HSE

Health & Safety Executive

OFFSHORE TECHNOLOGY REPORT- OTO 2000 022

Review of SSSV Safety Issues

Date of Issue: March 2000

Health & Safety Executive

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EXECUTIVE SUMMARY

A previous appraisal of the risk impact of annulus safety valves has been reviewed. Failure information has been updated with the cooperation of suppliers, operators, and service companies.

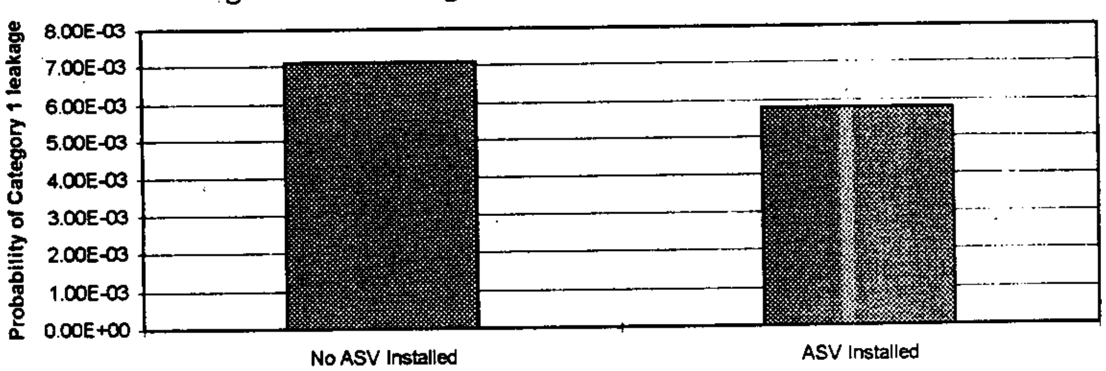
Earlier work assumed that the Mean Time Between Failure (MTBF) for an annulus safety valve would be the same as for a tubing retrievable safety valve, 19 years. On the basis of equipment installed to date, a MTBF of 29 years is suggested. This incorporates a number of early failures which prompted some redesign.

The longer time between failures indicates that the additional workovers required to maintain the ASV equipped well are less than previously predicted. Also the risk of catastrophic leakage from the ASV equipped well is even less than previously projected. These are positive factors which increase the desirability of ASV inclusion.

The downside of ASV inclusion is the intervention required as a consequence of the added components. Information gathered for the review indicates that the duration of many workover elements will be less than previously assumed but that component failure risks may be higher. Some of this is due to incorporation of human failures in the newly gathered information whereas the original analysis did not incorporate these. As a result, the hourly risk associated with the intervention is believed higher than previously assumed but this is partially mitigated by shorter durations and reduced intervention frequency.

It is clear that the through life risk for the gas lifted completion is reduced by ASV inclusion. This conclusion, supported by both the earlier work and this review, stands even in the face of the currently more pessimistic view of intervention risks. The results are summarized in **Figure 1**.

Figure 1 - Through Life Risk of Category 1 Leakage



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INTRODUCTION

The annulus of a gas lifted completion stores a substantial amount of compressed gas. In the event of uncontrolled leakage from a wellhead or tree, this inventory of gas poses a substantial hazard. Valves have been developed to provide a positive annulus seal to prevent the release of the compressed gas inventory. Despite the intuitive benefit of an annulus safety system, they are not universally utilized.

There is widespread belief that simple completion designs are preferable. They are less costly and, more importantly, fewer components minimize potential leak paths and thereby the requirement for major mechanical workovers. It is not surprising therefore that inclusion of the annulus safety valve has been subjected to detailed assessment. Appraisals, conducted for the Health and Safety Executive (Jardine Associates Report entitled "Gas Lift Well: Safety Study") and operators, have indicated that the risk reduction afforded by the annulus safety valve was mitigated by additional workover risk and that well availability was reduced by increased workover frequency.

The methodology used for previous appraisals was a probabilistic, Monte Carlo, approach. There is little doubt that such an approach can be superior to a simple deterministic appraisal but in any statistical endeavour, results depend upon assumptions and data utilized.

Periodic review of risk analyses has merit. When new technology is considered, little historical information will be available. The best that can be done under such circumstances is to assume that reliability is similar to that for analogous equipment. There is nothing essentially wrong with this approach. After a period of use however, failure rate information can be collected to provide a more rational basis for the analysis. In the case of the annulus safety valves being examined, little experience has been available to confidently predict increased workover frequency. Additionally, some of the factors impacting workover risk and duration change with continuously improving technology. As in all areas, equipment causing the greatest difficulty tends to receive the most development attention; improved equipment and methodology can reduce workover duration and risk.

This study does not challenge the methodology of earlier appraisals. It concentrates on the data utilized for earlier work and examines critical input with the benefit of several years of experience and in the light of evolving completion and workover technology. The numerical results of the simple appraisals made cannot be directly compared with the results of the probabilistic analysis but the directional changes indicated are valid.

