# Oil Gas Pipeline Failure Rates (detailed)

# 🔼 Analysis of Oil Pipeline Failures in the Oil and Gas ...

http://www.iaeng.org/publication/IMECS2012/IMECS2012\_pp1274-1279.pdf December 07, 2014

... This research work on the analysis of oil pipeline failures in oil and gas industries in the ... Variation of Failure Rate by NDSs for All Oil Pipeline ...

Proceedings of the International MultiConference of Engineers and Computer Scientists 2012 Vol II, IMECS 2012, March 14 - 16, 2012, Hong Kong

Analysis of Oil Pipeline Failures in the Oil and Gas Industries in the Niger Delta Area of Nigeria

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Abstract - This research work on the analysis of oil pipeline failures in oil and gas industries in the Niger delta area of Nigeria was carried out to ascertain the causes of these failures. Information on pipeline conditions was gathered for the period between 1999 and 2010. Observations showed that the major

causes of failure include: Ageing, Corrosion, Mechanical failures - welding defects, pressure surge problems, stress, wall thickness, etc. From the data got and results that were obtained, recommendations were given on measures to minimize these failures. According to the Gas and Oil Pipeline Standards (GOST) of Nigeria, the standard lifetime of a pipeline is 33 years but this research findings revealed that 42% of failures were mechanically induced, 18% by corrosion, third party activity contributed 24%, 10% through operational error and 6% by natural hazards. Besides applying good

cathodic protection, or anti-corrosive agents, reinforced thermoplastic pipe (RTP) seems to be the best remedy, as it is able to withstand many factors that lead to failures. The use of RTPs is therefore recommended as a good measure against pipeline failures in the Oil and Gas Industries in Nigeria.

Index Terms - Cathodic protection, Corrosion, Mechanical failure, Niger Delta, Reinforced thermoplastic pipe.

#### INTRODUCTION

MAJOR pipelines across the world transport large quantities of crude oil, natural gas, and petroleum products. These pipelines play an important role in modern societies and are crucial in providing needed fuels for sustaining vital functions such as power generation, heating supply, and transportation. In light of the hazardous properties of the products being transmitted through these pipelines, a ruptured pipeline has the potential to do serious environmental damage. This problem is further compounded by the fact that many developing countries have not established proper guidelines and standards for the design, construction, and operation of major oil pipelines. This study concerns the analysis of oil pipeline failures in the Niger delta area of Nigeria with the aim to undertake a desk study to evaluate the procedures for pipeline maintenance and contingency plans for addressing oil pipeline failures in the Niger delta area of Nigeria. The risk associated with pipeline in terms of safety of people, damage to the environment and loss of income has been a

major concern to pipeline integrity managers.
Sources of failure include Structural problem 40%, Operator error 6%, Others 25%, Outside force damage 27% and lastly Control problems 2%. Agbaeze [1]

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shared his view on how to improve pipeline Integrity Management, opining that Pipeline operators can realize many benefits by implementing a data integration approach that; enables integrity managers,

risk assessment specialists and pigging Engineers to view

and analyze combined information from disparate surveys and to increase the value of data by shaving it across the entire corporation. There have been a number of studies conducted by researchers on causes of oil pipeline failures in the oil and gas industry.

Ikporukpo [2] examined the causes of pipeline leaks versus pipeline ruptures and the proportion for each. failures resulting in product loss, leaks constituted 86.8% of

failures and ruptures 13.2%. Corrosion is the predominant

cause of leaks. According to the findings, third party damage is the leading cause of line ruptures. Since 1994, 191 thits were recorded, and these are not included on the graph as they did not result in either leaks or ruptures. The hits equalled 47% of all recorded third-party incidents for the years 1994-1997, demonstrating that approximately half of all third party incidents resulted in a pipeline failure. Reference [3] showed that about 50% of third-party incidents resulted in loss of pipeline products. Ndifon [4] reviewed the number of internal corrosion failures for multiphase pipelines and discovered that internal corrosion failures increased steadily while the number of external corrosion failures held steady. However, the failure frequency has been quite consistent [5],

Moffat and Linden [7] compiled background research and information that is associated with oil pipeline failures, it shows that for crude oil pipelines, the causes of failures appeared to be fairly random in nature, and that no trends were apparent. They stated for sour gas pipelines, internal corrosion is the major cause of failure. External corrosion failures have declined in recent years, possibly as the result of improved coatings and increased inspection. Of the sour line failures, about 86% were leaks and 14% were ruptures. They used the latest technology in the fields of internal electronic inspection, metallurgy, coatings, cathodic protection, and chemical inhibition.

Nwankwo et al [8] and Odusola [9] extensively studied the

effects of internal corrosion failures for natural gas pipelines which have generally been increasing. Some "other" category which include high vapour pressure liquids, low vapour pressure liquids, fuel gas, and all others showed failure rates to be relatively few and the causes to be relatively random.

# MATERIALS AND METHODS

The aim of this study is to rank the oil pipeline incident from data collected from oil and gas industry, so that

IMECS 2012

ISBN: 978-988-19251-9-0

ISSN: 2078-0958 (Print); ISSN: 2078-0966 (Online)
Proceedings of the International MultiConference of Engineers and Computer Scientists 2012 Vol II,

IMECS 2012, March 14 - 16, 2012, Hong Kong

pipeline managers can prioritize their strategies for managing the risk involved.

The objectives of the study have been categorized into the following different areas of activities:

- Study the historical oil pipeline failures.
- Assess oil pipeline rupture risks and recommend measures to reduce oil spill probability and impact
- Identify the best practices in developed countries and recommend ways of translating them to areas having inadequate arrangements or combating oil pipeline failures and mitigation of their effects.

  Promote establishment of regulatory and
- monitoring systems.
- Promote the development of incentive systems to encourage the oil industry to minimize environmental degradation arising from oil pipeline spills (in particular).

flow stations for crude oil processing, with more than 7,000 km of oil and gas pipelines traversing the entire area and seven export terminals.

In order to fulfil the study objectives, a number of work tasks were identified, comprising:

② Collection of data on pipeline network of

Shell Petroleum Development Company

(SPDC) in the Niger Delta Area of Nigeria;
☑ Analysis and risk assessment of the causes of oil pipeline failures in the Niger Delta Area of

Nigeria; ☑ Review of the legal and regulating regimes of Shell Petroleum Development Company (SPDC)
pipelines in the Niger Delta Area of Nigeria; and
ecommendations for strengthening

Recommendations regulatory and monitoring systems in the Nigerian oil and gas industry.

Fig. 1. Nigeria showing Niger Delta, major cities & 5 Operational Zones; Source: Anifowose (2006)

The Niger Delta (Fig.1) is located in Southern Nigeria and is world's third largest wetland. It is characterized by significant biological diversity and contains the bulk of Nigeria's proven oil and gas reserves. The region has about 606 oilfields with 355 situated onshore and 251 offshore (Fig.2). There are about 5,284 oil wells drilled and 527 Fig. 2. Niger Delta Showing the Distribution of Onshore and Offshore Oil Fields; Source: NDRDMP (2006)

The land area within which the network of transport pipelines are located is estimated at 31,000km2. There are ten gas plants and about 30 marginal oil fields farmed out, through the network of pipelines, to local companies and for export. Three of Nigeria's four refineries, Port-Harcourt I & II and Warri, are located in the region, while the fourth is located in Kaduna, Northern Nigeria.

Data was collected from known periodicals and other literature, as well as the databases of Nigerian National Petroleum Corporation (NNPC), Department of Petroleum Resources (DPR), Shell Petroleum Development Company (SPDC) and other secondary sources that are responsible for operating oil and gas pipelines in the Niger Delta

Area of Nigeria. The data collected included the following:

Pipeline network data of the major crude oil and product trunk transportation pipelines, including feeder lines and local gathering systems (where applicable) in the States of Niger Delta area of Nigeria.

Pipeline failure data during the period 1999-2005 from the pipelines. Types of data collected included: date of event, site specification (that is, pipeline identification and geographical location), spill quantity and duration,

causes and consequences, cleanup and restoration, etc.

Geographical and environmental data to identify important environmental factors, as well as populations, habitats, or other environmental features of each state of Niger Delta area along the pipelines that are vulnerable to oil spills.

Oil spill contingency plan data including existing contingency plans, type of cleanup equipment, capacities, and so forth in the given countries.

Most of the pipeline data were accessed from a digital map of main oil pipelines. The data included location of pipelines, diameter in millimeters, and length in kilometers. The data have been categorized on a state-by-state basis and are

summarized in Table 1 below.

There were approximately 84,000kilometers of pipeline in Nigeria as of 1998. About 90% of this pipeline has a diameter of greater than 504mm (20inches) while about 64,000 pipeline kilometers, or 76% of the total, are

IMECS 2012 ISBN: 978-988-19251-9-0

ISSN: 2078-0958 (Print); ISSN: 2078-0966 (Online) Proceedings of the International MultiConference of Engineers and Computer Scientists 2012 Vol II, IMECS 2012, March 14 - 16, 2012, Hong Kong

located in the Niger Delta States. The distribution of these pipelines in the Niger Delta area of Nigeria is shown in

Unlike other countries, the main pipelines in the Nigerian  $\,$ Niger Delta states are combined into unified systems that transport natural gas, oil and petroleum fuels to both domestic and international end users, Natural gas is transported network

exclusively by the Nigerian National petroleum Corporation (NNPC); oil is transported by a combination of multinational oil companies and the national pipeline operator; and refined petroleum fuels are taken care of by independent oil marketers.

TABLE 1

NUMBER OF PIPELINE KILOMETERS BY DIAMETER IN THE NIGER DELTA STATES

Cross-River

Akwa-Thom Diameter

Bayelsa

TABLE 2 AGE AND PERFORMANCE RATING OF NIGERIAN MAIN OIL PIPELINES AS AT THE YEAR 2000

| Age (years) |               | Year 2000<br>% total |
|-------------|---------------|----------------------|
|             | % reliability | length               |
| <20         | 46            | 27                   |
| 20-30       | 29            | 32                   |
| >30         | 25            | 41                   |

(Source: Pipeline Oil Spill Prevention and Remediation in NDS, NNPC, 2007)

The main sources of information for oil pipeline failures cited in this study are the following:
☐ Database of the Oil Spill Intelligence Report

(NNPC), Port Harcourt.

Rivers

Total

Shell Nigeria Annual Reports, Port Harcourt, Nigeria.

(mm)

Delta

| 152<br>228                 | _                              | 28         |             | 48<br>148      | -        |             |             | 48     | 104<br>148   |  | as Journal (OGJ<br>ard Incident Da |               |   |
|----------------------------|--------------------------------|------------|-------------|----------------|----------|-------------|-------------|--------|--------------|--|------------------------------------|---------------|---|
| 304                        | -                              | -          | -           | - 14           | -        |             | 14          | 8      | 168          | (MHIDAS                                | S); Health and                     | Safety Execut | tive (owner),                           |
| 381<br>457                 | 136<br>-                       | 197        |             | · 165<br>· 169 | -        |             | 60          | -      | 301<br>396   |  | chnology (opera<br>on of Chemical  |               |   |
| 533<br>609                 | 24                             | -          |             | - 52           | 197      |             | 35<br>27    |        | 629<br>274   |  | se (I.Chem. E),<br>of Niger Delta  |               |   |
| 685                        | -                              | 742        | 2 -         | 670            |          |             |             | -      | 1412         |  | _                                  | _             | _                                       |
| 762<br>838                 | 183                            | 287        | -<br>74 753 | · 28<br>3 197  | 742<br>- |             | 148<br>39   |        | 2436<br>4222 | Note: Ministry of projects in the (    |                                    |               | developmental                           |
| 914                        | 403                            | -          | -           | 1567           | -        |             | 95          |        | 2928         | The relevant da                        | ata on each of                     | the oil pipe  | line failures are                       |
| 990                        | -                              | 456        | -           | 342            | -        |             |             | -      | 798          | summarized in Tab<br>were analyzed in  |                                    |               |   |
| 1066                       | -                              | 81         | L -         | 43             | 456      |             | 259         | 7      | 3117         | accepted nomencla                      | ature (NNPC 199                    | 17)           |   |
| 1143<br>1219               | -<br>501                       | 161<br>197 |             | 897<br>1231    | 81       |             | 192         | -      | 1139<br>4019 | ·                                      | `                                  | •             |   |
|                            |                                |            |             |                |          |             |             |        |              |  | TABLE 3                            |               |   |
| Total                      | 1247                           | 453        | 39 753      | 3 5471         | 1367     |             | 825         | 1      | 21528        | A SUMMARY OF<br>PIPELINE FAILUR        | F THE VARIOUS C<br>RE IN THE NIGER |               | N OF                                    |
| (Source: D                 | -<br>Department of             | = Not a    |             |                | cas (DD  | R\ Shell    |             |        |              |  | NIGERIA                            |               |   |
| (Source: D                 | repair ciliente of             | 1 6 61 01  | Leam N      | coour          | ces (bi  | K), SHEII   |             |        |              |  |                                    | Operation:    | al                                      |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               | Third-party                             |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               | . , ,                                   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
| petroleum                  | Development                    | Company    | / (SPD      | C), P          | ort-Har  | court,      |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              | Mechanical                             |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  | Corrosion                          |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
| 2010)                      |                                |            |             |                |          |             |             |        |              |  |                                    |               | A = + + + + + + + + + + + + + + + + + + |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               | Activity                                |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
| Natural                    |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
| Hazard                     |                                |            |             |                |          |             |             |        |              |  |                                    | Failure       |   |
|                            |                                |            |             |                |          |             |             |        |              | Failure                                |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                | _          |             |                |          |             |             |        |              |  |                                    |               |   |
|                            | cific age of<br>possible to    |            |             |                |          |             | n,          |        |              |  |                                    |               |   |
| between th<br>Subside-     | ne age of pip                  | elines     | and t       | heir           | rate of  | rupture [1  | 0].         |        |              | Construc-                              | Internal,                          | System,       | Accidental,                             |
| However, a                 | large numbe                    | er of th   | ne oil      | pipe           | lines i  | n the Niger |             |        |              | tion,                                  | External                           | Human         | Malicious                               |
| nce,<br>Delta area         | were put in                    | ito oper   | ration      | in t           | he 1960  | s and 1970' | S           |        |              | Material                               |                                    |               | (Sabotage),                             |
| Flooding<br>(see Table     | e 2 below). A                  | s at th    | ne vea      | ar 200         | 0, pipe  | lines older | than        |        |              | and                                    |                                    |               | Incidental                              |
| and                        | ,                              |            | ,           |                | , , ,    |             |             |        |              | Structural                             |                                    |               | and Acts of                             |
| Others                     | onstituted 7                   |            |             |                |          |             |             |        |              | Sci uccur'd1                           |                                    |               |   |
|                            | old accounted<br>by rating for |            |             |                |          |             |             |        |              |  |                                    |               | Vandalism                               |
|                            | e about 46%<br>shows a decl    |            |             |                |          |             | t           |        |              | (Source: Pipeline NDA, NNPC, 2007)     | e Oil Spill Pre                    | vention and F | Remediation in                          |
|                            | pattern with                   |            |             |                | uu u     | 010.022     |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
| ISBN: 978-98<br>IMECS 2012 | 88-19251-9-0                   |            |             |                |          |             |             |        |              |  |                                    |               |   |
| ISSN: 2078-0               |                                |            |             |                |          |             | ns and Comn | uton ( |              | - 2012 Vol II                          |                                    |               |   |
|                            | March 14 - 1                   |            |             |                |          | or cultinee | is and comp | uter S | ocientist:   | s 2012 Vol II,                         |                                    |               |   |
|                            | TABL                           | .E 4       |             |                |          |             |             |        |              | Akwa-lbom, Cross-Ri                    | iver, and Edo f                    | ew pipeline 1 | failures                                |
|                            | OIL PIPELINE<br>AND CAUSE OF   | FAILUF     |             |                |          |             |             |        |              | were reported. The represented by ligh | spill frequenc                     | ies for these | e states are                            |
| (SIMIL)                    |                                | ise of s   |             | ., 199         | - 2003   |             |             |        |              | frequencies are bas                    |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             |                |          |             |             |        |              |  |                                    |               |   |
|                            |                                |            |             | Th             | ird par  | tv.         |             | by     | /            |  |                                    |               |   |
|                            |                                |            |             | ın             | ııu par  | Ly          |             |        |              | failures (50 percer                    | nt confidence i                    | n Poisson di  | stribution for                          |

Operational

Mechanical

Corrosion

Location

zero events).

|                                       | Failure                |         | Natur<br>Hazar<br>activ | rd      |        |        |       |         |      | location |                                      |                |                 |                       |               |
|---------------------------------------|------------------------|---------|-------------------------|---------|--------|--------|-------|---------|------|----------|--------------------------------------|----------------|-----------------|-----------------------|---------------|
|                                       |                        |         |                         |         |        |        |       |         |      | Total    | Rivers state                         | has a high     | pipeline failu  | re rate. <sup>-</sup> | This high     |
|                                       |                        |         | erro                    | r       |        |        |       |         |      |          | rate could be du                     | e to good      | reporting of oi | l spills.             | One oil       |
| Akwa-                                 | 2 3                    |         |                         | 1       |        | -      | -     | 6       |      | 12       | spill in Rivers                      |                | -               |                       | _             |
| Ibom                                  |                        |         |                         |         |        |        |       |         |      |          | The ages of Rive                     |                |                 |                       |               |
| Bayelsa                               | 8 7                    |         |                         | 4       |        | 9      | 1     | 18      |      | 47       | Rivers state is assumption is the    | at the pip     | elines are olde | r than ave            | erage.        |
| Cross-<br>River                       | 1                      | -       |                         | -       |        | -      | -     | 3       |      | 4        | be due to poor re                    | eporting o     |                 | ewer pipe             | lines, better |
| Delta<br>corrosive                    | 5 4                    |         |                         | 3       |        | 7      | 1     | 3       |      | 23       | quality of mater                     |                |                 |                       |               |
| Edo<br>Rivers                         | 1 2<br>6 5             |         | 7                       | 2       | 8      | 4      | 1     | 3<br>10 |      | 12<br>37 | soil. As stated of                   | s or wear-     | and-tear on old | pipelines             | s. The age    |
| Total by                              | 23 2                   | 1       | 17                      |         | 28     |        | 3     | 43      |      | 137      | of the pipelines<br>difficult to spe |                |                 |                       |               |
| cause<br>(Source: Pipeline O          | - =Not                 |         |                         | d Dom   | adi at | ion    |       |         |      |          |                                      |                |                 |                       |               |
| in NDS, NNPC, 2007)                   | ii Spiii i             | evenci  | on and                  | u Keiik | culac  | 1011   |       |         |      |          | FAILURE RATES F                      |                | ELTA STATES, 19 | 99-                   |               |
| NUMBER OF OIL SPILE                   | TABLE 5                | S BV IC | CATTON                  | M       |        |        |       |         |      |          | Location                             | 2005<br>No. of |                 | Cail                  | ure rate      |
| (STATE) AND DIAME                     |                        |         |                         |         |        |        |       |         |      |          | by                                   | oil            | Kilometer-      |                       | ,000km-       |
| Diar                                  | meter clas             | s(mm)   |                         |         |        |        |       |         | by   | 2,       | 011                                  | years          | pc              | , 00011111            |               |
|                                       |                        |         |                         |         |        |        |       |         |      | -,       |                                      |                |                 |                       |               |
|                                       |                        |         |                         |         |        |        |       | Unkr    | nown |          | State                                | Spills         |                 | уe                    | ears          |
| Location                              | 20.                    | 3       | 381                     | 6       | 509    |        |       |         |      |          |                                      |                |                 |                       |               |
|                                       |                        |         |                         |         |        |        |       |         |      | location | Akwa-Ibom                            | 12             | 3,115           |                       | 0.19          |
|                                       | to                     |         | to                      | 1       | to     | :      | ×812  |         |      | Total    | Bayelsa                              | 39             | 5,222           |                       | 0.20          |
|                                       | 35                     | =       | 558                     | ,       | 812    |        |       |         |      |          | Cross-River                          | 3              | 756             |                       | 0.14          |
| Akwa-Ibom                             |                        | -       |                         | 3       |        | 1      | 1     |         | 1    | 6        | Delta                                | 41             | 6,328           |                       | 0.22          |
| Bayelsa                               |                        | _       | 14                      |         | 13     | -      | 11    |         |      | 39       | Edo<br>Rivers                        | 5<br>46        | 890<br>7,490    |                       | 0.16<br>0.23  |
| Cross-River<br>Delta                  |                        | 3       |                         | 5<br>4  |        | 1<br>6 | 2     |         | 1    | 12<br>15 | Total                                | 146            | 23,801          |                       | 1.14          |
| Edo                                   |                        | -       |                         | -       |        | 1      | 10    |         |      | 12       | (Source: Pipelin                     | e Oil Spil     | l Prevention an | d Remedia             | tion          |
| Rivers                                |                        | 5       |                         |         | 10     | •      | 5     |         |      | 33       | in NDS, NNPC, 19                     | 97)            |                 |                       |               |
| Total by class                        | 11                     |         | 34                      |         | 32     |        | 30    | 10      | •    | 117      |                                      |                |                 |                       |               |
| (Source: Pipeline O: NDS, NNPC, 2007) | - =Not a<br>il Spill P |         |                         | d Reme  | ediat  | ion :  | in    |         |      |          | Over:<br>12<br>10<br>8               | all Failur     | e Rate          |                       |               |
| III.                                  | RESULTS                | AND AN  | ALYSIS                  | S       |        |        |       |         |      |          | 6<br>4                               |                |                 | 0verall               | Failure       |
| Assessment of res                     | sults gene             | rated i | n this                  | s stud  | dy of  | pipe   | eline |         |      |          | 2                                    |                |                 | Rate                  |               |
| failures, including                   | risk asse              | ssment  | of the                  | e env   | ironm  | ent    |       |         |      |          |                                      |                |                 |                       |               |

from oil pipeline spills, was analyzed on a state-by-state basis of the Niger Delta States (NDS). The analysis was performed on data collected for the 113 NDS pipeline spills used in this study that occurred between 1999 and 2005.

Table 5 and Fig. 3 present the number of spills, spill frequency expressed as kilometer-years, and the failure rate for each ND State. Except for Bayelsa, Delta and Rivers, the number of oil pipeline failures is limited. For Fig. 3. Variation of Failure Rate by NDSs for All Oil Pipeline Spills, 1999-2005; (Source: Pipeline Oil Spill Prevention and Remediation in NDS, NNPC, 2007)

ISBN: 978-988-19251-9-0 IMECS 2012 ISSN: 2078-0958 (Print); ISSN: 2078-0966 (Online)

Proceedings of the International MultiConference of Engineers and Computer Scientists 2012 Vol II, IMECS 2012, March 14 - 16, 2012, Hong Kong

## Causes of Oil Pipeline Failures, NDA

45 40 35 30 25 20 15 10 a

> Causes of Oil Pipeline Failures,NDA

Fig. 4. Distribution of Causes of Oil Pipeline Failures in the NDS, 1999-2005 (Source: Pipeline Oil Spill Prevention and Remediation in NDS, NNPC, 2007)

#### CONCLUSION

The following are the main conclusions of this study:
(a) Comparing the six states (Akwa-lbom, Bayelsa, Cross-river, Delta, Edo, and Rivers) of the Niger Delta area as used in this report, Rivers, Delta and Bayelsa, which are the main hub of oil and gas exploration in Nigeria, have higher pipeline failure rates (at 0.6, 0.5 and 0.45 per 1,000 km-years respectively) as compared to Akwa-lbom , Edo and Cross-river states with pipeline

rupture rate of about 0.25, 0.2 and 0.15 per 1,000 km-years,

highlighting the fact that the pipelines in Rivers. Delta and

Bayelsa states are more susceptible to rupture than in the other Niger Delta states.

- (b) The specific ages of the pipelines in which the failures occurred were not available, and hence, it was not possible to clearly establish the statistical significance of this parameter as a cause of pipeline failure. The failure rate of pipelines usually follows a bathtub curve. At the start and the end of the lifetime, failure rates are high; in the middle of the lifetime failure rates are usually low. This could be due to "teething" troubles for new pipelines and due to wear-and-tear
- as the pipeline gets old.

  (c) The severity of spillage, measured by the amount of oil spilled, is higher in the Niger Delta than in Western Europe. The reason could be poor contingency planning for rapid response to spills; poor detection procedures; lo procedures; long between emergency shutdown valves; or the
- larger average diameter of pipelines.
  (d) Prevention of failures caused by equipment malfunction

is a matter of choosing the right equipment and of proper

maintenance and appropriate testing of the particular equipment.

Hydrostatic testing by which the pipeline is subjected to pressure above the operating pressure, to blow out defects before they reach a critical size in service is also used to detect corroded pipe before it fails in service.

#### V. RECOMMENDATIONS

(a) Among the NDs, Rivers state, with 0.8% of total pipeline kilometers had the highest pipeline failure rate during the period of the analysis. Akwa-lbom and Cross-river states had the

lowest failure rates, with 3.4% and 9.8% of total pipeline kilometers respectively. These variations could be due to a

number of factors, including the following: Differences in the ages of pipelines; Differences in environmental, climatic, geological, and soil conditions and their effects on pipelines and

pipeline routing; Differences in construction standards; Differences in implementation of contingency plans; and Differences in reporting thresholds for oil spill events.

These factors should be reviewed in greater detail so as to establish more precisely the parameters that would explain the differences in failure rate.

(b) Failures due to third-party activities are significant in both the NDs and Western Europe, thereby

- highlighting the need for establishing an effective regulatory and monitoring mechanism for oil pipeline operation in the country.
- (c) External corrosion can be tackled by improved coatings and cathodic protection e.g. use of polyethylene and multilayer coatings have longer life. Early detection of coating degradation is an important strategy and pipes should be
- subjected to hydrostatic testing [11].

  (d) Internal corrosion can be prevented by dehydration of gases and periodic pigging of lines to remove accumulated water and deposits.

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ISBN: 978-988-19251-9-0 TMFCS 2012

ISSN: 2078-0958 (Print); ISSN: 2078-0966 (Online)

Proceedings of the International MultiConference of Engineers and Computer Scientists 2012 Vol II, IMECS 2012, March 14 - 16, 2012, Hong Kong

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ISBN: 978-988-19251-9-0 IMECS 2012

ISSN: 2078-0958 (Print); ISSN: 2078-0966 (Online)

## Long-Distance Oil/Gas Pipeline Failure Rate Prediction Based on Fuzzy Neural Network Model

http://www.computer.org/csdl/proceedings/csie/2009/3507/05/3507e651-abs.html December 07, 2014

... for predicting the failure rates of the long-distance oil/gas ... "Long-Distance Oil/Gas Pipeline Failure Rate Prediction Based on Fuzzy Neural ...

With an aging underground long-distance oil/gas pipeline, ever-encroaching population and increasing oil price, the burden on pipeline agencies to efficiently prioritize and maintain the rapidly deteriorating underground utilities is increasing. Failure rate prediction is the most important part of risk assessment, and the veracity of the failure rate impacts the rationality and applicability of the result of the risk assessment. This paper developed a fuzzy artificial neural network model, which is based on failure tree and fuzzy number computing model, for predicting the failure rates of the long-distance oil/gas pipeline. The neural network model was trained and tested with acquired Lanzhou - Chengdu - Chongqing product oil pipeline data, and the developed model was intended to aid in pipeline risk assessment to identify distressed pipeline segments. The gained result based on fuzzy artificial neural network model would be comparatively analyzed with fuzzy failure tree analysis to verify the accuracy of fuzzy artificial neural network model

Xing-yu Peng, Peng Zhang, Li-qiong Chen, "Long-Distance Oil/Gas Pipeline Failure Rate Prediction Based on Fuzzy Neural Network Model", CSIE, 2009, 2009 WRI World Congress on Computer Science and Information Engineering, CSIE, 2009 WRI World Congress on Computer Science and Information Engineering, CSIE 2009, pp. 651-655, doi:10.1109/CSIE.2009.738

# Oil and Gas Pipelines - University of Colorado Boulder

http://www.colorado.edu/hazards/shakeout/pipelines.pdf December 07, 2014

Oil and Gas Pipelines Prepared for United States Geological Survey Pasadena CA ... failure rates on the order of 0.4/km for high quality welded steel

Oil and Gas Pipelines

United States Geological Survey

Prepared for Pasadena CA

and

California Geological Survey

Sacramento CA

Under contract to SPA Risk LLC Denver CO

By Donald Ballantyne MMI Engineering, Inc. Tacoma WA May 2008

The ShakeOut Scenario: U.S. Geological Survey Open File Report 2008-1150 California Geological Survey Preliminary Report 25 version 1.0

Note: over the course of the ShakeOut Scenario, the project name evolved. Where a study mentions the SoSAFE Scenario or San Andreas  $\,$ 

U.S. Geological Survey Circular 1324

Fault Scenario, it refers to what is now named the  $\mbox{\it ShakeOut}$  Scenario.

California Geological Survey Special Report 207 version 1.0 M7.8 Southern San Andreas Fault Earthquake Scenario: Oil and Gas Pipelines

Donald Ballantyne, MMI Engineering, 206-226-7496, dballantyne@mmiengineering.com

Physical and Operational Impacts of Pipeline Failures

There is a long record of oil and gas transmission pipeline failures in California earthquakes due to ground shaking and liquefaction. The large majority of these have been joint failures where the joints were constructed using oxy-acetylene welds installed prior to approximately 1930. Pipelines constructed using electric arc welding (post-1930) have performed much better. There has been only limited mixed experience of modern pipeline performance at fault crossings.

In the 1994 Northridge earthquake, there were 209 repairs required to metallic distribution lines, and 27 to polyethylene lines. There were 35 non-corrosion -related transmission pipeline repairs of which 27 occurred on pipe joint with oxy-acetylene girth welds in pre-1930 pipelines. At one of those failures, gas leaked from a failed 56-cm line on Balboa Boulevard and was ignited by the ignition system on a nearby truck (T. O'Rourke, 1994). The fire resulted in burning nearby houses (Figure 1).

In the 1989 Loma Prieta Earthquake, PG&E had three failures of transmission lines, and extensive damage to the cast iron distribution system in the San Francisco Marina District resulting in an extensive pipe cast iron pipe replacement program using polyethylene. (EERI, 1990).

In the 1979 Imperial Valley Earthquake, three pipelines were impacted by fault movement; none failed. A 10-, 20-, and 25-cm pipe were subject from 40- to 60-cm of movement. The 10-cm line had oxy-acetylene welded joints, while the other two had electric arc welded joints. These lines were operating at pressures of up to 725 psi. (Dobry, 1992).

In the 1971 San Fernando earthquake, over 80 transmission line failures occurred in pipelines due to shaking that had oxy-acetylene welded joints while less than five occurred in pipelines with electric arc welded joints (including reconditioned joints). For transmission lines subjected to permanent ground deformation, approximately 10 failures each occurred in oxy-acetylene

and electric arc welded pipe. Failures in electric arc welded pipe occurred in areas with offsets of two meters while no failures occurred in another are subjected to two to three meters of displacement (O'Rourke, 1994).

In Washington State, two high pressure gas transmission line failures occurred in 1997, both resulting from ground movement. Another failure occurred in 2003. One of the 1997 failures resulted in an explosion. In 1999, a pipeline carrying gasoline failed due to damage caused by a third party during construction on adjacent facilities. The pipeline failure resulted in discharging 277,000 gallons of product into a creek bed. In the ensuing fire, two boys burned to death, and one young man was killed after he was overcome by fumes.

1

In summary, modern steel pipelines with electric arc welded joints perform much better pipelines with oxy-acetylene welded joints (typically pre-1930 construction). Steel pipelines have performed well when subjected to ground displacements of 60 cm, but sometimes fail when displacements reach several meters. High pressure gas lines do fail when subjected to permanent ground deformation due to slides, and if an ignition source is available, can explode. Gasoline leaked from a damaged product line fueled a fireball when ignited.

