PIPELINE EMERGENCY SHUTDOWN VALVE (PESDV) INTEGRITY STUDY: CASE STUDY OF UNOCAL THAILAND LIMITED

INTRODUCTION

Pipeline Emergency Shutdown Valves (PESDVs) are used on offshore production platforms to provide a secure isolation between the contents of the pipeline and the processing facilities on the platform. Under normal operations the PESDV will be in the open position allowing hydrocarbons to flow either from the pipeline to the facility or from the facility to the pipeline. The PESDV is closed in two general scenarios.

1. To provide isolation as part of a normal process shutdown when equipment on the platform is shutdown and processing of the hydrocarbons ceased. This type of shutdown has many designations in the industry but will be referred to here as a process shutdown or PSD.

2. To provide isolation during an emergency situation/shutdown either on the platform or the pipeline itself. This would include a leak, fire or explosion event where personnel safety, environmental pollution or asset damage would be a primary concern. This type of shutdown is typically referred to as an emergency shutdown or ESD.

The PESDV is an 'active' type of safeguard. 'Active' means that the system is required to respond by moving from one state to another as a result of a measurement or signal. For a PESDV the valve is required to receive a signal (either from a manual station or from a sensor via a shutdown system) and closed on demand. As an active safeguard the PESDV has the following important functions:

1. It has to be reliable on demand, that is, it must be closed when requested.

2. The PESDV has to provide good isolation against the pressure in the system in order to prevent hydrocarbons flowing in either direction.

3. It has to have high availability. This means that the valve should not be closed when not requested. When this occurs it may result in a process upset, loss of production and loss of revenue to the company.

4. The PESDV must maintain a good isolation under emergency conditions. The impact of an emergency event on the platform or pipeline (such as fire or explosion) should not prevent the valve actuating/closing and the valve needs to maintain good isolation for the duration of the emergency.

This study will address these issues with regards to the main offshore complexes feeding the 3 sales gas pipelines that direct gas from the Gulf of Thailand to the onshore processing and distribution facilities at Rayong on the Eastern Seaboard of Thailand.

Objectives

1. To identify the general arrangement of PESDVs in the Thailand offshore oil and gas operations.

2. To identify the risk associated with failures of those PESDVs.

3. To conduct a pilot test on PESDVs to ensure reliability on demand and adequate isolation.

Scope

The scope of this study will be limited to the test of PESDVs in Unocal Offshore Fields. Cost effectiveness is not in this scope.

Benefits

1. Provide a guideline that outlines the testing requirements for PESDVs on Offshore Platforms

2. To maintain the operational integrity of PESDVs.

LITERATURE REVIEW AND RELATED THEORIES

Literature Review

Past incidents, practices and studies are all valuable resources for the Oil and Gas industry to review and ensure that their facilities are fully protected and complied with the possible and recognized standards. A review of each of these documents in given in the attached Appendices and a summary of the salient points relating to PEDSVs is given below.

The Piper Alpha Incident

This major incident happened in 1988 on an operating offshore platform in the U.K. sector of the North Sea. The results of the incident provided a considerable number of lessons learned for the for petroleum exploration and production industry. One of the contribution causes to the large human and asset loss was the failure of the integrity of the PESDV system. The incident escalated rapidly and catastrophically once the contents of the attached high pressure gas pipeline were released and ignited. Despite being designed according to best practices at the time, the results of the investigation demonstrated the importance of PESDVs and led to a number of key recommendations, made in the Lord Cullen report of the incident, to be implemented or considered on existing and new offshore platform designs.

#47 The arrangements for activation of the PESDV

#48 The vulnerability of PEDSVs to severe accidents including fire, explosion and vibration.

#48 The requirement for fire risk analysis including active and passive fire protection and the availability of the fire protection elements. This included the need for such protection on PEDVs.

#52 Development and/or verification of hydrocarbon fire and similar tests. This included fire testing requirements for PESDVs and associated components.

#71 Review of pipeline emergency procedures and manuals which included the use of the PESDVs to isolate the contents of a pipeline from a processing facility..

#72 Review of procedures for shutting down production on an installation in the event of an emergency.

Topside Emergency Shutdown Valve (ESV) Survivability

This study was in response to recommendation #48 from the Lord Cullen report on the Piper Alpha incident. (See Appendix D for more detail)

A Study of the Dynamic Response of Emergency Shutdown Valves Following Full Bore Rupture of Gas Pipelines

Mahgerefteh (1997) studied on a numerical simulation based on the method of characteristics is employed to study the dynamic response of ball valves and check valves following full bore rupture of high pressure gas pipelines. (See Appendix D)

Emergency Pipe-line Valve Regulations (Safety Instrument SI 1989/1029)

The Regulations provide for the protection of Offshore Installations, and persons on them, which are connected to pipelines conveying flammable or toxic substances, from dangers arising from the uncontrolled release of such substances.
(See Appendix D)

METHODOLOGY

The test method in this study can be listed in steps and explanations below:

- Describe the facilities including PESDVs
- Assess the risks
- Identify safe guards
- Identify testing requirements (Test opportunity and methods)
- Conduct the test
- Conclude the test results including recommendations

Description of Facilities

General

Unocal Thailand has developed offshore fields in the Gulf of Thailand (GoT) since 1980. Erawan was the first gas field; it started to produce gas in 1982. The diagram below give a simplified view of the platforms and interconnecting pipelines for Erawan field. The field consists of a one Central Processing Platform (CPP), a 150-man Living Quarters (LQ), four smaller remote Production Platforms (referred to as 'Phase 1s') bridged connected with a Wellhead Platforms and other remote Wellhead Platforms (WHP or Single Platforms). The following additional fields were developed gradually:

Satun Field in 1985
Platong Field in 1985 (initially gas field then became oil & gas field in 2000)
Funan Field in 1991 and;
Pailin Field in 1997

Platforms & Floating Units

The above field developments consist of one CPP and additional remote Wellhead Platforms (WHPs). The WHPs are connected by one or more various sizes of submarine pipelines and a PSEDV at the discharge end of each pipeline.

Central Processing Platform (CPP)

This is the heart of the field. It normally consists of a processing platform and bridged connected Living Quarters (LQ). A typical facility (such as Erawan) consists of a CPP, “A” Wellhead Platform and Compression Platform (CP). The processing platform is equipped with the following; separation, dehydration, stabilization and compression processes. A numbers of PESDVs are installed around this complex to enable isolation of all incoming and outgoing hydrocarbon fluids to attached pipelines as shown in Figure 1. There are no PESDVs at the LQ as there are no connecting pipelines.

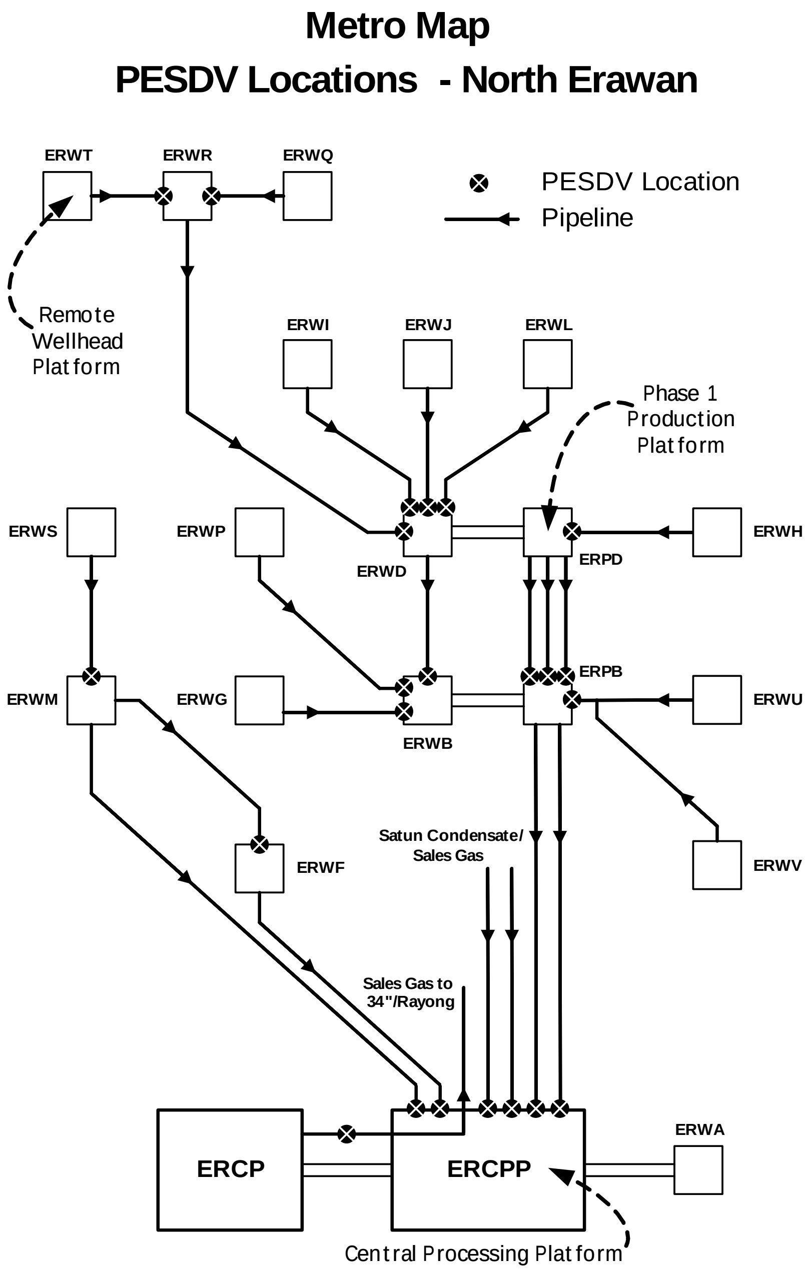

Figure 1 Typical Metro Map shows location of PESDVs

Source: Unocal Thailand Limited (2006)

Remote Wellhead Platforms (WHPs)

These are normally unmanned platforms. They are not fitted with PESDV's on outgoing pipelines consistent with the requirements of API RP14C (Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms, 7^{th} Edition, March 2001) and previous risk appraisals within Unocal Thailand. Automated isolation of production fluids from the pipeline is via the valves on the wellheads. These isolations are tested under an existing annual Preventive Maintenance Program. As required by API RP14C a manually operated (ball) valve isolation is provided on the inlet to the pipeline together with a check valve to prevent backflow to a leak on the platform from the contents of the pipeline. No additional valve or outgoing check valve testing is mandated under this study.

Hub Platforms

These are platforms that are transited by other upstream platform pipelines and are generically the same as the remote wellhead platforms. They are also normally unmanned platforms. In line with API RP14C, PESDV's are fitted on the incoming pipelines only with isolation of locally produced fluids via the wellheads (similar to remote wellhead platforms).

Phase 1 Complex (Erawan)

These are normally manned complexes. They consist of a pair of platforms, a production platform and a wellhead platform bridged-connected as one complex. The production platform is equipped with separation, dehydration and compression facilities. The other utility processes are gas or diesel generators, utility/instrument air system and fire water systems. Incoming PESDV's may be located on either or both of the wellhead and production platforms on the complex. These platforms are not fitted with PESDV's on the condensate, gas or three phase outgoing pipelines in line with API RP14C requirements.

Production/Compression/Riser Platforms

These are normally manned complexes. The process on these platforms is mainly compression with some supporting equipment (e.g. vessels and utilities). All incoming and outgoing pipelines are provided with PESDVs.

All of the offshore facilities are connected by various sizes of sub-sea pipelines which contain three-phase fluids (hydrocarbons gas and liquid, produced water), gas, oil or condensate. The Figure 1 explains a typical map shows the connection of offshore pipeline network and location of ESDV. The complete metro maps (in the Appendix A) explain the connection of the pipeline network and location of PESDVs in the GoT operation.

There are two Floating Storage and Offloading units (FSO's) or tankers. They are the Erawan FSO (660,000 barrels - condensate storage) and a chartered tanker the Pattani Spirit (910,000 barrels - crude oil storage). Each of the vessels has an incoming pipeline to receive product from the processing facilities with an associated PESDV. There is one incoming PESDV on each vessel. The PESDVs operate at low pressures (typically 20-30 psig) and are considered low risk because of the pressure and low potential exposure to accidental events. These PESDVs are not included in this scope.

PESDVs are installed to pig receivers and launchers upstream and downstream of sub-sea pipelines (compliant to the requirements of API RP14C at the time they were designed and built).

The PESDVs are operated by pneumatic or hydraulic actuators and are also equipped with Emergency Shutdown (ESD) system which is activated when the pipeline pressure is excessively high or too low (possible pipeline rupture). The ESD also enable manually shutdown locally by the local shutdown system or remotely—from central control room. A typical PESDV arrangement is shown below (Figure 2).

The sub-sea pipeline passes the PESDV,with a bypass valve, and enter to either production valve or the reviver (during pigging operation).

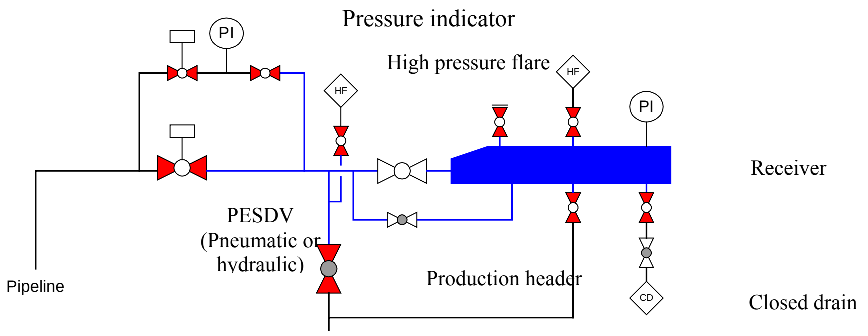

Figure 2 Typical PESDV arrangement

Source: Unocal Thailand Limited (2006)

Risk Assessment

As demonstrated by the Piper Alpha accident, the PESDV is a critical piece of equipment on an offshore platform. It ensures that the hydrocarbons in the pipeline and on the platform can be isolated on demand, preventing flow of hydrocarbons between the two and minimizing the risk of escalation.

When designing an offshore platform there are well established numbers of potential ‘accidental scenarios” that have to be considered during the design. These are best demonstrated in the form of a “bow tie” diagram as shown below.

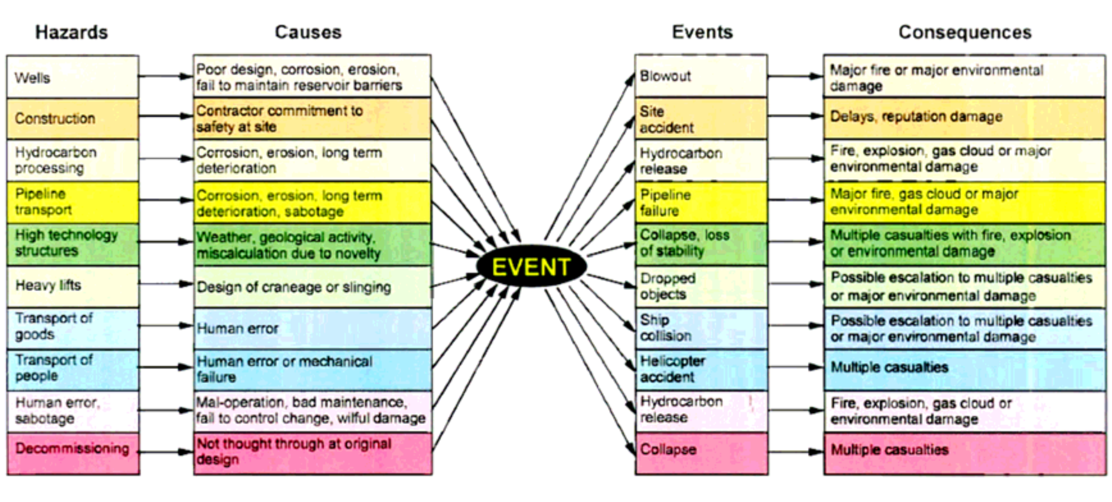

Figure 3 Major hazards and consequences

Source: Guidance for safer design of offshore installation: an overview. (2006)

Of the events shown above there are a number that may directly impact the attached pipeline and PESDV.

1. **Blowout**. This is where there is a loss of control and containment of well fluids from the wellhead.

2. **Site accident**. Any number of activities (such as construction or maintenance) could result in a site accident that might impact the integrity of the pipeline and PESDV. These accidents are prevented by the use of such tools as extensive training of personnel, planning and execution of work and procedures.

3. **Structural Collapse.** This could be as a result of a collision (boat or helicopter) or because of abnormal weather conditions (such as typhoon).

4. **Hydrocarbon Release**. This could result from an initiating event either upstream or downstream of the PESDV.

The risk of escalation, threat to personnel and loss of assets from the contents of the pipeline becomes clear when the typical hydrocarbon inventories of each are considered. The following tables show the calculated contents of the equipment on the Erawan central processing platform processing equipment and attached pipelines.

Table 1 Hydrocarbons Inventory in Process Equipment

	Gas		Condensate		Water	
	Volume	Mass	Volume	Mass	Volume	Mass
Summary	ft^3	lbs	ft^3	lbs	ft^3	lbs
Test Separator	69.2	416	40.4	1638	32.5	2029
Production Separator No. 1	189.8	1140	108.1	4380	87.6	5461
Production Separator No. 2	189.8	1140	108.1	4380	87.6	5461
Suct Scrbbr/Cond Separator	1200.2	5726	214.8	8705	214.8	13392
Glycol Dehydration	1955.1	13333	698.4	28301	42.4	0
Produced Water	240.3	23	128.1	5191	138.1	8606
Condensate Stabilisation	1583.4	3724	863.3	34983	1.7	109
Totals	5427.9	25502	2161.3	87579	604.8	35057
Volumes m^3	153.71	-	61.20	-	17.13	-
Volumes barrels	967	-	385	-	108	-
Mass kg	-	11567	-	39725	-	15902
Mass tons	-	11.38	-	39.10	-	15.65

Source: Unocal Thailand, Limited (2006)

Table 2 Hydrocarbon Inventory from Incoming Pipelines to ECPP

Location: ECPP									Mass in P/L*		Flowrate	
Tag	From-To	Duty	Pipeline	Phase	P/L ID inches	P/L length feet	Pressure In psig	Out psig	Gas tons	Liquid tons	Gas MMSCFD	Liq BPD
SDV-2020	JCPP-ECPP	West Jak Gas from JCPP	EGLE	G	16	18,363	1090	1065	69	-	31.66	-
SDV-2085	EWM-ECPP	EWM/EWS production	EPLM2	3P	10	33,422	970	870	40	17	30.57	477
SDV-2125	EWE-ECPP	CEKNO production from EWE	EPLE	3P	10	18,342	510	500	11	9	28.23	2,029
SDV-2000	EWF-ECPP	EWF production	EPLF	3P	10	12,806	620	500	8	6	9.35	162
SDV-2005	EPB-ECPP	North Erawan Gas	EGLB	G	16	16,635	1090	1070	66	-	142.62	-
SDV-2010	EPC-ECPP	Baanpot + South Satun Gas	EGLC	G	16	14,946	1080	1065	59	-	31.32	-
SDV-2015	SCPP-ECPP	Sales Gas from SCPP	SGLCP	G	16	95,948	1340	1065	442	-	157.37	-
SDV-2030	EPB-ECPP	North Erawan Condensate	ECLB	L	6	16,521	240	228	-	59	-	5,331
SDV-2035	EPC-ECPP	Baanpot + South Satun Condy	ECLC	L	6	14,925	240	228	-	53	-	937
SDV-2045	JCPP-ECPP	West Jak Condy from JCPP	ECLE	L	6	18,406	250	228	-	65	-	1,005
SDV-2040	SCPP-ECPP	Condensate from Satun/Platong	SCLCP	L	6	97,001	193	-	-	345	-	6,474
SDV-2095	ECPP-SPM1	Condensate Product to SPM 1	CLFSU	L	8	17,285	-	-	-	109	-	Not in Use
SDV-2090	ECPP-SPM2	Condensate Product to SPM 1	CLFSU2	L	10	24,573	-	-	-	243	-	36,107
SDV-2820	ECPP-ECP	Erawan gas to ECP	Bridge	G	-	-	-	-	-	-	213.30	-
SDV-2830	ECPP-ECP	Satun gas to ECP	Bridge	G	-	-	-	-	-	-	157.37	-
									697	906		

Source: Unocal Thailand, Limited (2006)

As can see from the above (Table 1 and 2) the total hydrocarbons in the Platform equipment is platform is 50.48 tons (11.38 + 39.10) compared to 1603 tons (697 + 906) in the attached pipelines. The pipelines contain some 32 times the amount of hydrocarbons as that on the platform. During an accidental release the processing platform numerous safeguards (explained in page 31) to control or mitigate the event.

Safeguards

Mechanical Integrity of the PESDV

The valves installed as PESDVs are ball valves –mostly manufactured by Grove (B-5 Fire Test Approved-Unocal Valve Study) although other manufacturers with equivalent quality have been used. This type of ball valve is built to meet API specification 6D (or ISO 14313: 1999, Petroleum and Natural Gas Industries-Pipeline Transportation Systems-Pipeline Valves). Under this specification the valve is required to provide pigging capability, pressure relief, bypass, drain/vent connection, locking device, sealant injection, fire resistance certified, anti-static, material standard (ASME B16.34 or by agreement, an equivalent standard) etc. The internal sealing principle and material specifications for a typical ball valve are shown in the figure 4 below and detail in appendix B.

