Pipeline Overpressure Protection using Layer of Protection Analysis

S. Shahidi, T. Little, N. Amott, Fluor Ltd., 140 Pinehurst Road, Farnborough, United Kingdom, GU14 7BF

This paper intends to promote the use of Layer of Protection Analysis (LOPA) for early assessment of Major Accident Hazards (MAH) in a pipeline and gathering system.

Often LOPA is carried out after HAZOP and SIL reviews and when the project's P&IDs are available so that the required Safety Integrity Level (SIL) is assigned to cater for MAH scenarios. However, by the time the P&IDs are developed for HAZOP, the overall project has progressed in a way such that fundamental changes can have a significant impact on the project as a whole. Therefore, engineers unconsciously miss-judge the process safeguarding adequacy or end up with assigning a high SIL to the Safety Instrumented Functions (SIFs) which in practice can be costly and difficult to achieve.

In this article, LOPA is proposed as a powerful problem solving tool to be used for early assessment of MAH scenarios prior to developing P&IDs and progressing the design.

The case study is a sour gas gathering project, consisting of 140 wellheads operating above 400 bar pressure. Gas pressure at the wellheads reduces to approximately 40 barg using a choke valve downstream of the Christmas Tree at the High Pressure/Low Pressure (HP/LP) Interface. Each wellhead is protected with a standalone pressure control system, as well as an Emergency Shutdown Valve (ESDV) downstream of the choke valve acting upon high pressure indication. The team were justifiably concerned about line blockage at the downstream of PG system.

In this case study the adequacy of existing safeguards to protect against the risk of over-pressuring the gathering system was evaluated. In particular, the overpressure scenario due to downstream plant total shutdown is assessed which could lead to a demand to trip all live wellheads; in this event, failure of one shutdown system on a wellhead may potentially lead to over-pressuring the associated pipeline and eventually Loss of Containment (LOC).

As a result of this assessment, the existing safeguarding integrity is deemed inadequate and an additional protection method, i.e. relief valves were added to close the safeguarding gap. The design is modified to cater for this requirement and a number of equipment items were added to the design.

Keywords: LOPA, Overpressure Protection, LOC, FTA, HP/LP Interface

Introduction

The subject project of this paper include a gathering system handling toxic and flammable fluids at high pressure. Due to the very large number of interconnected wellheads involved, the team executing the Front End Engineering Design (FEED) were justifiably concerned that the initial safeguarding concept might be inadequate. A technique was required to perform a preliminary risk assessment. The concern was compounded by the fact that some remote farms are near or adjacent to the main field security fence with a few wellheads and manifold stations nearby the fence line. This potential risk of toxic gas exposure to public in the proximity of wellpads and pipeline manifolds is due to the over-pressurisation hazard and sour gas release.

A review of the Pipeline Gathering System Overpressure Protection was conducted to evaluate the adequacy of safety systems to prevent potential impacts to operations and maintenance personnel as well as members of the public in the vicinity of pipelines due to a Major Loss of Containment (LOC).

This paper intends to promote the use of LOPA as a tool for design and safeguarding development in conjunction with application of codes and standards. The methodology presents “gaps” between tolerable levels of risk and the predicted risk inherent in the design being reviewed. This then allows the team to assess ideas and potential design changes to close or eliminate these “gaps”

Background

The original review of the overpressure protection system was initiated to resolve the project team's concern with regard to adequacy of the safeguarding system. The project was a Front End Engineering Design (FEED) development of an upstream Pipeline and Gathering (PG) system for a sour gas facility. Because of the complexity of the system (as described below), our experienced HSE professionals proposed the use of Layer of Protection Analysis (LOPA), as a tool to make a preliminarily assessment of the reliability of safeguards.

The project was at early stages, where no P&ID was available, therefore any assessment could not be as detailed as HAZOP and SIL reviews. However, this was a good opportunity for the project team to implement any major design changes, if deemed necessary from a safety perspective, without worrying about change being cascaded into other engineering disciplines leading to a significant amount of re-work.

This was valuable experience for Fluor as it addressed a number of execution challenges in terms of quality, safety, and consistency and provided an alternative approach to the typical project execution model. In addition, this LOPA review was used to address the owner's concerns about operations, maintenance and potential community impacts.

Case Study Description

The Project is subdivided into two distinct scopes as detailed below:

- The Central Processing Facility (CPF) – Denotes all permanent plant facilities including the Processing Facility, Utility Systems, the separate Administration building, workshops and stores/warehouses; and
- The Pipeline Gathering (PG) includes the entire upstream Hydrocarbon pipeline gathering system (including well location piping, all field manifolds stations and any other field-located facilities), all Gas and Oil export lines (up to and including the tie-ins), and power distribution and all cabling between the CPF and any field-located facility.

The purpose of this review was to only focus on the PG safeguarding assessment and was not concerned with the entire scope of project. Figure 1 shows a schematic of PG system for the project.