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The report is divided into segments covering the reliability of annulus safety valves, probable workover frequency and duration, the directional impact of the newly acquired input, and a summary of impressions gained through discussions with equipment suppliers, operators, and service companies.

SPECIFIC OBJECTIVES

The specific objectives of the work are:

1. To assess the failure rate of annulus safety valves on the basis of field experience.

2. To determine the failure probability of critical workover equipment and to assess the likely duration of a workover to repair a failed annulus safety valve.

3. To review previous modelling to isolate the most critical input data and to assess the validity of this data.

4. To assess the relative impact of the information collected on projections of the risk impact of annulus safety valves in gas lifted completions.

5. To generate a concise series of questions and answers summarizing the findings of the work.

CONCLUSIONS

Conclusions are presented as a series of questions and answers.

1. ***Discounting subsea wells fitted with annulus tailpipe valves or check valves, how many wells are fitted with surface controlled annulus safety valves?***

   By first quarter 1997, 179 surface controlled annulus safety valves had been installed.

2. ***Who has installed annulus safety valves?***

   BP, Elf, Marathon, Mobil, Oryx, Phillips and Shell, have installed valves in twelve fields.

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3. ***How have the valves performed?***

Twenty-one valves have failed. More than half of these were the product of one supplier in one installation. This valve has been redesigned and has suffered no further failures. A number of failures have been attributed to imperfect installation by imperfectly trained personnel. On the basis of field data, the mean time between failures of an annulus safety valve is 29 years.

4. ***What additional completion equipment is required for annulus safety valve incorporation?***

Typically, a packoff tubing hanger, which incorporates the annulus safety valve receptacle, and a tubing seal assembly, a safety joint, and a control line for the ASV are required.

5. ***What it is the positive impact of inclusion of an annulus safety valve in a gas lifted completion?***

Over a 20 year well life, the probability of a category 1, catastrophic, leak is reduced by more than 60% by the annulus safety valve.

6. ***Additional completion components invariably lead to a greater probability of intervention for mechanical repairs. How much additional intervention will be required for the annulus safety valve?***

On the basis of the completion designs studied, the ASV equipped wells will probably require 0.7 additional major workovers during their life time. There is no such thing as a 0.7 workover; what this means is that some wells will not require additional workovers. The study predicts a common requirement for wireline interventions (3.13) in both ASV and Non-ASV wells and 2.8 major workovers for the ASV equipped well versus 2.1 for the Non-ASV well.

7. ***Intervention is a riskier business than production. How does the risk level compare for ASV and Non-ASV workovers and what impact does this have over the well's life?***

There is virtually no difference in the hourly risk of catastrophic leakage during workover on ASV or Non-ASV wells. The slightly longer duration and additional requirement leads to an increased risk of Category 1 leakage of about 25%. Some operators optimize risk exposure by combining ASV intervention with other wellbore needs to eliminate any additional risk while taking advantage of the increased security afforded by the ASV during the majority of production operations. Others do not believe the well should be gas lifted without a functional ASV.

8. ***Extra workover requirements lead to more downtime for the annulus safety valve equipped well. What is the expected difference in well availabilities?***

The duration of workovers can vary significantly due to derrick availability, well geometry, and other factors. Workover specialists believe a relatively few additional hours are required for the ASV equipped well workover. The major difference is the additional workover requirement for the ASV well. Based on their input, a difference in well availability of 280 hours, or 0.16%, is predicted over the 20 year well life.

9. ***There is a trade-off between the reduced probability of catastrophic leakage during production and the increased probability of similar leakage during intervention operations. How do these balance out during the well's life? How does this compare with earlier evaluations?***

The risk of catastrophic leakage over a gas lifted well's life, including both production and workover operations, is diminished by 18% by inclusion of an annulus safety valve. Earlier work projected an improvement of almost 30%. The difference is largely attributed to the inclusion of human failure in the failure information used for predicting intervention risks.

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DISCUSSION

METHODOLOGY

The initial step was to contact suppliers of annulus safety valves to determine details of the equipment and application locations. Camco, Baker Oil Tools, and PES (Petroleum Equipment Services) supported the study on the basis that the generic equipment would be evaluated but that the report would not recommend any particular supplier's equipment. While Otis and AVA declined to support the study, they supply only a small percentage of the equipment in the field and, in any event, operators did provide information on their products. On the basis of the information supplied, 7 operators, incorporating experience from 12 fields, were contacted. Again, their support was on a non-attributable basis. Operators were asked to confirm the number and type of valves installed and provide application details including service history. The format of these discussions is contained in the Appendix. Input from the operators was utilized to project the failure rates of annulus safety valves.

