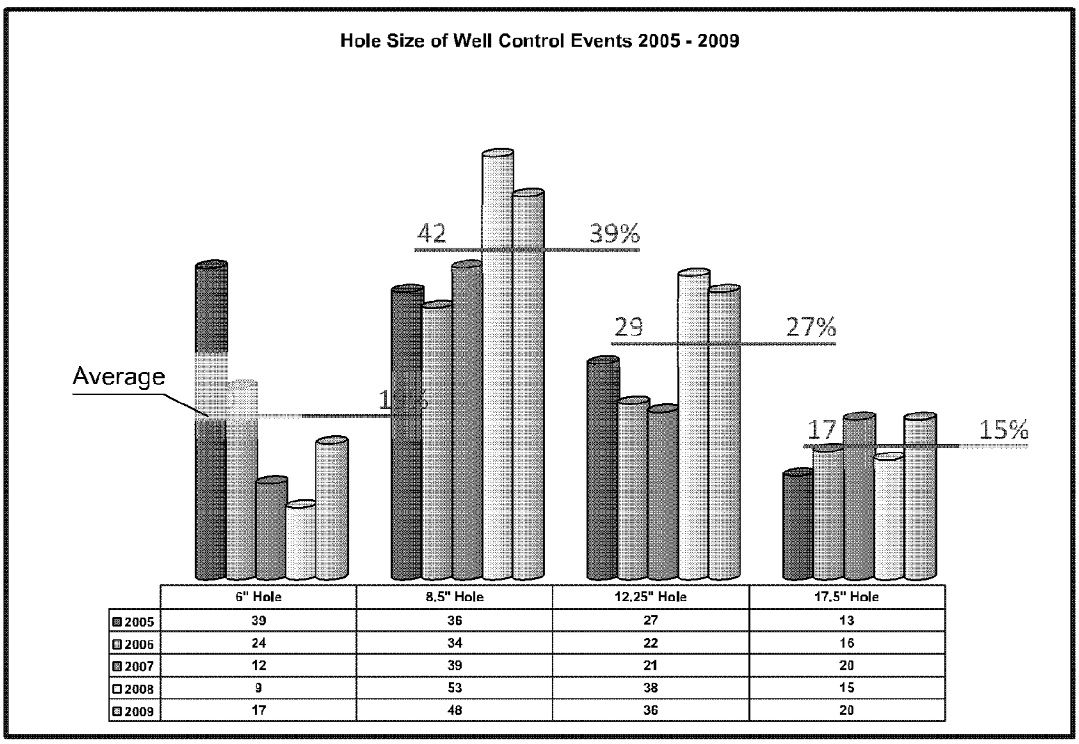
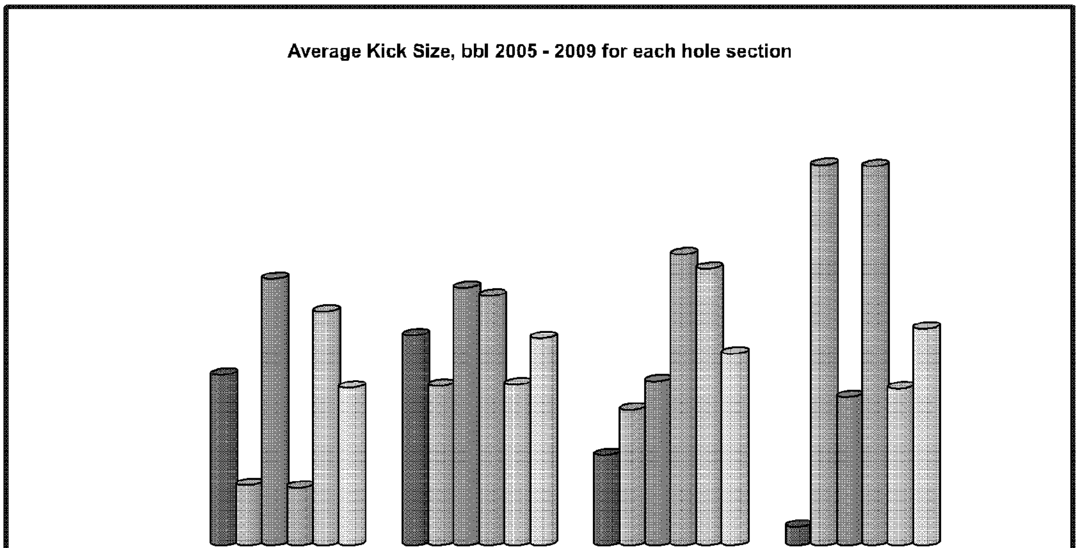


Chart 17: Average number of well control events by hole size, '05-'09

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.