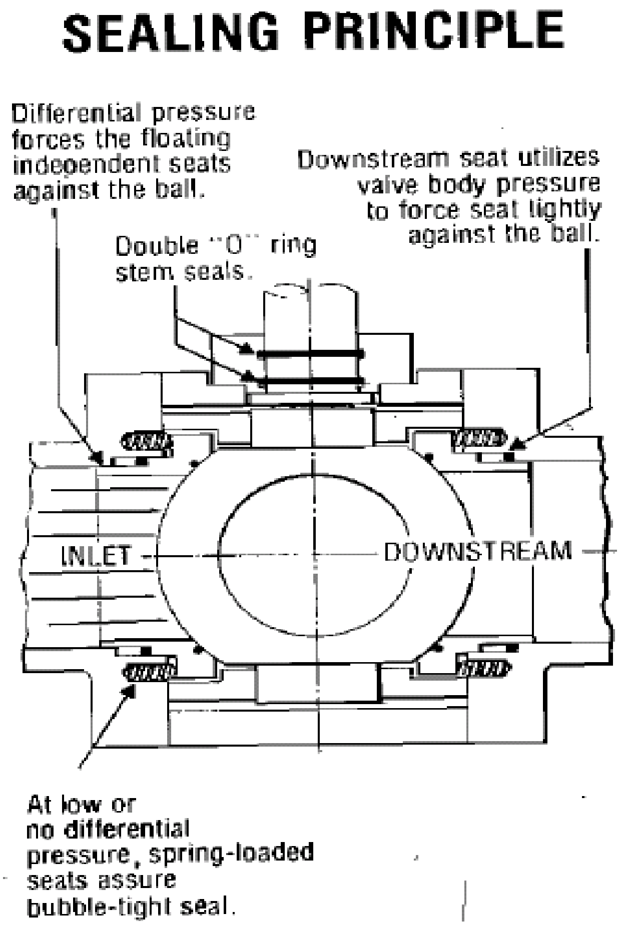

Figure 4 Ball Valve Sealing Principle

Source: Grove Ball Valve Catalogue (1991)

In addition to the above valve integrity, the reliability of the valve is referred to the comprehensive analysis of generic air/hydraulic operated ball valves (exida Equipment Reliability Handbook, 2003). The air valve Fail Dangerous Undetected was $1350/10^9$ Failures in Time (FITs). These failures can be reduced to 540 FITs for stroke test. (See Table 3 and 4)

Table 3 Air Operated Ball Valve (for emergency service) Reliability

EQUIPMENT ITEM	Generic Air Operated Ball Valve		ITEM NO.	5.3.1
GENERAL INFORMATION				
MANUFACTURER	Generic equipment			
MODEL	~~~			
ACTUATOR TYPE	Pneumatic, Spring Return			
VALVE TYPE	Ball, Air-To-Open			
ARCHITECTURE TYPE	A	HARDWARE FAULT TOLERANCE	0	
DATA SOURCE	exida Comprehensive Analysis			
REMARKS	Emergency Shutdown Service.			

FAILURE RATE DATA	PER 10^9 HOURS [FITS]			
	FULL STROKE		TIGHT SHUT-OFF	
	NORMAL	PARTIAL VALVE STROKE TESTING	NORMAL	PARTIAL VALVE STROKE TESTING
FAIL LOW				
FAIL HIGH				
FAIL DANGEROUS DETECTED		810		810
FAIL DANGEROUS UNDETECTED	1350	540	2350	1540
FAIL SAFE DETECTED		1650		1650
FAIL SAFE UNDETECTED	1650		1650	
FAIL NO EFFECT				
SFF [%]	55.0	82.0	41.3	61.5

Source: exida Safety Equipment Reliability Handbook (2003)

Table 4 Hydraulic Operated Ball Valve (for emergency service) Reliability

EQUIPMENT ITEM	Generic Hydraulic Operated Ball Valve			ITEM NO.	5.3.6
GENERAL INFORMATION					
MANUFACTURER	Generic equipment				
MODEL	~~~				
ACTUATOR TYPE	Hydraulic, Spring Return				
VALVE TYPE	Ball				
ARCHITECTURE TYPE	A			HARDWARE FAULT TOLERANCE	0
DATA SOURCE	exida Comprehensive Analysis				
REMARKS	Emergency Shutdown Service.				

FAILURE RATE DATA	PER 10^9 HOURS [FITs]			
	FULL STROKE		TIGHT SHUT-OFF	
	NORMAL	PARTIAL VALVE STROKE TESTING	NORMAL	PARTIAL VALVE STROKE TESTING
FAIL LOW				
FAIL HIGH				
FAIL DANGEROUS DETECTED		1350		1350
FAIL DANGEROUS UNDETECTED	2250	900	3250	1900
FAIL SAFE DETECTED		750		750
FAIL SAFE UNDETECTED	750		750	
FAIL NO EFFECT				
SFF [%]	25.0	70.0	18.8	52.5

Source: Exida Safety Equipment Reliability Handbook (2003)

A typical ball valve showing these safety critical parts is shown below.

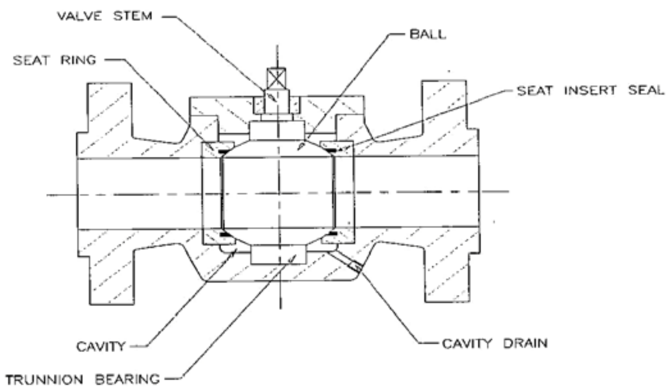

Figure 5 Section View – Typical Ball Valve

Source: API 6FA--Specification for Fire Test for Valves (1999)

From a risk standpoint, as indicated in the Lord Cullen report, the sustained mechanical integrity of the PEDV is paramount particularly during an emergency situation where the valves must maintain tight isolation between the platform facilities and contents of the pipeline during a potential scenario involving fire and/or explosion.

Fire Protection

A survey of the facilities found a number of design and physical conditions associated with the PESDV that address active and passive fire/explosion protection including hardware and software.

Valve Actuators and Emergency Shutdown Systems

Another key aspect of the PESDV is its ability to close on demand (automatically or on manual request). PESDVs installed in GoT are operated by either pneumatic (Bettis T520 or 310 Series) or hydraulic actuators. (Shafer hydraulic packages). The reliability analysis of a typical Bettis actuator is shown below.

Table 5 Pneumatic Actuator (for emergency service) Reliability

Equipment Item	Bettis CB-Series		Item No. 5.2.1
General Information			
Manufacturer	Bettis Corporation		
Model	CB-Series		
Actuator Type	Pneumatic, Scotch Yoke		
Actuator Action	Spring Return		
Architecture Type	A	Hardware Fault Tolerance	0
Data Source	FMEDA by exida		
Remarks	Emergency Shutdown Service.		

Failure Rate Data	Per 10^9 hours [FITs]		
	Normal	Partial Valve Stroke Testing	
Fail Low			
Fail High			
Fail Dangerous Detected		484	
Fail Dangerous Undetected	517	33	
Fail Safe Detected		1040	
Fail Safe Undetected	1040		
Fail No Effect	73	73	
SFF [%]	68.3	98.0	

Source: Exida Safety Equipment Reliability Handbook (2003)

The pneumatic operated PESDV utilizes a pneumatic actuator to operate the ball valve. The valve is kept open by a applying a continuous compressed, dry instrument air supply operating at 150 psig to the actuator. These actuators are a fail safe design that is on loss of the air supply the actuator will close the valve by means of an internal spring. A solenoid valve (Figure 6) is installed in the air supply line to the actuator – a local (manual) or remote (automatic) actuation of the solenoid will bleed off the air supply to the actuator and close the valve. The solenoids are also of fail safe design – these devices are "normally energized" (i.e. power is normally continuously supply to the solenoid). On loss of power to the solenoid it will fail safe by bleeding off air to the actuator and closing the valve.

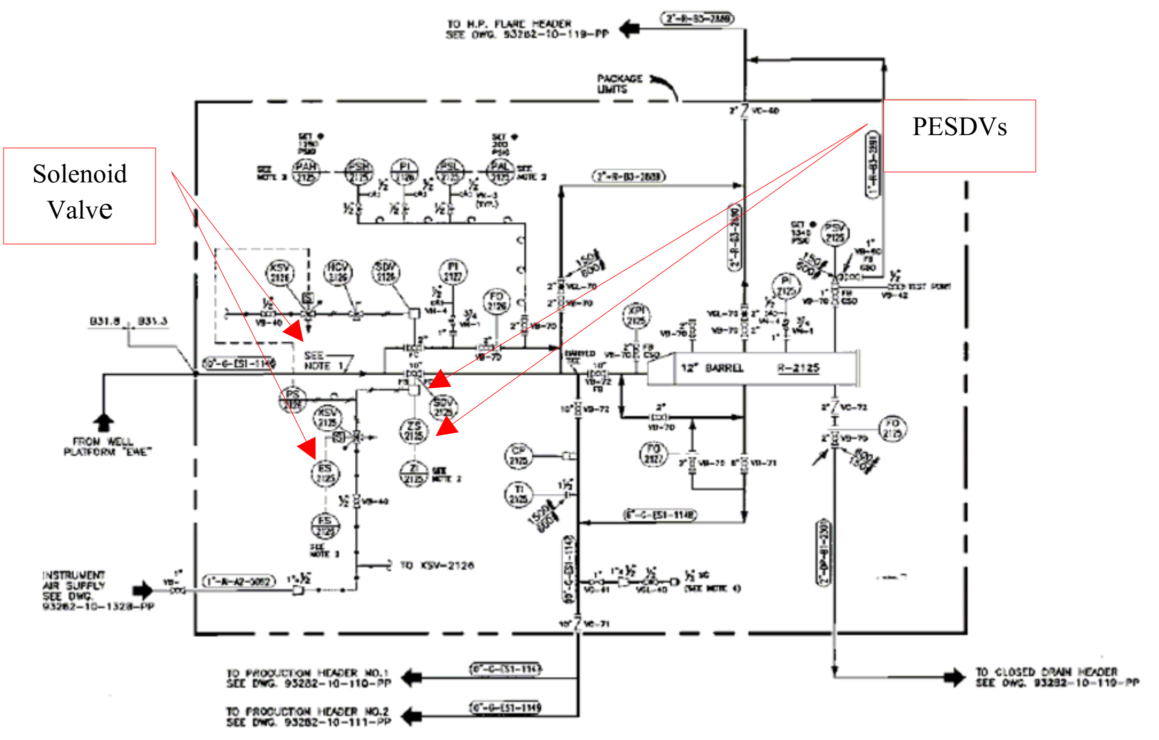

Figure 6 PESDV Shutdown Loop

Source: Unocal Thailand, Limited (1997)

For hydraulic type, the valve will be operated by an actuator with hydraulic pressure on both sides of the valve operator. These devices are of a barrel design with an internal paddle. The actuator will only operate when hydraulic pressure is applied to the barrel allowing it to rotate and drive the valve to either the open or closed position. A separate reservoir of hydraulic oil with a high pressure pump is required to operate these units. Local manual controls are provided to operate the actuator using hydraulic pressure either from the pump or via a local manual hand pump.

The PESDV is actuated/closed via instrumented systems:

1. By the platform shutdown system on response to fire or gas detection.
2. On remote request by pushbutton in the control room.
3. By a pushbutton local to the PESDV.

Each PESDV is fitted with limit switches (closed and open) or position transmitter to indicate the current position to the operator in the central control room.

Risks to the Personnel and Assets

The Piper Alpha report gives a clear indication of the impact from the failure to provide adequate isolation of a pipeline from the platform processes during a major incident. Whilst the fire was limited to the contents of the platform the size, extent and duration of the fire was limited. Once the contents of the pipeline came into play the situation rapidly deteriorated with deadly escalation. The picture below shows the size and intensity of the resulting fireball

Figure 7 Piper Alpha, Major Explosion when the risers burst, the resulting jet of fuel dramatically increased the size of the fire from a billowing fireball to a towering inferno.

Source: http://www.cf.ac.uk/engin/staff/pjb/

This section will study the risks associated with hydrocarbons inventory in the processing equipment as well as in the incoming pipelines to ECPP. This will include PESDV integrity and its environment will be identified with Potential Hazards and Safeguards.

Potential Hazards from pipe rupture when PESDV fail to close

A potential risk scenario when there is a hole on the pipeline downstream of a PESDV. This will create a massive risk of gas cloud, fire that would direct impact to the asset and life's of people who are working and living on the platforms. The risk of fire and explosion when pipeline leaked and PESDV was out of control can be defined by using the Formula from Fire Radiation Explosion and Dispersion (FRED) User Guide version 2.1. At the normal operating pressure at 1260 PSIg could have a gas release of 21 MMSCFD from an 1" hole leaking. (See example of the calculation in appendix B)

Requirements for PESDV

Basic requirements of an ESDV are a fail safe valve which will be automatically closed by the installation's emergency shut-down system and can be closed by a person positioned close to it. The ESDV must be protected from fire, explosion or impact and maintained in efficient working order and good repair.

There two main issues of Operability Concerns, the ESDV closes on demand (either through shutdown system or local station and it gives tight isolation when closed. But the current practices reveals that no specific leak testing of ESDV's. Valve operational testing only when platform is emergency shutdown (either deliberately shutdown or otherwise). This brought to the following risks:

- Leak on platform - pipeline contents feeds the leak
  ECPP - 50 tons of HC's, SCPP-ECPP 16" gas pipeline - 400 tons

- Leak in pipeline - platform contents feeds the leak

- Potential overpressure/overfill of immediate downstream equipment (such as inlet separators)

Other than the above, there are some relative risks:

- CPP's - manned, large inventory pipelines attached
- Hub wellhead platforms - loss of upstream production
- Individual wellhead platforms - no outgoing ESDV to isolate

In term of Regulatory Requirements, there is no specific regulations in Thailand, however a number of industry practices and statutory requirements exist elsewhere. They are:

- North Sea(UK):
  SI 1029/Pipeline Safety Regulations
- Gulf of Mexico:
  30 CFR 250 (Mineral Management Services), legal requirement in US
- Organizations:
  API RP14C/ISO 10418 (Safety Devices)
  ISA S84/IEC 16508 (Safeguarding Systems)

An emergency shut-down valve shall be maintained in an efficient state, in efficient working order and in good repair. Basic Requirements under Regulations/ Standards required that

Valve Action: Partial and/or fully closing valve
Frequency: 1 month - 6 months frequency
Leakage: Max Rate: Gas - 35 SCFM, Oil 0.04 GPM
Frequency: Annual or not required
North Sea: Three monthly visual inspection

<u>Classification of PESDVs Installed</u> *(based on risk.)*

In this study, the PESDVs are classified by using historical review, risk assessment, prescriptive standards and performance based evaluation. This gives of the valve classification in to 4 types or classes (A, B, C and D) as explained below:

Class "A"

Locations: All facilities where PESDV's are installed on ***incoming and outgoing liquid (oil and condensate) pipelines***.

Testing Requirements: Reliability (function) test only at frequency prescribed by this procedure.

Class "B"

Locations: ***Hub wellhead platforms*** (PESDV's on incoming pipelines).

Testing Requirements: Reliability (function) test only at frequency prescribed by this procedure.

These valves should be tested in line with this procedure as opportunities arise (See Testing Opportunity page 23-24). Current three phase pipeline batch treatment frequencies should permit concurrent testing of these valves at least annually.

Class "C"

Locations: ***Gas and three phase fluid bearing incoming pipelines on Erawan Phase 1 complexes and incoming/outgoing pipelines on production/compression/ riser platforms***. Valves that can be tested during planned pigging/batch treatment operations, partial (train) or total shutdown of a facility.

Testing Requirements: Reliability (full closure) and effectiveness (leak) testing offline at frequency prescribed by this procedure.

Class "D"

Locations: ***Gas and three phase fluid bearing incoming pipelines on incoming/outgoing pipelines on production/compression/riser platforms***. ***Valves that <u>cannot</u> be routinely tested offline*** because of their criticality to production and sales. These PESDV's will be on systems in continuous use and that cannot be accessed for a full closure test during partial shutdown of a facility. Partial closure testing devices will be provided on each of these PESDV's to enable online testing.

Testing Requirements: Reliability (partial closure) testing online at frequency prescribed by this procedure. Reliability (full closure) and effectiveness (leak) testing offline at frequencies prescribed by this procedure.

<u>Risk Based Testing</u>

Testing of PESDV will covers the following key components:

- Establish testing criteria including close on demand, reliability and effectiveness
- Test frequency; and
- Test opportunity

<u>Testing Opportunities</u>

A number of opportunities may arise when PESDV testing can be performed such as:

1. As a part of pigging/batch treatment operations (three phase pipelines). It should be noted that closure (reliability) testing of the PESDV on the receiving end of the pipeline is not part of the current pigging procedure but would not have a significant impact on the overall execution time or production rates.

2. During planned compression train shutdowns on CPP's, CP's and Erawan Phase1

3. During planned total platform shutdowns.

4. When associated pipelines are not in use (such as JWC-JCPP and SWJ-EPC pipelines when routing to JWA/FCPP and SWE/SCPP respectively).

Inadvertent testing of PESDV may also take place when a facility has an short term unplanned shutdown (such as on initiation of PSD). Whilst these occasions provide useful indication of valve action/closure they will not be used in lieu of scheduled PESDV tests. During unplanned shutdowns the emphasis is generally on reinstating platform production as quickly as possible and close observation and diagnostics of the valve (quality and time of closure, performance of actuator and associated instrumentation) may not be reliably made.

By using Risk Based Testing as long as other requirements, the table 8 below shows the testing criteria of all types of PESDV (A, B, C and D) in term of reliability and efficiency and frequency of the test.

Table 6 Prescribed Testing Frequency

	Prescribed Testing Frequencies (months)					
	Reliability				Effectiveness	
	full closure		partial closure		(valve leakage)	
PESDV Class	Nominal	Maximum	Nominal	Maximum	Nominal	Maximum
"A"	24	48	Not applicable		Not required	
"B"	12	24	Not applicable		Not required	
"C"	6	12	Not applicable		6	12
"D"	5 years		3	12	5 years	

Source: Unocal Thailand, Limited (2006)

From table 6:

'Nominal frequency' – target frequency for PESDV testing. This is the frequency at which preventive maintenance job cards

'Maximum frequency' – maximum frequency allowable between PESDV tests.

The total numbers of PESDVs are 123 installed by the fields as shown below:

Table 7 Risk Based Classification of PESDVs to be tested

	A	B	C	D	Total
Erawan	10	6	24	11	51
Satun	2	10	7	1	20
Platong	2	9	7	1	19
Funan	1	12	6	1	20
North Pailin	1	0	4	1	6
South Pailin	1	0	5	1	7
Total	17	37	53	16	123

Source: Unocal Thailand, Limited (2006)

Test Methods

Reliability

Reliability testing may be carried out by one of two methods:

1. Offline functional check by initiating full closure of the PESDV via the shutdown system or local manual station.

2. Online functional check by partial closure of the valve to a point that will not impact ongoing production operations (typically 10-20% closure).

Offline functional checking will be performed during one or more of the potential opportunities detailed previously. Online testing will make use of partial stroking devices with diagnostic capabilities (will be explained later). Bleeding off pressure to the actuator to achieve partial stroking online is <u>not</u> an acceptable means of testing.

A number of checks and actions will be performed during reliability testing that will verify the ongoing performance and reliability of the PESDV:

a. Inspection for leaks around the PESDV (flanges and stem) and associated instrumentation (pilots, solenoids, actuators, tubing)

b. Visual inspection for corrosion on all parts.

c. Condition and operability of limit switches, exhaust ports, air filters and regulators.

d. Quality of wiring and connections.

e. Operation of latch mechanisms.

f. Lubrication of valve stem and body, stuffing box and actuator.

g. Performance of control devices (actuator, pilot, solenoid) to ensure that PESDV response is rapid and within the specified acceptable limits.

h. For full closure, rate of closure of the PESDV.

i. Visual observation of the actuator and valve movement that may indicate potential problems with internals. (See Example Job Card for PESDV Testing in Appendix E)

Effectiveness

Effectiveness of PESDV isolation will be performed using the pressure build up method similar to that used on remote wellhead platforms for the testing of SCSSV's (compliant to API RP14B) and flowline check valves (compliant to API RP14C). This will require shutdown of associated process systems on the platform but with pressure remaining in the pipeline. The basic steps for this are as follows:

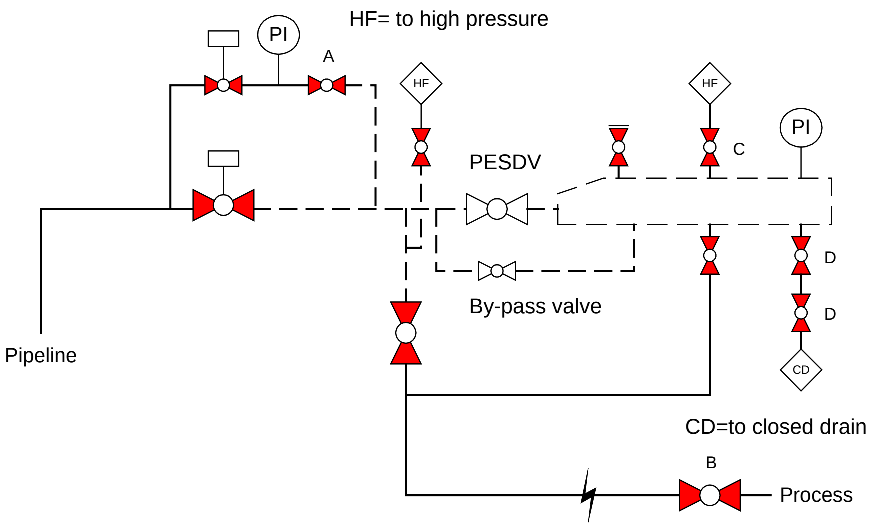

Figure 8 PESDV Leakage (Effectiveness) Testing Arrangement

Source: Unocal Thailand, Limited (2006)

1. The pipeline will be isolated from the facility by means of the shaded valves in Figure 11 above. This includes the PESDV, PESDV bypass, all valves around the launcher/receiver and manual isolation valve connecting to the main process on the facility.