The next step was to analyse the previous probabilistic analysis to isolate the input variables of greatest importance. Knowing these, the input of service companies was solicited. Two areas were of interest; the duration of workover elements and the failure frequency of critical items. This information was solicited using an interview form contained in the Appendix.

The final stage was to collate the data retrieved and apply it in a series of simple expressions to assess the impact on the original modelling. Similar evaluations were conducted with the input data used for the original probabilistic modelling and those recovered during the study. On the basis of the projections made, the results which might be expected if the more complex probabilistic model were rerun, utilizing using more appropriate input data, were assessed.

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ANNULUS SAFETY VALVE RELIABILITY

The mean time between failures for an annulus safety valve has been determined by acquiring service times and failure information from users. The information retrieved is shown in **Figure 2** (showing failures by manufacturer) and **Figure 3** (showing failures by field). The failure data is somewhat skewed by a high failure rate associated with manufacturer B product. These failures were suffered in one location where 12 of 15 valves failed, and was addressed by redesign. Since redesign, only 2 of 38 valves have failed.

Figure 2 - Annulus Safety Valve Performance

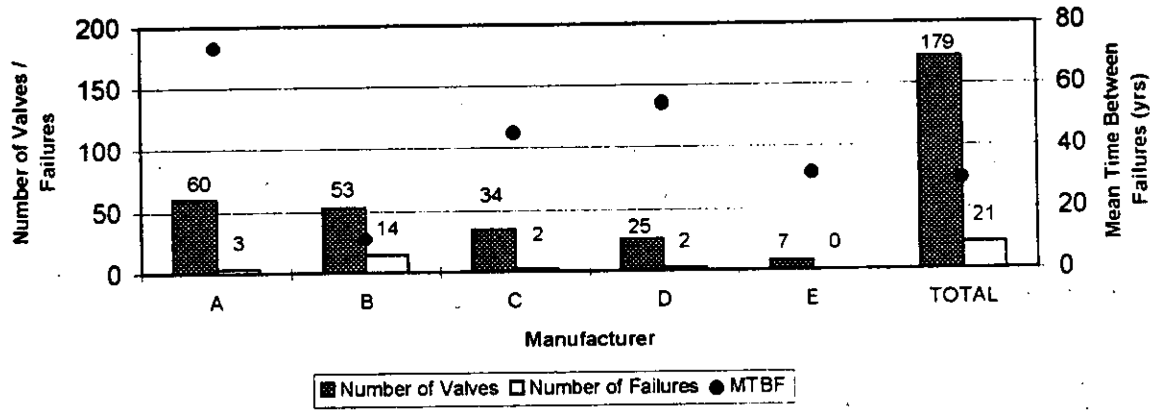
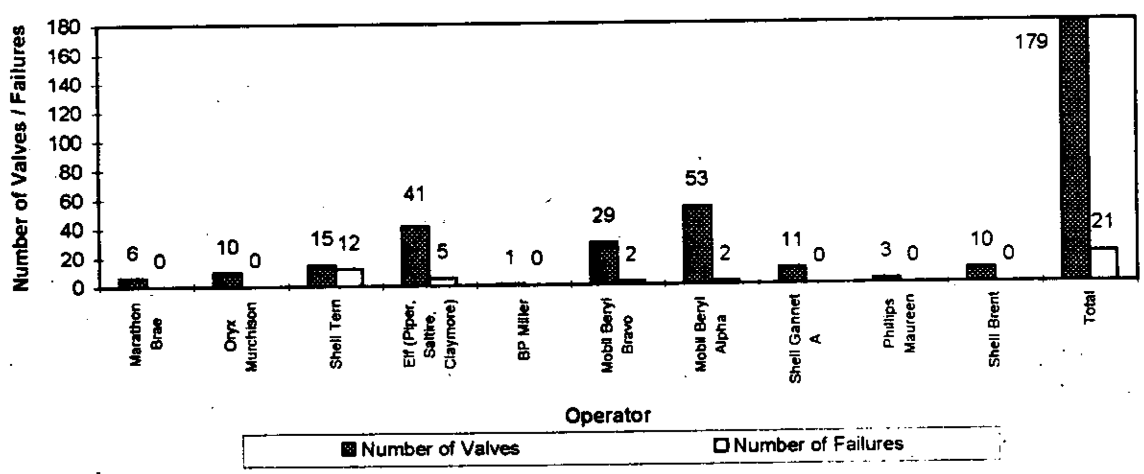


Figure 3 - Annulus Safety Valve Performance



In the original report, the only failure mode identified of the ASV was failure to seal. Contact discussions have provided some further details on failure modes of the valves. These include elastomer seal failures, incorrect setting of the valve by poorly trained field personnel or simply failure to set, the poppet propped open by debris, and movement or expansion of the polished bore receptacle (PBR).