#### Exposed Assets

Pipeline information was acquired using the HSIP Gold database, provided in both Google Earth and ArcGIS format. Six product pipelines were identified in areas of strong ground shaking, two of which cross the fault at Cajon Pass. Three run westerly from the node/distribution terminal in Colton towards Los Angeles, and one runs easterly from that same node as shown in Table 1.

Table 1. Product Pipelines Impacted by the Earthquake Scenario

| Pipeline Name                             | Diameter | Location   | Hazard  |
|---|----------|--|---|
| Colton-Barlow, CalNev<br>Pipeline Company | 35-cm    | Cajon Pass; San Andreas<br>Fault Crossing  | Fault Crossing, Landslide,<br>Liquefaction/Lateral Spread             |
| Colton-Barlow, CalNev<br>Pipeline Company | 20-cm    | Cajon Pass; San Andreas<br>Fault Crossing  | Fault Crossing, Landslide,<br>Liquefaction/Lateral Spread             |
| Colton-Yuma, Kinder<br>Morgan SFPP LP     | 50-cm    | Colton, east south-east<br>along the west side (and<br>crossing) of the San Andreas<br>Fault to the Salton Sea | Fault Crossing, Landslide,<br>Liquefaction/Lateral Spread,<br>Shaking |
| Nogales-Colton                            | 50-cm    | Colton - Los Angeles   | Landslide, Liquefaction/Lateral Spread, Shaking                       |
| Watson-Colton                             | 40-cm    | Colton - Los Angeles   | Landslide, Liquefaction/Lateral<br>Spread, Shaking                    |
| Colton-March                              | 15-cm    | Colton to March AFB  | Landslide, Liquefaction/Lateral<br>Spread, Shaking                    |

Southern California Gas owns gas transmission and distribution pipelines throughout the region. Twenty-seven fault crossings were identified; eighteen transmission, and nine distribution pipelines (some lines are counted multiple times as they cross multiple splays of the fault). Two of these cross at Cajon Pass (transmission), one at San Bernardino (distribution), fourteen at Palm Springs (seven transmission and seven distribution), and ten at Palmdale (nine transmission and one distribution). The diameter of these lines is unknown. Southern California

Gas's entire pipeline inventory in areas with PGA's exceeding 10 to 15 percent gravity are subject to landslides and liquefaction/lateral spread through the region.

It is assumed that all of the product and gas transmission lines are constructed using welded steel joints. Some of these pipelines may have been constructed using oxy-acetylene welded joints (typically pre-1930), and some using electric arc welded joints (post-1930). Some of the distribution pipelines may be constructed of cast iron. In most cases, the cast iron would have been replaced with polyethylene.

## Vulnerability of Assets

Buried pipelines are vulnerable to permanent ground deformation and wave propagation (shaking). Ground deformation can include fault rupture, landslide, and liquefaction and associated lateral spreading and settlement. Pipe damage mechanisms include: compression/wrinkling, joint weld cracking/separation (particularly for oxy-acetylene welds), bending/shear resulting from localized wrinkling, and tension.

This earthquake scenario is focusing on an event on the southern segment of the San Andreas Fault that is expected to offset as much as 13 meters near the Salton Sea. A 4.5 meter offset is expected at Cajon Pass. In addition to lateral movement, there may be an additional vertical offset. The fault offset places the buried pipe in shear, compression, or tension depending on the geometry of the pipe relative to the fault. The preferred alignment would be to place the pipe in pure tension; the worst alignment would place the pipe in pure compression. In tension, steel pipelines with welded joints can distribute tensile strain over hundreds of meters minimizing localized stresses. Anchor points (valves of bends) can result in local stress concentrations. By comparison, pipelines readily wrinkle in compression. It may be possible for the pipelines crossing the San Andreas Fault at Cajon Pass to survive if they have been properly designed. If special considerations were not taken into account, it is unlikely the pipelines could accommodate 4.5 meters of offset. The American Lifelines Alliance (2001) estimates that high quality welded steel pipe would have a failure about every 400 meters given these conditions. The Colton-Barstow CalNev pipelines and the Kinder Morgan Colton Yuma pipeline appear to run parallel to and nearly on top of the fault. Depending on the exact fault location, this alignment could put these pipelines into almost pure compression causing them to fail.

Landslides can load buried pipelines in a similar manner to fault rupture. Pipelines crossing block landslide failures (but moving only several meters) laterally are put into shear at both edges of the block. If they run through longitudinally, they are put into tension at the top of the slide, and into compression at the toe. In catastrophic landslide failures, the pipe may be left unsupported. It is difficult to speculate about vulnerability due to landslides without site specific assessments. However for example, pipeline alignments approaching Cajon Pass, the Kinder Morgan pipeline north of Redlands, and the Nogales-Colton pipeline east of Whittier are all in rugged terrain,

3

Liquefaction and associated lateral spread and settlement occur in alluvial deposits with a shallow groundwater table (less than 10 meters deep). Most of the study area receives minimal rainfall, and as a result has a deep groundwater table. Additional information is required to identify areas that might be vulnerable to liquefaction. If liquefaction does occur, the greatest vulnerability occurs when buried pipelines move as part of large blocks of soil, down gradient. The vulnerable locations are at the block interfaces. The pipelines are subject to similar loading that would be encountered in landslides.

Compression wave propagation along pipelines puts them first in tension and then in compression. Standing on the ground surface, humans feel this as shaking. Pipelines can readily accommodate wave propagation moving the pipe tangential to its alignment.

Historically, steel pipelines with high quality electric arc welded joints perform very well in this shaking environment. Pipelines with joints using oxy-acetylene welds can have failure rates nearly 100 times greater than those with electric arc welded joints.

The most extreme shaking intensity in the study area is expected to be about 250 cm/second, located just north of Cajon Pass and in the Palm Dessert-Coachella area along the Kinder Morgan pipeline. For this level of shaking, the American Lifelines Alliance (2001) estimates failure rates on the order of 0.4/km for high quality welded steel pipelines (Figure 2). Pipelines in the San Bernardino and Palmdale areas would be expected to experience velocities of 150 to 200 cm/sec resulting in failure rates of 0.28/km for high quality electric arc joint welded pipe.

If a pipeline does fail, the consequences are dependent on its contents, its diameter, and the pressure of its contents. The two general categories of contents are "product" including liquid fuels that could be gasoline, jet fuel, diesel fuel, or other liquid fuels, and natural gas. The operating pressure in natural gas pipelines can approach 1,000 psi. Gas released through failures in small diameter low pressure gas mains (distribution mains) will generally dissipate quickly. Failure of large diameter high pressure natural gas pipelines can result in an explosion that can blast a crater in the surrounding soil, and damage nearby and overhead structures and facilities (such as power transmission lines). In any case, an ignition source is required to initiate the explosion. A human caused source could be a vehicle ignition system, cigarette lighter, or spark from a metal on stone impact. There is speculation that pipelines running parallel to overhead high voltage power transmission lines carry an induced current that could cause a spark if the pipeline was ruptured. In any case, there is a high probability that there will be an ignition source in the event of rupture of a high pressure pipeline. As evidenced by the fire that occurred in Washington State, failure and leakage of gasoline can result in an extensive fire if an ignition source exists. For some liquid fuels such as diesel, the potential for a fire is low, but would result in environmental contamination.

Damage Scenario and Lifeline Interaction

Natural gas, gasoline, and diesel pipelines rupture at fault crossings at Cajon Pass, Palm Springs, and Palmdale. A product line carrying gasoline ruptures at Cajon Pass; in the hills east of

4

Whittier another product line fails spewing jet fuel into the air. The product receiving station tank farm in Colton is heavily damaged.

One of the two Southern California Gas transmission pipelines at Cajon Pass will rupture at the fault and explode (See Figure 3) resulting in a large crater (see Figure 4). The Southern California Gas pipeline-fault interface occurs where the pipeline intersects the CalNev 14-inch product pipeline, so when the explosion occurs the CalNev pipeline ruptures. The CalNev pipeline is transporting gasoline, so the gasoline adds to the fire (see Figure 5). Power transmission lines are overhead, and the fire reaches the lines causing them to fail.

The Southern California Gas pipeline is one of two parallel lines at Cajon Pass. Delayed by highway damage and traffic congestion, operations personnel reach the site and isolate the damaged pipe four hours after the earthquake occurs. Their second pipeline is taken out of service as a precautionary measure to check for damage due to the 5 meter fault offset. The second pipeline is temporarily put back in service until the ruptured one is repaired. CalNev operations personnel reach the site and isolate their line 6 hours after the earthquake. Electrical power is rerouted around the damaged transmission line.

The 20-inch Kinder Morgan product line is ruptured in Palm Springs (Figure 6). The pipeline is aligned directly over the fault. When the earthquake occurs, the pipeline is shortened five meters causing it to wrinkle and rupture (Figure 7). The pipeline is carrying diesel which is sprayed into the air. Ultimately 200,000 gallons of product is discharged into the local drainage until the line can be isolated. A smaller natural gas distribution pipeline is located in the same right-of-way. The fault displacement also ruptures this line. Although the volume of discharging gas is much smaller than that coming from the break at Cajon Pass, the gas hampers response efforts. The Kinder Morgan Pipeline fails at an additional 15 locations due to shaking at locations along the 60 km alignment paralleling the fault trace. Each failure location requires environmental cleanup of the discharged diesel product.

In Palmdale, a natural gas transmission line crosses the fault multiple times. It ruptures when the earthquake occurs, spewing gas into the air. First responders quickly evacuate the area and are able to keep the gas from igniting until a Southern California Gas crew arrives to isolate the break.

A landslide in the hills east of Whittier shears off the 20-inch Nogales pipeline in the hills east of Whittier releasing jet fuel. 100,000 gallons of product is discharged before the line can be shut down. The jet fuel finds its way into a local drainage.

The Colton Receiving Station (Figure 8) is subjected to 40 percent g shaking. The receiving station is a node for distribution of gasoline, diesel and jet fuel. The facility also controls flow of jet fuel to March Air Force Base. Unanchored tanks bounce around breaking connecting pipe. Fuel discharges into the retaining dikes, and is ignited by passing vehicle ignition system.

area. In recent years, they have replaced most of the cast iron pipe in the distribution system with polyethylene. They still suffer approximately 200 pipeline failures, primarily at fittings and transitions.

#### Mitigation

To mitigate pipe failures, there is a series of possible mitigation measures that can be considered on a site by site basis. Seismic resistant design of pipelines at fault crossings may be the most effective compared to landslide and liquefaction areas because fault (particularly strike-slip faults) locations can be determined with reasonable accuracy. The same mitigation measures can be employed for areas with high susceptibility to landslides or liquefaction/lateral spreading except that the locations of block interfaces may be less certain. There may be an opportunity to avoid landslide and liquefaction zones when selecting the alignment of new pipelines. Selection of pipe joint design is important in mitigating pipe damage due to wave propagation.

To mitigate damage due to permanent ground deformation (fault movement, landslide, liquefaction) use modern welded steel pipe with butt electric arc welded joints. Replace old pipe that has oxy acetylene welded joints within the fault zones and several thousand feet beyond. The pipeline geometry should be designed so the pipe will go into tension when the fault moves. Install the pipe with a coating/covering to minimize soil-pipe friction allowing the pipe to easily slide through the ground. Avoid use of "anchors" (valves, sharp bends, etc.) to allow the pipe to move so that pipe stresses can be distributed along the pipe. Design the backfill to allow the pipe to move laterally in the trench if required to accommodate the fault movement.

To mitigate damage due to wave propagation (shaking), use modern steel pipe employing electric arc welded joints (the standard in the industry). Replace old (pre-1930) pipe with oxyacetylene welded joints.

To mitigate the consequence of pipe failure, implement an automated control system to allow quick shutdown of the pipeline systems. Construct parallel (redundant) pipelines in independent alignments so if one fails, the other may remain intact.

6

Figure 1. Balboa Neighborhood Burned by Exploding Gas Line in Northridge Earthquake (left); Fire ball that Burned the Neighborhood.

Failure Rate (failures/km)

Welded Steel Pipe

Peak Ground Velocity (cm/sec)

Figure 2. Wave Propagation Pipeline Fragility (After ALA 2001)

7

Electric Power

Product Pipelines

San Andreas Fault

Rail

Highways

Figure 3. Oil, Electric Power, Highway, and Railway Lifelines in Relationship to the San Andreas Fault at Cajon Pass (Natural Gas Pipelines Not Shown).

Figure 4. Crater Resulting from Williams 26-inch Pipeline Explosion in Washington State, December 13, 2003. (Photo Credit - Washington Utilities and Transportation Commission)

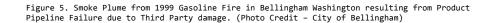


Figure 6. Layout of Kinder Morgan 20-inch Product Line (brown) and Southern California Gas Pipelines (pink). Relative the San Andreas Fault in Palm Springs (dotted).

Figure 7. Wrinkled Pipeline Failed in Compression

10

Figure 8. Colton Receiving Facility with Tank Farm Vulnerable to Earthquake Ground Motion

11



# Key factors for the estimation of cross-country pipelines ...

http://www.erm.com/PageFiles/1962/Key-factors-for-the-estimation-of-cross-country-pipelines-failure-rates.pdf December 07, 2014

... the failure rate for natural gas pipeline has bucked the trend and has increased by approximately ... do not differ for gas pipelines or oil pipelines.

Key factors for the estimation of cross-country pipelines failure Glenn Petitt with comments acknowledged from Richard Espiner

## Introduction

Underground cross-country pipelines are widely used in the Oil & Gas and Petrochemical Industries to transport raw materials and products, e.g. crude oil, natural gas and gasoline. The loss of mechanical integrity of such pipelines has occurred on numerous occasions world-wide, due to a variety of causes such as corrosion, external impact, defects, operational errors and natural hazards. With materials being transported at very high pressures, pipeline failures may result in major releases of hazardous materials. An example is shown in Figure 1: the destruction of many houses after a major fire following a gas pipeline rupture in San Bruno, California, USA in September 2010. Such failures present a risk to people (in the case of ignition of high pressure gas) and the environment (in the case of oil and other liquid products).

There are a number of recognised failure rate databases for cross-country pipelines, such as CONCAWE (European liquid pipelines) [1], EGIG (European gas pipelines) [2] and the US DoT (both liquids and gas pipelines) [3]. It is remarkable how close the base data from the different systems are, which leads to some confidence that the figures are sufficiently robust to be used in risk analyses.

For each database there is a number of failure modes included, such as corrosion, third party impact, material defects, natural hazards. For some of these failure modes, the databases have shown that there is a correlation between the failure rates and various risk reduction mechanism, such as heavy wall thickness. In particular, a reduction in failure rate can be applied for the corrosion and third party impact failure modes for heavy wall thickness.

However, for other failure modes, in particular material defects, the databases show no correlation between the failure rate and key risk reduction mechanisms such as heavy wall thickness. It would seem logical that the failure rate for material defects should decrease with increasing wall thickness, but for frequency assessments this has often been a constant in past studies, by simple use of statistics from the various databases.

The author has extensive experience of assessing the risks associated with pipeline systems, having been heavily involved in the design and subsequent operation of a number of high-profile pipelines world-wide (from a risk perspective). This experience has been applied to the analysis of the various failure modes in order to determine how various risk reduction techniques can reduce the frequency of failure. This includes the assessment of statistics where there is no immediate correlation from the various databases for specific failure modes.

The paper discusses how such data can be applied where logic would suggest that there should be a reduction in failure rates, although this is not immediately apparent from the various databases.

#### Historical databases

Table 1 provides a summary of historical pipeline failure data from some of the best sources of data for onshore pipeline systems. All these sources provide raw data on failure incidents and pipeline length and an analysis of the failure causes. The most relevant and up to date databases available are those of:

- CONCAWE.
- European Gas Pipeline Incident Data Group (EGIG),
- US Department of Transportation (US DoT).

| Table 1 | C | of Vanious | International | Dimalina | Failusa Data |
|---------|---|------------|---------------|----------|--------------|
|         |   |            |               |          |              |

|             | abic i comparison or | var ious incernacional | i i ipciine i dilui e baca        |
|-------------|----------------------|------------------------|-----------------------------------|
| Source      |                      | Period                 | Overall (i.e. unmodified) Failure |
|             |                      |                        | Frequency (per km.year)           |
| CONCAWE     |                      | 1971-2010              | 3.5 E-4*                          |
|             |                      | 1981-2010              | 2.8 E-4*                          |
|             |                      | 1991-2010              | 2.4 E-4*                          |
|             |                      | 2001-2010              | 2.2 E-4*                          |
| EGIG        |                      | 1970-2010              | 3.5 E-4                           |
|             |                      | 1981-2010              | 2.9 E-4                           |
|             |                      | 1991-2010              | 2.0 E-4                           |
|             |                      | 2001-2010              | 1.7 E-4                           |
| US DoT, Lic | uids .               | 1988-2001              | 4.9 E-4                           |
|             |                      | 2002-2011              | 4.5 E-4                           |
| US DoT, Nat | ural Gas             | 1988-2001              | 7.2 E-5                           |
|             |                      | 2002-2011              | 1.1 E-4                           |

<sup>\*</sup> These frequencies have been filtered to include those only from the cross-country sections.

The CONCAWE database [1] applies to crude oil and petroleum pipelines that are located in Western Europe, although since 2001, pipelines from a number of Eastern European countries have also been included in the database. Data are collected for the pipeline network every year. A number of figures are provided in Table 1 that show that the general trend of pipeline incidents is decreasing.

EGIG has compiled data collected by a group of 15 major gas transmission operators in Western Europe over the period 1970 to 2010 [2]. Failure rates for the whole of this period are provided in Table 1, but again, more recent data show that the performance of gas pipelines has generally improved.

The US DoT collects annual statistics on pipeline failures from reportable incidents. Results can be obtained from the internet back to 1988 [3]. Data from 2002 onwards are more detailed in terms of the failure mode, hence the split in the periods shown in Table 1. It is interesting to note that whilst the failure rate has again decreased for liquid pipelines in the later period shown in Table 1, the failure rate for natural gas pipeline has bucked the trend and has increased by approximately 50% (probably due to improved reporting in recent years), although the overall failure rate is still below that of EGIG.

The overall failure rate data show a relatively good similarly. Data from the most recent years is recommended for estimating failure rates due to the improving performance. These data take into account improved mechanisms for pipeline integrity, such as superior pipeline coatings and better cathodic protection systems to reduce the likelihood of corrosion failures; improved mill quality control and construction techniques to reduce the likelihood of material fault failures; and enhanced protection methods, such a concrete slabbing at crossings to reduce the likelihood of external interference failures. However, a number of the older pipeline systems still do not have such enhanced protection mechanisms and data that includes earlier years may be more appropriate for these.

It should be noted that the data are an average over different countries in Europe and over different states in the US. The addition of Eastern European liquid pipelines into the CONCAWE database resulted in a slight increase in the overall failure rate data when these were first included, due to the inferior performance of these pipelines.

Analysis of the raw data is described in more detail in a previous paper [4], although data from the last few years is not included. This current paper is more concerned with how key factors can be applied for the estimation of cross-country pipelines failure rates.

## Failure causes

The historical databases also provide good data on the various failure modes. For all databases the most common failure mode is due to third party interference. Other key failure causes are corrosion, material defects and natural hazards. Certainly with regard to gas transmission pipelines, third party interference is a major cause of full bore ruptures, which is a key focus of this paper. Failure causes are dealt in detail elsewhere and so not discussed in detail in this paper. However, Figures 2 and 3 show the latest data from CONCAWE (cross-country sections only) and Figure 4 shows the latest data from FGTG.

## Release siz

A major issue for the potential safety and environmental impact of releases from oil and gas pipelines is the size of the release.

In particular for gas pipelines, serious impact is most likely if there is a full bore rupture; this is generally 'unzipping of the pipeline' such that a complete section is lost and gas is released from both ends, initially at a very high release rate. If the failure mode is accompanied by ignition, or if ignition occurs during the early part of a release, then a catastrophic fire may ensue. (If ignition is delayed, there may still be a major fire, although much of the early inventory will be lost as the pipeline rapidly depressurises.) Hence, for high pressure gas pipelines, one is generally concerned with full bore ruptures, with consequences demonstrated as shown in Figure 1. (Leaks may also result in serious fires, but the magnitude of these is relatively small in comparison.)

For oil pipelines the size of release is not as significant with regard to environmental impact. A small release has the potential to continue for a large amount of time (possibly many days) if it remains undetected. This may cause significant damage to the local environment. For environmental impact, the amount of oil or petroleum product lost is the key factor rather than the release rate; hence, a small release that continues for many days may be as significant as a large release that is quickly detected and responded to.

## Concawe data

Accidents statistics were analysed for hole size distribution [4]. The hole size failure rate by cause is shown in Figure 5. In the CONCAWE data the various hole sizes are described as follows:

• Pinhole: less than 2 mm x 2 mm

Fissure: 2 to 75 mm long x 10% max wide
 Hole: 2 to 75 mm long x 10% min wide
 Split:75 to 1000 mm long x 10% max wide
 Rupture: >75 mm long x 10% min wide

In terms of terms of their equivalent diameter, (required for consequence modelling in a risk analysis) these have been interpreted as shown in Table 2. The 'rupture' hole size is interpreted as any hole size above 150 mm.

# Table 2 Estimated Hole Size by Failure Mode (CONCAWE) Failure Mode

|                      | 5 mm  | 50 mm | 100 mm | Rupture |
|----------------------|-------|-------|--------|---------|
| Mechanical failure   | 50.0% | 38.0% | 8.0%   | 4.0%    |
| Operational          | 18.8% | 43.8% | 25.0%  | 12.5%   |
| Corrosion            | 55.3% | 37.8% | 4.7%   | 2.3%    |
| Natural hazard       | 42.0% | 29.0% | 19.3%  | 9.7%    |
| Third party activity | 37.5% | 29.5% | 22.0%  | 11.0%   |
| Easia data           |       |       |        |         |

Accidents statistics have also been analysed for hole size distribution. The hole size distribution by cause is shown illustrated in Figure 6, which shows the overall failure rates. A 'pinhole / crack' is interpreted as a 5 mm equivalent hole and a 'hole' is interpreted as a 50 mm

hole

There are a number of risk reduction mechanisms that will have an influence on the overall failure rate of the pipeline. These can be listed under the various failure modes.

In this section all potential risk reduction mechanisms are discussed. For 'external interference / third party activity' and 'corrosion', the risk reduction mechanisms have been discussed in a previous paper presented at Hazards XXI in November 2009, and there has been little change in the analysis. However, for 'material failures' further research has been carried out on the potential risk reduction mechanisms and this is described in more detail in this paper.

External interference / third party activity

Probably the most significant effort in risk reduction is made to reduce the chance of pipeline failures due to third party activities, whether these are accidental, intentional or incidental. (Incidental failures are which there is an external impact, which does not cause a failure at that time, but where a loss of containment eventually occurs, as the integrity of the pipeline reduces at that point.)

Some of the more common risk reduction mechanisms are as follows:

- Pipeline safety zones,
- Increased wall thickness,
- · Increased depth of cover,
- Warning marker posts,Plastic marker tape,

- Concrete slabbing,Physical barrier within pipeline trench,
- Vibration detection,
  Regular inspections of pipelines ROW,
- · Intelligent pigging.

Pipeline safety zones may be established during the pipeline construction. The intention is to avoid construction activity along or near the right-of-way (ROW). Regular inspections of a pipeline ROW would help to decrease the failure rate due to third party activity, certainly accidental and intentional, and an appropriate reduction factor may be applied depending on the inspection interval.

Probably the risk reduction mechanism with the largest influence is the wall thickness (WT). This shown by the EGIG data (Figure 7), where there is a large drop in failure rate for pipelines with a WT above 10 mm and no failures for a WT above 15 mm. Unsurprisingly, the failure rate is much higher for pipelines with a WT of less than 5 mm. In deriving failure rates for a specific pipeline, the WT should be taken into consideration, but the maximum allowable operating pressure (MAOP) should also be considered, particularly with regard to liquid pipelines, as this would be taken into account in the pipeline design, e.g. a liquid pipeline that traverses a mountainous route may have a thicker wall at the bottom of a slope than at the top, due to the change in pressure head. (For gas pipelines, essentially the MAOP will not vary with change in elevation.)

The depth of cover may also influence the failure rate, again as shown by Figure 8 for EGIG data. Certainly, where the depth of cover is less than 0.8 m, the failure rate due to third party interferences increases significantly. One would expect that the failure rate decreases significantly as the depth of cover increases to, say, 2 m, but there is not the data to support this, probably as the nominal depth for most pipelines is in the order of 0.9 to 1.0 m.

The other risk reduction mechanisms listed above would also have an influence on the failure rate due to third party activity. Mechanisms such as warning posts, concrete slabbing and plastic marker tape are often used at road crossings, for example, although the crossing itself may warrant an increase in the failure rate at that point, and so the risk reduction mechanisms may serve to keep the failure rate the same, i.e. the failure rate at a crossing would be increased from that on the rest of the pipeline if there were no mechanisms such as concrete slabbing. Work by British Gas, summarised by Morgan 1996 [5], found that a combination of slabbing with a visual warning such as plastic marker tape was particularly effective in preventing accidental damage. These techniques may therefore be usefully deployed in other sensitive areas to reduce the likelihood of damage by machinery.

Some pipelines may include mechanisms to guard against illegal hot-taps (intentional third party failures), such as a physical barrier in the trench and vibration detection. Also, there may be increased patrols by military personnel. In such cases, the failure rate due to illegal hot-taps would become very small, although the failure rate due to intentional activity would change depending on the country or area that the pipeline runs through, as illegal hot-taps are a significant problem in some

Intelligent pigging may reduce the risk of latent incidental third party failures, by detecting a potential failure before this becomes critical after the initial damage has occurred. CONCAWE reports [1] that over the past 40 years, 51 spills have been caused by mechanical damage (including incidental damage by third parties) or faulty welds that could, in principle, have been detected by intelligent pigs.

Risk reduction factors for external interference are also discussed in detail in PD 8010-3 [6], which applies to steel pipelines on land, and IGEM/TD/2 [7], which applied to natural gas pipelines only. Corrosion

A significant effort is also made to reduce the risk of pipeline failure due to corrosion (internal and external). Risk reduction mechanisms include:

- Increased wall thickness,
- Pipeline coating,
- Cathodic protection (CP) system,Internal lining,
- Intelligent pigging.

Similarly to external interference, the WT plays a major role in determining the failure rate due to corrosion. Again, this shown by the EGIG data (Figure 9), where there is a large drop in failure rate for pipelines with a WT above 10 mm and no failures for a WT above 15 mm.

The relationship between pipeline coating, CP and failure rate due to corrosion has been analysed by de la Mare et al. [8] in a study on US gas transmission pipelines. The study showed that during the years 1970-1973, on average, the corrosion failure rate was reduced by a factor of about five for pipelines that had either a coating or CP. Most pipelines now have an external coating, CP, or both and this is reflected in the base data. Review of the CONCAWE data shows that where there was a failure due to external corrosion, this is generally due to a failure of the external coating or of the CP system. Hence, it would be appropriate to increase the failure rate due to corrosion if a pipeline was not protected, rather than reduce the failure rate if it was protected, particularly if there was an aggressive soil type or in areas where the soil was wet, i.e. where there may be more of a potential for external corrosion.

An internal lining may reduce the potential for internal corrosion, although such linings are often used if the internal fluid is corrosive, e.g. sour gas.

Certainly, if the pipeline fluid is transported at elevated temperatures due to a high viscosity at ambient temperatures, then it may be appropriate to increase the failure rate data due to corrosion, as this failure mechanism is enhanced at elevated temperatures, shown by CONCAWE data.

One would not expect high corrosion rates for newly laid pipelines, but this would change with time, so a reduction factor would not be expected, as one should be studying the pipeline over its life-cycle. It may be appropriate to increase the failure rate for older pipelines, e.g. pre-1960, but there are little data to substantiate such an increase in the case of CONCAWE.

Again, intelligent pigging may reduce the risk of corrosion failures, by detecting a potential failure before this becomes critical. One would need to take into consideration how often intelligent pigging is conducted. CONCAWE reports [1] that over the past 40 years, there have been 102 spillages related to external corrosion and 25 to internal corrosion, at least some of which could have been detected. (Nearly two thirds of the 102 spillages related to external corrosion occurred in 'hot' pipelines, most of which have now been retired.)

Risk reduction factors for corrosion are also discussed in detail in PD 8010-3 [6], which applies to steel pipelines on land, and IGEM/TD/2 [7], which applied to natural gas pipelines only.

#### Natural hazard

The base failure data contain a background rate for natural hazards, although in reality, this is due to the environment where some pipelines in the database pass through. Where a pipeline crosses, for example, rivers, seismic fault lines and areas susceptible to landslides, the failure rate should be increased at that point, unless there are substantial measures taken in the pipeline design to mitigate against such hazards. Natural hazards are particularly relevant where a pipeline passes through mountainous regions, where all three examples of potential failure mentioned above may exist.

Such mitigation measures may include micro-tunnels for river crossings, in particular where there may be a severe washout hazard during a spring melt of snow, seismic fault design, and ensuring that a pipeline is laid in the direction of a potential landslide area rather than across it. Soil erosion control and geohazard monitoring may also be factors in reducing the potential stress on a pipeline and hence the likelihood of failure.

There is insufficient historical data to establish a relationship between ground movement failure data and individual pipeline parameters [7]. For example, the pipeline wall thickness is not taken into consideration. The failure frequency for natural hazards along the pipeline ROW should be assessed on the particular natural hazards encountered at specific locations and the particular mitigation mechanisms should be taken into consideration. For example guidance on the pipeline rupture rate is given in IGEM/TD/2 for different slopes where a landslide may be present, as shown in Table 3 [7].

#### Table 3 Failure Rate due to Landslide from Different Slope Types

| Description  | Pipeline | Rupture Rate  |
|--|----------|---------------|
|  | (per     | km-year)      |
| Slope instability is negligible or unlikely to occur, but may be affected by | 0        | to 9 E-5      |
| slope movement on adjacent areas   |          |               |
| Slope instability may have occurred in the past or may occur in future - is  | 1 E-4    | 4 to 2.14 E-4 |
| present and may occur in the future  |          |               |

Slope instability is likely and site specific assessment is required >3 E-4
With regard to landslides, there are a number of experts who can provide judgements as to the likely occurrence of a
landslide and whether these may cause a rupture of the pipeline. Such experts have worked with the author to provide
value judgements at potential landslide areas. Measures can be taken for modern pipeline systems (and current systems) to
mitigate the effects, certainly by designing the pipeline route such that landslide areas are avoided, or where this may not be
possible, such that the pipeline runs in the direction of the potential landslide and not across it.

#### Material failures

There are no significant mechanisms to reduce the risk of material failures or construction faults once a pipeline is laid, other than intelligent pigging, which may detect potential weak points before these become critical. As noted above, CONCAWE reports [1] that over the past 40 years, 51 spills have been caused by mechanical damage (including incidental damage by third parties) or faulty welds that could, in principle, have been detected by intelligent pigs. However, it should be noted that faulty welds come under the category of 'construction faults'; the spill sizes from these tend to be much smaller than 'material faults' (by a factor of about 40 on average), as shown by Figure 10. Hence, if only faulty welds may be discovered by intelligent pigging, this may not reduce the risk of a much larger failure due to a fault in the material.

One major issue is that the manufacture of pipework in terms of the milling process has improved with time, such that modern pipework systems are less likely to develop failures. This can be shown by Figure 11 where the failure rate versus year of construction is considerably reduced (EGIG data). Of course, one key factor is that there are far more km years for older pipelines in the data set and one would expect a reduction in the number of failures in later years for this reason alone.