	6" Hole	8.5" Hole	12.25" Hole	17.5" 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
Average	8.4	11.1	10.3	11.6

Chart 18: Average kick volume by hole size, '05-'09

NOTE

- The wide variation in kick volume from year-to-year for each hole section category makes the averaged figures relatively meaningless.
- However, the most common kick section (8-1/2 inch) has the most consistent results and averages 11bbls.

3.8 Well control events and statistics by Division, 2005-2009

DIVISION	WC Hours	Events	Kicks	Hours / WCE
IME	5,452	141	91	38.7
FEA	2,762	94	68	29.4
NAM	4,638	103	59	45.0
GGA	3,388	68	34	49.8
MED	1,339	45	23	29.7
NRS	1,429	46	22	31.0
SAM	3,686	29	17	127.1
WAS	439	22	9	20.0
NRY	127	8	6	14.1
Totals	**23,260**	**556**	**329**	**41.8**

Table 22: Well control event summary by Division, '05-'09

NOTE

- Few events occur in NRY in general, but those that do are handled efficiently.

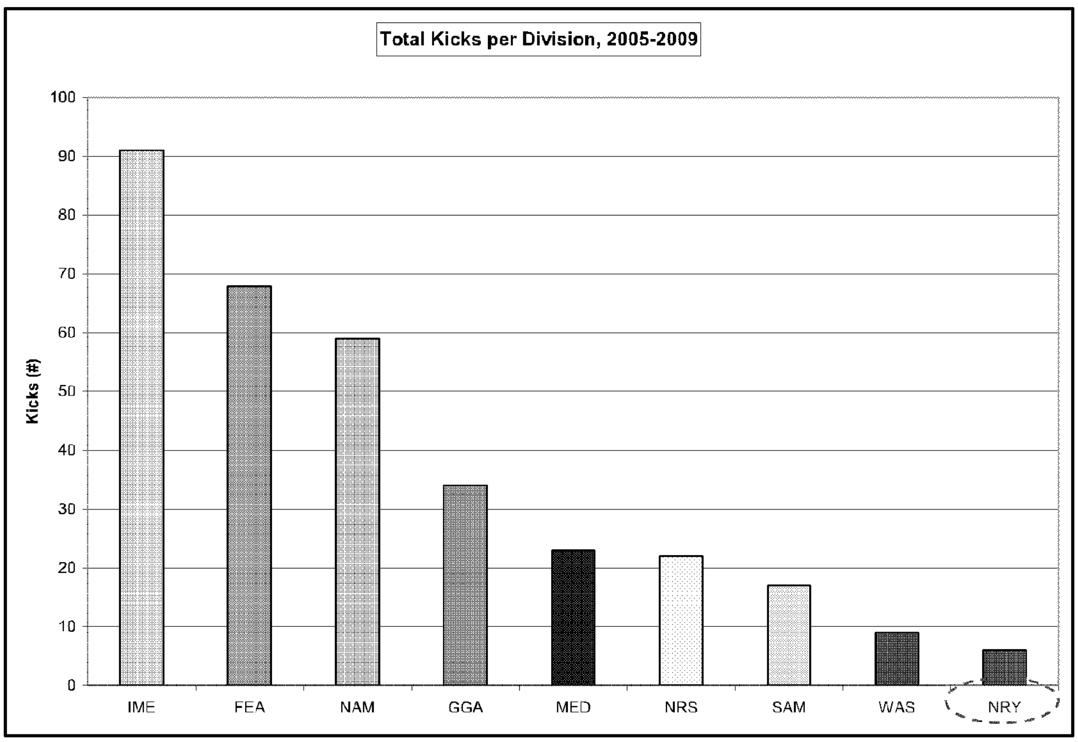


Chart 19: Total kicks taken in each Division, '05-'09

NOTE

- Although NRY has a relatively small sample group of rigs and wells, the well control performance continues to be good. This is in terms of both well control events and kicks, and also the time spent dealing with the events that do occur.