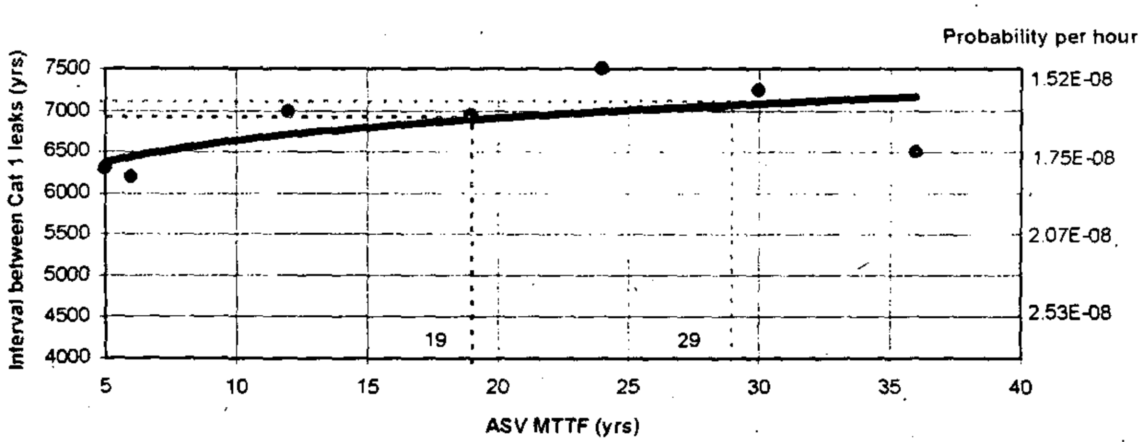
On the basis of the field information, the MTBF is 29 years. If the systematic failure of now redesigned valves is discounted, the MTBF increases to 58 years. The value used in the original analysis was 19 years.

This newly acquired information reduces the probability of a category 1 leak in the production mode and decreases the probable workover frequency.

PROBABILITY OF CATEGORY 1 LEAKAGE

The primary objective of annulus safety valve inclusion is to reduce the probability of category 1, catastrophic, leakage. The impact of extended ASV life is readily projected from the sensitivity work completed in the original study. The results of the earlier work (Figure 5.3.6.1 in the Jardine Report) are replicated in **Figure 4**

Figure 4 - Impact of Extended ASV MTBF



The mean time between category 1 leakage for the non-ASV completion was 4237 years, a probability of $2.69E^{-8}$. Referring to **Figure 4**, the completion fitted with an ASV with a MTBF of 19 years, has a forecast of mean time between leaks of 6944 years, a probability of

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$1.64E^{-8}$. As shown on **Figure 4**, the extended ASV MTBF of 29 years leads to an increased interval of 7080 years or a decreased probability of $1.61E^{-8}$.

Considering the major improvement afforded by the ASV in the initial appraisal, the change is hardly significant. The initially quoted improvement of 63.8% ((6944-4237)/4237) has risen to 67.1% ((7080-4237)/4237).

INTERVENTION REQUIREMENTS

The point to be examined is the increased intervention requirement accompanying ASV use. Table 5.2.1 in the Jardine and Associates Report is replicated below to ease discussion

Table 5.2.1

Workover Requirements

Workover Programme	ASV Installed Y/N	Expected No of Workovers per Well Life	Additional Wireline Interventions	Total Interventions Expected
Replace Entire String	N	0.83	3.13	5.66
Replace Upper String	N	1.27		
Replace Entire String	Y	1.04		6.73
Replace Upper String	Y	2.59		

This table is slightly confusing. It is not clear why the total intervention is not the sum of string replacements and additional interventions. What the current study considers is directional changes, not absolute values, so whatever the esoteric reason for this anomaly may be is of little concern.

The most obvious difference in the completions is the additional components required by inclusion of the ASV. These are:

Table 1

COMPONENT	MTBF
Annulus Safety Valve	19
Safety Valve Control Line	200
Packoff Tubing Hanger	1000
Upper Tubing Disconnect	250
Safety Joint	200

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The differences in workovers per well life, as tabulated in Table 5.2.1, are related to general completion geometry as well as equipment inclusions. For example, failure of tubing below the packoff tubing hanger (with a MTBF of 25 years - not dissimilar to the ASV) requires more work with the ASV in place than without. On the other hand, failures of some components, such as the tubing retrievable safety valve, in the non-ASV completion requires pulling a great deal more tubing in the absence of the intermediate hanger. These differences are not detailed in the original report.

Despite these anomalies, the major difference in the completions, is the additional components. In order to segregate their effect, further consideration of Table 5.2.1 is warranted. The difference in the need to replace the entire string, 0.83 for the non-ASV completion and 1.04 for the ASV design, is due to failures of the packoff tubing assembly and the tubing seal assembly. Everything else added can be replaced by pulling the tubing string above the packoff tubing hanger. Other failures in the tree or casing head are common and covered by the 3.13 additional wireline interventions allocated to both designs.