Data shown in PD 8010-3 [6] for the failure frequency due to material and construction defects is given in Table 4, which shows that the failure rate decreases as the wall thickness increases. UKOPA data have indicated that the material failures manifest as gas leaks, and that there have been no full bore ruptures within the UK to date. This is contrary to the EGIG data shown in Figure 11, which indicates that there have been a number of full bore ruptures within the rest of Europe.

| Table 4 Failure Rate | due to | Material Failures vs Wall Thicknes |
|----------------------|--------|------------------------------------|
| Wall Thickness Range | (mm)   | Failure Rate (per km-year)         |
| WT < 5               |        | 5.05 E-4                           |
| 5 < WT d 8           |        | 6.4 E-5                            |
| 8 < WT d 10          |        | 4.6 E-5                            |
| 10 < WT d 12         |        | 3.1 E-5                            |
| 12 < WT d 15         |        | 7 E-6                              |
| WT > 15              |        | 4 E-6                              |

The failure rate due to material failures in the UK is dependent upon the year of construction and hence the age, design and construction standards, in particular the material selection controls and welding inspection standards applied which have improved significantly since the early 1970s [7]. For pipelines commissioned after 1980, UKOPA states that the material failures failure rate can be assumed to be reduced by a factor of 5, as shown by IGEM/TD/2 [7].

A key point is that there have been no full bore ruptures in pipelines constructed from 1984 onwards in Europe as a whole, not just in the UK. This does not mean that such an occurrence will not happen; however, there have been over 25 years in this data set from EGIG and it is an encouraging factor that there have been no full bore ruptures due to material failures in pipelines constructed from 1984 onwards. Hence, there is justification for reducing the full bore rupture failure rate significantly for gas transmission pipelines constructed after 1984. This has a major implication on European gas pipeline risk assessments (and possibly beyond), i.e. rather than using a figure of about 4 E-6 per km-year for full bore ruptures, which can be taken from Figure 6, a much reduced level could be applied. If a reduction by a factor of 5 is assumed for pipelines commissioned after 1980, this reduces to 8 E-7 per km-year. However, a further factor can be applied to take into account that there have been no full bore rupture events for pipelines constructed in Europe from 1984 onwards.

If the wall thickness is taken into account as shown in Table 4, then this reduction becomes even greater for heavy wall pipelines. For example, the data in EGIG show that the failure rate for material failures is about 5.8 E-5 per year. This ties in well with the data shown in Table 4. Hence, for a heavy wall pipeline of wall thickness greater than 15 mm and constructed from 1984 onwards, a significant reduction in the failure rate could be justified.

This was demonstrated in a recent quantitative risk assessment conducted by the author for a modern gas pipeline system with heavy wall thickness. A significant reduction in the external interference and corrosion failure rates was applied in an area where there were no significant natural hazards and where a hot tap in error would be extremely remote. In this case, by applying the generic EGIG data, the full bore rupture failure rate due to material failures was calculated to be about 98% of the overall full bore rupture frequency. Certainly this was not logical given the modern pipeline system and the very heavy wall thickness. By using the reduction mechanisms noted above, the failure rate for material failures became more reasonable, i.e. more in line with the other failure mechanisms where one would expect heavy wall thickness to be an allround risk reduction factor.

With regard to oil pipelines, those constructed from 1984 onwards would also be expected to have a drop in the failure rate of large failures, as the pipeline construction method (at the mill and at the construction site) do not differ for gas pipelines or oil pipelines. For material defects, the CONCAWE data show only one failure for pipelines constructed from 1984 onwards. (There have also been construction defects for such pipelines, but these failures tend to be small as shown in Figure 10.) For significant releases of oil or petroleum product (although as noted above this may not be for a large leak) there have been a number of failures in recent years, most notably a release of 5,401 m3 in 2009. However, all significant failures have been in pipelines constructed prior to 1984 (where the pipeline age was noted), which ties in with the data for gas pipelines. Hence, it would also be appropriate to apply similar reduction factors for oil pipelines based on age and wall thickness. Overpressure protection

Liquid pipelines in mountainous area may require overpressure protection. The MAOP and the minimum wall thickness requirements are taken into consideration in the pipeline design. Some pipelines require surge relief (tanks at pump stations

or pressure reduction stations), and again, these are considered in the pipeline design due to the potential for a surge, so a reduction in the base failure rate would not be appropriate.

The pipeline design factor (the ratio of hoop stress to material yield stress) should be taken into consideration when assessing potential hole sizes for gas pipelines. The design factor is a function of the type of steel, pipeline diameter, wall thickness and the MAOP. In particular the WT would have already been taken into account in determining the overall failure rate, but it should be noted that at design factors of 0.3 and WT of >11.91 mm, propagation to rupture is extremely remote [9], i.e. to get a benefit from both effects, it requires a DF achieved through a WT >11.91mmm, and not merely from getting a low DF from higher grade steel. (The 0.3 DF relates to leak before break behaviour from crack growth mechanisms. The 11.91 mm relates only to ruptures due to impact from e.g. digger teeth and other external impact implements common in agriculture and construction in the UK during the 1970s.)

However this 0.3 figure for design factor may be considered somewhat conservative, particularly for large diameter, heavy wall pipelines, and therefore the factor is sometimes increased (i.e. less onerous), e.g. in the UK Institution of Gas Engineers code IGEM/TD/1 [10], to 0.5 for pipelines with a wall thickness over 19.1 mm.

Risk reduction factors for design factor are discussed in detail in IGEM/TD/2 [7], where failure rate predictions for external interference rupture and leak frequencies vs design factor are given for specific diameter and wall thickness pipelines.

#### Conclusion

The various databases give excellent base data to estimate the likelihood of failures of cross-country pipelines. However, it is not sufficient to rely on these databases alone in predicting the failure rate. One needs to include the various factors: design, operating, and environmental in the estimation of the failure rate, which may change along the pipeline ROW. A previous paper presented at Hazards XXI [4] discussed how the various risk reduction mechanisms could be applied for the key pipeline failure modes of external interference and corrosion. However, at that time there was no discussion of how risk reduction mechanisms would affect the failure rate of the material failure release mechanism. This paper has provided such a discussion, as materials failure is a key release mechanism in estimating the overall failure rate from a cross-country pipeline, and several factors should be taken into account when conducting a pipeline risk assessment. REFERENCES

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Figure 1 Gas Pipeline Incident in San Bruno, California, USA in September 2010 Figure 2 Failure Causes from CONCAWE (1971 to 2010)

> Construction Incidental TP Fault damage 7.5% Malicious TP 7.2%

Materials Fault 8.3%

> Human Error 2.5%

Accidental TP damage 33.5%

damage 5.0%

> External corrosion 26.0% Internal corrosion 5.3%

Other natural hazards 0.3%

Stress Cracking 1.1%

Figure 3 Failure Causes from CONCAWE (2001 to 2010)

7.8%

Ground

movement 3.3%

Construction Incidental TP Fault 10.4% damage

Materials Fault 13.0%

Malicious TP damage 15.6%

Accidental TP damage 32.5%

External corrosion 14.3%

Internal corrosion 3.9% Stress Cracking 1.3%

Other natural hazards 0.0%

Ground movement

Figure 4 Failure Causes from EGIG (1970 to 2010)

Other and unknown

Hot-tap made by error 4.8%

6.6%

External interference Ground movement 7.4% 48.4%

Corrosion 16.1%

Construction defect / Material failure 16.7%

Figure 5 Hole Size Failure Distribution by Cause (CONCAWE)

100.0%

90.0%

80.0%

70.0%

Rupture Percentage

60.0%

Split

Hole

Fissure

40.0%

50.0%

Pinhole

30.0%

No hole

20.0%

10.0%

0.0%

Mechanical

Operational

Corrosion

Natural hazards

Third party

Figure 6 Hole Size Failure Distribution by Cause (EGIG)

1.0 E-4

9.0 E-5

8.0 E-5

Failure Rate (per km-yr)

7.0 E-5

6.0 E-5

Pinhole/crack

5.0 E-5

Rupture

4.0 E-5

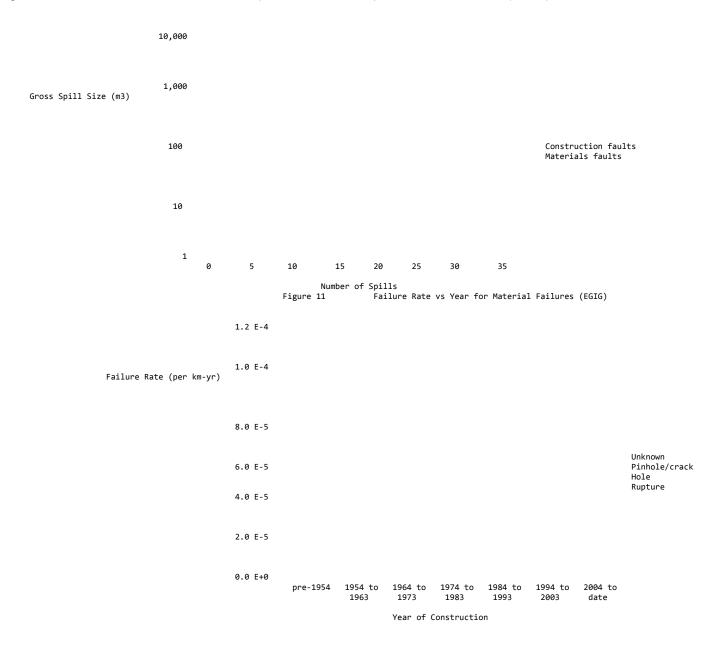
3.0 E-5

Hole

```
1.0 E-5
                                0.0 E+0
                               External Construction defect Corrosion Ground interference / Material failure
Figure 7 Failure Rate vs Wall Thickness for Third Party Activity (EGIG)
                                                                                                        Ground movement Hot-tap made by
                                                                                                                                   error
                              3.0 E-4
                              2.5 E-4
Failure Rate (per km-yr)
                              2.0 E-4
                                                                                                                        Unknown
                              1.5 E-4
                                                                                                                        Pinhole/crack
                                                                                                                        Hole
Rupture
                              1.0 E-4
                              5.0 E-5
                              0.0 E+0
                                                      5-10 mm 10-15 mm 15-20 mm 20-25 mm 25-30 mm e 30 mm
                                         d 5 mm
                                                                    Wall Thickness (mm)
                               Figure 8 Failure Rate vs Depth of Cover for Third Party Activity (EGIG)
                              4.0 E-4
                              3.5 E-4
                              3.0 E-4
Failure Rate (per km-yr)
                              2.5 E-4
                                                                                                                        Unknown
                              2.0 E-4
                                                                                                                        Pinhole/crack
                                                                                                                        Hole
Rupture
                              1.5 E-4
                              1.0 E-4
                              5.0 E-5
                              0.0 E+0
                                                   < 80 cm
                                                                           80-100 cm
                                                                                                   > 100 cm
                                                Cover Class (cm)
Figure 9 Failure Rate vs Wall Thickness for Corrosion (EGIG)
                                    1.4 E-4
                                    1.2 E-4
                                    1.0 E-4
      Failure Rate (per km-yr)
                                     8.0 E-5
                                                                                                                                      Unknown
                                                                                                                                     Pinhole/crack
Hole
                                    6.0 E-5
                                                                                                                                      Rupture
                                    4.0 E-5
                                    2.0 E-5
                                    0.0 E+0
                                                    d 5 mm 5-10 mm 10-15 mm 15-20 mm 20-25 mm 25-30 mm e 30 mm
```

Wall Thickness (mm)

2.0 E-5



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## Long-Distance Oil/Gas Pipeline Failure Rate Prediction Based on Fuzzy Neural Network Model

http://doi.ieeecomputersociety.org/10.1109/CSIE.2009.738 December 07, 2014

Long-Distance Oil/Gas Pipeline Failure Rate Prediction Based On Fuzzy Neural Network Model Xing-yu Peng Peng hang Li-qiong Chen Southwest Petroleum University

With an aging underground long-distance oil/gas pipeline, ever-encroaching population and increasing oil price, the burden on pipeline agencies to efficiently prioritize and maintain the rapidly deteriorating underground utilities is increasing. Failure rate prediction is the most important part of risk assessment, and the veracity of the failure rate impacts the rationality and applicability of the result of the risk assessment. This paper developed a fuzzy artificial neural network model, which is based on failure tree and fuzzy number computing model, for predicting the failure rates of the long-distance oil/gas pipeline. The neural network model was trained and tested with acquired Lanzhou - Chengdu - Chongqing product oil pipeline data, and the developed model was intended to aid in pipeline risk assessment to identify distressed pipeline segments. The gained result based on fuzzy artificial neural network model would be comparatively analyzed with fuzzy failure tree analysis to verify the accuracy of fuzzy artificial neural network model

Xing-yu Peng, Peng Zhang, Li-qiong Chen, "Long-Distance Oil/Gas Pipeline Failure Rate Prediction Based on Fuzzy Neural Network Model", CSIE, 2009, 2009 WRI World Congress on Computer Science and Information Engineering, CSIE, 2009 WRI World Congress on Computer Science and Information Engineering, CSIE 2009, pp. 651-655, doi:10.1109/CSIE.2009.738

## Pipelines

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# Analysis of Gas Pipeline Failure - Iowa State University

http://home.eng.iastate.edu/~jdm/katrina/Data/Natural%20Gas/NG%20Transportation/Analysis%20of%20Gas%20Pipeline%20Failure.pdf December 07, 2014

Analysis of Gas Pipeline Failure E. Phillip Dahlberg and T. V. Bruno SUMMARY Failure of an operating gas pipeline is a rare event. However, when it does occur, it must

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#### SUMMARY

Failure of an operating gas pipeline is a rare event. However, when it does occur, it must be properly analyzed to prevent recurrence. What follows are analytical procedures for analyzing pipelines along with examples and characteristics of some typical failures.

#### INTRODUCTION

Failure of a natural gas transmission or gathering line during service is extremely serious because of the potential for loss of life. Yet statistics show that failures occur only once a year per thousand miles of pipeline. Part of the reason for this excellent record is the pipeline industry research over the past thirty years into failures and means of prevention. Figure 1. This work, sponsored by such organizations as The American Gas Association, The American Iron and Steel Institute, and The British Gas Corporation, has resulted in improved pipeline steels, manufacturing and inspection procedures, and improved pipeline designs.

#### ANALYTICAL TECHNIQUES

While pipeline configuration simplifies the geometrical aspects of analysis, the trauma accompanying the failure often obscures or destroys characteristics important to identifying the causes. The sudden release of large amounts of stored elastic strain energy can badly deform the pipe, while gas fires, if they occur, can alter pipe properties. In addition, post-failure corrosion and handling away from laboratory facilities may obliterate fine-scale fracture features. To overcome inherent difficulties and accurately determine causes, a variety of analytical techniques must be applied in a careful and well-prescribed fashion.

- Overall Macroscopic Visual Inspection-To identify the failure origin, it is imperative that a careful macroexamination of the entire available fracture surface be done. In-service pipeline ruptures generally develop from a region of stable crack growth or from a defect caused by an outside force or corrosion. Certain macrofeatures on the fracture surface can aid in locating the failure origin. The most common of these is the chevron pattern on plane strain fracture areas pointing back to the origin. The acute angle edge of a full shear propagation ductile failure often contains secondary cracks which form saw tooth-like ridges pointing back to the origin. Running a finger back and forth along this edge will often indicate by roughness differences, which way the crack was propagating. Since crack branching will show propagation directions, putting a fragmented pipeline together (usually done by matching paper patterns of the various pieces) will help identify the origin area.
- Sectioning and Cleaning-Often, the critical areas identified by the visual analysis will have to be sectioned from the rest of the pipe allowing detailed fractography and microstructural analysis1. Care must be exercised to prevent damage to the fracture area when cutting small pieces for laboratory analysis. In particular, torch cutting of samples requires caution to avoid thermal damage to the metal in the fracture area. The orientation of small pieces relative to the macro-crack propagation direction and the pipe outside and incidence of the propagation of the micro-propagation direction and the pipe outside and incidence of the pipe of the inside surfaces should be marked for identification during the microanalysis.

The techniques for cleaning debris and corrosion products from pipeline fractures include washing with a mild detergent and bristle brush, solvent cleaning and degreasing in an ultrasonic cleaner, replica stripping, and chemical or electrochemical etching in mild or inhibited alkaline or acid solutions. The techniques should be applied in a serial fashion employing only the minimum necessary for cleaning the specific fracture region analyzed. Prior to cleaning, potentially significant corrosion products should be carefully removed and saved for analysis.

• Microfractography-The aim of high magnification fractography, using transmission or scanning electron microscopy, is to relate the fracture appearance to the cause or mechanism of fracture. This procedure involves comparing the service failure resulting Figure 3. A 3-1/2 inch long gouge found near the midpoint of the rupture shown in Figure 2. Figure 4. A cross section through the gouge Shows a dark etching area near the outside Surface with a small secondary crack (arrow) Near the fracture.

Number of gas pipeline service Figure 1. incidents versus year of occurrence by cause. (From Giedon, D.N. and R.B. Smith, "An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1970 through 1978," NG-18 Report No. 121, Sept. 1980.)

Figure 2. Rupture sections of 8-5/8 inch gas pipeline that failed due to external mechanical damage.

Figure 5. SEM fractrograph of fatigue damage associated with the longitudinal weld seam of a 34-inch O.D. pipeline.

from unknown conditions to "pedigreed" fractures generated in the laboratory under known conditions of stress, strain, strain-rate, and environment. Fractographic examinations can also reveal changes in fracture mode, local crack propagation directions, and the progress or history of cracking.

- Metallographic Analysis-The fracture path relative to grain boundaries, inclusions, transformed and second phases, and external defects can be determined by metallographic analysis using standard techniques. The mounting and polishing of a cross section of matching fracture surfaces at the failure origin often provides evidence to positively identify the failure mode.
- Chemical Composition and Mechanical Properties-Chemical analyses and mechanical tests are generally run to determine: if the pipe is of the proper type and grade, whether it meets appropriate standards, and whether any deviation contributed to the failure. The most common mechanical tests are tensile, bend, and flattening tests. Other tests, such as Charpy impact tests or crack tip opening displacement (CTOD) tests may be useful in determining fracture behavior.

CAUSES OF PIPELINE FAILURES

Over half of all in-service pipeline failures result from some externally applied mechanical force as shown in Figure 1. The following are examples of five typical failures.

Figure 2 shows the rupture that developed in a section of 8-5/8 inch 0.D. electricresistance line pipe. Visual and metallographic examination revealed the failure was caused

Figure 6. Inside surface at the failure origin of a 20-inch pipeline.

Figure 7. Cross section taken adjacent to the fracture shown in Figure 6. The arrow identifies the fracture surface in the pipeline. by mechanical damage, in the form of a gouge and dent, often associated with heavy equipment such as a back-hoe. Figure 3 shows a detail of a gouge that was near the midpoint of the rupture. The profile of the gouge, shown in Figure 4, is a polished and etched cross section of matching fracture surfaces at the failure origin. The combination of a gouge and dent is particularly damaging. The gouge cold works the steel and reduces its resistance to crack initiation. The dent, by changing the geometry, creates an area of high stress and

stress concentration.

A second form of external damage can be introduced by fatigue cracking during pipe shipment, particularly in rail and sea shipment. The damage, sometimes called transit fatigue, results from flexing the pipe during load movement. Transit fatigue in seamless pipe and the base metal of welded pipe results from concentrated stresses where the pipe contacts a protrusion, such as a rivet or bolt, the weld of an adjacent pipe, or bearing strips of insufficient size. In submerged-arc welded pipe, transit fatigue cracks can develop at the toe of the weld even in the absence point contact. Figure 5 shows the fine ductile fatigue striations and secondary cracking that characterize transit fatigue damage.

Corrosion can cause failures by thinning the wall over a large area or localized pitting. Both external and internal corrosion can lead to failures, but the widespread use of cathodic protection has greatly reduced external corrosion. Figure 6 shows the inside surface at the failure origin of a 20-inch gas line that failed shortly after the operating pressure was increased. The failure resulted from internal pitting corrosion on the bottom of the pipeline that significantly reduced its wall thickness. Figure 7 shows the depth or the pitting on a polished cross-section cut transverse to the fraction (arrow).

Another form of corrosion, stress-corrosion cracking, can also lead to failures.

Figure 8. Outside surface of pipeline section removed because of a leak. The arrows indicate two clusters of crack indications visible after magnetic particle inspection.

Figure 11. Hydrostatic test rupture of seamless 6-5/8'inch 0.D. pipeline showing thin tongue of metal protruding from around a pipe lamination.

External stress-corrosion cracking results from the accumulation of moisture on the pipe surface at imperfections in the pipe coating. Certain corrosives in the moisture in conjunction with normal operating stresses cause cracking. Stress corrosion cracking in pipelines is identified by the distinctive intergranular nature of the cracks. Figure 8 shows cracks in a section of pipe removed for examination because of a leak. The cracks resulted from stress-corrosion cracking. The surface of a crack, extending across the wall, was broken open in the laboratory and is shown in Figure 9. A metallographic cross-section, Figure 10, showed the cracks to be intergranular.

Material defects are not common causes of service failures because they are usually found before the pipe is placed in service, either during inspection of the pipe or during hydrostatic testing. The few failures that do result typically originate at longitudinal weld seams or at laminations in seamless pipe. Figure 11 shows the rupture of a 6-5/8 inch Figure 8) that O.D. seamless pipeline that resulted from a pipe lamination. In this instance, failure

occurred during hydrostatic testing.

CONCLUSIONS

Despite advances in manufacturing, testing, and inspection of gas pipelines, failures do occur. Research and experience have helped characterize the different types of failures so that their cause can be determined and appropriate preventive measures applied. By using careful analytical techniques, and with a thorough understanding of the pipeline operating conditions, the cause of failure can almost always be determined.

Figure 9. Surface of crack (see was broken open in the laboratory. inside surface is at the top.

of second-

cracking

Figure 10. Microstructure in area ary crack showing an intergranular

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http://research.niqc.ir/files/Info\_Res/Articles/86123AN\_R32.pdf December 07, 2014

The failure rate data for offshore pipelines and risers is to be found in Battelle Research (1985) and (PARLOC 96, ... OIL AND GAS PIPELINE FAILURE MODELLING 9.

www.ingentaselect.com=titles=09575820.htm

0957-5820/03/\$23.50+0.00 # Institution of Chemical Engineers Trans IChemE, Vol 81, Part B, January 2003

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OIL AND GAS PIPELINE FAILURE MODELLING
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his paper examines the key parameters for risk assessment near to oil=gas pipelines with particular reference to ames. In particular it examines out ow characteristics of the different uids handled. It then examines the consequence modelling; more particularly the surface emissive powers of the ames, the failure rate data, the consequences using the Piper Alpha reball and nally failure statistics. It is shown that the out ow characteristics are more complex than might be expected; the assessment of surface emissive powers has to be done with care; and nally, older pipelines distort the failure rate statistics or failure modes which are not relevant to a modern pipeline system. One speci c conclusion of this paper is that the land-use planning zones round modern landlines may be reduced by more rigorous analysis of both effects of the leakage and the appropriate pipeline failure data, both in Keywords: pipeline; failure; risk assessment.

#### INTRODUCTION

All of the North Sea gas and nearly all of the oil produced in the UK Continental Shelf (UKCS) is transported to shore in pipelines with diameters of typically 24 inches or 0.6 m (this should be treated as indicative) (DTI, 1993). Under the sea there are approximately 3000 km of pipelines operating at pressures between 7 and 11 MPa (DTI, 1993) and over 17,000 km of on-shore natural gas distribution piping operating at about 7 MPa (Braithwaite, 1985). Not only is oil and gas handled on land but also ethene, LPG, petrol, diesel oil and other chemicals. Around the land-based pipelines (land-lines) there are land-use planning zones where there are restrictions on some types of developments. This could create a limitation on land use near the receiving station, which would be, normally, an industrial site with housing in the vicinity. While the majority of the land affected will be countryside the routing of the landline may be affected by the presence of farms and small villages.

The pipelines carrying the products of the offshore oil and gas industry can be analysed in four sections. The rst is the riser or the rigid section of piping, which conveys the uids from the production facilities to the seabed (and vice versa); this can be up to 175 m long. Failure of this section will affect the production platform and the production personnel, as shown in the Piper Alpha Disaster (Cullen, 1992). The second section is the sealine, which transports the uids to the shore; this can be over 100 km long. Failure of this section will affect shipping and also create potential pollution. The third section is the land approach; this is about 1 km long; failure of this section could affect the public. The nal section is the landline, which is buried under the ground; this can be any length. Failure of this section could also affect the

public. Occasionally the uids from one platform ow to a second which acts as a gathering station before it ows on to a nal destination (as with Piper Alpha).

In the case of North Sea gas lines the distribution network covers nearly all of Britain from the processing facilities on the east and west coasts to the user. Failure of almost any part of the gas grid would affect the public. The transportation of oil with an elevated vapour pressure is limited to a few discrete areas. The transportation of high-pressure LPG and ethene is also limited to clearly de ned areas. Failure of these lines would affect the public and also the environment.

The out ow characteristics from a severed pipeline are in uenced not only by the pressure, diameter and length but also the properties of the uid. In the case of a gas the uid could enter the two-phase regime due to retro-condensation as the uids pass into the two-phase envelope and create a two-phase choked ow within the pipeline. This reduces the out ow and affects the crack propagation characteristics, as the crack propagation velocity can be higher than the compression wave velocity in the uid=gas resulting in a running crack. Likewise oil will evolve light hydrocarbons (from gas in solution) resulting in a foaming system in a vertical line (riser) or a landline. The lower head of frothing oil can result in a hydrostatic head which is less than the uid vapour pressure. The loss of this hydrostatic head will

uid vapour pressure. The loss of this hydrostatic head will result in the out ow of oil froth, which can last for many hours. This characteristic can result in a large sea re and a gross error in the prediction of the consequences that may occur following a pipeline failure.

There are two methods for the assessment of the ame characteristics. The rst is to assume a percentage of the total combustion energy is released as radiant heat from one or more point sources. The second is to de ne the morphology

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of the ame and then to ascribe a surface emissive power (heat ow per unit area of the ame boundary, SEP). From this the radiant heat impact can be assessed by means of view factors. Each method has potential errors. This will be discussed in more detail in the section titled Flame Characteristics.

Nearly all reliability data sources will include relevant and non-relevant data, and so it is with pipeline failure data. The older pipelines, which may not necessarily have been built to the same standards as more modern pipelines, can dominate the data in the database. It is therefore necessary to analyse the data with care. In general this results in lower failure rates for the more modern designs=builds.

Taking all of these factors together it is evident that there could be a signi cant error in the perceived risk if the out ow, effects and failure models are not analysed correctly. This paper highlights the main sources of error, the problem areas in assessing risks on sealines and landlines and shows, for landlines, that a more rigorous treatment could reduce the consultation distances and free land for bene cial use.

The results of the study draw heavily from the oil and gas industry but there is a re ection of the results of this information on the on-shore pipelines. The out ows will change slightly due to lower backpressures and the ame modelling is identical, but the different environment in uences the failure rate data.

## OUT-FLOW CHARACTERISTICS

## Crude Oil

The properties of the uids under discussion are such that they require special analysis. Oil is a mixture of hydrocarbons and to a good approximation the higher the mole fraction of the lower molecular weight hydrocarbons, the higher the vapor pressure. As a generalization it is better to transport oil with lighter hydrocarbon molecules to the Stabilization plant and to recover the methane to butane there for bene cial use. The actual vapour pressure is a function of the composition; a higher mole fraction of propane will have the same effect as a lower mole fraction of methane. As the oil is oversaturated at the transport pressure, the lighter hydrocarbons come out of solution when the pressure is reduced; this process is relatively slow and, due to the surface physics of the oil (including viscosity), the oil starts to foam (this also inhibits the formation of aerosols, see later). This is a known problem in stabilization units and is therefore accentuated in a con nement such as a pipeline where gas=liquid separation is more dif cult due, once again, to the surface physics of the oil. The establishment of an equilibrium is relatively slow, and, while it might be expected that the hydrostatic head of oil in a riser would suppress de-solution of gases, in fact the foam density falls to such a level that the hydrostatic head is less than the vapour pressure of the oil. The effects

Following line rupture the initial out ow from a ruptured pipeline is the result of the release of the strain energy in both the oil and the pipeline walls; this is often referred to as line pack. This takes place over a time-scale of some minutes; thereafter the line dynamics dominate the out ow. The key feature is the reservoir of dissolved gas (solution gas) within the horizontal section of the sea-line on the seabed. Once the pressure at the foot of the riser falls below the vapour pressure of the oil the amount of gas available to drive the frothy ow increases signi cantly. Following the release of the line pack the mean density of the two-phase uids in the riser falls by a factor of about 3. This suggests

uids in the riser falls by a factor of about 3. This suggests that, in order to prevent the pressure pro le in the riser dropping to a level where the oil in the pipeline acts as a driver for two-phase ow, the vapour pressure of the oil must not exceed about 30% of the hydrostatic head in the riser

Six simulations were carried out, using the computer code 'OLGA' (Bendikson et al., 1991) with three synthesized oils, three on the 175 m riser and three on the 125 m riser as shown in Table 1. The approximate compositions are shown in Table 2.

The out ows for the four highest vapour pressures are shown in Figures 1-4. The difference in the two gas-to-oil ratio curves between the 175 and 125 m risers is a function of the way in which the two ends were modelled as, for simplicity and reality, the sea-line was treated as two risers of 175 and 125 m length joined by a gently rising sea-line. Further, for reality, the line was simulated with heat loss from the wall to sea such that the uids cooled from 333 to 283K over the length of the line; the temperature 10 km into the line was about 298K. The two lower vapour pressures

de-packed and ow arrested within a few minutes as predicted from the analysis of the higher vapour pressure oils. The total release of oil during depack was 25-50 tonnes. The two highest vapour pressure oils still owed after 3 h, but the middle two arrested in the interval 2-3 h. It should be noted that the oil with the highest vapour pressure in the 175 m riser was in hydrostatic equilibrium at the foot of the riser. During the line de-packing the peak oil ows were initially over 1200 kg s; 1 falling rapidly to about 500 kg s; 1 and then to below 250 kg s; 1 within 20 min. The out ows showed a general decay curve until the ow arrested; following this there was a period of intermittent slugging lasting many minutes. During the slugging period the net out ow was relatively small. The slugging may be an artefact of the simulation or it may be real and represent gas bubbles formed in the horizontal section of sea-line entering the riser, before they re-entered solution, so discharging small quantities of oil in slugs.

Of more note is the general rising curve of gas-to-oil ratio. This re ects a depletion of the solution gas in the horizontal section of the sea-line and that the ow will

Table 1. Vapour pressure of three synthesized live oils.

of the foaming in severed risers were studied shortly after the failure of Piper Alpha (Cullen, 1992) using a typical sealine 0.6 m (DTI, 1993) diameter (24 inch) and a length of 100 k with riser heights of 175 and 125 m (DTI, 1993). The

oil vapour pressure was controlled by systematically varying the mole fraction of light hydrocarbons

Composition 175 m Riser 125 m Riser 1.5 (333K) 0.9 (298K) 1 (333K) 0.6 (298K) 0.55 (333K) 0.2 (298K)

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Table 2. Composition of three synthesized oils.

#### Mole fraction

| Compound | Composition 1 | Composition 2 | Composition 3 |
|----------|---------------|---------------|---------------|
| C02      | 0.0018        | 0.0015        | 0.0007        |
| C1       | 0.03          | 0.018         | 0.004         |
| C2       | 0.035         | 0.032         | 0.02          |
| C3       | 0.1           | 0.1           | 0.09          |
| C4       | 0.079         | 0.07          | 0.068         |
| C5       | 0.082         | 0.084         | 0.084         |
| Higher   | Residue       | Residue       | Residue       |

eventually arrest. The time to arrest follows the vapour pressure relationship and the riser height (imposed pressure), as would be expected. The increase of the gas-to-oil ratio was as might be expected with the greater frictional

losses in the sea-line (a lower density required to drive the uid pump), but the maximum in the 175 m riser cannot be explained easily. (It will be noted that the gas-to-oil ratio is about 1-2% wt=wt in this model. Normally a value of nearer 5% might be expected for live oils which have undergone at least one stage of separation, but again it will be dependent on the composition, particularly the methane mole fraction.) The total out ow for these examples represents between

12 and 7.5% of the total sea-line inventory.