2. Where available, alternate isolation valves should be closed on the PESDV bypass line (i.e. provide double block isolation on this line – valve A).

3. Where the associated process systems have not been fully depressurized, an additional isolation should be sought to provide double block isolation from process systems (valve B).

4. Vent/drain the contents of the piping upstream of the PESDV (shown by dotted line section) via drain and vent valves provided (such as valves C and D) down to zero (atmospheric) pressure.

5. With the vent and drain valves closed observe the rate of pressure build up in the piping over a period of 10-30 minutes.

6. The leakage rate will be calculated from the known volume of the piping (dotted line section) and rate of pressure build up as follows:

$$\text{Leakage Rate (ft}^3\text{/min)} = \frac{P_{final} \text{ x } V_{system}}{P_{initial} \text{ x } T} \quad \text{………(1)}$$

Where:

P_{final} = final pressure (absolute - psia) = final pressure (psig) + 14.7

$P_{initial}$ = initial pressure (absolute - psia) = 14.7 psia if system depressurized

V_{system} = volume of system (piping and launcher/receiver – feet^3)

T = time take to reach final pressure (minutes)

Acceptance Criteria

Reliability

For full or partial closing, the reliability of the PESDV is considered acceptable provided it moves on request from the shutdown system or local manual station to the required position and all associated equipment (solenoids, pilots, actuators etc.) function as intended and is in good working order.

For full closure testing, the failure of a PESDV to fully close must be remedied before the facility is allowed to startup/recommence processing fluids from the pipeline.

Effectiveness

The effectiveness of gas and three phase pipelines, the acceptable leakage rate on a PESDV, a performance based requirement that obtained by reviewing RP-14C, is shown in the table below:

Table 8 Effectiveness Acceptance Criteria

Isolation Quality	Leakage Rate (ft^3/min)	Approx Equivalent Gas Rate (lbs/sec)
Tight Isolation	<35	0.04
Poor Isolation	>500	0.55

Source: Unocal Thailand, Limited (2006)

Online PESDV Testing

As indicated above, a number of the most critical PESDVs (Class ‘D”) are both difficult to test and are in potentially high risk duties. The important considerations for these valves are as follows:

1. They are on larger pipelines (bigger than 16 inch inside diameter) and have large inventories. This represents a potentially high risk to the attached processing platform.

2. As many of these valves are in service on export or interfield sales gas pipelines they represent a major financial loss should they need to be closed for testing, close inadvertently (i.e. close when not requested) or are damaged as a result of an incident.

3. These pipeline operate at relatively high pressures (1000+ psig) again increasing the risk to the attached processing platform.

4. These PESDVs are often on platforms that cannot be readily totally shutdown sufficiently to provide adequate time and access to fully test the valves. On Erawan CPP many fields send their sales gas through this platform to the main sales gas pipelines to shore. Planning regular shutdowns for PESDV testing could severely impact on the ability to supply gas to the Kingdom of Thailand. Details and results for each of these devices is summarized in appendix E.

RESULTS AND DISCUSSION

Aging Facilities

There are 168 offshore platforms in the operation area. Three fields are over 20 years of service—Erawan, Satun and Platong. Those aging platforms are good example to bring to this study. The design was based on the requirements of API RP14C (Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms, 7^{th} Edition, March 2001). The outgoing ESDV is not a requirement by RP14C; however, there was no related incidents due to this design over the 20 years. The design of the production platform is bridged-connected, this will add in a safety feature in safety of life.

Risk Associated of an Offshore Platform

The Blowout potential will not impact to PESDV as this applies only to wellhead platforms since wells are not installed on production platforms in the GoT; unlike other locations such as the North Sea where platforms may be integrated with wells and production. A blowout may be considered the same as a hydrocarbon release event specifically for a wellhead platform.

The structure collapse by Helicopter collision is not considered a credible Event. Pipelines and PESDV are located at the lower levels of the platform. On CPPs helicopter operations are to/from the living quarters structure some 150-250 feet from the processing platform. Collision by boat is a credible scenario and the risk is managed by the use of structural or riser guards for the pipelines and risers and restriction and control of boat operations around pipelines such as permit required for activity within 500 meter-safety zone, approved anchor pattern, Hazard Identification process for special work in the safety zone etc. Structural collapse of the platform in abnormal weather is covered under the design basis for the platform where the structure is designed to withstand extreme weather conditions.

Hydrocarbons release from upstream of PESDV (i.e. pipeline side) could be as a result of a leak in the pipeline (another of the above events) from corrosion, erosion or impact (such as a boat anchor or object dropped from the platform or boat cranes). In this case the whole contents of the pipeline could be released as there are no subsea isolations between platforms. If such a release was near a platform the results could be catastrophic should the release be ignited with a large jet fire being generated for many hours as the pipeline depressurizes to atmosphere. This was the case for the Piper Alpha incident. Stringent procedural controls are therefore put in place for lifts over pipelines, locations of ships anchors (a minimum of 30 meters from pipelines for GoT) and the routine control and monitoring of erosion and corrosion of pipelines. This includes the routine use of “smart pigs” which are capable of performing corrosion and erosion inspection of pipelines internally.

A downstream release (i.e. platform side) could result in damage to PESDV and/or pipeline allowing the contents of the pipeline to feed an accidental event (fire or explosion) on the platform. The platform processing systems have extensive safeguards to minimize the potential for escalation of a fire/explosion release on the platform. These include:

a. The use of inherent safety principles. This includes minimizing inventory of hydrocarbons and providing equipment layout that reduces the impact of a fire or explosion and minimizes the risk of escalation.

b. Design, maintenance and inspection of processing equipment such as piping, vessels. This reduces the chance of a release occurring.

c. The use of process control systems to keep the operating parameters within the design condition of the equipment such as pressure and level control.

d. The use of alarms to warn the operator of abnormal conditions and allowing them to act to prevent a release.

e. The use of active process safeguards such as high and low level trips to stop and isolate the process and prevent a release. This includes the use of devices such as low and high pressure trips. These devices do not require human intervention (are automated instruments).

f. The use of mitigation safeguards such as fire and gas detection. Again these devices do not require human intervention (are automated instruments).

g. The use of passive safeguards such as blast and fire walls. These devices require no active response (are safeguards by virtue of their presence) and minimize the chance of escalation by restricting or containing fire and explosion.

h. The use of active mitigation firewater deluge and fire fighting equipment. This is provided throughout the process and can be automatic (deluge on response to fire detection) or manual such as monitors and portable equipment.

i. The use of equipment “blowdown”. These systems will automatically isolate sections of the process and blowdown (i.e. release the contents) in a controlled, safe manner to the platform flare system. This is performed within a limited time (typically 15 minutes or less). This safeguard is a key risk reduction measure as it releases hydrocarbons which may contribute to a release, fire or explosion and rapidly reduces operating pressures that preventing equipment from failing under the impact of fire and reduced mechanical strength of the material of construction at high temperatures.

The Risk to Personnel and Assets

The study on the above risk with volumetric calculation identified that the content of the pipelines to Erawan CPP is 32 times greater than the content in the processing equipment (table 1 and 2 on page 12 and 13). The process side will reduce the risk by having a platform blowdown system to release the content to zero in emergency case. The contents of the pipeline does not have such as extensive protection in particular:

1. Platform systems have numerous isolations to prevent the hydrocarbon contents of one section from flowing to another. This reduces the inventory that may be involved in a fire or explosion scenario. Pipelines only have automated valves (the PESDVs) at either end – the entire contents of the pipeline could be contribute to an accidental event.

2. Blowdown of platform systems rapidly reduces the contents and pressure in platform process systems. Pipelines are not fitted with automated blowdown systems. This is because with the large volumes and pressures involved it is not practically possible to install a flare system capable of handling the enormous rates involved for a timely depressurization.

The PESDV therefore becomes a critical item of equipment for protection of both personnel and assets. It must have a number of safety critical characteristics:

1. It must maintain mechanical integrity should there be an accidental event on the platform such as release, fire, explosion or impact (dropped object or projectile).

2. It must close when requested either automatically or manually.

3. It must maintain a seal against the pressure and contents of pipeline preventing the contents from entering the process systems.

Mechanical Integrity of Valves and Actuators

The design of the valves that used on the PESDVs has a high positive impact to safety. The mechanical integrity of the PESDVs installed in GoT is ensured via compliance to two industry standards; one that specifies the design and leak tightness under normal (non fire) test conditions (API 6D) and one that determines the integrity of the valve under fire conditions (API Spec 6FA/BS 6755 Part 2).

API 6D, in addition to specifying design and construction requirements, also specifies a zero design leakage rate for the valve under bench test conditions. Whilst this is useful for quality assurance of new valves it does not give an indication of the quality of the isolation in an emergency (fire) condition. API Spec 6FA/BS 6755 Part 2 provide a performance specification for the valve under fire conditions as indicated by the table 3 below which gives a comparison of a number of different international fire tests that can be applied to the valve.

Table 9 Comparison of Ball Valve Fire Testing Standards

Fire Test Specifications	API 607 2nd Edition	API RP6F	FM 6033	API 6FA 1st Edition BS 6755 Part 2	Exxon EXES 3-14-1-2A
Fire Test Parameters	Temp & Time	Temp & Time	Fuel & Time	Temp, Time & Heat Flux	Temp & Time
Performance Requirements	None	None	20,000 blowdown cycles without leakage prior to test	None	Test per API 598
Valve Position	Closed	Closed	Closed	Closed	Open
Flow Material	Water	Water	Water	Water	Hydrocarbons
Flame Temperature	1400 - 1800°F	1400 – 1600°F	Not Specified	1400 - 1800°F	1400 – 1800°F
Heat Flux	Not specified	Not specified	Not specified	Specified	Not specified
Fire Duration	30 minutes	30 minutes	15 minutes	30 minutes	15 mins at >1200°F
Allow Seat Leakage	40 ml	400 ml	95 ml	400 ml	N/A
Allow Ext Leakage	20 ml	100 ml	drops	100 ml	Negligable

Source: Unocal Thailand, Limited (n.d.)

It should be noted that this specification is the only one that specifies heat flux rates. Both acceptable leakage rates and test duration are specified in order for the valve to pass or fail the test. The test pressure to be applied is also specified (see table 4 below) and is dependent on the valve "class" or flange pressure rating of the valve. For GoT facilities these ratings range from class 300 (low pressure condensate pipelines) to class 900 (high pressure gas pipelines).

Table 10 Test Pressure of Valve during Fire Test

	Valve Rating			High Test Pressure			Low Test Pressure		
	Class	(PN)[a]		psi	(bar)	(MPa)	psi	(bar)	(MPa)
Spec 6D Valves	150	(20)	–	210	(14,5)	(1,5)	29	(2,0)	(0,2)
	300	(50)	–	540	(37,2)	(3,7)	50	(3,4)	(0,34)
	400	(64)	–	720	(49,6)	(5,0)	70	(4,8)	(0,48)
	600	(110)	–	1080	(74,5)	(7,5)	105	(7,2)	(0,72)
	900	(150)	–	1620	(111,7)	(11,2)	–	–	–
	1500	(260)	–	2700	(186,2)	(18,6)	–	–	–
	2500	(420)	–	4500	(310,3)	(31,0)	–	–	–
	psi	(bar)	(MPa)	psi	(bar)	(MPa)			
Spec 6A Valves	2000	(138)	(13,8)	1500	(103,4)	(10,3)	–	–	–
	3000	(207)	(20,7)	2250	(155,1)	(15,5)	–	–	–
	5000	(345)	(34,5)	3750	(258,6)	(25,9)	–	–	–
	10000	(690)	(69,0)	7500	(517,1)	(51,7)	–	–	–
	15000	(1034)	(103,5)	11250	(775,7)	(77,6)	–	–	–
	20000	(1379)	(138,0)	15000	(1034,2)	(103,5)	–	–	–

[a]PN is the pressure class designation utilized in ISO (International Standards Organization) documents.
Tolerance on all test pressures is ± 10%.

Source: API 6FA--Specification for Fire Test for Valves (1999)

Whilst the use of standard requirements for valve design and performance under fire conditions assist in ensuring its integrity in an emergency the conditions during an incident may be more or less severe than the testing conditions. In particular:

1. Heat flux rates may be lower or higher than those specified. An example might be if a jet fire impinges directly on the valve.

2. The duration of the fire might be shorter or longer depending on the ability to isolate the sources and depressurize/remove the fuel.

3. The integrity of the valve may be compromised by other events during an emergency such as the blast from an explosion or impact by an object or projectile.

Fire Protection

Physical location of the PESDVs. Location of the PESDVs provides ‘passive’ protection against fire and explosion. A passive safeguard is one in which the safeguards acts upon the hazard simply by its presence. The safeguard is not required to take an action. This is achieved by locating the PESDV under the lowest deck (Figure 9) containing topsides equipment (separators, pipes etc.). The deck itself then provides a barrier against fires and explosions that may occur during an incident in the main processing facilities. There is still some potential threat however from adjacent pipeline risers and PESDVs. This risk is reduced by the design of the piping and PESDV:

a. Pipeline risers are given an extra safety factor in their design and as such have a higher piping wall thickness.

b. PESDVs may have two different types of connection to the upstream or downstream piping. Flange connections provide for easier installation but provide a potential source of leak (such as from a gasket or ring joint) and escalation around the PESDV. All welded connections reduce this risk significantly but have the disadvantage of making a change out of the valve, should it be required, difficult and potentially costly.

c. Fire detection. This is an ‘active’ safeguard. An active safeguard is required to respond by moving from one state to another as a result of a measurement or signal. Fire detection around the PESDV and receivers/launchers comes in two forms. A fusible plug (Figure 10) is a simple device that is connected to a loop of tubing pressured with instrument on. In the event of a fire the plug will melt (typically at 160^{O}F) and the loop will depressurize. A low pressure detection device (switch or transmitter) registers the loss of pressure and initiates a platform shutdown (ESD) which closes the PESDV. In addition it initiates the spraying of firewater around the PESDVs keeping them cool and maintaining their mechanical integrity. An additional secondary means of fire detection is also provided via a flame detector (UV, combination UV/IR or IR—Figure 11)

d. Firewater deluge is provided at the area of potential leak around the PESDVs. This too is an 'active' safeguard. This is automatically initiated on detection of a fire via a deluge valve, which can also be actuated manually.

Figure 9 Safe Location of PESDV

Source: Unocal Thailand, Limited (2006)

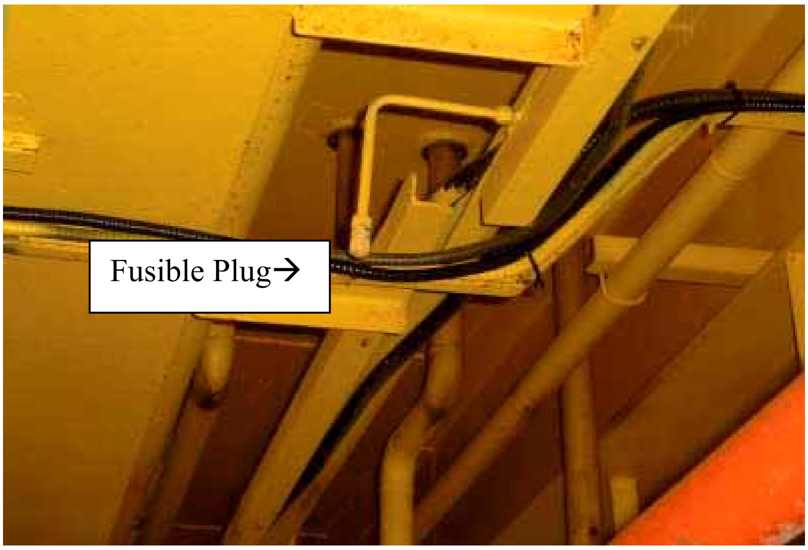

Figure 10 Fusible Plug at the PESDV location

Source: Unocal Thailand, Limited (2006)

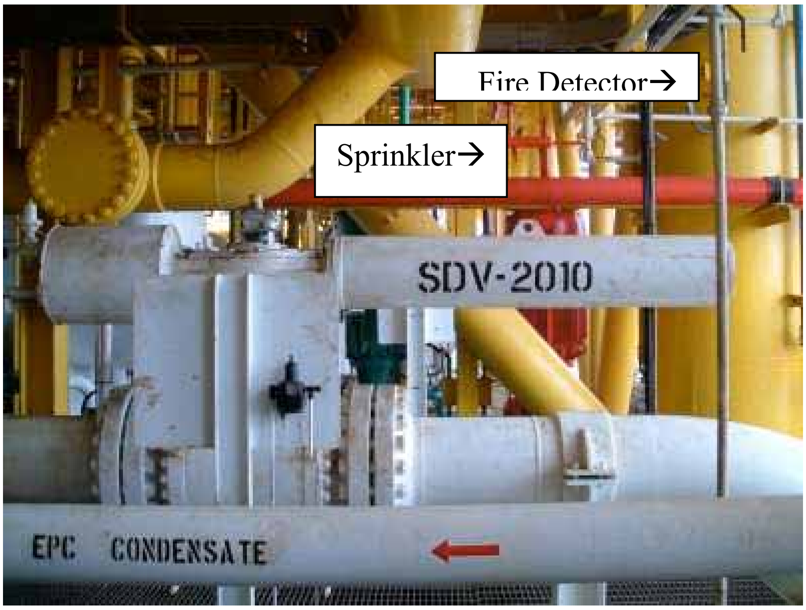

Figure 11 UV Detector and Sprinklers

Source: Unocal Thailand, Limited (2006)

Valve Actuators and Emergency Shutdown Systems

The result of the research of the PESDV actuators tells that both pneumatic and hydraulic actuators are selected by referring to the high reliability standards (10^9) Failure in Time, FIT as referred to exida equipment reliability hand book 2003 (Table 11).

Table 11 Pneumatic Actuator (for emergency service) Reliability

EQUIPMENT ITEM	Bettis G-Series	ITEM NO.	5.2.2
GENERAL INFORMATION			
MANUFACTURER	Bettis Corporation		
MODEL	G-Series		
ACTUATOR TYPE	Pneumatic, Scotch Yoke		
ACTUATOR ACTION	Spring Return		
ARCHITECTURE TYPE	A	HARDWARE FAULT TOLERANCE	0
DATA SOURCE	FMEDA by exida		
REMARKS	Emergency Shutdown Service.		

FAILURE RATE DATA	PER 10^9 HOURS [FITS]		
	NORMAL	PARTIAL VALVE STROKE TESTING	
FAIL LOW			
FAIL HIGH			
FAIL DANGEROUS DETECTED		426	
FAIL DANGEROUS UNDETECTED	460	34	
FAIL SAFE DETECTED		919	
FAIL SAFE UNDETECTED	919		
FAIL NO EFFECT	561	561	
SFF [%]	76.3	98.2	

Source: exida Safety Equipment Reliability Handbook (2003)

Both types of actuator (hydraulic and pneumatic) have pros and cons as illustrated below.

Table 12 Pneumatic and Hydraulic Actuator Comparison

Parameter	Actuator Type	
	Hydraulic	Pneumatic
Cost	Cheaper, particularly if reservoir, pumps used for multiple valves.	More expensive, particularly for larger, high pressure applications.
Size	Actuator small because of use of high pressure hydraulics. Additional space required for support equipment.	Not a concern for smaller, lower pressure applications. Can be very large (4-5 metres) for large, high pressure systems.
Failure mode	Automatic actuation fail safe. Motive power (hydraulics) system not fail safe.	Both automatic actuation and motive power fail safe.
Reliability on demand	Lower (2250 dangerous failures per 10^9 hours)	Higher (1350 dangerous failures per 10^9 hours)

Source: Unocal Thailand, Limited (2006)

From a safety standpoint, pneumatic actuators are a better selection that hydraulics being both more reliable and having better fail safe protection. Hydraulic actuators have been used however in GoT on the older platforms in services where there are large pipe sizes and high operating pressures (such as high flow rate, sales gas pipelines). The trend on newer platforms is to use pneumatic actuators, regardless or cost of space requirements. The above indicates the need to ensure that the operation and reliability of hydraulically operated valves can be proven in service.

Testing and Requirements

The benefit of reviewing the related regulations and codes (no specific regulations in Thailand) is to have a guideline to the testing criteria of the PESDVs. The criteria are defined in term of the testing frequency the reliability (close on demand) and the effectiveness acceptance. (Table 8)

The leakage rate numbers are based on a number of sources. A new, PESDV designed and tested to API 6D will have zero leakage (by specification). A valve has been in service will be exposed to process fluids and the tight shut off (zero leakage) capability is unreasonable to expect. Adopting a zero leakage philosophy would result in an unreasonable level of risk reduction and could mean expensive and time consuming valve repairs and replacements. These repair and replacements operations may introduce more risk than is being experienced from the lack of zero leakage.

The 'tight isolation' value is a common, experience based value used in the offshore industry. This value is specified in UK SI 1989/1029 for PESDVs and is consistent with industry recommended practices for isolation of wells via subsurface safety valves (API RP14B) and surface safeguarding equipment (such as check valves under API RP14C).

The 'poor isolation' value corresponds to a 'minor' leak rate that is used for evaluating and designing safeguards for processing equipment on the platform. This value can be found in a number of industry standards (Industrial Practice Code Part 15 for hazardous areas and UKOOA Fire and Explosion guidelines). Should a minor leak develop topsides then the maximum flow that should be tolerable through the PESDV that would feed the leak should be equivalent to this value since this is the minimum value that the platform safeguards can safely accommodate.