Most of the intervention impact is in the requirement to pull the upper string. The components necessitating this are the ASV, the safety joint seals and the ASV control line. As shown in **Table 1**, the ASV dominates the requirement. Considering only these three additional components, the impact of extended ASV MTBF is shown in **Table 2**.

Table 2

	NUMBER OF UPPER STRING REPLACEMENTS	
ASV MTBF	**BJA PROJECTION**	**DETERMINISTIC PROJECTION**
19	2.59	2.52
29		2.16
58		1.81

In overall context, this reduces the difference in total interventions required from the 1.07 (6.73-5.66) additional for the ASV design (Table 5.2.1) to 0.71 for a 29 year ASV MTBF or 0.36 for a 58 year ASV MTBF.

The ramifications of a reduced workover requirement are that cumulative workover risk is reduced and well availability increased. These effects are quantified in report sections following.

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INTERVENTION MODE

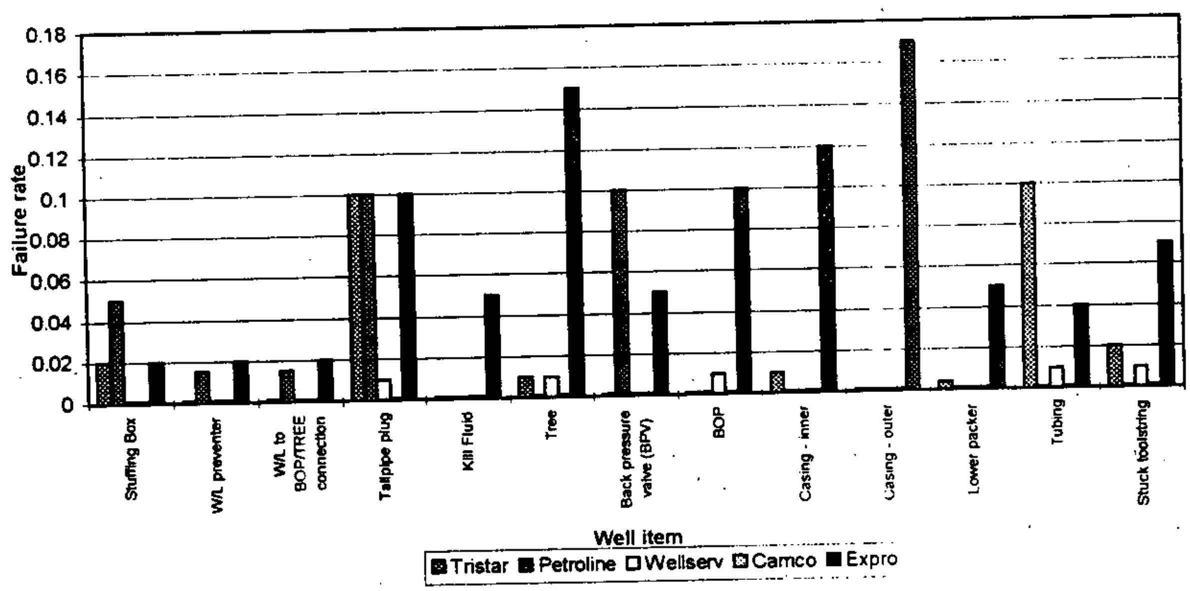
The idea that intervention poses significant risk is unchallenged. The difference in workover frequency may not be as much as originally forecast but it is obvious that even a relatively small increase in high risk exposure could seriously compromise the advantages of annulus safety valve inclusion.

At the outset it was known that the probability of uncontrolled loss of containment was dominated by the common activity of setting a tailpipe plug in all the workovers considered. The data retrieval exercise conducted looked at the activities originally considered. (The workover programmes may not conform to everyone's expectation but to introduce changes would have unnecessarily complicated comparisons.)

There is a major difference between the data collected and that originally used. The original work did not include human error; the information retrieved from wireline operators does. This leads to an escalation in the risk associated with some intervention operations.

The failure probabilities developed from service company input are shown in **Figure 5**; blank entries indicate a lack of input rather than zero risk.