The out ow from smaller holes (the size of the few centimeters diameter) is less certain. In this hypothetical example, 25-50 tonnes of line pack will be ejected whatever the breach size; the dynamics thereafter will depend upon the breach size itself. For small sizes the mass ow across the breach must be balanced against the two-phase pressure drop, the oil=gas separation in the riser and the imposed pressure at the base of the riser both hydrostatic and dynamic. For breaches of less than 10 cm diameter, once the pipe line had de-packed, there would be a period of reducing two-phase ow in the riser until out ow became a gas as the riser section developed a gaseous zone at the top

(of the riser) where oil and gas may disengage.

The out ow from a horizontal section of sea-line would depend upon the imposed backpressure. It is to be expected that for major ruptures the main oil line pumps will shut down on low pressure and the system pressure will rapidly approach that of the vapour pressure of the oil. On the

Figure 2. Out ow from ruptured 175 m Riser TVP 8 Bar.

seabed oil would still ooze out of small breaches after the line de-packed but the out ow from a full bore breach would then be determined by the local seabed topography. At operating conditions a 25 mm puncture at the seabed would produce an out ow of around 39 kg s¡1 at a line pressure of 70 bar, assuming that the pumps did not shut down. A rupture would be more problematic; rst the hydrostatic head could equal the vapour pressure and the

ow could involve displacement of oil by seawater. Alternatively the vapor pressure may be higher than the hydrostatic pressure so the balance of the driving force (vapour pressure minus imposed head) would determine the out ow against friction losses.

For horizontal landlines a similar analysis to that above shows that the out ow will depend upon the breach size, line topography and breach orientation. Small breaches are very problematic but the out ow from a 25 mm puncture would be around 53 kg s; 1 at pipeline pressure. Large, full-bore breaches will result in the vast majority of the line contents being ejected at similar mass uxes and due to the same mechanism as the breached risers. Because of the abrupt drop in pressure the main oil line pumps will, once again, shut down due to the low line pressure. Thereafter the initial out ow will be a little higher but eventually the driving force will reduce to the vapour pressure which has to overcome the frictional forces. The initial de-pack

Figure 1. Out ow from ruptured 175 m Riser TVP 14 Bar.

Figure 3. Out ow from ruptured 125 m Riser TVP 8 Bar.

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problems for line repair. A running crack will not necessarily increase the risk at the process platform, as the effective release point would be more remote from the platform. It could, however, affect the public if the crack propagated from a remote area to an inhabited area. As a means of reducing the propagating conditions, special tough steels can be used. However there is an alternative on sub-sea lines: tests have been carried out in water of about 100 m deep to investigate the effects of the local shock wave at the crack tip and the compensation pressures which might hold the crack tip closed (con dential study). These tests veri ed that it was not necessary to use special steels for deep-water pipelines. A 60 m length of pipe was sunk in about 100 m of seawater and lled with a synthetic gas mix simulating typical North Sea gas. The line containing about 15 tonnes of mixed gas was scored and split using hydraulic rams. When ruptured, the gas would have cooled to about 200K and behaved as a dense gas at the point of release. However when the gas reached the surface the cone was about 10-20 m diameter and the gas had warmed sufciently during the turbulent rise to the surface for it to behave as a buoyant gas. This experiment has not been reported in any subsequent literature. The cone diameter and the warming of the gas are very important pieces of data as they help to de ne the source terms for the subsequent dispersion of the gas. The arrest of the running crack gives some con dence that a crack will not run to the platform and that any damaged gas sealine would be capable of being

repaired. The peak, instantaneous, out ow from the ruptured Tartan riser has been assessed to be 7000 kg s;1 at a system

pressure of 12 MPa, falling to between 1200 and 2400 kg s $_1$ 1 (depending on the friction factor used) after 15 s. The reduction in ow is due to the acceleration losses in the pipeline, the frictional losses and the choking of the

Figure 4. Out ow from ruptured 125 m Riser TVP 6 Bar.

will again be of the order of 50 tonnes over a few minutes but thereafter the frothy oil will have a lower density, resulting in a higher velocity, which will result in a higher pressure drop, thus inhibiting the gross out ow. A typical 0.6 m (24 inch) pipeline would have a capacity of about 300 kg s¡1 with a pressure drop of about 1-2 MPa per 100 km. The nal analysis will depend upon the vapour pressure and the gas-to-oil ratio following de-solution; higher gas-to-oil ratios should produce lower out ows than lower gas-to-oil ratios, the reverse of what might be expected intuitively.

## High-pres sure Gases

The rupture of a high-pressure pipeline will result in an expansion which is between isenthalpic and isentropic. The temperature will fall and, depending on the upstream conditions, the gas could enter a two-phase regime. In this case the compression wave velocity falls below the recognized value. The compression wave velocity for a pure dry gas for a typical northern North Sea gas of relative molecular weight ca 21 and pressure ca 17 MPa is 380 m s; 1. During the de-pressuring cycle the uid enters a two-phase regime, the uid temperature falls to about 200K at the point of release (even with heat gain from the pipe wall and heat soaking from the seabed) and the compression wave velocity falls to ca 200 m s;1 (con dential study). (This should be compared to a typical crack propagation velocity of ca 200 m s;1.) Should there be a failure in the pipeline resulting in a crack, the crack will propagate down the line at the same speed as the compression wave velocity thus resulting in a running crack. A similar effect is noted for propane using BLOWDOWN (Richardson and Saville, 1996), where the pressure at the end of the pipeline remains fairly constant as the line contents pass through the phase envelope and produce a form of moving choke. (In the case of ethene the minimum temperature could be as low as 169K.) The ow exit of the pipe will be effectively sonic until the pressure falls to about 2 MPa under 100 m of sea and to 200 kPa on land.

The effects of temperature and compression wave velocity

have a signi cant impact on the risk assessments. First, any emergency isolation valve (be it on land or sub-sea) in the pipeline must be closed promptly for reasons of safety and valve integrity and the running crack could create its own

ow as it entered the two-phase regime. The initial out ow would have been sonic at the point of rupture but would have been slowed by impingement on the under-sides of the modules. Even after an hour the out ow would be over 100 kg s;1. The picture of a torch re (about 2 h into the event after the collapse of the accommodation module) in the Piper Inquiry report (Cullen, 1992) shows a ame equivalent to between 50 and 100 kg s;1; the nal picture of the stumps of the jacket show a ame from a severed riser of between 1 and 3 kg s;1 (blowdown of long lines is a long decay curve). These ows are very much as might be

The ows from simple holes of 10 and 25 mm give out ows of around 1 and 7 kg s;1, respectively (at the same conditions), but will always be sonic until the pressure at the exit falls to about 2 MPa. These results show there are major differences in the out ows for a gas and a liquid system. Similar out ows would be expected from landlines. The

Similar out ows would be expected from landlines. The effects of the pressure wave should be more accentuated, as the backpressure will be lower. The nal out ows will not be regulated by the high static head backpressure. The nal modelling will not be signi cantly different.

#### CONSEQUENCES

The consequences of large out ows of hydrocarbon on offshore installations tend to dwarf the understanding of the combustion process. The res are potentially exceedingly

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large and there are many persons who are at risk with only one means of escape, the TEMPSC (totally enclosed motor propelled survival craft). Onshore, be it on a process plant or the public, there are redundant and often multi-directional escape routes. The main differences between the two areas

are the immediate impact on escape and the 'safe haven' (or refuge). Offshore the two are intimately tied up with the integrity of the supporting structure (jacket) but onshore it is

more closely allied to the ability to arrest escalation.

The oil riser failure on an offshore platform is most likely

to be the result of a re, but if the failure was due to impact, or other failure modes, the gas release (as solution gas) is signi cant, being about 5 kg s;1 (18 tonnes h;1). Release rates such as those assessed in this paper would have a high probability of ignition over the release time. The resultant pool re diameter, for a severed 0.6 m diameter riser, would be in the range 75-100 m diameter (Rew and Hulbert, 1996); this would inhibit evacuation and have a high probability of total human and facility loss due to smoke effects or the collapse of the jacket. The only mitigation would be the effects of pool drift under the in uences of the wind and free-fall TEMPSC.

The requirements for the protection of installations against riser failure on offshore platforms are covered by the Offshore Regulations (Pipeline Safety Regs, 1996) and are not considered further.

The rupture of the Tartan riser on Piper Alpha demonstrated the need to model and understand the history of the uid out ows and consequential res. The out ows have already been outlined. The reball was the result of the high-velocity jet of gas leaving the riser impacting on the under-

side of the platform. The initial re started as a reasonably well-de ned reball but rapidly became an elongated reball or fat torch. Observation of video footage of the actual rupture shows the period of growth of the Piper reball was very typical of a boiling liquid expanding vapour explosion (BLEVE) which is then followed by a steady shrinkage of the ame. The growth period to a maximum dimension was about 5-7 s, when the reball was about 340 m in diameter. After about 15-18 s the shape of the re was an elongated bubble with an effective diameter of about 250 m.

Simple theory of reballs gives equations for the effective diameter and duration based on the mass of uid (gas and liquid, W kg) as shown in Table 3.

Whichever reference is used, the power of W for area f time equals nearly to unity, so it is possible to derive a burn rate for the reball ame area in kg mį2 sį 1; this is 0.021 kg mį2 sį1 (using MHAP, 1982; for the traditional diffusion ame of a pool re the combustion rate is in the range 0.008 kg mį2 sį1 for small pool res rising to 0.014 kg mį2s į1 for large pool res). The equivalent leak rate for the two reballs is given in Table 4. It is of note that the Piper reballs have some pre-mixing and are not the traditional semi diffusion type of BLEVE.

| Model       | Table 3. Two reball models. Diameter (m) 1=3 | Duration (s)<br>1=3 |
|-------------|--|---------------------|
| MHAP (1982) | 5.8 W  | 0.45 W              |
| Lees (1996) | X<br>K1W                                     | y<br>K2W            |
| Lees (1990) | K1 ^ 5.25-6.48                               | K2 ^ 0.8-1.07       |
|             | x ^ 0.314-0.333                              | y ^ 0.167-0.333     |

Table 4. Leak rate from Tartan riser by calculated out ow and by reball dimensions.

| Diameter (m) | Out ow assessed from reball dimensions (using the combustion rate of 0.021 kg m;2 s;1) (kg s;1) | Assessed<br>out ow<br>from line<br>dynamics<br>(kg s¡1) |
|--------------|---|---|
| 340          | 7600  | 7000  |
| 180          | 2000  | 1000–2000a  |

Dependent on the surface roughness.

This analysis suggests that the reballs from ruptured gas pipelines can be modelled as a form of BLEVE and knowing the out ow at any time, t, it is possible to assess the safe standoff of a riser installation from the host platform on the basis of a heat dose or radiation criterion. This method has been used already on at least one North Sea platform.

## FLAME CHARACTERIZATION

The ame characterization for any hydrocarbon re is fundamental to the nal risk assessment. As already indicated in the Introduction it is dependent on the SEP and the surface shape which dictates the view factor. This section addresses both together.

## Surface Emissive Powers

There are many quoted surface emissive powers (SEP) in the literature, ranging from over 1000 kW m;2 to well under 50 kW m;2. The reality is that full recognition of both the fuel source and ame structure is essential. Jet, or premixed, ames are well aerated and burn more cleanly than pool res. A series of tests are illustrated in a video 'Hot Stuff': an Introduction to Fire Hazards by BP (contact BP Exploration, Dyce, Aberdeen) and with this are quoted ame temperatures and maximum heat transfer uxes

ame temperatures and maximum heat transfer uxes which are informative. (Heat transfer ux includes both forced convective and radiant heats transfer so the SEP could not exceed 350 kW m<sub>1</sub>2. Peak temperatures were of the order of 1573K. First the nature of the ame, its temperature and its emissivity, is critical. Methane ames produce little or no carbon (soot) and therefore are grey body radiators (see below), whereas heavy hydrocarbons 'pyrolize' and produce carbon. In suf cient depth carbon can act as a totally black body with emissivities tending to unity while deep clouds of carbon dioxide and water vapour have an emissivity value nearer 0.1. In the case in question the very actively aerated ame at or nearest to the jet will be optically thin and, although the theoretical SEP might approach 350 kW m<sub>1</sub>2, the true value would be nearer 275 kW m<sub>1</sub>2. Against this is the partial combustion of the fuel, leaving soot in the plume path, again reducing the true SEP. A simple energy balance round a ame would

suggest that in the idealized conditions the SEP for any jet ame should not exceed about 400 kW  $\rm m_{\rm i}\,2;$  a value higher

than this would indicate grey body radiators with ame

colours approaching the white end of the spectrum (over

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The measured uxes in the Kuwait well res (OTI Report, 1992) were of the order of 150 kW m; 2; such values were determined near to the ame centre and at the upwind side. This is as would be expected. The average taken over the whole ame surface would not exceed 150 kW m;2. This is

as would be expected for a smoky ame.

The analysis of the structure of the reball in the previous section gives a burn rate; if this is converted into as SEP with a worst case heat radiated fraction of 0.35, the SEP cannot exceed 330 kW m<sub>i</sub> 2. In reality, due to incomplete combustion, the value is nearer 225 kW m<sub>i</sub>2 as quoted by Moorhouse and Pritchard (1982), who give values in the range 150-300 kW m;2. For an oil line rupture where some small amount of oil may be atomized, the ame could be smoky and as a result the SEPs quoted may be a little high. The values quoted by BP in the 'Hot Stuff' video give maximum temperatures for a well-aerated oil jet ame at the brightest part of the ame structure of 1573-1623K, which for a true black body gives SEPs in the range  $350-400~{\rm kW}$  m; 2. However, these are theoretical maxima for optically dense ames and the true SEPs and those at the

smoky, feathered ame tips would be signi cantly lower. Methane ames were approaching translucent giving SEPs which would not exceed 75 kW m;2. For ethene, which can produce smokey ames in a poorly aerated state, the SEP should not exceed 350 kW  $\ensuremath{\text{m}_{1}}\xspace 2$  .

Jets of oil, however, began to rain out un-burnt oil when the pressure at the jet was less than 300 kPa ('Hot Stuff' video). This is again easy to understand, as there would be insuf cient energy to produce adequate size reduction and droplet formation and this would result in a mixture of a jet re and a pool re. The jet re, being more aerated, is by far

Moorhouse and Pritchard (1982) has proposed various SEPs for different ames. It is essential that the values are based on thick ames where the ame is a true black body and not a grey body radiator. The values for JP4 pool res in this reference show a maximum value for the SEP, as would be expected, between two pool size extremes. When the pool is small the ame will not be optically dense but as the size is increased the pool becomes more optically dense but also smoky, hence the maximum. For oil the value for a pool re

will be about 75 kW m<sub>|</sub>2
Mizner and Eyre (1982) quote the SEP for pool res of natural gases in the range 150-200 kW m;2. These values were measured low in the ame and lower values are measured nearer the top of the ame. This re ects the nature of a diffusion ame and t in well with the expectations from pipe ares where the fraction of heat released from methane is about half that of the mixed hydrocarbons. from methane is about haif that of the mixed hydrocarbons. The re on the Ocean Odyssey (shown in the newscasts but also reproduced by BP in the 'Hot Stuff' video) following a sub-sea gas release during drilling) also showed this ethereal burning. The same reference gives SEPs for LPG and kerosene pool res of 48-35 kW m<sub>i</sub>2.

The graduation in SEPs along a ame boundary is modeled in the pool re thermal radiation model by Rew and Hulbert (1996).

#### Aerosols

There is a general assumption that the ash from any volatile uid should be enhanced by a factor of 2 or 3 to re ect the aerosol effect. This may well be valid for such uids as propane or butane but this is less credible for de-solution effects where the viscosity and mass transfer will result in a relatively slow and non-vigorous release of vapour (typical separators are designed with a residence time of 180-300 s). Furthermore, following the rupture of a long line the ef ux velocity is relatively low (of the order of 10 m s;1) so little or no secondary aerosol formation should be expected from an oil line rupture. This could result in a signi cant reduction in the reball dimensions and also it could moderate the SEP.

#### Flame Shape Modelling

The modelling of the shape of pool and BLEVE reballs is relatively well-developed technology (Rew and Hulbert, 1996; MHAP, 1982).

The modelling of jet ames is often carried out using the

method proposed by Chamberlain (1987). In this the ame is modelled as the frustum of a cone and SEPs are then deduced from the fraction of heat radiated from the ame. The shape of the ames from the Kuwait oil wells is also a useful model of an oil jet re as the exit velocity and the gas-to-oil ratio are similar to those in question. The shape of the frustum is dictated to a degree by the release conditions (source terms). In the BP releases the upstream pressures were over 1 MPa and the diameter-to-length ratio was of the order of 0.3 (0.25-0.35). In the Kuwait res (OTI Report, 1992) the ratios were also of the order of 0.3. Of more particular signi cance was the fact that the maximum received heat uxes were experienced at right angles to the ame=wind. This is due to the higher view factor and the view of the hotter parts of the ame. An analysis of the res in the OTI report (1992) (which had a gas-to-oil ratio of 10% wt=wt and were not unlike pipeline uids) was compared with the results using Chamberlain (1987). Only one of the wells could be analysed in detail as there were some doubts as to the true source terms (exit ori ce dimensions) and also the true release rates. Well 17A data seems to be the most secure and the results of the observed and calculated dimensions are somewhat different as tabulated below. The SEP measured on well 19B was used to  $\,$ draw this up in Table 5.

In effect the Chamberlain model does appear to indicate

that ame surface area is almost twice that of the observed well 17A ame. This in turn will increase the view factor and overestimate the received radiant heat. Well 17C

Table 5. Analysis of well 17A.

| Observed   | Observed maximum | Assessed fraction of heat | Calculated | Calculated      | Percent of heat  |
|------------|------------------|---------------------------|------------|-----------------|------------------|
| frustum    | diameter of      | radiated based on         | frustum    | maximum frustum | radiated         |
| length (m) | frustum (m)      | ame shape (%)             | length (m) | diameter (m)    | (from graph) (%) |
| 45         | 17               | 11.1                      | 65         | 27              | 28               |

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appeared to be more vertical than well 17A and it is likely that the source is a damaged Christmas tree and not a severed wellhead. The percentage of heat radiated in the case of well 17C was about 16%. The Chamberlain correlation predicts both longer (50% more) and wider ames (again by about 50%). (The OTI ames are both shorter and narrower.) The reasons for this are not entirely clear but could be due to the very high relative density of the blow out, the droplets in the released uids, the relatively high

out, the droplets in the released uids, the relatively high molecular weight of the released uids and of course the high momentum ux at the source.

The SEP assessed by Chamberlain method was similar to that measured on well 19B, but the ratio of the radiant heat released to the total potential heat released (the API F factor) back-calculated from OTI data was about 10-15%. This also suggests that the area calculated by the Chamberlain method is a little high and therefore also the view factors. The actual percentage of heat radiated (the API F factor) can be subjectively assessed from the degree of smokiness, the

ame colour and reference to other are types. A value of 10-15% would seem very likely for the Kuwait blowouts, not

28% from the Chamberlain model. The typical percentage of radiant heat released from a low velocity pipe are burning methane (F) is taken as 15% of the total heat as the basis of

are stack designs. The Chamberlain model infers that at sonic velocity the value is between 15 and 20% but the BP tests show an almost translucent ame with a percentage

In all 39 were rejected as irrelevant, for example the vandalism was on an above-ground line in a site and one earth slip was due to a failure of a trestle across a river. The nal pipeline failure rate is 0.00026 per km-year. Of the  $45\ \text{remaining}$  events the only evidence for full bore rupture are those of sabotage, one failure during pressure test, one failure due to stress corrosion cracking and one unspeci-

ed failure. By far the greatest leakage was due to damage induced by diggers, trenchers or similar. While the breach size is not speci ed, it does appear from the leakage and mass of un-recovered uids that the majority of failures were punctures and of a few centimetres in size. This also suggests that running cracks are relatively rare, as indicated by the analysis of Fearnehough (1985). The rupture rate for a properly controlled pipe corridor should therefore be of the order of 0.00002 per km-year and the other failures split, probably, one third-25 mm and two thirds 5-10 mm diameter. The spectrum (per km-year) is as follows:

| 1   | 0-10 mm  | 1.7  | £ | 10;4 |
|-----|----------|------|---|------|
| 2   | 10-25 mm | 0.9  | £ | 10;4 |
| 3   | Rupture  | 2.0  | £ | 10;5 |
| To: | tal      | 2.62 | f | 10:4 |

radiant heat release of 10-5% or less. Typically, methane

burnt on a Kaldair, or low emissivity, are also produces an F value of about 7.5%. The Chamberlain model does appear to

overestimate the percentage of heat radiated from jet ames.

These features suggest that the application of the Chamberlain model to oil-based releases may be outside the boundary of validation and any attempt to modify the

source terms to avoid some of the areas of dif culty may lead to further errors.

#### Failure Rate Data

CONCAWE (CONservation of Clean Air and Water-

Europe) produces an annual record of on-shore piping incidents. In the 10 years 1982–1991 there were 183,000km-years experience and 84 leaks. Of the leaks the following failure categories were not necessarily applicable or relevant in terms of predicting the failure rate for a particular pipeline:

| 1  | Vandalism                       | 5  |
|----|---------------------------------|----|
| 2  | Earth slip=movement             | 2  |
| 3  | Gasket failure                  | 5  |
| 4  | Collapsed steel                 | 1  |
| 5  | Rubber hose                     | 1  |
| 6  | Pump gland                      | 1  |
| 7  | Draining for maintenance        | 2  |
|    |                                 |    |
| 8  | Trenching or equivalent         | 10 |
| 9  | Geological drilling             | 2  |
| 10 | Pump logic failure              | 1  |
| 11 | Salt in line                    | 1  |
| 12 | Acid in line                    | 1  |
| 13 | Failure in pressure test        | 2  |
| 14 | Flange failure (under speci ed) | 1  |
| 15 | Farm activity (unspeci ed)      | 1  |
| 16 | Heat treatment                  | 1  |
| 17 | Bellows failure                 | 1  |
| 18 | Poor fabrication of a tee       | 1  |
|    |                                 |    |

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0.0044 incidents per year around platforms and 0.00072 incidents per Km-year in open water'. On a super cial analysis the two data sets are not truly comparable. Further the modelling by Battelle is based on a number of variables: pipe diameter, age, pressure test procedure, line trenching and inspection. It is possible that the size of the database would not allow accurate multi-variable assessments. The bath tub 'wear in' curve, in particular, is simulated by a correction factor after 4 years' exposure. This is an odd approach as corrosion is an aging effect, not an infant mortality effect, but impacts are more likely during construction when the no anchor zones are less rigorously controlled. This data set may be at risk of double counting. Finally the Battelle data refers to only the pipeline while the

PARLOC data includes ttings.
For the rst 4 years the Battelle data show a failure rate of 0.0065 per year for risers and the rst 100 m of sea line falling to 0.00142 per annum after 4 years. The spectrum (per riser and 1000 m sea-line year) is:

| 1 Leak ^ 10 mm  | 9.32 £ 10¡4 |
|-----------------|-------------|
| 2 Split ^ 25 mm | 2.44 £ 10;4 |
| 3 Rupture       | 2.44 £ 10;4 |
| Total           | 1 /2 £ 10:3 |

The PARLOC data gives a different spectrum:

| 1   | Leak ^ 10 mm  | 1.74 £ 10;3 |
|-----|---------------|-------------|
| 2   | Split ^ 25 mm | 5.04 £ 10;4 |
| 3   | Rupture       | 4.43 £ 10;4 |
| Tot | tal           | 2.69 £ 10;3 |

These values contain the ttings which are not contained in the Battelle data but which make up half the total failure rate. It is of note that the failure rates, allowing for the missing ttings in one data set, are in remarkable agreement. However the rst source is based predominately on the Gulf of Mexico data and has an arti cial aging factor of 0.2 (that

Similar trends are to be found in subsequent more up to date  $\ensuremath{\mathsf{CONCAWE}}$  data.

Fearnehough (1985) suggests that the evidence from gas transmission piping gives a failure spectrum ( per km-year) as:

| 1 0-20 mm    | 2.0 £ 10; 4 |
|--------------|-------------|
| 2 20-80 mm   | 2.2 £ 10; 5 |
| 3 over 80 mm | 7.5 £ 10; 6 |
| Total        | 2.3 £ 10; 4 |

A further analysis of the residual CONCAWE data shows that the leakage is dominated by internal and external corrosion. Modern on-line inspection vehicles (OLIV) or intelligence pigs can detect very early evidence of corrosion. Fearnehough (1985) also show that, if the imposed stress to yield stress ratio does not exceed 0.3 for arti cially created defects and 0.6 for corrosion defects, there is a leak before break, that is the line will not rupture spontaneously under a corrosion regime. However, there will be an upper limiting breach size (or defect) which will result in a running defect

with a breach size equivalent to a full bore rupture. This suggests that the use of intelligence pigging on a regular basis should afford at least a further factor of 2 reduction in the failure rates.

The failure rate data for offshore pipelines and risers is to be found in Battelle Research (1985) and (PARLOC 96, 1996). The Battelle data (the rst data set) were compiled from mostly Gulf of Mexico data and is a mixture of results taken from UKCS and the Gulf of Mexico. The second,

PARLOC, is totally UKCS data. The spreads of the two data sets are signi cant. The following is an abstract: 'The North Sea data provide frequencies of 0.02 incidents per year in the vicinity of platforms, 0.038 incidents per year in shore

approaches and 0.00016 incidents km-year in open waters. This compares to the gures for the Gulf of Mexico of

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reduce the instantaneous out ow but extend the duration. In the case of uids=gases transported above the critical pressure the out ow will again be reduced and duration extended by the retrocondensation of droplets and the production of a two-phase choke

production of a two-phase choke.

There are also signi cant differences between the aerosol formation between uids. After the initial de-packing of an oil line the aerosol formation cannot realistically exceed a factor of 2 but for LPG the aerosol factor could readily reach unity. Live oils can take over 180 s for the de-solution process to reach a form of equilibrium. This is due to mass transfer limitations inside the liquid, which in turn are affected by the physical properties of the liquid. This will result in a much smaller potential reball at the point of rupture.

Current approaches to ame modelling, not only in its morphology but also surface emissive power, can produce an overestimate of the risk. The SEP is non-uniform across the ame surface (with the exception of a BLEVE) and more sophisticated ame models are required. The analysis of jet ames in particular is very sensitive to the upstream pressure and hence not only atomization but also air

entrainment. The ame shape as a cone with height and base dimensions is equally important. The use of an arti cial F factor to reset the SEP can produce errors not only in SEP but also view factor, particularly if the SEP varies across the surface of the ame owing to the ame structure. The analysis of blowouts, which most closely resemble holed pipelines, suggests that the maximum heat ux is on an axis normal to the wind and through the ame

ux is on an axis normal to the wind and through the am axis. It also shows that for oil=gas jets the SEPs are somewhat higher than might be expected from the equivalent are models. This is probably due to the higher

predicted ame dimensions. Of more importance is the

rain-out of oils which could occur with an oil line rupture (and was evident in the clean-up required after the Kuwait res). The rain-out will burn as a very smoky pool re and not contribute to the jet re dimensions and heat ow. In effect the jet re modelling for oil line failure may be signi cantly in error.

signi cantly in error.

The modelling of any gaseous re is by de nition as a jet or loose diffusion ame. The use of are type models does appear to produce some discrepancies. This may be due to the very high momentum uxes in two-phase release and

is a reduction in the failure rate with time), which might not be fully justi ed as it probably results in some double counting.

All in all there are grave discrepancies between on and offshore data and signi cant error potential if the data is not correctly purged of irrelevant data.

#### DISCUSSION

This paper has shown that there are potentially mitigating circumstances for the assessment of the thermal effects following the loss of containment of a ammable uid from a pipeline. In the case of a live uid such as highvapour-pressure oil the de-solution of gases may both exacerbate and reduce the potential risk. Offshore the desolution will assist in the deburdening of the pipeline but onshore it will reduce the out ow. In the case of truly ashing ow uids the two-phase choking effect will

the pyrolysis of higher molecular weight molecules in the combustion zone. The very high-pressure gaseous methane jets appear to produce more radiative ames than test  $% \left( 1\right) =\left\{ 1\right\} =\left\{ 1\right$ evidence might suggest. While these models are the only ones available at present they may be being used outside their area of application.

The reliability data for pipeline failure is very sensitive to the source and applicability. The reliability data should be taken from an equivalent environment and equivalent uid,

not a global set of data. The offshore rupture rate is, from the data, signi cantly higher than for the onshore equivalent. There are many reasons for this, none less than the uids could contain water and of course the sealines are always under water. The use of 'raw' data, which treats the failure data as a global average without any allowance for its geographic location, could result in a factor of up to 5 pessimism, particularly if age effects (post-construction damage, and all causes) are included without the removal of irrelevant data. Further, it is necessary to include mitigating

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factors such as patrol and on-line inspection. These are essentially software safety not hardware and therefore it may be more dif cult to assess the bene ts in a numerate  $\,$ manner. It is suggested that the are-based models hitherto used for torch res should be reviewed in the light of more data on well blowouts and other high-momentum jets. This will take some years to achieve but it could be of use in more accurate assessment of risks near pipelines and so free

land for other uses.

#### CONCLUSIONS

The modelling of any failure of a landline must rst

recognize that the out ows must be modelled by an appropriate method which takes into account the physical properties of the uids and also models the frictional and inertial effects properly. A simple model which attempt to model the out ows taking the source as a large vessel will produce

higher ows but shorter duration. In particular, uids which involve a phase change in the out ow process (gas to liquid or liquid to gas) must be modelled using the appropriate vapour=liquid equilibrium models and where necessary the

heat ows into the pipeline modelled.

Flame modelling for pools and BLEVEs is reasonably secure, but the assessment of surface emissive powers still requires an element of judgement. Modelling jet res by a

are type model is open to error. The ux pro les near to a

breach could be overestimated if the ame properties are not modelled correctly.

Taking these two points together the ame size and SEPs could be overestimated, resulting in higher radiant heat

uxes than might be expected. The failure rate data varies for uid and location. Wet uids result in internal corrosion but equally subsea lines are more vulnerable to external corrosion and impact from shing trawlers. Global data may include inappropriate failure models so that those lines must be purged from the

data sets.

The data gained from the particular offshore needs following the Piper Alpha disaster can be readily transferred

to the onshore analysis of pipeline failures.

Taking all of these results together there is good reason to believe that a more rigorous analysis around landlines should result in smaller consultation distances. However,

this conclusion should not be used arbitrarily to challenge existing distances without detailed site-speci c analysis.

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The manuscript was received 3 May 2002 and accepted for publication after revision 30 September 2002.

Trans IChemE, Vol 81, Part B, January 2003

# ERM paper on cross-country pipelines failure rates as presented at the IChemE Hazards XXIII Conference

http://www.erm.com/en/Analysis-and-Insight/Publications/ERM-paper-on-cross-country-pipelines-failure-rates-as-presented-at-the-IChemE-Hazards-XXIII-Conference/

ERM paper on cross-country pipelines failure rates as ... pipelines are widely used in the Oil & Gas and ... of cross-country pipelines failure rates by

by Glenn Petitt with comments acknowledged from Richard Espiner

This paper was presented at the IChemE Hazards XXIII Conference in November 2012. Proceedings for the conference can be found at the IChemE

Underground cross-country pipelines are widely used in the Oil & Gas and Petrochemical Industries to transport raw materials and products, e.g. crude oil, natural gas and gasoline. The loss of mechanical integrity of such pipelines has occurred on numerous occasions world-wide, due to a variety of causes such as corrosion, external impact, defects, operational errors and natural hazards. With materials being transported at very high pressures, pipeline failures may result in major releases of hazardous materials. An example is shown in Figure 1: the destruction of many houses after a major fire following a gas pipeline rupture in San Bruno, California, USA in September 2010. Such failures present a risk to people (in the case

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of ignition of high pressure gas) and the environment (in the case of oil and other liquid products).