PESDV's providing tight isolation should be considered fit for service. PESDV's ranging from tight to poor isolation should be monitored for degradation of performance. The frequency of testing of valves in this category should be increased.

PESDV's showing poor isolation should be raised to management for further risk evaluation and action planning.

Where pressurization bypasses are fitted around PESDV's, the testing will verify that the effectiveness of the total isolation (PESDV + bypass) meets the above requirements.

Online or Stroke Test with Special Devices

For Class D valves an alternative option has been selected; the use of a proprietary device to enable on line function testing of the PESDVs. Four "partial valve stroke testing--(PVST) technology" devices have been investigated. This involves stroking the valve to a position where it does not impact significantly on the flow through the valve (typically 20-30% closure) but where the function or operation of the valve can be verified on line. The use of PVST technology can greatly decrease the probability of failure on demand (PFD) of the PESDV assembly (Table 11).

Table 13 Valve Actuator Reliability

Type	Actuator Type Reliability (failure per 10^9 hours)	
	Hydraulic	Pneumatic
Normal (PSI)	2250	1350
With PVST	900	540
% reduction	60%	60%

Source: Unocal Thailand, Limited. (n.d.)

In this study, it is good to have four devices to test and verify the operational and safety suitability. By various requirements i.e. EIC 61508-1998, this defined the requirements of the devices into must have, should have and nice to have (Table 14). Although stroke test devices would help operators to verify the test of class D valves, there are some limitations to explain for selection guideline:

Table 14 Stroke Test Devices Comparison

	Must Have			Should Have					Nice to Have		
	Tests operation of ESDV online	High Reliability during Normal Operations	High Availability during Normal Operations	Suitable for hydraulic & pneumatic actuators	Cost effective	Provides diagnostics	Operator friendly (easy to use)	Proven usage in industry	Can be installed on line	High Reliability during Testing	Measure or indicates leakage rate
Class 'D' PESDV's Required Features	√	√	√	√	√	√	√	√	√	√	√
Drallim SVM	√	√	x	x (1)	√ (2)	√	√	√	x	√	√
D-Stop	√	√	√	√	√	√ (3)	√	√	x	x (4)	x
Crane ValveWatch	x	√	√	√	x	x	√	√	√	√	√
Neles Valvguard	√	√	√	x (5)	√	√ (3)	√	√	√	√	x

Source: Unocal Thailand, Limited (2006)

1. The Drallim device was found to be incompatible with solenoid/reset function associated with Shafer hydraulic actuator system. Function tested successfully on pneumatic actuators.

2. The testing cost per valve of Drallim device is excessively high (USD 6800/unit where the average devices = USD 5500/unit)

3. The D-stop and Neles Valvguard have a limited diagnostics on devices.

4. D-Stop being a mechanical device has the inherent disadvantage of not being able to function during ESD initiated closure when the valve is being stroked. Although this is a low probability event (likelihood of ESD initiation during short duration of test), the consequences could be very severe.

5. Neles device currently is not suited for the high pressure required in hydraulically activated SDVs. Neles is working on an upgraded device, but it is not yet available. Function tested successfully on pneumatic devices.

The investigation and testing of the different devices has not yielded a single device that is suitable for the testing of all Class D PESDVs. The investigation will remain ongoing as new devices become available and modifications are made to existing available devices to improve their capabilities. The company currently plans to test the functionality of the Class D PESDVs on an opportunity basis (i.e. plan to test during periods of partial or total shutdown) and install function testing devices as and when they become available.

Overall Test Results

The total of 123 PESDVs was identified in all classes to this study, 93 or 76% were tested with satisfactory results. The first impression was that the Emergency Shutdown System worked well in both local and remote command. This is a result of the effective maintenance program.

84 out of 107 of Class A,B and C were tested by off-line procedure. Determination of leakage of Class A (Liquid Pipelines) cannot be readily performed for pipelines in liquid service since:

1. Liquids are incompressible (i.e. in the event of leakage past the PESDV the rates of pressure build up will be rapid).

2. The source of pressure (such as a pump) is normally removed after shutdown of the process unlike gas and three phase pipelines which remaining pressured.

The class B and C valves test results (84/107 valves) are exceptional. They were in the effectiveness limit of < 35 ft^3/min (tight isolation). The reliability (close on demand) is 1.9 inch/sec in average which is acceptable (performance based). Three valves appeared slightly sluggish on closing—this can be maintain the performance by manufacturer recommendation.

56% or 9 of 16 of Class D valves were complete testing on-line by the stroke devices. Some limitations were explained in on-line testing section above.

There are some discussions about the cost of stroke test devices during the testing process; however, this is not a scope of this study. The objective of this thesis was aimed to find possibility method to verify the safety integrity of the PESDVs. The financial aspect should be in a future discussion.

Table 15 Total Numbers of Valve Tested

Total Number of Valves v.s. Tested

	Offline			Online	
	A	B	C	D	Total
Erawan	10	6	24	11	51
Satun	2	10	7	1	20
Platong	2	9	7	1	19
Funan	1	12	6	1	20
North Pailin	1	0	4	1	6
South Pailin	1	0	5	1	7
Total	17	37	53	16	123

Number of Valves Tested

	A	B	C	D	Total
Erawan	7	6	22	4	39
Satun	2	6	5	1	14
Platong	2	9	7	1	19
Funan	1	0	6	1	8
North Pailin	1	0	4	1	6
South Pailin	1	0	5	1	7
Total	14	21	49	9	93

% Complete

	A	B	C	D	Overall %
Erawan	70	100	92	36	76
Satun	100	60	71	100	70
Platong	100	100	100	100	100
Funan	100	0	100	100	40
North Pailin	100	-	100	100	100
South Pailin	100	-	100	100	100
Overall %	82	57	92	56	76

Source: Unocal Thailand, Limited (2006)

The overall testing program gave a result in line with Peter (1998) explains in the Emergency Shut-Down Valve Study that of the approximately 200 installed valves surveyed, they have been in reasonably reliable. Some of them have been in service for more than 15 years are still achieving zero leakage (the original specification) under test (non fire) conditions. The upstream and downstream valve seats and seals on the valves uses either soft seal inserts or hard metal/surface treated metal seats. Many operators prefer to use a soft seal material (e.g. nylon) as they tend to be easier to affect a seal although metal seals are selected by some operators as these may provide better integrity under fire conditions.

CONCLUSION AND RECOMMENDATION

Conclusion

Identify General Arrangement of PESDVs in the GoT

This study gives an overview of the Thailand offshore Oil & Gas Exploration and Production Facilities especially the arrangement of the PESDVs. Compliance with API RP14C in design may not be a modern standard however the material selection and design philosophy of the safe system support the PESDVs in a safe place and protected, for example the separation of Processing Platform from Living Quarter by bridged-connection. Key points in this section cover:

- GoT pipeline net work
- PESDV and its receiver arrangement
- PESDV shutdown system—local and remote
- Different types of offshore fixed and floating facilities

Identify Risk Associated with Failures of those PESDVs.

Risk of the PESDV failure is not only the PESDV itself but also the associated engineering design standard of the valve such as valve and actuator specifications, the safe location of the valve, passive and active fire protection, corrosion control of the associated pipeline. Planned inspection and maintenance program of both the valve and it emergency shutdown loop is also the safety management side of the safe system of PESDV. The conclusion of risks includes:

- Blowout
- Site accident
- Spill and release
- Risk of life and asset
- Fire Protection
- Integrity of PESDV etc.

<u>Conduct Pilot Test on PESDVs</u>

The test procedure developed in this study is based on the historical review of the operations, the existing practice of the oil and gas demand in Thailand became a test opportunity for the offline test. Moreover, with the stroke test technology, also provide additional opportunity PESDV safety and reliability selections. The Test Procedure includes:

- Classification of valves (based on risk)
- Testing requirements
- Test methods—offline and online
- Verification of testing devices; and
- Conclusion of the test with recommendations

Recommendations

Some aspects found in this thesis could be benefit to recommendation for future improvements:

1. Adopt and review the testing procedure with new technology to make it current at all the time

2. As the platform aging become older, the frequency of the test should be addressed in future test

3. Take PESDV maintenance and testing to consideration during oil/gas demand planning to ensure having adequate time frame to ensure the integrity of the PESDV system

4. Do more research about the on line testing device development

5. Include Lord Cullin report and recommendations to the platform and pipeline design stage

6. Consider contingency plan during testing of PESDV

7. Consider the Reliable Centered Maintenance (RCM) program due to numbers of valves are over 20 years of service

8. Future review of the online testing should include financial aspect to add value to the research

9. Discuss with local authority to consider developing a country specific requirement for offshore PESDV management

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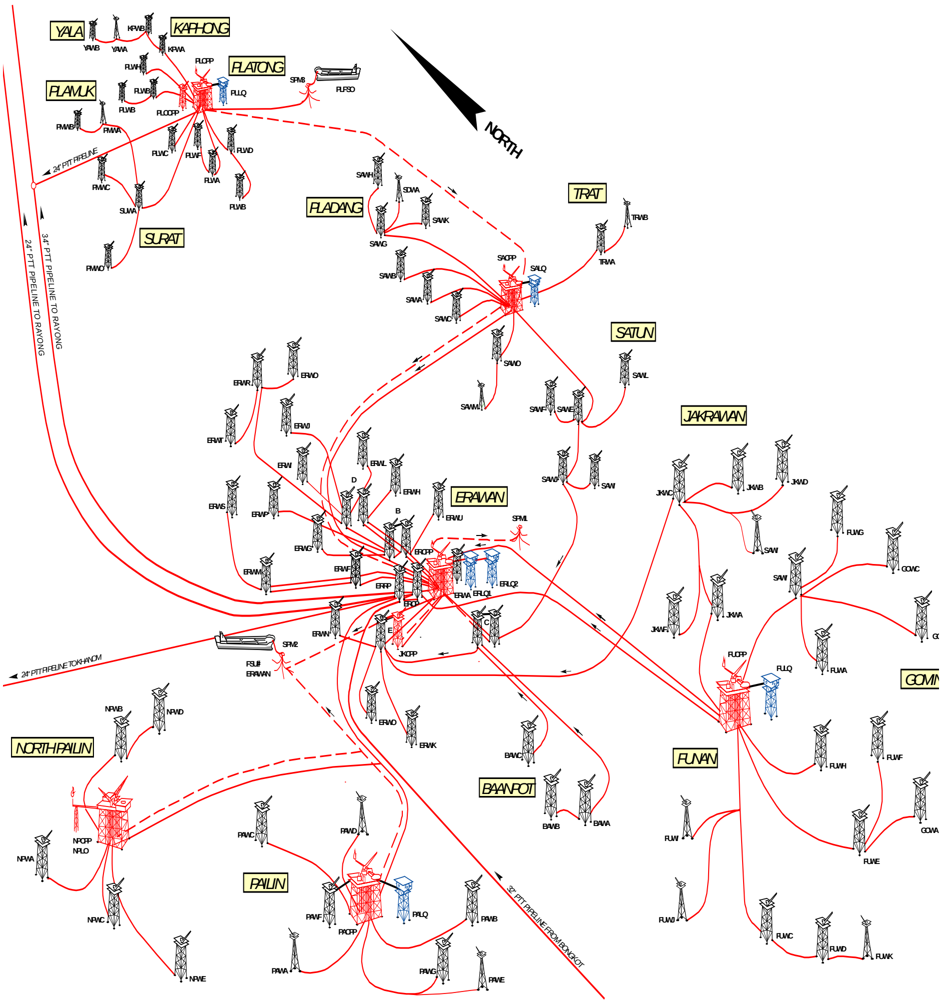
APPENDIX

Appendix A

Overview of offshore facilities where ESDV located and Metro maps of Gulf of Thailand Pipeline Network

Overview of offshore facilities where ESDV located

Offshore production facilities consist of three main types of facilities; they are fixed steel structured platforms including Wellhead Platforms where oil and gas wells are drilled from subsurface and delivered to other platforms via submarine pipelines. Production Platforms are that platforms that equipped with production facilities i.e. separation, stabilization, dehydration and compression etc. and Living Quarters (LQ) where the offices, accommodation and workshops are located. There are floating units in the gulf to support the operations such as liquid storage tanker, drilling support tender and construction barges.



Appendix Figure A1 Typical field network

Source: Unocal Thailand Limited (2006)

Appendix Figure A2 Remote Wellhead Platform (WHP)

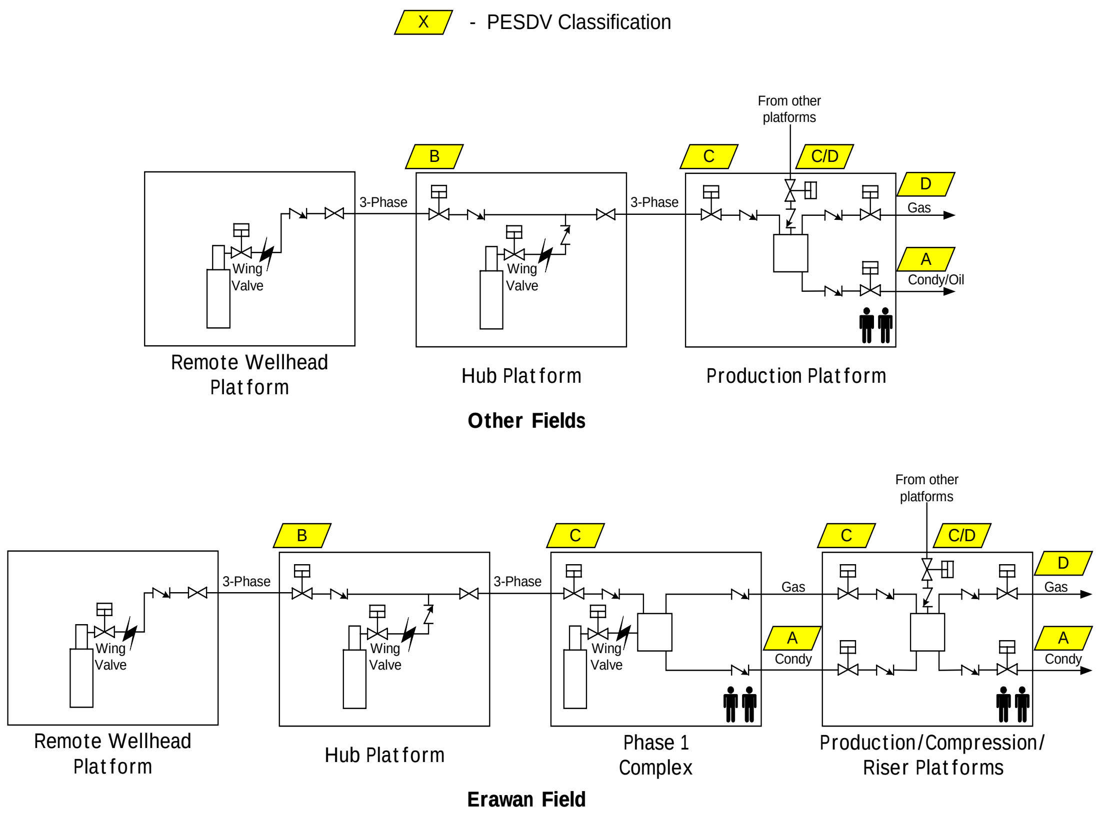
Source: Unocal Thailand, Limited (2006)

Appendix Figure A3 Three types of main facilities

Source: Unocal Thailand, Limited (2006)

Metro maps of Gulf of Thailand Pipeline Network

The following figures show the schematic diagram of the connection between one platform to other(s) and also indicated the location of PESDV (by classifications) Remote Wellhead and Hub Platform are unmanned while the production platforms are manned platforms (Appendix Figure A4).



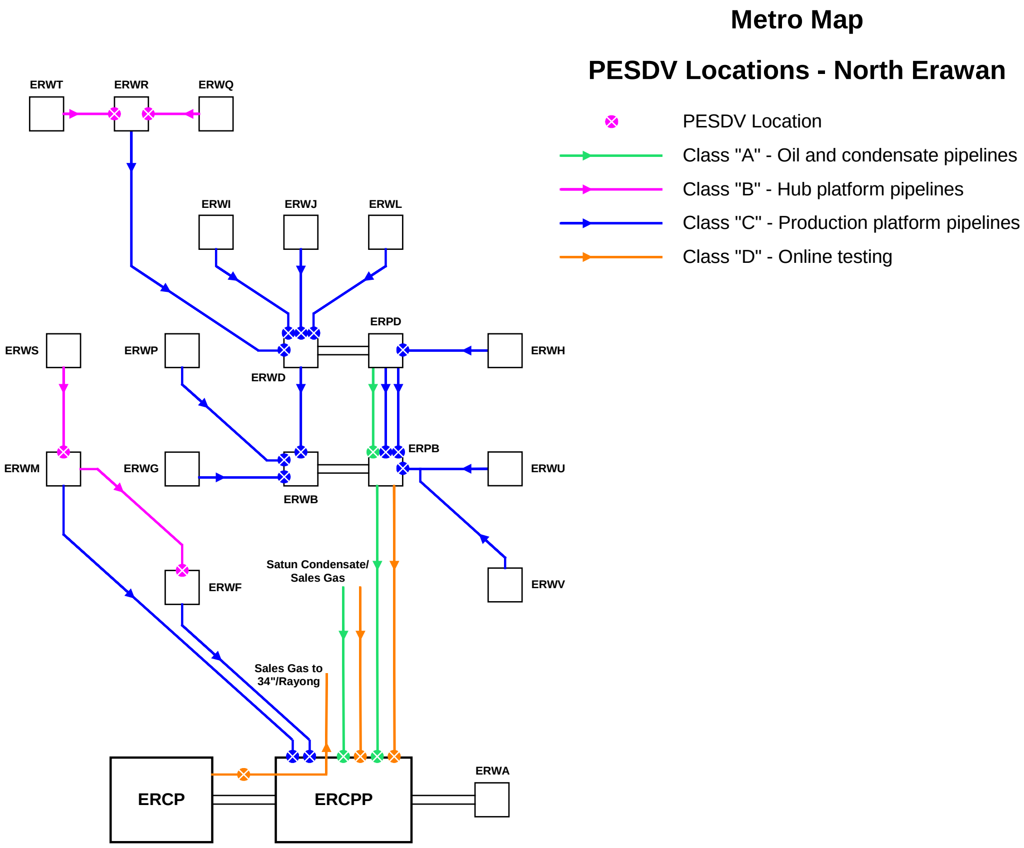
= Classification of ESDV

Appendix Figure A4 General Configuration for Pipelines ESDVs and valve classification

Source: Unocal Thailand, Limited (2006)

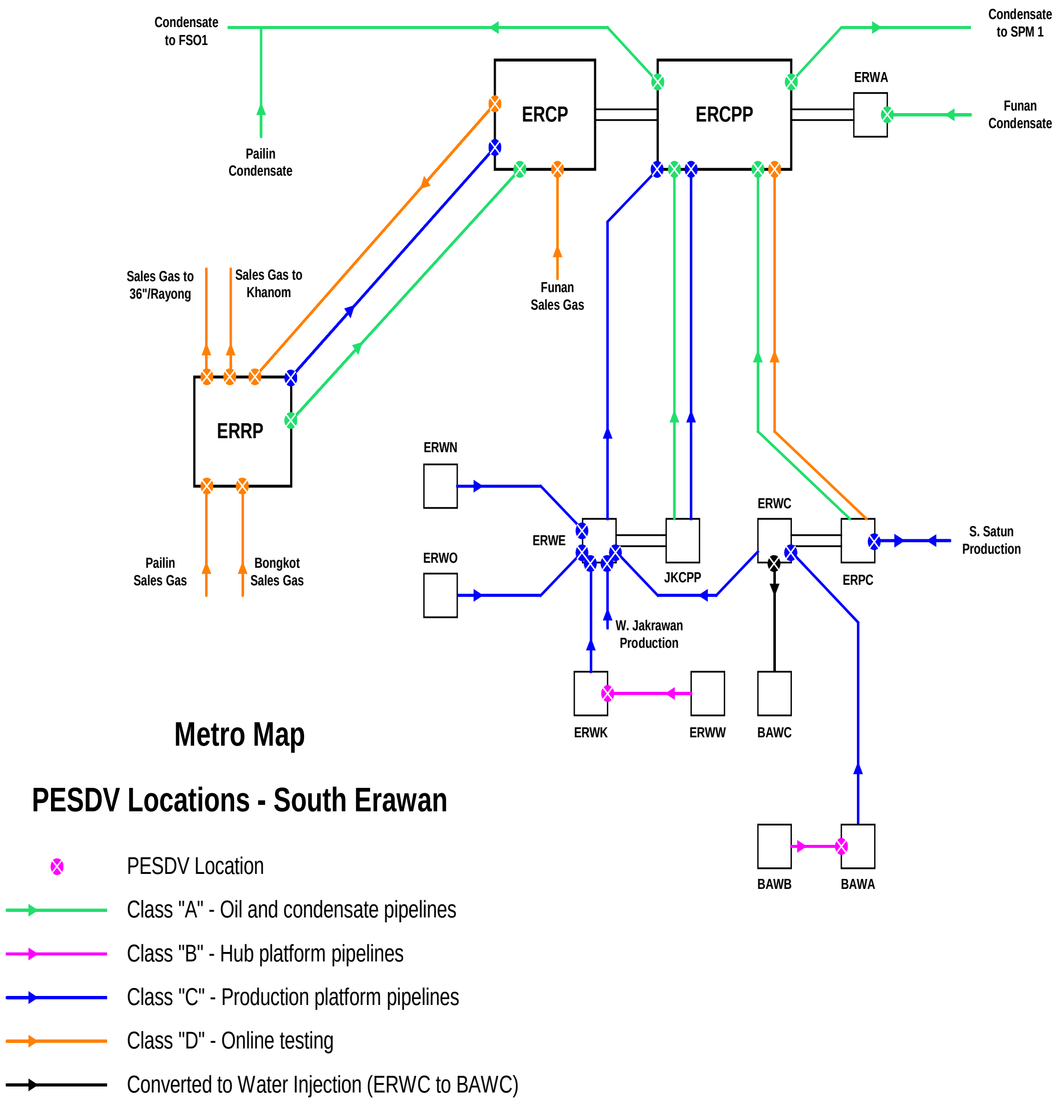
The actual location of PESDVs in the Gulf of Thailand Operations can be simply described by using the metro map which separated the following areas