Division	2005	2006	2007	2008	2009	Div Totals
IME	42	29	23	25	22	141
NAM	22	18	24	14	25	103
FEA	23	26	10	17	18	94
GGA	16	10	10	15	17	68
NRS	5	6	8	15	12	46
MED	8	7	8	13	9	45
SAM	8	4	6	2	9	29
WAS	1		2	12	7	22
NRY	3		1	2	2	8
Year Totals	**128**	**100**	**92**	**115**	**121**	**556**

Table 23: Well control event breakdown by Division, '05-'09

NOTE

- NAM, FEA, GGA and SAM each showed an increase in Well Control Events in 2009. The increases were largest in NAM and SAM.

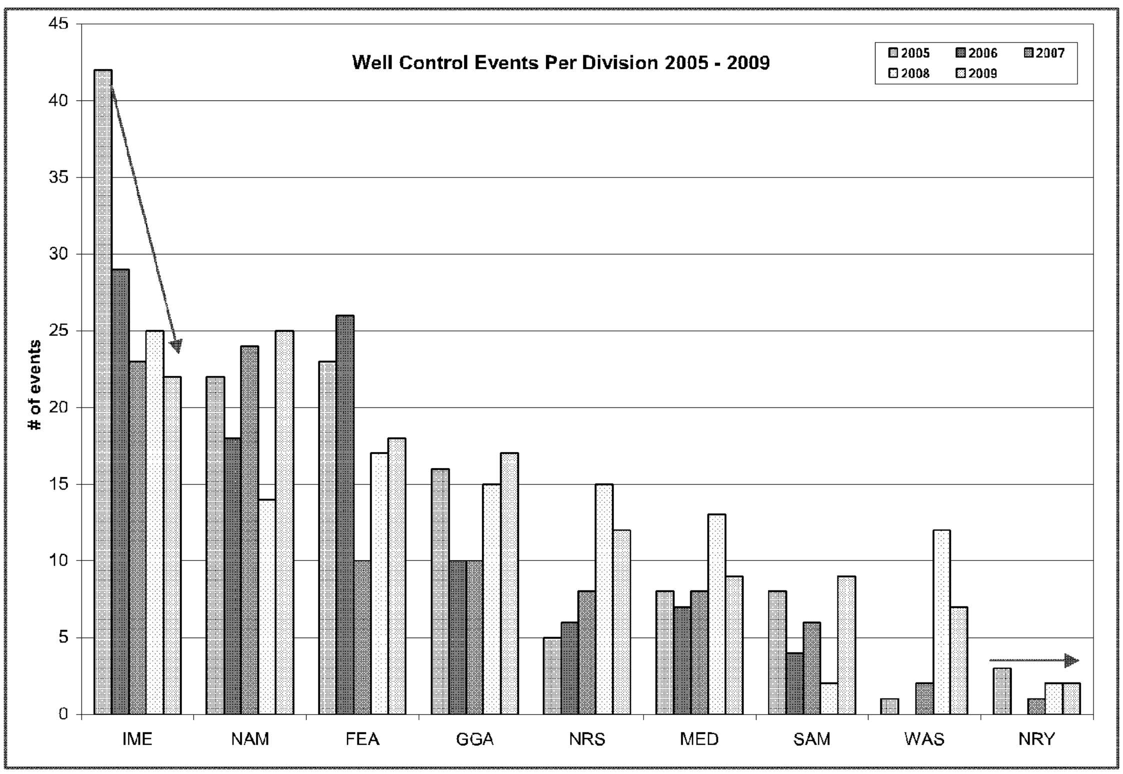


Chart 20: Annual well control events by Division, '05-'09

NOTE

- IME continues to have one of the highest incidence rates for well control events but is also one of the only divisions showing a steadily downward trend between 2005 and 2009.
- NRY continues to have a low incidence of events from year-to-year.