Figure 5 - Failure Rates for Intervention Tasks/Equipment



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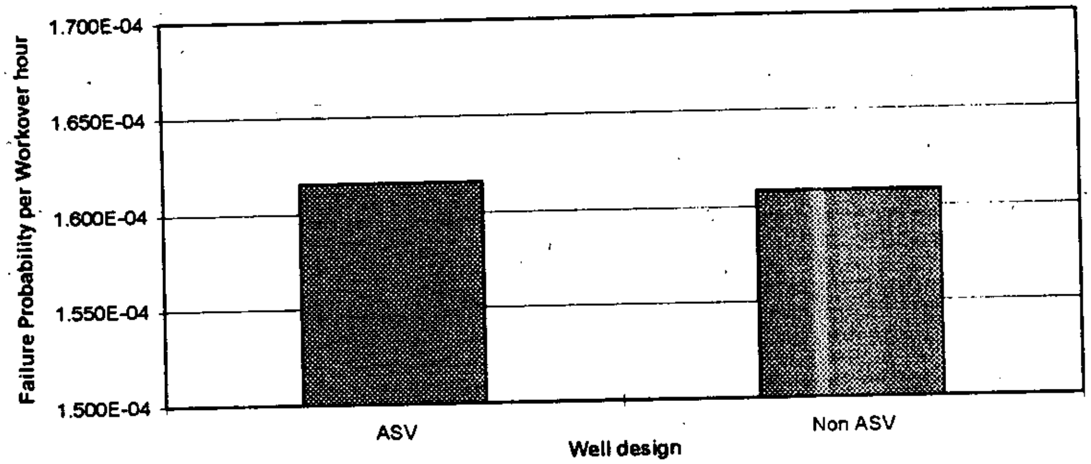
Results are averaged and compared in **Figure 5** with the values used in the original analysis in **Table 3**. In almost all instances the service company input leads to a greater risk level than used in the original analysis.

Table 3 - Failure Probabilities per Workover Hour

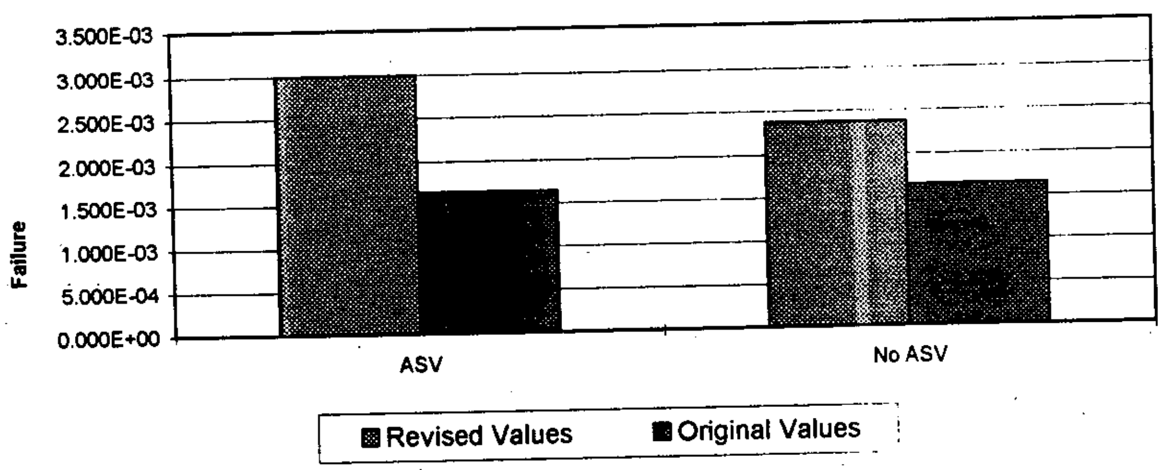
Item	PROBABILITY PER HOUR	
	Average Responses	Previous Value
Stuffing Box	3.24E-04	1.00E-03
Wireline Preventor	1.75E-04	8.90E-05
Wireline to BOP/Tree connection	2.11E-04	6.80E-05
Tailpipe Plug	5.24E-04	2.50E-07
Kill Fluid	2.91E-04	1.00E-06
Tree	1.10E-03	8.80E-06
Back Pressure Valve (BPV)	6.27E-04	1.00E-07
BOP	1.32E-03	1.00E-05
Casing - Inner	2.49E-07	7.61E-07
Casing - Outer	9.70E-07	2.85E-06
Lower Packer	1.54E-07	1.14E-07
Tubing	2.85E-07	6.09E-06
Stuck Toolstring	1.05E-03	1.00E-03

Figure 7 - Failure Rate for Entire String Replacement



The impact of the newly acquired data can be readily appreciated by referral to **Figure 8**. What is illustrated is the product of hourly risk and durations, a measure of the cumulative risk of interventions during the well life. This is a reasonable, although not necessarily completely accurate, measure of the additional intervention risk penalty. It is noted in the synopsis of operator discussions that at least some operators effectively manage the risk by incorporating the ASV but not necessarily intervening immediately upon its failure. In this way, intervention risk would approach that of the completion without the ASV but for some fraction of the well life production risks would be diminished.

Figure 8 - Cumulative Intervention Risk



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PRODUCTION AVAILABILITY

One of the downsides of inclusion of the ASV is reduced well availability with attendant higher production costs. Newly acquired data impacts this in two ways; reduced intervention requirement and workover durations.

The accepted definition of availability is:

$$A = \frac{MTBF}{MTBF + MTTR}$$

where MTBF = mean time between failures
MTTR = mean time to repair

The original, more elegant, Monte Carlo simulation provides a range of probable availabilities which cannot be replicated with a simple deterministic approach. Nevertheless, the directional impact of the newly acquired information can be projected.