- North Erawan
- South Erawan
- Platong Field
- Satun Field
- Funan Field; and
- Pailin field



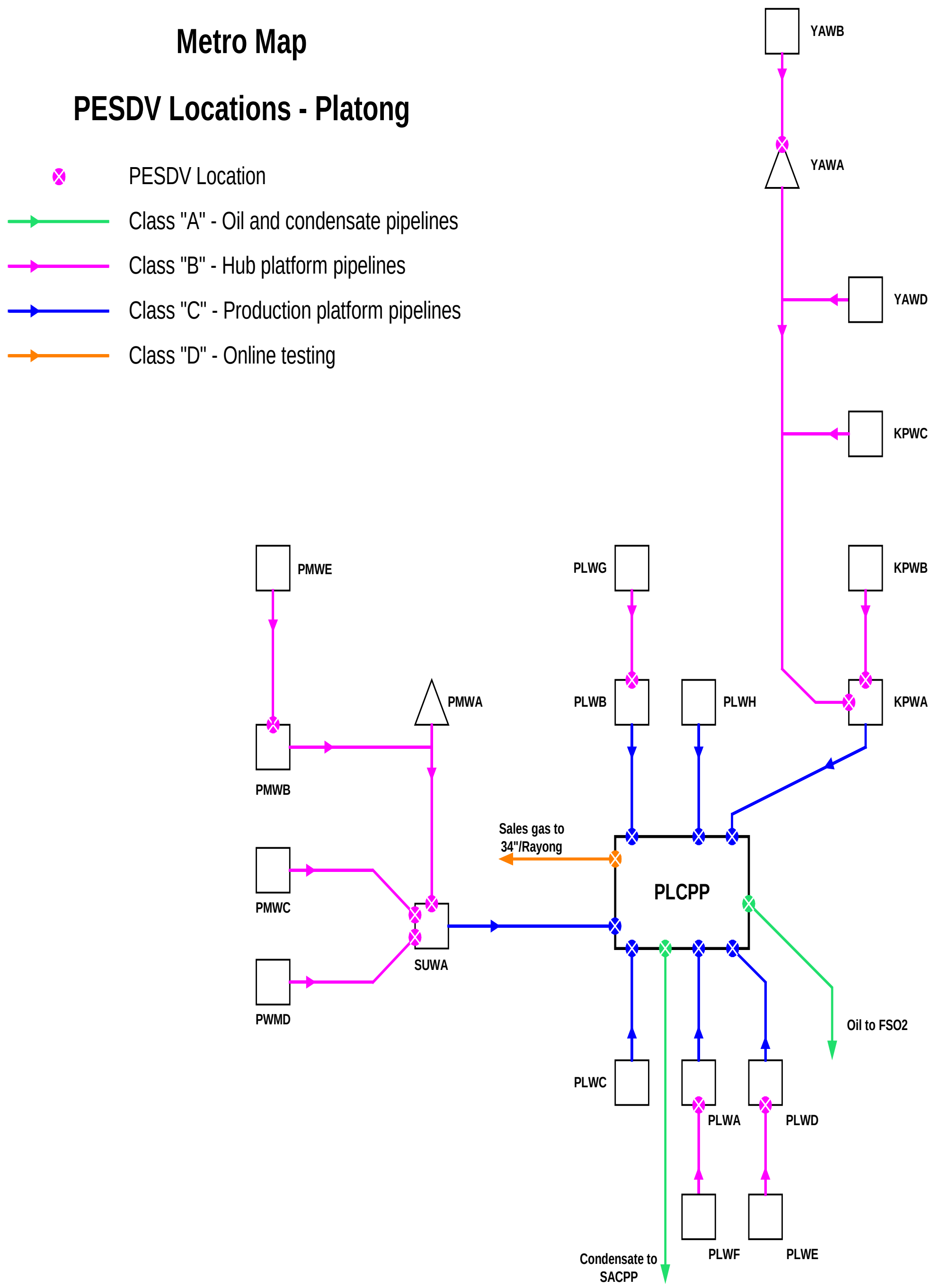
<u>Appendix Figure A5</u> PESDV – North Erawan

Source: Unocal Thailand, Limited (2006)



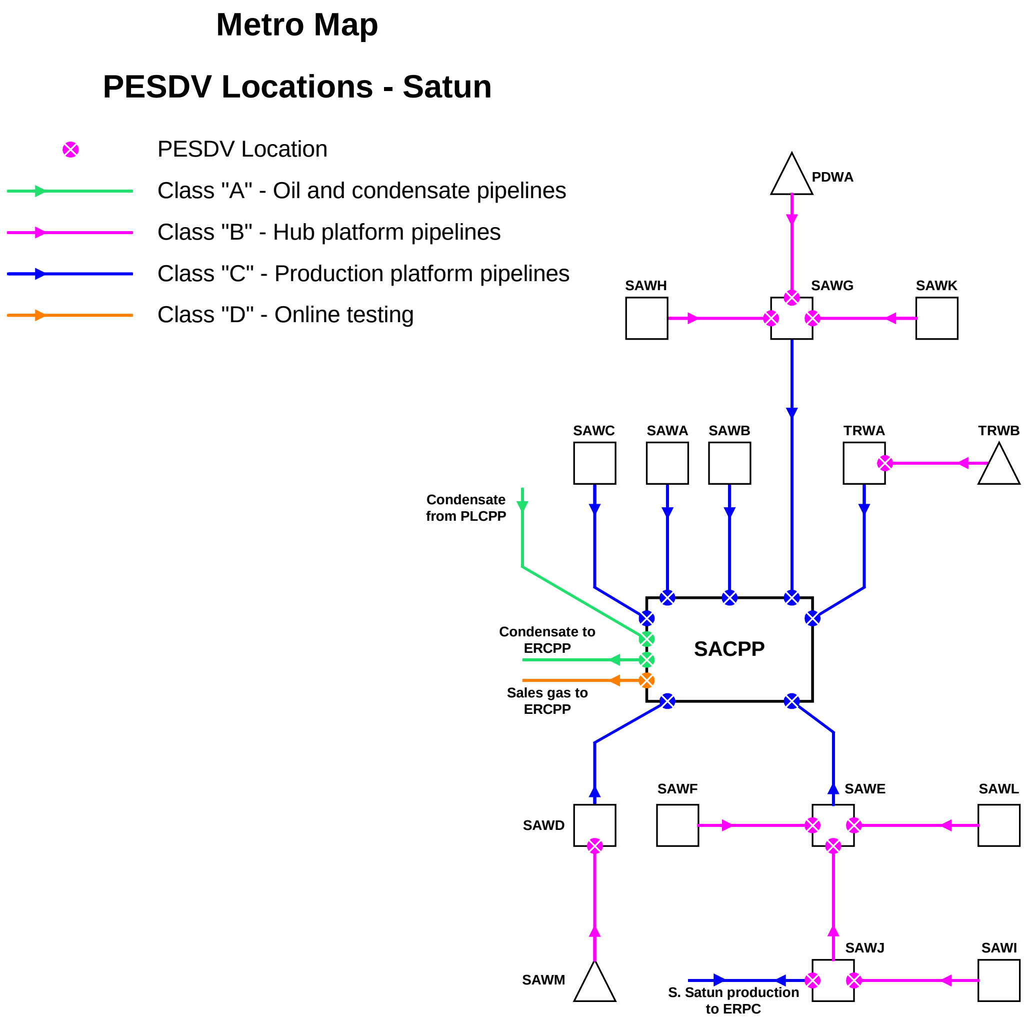
Appendix Figure A6 PESDV – South Erawan

Source: Unocal Thailand, Limited (2006)



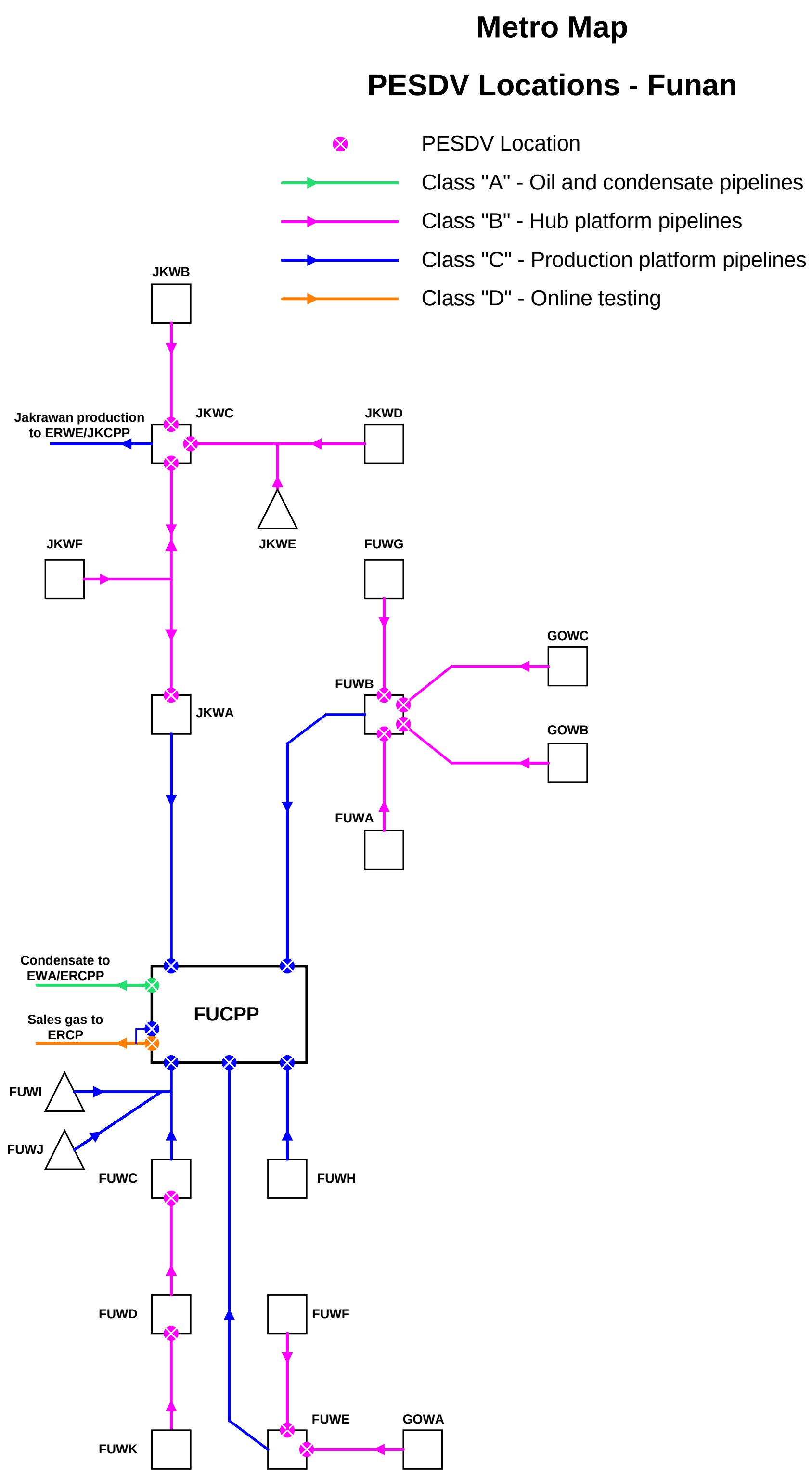
__Appendix Figure A7__ PESDV – Platong

Source: Unocal Thailand, Limited (2006)



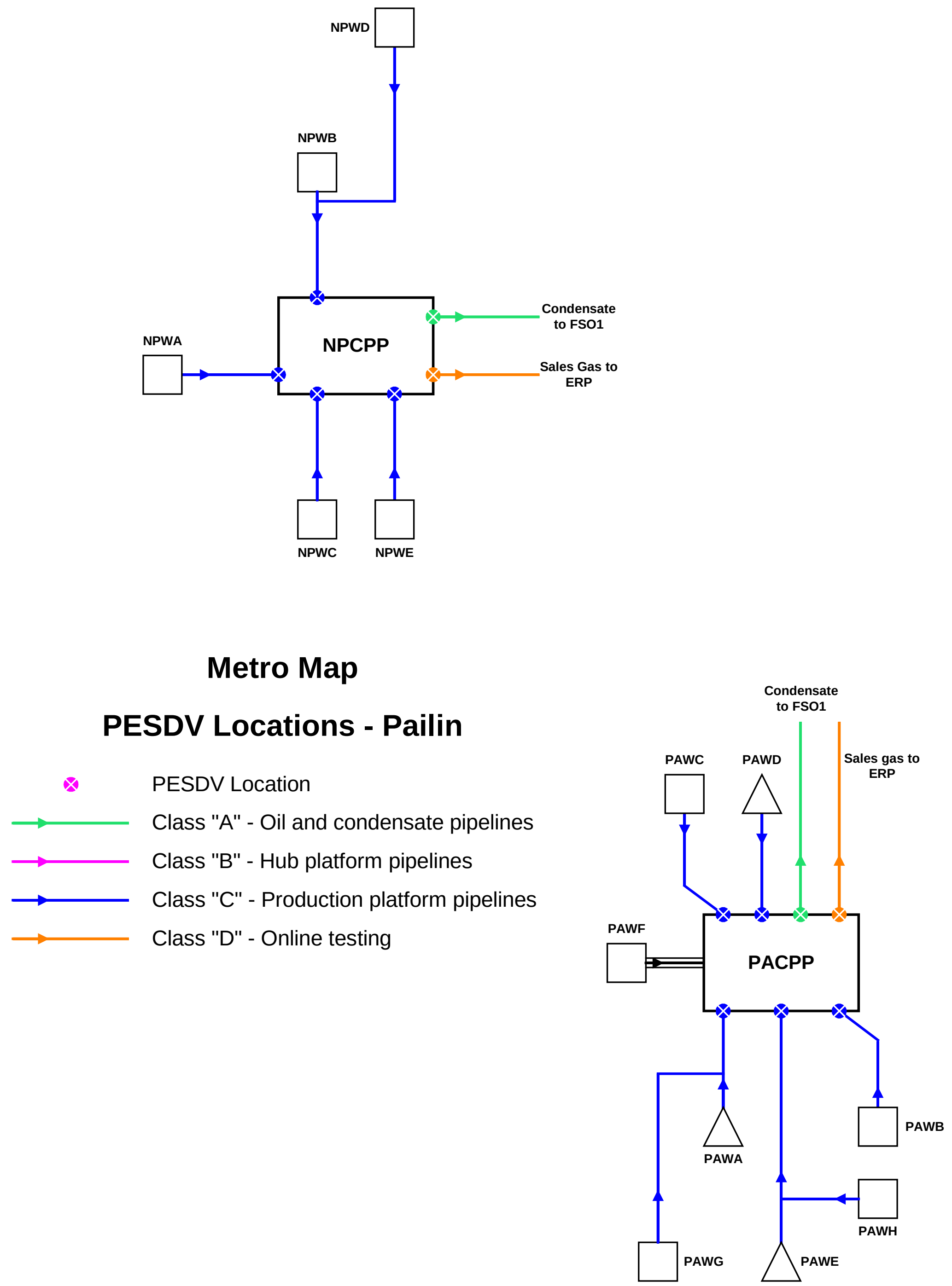
<u>Appendix Figure A8</u> PESDV – Satun

Source: Unocal Thailand, Limited (2006)



Appendix Figure A9 PESDV – Funan

Source: Unocal Thailand, Limited (2006)



<u>Appendix Figure A10</u> PESDV – Palin

Source: Unocal Thailand, Limited (2006)

Appendix B

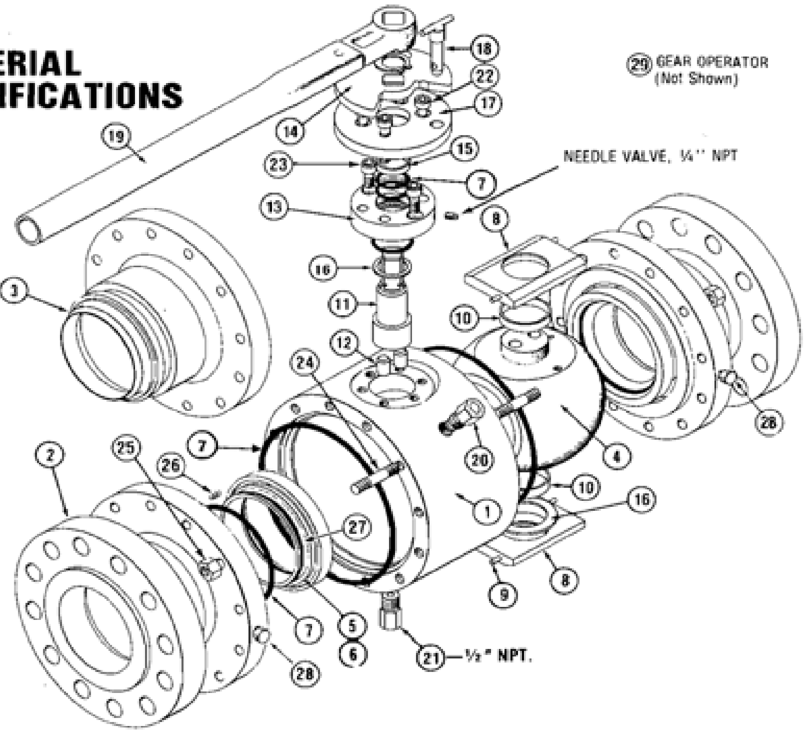
Support Documents used for Risk Assessment

Grove Ball Valve –Safety Components and Specifications

PESDVs were selected from the API and related industrial standards. This included fire test.

B-5

MATERIAL SPECIFICATIONS



PART NAME	MATERIAL
1. Body	Steel-A-105, A-350-LF2, A-106, A-216 Gr. WCC or WCB
2. Closure—Flanged End	Steel-A-572, A-537, A-106, A-216 Gr. WCC or WCB, A-350-LF2
3. Closure—Weld End	Steel-A-572, A-537, A-105, A-216 Gr. WCC or WCB, A-350-LF2
4. Ball	Nodular Iron-ASTM A-395 Grade 60-40-18**: or Steel ASTM A-148,A-216, A-350 Gr., LF2, A-105, Electroless Nickel Plated
5. Inner Seat Ring	Steel-ASTM A-36, A-572, A-537, Electroless nickel plated
6. Outer Seat Ring	Steel-ASTM A-36, A-572, A-537, Electroless nickel plated
7. ''O'' Rings	* Grovex Composition
8. Bearing Retainers	Steel-ASTM A-36, A-572, A-537
9. Dowel Pins (Retainer)	Steel-AISI C1212, or 4140
10. Bearings	DU® Self lubricated TFE fluorocarbon resin bonded to low carbon steel backing
11. Stem	Steel-AISI, C-1018 Electroless Nickel Plated

* GROVEX covers a variety of elastometric materials
** For Class 1500 Valves
NOTE: Always consult Grove direct for an exact description of materials currently being used or available and for different trim and material requirements.

PART NAME	MATERIAL
12. Drive Pins	Steel-AISI 4140, Heat Treated
13. Gland Plate	Steel-ASTM A-36, A-572, A-537
# 14. Stop collar, (Older Valves)	Steel-ASTM A-36, A-572, A-537
15. Gland Bushing	Steel-AISI C-1015, ASTM A-106 Pipe
16. Thrust Washers	Ryton Coated Steel
# 17. Adaptor Plate	Steel-ASTM A-36
18. Lock Pin	Steel-AISI C-1018
19. Wrench	Nodular Iron-ASTM A-395 Steel-ASTM A-106 Pipe
20. Relief Valve Assembly	Steel-AISI 1018
21. Drain Valve	Steel-AISI 1018 & AISI 4140
22. Capscrew (Stop Plate)	Alloy Steel ASTM A-574
23. Capscrew (Gland Plate)	Alloy Steel ASTM A-574
24. Stud	Steel ASTM A-193 B7M
25. Nut	Steel ASTM A-194 2HM
26. Seat Springs	Inconel X-750
27. U Cup Ring	Grovex Composition
28. Check Valve & Grease Fitting	Steel-AISI C-1213
29. Gear Operator	See Page 18 for Material Spec. on a typical Grove SY Operator

\# Newer valves have a one piece combination stop plate and adaptor plate.