There are a number of recognised failure rate databases for cross-country pipelines, such as CONCAWE (European liquid pipelines) [1], EGIG (European gas pipelines) [2] and the US DoT (both liquids and gas pipelines) [3]. It is remarkable how close the base data from the different systems are, which leads to some confidence that the figures are sufficiently robust to be used in risk analyses.

For each database there is a number of failure modes included, such as corrosion, third party impact, material defects, natural hazards. For some of these failure modes, the databases have shown that there is a correlation between the failure rates and various risk reduction mechanism, such as heavy wall thickness. In particular, a reduction in failure rate can be applied for the corrosion and third party impact failure modes for heavy wall thickness.

However, for other failure modes, in particular material defects, the databases show no correlation between the failure rate and key risk reduction mechanisms such as heavy wall thickness. It would seem logical that the failure rate for material defects should decrease with increasing wall thickness, but for frequency assessments this has often been a constant in past studies, by simple use of statistics from the various databases.

The author has extensive experience of assessing the risks associated with pipeline systems, having been heavily involved in the design and subsequent operation of a number of high-profile pipelines world-wide (from a risk perspective). This experience has been applied to the analysis of the various failure modes in order to determine how various risk reduction techniques can reduce the frequency of failure. This includes the assessment of statistics where there is no immediate correlation from the various databases for specific failure modes.

The paper discusses how such data can be applied where logic would suggest that there should be a reduction in failure rates, although this is not immediately apparent from the various databases.

Read the full paper, with comments acknowledged from Richard Espiner (434Kb PDF)

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# Analysis of Oil Pipelines Failure C.H. Achebe IMECS 2012 6p

https://www.scribd.com/doc/189336531/Analysis-of-Oil-Pipelines-Failure-C-H-Achebe-IMECS-2012-6p December 07, 2014

Analysis of Oil Pipelines Failure C.H. Achebe IMECS 2012 6p. ... fuel gas, and all others showed failure rates to be relatively few and the causes to be relatively ...

pipe line manag ers can prioritize their strategies for The objectives of the study h ave been categorized into the following different areas of activities:

Identify the best practices in developed countries and recommend ways of translating them to areas oil pipeline failures and mitigation of their effects.

Promote the development of incentive systems to In order to fulfil the study objectives, a number of work

Collection of data on pipeline network of (SPDC) in the Niger Delta Area of Nigeria;

Analysis and risk assessment of the causes of oil pipeline failures in the Niger Delta Area of

Review of the legal and regulating regimes of pip eli nes in the Nig er D elt a Area of Nigeria; and

regulatory and monitoring systems in the Nigerian The Niger Delta (Fig.1) is located in Southern Ni ge ri a and is world's third largest wetland. It is the bulk of Nigeria's proven oil and gas reserves. The region has about 606 oilfields with 355 situated onshore and 251 offshore (Fig.2). There are about 5,284 oil wells drilled and 527 flow stations for crude oil processing, with more than 7,000 km of oil and gas pipelines traversing the entire area and The land area within which the network of transport

gas plants and about 30 marginal oil fields farmed out, through the network of pipelines, to local companies and for export. Three of Nigeria's four refineries, Port-Harcourt I & II and Warri, are located in the region, while the fourth is Data was collected from known periodicals and other literature, as well as the databases of Nigerian National Company (SPDC) and other secondary sources that are responsible for operating oil and gas pipelines in the Niger Delta Area of Nigeria. The data collected included the following:

of the major crude oil and lines and local gathering systems (where applicable) in the

from the pipelines. Types of data collected included: date of event, site specification (that is, pipeline identification and causes and consequences, cleanup and restoration, etc.

important environmental factors, as well as populations, habitats, or other environmental features of each state of Niger Delta area along the pipelines that are vulnerable to oil spills.

so forth in the given countries. Most of the pipeline data were accessed from a digital map of main oil pipelines. The data included location of pipelines, diameter in millimeters, and length in kilometers. The data have been categorized on a state-by-state basis and are There were approximately 84,000kilometers of pipeline in Nigeria as of 1998. About 90% of this pipeline has a diameter of greater than 504mm (20inches) while about 64,000 pipeline kilometers, or 76% of the total, are

Proceedings of the International MultiConference of Engineers and Computer Scientists 2012 Vol II,

# AN INNOVATIVE APPROACH TO MANAGING THE INTEGRITY OF OIL ...

http://www.vurup.sk/sites/default/files/downloads/pc 1 2012 usman 152.pdf December 07, 2014

... the development of a plan for the maintenance of the pipeline system is a requirement ... in failure rates, ... System for oil and gas pipelines ...

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Petroleum & Coal
ISSN 1337-7027

Available online at www.vurup.sk/petroleum-coal
Petroleum & Coal 54 (1) 1-8, 2012

AN INNOVATIVE APPROACH TO MANAGING THE INTEGRITY OF
OIL AND GAS PIPELINES: PIPELINE INTEGRITY MANAGEMENT
SYSTEM
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Received August 17, 2011, Accepted January 5, 2011

#### Abstract

In the oil and gas industry, management of the integrity of pipeline has grown to become a serious business because of the overall consequence of pipeline failure: economic, social, environmental, and possibly legal. This research is an attempt to check pipeline failures by carefully following a suite of activities. This suite of activities, also called Pipeline Integrity Management System (PIMS), is generated for an operational pipeline and populated with data gathered on the pipeline system. An analysis of the data collected on the pipeline over a period of five years indicates improved monitoring, reliability, availability, and compliance to regulatory guidelines in the operation of the pipeline systems.

Key Words: Pipeline; Failure; Integrity; Management; System.

#### 1. Introduction

In the past, management techniques for pipelines were minimal. In general, pipelines were typically not maintained regarding their structural integrity until a failure occurred, at which time either the failed section, or the entire pipeline would be replaced. These pipelines may have been inspected at planned outages, at which time obvious problems were typically repaired. Systematic methods of managing pipe, pipelines, or pipe systems were not used to anticipate failures and attempt to conduct preventive maintenance or replace the pipe before failure occurs [1]. The approach of fixing the pipeline when it fails may not be acceptable in cases where burst of pipe may lead to huge damage to property or injury to people, or where loss of the fluid would have deleterious environmental consequences. The upward and continuous surge in the cost of energy will also compel the operator to make appropriate plans to avoid production down time due to pipeline failures. A pipeline integrity management program is needed for these pipeline systems to increase their reliability and availability, and to effectively manage and minimize maintenance, repair, and replacement costs over the long run.

and replacement costs over the long run.

Pipeline Integrity Management System is an innovative approach to generate a suite of activities required to properly manage pipeline assets so as to deliver greater safety by minimizing risk of failures, higher productivity, longer asset life, increased asset availability from improved reliability, lower integrity related operating costs, and ensure compliance with the regulations. Pipeline Integrity Management Systems are developed to serve unique operational needs peculiar to particular pipeline system. For new pipelines systems, the functional requirements for integrity management shall be incorporated into the planning, design, material selection, and construction of the system. However, for pipelines which are already in operation, the integrity management plan is drawn after baseline assessments and data integration. An integrity management program provides the operator with information to effectively allocate resources for appropriate prevention, detection and mitigation activities that will result in improved safety and reduction in the number of incidents [2].In the development of the Pipeline Integrity Management Systems, the integration of information from some relevant sources with the evaluated results of integrity assessment on the pipeline system is necessary. The operator will normally use a risk-based approach in prioritizing repair and maintenance activities, and thus the need to identify the location, more relevant risk of features that could threaten the integrity of each pipeline segment M. A. Uman, S. E. Ngene/Petroleum & Coal 54(1) 1-8, 2012

beforehand. In Nigeria's oil and gas industry, the development of a plan for the maintenance of the pipeline system is a requirement for the grant of Oil Pipeline License to the pipeline system. On this instance, the Pipeline Integrity Management System is preferred to any other form of plan: it has the capacity to manage all known type of operational difficulties with pipeline failures.

## Methodology

## 2.1 The Pipeline System

This work relied on System A (Table 1), a major crude oil export pipeline, to show the effectiveness of the Pipeline Integrity Management System (PIMS) in providing availability, reliability, and regulatory compliance for oil and gas pipelines. The pipeline system was commissioned in 1971 with a crude oil export capacity of 550 Kbpd and had operated till 2005 without a formal integrity management plan. External corrosion, internal corrosion, and fatigue cracking were the most likely deterioration mechanisms for this pipeline system. CO2 and Sulfate Reducing Bacteria (SRB) are the key internal corrosion agents. Stagnant water is swept from pipeline by high flow rates thus making water unavailable to sustain SRB growth.

## 2.2 The Process

The process could be summarized in the chart below:

Identifying

Potential Impact

Gathering, Reviewing,

----

and Integrating Data

by Threats

Risk Assessment

No

All Threats Evaluated?

Yes

Integrity Assessment

Responses to Integrity Assessment and Mitigation

[2]

- required to fully define System A.
- ii. Integrity Assessment Plan (Table 2) which is focused on the major threats on the system: external corrosion, internal corrosion, fatigue cracking, and to a lesser extent third party damage. Operational information and regulatory compliance were used as guides in determining integrity assessment intervals for the identified threats. Mitigative measures suggested were also dependent on the outcome of the assessment and are as stated in the plan. The Failure Mode and Effect Analysis (FMEA) is evaluated using the Risk Matrix in the Appendix B. The Likelihood of Occurrence (LOO) and the Consequence of Failure are obtained from the Risk Matrix and recorded on the MRP.
- iii. Maintenance Reference Plan (Table 3) activities are scheduled with keen interest on checking external corrosion, internal corrosion, and 3rd party damages [4]. CO2, H2S, and SRB are key internal corrosion agents and thus were be properly monitored through the plan to ensure reliability and availability of the pipeline system. Pigging, CP installation and upgrade, inhibition, and other corrosion control activities are included in plan [3,4]. iv. The Integrity Verification Plan (Table 4) considered a five-year review period for the
- system (2005 2009). The Technical Integrity Indicators and Performance Indicators (PI) for the various activities were calculated and recorded to indicate the integrity M. A. Uman, S. E. Ngene/Petroleum & Coal 54(1) 1-8, 2012

status of the pipeline and the degree of execution of the prepared MRP. The overall integrity of the pipeline indicates that it is still fit for purpose at its de-rated operating pressure of 400 psi.

- v. The performance Measurement Plan (Table 5) shows a 5-year plan which could lead to verifiable deductions that PIMS leads to improved monitoring and management of the system's failures and repairs. There is marked reduction in failure rates, leaks, and volume of fluid spilled and subsequently the total number of repairs but an increase in the percentage of planned of planned activities completed as well as action that impacted safety as the year progressed.
- 3. Results

The summary of the recorded effect of PIMS is shown in the table below:

| Indices for Evaluation                   | Year |      |      |      |      |      |
|--|------|------|------|------|------|------|
| indices for Evaluation                   | 2000 | 2005 | 2006 | 2007 | 2008 | 2009 |
| Volume of Fluid Spilled (Barrels)        | 4000 | 2400 | 1100 | 600  | 400  | 100  |
| Repair Actions due to Direct             |      |      |      |      |      |      |
| Assessment Results                       | 3    | 7    | 6    | 5    | 4    | 2    |
| Leaks due to Pipeline Failures           |      |      |      |      |      |      |
| reaks due to riperine rariares           | 4    | 2    | 1    | 1    | 1    | 1    |
| <pre>(willful damage not included)</pre> |      |      |      |      |      |      |
| Actions Completed which Impact           |      |      |      | 0    | 10   | 10   |
| on Safety                                | 1    | 4    | 6    | 9    | 10   | 12   |
| Anomalies Found Requiring                |      |      |      |      |      |      |
| , ,                                      | 12   | 8    | 7    | 6    | 5    | 4    |
| Mitigations                              |      |      |      |      |      |      |

#### 4. Conclusions

The current continuous and sustained increase in the price of steel has placed the cost of steel pipes in international markets in a continuous hike and thus the reason for series of cost reviews in most recent pipeline projects. The availability and reliability of pipelines for operations are threatened by pipeline failures. Environmental degradation due to spills from line failures has also created a regulatory demand for new and operating pipeline systems to be appropriately monitored. These are obvious reasons why generation and implementation of Pipeline Integrity Management System for oil and gas pipelines is

This research work generated Pipeline Integrity Management Systems for System A, an operating pipeline system. The effectiveness of PIMS was monitored over five years period using the information from the operating System A whose operator has been taking some actions considered components of PIMS in the last six years to ensure reliability and availability of the pipeline. Evaluation of the results generated from the PIMS for the operating pipeline system using the review period indicated improvement on the threat situation and failures observed as the years progressed. This corresponds to decrease in anomalies requiring repairs not minding that the pipeline system is already past its design life. It is an indication of how important PIMS is to the life of an operating pipeline. In all, PIMS has been found to be effective tool for resources allocation in the prevention, detection, and mitigation activities that will lead to improved safety and reduction in the number of incidents on pipeline systems. References

- Pittalwala, S.H and Wittas, D. J (2006) "System and Method for Pipeline Reliability Management" Patent No: US 7,043,373 B2.

  ASME B31.8s (2001). "Managing System Integrity of Gas Pipelines" Supplement to [1]
- [2] ASME B31.8.
- Mobil Producing Nigeria Unlimited (2008): Presentation to Department of Petroleum
- Resources (DPR) on "Critical Crude Pipeline Segments Replacement".

  Shell Petroleum Development Company of Nigeria Limited (2006): A Presentation to the Department of Petroleum Resources on "PIMS Engagement".

  API Recommended Practice 1160: "Managing System Integrity for Hazardous Liquid Pipelines" First Edition (August 2001). [4]

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## APPENDIX A

Table 1 Segment Data for System A

Segment Data Type API 5L X60 Pipe Grade Nominal Diameter Wall Thickness 12.7mm Pipe Attributes N/A Date of Manufacture N/A Spiral Welded Seam Type Operating Pressure 280 psi Design Pressure 720 psi Coal Tar/Cement Coating Type Coating Condition Good Design/Construction Pipeline Commission Date 1971

Joining Method Medium Type Hydrostatic Test Désign Temperature

Electric Arc Process Offshore 890 psi 0 - 80oC

Crude Quality API=36.8 Flow Rate 550 KBPD Operation Planned Repair Method Replacement Leak/Rupture History 3rd Party Damage / Corrosion Sacrificial Anode Cathodic Protection SCC Indications Yes Table 2 Integrity Assessment Plan Criteria/Risk Integrity Mitigation Interval Threat Assessment Assessment Conduct Replace / Repair hvdrostatic Some external locations where External Corrosion test or perform 10 Years corrosion observed CFP is helow Direct 1.25 x MAOP. Assessment Internal corrosion is Conduct in-line Internal Corrosion -do-5 Years suspected inspection Potential concern for Conduct Replace / Repair Fatigue Cracking fatigue cracking of hydrostatic pipe at failure 10 Years spiral weld pipe test locations No Manufacturing Manufacturing -do--do-N/A issues No Construction/ Construction/Fabrication None Required N/A N/A Fabrication issues Equipment No Equipment issues -do--do--do-Conduct hydrostatic After every test, perform Replace / Repair 3rd party damage is repair/replace ILI and pipe at failure Third Party Damage observe ment due 3rd observe locations damage repaired locations No incorrect Incorrect Operations None required N/A N/A operation issues Weather & Outside No Weather/Outside -do--do--do-Force Force issues M. A. Uman, S. E. Ngene/Petroleum & Coal 54(1) 1-8, 2012 Table 3 Maintenance Reference Plan System A Export Pipeline Line Pacer ID SYS A 003 Dia (") 1971 0i1 Installation Date Service Environment Offshore MRP Review Date Failure Mode and Effect Analysis Failure Mode 1.00 COF Remarks External Corrosion М 5 Line Blockage (Sand) 4 Line Blockage (Scale) 1 4 3rd Party Damages М 5 Internal Corrosion Н Last IP ( 2005 ) Next IP (2010 ) Line Piggability (Y/N) Yes Last UT ( ) Next UT (`) No MRP Activities Activity Title
Offshore CP Potential profile and Frequency Six Monthly Nο Comment 001 Replace missing / faulty anode condition survey anodes 992 Offshore CP shore approach -dosurvev 003 Offshore risers CP survey -do-Offshore riser coating survey Offshore line position survey 994 Annually 005 -do-Non-supported span survey 5 Yearly 006 Debris > 0.5 kg; Mechanical 007 Routine pigging Monthly de-scaling before IP. 008 Non-routine pigging As Required Third party damage H2S Monitoring (MIC) Monthly Six Monthly 999 H2S and pH Measurement 010 Biocide Treatment & Bacteria Check effectiveness on SRB 011 Count 012 Water Chemistry Six Monthly CO2 corrosion rate prediction 013 -do-014 Oxygen Ingress Control As Required Acid Corrosion Control H2S Monitoring (Sour Service) pH check 015 -do-Six Monthly 016 Impingement /Erosion Monitoring As Required
Intelligent Pigging 5 Yearl
ROW Surveillance & Maintenance Quarter 017 5 Yearly 018 Quarterly 019 020 Valve Maintenance Annually Inspection of offshore manifolds 021 -doand piping 022 CP System Upgrade -do-Follow the recommendation of CP System Audit 023 Pipeline equipment condition Annually survey maintenance Operational Control As Required 024 5 Yearly 025 Manifold painting

Process Fluid Temperature

25oC

026 Corrosion Inhibition Corrosion Monitoring As Required 027 Six Monthly

028 Protection of Mothballed pipelines -do-029

CP System Audit -do-M. A. Uman, S. E. Ngene/Petroleum & Coal 54(1) 1-8, 2012

Table 4 Integrity Verification Plan Line 42" System A Export Pipeline Wall Thickness (mm) 12.7 Coal Tar /Concrete SYSB 03 Coating Diameter (") 42 Pacer ID Service Oil Length 35.00 Commissioning Year 1971 (Km) API 5L X60 Offshore Grade Reviewer SN

6

Environmen Third Party Technical Integrity Indicator ΡI Comments Period Sabotage Mech. Damage 09/04-1 70% 08/05 09/05-60% 08/06 a 50% 99/96-08/07 09/07-60% 08/08 60% 09/08-08/09 Internal Technical Integrity Indicator Last IP 2005 MRP Corrosion Year Repairs Yes/No 2005 CO2 Meas 100% 2006 H20 Chem N 9% 2007 H2S Check 50% 2 2008 pH Check 60% 2009 1 Biocide 75% Treatment Bacteria 50% Count

100% Sampling Inhibition 75% Technical Integrity Indicator
Year Repairs MRP External Comments TII ΡI Corrosion 2005 0 CP main 75% stations 2006 2 100% Test post checks CIPS CP Audit 2007 0 50% 2008 50% 1 1 2009 Riser 75% Survey Coating 100%

Survey

Failure of Ancillary Equipment

During period of review four (4)

ancillary equipment failures

Operational Error

Comments

None

occurred

Overall Integrity Status

The pipeline which has been de-rated to 400 psi is still fit for purpose. M. A. Uman, S. E. Ngene/Petroleum & Coal 54(1) 1-8, 2012

Table 5 Overall Performance Measurement Plan

| S/<br>N | Description   | 2005  | 2006  | 2007 | 2008 | 2009 |
|---------|---|-------|-------|------|------|------|
| 1       | Km of pipeline inspected Vs Integrity<br>Management Program requirement | 40%   | 50%   | 70%  | 80%  | 85%  |
| 2       | Integrity Management Program Changes requested by authorities           | 8     | 5     | 3    | 2    | 1    |
| 3       | Percentage of planned activities completed                              | 40%   | 55%   | 70%  | 75%  | 80%  |
| 4       | Fraction of the system included in<br>Integrity Management Program      | 0.4   | 0.5   | 0.7  | 0.8  | 0.85 |
| 5       | Actions completed that impact safety                                    | 4     | 6     | 9    | 10   | 12   |
| 6       | Anomalies found requiring repairs / mitigation                          | 8     | 7     | 6    | 5    | 4    |
| 7       | External corrosion leaks  | 2     | 0     | 1    | 0    | 0    |
| 8       | Internal corrosion leaks  | 3     | 2     | 2    | 1    | 0    |
| 9       | Leaks due to equipment failures   | 2     | 1     | 1    | 1    | 1    |
| 10      | Leaks due to third party damage   | 3     | 4     | 4    | 2    | 2    |
| 11      | Leaks due to manufacturing defects                                      | 0     | 0     | 0    | 0    | 0    |
| 12      | Leaks due to construction defects                                       | 0     | 0     | 0    | 0    | 0    |
| 13      | In-service Leaks due to stress corrosion cracking                       | 1     | 0     | 0    | 0    | 0    |
| 14      | Repair actions taken due to In-Line<br>Inspection results               | 0     | 0     | 0    | 0    | 0    |
| 15      | Repair actions taken due to direct assessment results                   | 7     | 6     | 5    | 4    | 2    |
| 16      | Hydrostatic test failures caused by external corrosion                  | 0     | 1     | 0    | 0    | 0    |
| 17      | Hydrostatic test failures caused by internal corrosion                  | 3     | 2     | 2    | 1    | 0    |
| 18      | Hydrostatic test failures due to manufacturing defects                  | 0     | 0     | 0    | 0    | 0    |
| 19      | 3rd Party damage events detected  | 3     | 2     | 4    | 2    | 3    |
| 20      | Unauthorized crossings  | 2     | 0     | 0    | 1    | 0    |
| 21      | Precursor events detected   | 1     | 2     | 3    | 3    | 4    |
| 22      | ROW encroachments detected  | 1     | 2     | 2    | 3    | 2    |
| 23      | Re-rating of pipelines  | 0     | 1     | 0    | 0    | 0    |
| 24      | Segments with deeper pitting than before                                | 0     | 0     | 0    | ø    | 0    |
| 25      | Volume of fluid spilled   | 2,400 | 1,100 | 600  | 400  | 100  |

APPENDIX B

Risk Matrix for Pipeline Systems

INCREASING LIKELIHOOD B C D CONSEQUENCES

Environment

Reputation

Severity

|   | People                     |               |               |                  | Never                    |                          | Incident                             | Happens                               | Happens                                     |
|---|----------------------------|---------------|---------------|------------------|--------------------------|--------------------------|--------------------------------------|---------------------------------------|---|
|   |                            | Assets        |               |                  | heard of in the industry | Heard of in the industry | has<br>occurre<br>d in our<br>compan | several times per year in our company | so many<br>times a<br>year in a<br>location |
|   | No health                  | No            |               |                  |                          |                          |                                      |                                       |   |
| 0 | effect/<br>injury          | damage        | No effect     | No impact        |                          |                          |                                      |                                       |   |
|   | Slight<br>health           | Slight        | Slight        | Slight           |                          |                          |                                      |                                       |   |
| 1 | effect/<br>injury          | damage        | effect        | impact           |                          |                          |                                      |                                       |   |
|   | Minor<br>health            | Minor         | Minor         | Limited          |                          | Low                      |                                      |                                       |   |
| 2 | effect/<br>injury<br>Major | damage        | effect        | impact           |                          | Risk                     |                                      |                                       |   |
|   | health                     | Localise      | Localised     | Considerabl      |                          |                          | Medium                               |                                       |   |
| 3 | effect/                    | d<br>damage   | effect        | e impact         |                          |                          | Risk                                 |                                       |   |
|   | injury<br>PTD or 1         | damage        |               |                  |                          |                          |                                      |                                       |   |
| 4 | to 3                       | Major         | Major         | National         |                          |                          |                                      |                                       |   |
| 7 | fatalities                 | damage        | effect        | impact           |                          |                          |                                      |                                       |   |
| 5 | Multiple                   | Extensiv<br>e | Massive       | Internation      |                          |                          |                                      | High Risk                             |   |
| - | fatalities                 |               | effect        | al impact        |                          |                          |                                      | -651                                  |   |
|   | Noto. The                  | damage        | has +hnoo (2) | nick classes Low | 'I ) Modium (M           | ) and Wigh (W)           |                                      |                                       |   |

Note: The Risk Matrix has three (3) risk classes: Low (L), Medium (M), and High (H).
The Likelihood of Occurrence (LOO) uses these 3 classes of risks.

# Oil and Gas Pipeline Failure Hazard Mitigation Plan <a href="http://gbra.org/documents/hazardmitigation/update/Section15-PipelineFailure.pdf">http://gbra.org/documents/hazardmitigation/update/Section15-PipelineFailure.pdf</a> December 07, 2014

Location of Oil and Gas Pipelines in the GBRA Basin ... a "pipeline failure," it is valuable to consider these events as presenting a range in ...

OIL AND GAS PIPELINE FAILURE

| Hazard Description                |
|-----------------------------------|
| 1                                 |
| ocation                           |
|                                   |
| Extent                            |
| 11                                |
| istorical Occurrences             |
| 11                                |
| Probability of Future Occurrences |
| Impact and Vulnerability          |
| 16                                |
|                                   |

Hazard Description

Fuel pipeline breach or pipeline failure addresses the rare, but serious hazard of an oil or natural gas pipeline. An estimated 2.2 million miles of pipelines in the United States carry hazardous materials. Natural gas pipelines transport natural gas, and oil or liquid petroleum pipelines transport crude oil and refined products from crude oils, such as gasoline, home heating oil, jet fuel and kerosene in addition to liquefied propane, ethylene, butane and some petrochemical products.

Sometimes oil pipelines are also used to transport liquefied gases, such as carbon dioxide.

Pipeline failure is a rare occurrence, but has the potential to cause extensive property damage and loss of life. Pipelines have caused fires a explosions that killed more than 200 people and injured more than 1,000 people nationwide and 50 people in Texas in the last decade.

Location

Figures 15-1 on the following page shows the locations of gas and oil pipelines throughout the GBRA Basin region. Figures 15-2 through 15-9 show locations of pipelines in each respective county. It is important to note that due to scale, some pipelines cannot be seen on maps where one pipeline runs directly over another or where pipelines appear too close together to be visible on the map.

HAZARD MITTGATION PLAN UPDATE:

PROTECTING

THE REGTON AGATNST ALL HAZARDS

SECTION 15: PIPELINE FAILURE

If any of these energy pipelines were to rupture, such an event could endanger property and lives in the immediate area. Immediate impacts can occur within a half-mile area and secondary impacts within a mile of the incident. Therefore, due to the location of both oil and gas pipelines in the county, each participating jurisdiction faces a moderate to high risk, with the exception of Jamaica Beach.

Figure 15-1. Location of Oil and Gas Pipelines in the GBRA Basin

Gas and Oil Pipelines in GBRA Basin

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Figure 15-2. Gas and Oil Pipelines in Caldwell County

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Figure 15-3. Gas and Oil Pipelines in Calhoun County

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Figure 15-4. Gas and Oil Pipelines in DeWitt County

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SECTION 15: PIPELINE FAILURE

Figure 15-6. Gas and Oil Pipelines in Kendall County

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Figure 15-7. Gas and Oil Pipelines in Refugio County

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Figure 15-8. Gas and Oil Pipelines in Victoria

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Figure 15-9. Gas and Oil Pipelines in Cibolo (in Guadalupe County)

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Extent
While many of the historical accidents presented in Table 15-1 are relatively small in terms of the amount of property damage that was reported, and while some may not meet the conventional idea of a "pipeline failure," it is valuable to consider these events as presenting a range in magnitude of a possible occurrence. Reading Table 15-1 in conjunction with the Figures 15-1 through 15-9 provides an indication of the possible intensity of an event. In addition historical occurrences provide an indication of the types of issues related to gas and oil present in the GBRA Basin and the preventable nature of many of these occurrences. For example, in Table 15-2, several of the incidents reported to the Railroad Commission of Texas were of unknown origin, the result of drivers hitting presumably unprotected facilities with their vehicles. Several incidents appeared to be the result of miscommunication or lack of communication regarding locates prior to digging Maintenance and possibly homeowers education communication regarding locates prior to digging. Maintenance and possibly homeowner education could have been a contributing factor in two of the events.

Historical Occurrences

The causes of pipeline failures can range from internal issues such as corrosion or material defects to outside forces. Such forces can include damage from natural hazards, such as earthquakes, or intentional destruction by humans. Table 15-1 summarizes the incident log of historical pipeline accidents reported by the Railroad Commission of Texas. Table 15-2 illustrates pipeline accidents that transpired between 2003 and 2008.

Table 15-1. Historical Pipeline Accidents (Gas and Oil Combined) (1985-2001)

Annualized

Number of Events

Expected Number of Pipeline Events =

1.571429

3

2

1

1987 1989 1993 1995 1997 1999 2001 1991

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## Table 15-2 Historical Pipeline Accidents1 (Gas and Oil Combined) (2003-2008)2

|          | INCIDENT | 3      |                           |        |        |          |            |              |
|----------|----------|--------|---------------------------|--------|--------|----------|------------|--------------|
| COUNTY   |          | TYPE   | OPERATOR                  |        | DEATHS | INJURIES | COST       | NEAREST CITY |
|          | DATE     |        |                           |        |        |          |            |              |
| CALDWELL | 07/01/05 | GAS    | TEXAS GAS SERVICE         |        | 0      | 0        | >\$5,000   | LOCKHART     |
| CALDWELL | 03/09/06 | LPG    | L & L TRANSPORT           |        | 1      | 0        | >\$5,000   | LOCKHART     |
| CALDWELL | 06/12/06 | LIQUID | TEPPCO CRUDE PIPELINE, LP |        | 0      | 0        | UNKNOWN LI | JLING        |
| CALDWELL | 06/18/06 | OG     | UNKNOWN                   |        | 0      | 0        | UNKNOWN S  | TAIRTOWN     |
| CALDWELL | 03/31/07 | OG     | UNKNOWN                   |        | 0      | 0        | UNKNOWN LO | OCKHART      |
| CALDWELL | 08/28/08 | GAS    | UNKNOWN                   |        | 0      | 0        | >\$50,000  | PRAIRIE LEA  |
| CALDWELL | 12/08/08 | LIQUID | UNKNOWN                   |        | 0      | 0        | UNKNOWN I  | LULING       |
| CALDWELL | 07/06/09 | OG     | UNKNOWN                   |        | 0      | 0        | UNKNOWN I  | LOCKHART     |
| CALDWELL | 01/02/10 | OG     | UNKNOWN                   |        | 0      | 0        | UNKNOWN I  | LULING       |
|          |          |        |                           |        |        |          |            | MATAGORDA    |
| CALHOUN  | 09/01/03 | GAS    | LAVACA PIPELINE COMPANY   |        | 0      | 0        | <\$5,000   |              |
|          |          |        |                           |        |        |          | .,.,       | ISLAND       |
| CALHOUN  | 10/20/03 | LIQUID | VINTAGE PETROLEUM         |        | 0      | 0        | \$10,000   | SEADRIFT     |
| CALHOUN  | 10/23/03 | GAS    | CENTERPOINT ENERGY ENTEX  |        | 0      | 0        | <\$5,000   | PORT LAVACA  |
|          |          |        | ATMOS ENERGY              | CORP., |        |          | .,.,       | PORT         |
| CALHOUN  | 12/15/03 | GAS    |                           |        | 0      | 0        | >\$5,000   |              |
|          |          |        | MID-TEX DIVISION          |        |        |          |            | O'CONNER     |
| CALHOUN  | 03/07/04 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | \$20,000   | OFFSHORE     |
|          |          |        |                           |        |        |          | , .,       | PORT         |
| CALHOUN  | 04/08/04 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | \$12,000   |              |
|          |          |        |                           |        |        |          |            | O'CONNOR     |
|          |          |        |                           |        |        |          |            | PORT         |
| CALHOUN  | 06/16/04 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | \$30,000   |              |
|          |          |        |                           |        |        |          | , ,        | O'CONNER     |
| CALHOUN  | 07/15/04 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | \$10,000   | OFFSHORE     |
| CALHOUN  | 01/14/05 | GAS    | CENTERPOINT ENERGY ENTEX  |        | 0      | 0        | <\$5,000   | PORT LAVACA  |
| CALHOUN  | 01/20/05 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | <\$5,000   | MATAGORDA    |
|          |          |        |                           |        |        |          | .,.,       | PORT         |
| CALHOUN  | 03/02/05 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | \$43,000   |              |
|          |          |        |                           |        |        |          | , -,       | O'CONNER     |
| CALHOUN  | 03/07/05 | LIQUID | NEUMIN PRODUCTION         |        | 0      | 0        | <\$50,000  | SEADRIFT     |
| CALHOUN  | 03/21/05 | LIQUID | NEUMIN PRODUCTION         |        | 0      | 0        | <\$5,000   | SEADRIFT     |
| CALHOUN  | 04/04/05 | GAS    | CENTERPOINT ENERGY ENTEX  |        | 0      | 1        | UNKNOWN S  |              |
| CALHOUN  | 04/18/05 | GAS    | CENTERPOINT ENERGY ENTEX  |        | 0      | 0        | <\$5,000   | PORT LAVACA  |
| CALHOUN  | 04/27/05 | GAS    | SABCO OPERATING COMPANY   |        | 0      | 0        | \$18,000   |              |
|          | . , .,   |        |                           |        | -      | -        | ,          |              |

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| COUNTY  | INCIDENT | TYPE3  | OPERATOR                | DEATHS | INJURIES | COST     | NEAREST CITY       |  |
|---------|----------|--------|-------------------------|--------|----------|----------|--------------------|--|
|         | DATE     | 25     | of Election             | DEATHS | INJUNIES | 2031     | PORT               |  |
| CALHOUN | 08/04/05 | GAS    | SABCO OPERATING COMPANY | 0      | 0        | >\$5,000 | O'CONNOR           |  |
| CALHOUN | 09/13/05 | LIQUID | NEUMIN PRODUCTION       | 0      | 0        | <\$5,000 | SEA DRIFT<br>POINT |  |
| CALHOUN | 10/19/05 | GAS    | LAVACA PIPELINE         | 0      | 0        | \$34,700 | COMFORT            |  |
| CALHOUN | 12/29/05 | GAS    | VINTAGE PETROLEUM       | 0      | 0        | <\$5,000 | SEADRIFT           |  |

Limitations of the data used to populate Table 15-2 include the following: more than 25 percent of the entries do not provide an operator name, 35 percent of the entries do not show a cost for the release, two incidents are undated, and the data range covers only eight years (2003-2010). All entries are shown in chronological order by county. LPG stands for liquefied petroleum gas.