Table 4 summarizes the deterministic values used in calculation.

Table 4 - Well Availability

	Non-ASV Completion		ASV Completion	
	(Original)	(New)	(Original)	(New)
Wireline Workovers	3.13	3.13	3.13	3.13
Major Workovers	2.1	2.1	3.63	2.81
Total Downtime (hrs)	1983	363	3360	454
Well Availability (%)	98.87	99.79	98.08	99.74

	(Original)		(New)	
	Wireline	Major	Wireline	Major
MTTR (hours)	30	900	30	128
Well Life = 20 Years				

The wireline frequency in all cases remains as the original work. The number of major workovers has been varied in accord with the ASV MTBF as determined in the current study. The times for the wireline and major workovers have been modified, in the "new" columns, to

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reflect workover specialist input. Total downtimes are simply the product of the number of workovers and the hours required per workover.

As can be seen, the difference in well availability is not large, approximately 0.05% or some 87 hours over a 20 year period. Using the same calculative method, and the original data, the difference in availability is a 0.82% or 1440 hours. Directionally, the improvement is significant. It must be emphasized that this single valued estimate is not as valid as the mean availability shown in the original report. What these numbers do reinforce is the intuitively obvious conclusion that if there is less difference in the number of major workovers (facilitated of course by the longer life of the ASV) and workover times are shorter, the difference in well availability must be less.

Lest there be concern that these availability calculations are unduly influenced by the reduction in waiting time for the derrick (which is, after all, a fairly arbitrary and random variable), the calculations were repeated using the same waiting time for both "original" and "new" workover time estimates. The results are shown in **Table 5**

Table 5 - Well Availability

	Non-ASV Completion		ASV Completion	
	(Original)	(New)	(Original)	(New)
Wireline Workovers	3.13	3.13	3.13	3.13
Major Workovers	2.1	2.1	3.63	2.81
Total Downtime (hrs)	472	363	747	455
Well Availability (%)	99.73	99.79	99.57	99.74

	(Modified Original)		(New)	
	Wireline	Major	Wireline	Major
MTTR (hours)	30	180	30	128
Well Life = 20 Years				

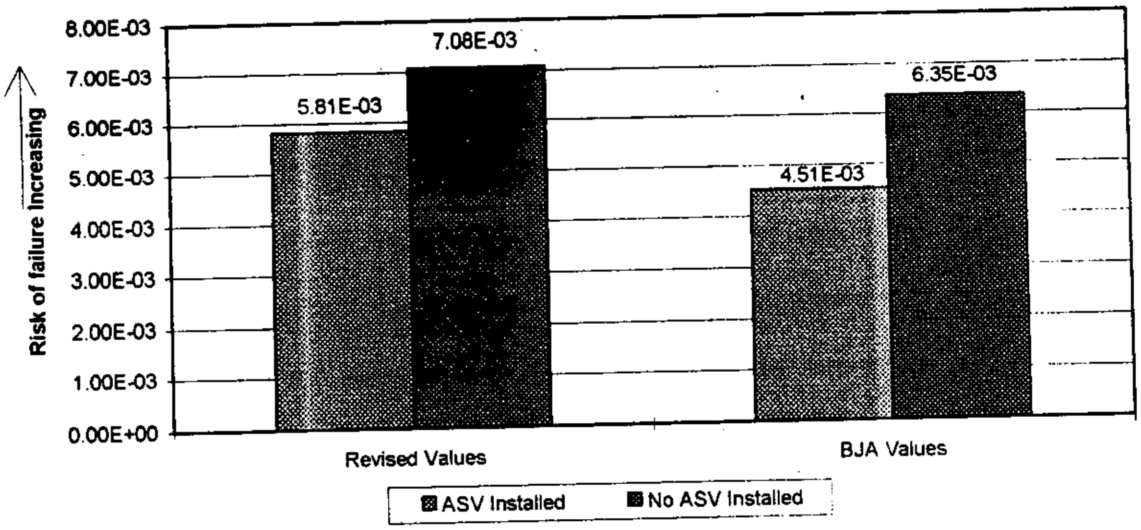
The only values which differ are the now modified "original" capabilities. The effect of this is to reduce the difference in availability for the "original" calculation from 0.82% (1440 hours) to 0.16% (280 hours).

However the problem is approached, the reduced requirement for major workovers afforded by the newly acquired projection of ASV life is worthwhile in terms of reducing unavailability.

NET IMPACT

All the preceding material, comparing completions with and without an annulus safety valve skirts the big question: "Does the ASV increase or decrease risks over well life?". In other words do the relatively brief high risk periods (interventions) lead to a sufficiently great risk to overwhelm the longer term improvement during production. The answer is shown in **Figure 9** which depicts the result using both the original analysis and the revised projections.