Appendix Figure B1 Grove B5 Ball Material Specifications

Source: Grove Ball Valve Catalogue (2006)

Potential Hazards from pipe rupture when PESDV fail to close

By using "Vapor outflow from a hole" formula, the flow calculation model below indicate the severity of the risk of life and asset when an 1-inch ruptured hole on a downstream of a pipeline while the ESDV fail to close.

$$m = Cd \bullet Area \bullet \frac{Pg}{\sqrt{\frac{8314}{Mw} \bullet Tg}} \bullet \sqrt{k \bullet \left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad \text{……….(2)}$$

Source:Shell FRED User Guide version 2.1

Where :

m = Mass discharged in kg/s

Cd = Discharge coefficient (1.0 for gases)

Area = Hole area in m^2

Mw = Molecular weight in kg/kmol

Tg = Temperature of the vessel in K

Pcrit = Critical pressure ratio

P = ambient pressure, Pascal

Pg = pressure of the vessel, Pascal

K = isentropic expansion factor (Cp/Cv)

Example Calculation - vapour outflow from a hole

Data: 24″ sales gas pipeline

Hole size = 1″ = 0.0254 m

Operating pressure = 1266 psig = P_g

Gas Mol Wt = 25.81

Temperature = $80^{o}F$

Isentropic expansion factor (K = C_p/C_v) = 1.23 for natural gas

Contraction Coefficient (assume thick plate type origin) = 0.8

Firstly, check if glow is sonic. The critical pressure ratio (P_c) is given by:

$$P_c = \left\{\frac{2}{K+1}\right\}^{\frac{K}{K-1}} = \left\{\frac{2}{1.23+1}\right\}^{\frac{1.23}{1.23-1}}$$

$$P_c = 0.5587$$

If the pressure ratio (atmosphere/pipeline pressure) is below P_c then the glow is sonic. Since pipeline pressure $\rightarrow$ atmospheric flow is sonic and mass flow rate is given by:

$$m\,(\text{Kg/sec}) = \frac{C_d \times \text{Area} \times P_g}{\sqrt{\frac{8314}{\text{MWt}} \times T_g}} \sqrt{K\left(\frac{2}{K+1}\right)^{\frac{K+1}{K-1}}}$$

$$\sqrt{K\left(\frac{2}{K+1}\right)^{\frac{K+1}{K-1}}} = \sqrt{1.23\left(\frac{2}{1.23+1}\right)^{\frac{1.23+1}{1.23-1}}} = 0.6543$$

$$T_g(^{o}K) = 273.16 + T\,^{o}C$$

$$= 273.16 + (80-32)\frac{5}{9} = 299.82\text{K}$$

$$\sqrt{\frac{8314}{\text{MWt}} \times T_g} = \sqrt{\frac{8314}{25.81} \times 299.82} = 310.77$$

$$P_g(\text{Pascals}) = \left\{\frac{\text{Psig}}{14.504} + 1.01325\right\} \times 10^5$$

$$= 88.3 \times 10^5\ \text{Pascals}$$

Area for 1″ hole - $m^2 = \frac{\pi}{4}(d^2) = \frac{\pi}{4}(0.0254)^2 = 5.067\times10^{-4}m^2$

$$m\,(\mathrm{Kg/sec}) = \frac{0.8\times5.067\times10^{-4}\times88.3\times10^{5}}{310.77}\times0.6543$$

$$= 7.534 \ \ \mathrm{Kg/sec} \ \ \ = 16.614 \ \ \mathrm{Uos/sec}$$

Density of gas $\rho \ (\mathrm{Uos/gt^3}) = \frac{MP}{ZRT}$

At Standard conditions (1 atm, $60\,^{\mathrm{o}}\mathrm{F}$) to get standard cubic feet

P = 14.696 psia

Z = compressibility = 1.0

R = gas constant = 10.731

T = temperature = 60+459.7 = $519.7\,^{\mathrm{o}}\mathrm{R}$

$$\rho \ (\frac{\mathrm{Uos}}{\mathrm{SCF}}) = \frac{25.81\times14.696}{1.0\times10.731\times519.7} = 0.0680 \ \ \mathrm{Uos/SCF}$$

Volumetric leakage rate (MMSCFD)

$$= \frac{\mathrm{Uos}}{\mathrm{sec}}\times3600\times24\times\frac{\mathrm{SCF}}{\mathrm{Uos}}\times\frac{1}{10^6}$$

$$= 16.614\times3600\times24\times\frac{1}{0.0680}\times\frac{1}{10^6}$$

$$= 21.10 \ \ \mathrm{MMSCFD}$$

Appendix Table B1 Gas leak rate from 1” hole of 24” pipeline

24" line, 1" hole (25.4 mm)

Pressure psig	Rate MMSCFD	Pressure psig	Rate MMSCFD
1266.0	21.10	1276.4	21.27
1276.4	21.27	1286.9	21.44
1286.9	21.44	1297.3	21.61
1297.3	21.61	1307.7	21.78
1307.7	21.78	1318.1	21.95
1318.1	21.95	1328.6	22.13
1328.6	22.13	1339.0	22.30
1339.0	22.30	1349.4	22.47
1349.4	22.47	1359.8	22.64
1359.8	22.64	1370.3	22.81
1370.3	22.81	1380.7	22.98
1380.7	22.98	1391.1	23.16
1391.1	23.16	1401.5	23.33
1401.5	23.33	1412.0	23.50
1412.0	23.50	1422.4	23.67
1422.4	23.67	1432.8	23.84
1432.8	23.84	1443.2	24.01
1443.2	24.01	1453.7	24.19
1453.7	24.19	1464.1	24.36

Appendix Table B1 (Continued)

24" line, 1" hole (25.4 mm)

Pressure psig	Rate MMSCFD	Pressure psig	Rate MMSCFD
1464.1	24.36	1474.5	24.53
1474.5	24.53	1484.9	24.70
1484.9	24.70	1495.4	24.87
1495.4	24.87	1505.8	25.04
1505.8	25.04	1516.2	25.22
1516.2	25.22	1526.6	25.39
1526.6	25.39	1537.1	25.56
1537.1	25.56	1547.5	25.73
1547.5	25.73	1557.9	25.90
1557.9	25.90	1568.3	26.08
1568.3	26.08	1578.8	26.25
1578.8	26.25	1589.2	26.42
1589.2	26.42	1599.6	26.59
1599.6	26.59	1610.0	26.76
1610.0	26.76	1620.5	26.93

Source: Unocal Thailand, Limited (2006)

Appendix C

Test Method and Testing Task Sheet

<u>Testing Task Sheet (Examples)</u>

<u>TYPICAL WORK INSTRUCTION: CLASS A PESDV</u>

JOB CARD	:	TASK001
WORK ORDER DESCRIPTION	:	ANNUAL ERESDV2090CPP – 10 IN CONDY TO SPM2
WORK GROUP	:	PRODUCTION
ASSIGNED TO	:	OPERATOR
EQUIPMENT	:	ERESDV2090CPP
RESOURCE TYPE	:	2X1=2 M/H
PRIORITY	:	2 GROUP A
EQUIPMENT STATUS	:	SHUTDOWN

MFGR AND ENGINEERING RECOMMENDATIONS (INFO ONLY):

1. ANSI/ISA S84.01
2. EUROPEAN IEC 61508
3. API RP6D/BS 5361
4. UNOCAL MAINTENANCE PROGRAM

JOB INSTRUCTIONS

EQUIPMENT UNDER THIS TASK:

ERSDV2090CPP = 10 IN CONDY LINE TO SPM2- GROUP A

A. VALVE, WKM 300
B. ACTUATOR, BETTISH T316-SR1

1. PREPARATION FOR PM WORK:

A. GET WORK PERMIT AND COORDINATE WITH PRODUCTION TO SHUTDOWN THE ESDV2090CPP
B. RECORD CONDY LINE PRESSURE___PSIG

2. INSPECT MAIN VALVE, ACTUATOR AND CONTROLS

A. INSPECT MAIN VALVE FOR CONDY LEAKAGES ON STEM SEALS AND FLANGES

B. INSPECT VALVE ACTUATOR, PILOT OR DIRECTIONAL CONTROL VALVE (XPV),
VENT PORT FOR PILOT AND SUPPLY AIR LEAKAGES AND CHECK CONDITION OF POSITION SWITCHES

C. INSPECT SOLENOID VALVE, LATCH MECHANISM, EXHAUST PORT, AIR FILTER / REGULATOR, WIRING AND JUNCTION BOX FOR LOOSE, LEAKAGES AND FOR CORROSION

COMMENT___________________________DONE BY__________

3. ESDV LUBRICATIONS:

A. LUBRICATE VALVE STEM, GREASE FITTINGS ON VALVE BODY, STUFFING BOX AND ACTUATOR AS APPLICABLE.

B. CLEAN AIR FILTER IF INSTALLED

C. CHECK FUNCTION OF ACTUATOR LUBRICATOR

4. FULL CLOSURE AND RE-OPENING TESTS

(PERFORM DURING PLANNED SHUTDOWN SCHEDULE):

A. CLOSE THE ESDV USING ESD SYSTEM.

B. OBSERVE ACTUATOR/VALVE
MOVEMENT____SMOOTH,____SLUGGISH

C. RECORD TIME TO CLOSE ______SECOND

D. RECORD DIFF PRESSURE (PI2090)______PSIG

E. RECORD ANY EXTERNAL LEAKAGES

COMMENT________________________DONE BY__________

5. RE-OPENING AFTER SERVICE OR REPAIRED AS REQUIRED (PERMISSION OBTAINED)
   A. OPEN THE VALVE
   B. OBSERVE ACTUATOR/VALVE MOVEMENT___SMOOTH,___SLUGGISH
   C. RECORD TIME TO OPEN_____SECOND
   COMMENT_______________________DONE BY_______/________

6. FINAL CHECK:
   A. ENSURE THAT ESDV IS PROPERLY MAINTAINED.
   B. RETURN ALL VALVES, LATCH AND CONTROLS IN NORMAL POSITION
   C. PUT SYSTEM BACK TO OPERATION
   SIGN DONE BY____________DATE_______________

REMARKS:

RETAIN HARD COPY FOR REVIEW AND REFERENCES FOR 2 YEARS

TYPICAL WORK INSTRUCTION: CLASS B PESDV

JOB CARD	:	TASK001
WORK ORDER DESCRIPTION	:	ANNUAL ERESDV1110WR - 10 IN GAS P/L FROM EWT
WORK GROUP	:	PRODUCTION
ASSIGNED TO	:	OPERATOR
EQUIPMENT	:	ERESDV1110WR
RESOURCE TYPE	:	2X1=2 M/H
PRIORITY	:	2 GROUP B
EQUIPMENT STATUS	:	SHUTDOWN

MFGR AND ENGINEERING RECOMMENDATIONS (INFO ONLY):

1. ANSI/ISA S84.01
2. EUROPEAN IEC 61508
3. API RP6D/BS 5361
4. UNOCAL MAINTENANCE PROGRAM

JOB INSTRUCTIONS

EQUIPMENT UNDER THIS TASK:

ESDV1110WR 10 IN GAS P/L FROM EWT-GROUP B

C. TK BALL VALVE P/N 101006JPNNTV

B. BETTISH ACTUATOR, SINGLE ACTION P/N T315-SR1

1. **PREPARATION FOR PM WORK:**

   C. GET WORK PERMIT AND COORDINATE WITH PRODUCTION/OPERATORS TO SHUTDOWN THE ESDV1110WR

   D. RECORD PIPLINE PRESSURE ___PSIG, TEMPERATURE ___F

2. INSPECT MAIN VALVE, ACTUATOR AND CONTROLS

D. INSPECT MAIN VALVE FOR GAS LEAKAGES ON STEM SEALS AND FLANGES

E. INSPECT VALVE ACTUATOR, PILOT OR DIRECTIONAL CONTROL VALVE (XPV),
VENT PORT FOR PILOT AND SUPPLY AIR LEAKAGES AND CHECK CONDITION OF POSITION SWITCHES

F. INSPECT SOLENOID VALVE, LATCH MECHANISM, EXHAUST PORT, AIR FILTER / REGULATOR, WIRING AND JUNCTION BOX FOR LOOSE, LEAKAGES AND FOR CORROSION
COMMENT __________ DONE BY _________

3. ESDV LUBRICATIONS:

D. LUBRICATE VALVE STEM, GREASE FITTINGS ON VALVE BODY, STUFFING BOX AND ACTUATOR AS APPLICABLE.

E. CLEAN AIR FILTER IF INSTALLED

F. CHECK FUNCTION OF ACTUATOR LUBRICATOR

4. FULL CLOSURE AND RE-OPENING TESTS

(PERFORM DURING PLANNED SHUTDOWN SCHEDULE):

F. CLOSE THE ESDV USING ESD SYSTEM.

G. OBSERVE ACTUATOR/VALVE MOVEMENT ___ SMOOTH,____SLUGGISH

H. RECORD TIME TO CLOSE _____ SECOND

I. RECORD DIFF PRESSURE _____ PSIG

J. RECORD ANY EXTERNAL LEAKAGES
COMMENT________________________DONE BY_________

5. RE-OPENING AFTER SERVICE OR REPAIRED AS REQUIRED

(PERMISSION OBTAINED)

D. OPEN THE VALVE

E. OBSERVE ACTUATOR/VALVE MOVEMENT ____ SMOOTH,,___SLUGGISH

F. RECORD TIME TO OPEN ___ SECOND

COMMENT______________________DONE BY____________

6. FINAL CHECK:

D. ENSURE THAT ESDV IS PROPERLY MAINTAINED.

E. RETURN ALL VALVES, LATCH AND CONTROLS IN NORMAL POSITION

F. PUT SYSTEM BACK TO OPERATION

SIGN DONE BY

____

REMARKS:

RETAIN HARD COPY FOR REVIEWED AND REFERENCES FOR 2 YEARS

TYPICAL WORK INSTRUCTION: CLASS C PESDV

JOB CARD	:	TASK001
W/O DESCRIPTION	:	SEMI-ANNUAL ERESDV2000CPP-10 INCH.
GAS P/L FROM EWF GROUP	:	PRODUCTION
ASSIGNED TO	:	OPERATOR
EQUIPMENT	:	ERESDV2000CPP
RESOURCE TYPE	:	2X1=2 M/H
PRIORITY	:	2 GROUP C
EQUIPMENT STATUS	:	SHUTDOWN

MFGR AND ENGINEERING RECOMMENDATIONS (INFO ONLY):

1. ANSI/ISA S84.01
2. EUROPEAN IEC 61508
3. API RP6D/BS 5361
4. UNOCAL MAINTENANCE PROGRAM

JOB INSTRUCTIONS

EQUIPMENT UNDER THIS TASK:

ESDV2000CPP 10 IN GAS P/L FROM EWF-GROUP C

D. GROVE B5 VALVE

B. BETTISH ACTUATOR, SINGLE ACTION P/N T-516-SR2

5. PREPARATION FOR PM WORK:
   E. GET WORK PERMIT AND COORDINATE WITH PRODUCTION TO SHUTDOWN THE ESDV2000CPP
   F. RECORD PIPLINE PRESSURE_______PSIG, TEMPERATURE______F
   G. INSTALL TEST PRESSURE GUAGE 0 – 500 PSI ON RECEIVER

6. INSPECT MAIN VALVE, ACTUATOR AND CONTROLS
    G. INSPECT MAIN VALVE FOR GAS LEAKAGES ON STEM SEALS AND FLANGES
    H. INSPECT VALVE ACTUATOR, PILOT OR DIRECTIONAL CONTROL VALVE (XPV),
    VENT PORT FOR PILOT AND SUPPLY AIR LEAKAGES AND CHECK CONDITION OF POSITION SWITCHES
    I. INSPECT SOLENOID VALVE, LATCH MECHANISM, EXHAUST PORT, AIR FILTER / REGULATOR, WIRING AND JUNCTION BOX FOR LOOSE, LEAKAGES AND FOR CORROSION
    COMMENT___________________________DONE BY____________

7. ESDV LUBRICATIONS:
    G. LUBRICATE VALVE STEM, GREASE FITTINGS ON VALVE BODY, STUFFING BOX AND ACTUATOR AS APPLICABLE.
    H. CLEAN AIR FILTER IF INSTALLED
    I. CHECK FUNCTION OF ACTUATOR LUBRICATOR

8. FULL CLOSURE AND RE-OPENING TESTS
    (PERFORM DURING PLANNED SHUTDOWN SCHEDULE):
    K. CLOSE THE ESDV USING ESD SYSTEM.
    L. OBSERVE ACTUATOR/VALVE
    MOVEMENT___SMOOTH,____SLUGGISH
    M. RECORD TIME TO CLOSE _______SECOND
    N. RECORD DIFF PRESSURE________PSIG
    O. RECORD ANY EXTERNAL LEAKAGES
    COMMENT_______________________DONE
    BY________/________

9. **INTERNAL BODY SEAL LEAKAGE TESTS**

(PERFORM DURING FULL CLOSURE TEST ITEM 4)

A. LEAKAGE MONITORING VOLUME (V1) 19.71 CU. FT.

B. USING V2 = V1(P1+14.7) / P2T (P2=14.7)

C. DEPRESSURIZE THE TOPSIDE PIPE WORK IN-BOARD OF THE ESDV

D. ENSURE THAT THE TEST PRESSURE GUAGE ON THE RECEIVER INDICATES O PSIG. PRIOR TO COMMENCE MONITORING

E. MONITOR PRESSURE BUILD UP IN THE RECEIVER FOR 10 – 30 MINUTES

F. RECORD LEAKAGE PRESSURE B/U (P1)______PSIG

G. RECORD LEAKAGE MONITORING TIME (T) _____MINUTES

H. DETERMINE VALVE LEAKAGE RATE (V2)_________CU.FT/MINUTE

COMMENT__________________________DONE BY_________/________

10. RE-OPENING AFTER SERVICE OR REPAIRED AS REQUIRED

(PERMISSION OBTAINED)

G. OPEN THE VALVE

H. OBSERVE ACTUATOR/VALVE MOVEMENT____SMOOTH,,___SLUGGISH

I. RECORD TIME TO OPEN______SECOND

J. RECORD DIFF PRESSURE_______PSIG

COMMENT________________________DONE BY________/________

11. FINAL CHECK:

G. ENSURE THAT ESDV IS PROPERLY MAINTAINED.

H. RETURN ALL VALVES, LATCH AND CONTROS IN NORMAL POSITION

I. PUT SYSTEM BACK TO OPERATION

SIGN DONE BY_____________/__________________

REMARKS:

RETAIN HARD COPY FOR REVIEWED AND REFERENCES FOR 2 YEARS

TYPICAL WORK INSTRUCTION: CLASS D PESDV

JOB CARD	:	TASK001
WORK ORDER DESCRIPTION	:	5 YEARS ERESDV2005CPP- 16 IN GAS P/L FROM EPB
WORK GROUP	:	PRODUCTION
ASSIGNED TO	:	OPERATOR
EQUIPMENT		ERESDV2005CPP
RESOURCE TYPE	:	2X1=2 M/H
PRIORITY	:	2 –GROUP D
EQUIPMENT STATUS	:	SHUTDOWN

MFGR AND ENGINEERING RECOMMENDATIONS (INFO ONLY):

1. ANSI/ISA S84.01
2. EUROPEAN IEC 61508
3. API RP6D/BS 5361
4. UNOCAL MAINTENANCE PROGRAM

JOB INSTRUCTIONS

EQUIPMENT UNDER THIS TASK:

ESDV2005CPP 16 IN GAS P/L FROM EPB-GROUP D

E. TK BALL VALVE P/N 161606JPNSTV

B. BETTISH ACTUATOR, SINGLE ACTION P/N T-520-SR1

5. **PREPARATION FOR PM WORK:**

H. GET WORK PERMIT AND COORDINATE WITH PRODUCTION / OPERATORS TO SHUTDOWN THE ESDV2005CPP

I. RECORD PIPLINE PRESSURE_________PSIG, TEMPERATURE______F

J. INSTALL TEST PRESSURE GUAGE 0 – 500 PSI ON RECEIVER

6. INSPECT MAIN VALVE, ACTUATOR AND CONTROLS

J. INSPECT MAIN VALVE FOR GAS LEAKAGES ON STEM SEALS AND FLANGES

K. INSPECT VALVE ACTUATOR, PILOT OR DIRECTIONAL CONTROL VALVE (XPV),
VENT PORT FOR PILOT AND SUPPLY AIR LEAKAGES AND CHECK CONDITION OF POSITION SWITCHES

L. INSPECT SOLENOID VALVE, LATCH MECHANISM, EXHAUST PORT, AIR FILTER / REGULATOR, WIRING AND JUNCTION BOX FOR LOOSE, LEAKAGES AND FOR CORROSION
COMMENT___________________________DONE BY___________

7. ESDV LUBRICATIONS:

J. LUBRICATE VALVE STEM, GREASE FITTINGS ON VALVE BODY, STUFFING BOX AND ACTUATOR AS APPLICABLE.

K. CLEAN IN LINE AIR FILTER, IF INSTALLED

L. CHECK FUNCTION OF ACTUATOR LUBRICATOR.

8. FULL CLOSURE AND RE-OPENING TESTS

(PERFORM DURING PLANNED SHUTDOWN SCHEDULE):

P. CLOSE THE ESDV USING ESD SYSTEM.

Q. OBSERVE ACTUATOR / VALVE MOVEMENT___SMOOTH,____SLUGGISH

R. RECORD TIME TO CLOSE _______SECOND

S. RECORD DIFF PRESSURE________PSIG

T. RECORD ANY EXTERNAL LEAKAGES____________________
COMMENT________________________DONE BY________/________

9. **INTERNAL BODY SEAL LEAKAGE TESTS**

(PERFORM DURING FULL CLOSURE TEST ITEM 4)

I. LEAKAGE MONITORING VOLUME (V1) 33.47 CU. FT.

J. USING V2 = V1(P1+14.7) / P2T (P2=14.7)

K. DEPRESSURIZE THE TOPSIDE PIPE WORK IN-BOARD OF THE ESDV ENSURE THAT BYPASS VALVE IS NOT LEAKING.

L. ENSURE THAT THE TEST PRESSURE GUAGE ON THE RECEIVER INDICATES O PSIG. PRIOR TO COMMENCE MONITORING

M. MONITOR PRESSURE BUILD UP IN THE RECEIVER FOR 10 – 30 MINUTES

N. RECORD LEAKAGE PRESSURE B/U (P1)______PSIG

O. RECORD LEAKAGE MONITORING TIME (T) _____MINUTES

P. DETERMINE VALVE LEAKAGE RATE (V2)_________CU.FT/MINUTE

COMMENT__________________________DONE BY_________/________

10. RE-OPENING AFTER SERVICE OR REPAIRED AS REQUIRED

(PERMISSION OBTAINED)

K. OPEN THE VALVE

L. OBSERVE ACTUATOR/VALVE MOVEMENT____SMOOTH,___SLUGGISH

M. RECORD TIME TO OPEN______SECOND

COMMENT________________________DONE BY________/________

11. FINAL CHECK:

J. ENSURE THAT ESDV IS PROPERLY MAINTAINED.

K. RETURN ALL VALVES, LATCH AND CONTROS IN NORMAL POSITION

L. PUT SYSTEM BACK TO OPERATION

SIGN DONE BY_____________/__________________

REMARKS:

RETAIN HARD COPY FOR REVIEWED AND REFERENCES FOR 2 YEARS

Appendix D

Additional Literature Review and Related Theory

1) The Piper Alpha Incident

2) Topside Emergency Shutdown Valve (ESV) Survivability

3) A Study of the Dynamic Response of Emergency Shutdown Valves Following Full Bore Rupture of Gas Pipelines

4) The Offshore Installations (Emergency Pipe-line Valve) Regulations 1989, Statutory Instrument SI 1989/1029, North Sea.