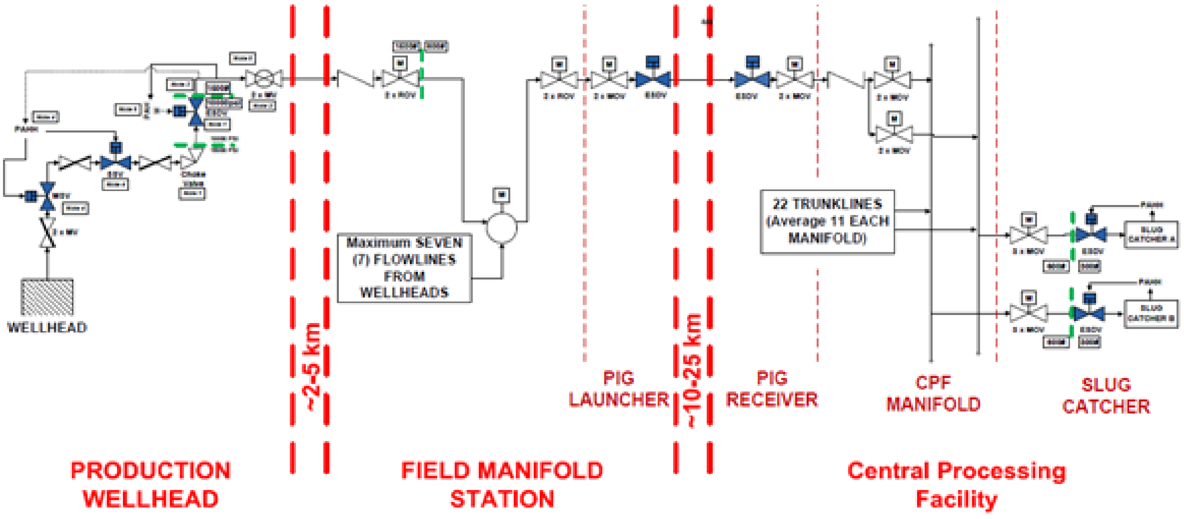

Figure 1: Pipeline Gathering System Schematic for an Upstream Sour Gas Project

The equipment and piping installed at each wellhead include:

- Subsurface Valves
- Wellhead and Xmas tree;
- Modulating choke valve – which is remotely controllable from Central Control Room via distributed Control System;
- Wellhead Control Shutdown system (WCSD) including hydraulic power unit;
- Instrumentation;
- Electrical power supply either by solar power or supply from the CPF;
- On-plot flowline piping including ESDVs and Motorised Valves (MOV).

Each Field Manifold (FM) Station consists of:

- a Multi-port Selector Valve allowing up to seven incoming flowlines to be connected to the common production header port or the test port;
- a multiphase flow meter for well testing;
- depressurisation and draining facilities;
- electrical power supply;

Dedicated trunklines run from each FM station to the CPF with pigging capability. The trunklines enter the CPF and are routed to one of two Process Facility Inlet Manifolds. Each trunkline can be routed to either manifold to allow approximately equal mass flow distribution to the 2 x 50% manifolds. The manifold sizing takes into consideration the potential mal-distribution of flow to each manifold at facility design flowrates. Each of the trunklines is provided with an ESD valve at the CPF Battery Limit and a pig receiver.

There are 2 x 50% trains for processing of the multiphase fluid from the inlet manifolds. Each processing train has a Slug Catcher which receives a dedicated feed from one of the inlet manifolds. The Slug Catchers also act as three phase separators to produce gas, oil and water streams;

The produced fluid is predominantly hydrocarbon gas containing a significant level of highly toxic Hydrogen Sulphide (H_2S). There are over 140 sour gas wellheads located in five neighbouring reservoirs. Pipelines from these wellpads are grouped in 22 Field Manifold (FM) stations and gas is transferred via trunklines to a Central Processing Facility (CPF) for separation and treatment. In the initial stage of operation only 69 wellheads are live; however, by the time pressure in the operating wellheads depletes, future wellheads have been brought into operation; the maximum numbers of wellheads in operation is expected between the years 4 to 12 (See Table 1). During this period the maximum numbers of wellheads which operate above the PG system design pressure is expected to be 94.