Figure 9 - Through Life Risks for Revised and Original Values



As can be see the through life risk is reduced by inclusion of the annulus safety valve As mentioned above, it may be possible to further reduce risk by carefully managing intervention strategy.

SYNOPSIS OF OPERATOR CONTACT DISCUSSIONS

Seven operators provided information covering twelve fields. In addition to application details and results, operators provided insight on their response to ASV failures, whether or not the valves hindered well accessibility, and offered general impressions on the usefulness of ASVs.

None of the operators used exclusively one make of valve. The valves were positioned at widely differing setting depths and all valves were hydraulically actuated. Valves had been in place from just a couple of weeks to several years. Most of the valves are leak tested every

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six months. The additional leak paths introduced with the inclusion of the ASV had not proved a problem with any of the operators.

Most of the operators had experienced at least one valve failure. Failure response varied from doing nothing (as the perceived hazard from the workover was seen as greater than continued production) to changing out the valve upon failure. The general consensus was that if the reservoir was producing unaided, the valves would be changed during the next scheduled workover. If the valve fails during gas lift operations some operators install a non-return valve in the side outlet of the tubing head to perform a similar function. Other operators would not continue gas lift without a functional, downhole, annulus safety valve.

The ASV has proved not to be an inconvenience or a barrier to scheduled workover for other well components or reservoir management. Installing the ASV completion takes just a few hours more.

Overall impressions ranged from "They are an important additional safety feature." to "They are very expensive and their overall benefit is doubtful". As in most cases, impressions stem from personal experience and one bad experience with an ASV completion clouds judgement even if that experience was several years ago. Most operators agree that ASV reliability, and compatibility with the rest of the completion, has increased markedly in recent years.

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CONTACTS

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DUNDEE Angus DD2 4HU
Contact: Mr Bill Marr

Wellserv Plc
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Altens Industrial Estate
ABERDEEN AB1 4LF
Contact: Mr Tom Brighton

Western Atlas International Inc
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Contact: Mr Brian Dundas

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Pitmedden Industrial Estate
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Contact: Mr Sid Smith

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Kirkhill Industrial Estate
Dyce ABERDEEN AB21 0GR
Contact: Mr Colin Mackie

Halliburton Drilling Systems
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Contact: Mr George Maitland

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APPENDIX

ANNULUS SAFETY VALVES - TELEPHONE CONTACT CHECKLIST

General

Confirm the number and type of valves installed in the field and installation date; date wells came on stream.

Approximate setting depth and the control mechanism employed (if unknown from company literature).

How often is the ASV and the SCSSV tested? How?

Has the inclusion of the ASV introduced any additional leak paths into the completion? If so, how many?

Reliability

Has the ASV or any part of the annular safety system ever failed?

Failure mode (Open/Closed?)
Time to failure
Consequences of failure (well shut in - workover - nothing?)
Condition of Annulus (what happens to the gas?)
Remedial action (workover?)

Have you ever had to perform a workover as a direct result of the inclusion of the ASV?

During routine workovers have you had to give special consideration or encountered any additional problems due to the presence of an ASV?

Additional risks
- Operational
- Increased workover frequency
- Elevated risk during workover?
- Hindrance on well accessibility?

How long did it take to run the completion with the ASV?
Who do you use for Wireline Operations/workovers?

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WIRELINE/ EQUIPMENT SPECIALIST CONTACT

The form/questionnaire used to obtain failure rates and intervention times.

PREPARE WELL FOR WORKOVER	
Activity	**Duration (hrs)**
Set tailpipe plug	
Install circulation valve and kill fluid	
Remove instrumentation/flowlines	
Well left waiting for derrick	
Skid derrick to slot	
Install BPV	
Nipple up BOP and test	

RUNNING NEW COMPLETION	
Activity	**Duration (hrs**
Press test new completion/rig wireline	
Release disconnect ass from pack off tubing hanger	
Rig up wireline from drift run	
Run in hole and unlock safety joint	
Rig down wireline and install dart in BPV	
Install gas injection valve	
Pull tailpipe plug	
Production handover	
Stuck toolstring freed?	

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SPECIFIC FAILURE RATES	
Item	**Failure Frequency**
Stuffing Box	
Wireline Preventor	
Wireline to BOP/Tree connection	
Tailpipe Plug	
Kill Fluid	
Tree	
Back Pressure Valve	
BOP	
Casing Inner	
Casing Outer	
Lower Packer	
Tubing	
Stuck Toolstring	

Above are the points I would like to discuss consisting of hours for each activity and failure rates for each item of equipment.

1. Are plugs and nipples still used, or have bridge plugs taken over? If so, how much more reliable and easier to use are they?

2. What percentage of workovers are performed as a result of mechanical failure? Of these, what percentage are caused by the production safety valve?

3. Has the inclusion of an ASV ever hindered you in performing a workover? If so, how?

4. Have you ever had to perform a workover as the result of failure of an ASV? Or of a GIV?