The Piper Alpha Incident

The following review will give a broad overview and then narrow down to the Lord Cullin's recommendation numbers 47 and 48 which are the purpose of this study.

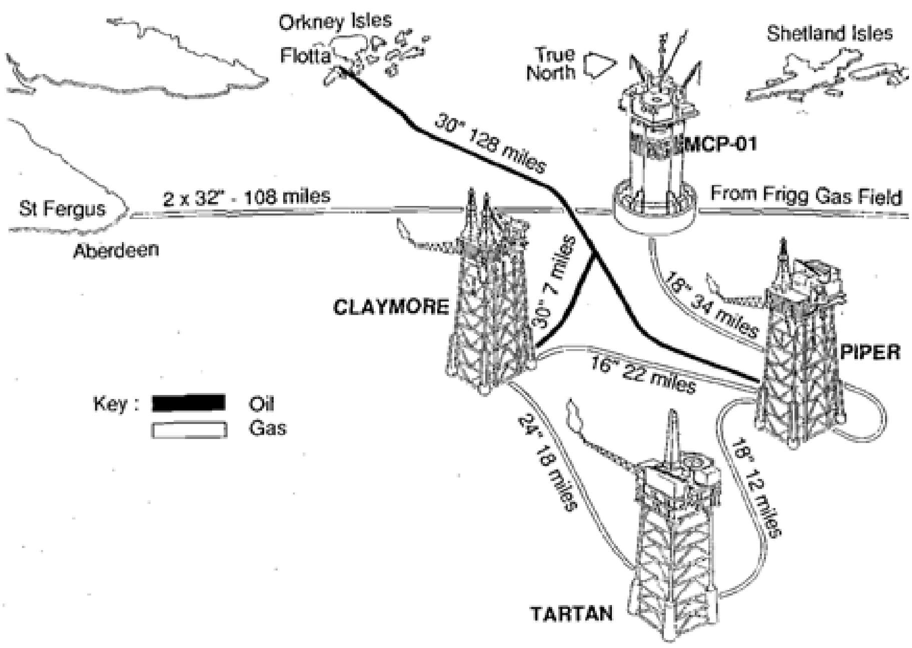
New Zealand Safety Council (2006) reported that the Piper Alpha Oil Platform catastrophe occurred in the North Sea, UK in July 1988. The platform was an impressive sight. It stood one hundred feet above some of the fiercest waters in the North Sea. Lights sprinkled around the huge accommodation block designed to hold over two hundred men, gantries held aloft a burning torch, a proud symbol of the thousands of tonnes of black gold it was pumping back to shore.

Occidental Petroleum was getting its money's worth; around £3½ m a day, to be precise. At its peak Piper Alpha accounted for 10% of the UK's North Sea oil production. But in just a few hours, this marvel of engineering was reduced to a blackened, smoking, stump. Most of the rig melted and fell away into the sea. Of the 225 men on board 167 died. The catastrophe in July 1988 shocked the oil industry into realizing that the dangers on a rig like Piper Alpha were worse than they have possibly imagined. As Lord Cullen's public enquiry rumbled on it also became clear that it was not an 'accident'.

Background and Events of the Disaster: Technical Viewpoint

Piper Alpha was an oil platform in the North Sea that caught fire and burned down on July 6,1988. It was the worst ever offshore petroleum accident, during which 167 people died and a billion dollar platform was almost totally destroyed. The platform consisted of a drilling derrick at one end, a processing/refinery area in the centre, and living accommodations for its crew on the far end. Since Piper Alpha was close to shore than some other platforms in the area, it had two gas risers (large pipes) from those platforms leading into the processing area. It processed the gas from the risers plus the oil products it drilled itself and then piped the final products to shore.

The disaster began with a routine maintenance procedure. A certain backup propane condensate pump in the processing area needed to have its pressure safety valve checked every 18 months, and the time had come. The valve was removed, leaving a hole in the pump where it had been. Because the workers could not get all the equipment they needed by 6:00 PM, they asked for and received permission to leave the rest of the work until the next day. Later in the evening during the next work shift, a little before 10:00 PM, the primary condensate pump failed. The people in the control room, who were in charge of operating the platform, decided to start the backup pump, not knowing that it was under maintenance. Gas products escaped from the hole left by the valve with such force that workers described it as being like the scream of a banshee. At about 10:00, it ignited and exploded.



Appendix Figure D1 Pipeline connection of Pipe field

Source: The public Inquiry into the Piper Alpha Disaster (2006)

Force of the explosion

The force of the explosion blew down the firewall separating different parts of the processing facility, and soon large quantities of stored oil were burning out of control. The automatic deluge system, (which was designed to spray water on such a fire in order to contain it or put it out), was never activated because it had been turned off. About twenty minutes after the initial explosion, at 10:20, the fire had spread and become hot enough to weaken and then burst the gas risers from the other platforms. These were steel pipes of a diameter from twenty-four to thirty-six inches, containing flammable gas products at two thousand pounds per square inch of pressure.

When these risers burst, the resulting jet of fuel dramatically increased the size of the fire from a billowing fireball to a towering inferno. At the fire's peak, the flames reached three hundred to four hundred feet in the air and could be felt from over a mile away and seen from eighty-five.

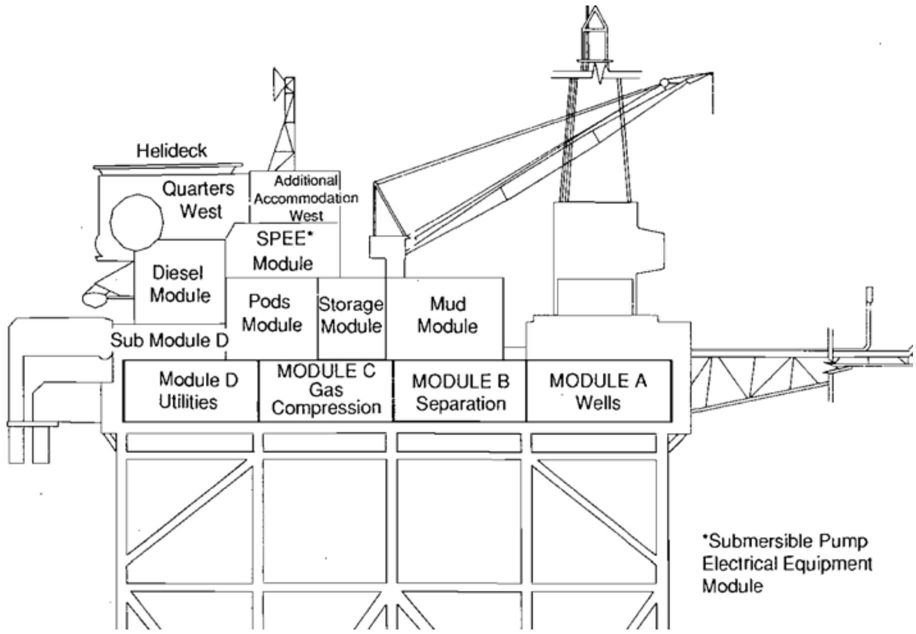
The gas risers that were fuelling the fire were finally shut off about an hour after they had burst, but the fire continued as the oil on the platform and the gas that was already in the pipes burned. Three hours later the majority of the platform, including the accommodations, had melted off and sunk below the water. The ships in the area continued picking up survivors until morning, but the platform and most of its crew had been destroyed.

Risk Assessment

Those risers were clearly the primary risk on the platform, but nothing was done to protect them. It was recommended that a specific deluge system be installed just for them, along with an automatic valve that would seal them off at sea level in the event of an alarming pressure loss, etc., but none of these measures was implemented. Most modern platforms do have such features where they are appropriate.

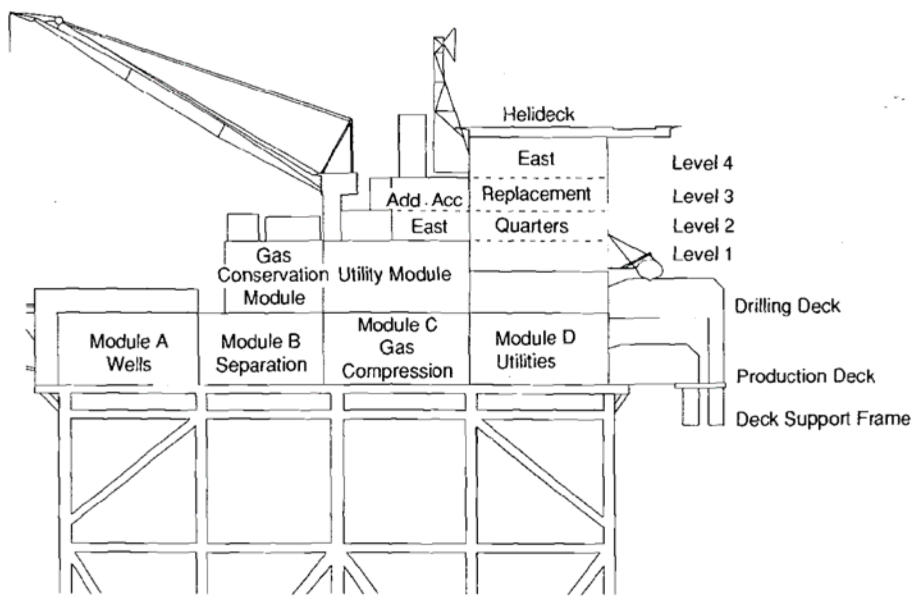
<u>Outbreak of fire in module B</u>

Cullin (1990), Drysdale, a Lecturer in the Fire Safety Engineering Unit of the University of Edinburgh, gave evidence as to his interpretation of these conditions in the light of the evidence of eye-witnesses and the available photographs. It is clear that the fuel for the fire in B Module must have been crude oil. According to Dr Drysdale stabilized crude oil on Piper contained about 7O% of light ends. An ignited leak of this oil would give flames both from the flashing vapor (for which he used a round figure of 10%) and from the resulting pool of oil. He suggested that the fire might have been due to a rupture in the 4 inch condensate line in B Module before it joined the main oil line (MOL), the rupture being either upstream or downstream of the non-return valve. In the latter case the rupture would release condensate in the normal direction of flow and also crude oil from the MOL in the reverse direction. In the former case oil would not be released from the condensate line unless the non-return valve had failed to function properly-- such malfunction was not uncommon. It is evidenced that rupture of the condensate line at either place could explain the subsequent fire. The running oil down to the oil line may have resulted from oil being sprayed on to the MOL during time when the fireball was occurring. Alternatively it was a leak from above ESDV which decreased when the valve closed. The fireball would have caused burning gas to spread from the existing fire in B module.



Appendix Figure D2 The Piper Alpha platform: west elevation (simplified).

Source: The public Inquiry into the Piper Alpha Disaster (2006)



Appendix Figure D3 The Piper Alpha platform: east elevation (simplified).

Source: The public Inquiry into the Piper Alpha Disaster (2006)

Lord Cullin's Recommendations

The Public Enquiry into the Piper Alpha Disaster provided 106 recommendations. They included engineering, management, regulatory and enforcement requirements. Only three recommendations will be referred in this thesis:

1. Fire and gas detection and emergency shutdown
2. Fire and explosion protection; and
3. Pipeline emergency procedures

Fire and gas detection and emergency shutdown

This included recommendation # 47 and # 48

Recommendation # 47: The arrangements for the activation of the emergency shutdown valves (ESVs), and of Sub Sea Isolation Valve (SSIVs) if fitted, on pipelines should be a feature of the Safety Case. Two point were mentioned here, one is the activation of the ESD for the pipelines. There were reasons for the system on Piper in which ESD had to be effected separately for each gas pipeline, since ESD of a pipeline would force an ESD on the connected platform and such forced ESD is generally undesirable. However, the arrangements for the ESD of pipelines are a matter of some importance if the full value of ESVs and SSIVs is to be realized. They should be one of the features considered in the Safety Case.

Recommendation # 48 : Studies should be done to determine the vulnerability of ESVs to severe accident conditions and to enhance their ability to survive such conditions The ESVs to close under severe accident conditions, which include fire, explosion and strong vibration. Platform vibration, or shock, caused by the explosion was discussed by Dr Cubbage and was one of the few explanations advanced for the apparent incomplete closure of ESVs on Piper. Work needs to be done to determine the vulnerability of ESVs to severe accident conditions and to enhance their ability to survive such conditions.

Fire and explosion protection

This included recommendation # 49 to # 54

Recommendation # 49 : Operators should be required by regulation to submit a fire risk analysis to the regulatory body for its acceptance. There should be a requirement in the regulations for a fire risk analysis covering both major and lesser hazards. This analysis should involve the identification of the locations where fires may occur; the scenarios of fire and of their escalation; the mitigatory measures available; and the assessment of the hazards and mitigatory measures. The acceptance standards for the design should be developed by the operator.

Recommendation #50 : The regulations and related guidance notes should promote an approach to fire and explosion protection:-

(a) which is integrated as between -

- Active and passive fire protection
- Different forms of passive fire protection, such as fire insulation and platform layout, and
- Fire protection and explosion protection;

(b) in which the need for, and the location and resistance of, fire and blast walls is determined by safety assessment rather than by regulations ;

(c) in which the function, configuration, capacity, availability and protection of the fire water deluge system is determined by safety assessment rather than by regulations;

(d) which facilitates the use of a scenario-based design method for fire Protection as an alternative to the reference area method; and

(e) which provides to a high degree the ability of the fire water deluge system, including the fire pump system, to survive severe accident conditions.

Recommendation # 51 : The ability of the fire water deluge system, including the fire pump system, to survive severe accident conditions should be a feature of the Safety Case.

The regulations and guidance should promote an approach to the design of fire protection systems which ensures that as far as is reasonably practicable the systems are able to survive severe accident conditions, including fire, explosion and strong vibration. The fire protection systems referred to here include the fire-water deluge system, the fire pump system, and the fire pump startup and changeover controls. The ability of these systems to survive severe accident conditions should also be a feature of the Safety Case.

Recommendation # 52: The regulatory body should work with the industry to obtain agreement on the interpretation for design purposes of its interim hydrocarbon fire test and other similar tests. If in the view of the regulatory body there exists a need for an improved test, such as a heat flux test, it should work with the industry in order to develop one.

Recommendation # 53: The Department of Energy (Den) discussion document on Fire and Explosion Protection should be withdrawn.

Recommendation # 54: The regulatory body should ask operators which have not already done so to undertake forthwith a fire risk analysis, without waiting for legislation.

Pipeline emergency procedures

This included recommendation # 71 and # 72

Recommendation # 71: Operators should be required by regulation regularly to review pipeline emergency procedures and manuals. The review should ensure that the information contained in manuals is correct, that the procedures contained are agreed with those who are responsible for executing them and are consistent with the procedures of installations connected by hydrocarbon pipelines

The quality of pipeline emergency procedures needs to be improved. There should be more co-operations between operators in a field in the formulation of arrangements and the writing of manuals. There should also be more involvement in these activities by the personnel most directly affected; those on the installations, to ensure that the information contained is correct and that the procedures proposed are the most practical and effective. The procedures should be reviewed regularly and the manuals updated in a coordinated manner.

Recommendation # 72: Operators should be required by regulation to institute and review regularly a procedure for shutting down production on an installation in the event of an emergency on another installation which is connected to the first by a hydrocarbon pipeline where the emergency is liable to be exacerbated by continuation of such production.

The pipeline emergency procedures for the installation should define the conditions which constitute reason to believe that there has been an incident on another installation connected to the first by hydrocarbon pipeline and the conditions for shutdown of the first installation. The overriding aim should be to ensure that the situation on the affected installation is not exacerbated. In general, shutdown should be the default action and should be effected at once unless it can be positively and reliably confirmed that the incident on the other installation is minor. The shutdown procedures should be reviewed regularly and the manuals updated.

Topside Emergency Shutdown Valve (ESV) Survivability

This study was conducted in 1996 in response to Cullin Recommendation 48. The study covered regulatory review for offshore North Sea petroleum industry. The study focus on the compliance survey and review with representatives from the industry representatives. The study did not cover the integrity testing technique. The following detail will explain how the study was conducted and what are the results and further recommendations.

Mansfield (1996) study ,in response to Cullen Recommendation 48, provides an overview of the range of approaches currently being adopted within the United Kingdom Continental Shelf (UKCS) for the protection of Pipeline Emergency Shutdown Valves (ESVs) from severe accident conditions. Its findings are also of relevance to other ESVs in use offshore. The study is based on the analysis of a representative sample of UKCS ESVs. The findings have been used to determine typical and best current practice in this area, and to highlight the main strengths and weaknesses in these approaches.

Overall Steps of Study

The study took a strategic route to the identification and assessment of the approaches to ESV specification and protection, which enabled a good overview of the situation to be gained but avoiding the need to look at all of the 400 or more ESVs installed in the UKCS. The overall screening approach had 3 stages:

Stage 1: Selection of UKCS pipelines based on simple "risk" related criteria and covering a selected range of typical types of operator.

Stage 2: Selection of a sample of ESVs on these pipelines for inclusion in the Survey.

Stage 3: Selection of a Representative Sample of ESVs for Assessment by "face to face" discussions with the operators.

The main findings are that:

1. Current ESV protection arrangements are generally well specified in terms of fire and blast hazards, but impact hazards and other secondary hazards such as vibration and jet erosion are less well recognized or addressed. The protection employed was found to range from specialist steel composite/multilayered boxes, through simple steel walls and wrap around fire insulation to relying on the location together with conventional deluge systems and fusible links on the actuator control lines to safeguard the pipeline contents and ESV operation.

2. All the approaches looked at took a holistic view of the ESV, its associated control systems and the riser, ensuring the overall integrity of the pipeline containment envelope.

3. The response to Statutory Instrument SI 1029 tended towards the use of "worst case" hazards sometimes resulting in the protection being "over specified".

4. More recent approaches have used an installation specific assessment of the likely hazard scenarios resulting in a more "fit for purpose" specification of the ESV and its protection.

5. Proposed future approaches are likely to rely on a more risk based approach to ESV protection, taking into account the reliability of the ESV, the degree of protection for the ESV vs. that for the installation as a whole and the escape, evacuation and rescue arrangements.

6. The principles of inherent safety are also likely to be favored in the future, by trying to reduce the inventory in the riser or pipeline, for example by the use of sub-sea isolation systems, and by locating the ESV and riser away from the effects of hazards.

7. The ability to test or otherwise demonstrate the adequacy of any protection or the ESV is an area that still needs development, both in terms of recognized test standards and recognized analysis codes and calculation methods.

Issues Raised

During the study a number of issues were raised that are relevant to ESV survivability in severe accident conditions, but which do not fall easily into the previous section of the report and are presented below.

ESVs on small not normally manned installations

The location and protection requirements of SI 1029 for ESVs on these installations sometimes appears excessive considering the compact nature of these installations and the overall effect the hazard would have on it. For example fire sufficiently severe to cause riser or ESV failure would probably effect the structure or prevent evacuation just as quickly. More innovative holistic approaches may provide a more effective means to secure the successful saving of lives, but these may come into conflict with current legislative requirements.

Interactions between ESV survivability, reliability and isolation performance

It is recognized that there is a need to gain a better view of the interactions between the survivability, reliability and the sealing performance of the ESV in order to optimize the requirements in these areas. For instance improving reliability may mean little if valves fail to provide an effective seal. Some of the pass rates for the larger ESVs are sufficient to fuel a significant fire or explosion and the design of any protection needs to recognize this potential for passing, since this can prolong or intensify the hazards on the installation. Also increased inspection and testing to improve reliability may cause protection systems that have to be removed and replaced each time to degrade.

The study concludes that:

- Operators have carried out studies to specify the protection for ESVs from severe accident conditions. A number of approaches have been taken and these are summarized in the report.

- There are a number of general and specific shortcomings in these approaches and these are highlighted to show where improvements could be sought in the future.

A Study Of The Dynamic Response Of Emergency Shutdown Valves Following Full Bore Rupture Of Gas Pipelines

Mahgerefteh (1997) studied on a numerical simulation based on the method of characteristics is employed to study the dynamic response of ball valves and check valves following full bore rupture of high pressure gas pipelines. The study, performed in conjunction with the hypothetical rupture of a 145 km pipeline containing methane at 133 bar, includes simulating the effects of valve proximity to the rupture plane and the delay in closure on the total amount of inventory released prior to pipeline isolation. The accompanying pressure oscillations and surges are also accounted for. The results are in turn used to recommend guidelines regarding the appropriate choice of emergency shutdown valve depending on the failure scenario.

Introduction

Long pipelines are frequently used for the transport of large quantities of hydrocarbons under high pressure. In the case of a typical offshore platform in the North Sea, for example, the amount of gas present in a 150 km pipeline at 100 bar is 637,000kg. This represents an enormous source of energy release which in the event of full bore pipeline rupture (FBR) poses the risks of general and extreme fire exposure to all personnel in "open platform" areas, and also undermines platform integrity. The Piper Alpha tragedy clearly demonstrated the catastrophic nature of this type of accident.

In order to isolate and thereby limit the amount of inventory which may be released as a result of pipeline rupture, it is now a statutory requirement3 that all pipelines larger than 40 mm diameter conveying flammable gases or liquids must be equipped with emergency shutdown valves (ESDV).