Division	2005	2006	2007	2008	2009	Div Totals
IME	33	20	13	13	12	91
FEA	21	16	6	11	14	68
NAM	7	7	16	10	19	59
GGA	6	7	8	7	6	34
MED	4	6	2	5	6	23
NRS	1	4	5	6	6	22
SAM	7	3	1	1	5	17
WAS			1	6	2	9
NRY	3		1	1	1	6
Year Totals	**82**	**63**	**53**	**60**	**71**	**329**

Table 24: Kick events breakdown by Division, '05-'09

NOTE

- NAM, SAM & FEA show the most significant increase in the number of kicks taken.
- Rig and drilling activity in SAM increased markedly in 2009, which may account in part for their increasing trend.

Division	2005	2006	2007	2008	2009	Div Totals
NAM	12	11	4	4	4	35
IME	5	7	8	5	8	33
GGA	4	2	1	6	5	18
FEA	1	9	3	4	1	18
NRS	3	2	2	5	2	14
MED	0	0	4	4	1	9
WAS	1	0	1	3	2	7
SAM	0	1	4	0	2	7
NRY	0	0	0	1	0	1
Year Totals	**26**	**32**	**27**	**32**	**25**	**142**

Table 25: Loss/Gain events breakdown by Division, '05-'09

	NAM	IME	GGA	FEA	NRS	MED	WAS	SAM	NRY
Loss/Gain events	35	33	18	18	14	9	7	7	1
All WC events	103	141	68	94	46	45	22	29	8
L/G as % of WC events	**34%**	23%	**26%**	19%	**30%**	20%	**32%**	24%	13%

Table 26: Ratio of Loss/Gain to WC events by Division, '05-'09

NOTE

- A larger proportion of WCE in NAM, WAS, NRS and GGA are Loss/Gain events in comparison with other areas.
- Table 12 in Section 3.2.1 showed that time spent on Loss/Gain events was one-third lower than the time taken to recover from kick events.
- Table 22 showed the time per WCE in WAS and NRS are lower than average while NAM and GGA remain well above it, despite having high incidence of Loss/Gain events.

3.9 Total hours and Contract time spent on well control, 2005-2009

	2005	2006	2007	2008	2009	*05 - '09*
Contract hours (from GRS/GMS)	661,606	668,405	655,360	1,092,440	989,539	*4,067,404*
Number of Well Control Events	128	100	92	115	121	*556*
Number of Kicks	82	63	53	60	71	*329*
Hours spent on WC Events	5,707	3,485	3,678	4,413	5,995	*23,278*
Average time per WCE	45	35	40	38	50	*42*
Percentage of contract time spent on WC Events	0.86%	0.52%	0.56%	0.40%	0.61%	*0.57%*

Table 27: Well control data based on operating hours, '05-'09

NOTE

- Although active fleet numbers dropped through 2009 (indicated by reduced contract time), the time spent on well control events increased and therefore so too did the percentage of contract time spent on well control events.