OG stands for oil and gas.

| CALHOUN<br>CALHOUN | 02/08/06<br>04/02/06 | LIQUID<br>GAS | SABCO OPERATING COMPAN<br>SABCO OPERATING COMPAN |                  |               | >\$50,000<br>>\$50,000                | ROCKPORT<br>UNKNOWN        |
|--------------------|----------------------|---------------|--|------------------|---------------|---------------------------------------|----------------------------|
| CALHOUN            | 04/02/06             | GAS           | VINTAGE PETROLEUM                                | 0                |               | >\$5,000<br>>\$5,000<br>>\$5,000, BUT | PORT LAVACA                |
| CALHOUN            | 05/05/06             | GAS           | VINTAGE PETROLEUM                                | 0                | 0             |                                       | SEADRIFT                   |
|                    |                      |               |  |                  |               | <\$50,000                             | MAGNOLIA                   |
| CALHOUN            | 07/29/06             | GAS           | LAVACA PIPELINE                                  | 0                | 0             | <\$5,000                              | BEACH                      |
| CALHOUN            | 08/06/06             | GAS           | CENTERPOINT ENERGY ENT                           | EX 0             | 0             | <\$5,000                              | SEA DRIFT                  |
| CALHOUN            | 10/24/06             | GAS           | LAVACA PIPELINE COMPAN                           | Υ 0              | 0             | <\$50,000<br>>\$5,000,                | PORT LAVACA                |
| CALHOUN            | 11/08/06             | GAS           | SABCO OPERATING COMPAN                           | Υ 0              | 0             | POSSIBLY                              | PORT                       |
| CALITOON           | 11,00,00             | GAS           | SADEO OF ENATING CONTAIN                         |                  | Ü             |                                       | O'CONNER                   |
|                    |                      |               |  |                  |               | >\$50,000                             |                            |
| CALHOUN            | 12/20/06             | OG            | AROC TEXAS, INC.                                 | 0                | 0             | UNKNOWN U                             | NKNOWN<br>POINT            |
| CALHOUN            | 03/05/07             | GAS           | LAVACA PIPELINE COMPAN                           | Υ 0              | 0             | <\$5,000                              | COMFORT                    |
|                    |                      |               |  |                  |               | >\$5,000 BUT                          | PORT                       |
| CALHOUN            | 03/13/07             | GAS           | SABCO OPERATING COMPAN                           | Υ 0              | 0             | 745,000 001                           | TOKT                       |
|                    | ,,                   |               |  | •                | -             | <\$50,000                             | OCONNOR                    |
|                    |                      |               |  |                  |               | \$177,100 FOR                         |                            |
| CALHOUN            | 05/13/07             | GAS           | SABCO OPERATING COMPAN                           | Υ 0              | 0             | -                                     |                            |
|                    |                      |               |  |                  |               | 30 DAYS                               |                            |
| CALHOUN            | 06/18/07             | GAS           | SABCO OPERATING COMPAN                           |                  |               | >\$5,000                              | UNKNOWN                    |
| CALHOUN            | 07/22/07             | GAS           | SABCO OPERATING COMPAN                           |                  |               | \$10,000                              | OFFSHORE                   |
| CALHOUN            | 09/13/07             | GAS           | MAIN ENERGY                                      | 0                |               | \$9,000                               | PORT LAVACA                |
| CALHOUN            | 12/15/07             | GAS           | LAMAR OIL & GAS                                  | 0                |               | <\$50,000                             | SEADRIFT                   |
| CALHOUN            | 02/13/08             | GAS           | UNKNOWN  | 0                | 0             | <\$5,000                              | PORT LAVACA<br>SAN ANTONIO |
| CALHOUN            | 03/12/08             | LIQUID        | UNKNOWN  | 0                | 0             | <\$50,000                             |                            |
|                    |                      |               |  |                  |               |                                       | BAY                        |
|                    |                      |               |  |                  |               |                                       | POINT                      |
| CALHOUN            | 04/05/08             | OG            | UNKNOWN  | 0                | 0             | UNKNOWN                               |                            |
|                    |                      |               |  |                  |               |                                       | COMFORT<br>POINT           |
| CALHOUN            | 09/22/08             | GAS           | UNKNOWN  | 0                | 0             | <\$50,000                             | COMFORT                    |
| CALHOUN            | 09/26/08             | LIQUID        | UNKNOWN  | 0                | 0             | UNKNOWN S                             | EA DRIFT                   |
| CALHOON            | 03/20/00             | LIQUID        | ONKNOWN  | O                | · ·           | OWNIVOWN 3                            | POINT                      |
| CALHOUN            | 11/18/08             | OG            | UNKNOWN  | 0                | 0             | UNKNOWN                               |                            |
|                    |                      |               |  |                  |               |                                       | COMFORT                    |
| CALLIOUN           | 12/17/00             | LTOUTD        | LINUANOUNI                                       | •                | •             | LINUANOLIN                            | POINT                      |
| CALHOUN            | 12/17/08             | LIQUID        | UNKNOWN  | 0                | 0             | UNKNOWN                               | COMFORT                    |
| CALHOUN            | 01/02/09             | GAS           | UNKNOWN  | 0                | 0             | <\$50,000                             | PORT                       |
|                    |                      |               |  | Hazard Mitigatio | n Plan Update | 2011-2016                             | 13                         |

SECTION 15: PIPELINE FAILURE

|           | INCIDENT |        |   |        |          |                                |
|-----------|----------|--------|---|--------|----------|--------------------------------|
| COUNTY    | DATE     | TYPE3  | OPERATOR                                | DEATHS | INJURIES | COST NEAREST CITY              |
|           | DATE     |        |   |        |          | O'CONNOR<br>PORT               |
| CALHOUN   | 05/11/09 | OG     | UNKNOWN                                 | 0      | 0        | UNKNOWN<br>O'CONNOR<br>POINT   |
| CALHOUN   | 05/28/09 | GAS    | UNKNOWN                                 | 0      | 0        | UNKNOWN COMFORT                |
| CALHOUN   | 07/22/09 | GAS    | UNKNOWN                                 | 0      | 0        | <\$50,000 PORT LAVACA<br>POINT |
| CALHOUN   | 09/13/09 | GAS    | UNKNOWN                                 | 0      | 0        | <\$5,000<br>COMFORT            |
| DEWITT    | 04/10/06 | GAS    | TEXAS GAS SERVICE                       | 0      | 0        | <\$5,000 CITY OF CUERO         |
| DEWITT    | 06/11/06 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 2        | UNKNOWN YORKTOWN               |
| DEWITT    | 07/20/06 | OG     | ROCK OIL                                | 0      | 9        | UNKNOWN YORKTOWN               |
| DEWITT    | 03/30/07 | OG     | UNKNOWN                                 | 9      | 0        | UNKNOWN NORDHEIM               |
|           | 03/30/07 |        |   | _      | _        | >\$5,000 BUT                   |
| DEWITT    | 05/21/07 | GAS    | ENTERPRISE PRODUCTS OPERATING           | 0      | 0        | HOPE                           |
|           |          |        |   | _      | _        | <\$50,000                      |
| DEWITT    | 03/04/09 | LIQUID | UNKNOWN                                 | 0      | 0        | UNKNOWN VICTORIA               |
| GONZALES  | 12/22/03 | GAS    | TEXAS GAS SERVICE DUKE ENERGY GUADALUPE | 0      | 0        | <\$10,000 NIXON                |
| GONZALES  | 06/20/04 | GAS    | DUKE ENERGY GUADALUPE                   | 0      | 0        | 424 000 CECUTN                 |
| GUNZALES  | 06/20/04 | GAS    | PIPELINE, INC.                          | О      | О        | \$24,000 SEGUIN                |
| GONZALES  | 12/13/05 | GAS    | CITGO PRODUCTS PIPELINE                 | 0      | 0        | \$0 GONZALES                   |
| GONZALES  | 01/15/06 | LPG    | LOGISTICS EXPRESS, INC.                 | 0      | 2        | >\$5,000 WAELDER               |
| GONZALES  | 09/28/06 | LIQUID | CITGO PRODUCTS PIPELINE                 | 0      | 0        | UNKNOWN LULING                 |
| GONZALES  | 09/18/07 | LIQUID | CITGO PRODUCTS PIPELINE                 | 0      | 0        | UNKNOWN GONZALES               |
|           |          | LPG    |   | 9      | 0        |                                |
| GONZALES  | 11/29/07 |        | PETRON, LLC                             | -      |          | UNKNOWN GONZALES               |
| GONZALES  | 12/20/07 | LIQUID | CITGO PIPELINE                          | 0      | 0        | UNKNOWN GONZALES               |
| GONZALES  | 09/12/08 | LIQUID | UNKNOWN                                 | 0      | 0        | UNKNOWN LULING                 |
| GUADALUPE | 01/08/04 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 MARION                |
| GUADALUPE | 03/30/04 | LIQUID | EXXON MOBIL PIPELINE                    | 0      | 0        | \$20,000 MCQUEENEY             |
| GUADALUPE | 12/03/04 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 MARION                |
| GUADALUPE | 04/26/05 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 SCHERTZ               |
| GUADALUPE | 06/05/06 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 SEGUIN                |
| GUADALUPE | 06/14/06 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 SEGUIN                |
| GUADALUPE | 09/19/06 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 SCHERTZ               |
| GUADALUPE | 03/08/07 | LPG    | MARSHALL PROPANE                        | 0      | 0        | >\$5,000 SEGUIN                |
| GUADALUPE | 04/20/07 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | >\$5,000 SEGUIN                |
| GUADALUPE | 06/26/07 | LIQUID | CITGO                                   | 0      | 0        | DRILL KINGSBURY                |
| GUADALUPE | 07/19/07 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 SEGUIN                |
| GUADALUPE | 01/11/08 | GAS    | CENTERPOINT ENERGY ENTEX                | 0      | 0        | <\$5,000 SEGUIN                |
| GUADALUPE | 06/08/09 | LIQUID | UNKNOWN                                 | 0      | 0        | UNKNOWN SAN ANTONIO            |
| KENDALL   | 02/21/10 | GAS    | UNKNOWN                                 | ø      | ø        | UNKNOWN BOERNE                 |
|           |          |        |   |        |          |                                |

## SECTION 15: PIPELINE FAILURE

|          | INCIDENT   |        |                               |       |        |          |                         |
|----------|------------|--------|-------------------------------|-------|--------|----------|-------------------------|
| COUNTY   |            | TYPE3  | OPERATOR                      |       | DEATHS | INJURIES | COST NEAREST CITY       |
|          | DATE       |        |                               |       |        |          |                         |
| LAVACA   | UNKNOWN GA | AS     | UNKNOWN                       |       | 0      | 0        | UNKNOWN UNKNOWN         |
| LAVACA   | 10/04/07   | LPG    | PETRON, LLC                   |       | 0      | 1        | UNKNOWN HALLETTSVILLE   |
| LAVACA   | 01/03/05   | GAS    | HOUSTON PIPE LINE COMPANY     |       | 0      | 0        | >\$5,000 HALLETTSVILLE  |
| REFUGIO  | 07/29/04   | GAS    | KINDER MORGAN                 |       | 0      | 0        | <\$5,000 REFUGIO        |
| REFUGIO  | 10/23/04   | LIQUID | KOCH PIPELINE CO              |       | 0      | 0        | >\$50,000 REFUGIO       |
| REFUGIO  | 02/21/05   | LIQUID | KOCH PIPELINE COMPANY, LP     |       | 0      | 0        | UNKNOWN TIVOLI          |
| REFUGIO  | 05/17/05   | LIQUID | EXXONMOBIL PIPELINE COMPANY   |       | 0      | 0        | \$0 TIVOLI              |
| REFUGIO  | 08/12/05   | LIQUID | UNKNOWN                       |       | 0      | 0        | UNKNOWN REFUGIO         |
| REFUGIO  | 09/24/06   | GAS    | NORTHERN NATURAL GAS          |       | 0      | 0        | UNKNOWN TIVOLI          |
| REFUGIO  | 04/14/07   | LIQUID | ENTERPRISE PRODUCTS           |       | 0      | 0        | UNKNOWN VICTORIA        |
|          |            | -      | NORTHERN NATURAL              | GAS   |        |          |                         |
| REFUGIO  | 08/10/07   | GAS    |                               |       | 0      | 0        | UNKNOWN TIVOLI          |
|          |            |        | COMPANY                       |       |        |          |                         |
| REFUGIO  | 07/19/08   | LIQUID | UNKNOWN                       |       | 0      | 0        | <\$50,000 REFUGIO       |
| REFUGIO  | 06/02/09   | LIQUID | UNKNOWN                       |       | 0      | 0        | \$5,000,000,000 REFUGIO |
| REFUGIO  | 11/13/09   | LIQUID | UNKNOWN                       |       | 0      | 0        | <\$50,000 REFUGIO       |
| VICTORIA | UNKNOWN GA |        | CROSSTEX ENERGY               |       | 0      | 0        | \$20,000 BLOOMINGTON    |
| VICTORIA | 10/25/04   | GAS    | CENTERPOINT ENERGY ENTEX      |       | 0      | 0        | UNKNOWN VICTORIA        |
| VICTORIA | 03/10/05   | GAS    | ENTERPRISE PRODUCTS OPERATING |       | 0      | 0        | <\$5,000 NURSERY        |
| VICTORIA | 03/13/05   | GAS    | CENTERPOINT ENERGY ENTEX      |       | 0      | 0        | <\$5,000 VICTORIA       |
| VICTORIA | 03/17/05   | LIQUID | CITGO PIPELINE                |       | 0      | 0        | UNKNOWN VICTORIA        |
| VICTORIA | 01/16/06   | GAS    | VICTORIA FIRE DEPARTMENT      |       | 0      | 0        | UNKNOWN VICTORIA        |
| VICTORIA | 05/04/06   | GAS    | CENTERPOINT ENERGY ENTEX      |       | 0      | 0        | <\$5,000 VICTORIA       |
|          |            |        | D&S LEASE SERVICE             | (HART |        |          | ,                       |
| VICTORIA | 07/02/06   | OG     |                               | `     | 0      | 0        | UNKNOWN VICTORIA        |
|          |            |        | PETOLEUM LEASE)               |       |        |          |                         |
| VICTORIA | 01/27/07   | GAS    | FUTURE GAS                    |       | 0      | 0        | UNKNOWN MCFADDIN        |
| VICTORIA | 03/13/07   | LIQUID | CITGO PRODUCTS PIPELINE       |       | 0      | 0        | UNKNOWN VICTORIA        |
| VICTORIA | 09/11/07   | GAS    | CROSSTEX ENERGY               |       | 0      | 0        | UNKNOWN MCFADDIN        |
| VICTORIA | 02/01/08   | GAS    | CENTERPOINT ENERGY ENTEX      |       | 0      | 0        | >\$50,000 VICTORIA      |
| VICTORIA | 04/02/08   | GAS    | UNKNOWN                       |       | 0      | 0        | <\$5,000 VICTORIA       |
| VICTORIA | 06/04/08   | GAS    | UNKNOWN                       |       | 0      | 0        | <\$50,000 VICTORIA      |
| VICTORIA | 06/24/08   | LIQUID | UNKNOWN                       |       | 0      | 0        | UNKNOWN VICTORIA        |
| VICTORIA | 07/19/08   | LIQUID | UNKNOWN                       |       | 0      | 0        | UNKNOWN VICTORIA        |
| VICTORIA | 02/27/10   | LIQUID | UNKNOWN                       |       | 0      | 0        | UNKNOWN VICTORIA        |
| WILSON   | 02/09/07   | GAS    | CENTERPOINT ENERGY ENTEX      |       | 0      | 0        | \$0 FLORESVILLE         |
| WILSON   | 12/05/07   | LPG    | MARSHALL PROPANE              |       | 0      | 6        | >\$5,000 NIXON          |
|          |            |        |                               |       |        |          |                         |

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## SECTION 15: PIPELINE FAILURE

## Probability of Future Occurrences

Based on the previous incident data and location of pipelines throughout the region, the possibility of a future occurrence is likely, meaning that an event could occur in the next three years.

# Impact and Vulnerability

Dipeline failure can have a substantial impact. Such events can cause multiple deaths, completely shut down facilities for thirty days or more, and cause more than fifty percent of affected properties to be destroyed or suffer major damage.

Table 15-3 and Table 15-4 are based on data from the Texas Railroad Commission and show the total number of people and buildings exposed to gas and oil pipeline ruptures, respectively. The analysis for gas pipelines consists of liquid petroleum gas (LPG) and natural gas (NG). The analysis for oil pipelines consists of crude oil (CRD) and natural gas liquids (NGL). The immediate (primary) area of impact for both types of pipeline accidents is a 500-meter buffer. The secondary area of impact for both types of pipeline accidents is a 2,500-meter buffer.

Table 15-3. Potential Impact Due to Gas Pipelines by Jurisdiction

|               | TOTAL    | TOTAL   |            | IMMEDIATE IMPACT |                    |            | SECONDARY IM | PACT               |
|---------------|----------|---------|------------|------------------|--------------------|------------|--------------|--------------------|
|               | POPULA   | BUILD-  |            | (500 METERS)     |                    |            | (2,500 MET   | ERS)               |
| JURISDICTION  | TION IN  | INGS IN | Number     | Number           |                    | Number     | Number       |                    |
|               |          |         |            |                  | Value of Buildings |            |              | Value of Buildings |
|               | JURISDIC | JURIS-  | People     | Buildings        |                    | People     | Buildings    |                    |
|               |          |         |            |                  | Exposed (\$)       |            |              | Exposed (\$)       |
|               | TION     | DICTION | Exposed    | Exposed          |                    | Exposed    | Exposed      |                    |
| Caldwell Co.  | 14,661   | 6,462   | 4,944      | 2,275            | \$220,481,000      | 8,871      | 3,998        | \$386,230,000      |
| Lockhart      | 11,591   | 4,217   | 4,484      | 1,239            | \$209,500,000      | 11,081     | 4,010        | \$599,465,000      |
| Luling        | 5,025    | 2,584   | 3,549      | 1,715            | \$183,244,000      | 5,025      | 2,584        | \$264,373,000      |
| Martindale    | 917      | 424     | Negligible | 0                | Negligible         | Negligible | 14           | \$4,849,000        |
| Calhoun Co.   | 8,541    | 6,463   | 4,092      | 2,940            | \$409,521,000      | 5,915      | 5,899        | \$696,161,000      |
| Point Comfort | 781      | 477     | 581        | 381              | \$108,781,000      | 781        | 477          | \$121,298,000      |
| Port Lavaca   | 12,035   | 5,489   | 762        | 334              | \$34,746,000       | 9,473      | 3,990        | \$490,796,000      |
| Seadrift      | 1,350    | 1,069   | Negligible | 27               | \$3,781,000        | 1,214      | 839          | \$57,555,000       |
| DeWitt Co.    | 8,805    | 5,417   | 6,333      | 2,777            | \$351,817,000      | 9,172      | 4,303        | \$523,970,000      |
| Cuero         | 6,544    | 3,824   | 2,465      | 478              | \$108,074,000      | 8,246      | 3,705        | \$445,559,000      |
| Nordheim      | 323      | 266     | 274        | 150              | \$19,004,000       | 473        | 266          | \$35,517,000       |
| Yoakum        | 5,729    | 3,306   | 911        | 518              | \$48,119,000       | 5,689      | 3,275        | \$368,441,000      |
| Yorktown      | 2,204    | 1,568   | 935        | 507              | \$47,553,000       | 2,698      | 1,568        | \$150,778,000      |
| Gonzales Co.  | 8,343    | 5,619   | 2,353      | 1,538            | \$114,617,000      | 3,910      | 2,565        | \$189,584,000      |

#### SECTION 15: PIPELINE FAILURE

| SECONDARY IMPACT                       | TOTAL         | TOTAL            | IMMEDIATE IMPACT |                |                    |                  |                  |  |
|--|---------------|------------------|------------------|----------------|--------------------|------------------|------------------|--|
|  | POPULA        | BUILD-           |                  | (500 METERS)   |                    |                  |                  |  |
| (2,500 METERS) JURISDICTION            | TION IN       | INGS IN          | Number           | Number         | Value of Buildings | Number           | Number           |  |
| Value of Buildings                     | JURISDIC      | JURIS-           | People           | Buildings      | Exposed (\$)       | People           | Buildings        |  |
| Exposed (\$) Gonzales                  | TION<br>7,160 | DICTION<br>3,636 | Exposed<br>1,478 | Exposed<br>700 | \$84,260,000       | Exposed<br>7,101 | Exposed<br>3,596 |  |
| \$397,921,000<br>Nixon<br>\$94,690,000 | 2,178         | 1,326            | Negligible       | 0              | Negligible         | 2,178            | 1,326            |  |
| Waelder<br>\$16,926,000                | 947           | 572              | Negligible       | 0              | Negligible         | 395              | 249              |  |
| Cibolo (Guadalupe<br>\$221,273,000     | 3,035         | 1,338            | 1,926            | 734            | \$151,541,000      | 3,035            | 1,338            |  |
| County) Kendall Co. \$675,621,000      | 17,618        | 8,189            | 4,721            | 2,036          | \$355,143,000      | 10,168           | 4,496            |  |
| Boerne<br>\$36,763,000                 | 6,125         | 3,016            | Negligible       | 0              | Negligible         | 297              | 161              |  |
| Refugio Co.<br>\$148,189,000           | 2,670         | 1,360            | 2,195            | 1,098          | \$126,752,000      | 2,667            | 1,349            |  |
| Austwell<br>\$28,397,000               | 192           | 176              | Negligible       | 0              | Negligible         | 192              | 176              |  |
| Bayside<br>\$26,026,000                | 360           | 304              | Negligible       | 0              | Negligible         | 360              | 304              |  |
| Refugio<br>\$186,843,000               | 2,920         | 1,805            | 2,254            | 1,328          | \$138,391,000      | 2,920            | 1,805            |  |
| Woodsboro<br>\$78,606,000              | 1,683         | 837              | Negligible       | 17             | \$1,480,000        | 1,686            | 837              |  |
| Victoria Co.<br>\$1,171,269,000        | 23,482        | 9,699            | 20,148           | 8,307          | \$1,018,746,000    | 23,407           | 9,671            |  |
| Victoria<br>\$3,793,993,000            | 60,606        | 24,412           | 28,685           | 10,803         | \$1,792,231,000    | 58,585           | 23,357           |  |
| 4<br>TOTALS<br>\$11,211,093,000        | 213,765       | 103,855          | 93,144           | 39,902         | \$5,527,782,000    | 185,548          | 86,158           |  |

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Table 15-4. Potential Impact Due to Oil Pipelines by Jurisdiction TAL IMMEDIATE IMPACT TOTAL SECONDARY IMPACT TOTAL POPULA-(500 METERS) (2,500 METERS) BUILDINGS JURISDICTION TION IN Value of Number Number Number Number Value of IN JURIS-Buildings Buildings JURIS-Buildings People People Buildings DICTION DICTION Exposed Exposed Exposed Exposed Exposed Exposed Caldwell Co. 14,661 6,462 5,108 2,219 \$207,861,000 8,097 3,513 \$330,166,000 Lockhart 11,591 4,217 Negligible 14 \$1,174,000 676 263 \$39,810,000 Luling \$264,373,000 Martindale 5,025 2,584 2,707 1,397 \$151,366,000 5,025 2,584 917 424 917 424 \$40,522,000 917 424 \$40,522,000 \$153,075,000 4,135 3,853 Calhoun Co. \$486,934,000 8,541 1,718 915 6,463 Point Comfort \$85,232,000 Port Lavaca 781 477 596 387 \$110,085,000 362 233 12,035 5,489 2,612 1,243 \$180,751,000 10,618 4,633 \$552,209,000 \$6,259,000 1,477 1,024 Seadrift 1,350 1,069 69 56 \$67,812,000 \$67,812,00 DeWitt Co. Negligible 8,805 5,417 Negligible 0 Negligible Negligible Cuero 6,544 Negligible Negligible Negligible 3,824

Totals for the study area may include values less than \$5,000 for dollar amounts and less than 50 for populations that are classified as "Negligible" in the table.

| 0 Negligible                        |         |         |            |        |                 |            |        |
|-------------------------------------|---------|---------|------------|--------|-----------------|------------|--------|
| Nordheim                            | 323     | 266     | Negligible | 0      | Negligible      | Negligible |        |
| 0 Negligible                        |         |         | 88         |        | 88              |            |        |
| Yoakum                              | 5,729   | 3,306   | Negligible | 0      | Negligible      | Negligible |        |
| 0 Negligible                        |         |         |            |        |                 |            |        |
| Yorktown                            | 2,204   | 1,568   | Negligible | 0      | Negligible      | Negligible |        |
| 0 Negligible                        |         |         |            |        |                 |            |        |
| Gonzales Co.                        | 8,343   | 5,619   | 1,868      | 1,040  | \$111,340,000   | 3,460      | 2,242  |
| \$194,858,000                       | 7.460   | 2 424   | 7.460      | 2 626  | 4404 705 000    | 7.460      | 2 525  |
| Gonzales<br>\$401,785,000           | 7,160   | 3,636   | 7,160      | 3,636  | \$401,785,000   | 7,160      | 3,636  |
| %1,785,000<br>Nixon                 | 2,178   | 1,326   | Negligible | 0      | Negligible      | 1,821      | 1,157  |
| \$75,870,000                        | 2,176   | 1,320   | Megiigibie | · ·    | Megiigible      | 1,021      | 1,157  |
| Waelder                             | 947     | 572     | 947        | 572    | \$37,972,000    | 947        | 572    |
| \$37,972,000                        |         | *       |            |        | **· ,-· -,-·    |            |        |
| Cibolo                              |         |         |            |        |                 |            |        |
| (Guadalupe                          | 3,035   | 1,338   | Negligible | 0      | Negligible      | Negligible |        |
| 0 Negligible                        |         |         |            |        |                 |            |        |
| County)                             |         |         |            |        |                 |            |        |
| Kendall Co.                         | 17,618  | 8,189   | Negligible | 0      | Negligible      | Negligible |        |
| 0 Negligible                        | - 40-   | 2 24 5  |            | •      |                 |            |        |
| Boerne<br>0 Negligible              | 6,125   | 3,016   | Negligible | 0      | Negligible      | Negligible |        |
| <pre>0 Negligible Refugio Co.</pre> | 2,670   | 1,360   | 1,220      | 649    | \$74,514,000    | 2,068      | 1,065  |
| \$113,495,000                       | 2,070   | 1,500   | 1,220      | 049    | \$74,514,000    | 2,000      | 1,005  |
| Austwell                            | 192     | 176     | 192        | 176    | \$28,397,000    | 192        | 176    |
| \$28,397,000                        |         |         |            |        | , ,             |            |        |
| Bayside                             | 360     | 304     | Negligible | 27     | \$3,216,000     | 279        | 240    |
| \$20,668,000                        |         |         |            |        |                 |            |        |
| Refugio                             | 2,920   | 1,805   | 126        | 108    | \$7,564,000     | 1,957      | 1,296  |
| \$127,492,000                       |         |         |            |        |                 |            |        |
| Woodsboro                           | 1,683   | 837     | 461        | 211    | \$18,121,000    | 1,686      | 837    |
| \$78,606,000                        | 22.422  | 0.500   |            | 2 224  | 4404 404 000    | 0.000      | 2 455  |
| Victoria Co.                        | 23,482  | 9,699   | 4,841      | 2,024  | \$194,184,000   | 8,828      | 3,655  |
| \$392,540,000<br>Victoria           | 60,606  | 24,412  | Negligible | 0      | Negligible      | 2,867      | 1,116  |
| \$106,593,000                       | 60,606  | 24,412  | Megiigibie | U      | Megiigibie      | 2,007      | 1,110  |
| ¥100,333,000                        |         |         |            |        |                 |            |        |
| 5                                   |         |         |            |        |                 |            |        |
| TOTALS                              | 213,765 | 103,855 | 32,751     | 16,424 | \$1,822,876,000 | 62,572     | 32,519 |
| \$3,445,334,000                     |         |         |            |        |                 |            |        |

Totals for the study area may include values less than \$5,000 for dollar amounts and less than 50 for populations (where applicable) that are classified as "Negligible" in the table.

Hazard Mitigation Plan Update | 2011-2016

#### Wikipedia, the free encyclopedia

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http://en.wikipedia.org/wiki/Oil pipeline December 07, 2014

... of the products based on pre-calculated absorption rates. ... Oil and gas pipelines also figure prominently in the ... 6B crude oil pipeline failure in ...

Pipeline transport is the transportation of goods through a pipe. Liquids and gases are transported in pipelines and any chemically stable substance can be sent through a pipeline. [citation needed] Pipelines exist for the transport of crude and refined petroleum, fuels - such as oil, natural gas and biofuels - and other fluids including sewage, slurry, water, and beer. Pipelines are useful for transporting water for drinking or irrigation over long distances when it needs to move over hills, or where canals or channels are poor choices due to considerations of evaporation, pollution, or environmental impact. Pneumatic tubes using compressed air can be used to transport solid capsules.

Oil pipelines are made from steel or plastic tubes which are usually buried. The oil is moved through the pipelines by pump stations along the pipeline. Natural gas (and similar gaseous fuels) are lightly pressurised into liquids knows as Natural Gas Liquids (NGLs). Natural gas pipelines are constructed of carbon steel. Highly toxic ammonia is theoretically the most dangerous substance to be transported through long-distance pipelines, but accidents have been rare. Hydrogen pipeline transport is the transportation of hydrogen through a pipe. District heating or teleheating systems use a network of insulated pipes which transport heated water, pressurized hot water or sometimes steam to the customer.

Pipelines conveying flammable or explosive material, such as natural gas or oil, pose special safety concerns and there have been various accidents. Pipelines can be the target of vandalism, sabotage, or even terrorist attacks. In war, pipelines are often the target of military attacks.