Table 1: Total Wellheads in Operation during Plant Life

Year of Operation	No. Wellheads in Operation	No. Wellheads with pressure > PG Design Pressure
1	71	71
2	90	86
4	108	94
10	122	48
12	100	0
15	78	0

A Choke valve at each wellhead reduces wellpad pressure of up to 450 barg to approx. 48 barg, almost 10 times lower. The base case design concept for wellheads provides for fully rated lines up to and including Emergency Shutdown Valve (ESDV) at each wellhead i.e. designed for the shut in condition of 600 barg. However, flowlines and trunklines downstream of the ESDVs including field manifolds are not fully rated for wellhead shut-in conditions. Therefore, an unplanned blockage downstream of the ESDV could immediately cause an overpressure event in any of the pipelines leading to a potential LOC and release of toxic hydrocarbon gas to atmosphere and highly toxic and flammable liquid oil spillage, eventually potential fire, explosion and/or toxic vapour cloud, injury and potentially loss of life. An unplanned blockage of an individual or grouped flowlines/trunklines could occur due to:

- spurious closure of an automated valve e.g. MOVs or ESDVs at a wellhead, FM or in the CPF due to mechanical failure or failure of control system e.g. hydraulic power failure and/or instrument air failure;
- inadvert closure of valves at wellhead, FM or CPF due to human error; or
- total shutdown/loss of electrical power in CPF/FM.

The purpose of this review was to identify the major causes of over-pressurisation in the gathering system and potential consequences and impact on safety for the operations and maintenance personnel as well as public. An assessment was performed to evaluate whether adequate safeguarding systems against overpressure events in PG are in place or whether there is further requirement for provision of additional safeguards.

Potential Initiating Causes of Overpressure

The following initiating causes may potentially lead to overpressuring events:

a. Wellhead Events

Inadvertent closure of the manual valves on production wellheads due to human error i.e. operator forgets to open the manual valve prior to start-up, which may lead to over-pressurisation, LOC and potentially fire, explosion and toxic release which may cause fatality for operators and Members of Public. Note that human error leading to inadvertent valve closure is discounted as valves are locked close.

b. FM Events

Any valve closing downstream of the multi-port valve on an individual trunkline may potentially result in an overpressure event in the upstream wellheads (maximum seven wells). This includes manual valves as well as MOVs and ESDVs.

c. CPF Events

Any inadvertent closure of valves downstream of the CPF inlet manifold e.g. MOV, manual valves and spurious trips may potentially result in overpressure in all associated wells (approximately 94 wells upstream slug catchers). The following initiating causes are included in the assessment:

- ESDV spurious trip upstream slug catchers;
- Total Loss of Power in CPF;
- Total shutdown due to an emergency situation in CPF; and
- Any other unplanned shutdown due to spurious trips e.g. fire and gas false detection.

Based on operational experience of similar plants it was recommended by the Owner to consider the likelihood of a CPF trip as once a year. Although this value seemed high in comparison with industry practices, it was considered realistic as it reflected the number of operational and maintenance difficulties on site. This scenario was evaluated during the review meeting to ensure that risk of over-pressurisation and eventually LOC events are reduced below the Owner's risk acceptability criteria.

Assumptions

The following assumptions were made for the purpose of this review:

- As a response to a potential pressure increase, DCS control will close the wellhead chokes;
- Accidental closure of valves downstream of the multi-port selector valve in FM may cause a maximum of 7 flowlines to be blocked in leading to a demand on a maximum of seven wellhead shutdown systems;
- Any closure of valves upstream of the slug catchers will result in a maximum of 22 trunklines being blocked in which leads to a demand on a maximum of 94 wellhead shutdown systems;
- Flowlines/trunklines are likely to be ruptured by pressure three times greater than design pressure;
- LOC resulting from a valve closure at a FM may occur within minutes (as demonstrated by dynamic simulation);
- LOC resulting from valve closure at the CPF may occur within ten minutes;
- It takes at least 15 minutes for the operator to take action upon initiation of a high pressure alarm;
- In the base case design no Relief Valve is provided for the PG system.
- No account has been taken for alarms from the F&G system that may indicate hydrocarbon releases in the early stages of an LOC event.
- All hydrocarbon releases are assumed to ignite when assessing the impact of fire and explosion.
- Credit has not been taken for emergency evacuation or the use of breathing apparatus as it is anticipated that the lethal impact of toxic gas release is immediate.
- Wellhead Shutdown (WHSC) system is a high SIL 1, therefore PFD value for wellhead SIF is considered 1.0E-01; and
- Wellhead ESD system is a high SIL 2, therefore PFD value for ESD SIF is 1.0E-02.

LOPA Methodology Overview

LOPA is a semi-quantitative risk assessment approach which is carried out to evaluate risk for each Major Accident Process Hazard (MAH) by measuring severity and likelihood of the event. The next step is to identify Independent Protection Layers (IPLs) to be implemented as safeguards for an individual MAH. IPLs are specifically designed for the purpose of prevention, control and/or mitigation of hazards and should be Independent, Dependable and Auditable. When IPLs are assigned to a single MAH their adequacy against the Target Mitigated Event Likelihood (TMEL) should be demonstrated. The following sections describe the LOPA procedure and how it was applied to the case study.

Severity of Consequence

Qualitative consequence modelling was performed to identify the severity of LOC scenarios in the PG. It was assumed:

- If LOC is followed by an explosion it will result in an impact to personnel but only minor impacts on members of public/third parties based on proximity; and
- If LOC is followed by a toxic gas release, it may result in impact to personnel and members of the public. This is based on Quantitative Risk Assessment (QRA) which was conducted during the project showing that toxic gas release may potentially extend into a large area and therefore may impact members of public, if not mitigated at source.