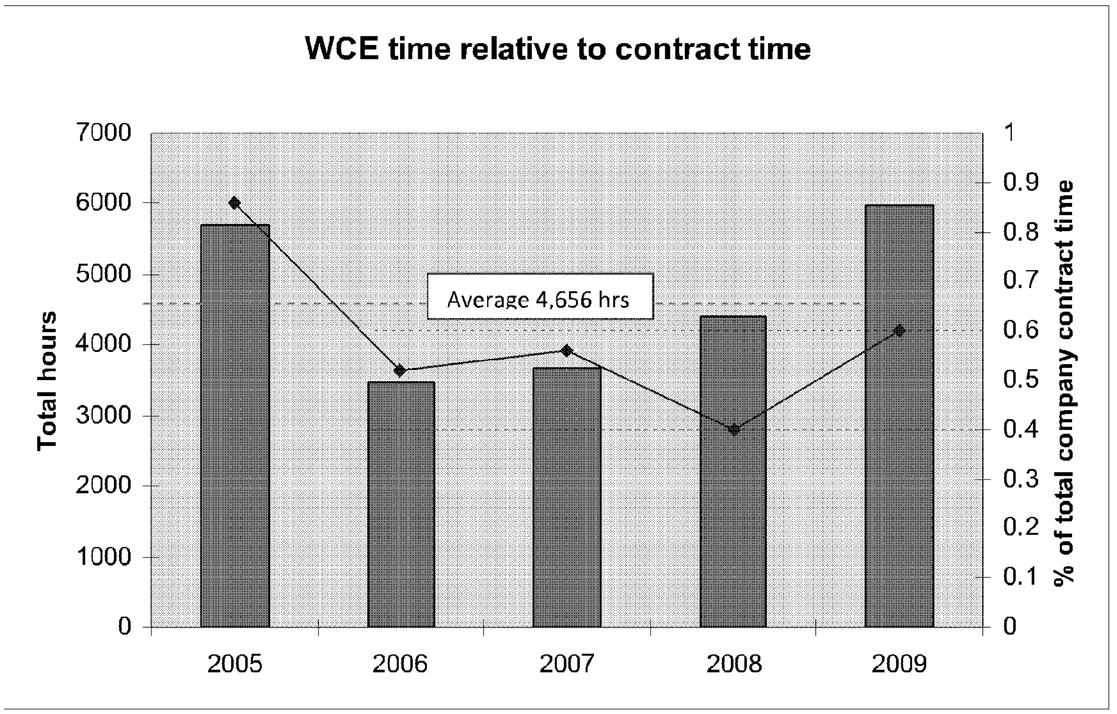


Chart 21: Total hours and % of contract time spent on well control, '05-'09

3.10 Well control event kill methods, 2005-2009

WCE Kill Method	2005	2006	2007	2008	2009	Method total
Drillers	57	33	35	33	35	193
Circulate	23	22	24	41	43	143
Wait & Weight	10	19	17	25	31	102
Bullhead	14	15	6	12	8	55
Bleed Off	13	3	6		1	23
Pump kill mud (pilot)		1	3		5	9
Dynamic kill			1	1	2	4
Volumetric	1	1		1	2	5
Stripping	5			1	2	6
Hot tap		1				1
Mudcap WC method						1
Off-bottom kill				1		1
Lubricate					1	1
Inadequate info	5	4			1	12
Yearly Totals	**128**	**100**	**92**	**115**	**121**	**556**

Table 28: Well control event kill methods, '05-'09

NOTE

- The Drillers Method has historically been most commonly used.
- However, Wait & Weight continues to increase in application and was almost 1:1 in 2009.
- NAM is the only Division where W&W predominated over Drillers Method (62% of kills).
- "Circulate" continued to increase, suggesting more precautionary events.