It is uncertain when the first crude oil pipeline was built. Credit for the development of pipeline transport is disputed, with competing claims for Vladimir Shukhov and the Branobel company in the late 19th century, and the Oil Transport Association, which first constructed a 2-inch (51 mm) wrought iron pipeline over a 6-mile (9.7 km) track from an oil field in Pennsylvania to a railroad station in Oil Creek, in the 1860s. Pipelines are generally the most economical way to transport large quantities of oil, refined oil products or natural gas over land.

Natural gas (and similar gaseous fuels) are lightly pressurized into liquids knows as Natural Gas Liquids (NGLs). Small NGL processing facilities can be located in oil fields so the butane and propane liquid under light pressure of 125 pounds per square inch (860 kPa), can be shipped by rail, truck or pipeline. Propane can be used as a fuel in oil fields to heat various facilities used by the oil drillers or equipment and trucks used in the oil patch. EG: Propane will convert from a gas to a liquid under light pressure under 40 psi (280 kPa), give or take depending on temperature, and is pumped into cars and trucks at less than 125 psi (860 kPa) at retail stations. Pipelines and rail cars use about double that pressure to pump at 250 psi (1,700 kPa).

The distance to ship propane to markets is much shorter as thousands of NGL processing plants are located in oil fields or close by when a number of pipelines tie into each other from various relatively close fields. Many Bakken Basin oil companies in North Dakota, Montana, Manitoba and Saskatchewan gas fields separate the NGL's in the field, allowing the drillers to sell propane directly to small wholesalers, eliminating the large refinery control of product and prices for propane or butane.

The most recent major pipeline to start operating in North America, is a TransCanada natural gas line going north across the Niagara region bridges with Marcellus shale gas from Pennsylvania and others tied in methane or natural gas sources, into the Canadian province of Ontario as of the fall of 2012, supplying 16 percent of all the natural gas used in Ontario.

This new US supplied natural gas displaces the natural gas formerly shipped to Ontario from western Canada in Alberta and Manitoba, thus dropping the government regulated pipeline shipping charges because of the significantly shorter distance from gas source to consumer. Compared to shipping by railroad, pipelines have lower cost per unit and higher capacity. Pipelines are preferable to transportation by truck for a number of reasons.

Employment on completed pipelines represents only "1% of that of the trucking industry."[1]

To avoid delays and US government regulation, many small, medium and large oil producers in North Dakota have decided to run an oil pipeline north to Canada to meet up with a Canadian oil pipeline shipping oil from west to east. This allows the Bakken Basin and Three Forks oil producers to get higher negotiated prices for their oil because they will not be restricted to just one wholesale market in the US. The distance from the biggest oil patch in North Dakota, is Williston, North Dakota, only about 85 miles or 137 kilometers to the Canadian border and Manitoba. Mutual funds and joint ventures are big investors in new oil and gas pipelines. In the fall of 2012, the US began exporting propane to Europe, known as LPG, as wholesale prices there are much higher than in North America.

As more North American pipelines are built, even more exports of LNG, propane, butane, and other natural gas products will occur on all three US coasts. To give insight, North Dakota's oil production has grown to 5 times in late 2012 compared to what it was just 6 years ago creating thousands of good paying long term jobs[citation needed]. North Dakota oil companies are shipping huge amounts of oil by tanker rail car as they can direct the oil to the market that gives the best price but pipelines are cheaper. Rail cars can be used to avoid a congested oil pipeline to get the oil to a different pipeline and get the oil to market faster and different less busy oil refineries.

Enbridge in Canada applying to reverse an oil pipeline going from east-to-west (Line 9) and expanding it and using it to ship western Canadian bitumen oil eastward.[2] From a presently rated 250,000 barrels equivalent per day pipeline, it will be expanded to between one million to 1.3 million barrels per day. It will bring western oil to refineries in Ontario, Michigan, Ohio, PA, Quebec and New York by early 2014. New Brunswick will also refine some of this western Canadian crude and export some crude and refined oil to Europe from its deep water oil ULCC loading port.

Although pipelines can be built under the sea, that process is economically and technically demanding, so the majority of oil at sea is transported by tanker ships.

The market size for oil and gas pipeline construction experienced tremendous growth prior to the economic downturn in 2008. The industry grew from \$23 billion in 2006 to \$39 billion in 2008.[3] After faltering in 2009, demand for pipeline expansion and updating increased the following year as energy production grew.[4] By 2012, almost 32,000 miles of North American pipeline were being planned or under construction.[5]

Oil pipelines are made from steel or plastic tubes with inner diameter typically from 4 to 48 inches (100 to 1,220 mm). Most pipelines are typically buried at a depth of about 3 to 6 feet (0.91 to 1.83 m). To protect pipes from impact, abrasion, and corrosion, a variety of methods are used. These can include wood lagging (wood slats), concrete coating, rockshield, high-density polyethylene, imported sand padding, and padding machines.[6]

The oil is kept in motion by pump stations along the pipeline, and usually flows at speed of about 1 to 6 metres per second (3.3 to 19.7 ft/s). Multi-product pipelines are used to transport two or more different products in sequence in the same pipeline. Usually in multi-product pipelines there is no physical separation between the different products. Some mixing of adjacent products occurs, producing interface, also known in the industry as "transmix." At the receiving facilities this interface is usually absorbed in one of the products based on pre-calculated absorption rates. Alternately, transmix may be diverted and shipped to facilities for separation of the commingled products.[7]

Crude oil contains varying amounts of paraffin wax and in colder climates wax buildup may occur within a pipeline. Often these pipelines are inspected and cleaned using pigging, the practice of using devices known as "pigs" to perform various maintenance operations on a pipeline. The devices are also known as "scrapers" or "Go-devils". "Smart pigs" (also known as "intelligent" or "intelligence" pigs) are used to detect anomalies in the pipe such as dents, metal loss caused by corrosion, cracking or other mechanical damage.[8] These devices are launched from pig-launcher stations and travel through the pipeline to be received at any other station down-stream, either cleaning wax deposits and material that may have accumulated inside the line or inspecting and recording the condition of the line.

For natural gas, pipelines are constructed of carbon steel and vary in size from 2 to 60 inches (51 to 1,524 mm) in diameter, depending on the type of pipeline. The gas is pressurized by compressor stations and is odorless unless mixed with a mercaptan odorant where required by a regulating authority.

Highly toxic ammonia is theoretically the most dangerous substance to be transported through long-distance pipelines. [citation needed] However, incidents on ammonia-transporting lines are uncommon - unlike on industrial ammonia-processing equipment. [citation needed] A major ammonia pipeline is the Ukrainian Transammiak line connecting the TogliattiAzot facility in Russia to the exporting Black Sea-port of Odessa.

Pipelines have been used for transportation of ethanol in Brazil, and there are several ethanol pipeline projects in Brazil and the United States.[9] The main problems related to the transport of ethanol by pipeline are its corrosive nature and tendency to absorb water and impurities in pipelines, which are not problems with oil and natural gas.[9][10] Insufficient volumes and cost-effectiveness are other considerations limiting construction of ethanol pipelines.[10][11]

Slurry pipelines are sometimes used to transport coal or ore from mines. The material to be transported is closely mixed with water before being introduced to the pipeline; at the far end, the material must be dried. One example is a 525-kilometre (326 mi) slurry pipeline which is planned to transport iron ore from the Minas-Rio mine (producing 26.5 million tonnes per year) to a port at Açu in Brazil.[12] An existing example is the 85-kilometre (53 mi) Savage River Slurry pipeline in Tasmania, Australia, possibly the world's first when it was built in 1967. It includes a 366-metre (1,201 ft) bridge span at 167 metres (548 ft) above the Savage River.[13][14]

Hydrogen pipeline transport is a transportation of hydrogen through a pipe as part of the hydrogen infrastructure. Hydrogen pipeline transport is used to connect the point of hydrogen production or delivery of hydrogen with the point of demand, with transport costs similar to CNG,[15] the technology is proven.[16] Most hydrogen is produced at the place of demand with every 50 to 100 miles (160 km) an industrial production facility.[17] The 1938 Rhine-Ruhr 240-kilometre (150 mi) hydrogen pipeline is still in operation.[18] As of 2004, there are 900 miles (1,400 km) of low pressure hydrogen pipelines in the US and 930 miles (1,500 km) in Europe.

Two millennia ago, the ancient Romans made use of large aqueducts to transport water from higher elevations by building the aqueducts in graduated segments that allowed gravity to push the water along until it reached its destination. Hundreds of these were built throughout Europe and elsewhere, and along with flour mills were considered the lifeline of the Roman Empire. The ancient Chinese also made use of channels and pipe systems for public works. The famous Han Dynasty court eunuch Zhang Rang (d. 189 AD) once ordered the engineer Bi Lan to construct a series of square-pallet chain pumps outside the capital city of Luoyang.[19] These chain pumps serviced the imperial palaces and living quarters of the capital city as the water lifted by the chain pumps was brought in by a stoneware pipe system.[19][20]

Pipelines are useful for transporting water for drinking or irrigation over long distances when it needs to move over hills, or where canals or channels are poor choices due to considerations of evaporation, pollution, or environmental impact.

The 530 km (330 mi) Goldfields Water Supply Scheme in Western Australia using 750 mm (30 inch) pipe and completed in 1903 was the largest water supply scheme of its time.[21][22]

Examples of significant water pipelines in South Australia are the Morgan-Whyalla pipelne (completed 1944) and Mannum-Adelaide (completed 1955) pipelines, both part of the larger Snowy Mountains scheme.[23]

There are two Los Angeles, California aqueducts, the Owens Valley aqueduct (completed 1913) and the Second Los Angeles Aqueduct (completed 1970) which also include extensive use of pipelines.

The Great Manmade River of Libya supplies 3,680,000 cubic metres (4,810,000 cu yd) of water each day to Tripoli, Benghazi, Sirte, and several other

cities in Libya. The pipeline is over 2,800 kilometres (1,700 mi) long, and is connected to wells tapping an aquifer over 500 metres (1,600 ft) underground.[24]

District heating or teleheating systems consist of a network of insulated feed and return pipes which transport heated water, pressurized hot water or sometimes steam to the customer. While steam is hottest and may be used in industrial processes due to its higher temperature, it is less efficient to produce and transport due to greater heat losses. Heat transfer oils are generally not used for economic and ecological reasons. The typical annual loss of thermal energy through distribution is around 10%, as seen in Norway's district heating network.[26]

District heating pipelines are normally installed underground, with some exceptions. Within the system, heat storage may be installed to even out peak load demands. Heat is transferred into the central heating of the dwellings through heat exchangers at heat substations, without mixing of the fluids in either system.

Bars in the Veltins-Arena, a major football ground in Gelsenkirchen, Germany, are interconnected by a 5-kilometre (3.1 mi) long beer pipeline. In Randers city in Denmark, the so-called Thor Beer pipeline was operated. Originally, copper pipes ran directly from the brewery, but when the brewery moved out of the city in the 1990s, Thor Beer replaced it with a giant tank.

A beer pipeline has been proposed for construction in Bruges, Belgium to reduce truck traffic on the city streets.[27]

The village of Hallstatt in Austria, which is known for its long history of salt mining, claims to contain "the oldest industrial pipeline in the world", dating back to 1595.[28] It was constructed from 13,000 hollowed-out tree trunks to transport brine 40 kilometres (25 mi) from Hallstatt to Ebensee.[29]

Between 1978 and 1994, a 15 km milk pipeline ran between the Dutch island of Ameland and Holwerd on the mainland, of which 8 km beneath the Wadden Sea. Every day, 30.000 litres of milk produced on the island were transported to be processed on the mainland. In 1994, the milk transport was abandoned.[30]

In places, a pipeline may have to cross water expanses, such as small seas, straits and rivers.[31] In many instances, they lie entirely on the seabed. These pipelines are referred to as "marine" pipelines (also, "submarine" or "offshore" pipelines). They are used primarily to carry oil or gas, but transportation of water is also important.[31] In offshore projects, a distinction is made between a "flowline" and a pipeline.[31][32][33] The former is an intrafield pipeline, in the sense that it is used to connect subsea wellheads, manifolds and the platform within a particular development field. The latter, sometimes referred to as an "export pipeline", is used to bring the resource to shore.[32] The construction and maintenance of marine pipelines imply logistical challenges that are different from those onland, mainly because of wave and current dynamics, along with other geohazards.

In general, pipelines can be classified in three categories depending on purpose:

When a pipeline is built, the construction project not only covers the civil engineering work to lay the pipeline and build the pump/compressor stations, it also has to cover all the work related to the installation of the field devices that will support remote operation.

The pipeline is routed along what is known as a "right of way". Pipelines are generally developed and built using the following stages:

Russia has "Pipeline Troops" as part of the Rear Services, who are trained to build and repair pipelines. Russia is the only country to have Pipeline Troops.[35]

Field devices are instrumentation, data gathering units and communication systems. The field Instrumentation includes flow, pressure and temperature gauges/transmitters, and other devices to measure the relevant data required. These instruments are installed along the pipeline on some specific locations, such as injection or delivery stations, pump stations (liquid pipelines) or compressor stations (gas pipelines), and block valve stations

The information measured by these field instruments is then gathered in local Remote Terminal Units (RTU) that transfer the field data to a central location in real time using communication systems, such as satellite channels, microwave links, or cellular phone connections.

Pipelines are controlled and operated remotely, from what is usually known as the "Main Control Room". In this center, all the data related to field measurement is consolidated in one central database. The data is received from multiple RTUs along the pipeline. It is common to find RTUs installed at every station along the pipeline.

The SCADA system at the Main Control Room receives all the field data and presents it to the pipeline operator through a set of screens or Human Machine Interface, showing the operational conditions of the pipeline. The operator can monitor the hydraulic conditions of the line, as well as send operational commands (open/close valves, turn on/off compressors or pumps, change setpoints, etc.) through the SCADA system to the field.

To optimize and secure the operation of these assets, some pipeline companies are using what is called "Advanced Pipeline Applications", which are software tools installed on top of the SCADA system, that provide extended functionality to perform leak detection, leak location, batch tracking (liquid lines), pig tracking, composition tracking, predictive modeling, look ahead modeling, operator training and more.

Pipeline networks are composed of several pieces of equipment that operate together to move products from location to location. The main elements of a pipeline system are:

Since oil and gas pipelines are an important asset of the economic development of almost any country, it has been required either by government regulations or internal policies to ensure the safety of the assets, and the population and environment where these pipelines run.

Pipeline companies face government regulation, environmental constraints and social situations. Government regulations may define minimum staff to run the operation, operator training requirements; pipeline facilities, technology and applications required to ensure operational safety. For example, in the State of Washington it is mandatory for pipeline operators to be able to detect and locate leaks of 8 percent of maximum flow within fifteen minutes or less. Social factors also affect the operation of pipelines. In third world countries, product theft is a problem for pipeline companies. It is common to find unauthorized extractions in the middle of the pipeline. In this case, the detection levels should be under two percent of maximum flow, with a high expectation for location accuracy.

Various technologies and strategies have been implemented for monitoring pipelines, from physically walking the lines to satellite surveillance. The most common technology to protect pipelines from occasional leaks is Computational Pipeline Monitoring or CPM. CPM takes information from the field related to pressures, flows, and temperatures to estimate the hydraulic behavior of the product being transported. Once the estimation is completed, the results are compared to other field references to detect the presence of an anomaly or unexpected situation, which may be related to a leak.

The American Petroleum Institute has published several articles related to the performance of CPM in liquids pipelines, the API Publications are:

As a rule pipelines for all uses are laid in most cases underground. [citation needed] However in some cases it is necessary to cross a valley or a river on a pipeline bridge. Pipelines for centralized heating systems are often laid on the ground or overhead. Pipelines for petroleum running through permafrost areas as Trans-Alaska-Pipeline are often run overhead in order to avoid melting the frozen ground by hot petroleum which would result in sinking the pipeline in the ground.

Maintenance of pipelines includes checking cathodic protection levels for the proper range, surveillance for construction, erosion, or leaks by foot,

land vehicle, boat, or air, and running cleaning pigs, when there is anything carried in the pipeline that is corrosive.

US pipeline maintenance rules are covered in Code of Federal Regulations(CFR) sections, 49 CFR 192 for natural gas pipelines, and 49 CFR 195 for petroleum liquid pipelines.

In the US, onshore and offshore pipelines used to transport oil and gas are regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA). Certain offshore pipelines used to produce oil and gas are regulated by the Minerals Management Service (MMS). In Canada, pipelines are regulated by either the provincial regulators or, if they cross provincial boundaries or the Canada/US border, by the National Energy Board (NEB). Government regulations in Canada and the United States require that buried fuel pipelines must be protected from corrosion. Often, the most economical method of corrosion control is by use of pipeline coating in conjunction with cathodic protection and technology to monitor the pipeline. Above ground, cathodic protection is not an option. The coating is the only external protection.

Pipelines for major energy resources (petroleum and natural gas) are not merely an element of trade. They connect to issues of geopolitics and international security as well, and the construction, placement, and control of oil and gas pipelines often figure prominently in state interests and actions. A notable example of pipeline politics occurred at the beginning of the year 2009, wherein a dispute between Russia and Ukraine ostensibly over pricing led to a major political crisis. Russian state-owned gas company Gazprom cut off natural gas supplies to Ukraine after talks between it and the Ukrainian government fell through. In addition to cutting off supplies to Ukraine, Russian gas flowing through Ukraine—which included nearly all supplies to Southeastern Europe and some supplies to Central and Western Europe—was cut off, creating a major crisis in several countries heavily dependent on Russian gas as fuel. Russia was accused of using the dispute as leverage in its attempt to keep other powers, and particularly the European Union, from interfering in its "near abroad".

Oil and gas pipelines also figure prominently in the politics of Central Asia and the Caucasus.

Because the solvent fraction of dilbit typically comprises volatile aromatics like naptha and benzene, reasonably rapid carrier vaporization can be expected to follow an above-ground spill—ostensibly enabling timely intervention by leaving only a viscous residue that is slow to migrate. Effective protocols to minimize exposure to petrochemical vapours are well-established, and oil spilled from the pipeline would be unlikely to reach the aquifer unless incomplete remediation were followed by the introduction of another carrier (e.g. a series of torrential downpours).

The Keystone XL extension is designed to be buried under four feet of soil, which will hinder post-spill vaporization of the carrier fraction. Diluent and bitumen will migrate at different rates, depending on the temperature- and composition of the surrounding soils, but separation will take place more slowly as the aromatics diffuse through sediment rather than through air.

The introduction of benzene and other volatile organic compounds (collectively BTEX) to the subterranean environment compounds the threat posed by a pipeline leak. Particularly if followed by rain, a pipeline breach would result in BTEX dissolution and equilibration of benzene in water, followed by percolation of the admixture into the aquifer. Benzene can cause many health problems and is carcinogenic with EPA Maximum Contaminant Level (MCL) set at 5 µg/L for potable water.[36] Although it is not well studied, single benzene exposure events have been linked to acute carcinogenesis. [37] Additionally, the exposure of livestock, mainly cattle, to benzene has been shown to cause many health issues, such as neurotoxicity, fetal damage and fatal poisoning.[38]

The entire surface of an above-ground pipeline can be directly examined for material breach. Pooled petroleum is unambiguous, readily spotted, and indicates the location of required repairs. Because the effectiveness of remote inspection is limited by the cost of monitoring equipment, gaps between sensors, and data that requires interpretation, leaks in buried pipe are more likely to go undetected

Pipeline developers do not always prioritize effective surveillance against leaks. Buried pipes draw fewer complaints. They are insulated from extremes in ambient temperature, they are shielded from ultraviolet rays, and they are less exposed to photodegradation. Buried pipes are isolated from airborne debris, electrical storms, tornadoes, hurricanes, hail, and acid rain. They are protected from nesting birds, rutting mammals, and wayward buckshot. Buried pipe is less vulnerable to accident damage (e.g. automobile collisions) and less accessible to vandals, saboteurs, and terrorists

Previous work[39] has shown that a 'worst-case exposure scenario' can be limited to a specific set of conditions. Based on the advanced detection methods and pipeline shut-off SOP developed by TransCanada, the risk of a substantive or large release over a short period of time contaminating groundwater with benzene is unlikely.[40] Detection, shutoff, and remediation procedures would limit the dissolution and transport of benzene. Therefore the exposure of benzene would be limited to leaks that are below the limit of detection and go unnoticed for extended periods of time.[39] Leak detection is monitored through a SCADA system that assesses pressure and volume flow every 5 seconds. A pinhole leak that releases small quantities that cannot be detected by the SCADA system (<1.5% flow) could accumulate into a substantive spill.[40] Detection of pinhole leaks would come from a visual or olfactory inspection, aerial surveying, or mass-balance inconsistencies.[40] It is assumed that pinhole leaks are discovered within the 14 day inspection interval, however snow cover and location (e.g. remote, deep) could delay detection. Benzene typically makes up 0.1 – 1.0% of oil and will have varying degrees of volatility and dissolution based on environmental factors.

Even with pipeline leak volumes within SCADA detection limits, sometimes pipeline leaks are misinterpreted by pipeline operators to be pump malfunctions, or other problems. The Enbridge Line 6B crude oil pipeline failure in Marshall, Michigan on July 25, 2010 was thought by operators in Edmonton to be from column separation of the dilbit in that pipeline. The leak in wetlands along the Kalamazoo River was only confirmed 17 hours after it happened by a local gas company employee in Michigan.

Although the Pipeline and Hazardous Materials Safety Administration (PHMSA) has standard baseline incident frequencies to estimate the number of spills, TransCanada altered these assumptions based on improved pipeline design, operation, and safety.[40] Whether these adjustments are justified is debatable as these assumptions resulted in a nearly 10-fold decrease in spill estimates.[39] Given that the pipeline crosses 247 miles of the Ogallala Aquifer,[41] or 14.5% of the entire pipeline length, and the 50-year life of the entire pipeline is expected to have between 11 – 91 spills,[39] approximately 1.6 – 13.2 spills can be expected to occur over the aquifer. An estimate of 13.2 spills over the aquifer, each lasting 14 days, results in 184 days of potential exposure over the 50 year lifetime of the pipeline. In the reduced scope 'worst case exposure scenario,' the volume of a pinhole leak at 1.5% of max flow-rate for 14 days has been estimated at 189,000 barrels or 7.9 million gallons of oil.[39] According to PHMSA's incident database,[42] only 0.5% of all spills in the last 10 years were >10,000 barrels.

Benzene is considered a light aromatic hydrocarbon with high solubility and high volatility. [clarification needed] It is unclear how temperature and depth would impact the volatility of benzene, so assumptions have been made that benzene in oil (1% weight by volume) would not volatilize before equilibrating with water.[39] Using the octanol-water partition coefficient and a 100-year precipitation event for the area, a worst-case estimate of 75 mg/L of benzene is anticipated to flow toward the aquifer.[39] The actual movement of the plume through groundwater systems is not well described, although one estimate is that up to 4.9 billion gallons of water in the Ogallala Aquifer could become contaminated with benzene at concentrations above the MCL.[39] The Final Environmental Impact Statement from the State Department does not include a quantitative analysis because it assumed that most benzene will volatilize.[40]

One of the major concerns about dilbit is the difficulty in cleaning it up.[43] Enbridge's Line 6B, a 30 inch crude oil pipeline, ruptured in Marshall, Michigan on July 25, 2010, mentioned above, spilled at least 843,000 gallons of dilbit.[44] After detection of the leak, booms and vacuum trucks were deployed. Heavy rains caused the river to overtop existing dams, and carried dilbit 30 miles downstream before the spill was contained. Remediation work collected over 1.1 million gallons of oil and almost 200,000 cubic yards of oil-contaminated sediment and debris from the Kalamazoo River system. However, oil was still being found in affected waters in October 2012.[45]

Pipelines conveying flammable or explosive material, such as natural gas or oil, pose special safety concerns.

Pipelines can be the target of vandalism, sabotage, or even terrorist attacks. In war, pipelines are often the target of military attacks, as destruction of pipelines can seriously disrupt enemy logistics.

# 🔼 4. Trends in Natural Gas Transportation Rates

http://www.eia.gov/pub/oil\_gas/natural\_gas/analysis\_publications/energy\_policy\_act\_transportation\_study/pdf/epactch4.pdf December 07, 2014

This chapter discusses trends in natural gas transportation rates delivered. ... Office of Oil and Gas, derived from: ... Pipeline Transportation Rates

4. Trends in Natural Gas Transportation Rates

This chapter discusses trends in natural gas transportation rates for the period 1988 through 1994 and how Federal regulations and policies affect those trends.55 Regulatory reform, new legislation, and restructuring in the natural gas industry have expanded options for sellers and buyers of natural gas, resulting in increased competition within the industry. Buyers now have more choices for purchasing gas, and ancillary services such as pipeline transmission and storage rights. Suppliers have a wider range of prospective customers and greater flexibility in setting the terms of sale. This competition has contributed to higher gas throughput on the interstate pipeline system and lower average transmission prices (Figure 9).56 From 1988 through 1994, deliveries to end users increased 16 percent, while average transmission markups declined 16 percent, from \$1.49 to \$1.25 per thousand cubic feet. In the face of increasing competition, many segments of the industry have become more efficient and reduced costs, to the general benefit of consumers.

Natural gas consumers have benefited in two ways. First, the wellhead price of natural gas, effectively the price of the commodity itself, has declined substantially. Between 1988 and 1994, the average wellhead price of natural gas, in real terms, fell 11 percent, from \$2.05 to \$1.83 per thousand cubic feet. Average prices paid by some customer classes, specifically onsystem industrial and electric utility customers, have declined even more than the decline in the wellhead price, indicating that additional benefits have been obtained from lower costs of transmission and other delivery services. Residential and commercial customers, who for the most part obtain all of their service from local distribution companies, have not experienced significant reductions in the costs of service beyond the decrease in wellhead prices. Although these customers have paid less for transmission, distribution costs have increased resulting in little overall change.

In total, EIA estimates that consumers paid almost \$6.5 billion (9 percent) less, in real terms, for natural gas service (including wellhead purchases combined with transmission and distribution charges) in 1994 than they would have in 1988. This estimate includes \$2.5 billion in reduced transmission and distribution charges and \$4 billion of savings resulting from the 11-percent reduction in wellhead prices since 1988. The bulk of the \$2.5 billion represents the reduction in the fixed costs of transmission and distribution that do not vary with the volumes

All rates and prices are quoted in terms of real 1994 dollars.

The transmission markup is calculated as the difference between the average citygate price and the average wellhead price. The transmission price (or markup) represents the average price paid for all services required to move gas from the wellhead to the local distributor. The data reflect the prices paid for gas sales services provided by LDC's only.

delivered. Because of data limitations, the estimate of total savings may be low because for offsystem industrial customers only the savings in wellhead prices are included. However, of the \$6.5 billion savings, industrial customers were the main beneficiaries, receiving over half of the savings (\$3.8 billion), while electric utilities and commercial customers each saw savings of \$1.4 billion.

Another way to estimate savings is to compare the average price per thousand cubic feet to each end-use sector in 1994 and 1988. This method assumes that transmission and distribution costs would vary with the volumes delivered. In 1994, the price of 1 thousand cubic feet of gas (wellhead price plus delivery charges) to the end-use sectors was between 3 and 19 percent less than 1988 levels. The differential in savings stems from the range of prices different customer groups pay for natural gas deliveries. The prices are based on a number of elements, particularly the level and quality of service required.

The analysis in this chapter focuses only on the costs associated with the delivery of natural gas from the wellhead to the end user. Interstate pipeline companies transport gas from the supply areas to serve some customers directly, but much of the gas they transport is to the "citygate" of a local distribution company (LDC). LDC's then provide the distribution and other services needed to supply homeowners, commercial establishments, and other customers. The interstate pipeline companies are regulated at the Federal level, and the extensive regulatory changes caused by Orders 436 and 636 have directly affected the rates they charge. LDC's are regulated at the State level, and while some changes are being made at the State level comparable to the Federal level, there have not been extensive changes to date.

As discussed in Chapter 1, there are no publicly available data series on the actual prices paid by shippers on interstate pipeline companies. The information available relates only to the tariff rates (maximum rates) authorized by the Federal Energy Regulatory Commission (FERC). The analysis of transportation rates in this chapter uses several approaches, both qualitative and quantitative, to illustrate how transmission costs have been affected by legislative and regulatory changes. Sections of the chapter address:

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates
Figure 9. Indices of Natural Gas Transmission Markups and Deliveries to End Users, 1988-1994

Sources: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Historical Monthly Energy Review 1973-1992 (August 1994). 1989-1994: Natural Gas Monthly (August 1995).

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- ! Factors affecting interstate transportation rates. To understand how changes in laws and regulations can affect transportation rates, it is useful to look first at how rates are structured. This section first describes some of the key determinants used to develop interstate transmission rates and how economic and regulatory changes between 1988 and 1994 have affected the calculation of the rates. In addition, as the restructuring of the industry proceeded over the period addressed by this study, FERC implemented mechanisms for companies to recover costs associated with the restructuring, such as reformation of contracts, stranded investments, and other transition costs. Finally, the effect of the more competitive environment on rates charged by pipeline companies is briefly addressed.
- ! Trends in maximum rates for selected interstate corridors (Corridor Rate Analysis). Some indication of the overall movement in transportation rates over time can be obtained from looking at changes in the maximum rates charged by pipeline companies. This section looks at rates for 16 pipeline companies along 14 corridors. However, because pipeline companies often discount rates, the rates actually paid by many customers may be substantially less than the maximum rate approved by

- ! Impact of revenue from pipeline capacity release in holding capacity rights on interstate pipelines may release that capacity in the secondary capacity market if they do not need it. Revenues obtained from that capacity release are not reflected in the overall maximum rates discussed earlier, even though they lower the overall cost of shipping gas.
- ! Changes in transmission markups at the national and regional levels. A more aggregate measure of trends in transmission markups can be obtained by comparing the differences between wellhead, citygate, and end-use prices. Because of the options available to customers to use alternative transmission routes, analyzing rates along specific corridors may miss the impact of the increased flexibility available to customers. This section examines markups from the wellhead to the local distribution company and from the citygate to the end user, at both the national and regional levels.

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Factors Affecting Interstate

Pipeline Transportation Rates

Pipeline company tariff rates for interstate transportation services are determined using the traditional cost of service approach. The maximum (tariff) rate that a pipeline company can charge a particular customer is determined by several factors. The key determinants are: the rate base, the allowed rate of return on the rate base, the level of operating costs, the amount of capacity reserved, the load factor, the expected level of interruptible throughput, and the rate design (see Appendix D for additional information on the determinants of rates). This section discusses the impact of each of these determinants in isolation, that is, assuming all other factors remain constant. A quantitative assessment of the trend in each factor is also

! Rate base. The rate base is the historical cost of physical capital on which the pipeline is entitled to earn a return. The rate base is generally calculated as net plant in service (gross gas plant in service plus construction work in progress less the accumulated depreciation, depletion and amortization) plus prepayments and inventory less accumulated deferred income taxes. Depreciation of the physical assets in service and abandonment or sales of lower the maximum rate that pipeline companies are allowed to charge. However, this effect is offset by any investment in new capacity or the refurbishment of existing capacity which increases the rate base, and the maximum allowable rates.

The 1988 through 1994 period was marked by a significant amount of new pipeline construction. As a result, the costs of new construction more than offset the effect of depreciation for the industry-wide rate base reflecting the physical capital used in providing transmission services. This new construction was undertaken for a variety of reasons, including hooking up new sources of supplies (both domestic and imports) and meeting the requirements of a 13 percent increase in consumption. As a result of this investment, the total rate base for the major pipeline companies grew, in nominal dollars, from \$20.2 billion in 1988 to \$25.6 billion in

1994 (Table 7).57 One would expect rates to have

increased over this period because of the increase in the rate base.