Personnel Exposure

Impact on personnel may be due to performing maintenance, metering or a manual operation in CPF and PG areas. Based on operational experience and nature of operations in an upstream facility, it is assumed that a single operator exposure to an LOC event should not exceed 10% of time, over a year.

Public exposure to toxic events is considered to be 100% for PG overpressuring scenarios. This is due to proximity of some of the sour gas wellheads and FM stations to the rural areas.

Event Likelihood

Likelihood of an initiating event was taken into account based on the initiating causes of overpressure; event likelihood is defined as frequency of occurrence per year based on Owner’s experience and industry data.

Target Mitigated Event Likelihood

This is a single event mitigated likelihood which is used as a target requirement for risk reduction based on a potential level of harm. TMEL is the key part of any LOPA review as it sets out the rules for defining adequacy of safeguards with regard to initiating event and its outcome.

Table 2: Target Mitigated Event Likelihood (TMEL)

People	No injury or damage to health	Minor injury	serious injury	Single fatality	Multiple fatalities	Multiple member of public fatalities
TMEL (per yr) for a single event	A	B	C	D	E	F

Note: A to F define the value of risk tolerability based on consequence. A is the highest value and the value of risk decend by an order of magnitude toward F (generally). Tolerability Criteria for a single event is defined based on Owner's overall Risk acceptability and regulatory requirements.

Independent Protection Layers

The following IPLs are known as typical preventive, control and mitigative measures for a process facility:

- Inherently Safer Design (ISD)

  Examples: fully rated pipes, flanges and valve to maximum achievable pressure
- Basic Process Control System (BPCS);

  Example: Pressure control device, using pressure transmitter to a close valve
- Critical alarms and operator intervention considering that operator has sufficient time to respond;

  Example: high pressure alarm to prompt operator to close a valve subject to adequate response time
- Safety Instrumented Functions (SIF);

  Example: an Emergency shutdown system which closes a valve upon receiving high pressure signal
- Physical/Mechanical protection

  Example: relief devices to reduce pressure if higher than a set point;
- Passive Protections

  Example: Fencing, restricted access to the potentially impacted area
- Emergency response plan (ERP)

  Example: Public alarms, escape routes, Temporary refuges, procedures

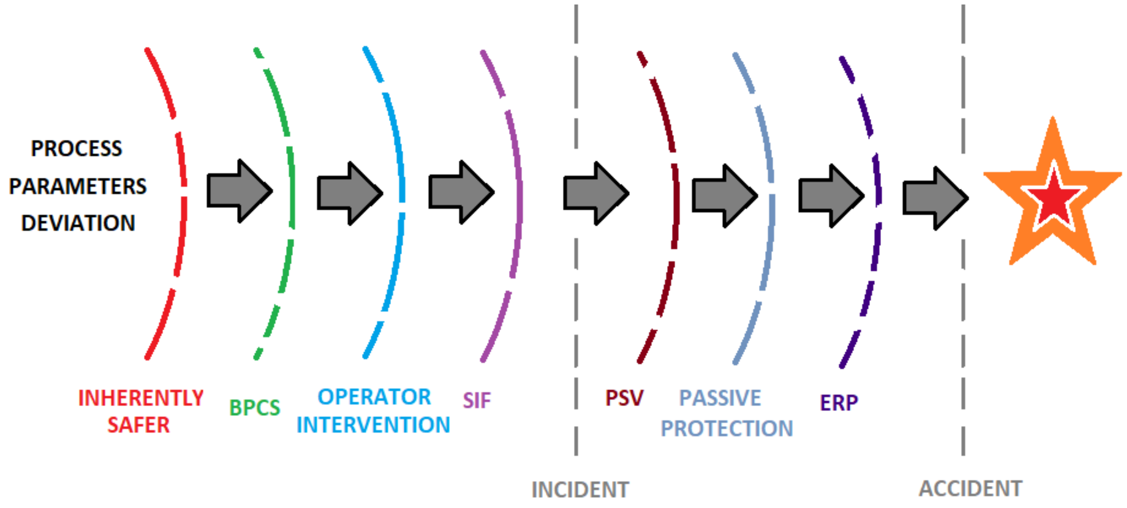

Figure 2: Layers of Protection for a Processing Facility

Risk Assessment

Further to designation of all relevant protection layers within the LOPA worksheet, the adequacy of the existing design can be determined by assigning initiating event frequencies and Probability of Failure on Demand (PFD) values to the various conditional modifiers and IPLs. The LOPA method provides an assessment of the current design and highlights potential gaps. For the purpose of the LOPA, an order of magnitude assessment was conducted for any single event without taking into consideration the actual PFD values and the effect of cumulating the scenario outcomes.