This paper employed a validated mathematical model for unsteady state now to demonstrate the importance of predicting the rapid variations in the fluid dynamics within the pipeline following FBR and their influence on the appropriate choice of ESDV. Of particular interest will be the evaluations of lost inventory and resulting pressure surges as a function of valve proximity to the rupture plane and its response time.

Summary

The study utilized conservation equations to generate a mathematic valve closing model. The study discussion includes Fluid Dynamic Data, Mass Release Data and Pressure/Time History. Detailed information will not discuss in this thesis but the results are as followed:

1. The dynamic response of both check valves and ball valves following FBR depends primarily on their proximity to the rupture plane and the flow reversal propagation speed. As the latter is directly related to the velocity of sound in the fluid medium relative to the escaping fluid:

1.1 pipelines containing gases are expected to be more susceptible delayed emergency shutdown compared to those containing liquids. This should be balanced, however, against the higher pressure surges expected in liquid pipelines;

1.2 shutdown delay is expected to be longer when rupture occurs during `normal' flow as compared to that occurring during `shut-in' . This is because in the former the expansion wave propagation velocity, which directly affects the valve activation time, is decelerated due to the normal flow of gas in the opposite direction.

2. In the case of a check valve, the amplitude and frequency of upstream pressure fluctuations following emergency shutdown are directly related to:

2.1 gas flow reversal velocity at the time of valve closure;
2.2 valve proximity to the rupture plane;
2.3 pipeline length;
2.4 fluid compressibility

Pipelines incorporating ball valves are generally not susceptible to pressure surges or oscillations.

3. No pressure surge is expected in the case of a check valve closing instantaneously upon sensing flow reversal. However, even in the case of a very short delay (ca. 2 s), a relatively large build-up in the pressure surge to a maximum value can be expected. It then diminishes in magnitude for larger closure delays.

4. In terms of limiting the amount of released inventory following emergency shutdown, a check valve offers a far better degree of performance compared to a ball valve when either is placed at close proximity of the rupture plane. At longer distances, however, the difference in performance becomes insignificant.

5. A deceptively simple argument that the total amount of inventory released following FBR is equal to that present in the isolable section of the pipeline prior to ESD may give rise to gross underestimates, particularly in the case of ball valves placed in close proximity to the rupture plane.

The Offshore Installations (Emergency Pipe-line Valve) Regulations 1989, Statutory Instrument SI 1989/1029, North Sea.

The Regulations provide for the protection of Offshore Installations, and persons on them, which are connected to pipelines conveying flammable or toxic substances, from dangers arising from the uncontrolled release of such substances.

SI 1989-1029 requires that emergency shutdown valves are fitted in the specified together with protection, period inspection and testing of the valves and their control systems.

Reliability

Valves should have the capability to close on demand or fail-safe close and block the flow of substance. Once it close it should remain closed until the safety of the platform is assured. ESDVs should stop the flow within the pipeline, disregarding any minor leakage past the ESDV cannot represent a threat to safety.

If at any time the ESDV is unable to close, the pipeline should not operated until the fault has been rectified.

Compliance to the regulations

Two types of pipelines are defined to comply with this reg. First, Existing Pipelines, the pipelines installed before 31 December 1990 are not legally required to comply with the full requirements of SI 1989/1029. However, in view of the obligations already imposed by the "Health and Safety at Work etc. Act 1974" and the "Offshore Installations (Operational Safety, Health and Welfare), Regulations 1976", and in the interests of good working practice, owners are advised to comply with the provisions of SI 1989/1029 from the earliest practicable date. Secondly, Proposed Pipelines, must have ESDVs incorporated with the emergency shutdown system prior to the issue of the consent to bring into use.

Prohibition on use of pipelines

Existing pipelines-- the foregoing will apply to existing pipe-lines after 31st December 1990.

Proposed pipelines-- All proposed pipe-lines will be required to comply with regulations 5 and 6 prior to issue of consent to bring into use or return to use.

Emergency Shut-Down Valve and Components

ESDV system consists of ESDV, the actuator and control system used for valve operation and maintenance facilities. The control system includes the platform emergency shut-down system and any local and remote control panels.

The ESDV system should be designed to minimize the possibility of both single and common mode failures, by, for example, provide sufficient diversity, independence and redundancy of equipment – has minimum maintenance and maximum reliability. All equipment should be checked for compatibility.

Recommendations for Equipments Comprising the ESDVs

Shut-Down Valves should meet these criteria:

- Closing against the maximum differential pressure and flow rate
- It is piggable , there for ball valve and gate valve are suitable
- Achieve both maximum reliability and rapid controlled closure
- Meet the minimum of API 6D
- Meet fire tested in accordance with the minimum provisions of BS 6755
- ESDVs should be matched to the actuator

Actuators should meet these criteria:

- Fail-to-Close purpose
- Enable ESDVs to be installed and achieve the rapid close capability i.e. within 60 seconds, subject to transient pressure in pipeline not exceeding 110% the maximum allowable operating pressure (MAOP)

Control System philosophy should meet the followings:

- Operate in a fail-safe manner
- Being closed by people position by it
- Automatic closure by platform ESD system

Maintenance philosophy should meet the followings:

- Accessible at all time;
- Adequately protected from the environments;
- Adequately ventilated and illuminated;
- Provided with sufficient working area;
- Provided sufficient lifting facilities
- Provided with efficient communication to control center

Fire Protection

Active fire protection systems acting on their own may not suffice and consideration should also be given to passive systems. Consideration should also be given to the incorporation of components in pneumatic or hydraulic control lines (such as fusible links or other temperature-sensitive devices) which can initiate rapid valve closure and thereafter prevent inadvertent re-opening of the valve due to expansion effects.

The ESDV actuator and all components necessary for ESDV fail-safe closure should remain fully operable under the anticipated fire conditions for at least fifteen minutes. This duration relates to the need to (i) initiate ESDV closure manually from the control room if for any reason the ESD system fails to automatically close the ESDV; and (i i) makes a realistic allowance for the reaction time of operators.

Riser Criteria

Although not a requirement under SI 1989/1029, Consideration should be given to protecting the riser outboard of the ESDV to the lower extent of the air gap, and in-board for the adjacent length of riser which, if-damaged, could impair the ESDV closure.

Explosion Protection

In general ESDV explosion protection will be achieved by locating outside congested equipment modules where the explosion overpressures and propagation speeds are known to be highest. ESDVs location should be therefore, where possible, be out of the path like missiles emitted from an explosion.

Impact Protection

Impacts should be considered from:

a) Dropped and fall objects;
b) Missiles resulting from explosions; and
c) Boats

It should noted that the fire protection measures should also be impact resistant to an extent that to ensure their effectiveness if impacted prior to the outbreak of a fire.

Location of ESDVs

The regulation 6 requires that the ESDV shall be located in a position:

a) In which it can be safely and fully inspected, maintained and tested;
b) Such that the ESDV is above water; and
c) Subject to the above, such that the distance along the riser from the ESDV to the base of riser is as short as reasonable practicable.

It is important to locate the ESDV above the water so that the inspection, testing and maintenance are practical at all times.

Inspection and Testing

The regulation 8 in this code requires that inspection, testing and maintenance schemes should be implemented on all pars of the ESDV system, including those parts designed to fail-safe close. This is considered essential for ensuring that the offshore installation personnel have confidence in the ESDV system. Consideration should be given to communicating the results of the inspection, testing and maintenance along with the ESDV reliability during the pipeline operation and any recommendations for valve/actuator etc. improvement, to the relevant manufacturer.

Inspection of ESD valves and actuators

The inspection intervals should not exceed three months. The following deficiencies will be identified e.g. internal/external leakage, corrosion, loosen connections etc. The inspection result should be recorded and countersigned by Offshore Installation Manager (OIM).

Control System

This also be tested in the similar criteria as the above and not exceed the three months intervals. Operator should conduct a six monthly test on the local control panels in a six monthly intervals--where partial closure is not practicable. Then the fully closed is required.

Full Closure Test

This test is required by regulation (8) (1) (C). The test should cover time to close, time to open, differential pressure, torque and power to actuate the ESDV. It is recommended that an internal seal leak test is also conducted. A differential pressure should be applied across the ESDV equal to the revealing pipeline operating pressure, by depressurizing the top side pipe work in-board of the ESDV.

Testing Equipment

Any equipment used to perform valve testing should be calibrated prior to using and also with calibration certificates.

Appendix E

On-line Stroke Testing Device Function and Summary

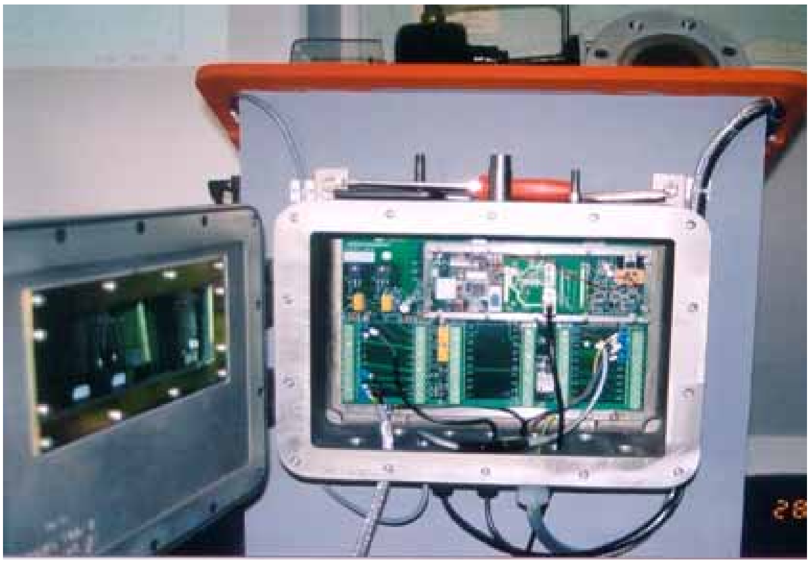
On-line Stroke Testing Device Function and Summary

Four stroke test devices were used in this thesis, the operational detail will be explained below:

Drallim SVM (SY740)

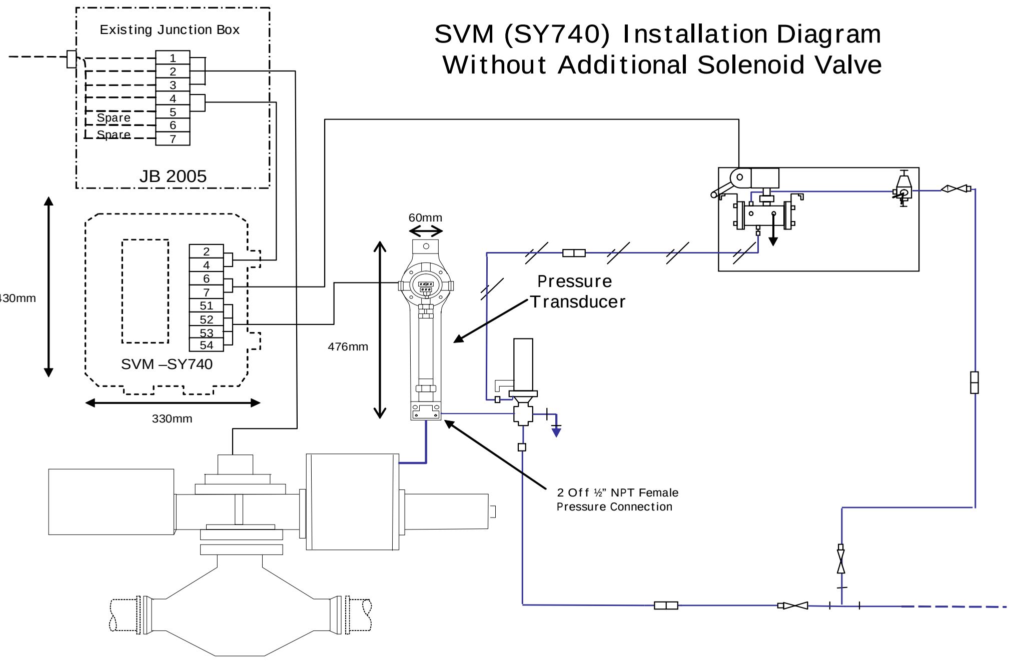
This is a self-contained electronic device (shown below). The device is placed between the ESD signal and the solenoid on the PESDV. It is also attached to a pressure transducer on the air inlet to the actuator. The device has to be first calibrated on the actuator to which it is installed. The device performs a full stroke closure of the valve and obtains a pressure-time signature for the valve (see red line on graph below). The device then obtains a partial stroke signature (green line). For future on line stroke tests the new signature can be compared to the test signature and a number of diagnostics can be obtained such as stuck valve, irregular valve movement, stuck or damage solenoid or irregular actuator movement (due to say a damaged spring). It also permits the ESD signal from the platform to override the test and close the valve. The signature below was obtained for SDV-1010A on Erawan CPP which has a pneumatic actuator. This device was successfully tested on 2 different PESDVs on the Erawan CPP (SDV-1010 and SDV-2005).

The biggest disadvantage of this device was its inability to operate on hydraulically operated actuators due to incompatibilities in the design of the control/solenoid systems. Another big disadvantage was the small installed base for these devices. There was little company or industry experience validating its performance. As these form the majority of the Class D valves this was considered an unacceptable choice. Further work will be required as these devices may be modified by the vendor to suit hydraulic actuators in the future.



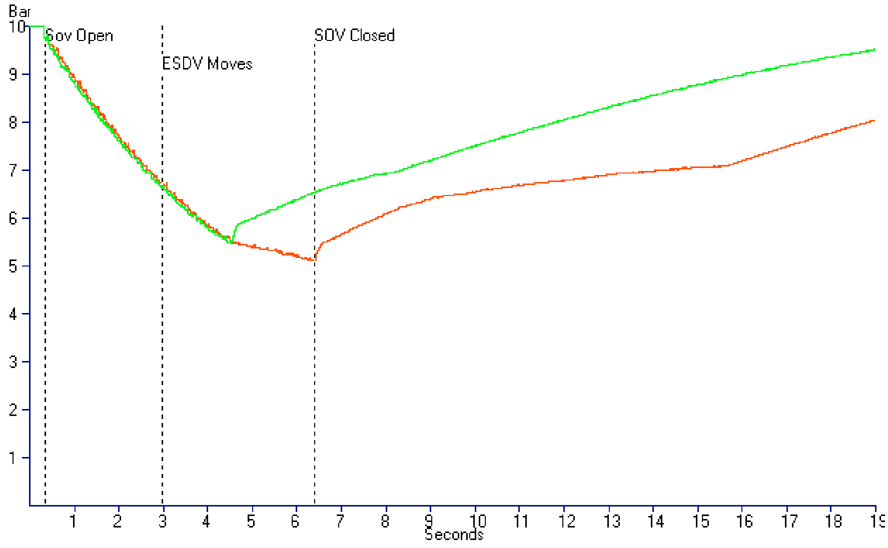
Appendix Figure E1 Drallim Hook Up to Junction Box

Source: Unocal Thailand, Limited (2006)



Appendix Figure E2 Drallim Device Hook Up Diagram

Source: Unocal Thailand, Limited (2006)

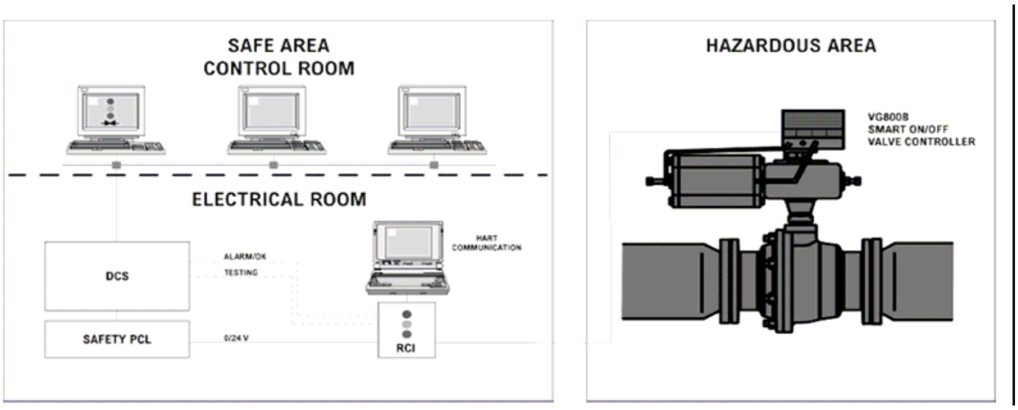


Appendix Figure E3 Drallim Stroke Test Diagnosis Diagram

Source: Unocal Thailand, Limited (2006)

Neles Valvguard

The Neles Valvguard is a well established product with an installed base of 000's of devices. This device is a mix of mechanical and electronic.



Appendix Figure E4 Neles Valvguard Device and Hook Up Diagram

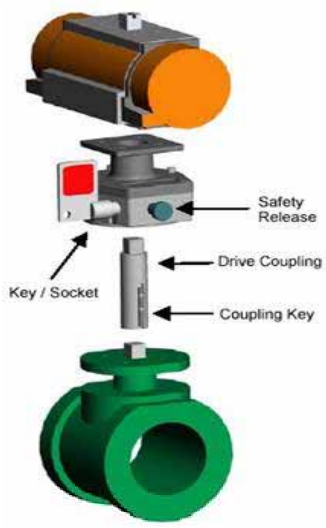
Source: Unocal Thailand, Limited (2006)

The device physically fits on top of the valve stem/actuator (Figure 15) and measures the rotational movement of the valve. Instrument air is fed through the device enabling the device to stop movement of the valve at a selected level of closure and then reopen the valve (via the solenoid). This device does not have the level and quality of diagnostics of the Drallim device but does have the advantage of simplicity and directly measures valve positions rather than implying it from the pressure at the actuator. As with the Drallim it also permits the ESD signal from the platform to override the test and close the valve. This device was successfully tested both on a test device at the construction yard at Laam Chabang and on a pneumatic actuator on Erawan CPP. Being a mechanical attachment to the valve/actuator the installation method is more difficult than the all electronic Drallim device.

Similar to the Drallim, the biggest disadvantage of the Valvguard is that is not currently compatible with a hydraulically actuated valve. The internals and fittings are not designed for the high pressures generated in a hydraulic system. Neles are currently working on a hydraulic system compatible device.

Dynatorque D-Stop

The D-Stop is a purely mechanical device. The device is installed on the valve spindle between the actuator and the valve itself (Figure 16). The device works by have a coupling key fitted to the valve stem with a mechanical protrusion on one side. As the valve closes the device locks onto the key and prevents the valve fully closing on action from the actuator. The % closure is preset on the device prior to installation and a key is required to operate the device. This device was successfully tested on SDV-2010 on Erawan CPP. It does have a number of disadvantages over the other two devices. It has no diagnostics other than the valve/actuator assembly functioning or not. It was demonstrated to be both heavy and difficult to install. It is expensive, the large mechanical device being required one per valve (there are 16 Class D valves). It has yet to be confirmed that the device could withstand the high torques generated on a hydraulic actuator. The biggest drawback is the fact that an ESD signal will not close the valve if received during testing. The mechanical stop will prevent the valve closing and cannot be readily disengaged.

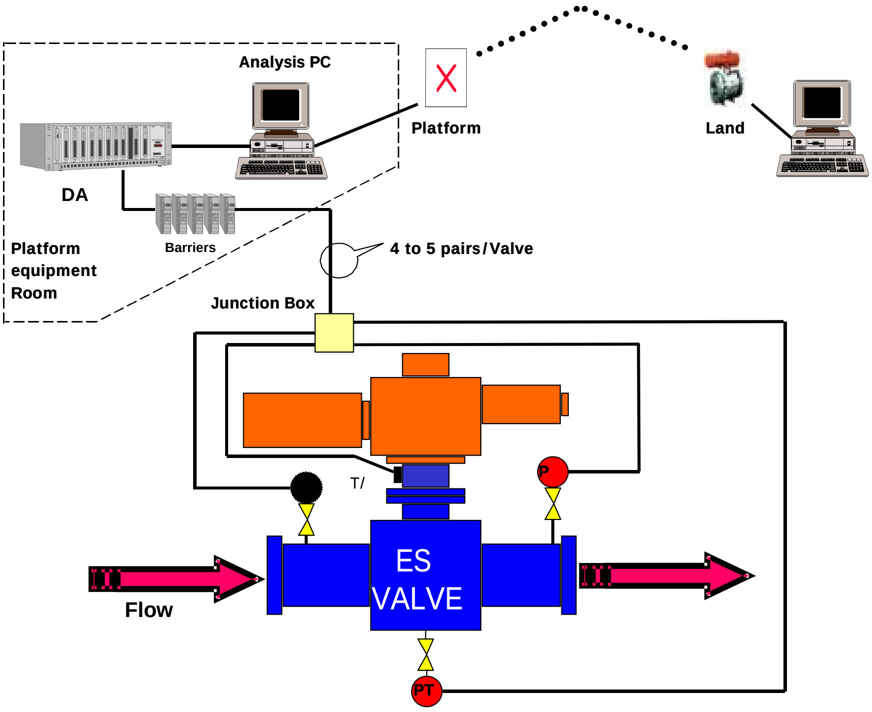


Appendix Figure E5 Dynatorque D-Stop Mechanical Device

Source: D-Stop Catalogue (2006)

Crane ValveWatch

This device is electronic in nature and operates by indirect measurements that imply the status of the valve. This device provides valve and actuator via a strain gauge on the valve body and pressure transducers fitted on the valve body and at upstream and downstream locations. The installation is expensive with proprietary technology. This option has not been pursued as the business unit would prefer a direct rather than implied means of verifying the functionality, the technology is still being developed and there is a very small installed base. This device may be considered at a later date should the technology become proven and accepted by the Corporation.



Appendix Figure E6 Crane ValveWatch Device and Hook Up

Source: Crane ValveWatch Catalogue (2006)