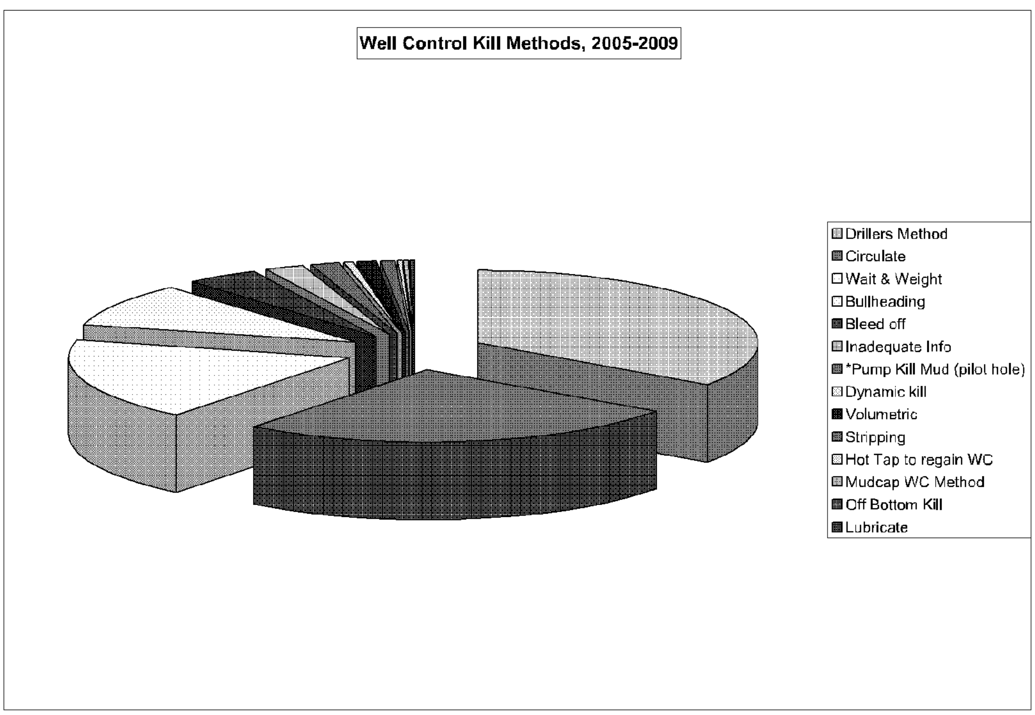


Chart 22: Breakdown of well control event kill methods, '05-'09

3.11 Operations ongoing at time of well control events, 2005-2009

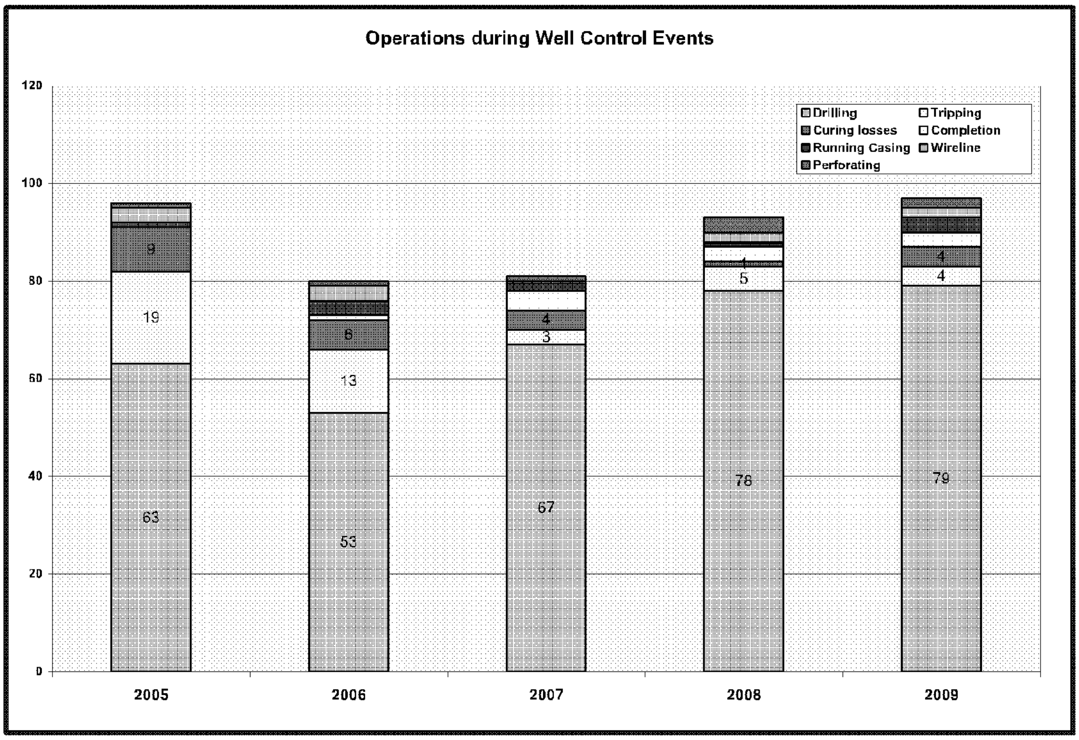


Chart 23: Operations ongoing at time of well control event, '05-'09

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 2009 and from years 2005 to 2009.