Failure Rate Data

A number of sources of failure rate data are available for assigning consistent values to the initiating event frequency. One of the most popular failure rate databases is the Offshore Reliability Database (OREDA). This book presents detailed statistical analysis on many types of process equipment. Other data sources include:

- Guidelines for Process Equipment Reliability Data, with Data Tables, 1989, Centre for Chemical Process Safety of AIChE, New York, NY;
- IEEE Std. 500, IEEE Guide To The Collection and Presentation Of Electrical, Electronic, Sensing Component, And Mechanical Equipment Reliability Data For Nuclear-Power Generating Stations, 1984, IEEE, New York, NY;
- Reliability Data for Control and Safety Systems, 1998, SINTEF Industrial Management, Trondheim, Norway;
- Industry data such as the Guidelines for Chemical Process Quantitative Risk Analysis (CCPS, 1989a) and the Second Edition (CCPS, 2000a), Guidelines for Process Equipment Reliability Data (CCPS, 1989b), and other public domain sources such as IEEE (1984), EuReData (1989), and OREDA (2002, 2009);
- Owner's experience (including hazard analysis team experience), where enough historical data is available to be statistically significant.

Table 3 and table 4 present typical values for failure frequency as well as Probability of Failure on Demand (PFD) which were used for the purpose of assessment.

Table 3: Frequency Values Assigned to the Initiating Events

Initiating Event Scenario	Frequency Value (per year)
BPCS instrument loop failure (e.g. Automated valves failure)	1.0E-01
Operator failure to execute routine procedure assuming operator is well trained, unstressed, not fatigued, but has not been operating sour facilities before	1.0E-01

Table 4 PFD Assigned to IPLs

Initiating Event Scenario	PFD Value
BPCS instrument loop	1.0E-01
Relief valve	1.0E-02
Inherently Safer Design	1.0E-02

Table 5: PFD Assigned to SIF (IEC 61508-Ed 2, 2010)

Initiating Event Scenario	PFD Range[Note 1,2]
SIL 1	1.0E-02≤ <1.0E-01
SIL 2	1.0E-03≤ <1.0E-02
SIL 3	1.0E-04≤ <1.0E-03

Note 1: PFD calculation for SIF is not included in this study; however it should be verified that SIL and PFD assigned to each SIF is achievable;

Note 2: Since this study is a preliminary review of PG safeguarding requirements, a conservative upper end of the SIL range for each SIF was used;

Pressure Protection Strategy

The base case wellheads pressure protection strategy included the following measures, associated with the typical IPLs shown in Figure 2:

a. **Inherently Safer Design (ISD):** Rating the pipeline and associated valves and flanges upstream of and including the ESDV for the wellhead shut-in pressure; which will protect wellhead safety devices in the event of overpressure.

b. **Basic Process Control System (BPCS)**; choke valve will initiate via a pressure transmitter; closure of this valve will reduce the pressure downstream;

c. **Safety Instrumented Function (SIF),** the Wellhead Shutdown (WHSD): Should the choke valve fail to reduce pressure downstream of the wellhead, a high pressure trip will be initiated via the WHSD. This trip will close the MSV and SSV as indicated in Figure 1; note that this is a field control panel and independent from DCS;

d. **Safety Instrumented Functions (SIF)**, e.g. Emergency Shutdown System: Should the WHSD fail to trip the wellhead, a high pressure trip will be initiated via pressure transmitters downstream of the ESDV resulting in closure of the ESDV.

The team then put forward some initial ideas for alternative IPLs in case the base case safeguards were found to be inadequate. As a starting point these are as follows:

- Replacing ESD system with High Integrity Pressure Protection System (HIPPS), suitable as a SIL3 system
- Providing Relief Valve (RV) for each trunkline with capacity of relieving the flow of the largest Wellhead at the manifold.

Use of HIPPS was discounted due to several maintenance and operation difficulties. For example, in order to achieve availability requirements of HIPPS, it is required to perform full stroke testing every six month at each wellhead. Considering the total number of wellhead (140), the duration of testing (12 hours) and test intervals (every six months), it was deemed far too onerous to use HIPPS in this arrangement, setting aside the substantial additional capital and operating cost.

The other option (RV), however, was a workable option despite adding a significant capital cost. Therefore, a sensitivity case was conducted to evaluate the benefit of adding an RV at each trunkline.

Pressure Protection System Availability

Availability of IPLs is often defined based on Probability of Failure on Demand (PFD).

$$\mathrm{Availability} = 1 - \mathrm{PFD}$$

However, where more than one IPL is required to work in order to prevent a MAH occuring, it should be ensured that the overall availability is calculated taking into account all possible failure case scenarios for multiple wellheads to shutdown. The following assessment is performed based on a standard safety system availability calculation methodology. Four scenarios for wellhead shutdown failure are studied:

- Base Case design: no Relief Valve (RV) on trunklines
  - Blockage in FMS causing demand on maximum seven wellheads to shutdown; and
  - Blockage in CPF, upstream slug catchers, causing demand on maximum 94 wellheads to shutdown and overpressurising pipelines.
- Alternate case adding to the base case assuming there is also one RV installed on each trunkline which is sized to relieve the load only from the largest Wellhead flow feeding the respective FMS:
  - Blockage in FMS causing demand on seven wellheads but six should be closed successfully in order to prevent LOC; and
  - Blockage in CPF causing demand on 94 wellhead for shutdown; however, Relief Valve allows one wellhead shutdown failure in each trunkline (22 trunklines overall).

The following formulae are used to calculate the availability of wellheads shutdown SIFs based on two main Scenarios (Lees Loss Prevention, 2005):

$$A_T = \sum_{m=r}^{m=n} {}^nC_m A^m (1-A)^{(n-m)}$$

$${}^nC_m = \frac{n!}{m!\,(n-m)!}$$

Where,
m is required number of events which should work successfully
n is total number of events
A is Single item availability;
A_T is total availability;
${}^nC_m$ is a Binomial Calculator – representing Common Cause Failure

$$\mathrm{PFD_T} = 1 - \mathrm{A_T}$$

The following tables show the results based on the above formula for the four cases and overall pressure protection system availability. The combined availability of each individual wellhead trip system is taken as 0.999 which is equivalent to a high end SIL 3. This is based on assuming WHSD to be SIL 1 and ESD to be SIL 2.

This PFD data will then be used in the assessment discussed in the following sections.

Table 6: Seven Wellheads Overpressure Protection System - Availability and PFD

No RV is Provided for PG			
Overall Availability A_T	0.99302	PFD_T	6.98E-03
Relief Valve is provided for protection of the MF			
Overall Availability A_T	0.99998	PFD_T	2.0E-05

Table 7: 94 Wellheads Overpressure Protection System – Availability and PFD

No RV is Provided for PG system			
Overall Availability A_T	0.91024	PFD_T	8.98E-02
Addition of RV at each Trunkline			
Overall Availability A_T	0.99956	PFD_T	4.40E-04

Note 1: When there is a demand on 94 wellheads to shutdown, overpressure protection system is the Shutdown System on each individual wellhead plus Relief Valve on each trunk line.
Note 2: Details of calculation have not been provided due to confidentiality. The above are preliminary calculations to provide guidance on likely achievable availability for the overpressure protection system.

Base Case Results

By taking the PFD data for each failure scenario and comparing that to the risk tolerance criteria (in numerical form as agreed with the Owner) the team were able to identify whether a scenario was tolerable or not and assess the positive effect of mitigating measures to reduce the PFD and therefore level of risk. Typically this was enumerated in the form of assessing a "gap" between the two when the risk is unacceptable by 1 or more orders of magnitude, thus illustrating the level of additional design mitigation required to resolve the problem.

Wellheads Initiating Events

Given the base case design circumstances, and low occupancy level, no safeguarding gap (unacceptable level of risk compared to tolerance criteria) was identified for protection of operational and maintenance personnel in the vicinity of the wellheads. For members of public however, the impacts from a LOC event at wellheads is considered borderline and subject to ALARP demonstration. This is based on an LOC event with high H_2S concentration and wellheads in the vicinity of Owner's security fence.

FM Initiating Events

The risk of LOC due to overpressure has increased by a factor of seven following to the need to shut down all wellheads should an initiating event occur in any of FM stations. For operators the acceptability criterion is borderline for toxic releases and therefore ALARP demonstration should be performed if the current design is desired. For the impact on the public, the design will require additional IPL(s) or it should be ensured that public exposure is prevented via fencing.

CPF Initiating Events

The risk of LOC due to overpressure has increased by a factor of 94 following to the need to shut down all 94 wellheads. The gap between risk (PFD) and acceptability criteria for operators and public have increased making it more difficult to rely on individual wellhead protection. In this case, for both operators and public the design will require additional IPL(s).

Therefore, it is required to add an additional IPL in order to meet TMEL required for all above scenarios.

RV Case Results

The design is also reviewed to take into account the potential mitigation of adding an RV to each trunkline upstream of the Pig Receiver at the battery limit of CPF. This RV should be sized to relieve the flow from the largest wellhead at each FM in the event of overpressure. Based on this assumption the review (and LOPA worksheet) was repeated to demonstrate whether the design is sufficiently robust to cater for wellheads and manifolds shut in conditions, failure of which would result in an explosion or toxic gas release. See Figure 3 for the modified PG system schematic.