5. APPENDICES

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5.1 Summary of Well Control Events *by Division*, 2005-2009

WCE				Kicks			Loss/Gain			Precautionary		
#	hours	hrs/#	DIVISION	#	hours	hrs/#	#	hours	hrs/#	#	hours	hrs/#
141	5,452	38.7	**IME**	91	4,145	45.5	33	936	28.4	9	73	8.1
103	4,638	45.0	**NAM**	59	3,365	57.0	35	1,153	32.9	4	33	8.1
94	2,762	29.4	**FEA**	68	2,213	32.5	18	511	28.4	6	12	2.1
68	3,388	49.8	**GGA**	34	2,118	62.3	18	1,069	59.4	4	47	11.6
46	1,429	31.1	**NRS**	22	952	43.3	14	393	28.1	9	33	3.7
45	1,339	29.8	**MED**	23	1,025	44.6	9	194	21.6	8	52	6.5
29	3,686	127.1	**SAM**	17	3,025	178.0	7	580	82.9	4	9	2.3
22	439	20.0	**WAS**	9	324	36.0	7	91	13.0	6	24	4.0
8	127	15.9	**NRY**	6	102	16.9	1	23	23.0	0	0	0.0
556	**23,260**	**41.8**	**Totals**	**329**	**17,270**	**52.5**	**142**	**4,950**	**34.9**	**50**	**283**	**5.7**

NOTE

- SAM is the most significant outlier in this data set, experiencing relatively low numbers of well control events for the amount of time spent recovering from them.
- NRY figures are low across the board and the well control time is not artificially low due to a high percentage of precautionary events (they have none).
- Considering the high number of well control events and kicks encountered in NAM, there have been relatively few precautionary shut-ins recorded.

5.2 Summary of Well Control Events *by Client*, 2005-2009

WCE				Kicks			Loss/Gain			Precautionary		
#	hours	hrs/#	Client	#	hours	hrs/#	#	hours	hrs/#	#	hours	hrs/#
78	3,572	45.8	ONGC	51	2,802	54.9	18	494	27.5	3	4	1.3
75	2,055	27.4	Chevron	49	1,629	33.2	20	374	18.7	2	4	2.0
44	1,490	33.9	RIL	35	1,273	36.4	6	163	27.1	2	29	14.5
39	1,211	31.1	Shell	15	743	49.5	13	371	28.5	4	8	1.9
33	1,013	30.7	BP	17	574	33.8	10	401	40.1	6	38	6.3
25	2,784	111.4	Petrobras	14	2,151	153.6	9	628	69.8	2	6	2.8
23	630	27.4	TOTAL	16	452	28.3	4	165	41.2	2	10	4.8
21	1,079	51.4	ENI	14	865	61.8	5	186	37.2	2	8	4.0
19	516	27.1	Petronas	12	329	27.4	2	134	66.9	4	19	4.8
15	769	51.3	BG	6	534	89.0	6	190	31.6	4	45	11.2
13	530	40.8	Nexen	6	489	81.5	4	29	7.3	3	12	4.0
9	444	49.3	Anadarko	6	264	43.9	2	174	87.0	1	7	6.5
9	586	65.1	Statoil	7	513	73.3	0	0	0.0	0	0	0.0
8	79	9.9	JVPC	3	30	10.1	3	47	15.6	2	2	1.1
7	107	15.3	Petrobel	5	99	19.8	1	6	6.0	0	0	0.0
6	328	54.7	AGIP	3	127	42.3	1	186	186.0	0	0	0.0
6	703	117.2	Cobalt	4	488	122.0	2	215	107.5	0	0	0.0
6	132	22.0	Esso	0	0	0.0	2	20	10.0	2	17	8.3
5	128	25.5	ConocoPhillips	3	71	23.5	2	57	28.5	0	0	0.0
5	13	2.7	PCVL	5	13	2.7	0	0	0.0	0	0	0.0
5	136	27.2	Reliance	3	62	20.7	2	74	37.0	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	67	16.6	ExxonMobil	1	62	62.0	1	2	2.0	2	3	1.3
4	234	58.4	Hess	1	21	21.0	3	213	70.9	0	0	0.0
4	139	34.6	Petrofrac	3	137	45.5	0	0	0.0	1	2	2.0
4	189	47.3	TFE	2	77	38.3	1	112	111.5	0	0	0.0
476	**19,038**	**40.0**	**Totals**	**285**	**13,874**	**48.7**	**120**	**4,252**	**35.4**	**43**	**232**	**5.4**

NOTE

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