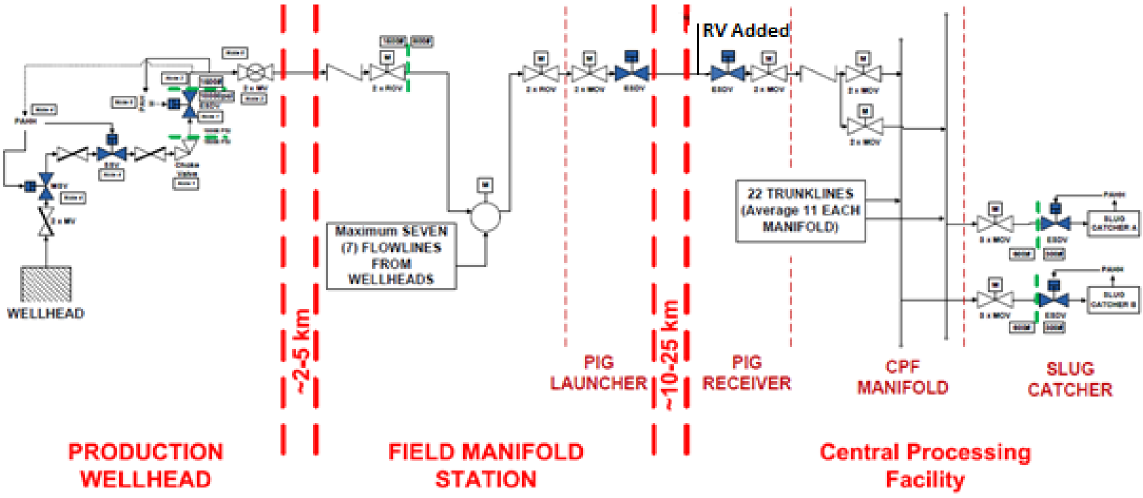

Figure 1: Modified Pipeline Gathering System Schematic after adding Relief Valve

As a result of adding the RV, the safeguarding gap was closed to be tolerable for all cases for both personnel and public impact. The event of CPF total shutdown leading to demand of shutting down all wellheads, required further assessment and was subject to ALARP demonstration.

Table 7 shows summary results of this review for the main three areas of concern: Wellheads, FM Stations and CPF. Depending on where the initiating cause of overpressure occurs, the impact to workers and members of public will be different. The assessment shows that by adding RVs on each trunkline there will be a significant improvement on the reliability of the safeguarding system.

Table 7. Summary of Reliability Analysis for PG Overpressure Protection

Initiating Cause of Overpressure	Is base case risk acceptable?		Is RV case Risk acceptable?	
	Personnel	Public	Personnel	Public
Production Wellhead	Yes	Yes if ALARP	Note 1	Note 1
Field Manifold Station	Yes if ALARP	No	Note 1	Note 1
CPF	No	No	Yes	Yes if ALARP

Note 1: adding RV did not reduce risk initiated by events at wellheads and FM stations. This is due to locating RV downstream of FM at the battery Limit of CPF.

As noted above, for some locations where the risk to public was not acceptable, further risk reduction to the public was achieved by extending the security fence to further restrict public access to the potentially impacted areas. A Quantitative Risk Assessment was conducted to define the required exclusion zone for wellheads and FM stations.

Recommendations

The following recommendations should be taken into account in the design and operation of the PG area:

Further work should be undertaken as part of the Quantitative Risk Assessment (QRA) Study to determine the proximity of members of the public to individual (particularly high H_2S) wellhead locations. To mitigate the risk, it is likely that exclusion zones may have to be established due to potential toxic gas releases. It is unlikely that the safety instrumented systems can be enhanced to close the protection gaps in this instance. Identification of zones for overpressure effects following an explosion should be determined, but are unlikely to present a higher risk than that determined for toxic gas releases. Therefore, it is recommended that further measures are taken to ensure members of public are kept outside the wellheads and pipelines Public Exclusion Zones (1.0E-05/yr Location Specific Individual Risk) in order to demonstrate Inherently Safer Design and prevent exposure to unacceptable risk of fire/explosion/toxic release. The extent of the zone should be systematically developed for each wellhead due to varying locations, toxic gas content in well fluids and other existing wellhead protection system (i.e. interface with MSV & SSV closure times)

As part of this study it was recommended to provide an RV for protection at CPF, upstream of each pig receiver ESDV, which is sized for relief of one well. Installing the RV will help in diversifying the layers of protection and reducing common cause failure and is considered to be good industry practice. The proposed location of the RV is shown in Figure 3. It should be ensured that the RV is designed to cater for the requirement of relieving flow from the largest wellhead at each trunkline. For this purpose, an additional knock out drum will have to be installed at the CPF to collect the relieved fluids from the trunkline RVs. The gas from the KO drum can be flared in the CPF flare and liquid can be pumped back to the process train.

If QRA demonstrates that there are still some intolerable risks after implementing this design change then the following options are recommended to prevent intolerable risk to Members of Public noting that there are a minimal number of wells near the overall field security fence. Decisions about using these options should be made based on the findings of a Coarse QRA study and PG HAZOP/SIL workshops later during FEED:

- Relocation of fence line around the wellheads in high population areas, individual fence lines around vulnerable wellheads with zoning based on dispersion modelling (as part of QRA study);
- Fully rated lines for part or all of the route up to and including the CPF inlet manifold, although this option may not be viable in some cases due to costs;
- Individual RVs associated with each impacted well located in the wellhead areas;
- Potentially using an independent SIL 3 SIF or HIPPS on identified wellheads at which societal risk exposure is significant in the public area; this should be assessed further during SIL workshop and detailed QRA study review; and
- Vulnerable wells not being used if risk to Members of public cannot be reduced by any of the above options.

This assessment has only taken into account the probability of Failure on demand for safeguards provided for the PG system. However, it is required to also consider process safety time for over-pressurization of PG (flowlines/trunklines) in order to ensure there is a sufficient reaction time for the wellhead shutdown system.

Conclusions

A preliminary assessment of the PG pressure protection system was conducted for a facility handling flammable and toxic gas at high pressure. PG is formed of about 140 wellheads scattered in a large area as well as 22 Field Manifold Stations, flowlines, trunklines and CPF. There are a large number of facilities located in the field but the flowlines and manifolds are not fully rated for maximum pressure of wellheads.

There was a concern raised by the FEED team that the risk of one of the many pressure protection system might fail leading to LOC which is not acceptable based on potential impact to personnel and members of the public.

The potential continuous presence of the public at the extremities of the field exacerbates the concerns

A LOPA technique was used to make an early assessment of tolerability of the risk and evaluate the concerns. Although LOPA was conducted early in the FEED, it did not replace the need for a comprehensive HAZOP and SIL assessment at a later stage. Consideration is given to all plausible upset conditions including flow interruption or blockages from a valve closure, whether inadvertent or in response to a safety system action, spurious or otherwise, loss of power, emergency shutdown in the CPF or any other such event. Therefore it should be proven that adequate provisions are considered for all relevant layers of protection. The following conclusions are derived from this assessment:

- Closure of ESD valves or the choke valve at the wellhead has no impact to operational personnel or members of the public, as the system is fully rated upstream and including ESD valves;
- Indications based on closure of ESDV upstream of each Slug Catcher at CPF with one demand per year highlights a safeguarding gap for Operators. This is based on an overall PFD of protective system associated with the maximum of 94 wellheads;

As a result of this assessment it was concluded that the base case design of the PG was not robust based on Owner's risk acceptability requirements. Therefore, it was recommended to provide an additional pressure protection system in the PG to cater for overpressure events i.e. provision of Relief Valve (RV) at each trunkline as an additional protection layer in conjunction with the existing safety systems.

By adding an IPL, in this case an RV, on each trunkline, this risk tolerability gap can be closed for hazards to the operators. The sizing basis of RVs will need to be clearly established.

Indications based on closure of ESDV upstream each Slug Catcher at CPF with one demand per year highlights a safeguarding gap for public. This is based on the overall PFD of the overpressure protection system associated with the maximum 94 wellheads. Therefore, inclusion of the RV does not close the IPL gap and safe siting of wellheads and provision of fencing to prevent public exposure to toxic/flammable hazards should be considered.

Definitions and Abbreviations

ALARP	As Low As Reasonably Practicable
CITHP	Closed-in Tubing Head Pressure
CPF	Central Processing Facility
FEED	Front End Engineering Design

FM	Field Manifold
H_2S	Hydrogen Sulphide
HAZOP	Hazards and Operability
IEC	International Electro-technical Committee
ISD	Inherently Safer Design
LOC	Loss of Containment
LOPA	Layers of Protection Analysis
MSV	Master Shutdown Valve
PG	Pipeline Gathering
PFD	Probability of Failure on Demand
ppm	parts per million
QRA	Quantitative Risk Assessment
RV	Relief Valve
SIF	Safety Instrumented Function
SIL	Safety Integrity Level
SSV	Surface Safety Valve
WHSD	Wellhead Shutdown

Reference Documents

The following codes and standards issued by several organisations shall be applicable to development of this review as a minimum requirement:

National and International Standards

BSI BS EN 61508 Functional Safety of Electrical/Electronic/Programmable Electronic Safety-related Systems, Ed. 2-2010.

BSI BS EN 61511 Functional Safety - Safety Instrumented Systems for the Process Industry Sector, 2004.

Guidelines for Process Equipment Reliability Data, with Data Tables, 1989, Centre for Chemical Process Safety of AIChE, New York, NY;

Reliability Data for Control and Safety Systems, 1998, SINTEF Industrial Management, Trondheim, Norway;

Industry data such as the Guidelines for Chemical Process Quantitative Risk Analysis (CCPS, 1989a) and the Second Edition (CCPS, 2000a), Guidelines for Process Equipment Reliability Data (CCPS, 1989b), and other public domain sources such as IEEE (1984), EuReData (1989), and OREDA (2009, 2002);

Lee’s Loss Prevention, third Edition