#### revised

! Approved rate of return. The allowed rate of return (or the cost of capital), approved by FERC for each pipeline

Rate base trends, only, are stated in nominal dollars to conform to the ratemaking process of computing rates. However, the return on rate base is converted to constant dollars to agree with other discussions.

company, is a weighted average of the firm's cost of debt and the rate of return on equity as determined by the regulatory process. FERC examines a number of elements in determining the rate of return for a particular pipeline company, including capital structure, risk conditions, and other factors. Modifications to a pipeline company's approved rate of return alter its total cost of service, which, in turn, can lead to changes in that company's maximum rates for transportation services. From 1988 through 1994, approved rates of return for pipeline companies decreased, partly because their marginal cost of debt declined, as reflected by generally lower interest rates. For example, the rate for AA utility bonds declined from 10.26 to 8.21 percent. During this period, the decrease in the average approved rate of return for pipeline companies was more modest than the reduction in interest rates. One possible explanation is the relatively higher interest costs paid by the pipeline companies as a result of their low bond ratings.58 Specifically, the settlement rates of return were largely flat at about 11.5 percent during most of the period but did decline in 1994 to approximately 10.2 percent59 (Figure 10).

! Operation and maintenance (O&M) expenses. These are the direct costs of operating and maintaining pipeline facilities necessary to keep the system operational. O&M costs are reviewed as part of a rate hearing and any increases approved by FERC can be expected to result in higher rates. Changes in these costs that were not anticipated at the time of the rate hearing are not addressed until the next hearing and therefore do not affect the approved rate in the interim. As a result of the increased competition under open access, pipeline companies appear to have become more efficient, as evidenced by reductions in operating costs and administrative and general expenses and increases in employee productivity (measured by natural gas deliveries per employee).60 Between 1988

For additional information, see Energy Information Administration

(EIA) report, Natural Gas 1994: Issues and Trends, DOE/EIA-0560(94) (July 1994). 59

It should be noted that the rates cited represent only those

rates that FERC approved ("settlement cases") during the year and hence, do not necessarily represent the entire industry. The number of settlement cases during 1993 and 1994 was 12 and 13, respectively, considerably below the 16 to 18 cases per year between 1989 and 1992. 60

For additional information, see the EIA report, "Natural Gas 1995: Issues and Trends," DOE/EIA-0560(95), to be published in the fall of

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates
Table 7. Composite Rate Base, 1988-1994

(Billion Naminal Policy)

(Billion Nominal Dollars) 1993 1994 Rate Base Elements 1988 1989 1990 1991 1992 Rate Base Gas Plant in Service 44.3 44.2 48.8 52.7 52.3 54.3 55.1 29.7 Accumulated Depreciation 26.1 26.5 28.1

| Net Plant in Service        | 18.2 | 17.7 | 20.7 | 22.2 | 23.7 | 24.7 | 25.4 |
|-----------------------------|------|------|------|------|------|------|------|
| Additions to Rate Base      | 8.3  | 7.4  | 8.5  | 8.9  | 7.8  | 6.9  | 5.9  |
| Subtractions from Rate Base | 6.3  | 6.1  | 6.0  | 5.4  | 5.2  | 5.5  | 5.7  |
| Total Rate Base             | 20.2 | 18.9 | 23.2 | 25.7 | 26.3 | 26.1 | 25.6 |

Note: Construction work in progress is included in additions to rate base.

Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1990 (April 1992). 1990-1994: Federal Energy Regulatory Commission (FERC) Form 2. "Annual Report of Major Natural Gas Companies," Balance Sheet File from FERC Gas Pipeline Data Bulletin Board System.

Figure 10. Average Yield on AA Utility Bonds and Rate of Return for Interstate Pipeline Companies.

| 1988-   | 1994 |                           |
|---------|------|---------------------------|
|         | 12   | Rate of Return            |
|         | 11   |                           |
| Percent | 10   |                           |
|         | 9    |                           |
|         | 8    | Yield on AA Utility Bonds |
|         | 7    |                           |
|         | 0    |                           |

Note: The rate of return represents the average settlement rate of return approved by the Federal Energy Regulatory Commission. Sources: Yield on AA Utility Bonds: Moody's Investor Service, Inc., extracted from DRI History file: USQ0993.WS. Rate of Return: Federal Energy Regulatory Commission, Office of Pipeline Regulation.

1992

1993

1991

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1990

and 1994, O&M costs declined in 1994 dollars from \$8.5 billion to \$5.4 billion (Table 8). In addition to efficiency improvements, falling 0&M costs may be the result of several factors including technology improvements and the spin-off of pipeline facilities.

1989

1988

- ! Load profile. The load profile of a pipeline customer is indicated by its load factor, which is simply the ratio of its average (usually, the annual average) level of pipeline throughput to the maximum pipeline capacity it has reserved. Shippers with relatively large load factors are said to have higher load profiles, while relatively smaller load factors equate to lower load profiles. For example, local distribution companies that serve residential and  $\hbox{\it commercial customers must reserve sufficient pipeline}\\$ capacity to satisfy the wintertime peak demands for these customers, even though their off-season demand can be satisfied with substantially less capacity. Thus, an LDC's throughput averaged over the year is likely to be relatively low compared with the capacity it must reserve to meet peak demands. When this is the case, it is said to have a low load profile. The load profile affects the way in which fixed costs are assigned in computing rates. Pipeline customers with a low load factor will be charged higher average rates compared with customers with a high load factor. While this is an important consideration in determining rates, there is insufficient information regarding load profiles to provide a quantitative assessment of the impact of load factors on changes in transportation rates
- Capacity reserved. An increase in the amount of capacity reserved on a pipeline tends to lower reservation rates because the fixed costs will be collected over more units of reserved capacity. Reservation charges are billed to a customer for each unit of capacity reserved, whether or not the capacity is used.61 Data limitations do not permit a precise assessment of the trend in reserved capacity between 1988 and 1994. However, there is evidence to suggest that the amount of reserved capacity has increased. Much of the increase in deliveries to end users from 1988 through 1994 is accounted for by firm services (Figure 11).62 While some of this increase in deliveries may be associated with higher utilization of

- Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates existing reserved capacity, the overall average utilization of the pipeline system was about the same in 1991 and 1994 (see Chapter 3). The combination of increased firm deliveries and pipeline expansion during this period may indicate that the amount of reserved capacity has increased.
  - ! Expected level of interruptible throughput. While interruptible rates may be lower than firm rates, interruptible throughput does contribute to fixed costs. When determining tariff rates, fixed costs are allocated between firm and interruptible services based on their respective loads on the pipeline.63 The interruptible customers' load is estimated from their forecasted annual throughput level. As a result, an anticipated decrease in the level of interruptible throughput raises firm transportation rates by increasing the level of fixed costs allotted to firm transportation services. Interruptible throughput declined over the 1988 through 1994 period (Figure 11) putting upward pressure on firm transportation rates.
  - ! Rate design. Firm customers pay a reservation charge to reserve pipeline capacity as well as a charge based on the amount of gas actually transported. Rate design refers to how fixed costs are allocated and collected in these two charges. From 1988 through 1991, the modified fixed-variable (MFV) rate design was widely used. Under this system, fixed costs were allocated to both the reservation and volumetric components of rates. FERC Order 636 stipulated the use of the straight fixed-variable (SFV) rate design. Under this method, all fixed costs are allocated to the reservation charge, while variable costs are allocated to a commodity or usage fee (Figure 12). This change in rate design tends to increase rates for low-load-factor customers and decrease rates for high-load-factor customers (see Chapter 2). The change to SFV reallocated approximately \$1.7 billion from the usage fee to the reservation fee.64
  - ! Take-or-pay costs. Contract reformation costs resulting from take-or-pay settlements associated with

If a customer requires 1 million cubic feet (MMcf) of gas on a day during the month of January (assuming the pipeline company does not offer seasonal rates), that customer must reserve 1 MMcf of space on the pipeline for every day during the year.

Besides traditional firm service, this includes released firm transportation, no-notice transportation, and short-term firm transportation. A pipeline company may sell the unused portion of any firm transportation capacity on its system on a short-term basis.

service customers reserve on the pipeline or the measured load firm service imposes on the pipeline system during the period of maximum

Monetary estimate from the Federal Energy Regulatory

Commission, Order 636-A, footnote 314, 57 F.R. 36128,36173 (1992). Actual costs paid by any class of customers depend on the discounts from the maximum allowable rates that may be obtained from the pipeline company.

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Energy Information Administration Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Table 8. Composite Cost of Service (Billion 1994 Dollars)

|   | Elements | 1988              | 1989              | 1990              | 1991              | 1992              | 1993              | 1994              |
|---|----------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|-------------------|
| Return on Rate Base<br>Operation and Maintenance Expenses<br>Other Expenses |          | 2.8<br>8.5<br>3.4 | 2.6<br>9.3<br>3.2 | 2.9<br>6.1<br>3.1 | 3.1<br>9.0<br>2.4 | 2.9<br>7.5<br>3.0 | 3.1<br>6.9<br>3.3 | 2.6<br>5.4<br>3.1 |
| Total Cost of Service   |          | 14.6              | 15.1              | 12.2              | 14.6              | 13.4              | 13.3              | 11.1              |

Note: Return on Rate Base = Total Rate Base multiplied by FERC Approved Rate of Return.

Sources: 1988-1989: Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies 1990 (April 1992). 1990-1994: Federal Energy Regulatory Commission (FERC) Form 2. "Annual Report of Major Natural Gas Companies," Balance Sheet File from FERC Gas Pipeline Data Bulletin Board System.

Figure 11. Natural Gas Transmission by Type of Service, 1987-1994

25

Firm Transportation Gas Sales

No-Notice Service

Interruptible Transportation 20

Released Capacity

Quadrillion Btu

10

15

5

1987

1989 1988

1990

1991

1992

1993

1994

Source: Interstate Natural Gas Association of America (INGAA), Gas Transportation Through 1994 (August 1995).

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Figure 12. Rate Design in Transition: Modified to Straight Fixed Variable

Modified Fixed Variable Commodity

Demand

Peak Day (D1)

Annual (D2)

Fi xed Costs Long-Term Debt A&G DDA Other Taxes

N&N

Variable Costs Nonlabor O&M Other O&M Fi xed Costs Return on Equity Related Taxes

Elements Changing

Demand Commodity

Peak Day (D1) Annual (D2)

Fi xed Costs Long-Term Debt A&G DDA Other Taxes 0&M

Variable Costs Nonlabor O&M Other O&M Fi xed Costs Return on Equity Related Taxes

Straight Fixed Variable

Reservation

Usage

DDΔ Depreciation, Depletion, and Amortization Expenses

Other Taxes Other Nonincome Taxes

∩&м Operation and Maintenance Expenses

Nonlabor O&M Nonlabor Operation and Maintenance Expenses Other O&M Other Operation and Maintenance Expenses

Fixed Costs Return on Equity Related Taxes Long-Term Debt A&G DDA Other Taxes 0&M

Variable Costs Nonlabor O&M Other O&M

Source: Energy Information Administration, Natural Gas 1992: Issues and Trends.

the implementation of Order 436 have totaled

approximately \$10.2 billion as of May 30, 1995.65 Pipeline companies have agreed to absorb about \$3.7 billion. Of the remaining \$6.6 billion, \$3.6 billion is being recovered through a surcharge on firm transportation customers and the remainder is being recovered through a surcharge on volumetric rates. Recovery of these take-or-pay costs began in the late 1980's and is expected to result in higher rates for some customers throughout the 1990's.

! Transition costs. As of August 1995, \$2.7 billion in transition costs associated with Order 636 have been filed at FERC for recovery through increased transportation rates to shippers.66 The \$2.7 billion of costs include \$1.4 billion of gas supply realignment costs; \$0.6 billion of unrecovered gas costs; \$0.7 billion of stranded costs, and resulted

\$9 million for new facilities. Additional transition costs

or-

45

3 to

A contract provision obligating the buyer to pay for a certain minimum quantity of product, whether or not the buyer takes that  $\frac{1}{2} \int_{-\infty}^{\infty} \frac{1}{2} \left( \frac{1}{2} \int_{-\infty}^{\infty} \frac{1}{2$ quantity during the stated period.

66 Shippers include any customer who uses transportation services. the

are likely and will probably affect rates for the next 5 years.

! Costs of pipeline expansion. For the period 1991 through 1994, the interstate pipeline companies spent \$6.5 billion on expanding interstate pipeline capacity. Expansion costs generally have been passed through to all customers and will continue to influence transportation rates, because they are amortized over many years. Pipeline expansion costs increase the rate base and, subsequently, transportation rates.

Changes in the elements described above for determining rates offset and counterbalance each other. The rate design, which determines how costs are allocated and recovered from  $\,$ customer classes, probably has the most significant direct impact on rates. In addition, industry restructuring has

in significant costs associated with the changes implemented in the new regulations, including more than \$10 billion in take-

pay costs under Orders 436 and 500, and an additional \$2.7

billion in transition costs associated with Order 636.

When Order 636 shifted the responsibility and risk of maintaining service from the interstate pipeline companies to

#### Energy Information Administration

Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates local distribution companies and consumers, the allocation of costs for some services changed. For example, a charge that was previously included in the price paid for interstate transmission service may now be included in the distribution costs (or it may be paid directly by the end user and hence not reported by either the interstate pipeline or the local distribution company). This can affect the accounting (and reporting) of both the costs of long-haul transportation (by interstate pipeline companies) as well as local delivery charges (by local distribution companies). For this reason, only aggregate costs of transmission and distribution service are examined for some of the areas analyzed. In addition, firm transportation rates previously may have included a number of other services, such as storage and load-balancing. In this analysis, it was not possible to adjust the data to reflect a consistent definition over time. Therefore, trends in transportation rates may only be approximations.

The difficulty of differentiating distribution from transmission costs presents additional problems when analyzing the effects of Federal policies and regulations on transportation rates. Distribution rates charged by local distribution companies are regulated by State utility commissions not by FERC. Recently, some of the larger consuming States have been experimenting with various types of rate designs, such as market- and incentive-based rates, to introduce greater competitive forces into the distribution system. Some States are even advocating that LDC's unbundle their services.

Because of these and other data limitations, this analysis does not attempt separately to attribute specific changes in transportation rates to specific Federal legislation or regulations. Rather, the chapter presents general trends in transmission rates, showing how they are influenced in aggregate by regulations, legislation, and policies, as well as economic and market

The Corridor Rate Analysis

A number of regulatory and market influences affected rates over the 1988 through 1994 period. One of the most significant regulatory changes that has had a direct impact on rates is FERC Order 636 and the resulting change in rate design to the straight fixed-variable (SFV) method. The analysis of transportation corridors examines the change in maximum transportation rates under Order 636 but does not isolate the changes in rates due exclusively to the SFV rate design. Rather, it assesses the net effect on transportation rates of all of the regulatory and market influences, including rate base changes, operating costs, taxes, depreciation, interest rates, capacity reserved, load profiles, rates of return, etc.

apply to customers who pay discounted rates for services, pipeline company core customers generally pay maximum tariff rates. Therefore, the analysis of maximum rates will provide a basis on which to gauge the general movement of firm transportation rates. The tariff rates analyzed include surcharges such as Order 636 transition costs.

Firm transportation rates in 1994 were compared with rates in effect in 1991 for a sample of 14 supply/demand areas or corridors (Figure 13). The 16 companies represented in the sample have a combined service area that spans the country and a throughput level that is almost half the total industry throughput. The sample of corridors was developed based on the market corridors presented in the Foster Associates' December 1994 publication Competitive Profile of Natural Gas Services (discussed in more detail in Chapter 5).67 For any single corridor in the sample, there may be several routes, with sample Control in the sample, there may be several routes, where papers are to the transportation services of one or more pipeline companies. For instance, the corridor from the Gulf Coast supply area to the Boston market area includes two separate routes: (1) Texas Eastern Transmission Company and Algonquin Gas Transmission Corporation and (2) Tennessee Gas Pipeline Company. An aggregate or "unit" rate, representing the total transmission charge for moving 1 millions. representing the total transmission charge for moving 1 million Btu (MMBtu) of gas, was developed for each of the 21 routes in the sample. The results from the rate analysis are presented in constant 1994 dollars.

The analysis compares the unit cost for firm (i.e., noninterruptible) transportation service, defined as the charge for transporting one unit (MMBtu) of gas, for two types of

! High-load-factor customers tend to transport gas at a constant level throughout the year. These customers impose a daily demand on the system that is about equal to the average of their annual volume transported. For example, a high-load-factor customer who transports 365

The analysis compares maximum firm transportation rates, including surcharges (tariff rates) charged before and after Order 636 went into effect. Although maximum rates may not

the analysis because they have a diverse load profile, have a geographically dispersed service area, and have readily available tariff schedules. The pipeline routes account for 43 percent of total U.S. throughput. See Appendix E for additional information including the names of pipeline companies included in this analysis.

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Figure 13. Interstate Transportation Corridors Used in Corridor Rate Analysis

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System.

MMBtu of gas per year will tend to transport about 1 MMBtu of gas per day. The industrial customers, such as an aluminum plant or food processing plant, with a high load factor tend to have gas requirements that are related to manufacturing needs as opposed to the seasonal demand for space heating. Some electric generators may have uniform usage throughout the year and thus be characterized as high-load-factor customers.

! Low-load-factor customers do not take gas at a constant rate throughout the year. These customers have a peak daily usage that far exceeds the average of their annual use. Residential and commercial sectors are generally low-load-factor customers because they depend on natural gas as a space-heating fuel. Their demand tends to fluctuate with weather temperature. Hence, the pipeline company must be prepared to meet the load requirement of these customers up to the maximum amount of capacity reserved even though the maximum load may occur only a few times a year.

The comparison of load factor rates illustrates the effect of the switch from the modified fixed-variable (MFV) rate design to the straight fixed-variable (SFV) rate design. As discussed

earlier in this chapter, many elements affect rates for pipeline service. Except for the change in rate design to SFV, each element will have the same general effect on customers regardless of their load factor. However, the switch from MFV to SFV rate design will tend to have a different impact on maximum tariff rates depending on the load factor, increasing low-load-factor rates while decreasing high-load- factor rates. (For additional information see Chapter 2.)

For this analysis a 100-percent load factor was used to represent high-load-factor customers and a 40-percent load factor for low load-factor customers. The 40-percent load factor assumes that the low-load customers will impose a peak-day load on the system that is two and one half times the customers' average daily requirements. The load factors were selected for purely illustrative purposes. Actual load factors for shippers may vary from these assumed levels, depending on their service requirements throughout the year. For local distribution companies, this will depend on the mix of residential, commercial, industrial, and electric utility customers and their service requirements.

The average unit rate paid by 100-percent and 40-percent loadfactor customers will vary depending on the level of the pipeline company's reservation charge. For example, assume that firm

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates transportation rates include a \$0.25 per MMBtu daily transportation rates include a \$0.25 per MMBtu daily reservation charge and a \$0.05 per MMBtu usage charge. The 100-percent load-factor customer that transports 1 MMBtu per day will pay, on average, \$0.30 per MMBtu for service (1 MMBtu reservation at \$0.25 per MMBtu + 1 MMBtu usage at \$0.05 per MMBtu). The 40-percent load-factor customer, however, will need to reserve enough space to meet his peak requirements. If the 40-percent load-factor customer transports an average of 1 MMBtu per day, its peak requirements would equal 2.5 MMBtu (load factor = average use / 40 percent = 40/100 = 1/2 5). Therefore the 40use/peak use = 40 percent = 40/100 = 1/2.5). Therefore, the 40-percent load-factor customer will pay an average rate of \$0.675 per MMBtu for service (2.5 MMBtu reservation at \$0.25 per MMBtu + 1 MMBtu usage at \$0.05 per MMBtu). (This simplified example ignores the seasonal rates pipeline

Findings of the Corridor Rate Study

companies may offer.)

No clear pattern emerges with respect to the change in maximum tariff rates and the respective corridor, supply area, or delivery point. However, there are some noteworthy differences between the 100-percent and the 40-percent load-factor rates. As discussed earlier, the change in rate design was the one phenomenon expected to have different impacts on highand low-load-factor customers. If the switch in rate design to SFV were the only change during the period, all highload-factor rates would be expected to decrease and all low load-factor rates to increase

It appears that the conversion to SFV rate design was the dominant influence on rate changes for both high- and low-load-factor customers from 1991 through 1994. While other influences may have mitigated SFV's downward pressure or high-load-factor rates and upward pressure on low-load-factor rates, the rate design shift widened the gap between high- and low-load-factor rates. Half the sampled 100-percent load-factor corridor rates increased between 1991 and 1994, while half decreased (Table 9). For the 40-percent load-factor rates, onethird of the corridor rates decreased while two-thirds increased. This higher incidence of rate increases for the low-load customers suggests that recent regulatory changes have benefited low-load-factor customers less than high-load-factor customers. Although both categories of customers had increases and decreases in tariffs, the change was more advantageous to the high-load-factor customers. More compelling evidence is provided by inspecting the differentials in the magnitudes of the rate changes. For instance, in every case where the high-load-factor rate increased, the low-load-factor rate also increased. Moreover, in all cases, the increase was larger in both absolute and percentage terms for the low-load-factor customers. For example, the high-load-factor rate for Canada to New York increased by 4 percent while the low-load-factor rate increased

by 19 percent.

In about half of the cases considered, rates to the high-loadfactor customers declined, while rates to the low-load-factor customers either decreased by a smaller amount or actually increased. For example, on route A from the Gulf Coast to Boston, the 100-percent load-factor rate declined by 23 percent while the 40-percent rate declined by 8 percent. On the Gulf Coast to Louisville route, the 100-percent rate declined 18 percent. In sharp contrast, the 40-percent rate on the same route increased by 9 percent.

The results of the analysis suggest that the hypothesis that all high-load-factor customers would face decreases in transmission  $% \left( 1\right) =\left\{ 1\right\} =\left$ rates and all low-load-factor customers would suffer economically as a result of Order 636 is overly simplistic. For both sets of customers, some rates increased between 1991 and 1994 while others declined. Clearly, there are elements other than the switch to SFV that had an impact on rates during this period. What is striking, however, is the large difference between the two customer classes in terms of the magnitudes of the rate changes. On any given route, the high-load-factor customers experienced a rate change that was more advantageous than the rate change experienced by the low-loadfactor customers. This has resulted in a widening of the gap between the 100-percent and the 40-percent load-factor rates between 1991 and 1994. Thus, SFV had a dominant influence on the widening gap in rates for these customer classes. As striking as these results are, they may actually understate the actual impact, because the data used in this analysis are for maximum posted rates. In reality, rates may be discounted. Discounted rates will tend to be obtained by high-load-factor customers, such as industrial customers with alternative fuel capability. Accordingly, the actual differentials in the percentage increases and decreases between the two customer classes are probably larger than those presented in this report.

In addition to the cost-of-service issues discussed earlier in this chapter, a number of regulatory elements affect rates. While rate design may have the most significant direct impact on rates, transition costs resulting from recent regulatory changes also affect rates. Order 636 transition costs include: (1) unrecovered gas costs, (2) gas supply realignment (GSR) costs, (3) stranded costs, and (4) the cost of new facilities.68 Of these transition costs, the GSR and stranded costs are passed through to customers in the adjustment charges included in the corridor rates. These charges increase overall

Federal Energy Regulatory Commission Docket No. RM91-11-002, et al., Order 636-A, August 3, 1992, p. 336.

1991 and 1994 (1994 Dollars per Million Btu)

| (133. 30114.3 per 1.11113.1 304) | 100-Pero | cent Load Facto | 40-Perd           |      |      |                   |
|----------------------------------|----------|-----------------|-------------------|------|------|-------------------|
| Supply to Market Routes          | 1991     | 1994            | Percent<br>Change | 1991 | 1994 | Percent<br>Change |
| Northeast Region                 |          |                 | 8-                |      |      |                   |
| Gulf Coast to Boston             |          |                 |                   |      |      |                   |
| Route A                          | 1.28     | 0.98            | -23               | 2.19 | 2.01 | -8                |
| Route B                          | 0.55     | 1.11            | 102               | 0.93 | 2.42 | 160               |
| Appalachia to Boston             |          |                 |                   |      |      |                   |
| Route A                          | 0.88     | 0.74            | -16               | 1.55 | 1.54 | -1                |
| Route B                          | 0.44     | 0.52            | 18                | 0.73 | 1.14 | 56                |
| Canada to Boston                 |          |                 |                   |      |      |                   |
| Route A                          | 0.85     | 0.98            | 15                | 1.69 | 2.26 | 34                |
| Route B                          | 0.52     | 0.64            | 23                | 0.71 | 1.43 | 101               |
| Gulf Coast to New York           |          |                 |                   |      |      |                   |
| Route A                          | 0.55     | 0.97            | 76                | 0.93 | 2.09 | 125               |
| Route B                          | 0.93     | 0.75            | -19               | 1.58 | 1.49 | -6                |
| Route C                          | 0.85     | 0.56            | -34               | 1.48 | 1.03 | -30               |
| Canada to New York               | 0.80     | 0.83            | 4                 | 1.69 | 2.01 | 19                |
| Southeast Region                 |          |                 |                   |      |      |                   |
| Gulf Coast to Louisville         | 0.66     | 0.54            | -18               | 1.08 | 1.18 | 9                 |
| Gulf Coast to Miami              | 0.38     | 0.55            | 45                | 0.73 | 1.19 | 63                |
| Arkoma to Louisville             | 0.75     | 0.77            | 3                 | 1.15 | 1.68 | 46                |
| Midwest Region                   |          |                 |                   |      |      |                   |
| Gulf Coast to Detroit            |          |                 |                   |      |      |                   |
| Route A                          | 1.03     | 0.82            | -20               | 1.82 | 1.80 | -1                |
| Route B                          | 0.71     | 0.54            | -24               | 1.13 | 1.14 | 1                 |
| Route C                          | 0.43     | 0.55            | 28                | 0.78 | 1.24 | 59                |
| Central Region                   |          |                 |                   |      |      |                   |
| Rocky Mountain to Denver         | 0.38     | 0.39            | 3                 | 0.67 | 0.83 | 24                |
| Mid-Continent to Kansas City     | 0.44     | 0.47            | 7                 | 0.70 | 1.03 | 47                |
| West Region                      |          |                 |                   |      |      |                   |
| San Juan to Southern California  | 1.04     | 0.80            | -23               | 1.35 | 1.26 | -7                |
| Canada to Southern California    | 1.53     | 1.36            | -11               | 1.53 | 2.52 | 65                |
| Southwest Region                 |          |                 |                   |      |      |                   |
| Arkoma Basin to Little Rock      | 0.46     | 0.29            | -37               | 0.70 | 0.59 | -16               |

Sources: Energy Information Administration, Office of Oil and Gas, derived from: 1991: Gulf Coast to Miami-H. Zinder & Associates, Summary of Rate Schedules of Natural Gas Pipeline Companies (March 1991); Other corridors-Foster Associates, Competitive Profile of U.S. Interstate Pipeline Companies (October 1991); 1994: Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foste r Associates, Competitive Profile of Natural Gas Services (December 1994).

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates transportation costs for firm service customers. The cost of new The reduced variability in rates may in facilities associated with Order 636 would tend to increase tariff or possibly as a result of competition rates.

Rate increases on a particular pipeline may be caused by the loss of customers who either chose to exercise their alternative fuel capabilities or chose other transportation options. (As discussed earlier, Orders 436 and 636 opened opportunities for customers to switch service providers.) As customers leave a pipeline system, its fixed costs may be recovered by fewer customers and lower throughput volumes, leading to increased rates. Pipeline companies may also be discounting services to retain certain customers and passing on additional costs to other customers who have no other service options (captive customers). Order 636 permits pipeline companies to discount services on a nondiscriminatory basis to meet competition. In order not to discourage discounting, FERC allows the discounted "units" to be factored into the determination of maximum rates. 69

In a competitive market, price differences across firms reflect quality and geographic (e.g., locational) differences. Price differences in excess of what can be accounted for by these elements may indicate the market's inefficiency at setting prices. On this score, the convergence in corridor rates, while not conclusive, suggests that the market for transportation became more efficient during the period 1991 through 1994.

Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have become more similar, as evidenced by a convergence in rates. In the sample, multiple routes are available within five corridors: Gulf Coast to Boston, Appalachia to Boston, Canada to Boston, Gulf Coast to New York, and Gulf Coast to Detroit (Table 10). For 100-percent load-factor rates, three out of five of these corridors showed a trend toward a convergence of rates, one corridor showed no change, and the fifth showed a modest increase in the variation of rates (Figure 14). The corridors that did exhibit convergence displayed a substantial reduction in the variation in rates. For example, for the two routes from the Gulf Coast to Boston, the rate difference for high-load-factor customers declined from \$0.73 per MMBtu in 1991 to \$0.13 per MMBtu in 1994 (Table 10). Particularly notable in this analysis is that low-load-factor customers have also seen a

reduction in the rate variation in four out of five corridors.

However, this reduced variability results from low-end rates moving up to the level of high-end rates rather than a reduction in high-end rates.

The reduced variability in rates may indicate that in addition to, or possibly as a result of competition, firm transportation services provided by various pipeline companies have become more similar. That is, notwithstanding geographical considerations, a customer may be able to substitute the transportation service offered by one company for transportation service offered by another. In addition, Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor. While intriguing, the finding of rate convergence should be interpreted with a high degree of caution given the small number of corridors on which the finding is based.

As previously discussed, the study cannot isolate numerous influences on the outcome of maximum firm transportation rates. Also, affecting the net cost of transportation is the revenue received for capacity release. Capacity release revenue credits are passed through to firm transportation customers; however, the unit decrease is not reflected in the maximum transportation rate. The extent of the released capacity's influence on transportation rates will depend on the development of the secondary market.

#### Capacity Releases and Transportation Rates

The capacity release program is another provision of Order 636 that has the potential to affect transportation rates directly. Prior to Order 636, capacity rights on a pipeline were nontransferable. A customer could either use the capacity itself or it would be available to the pipeline company with no compensation to the customer. Under Order 636, a shipper with excess reserved capacity can release that capacity to another shipper in return for a credit on its reservation charges.70

There are two ways in which a release arrangement is processed.

(1) A releasing shipper may make a prearranged deal with the

replacement shipper if the price for the capacity is equal to the maximum firm rate in the tariff or if the duration of the contract does not exceed one calendar month. (2) If neither of these conditions are met, the releasing shipper will post the release (along with the corresponding limitations or conditions, such as recall rights and award criteria) on the pipeline company's electronic bulletin board where

In other words, a pipeline company that transports 100 MMBtu of gas at half of its maximum transportation rate will develop rates assuming 50 MMBtu were transported for that service. If the transportation costs remain the same, firm transportation rates will increase because those costs will be recovered on fewer units of gas.

(1994 Dollars per Million Btu)

prospective replacement shippers bid on the capacity rights. This process results in capacity release rates that are set by the market conditions instead of a FERC ratemaking process. Currently, the maximum rate for capacity release may not exceed the maximum firm rate stated in the pipeline company's tariff.

# 50 Energy Information Administration Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Table 10. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994

| -                      |                            | 100-Percent Lo | 40-Percent Load |      |
|------------------------|----------------------------|----------------|-----------------|------|
| Factor                 | Supply to Market Corridors |                |                 |      |
|                        | Supply to harket torridors | 1991           | 1994            | 1991 |
| 1994                   |                            |                |                 |      |
| Gulf Coast to Boston   |                            | 0.73           | 0.13            | 1.26 |
| 0.41                   |                            |                |                 |      |
| Appalachia to Boston   |                            | 0.44           | 0.22            | 0.82 |
| 0.40                   |                            |                |                 |      |
| Canada to Boston       |                            | 0.33           | 0.34            | 0.98 |
| 0.83                   |                            |                |                 |      |
| Gulf Coast to New York |                            | 0.38           | 0.41            | 0.65 |
| 1.06                   |                            |                |                 |      |
| Gulf Coast to Detroit  |                            | 0.60           | 0.28            | 1.04 |

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1991: Foster Associates, Competitive Profile of U.S. Interstate Pipeline Companies (October 1991); 1994: Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, Competitive Profile of Natural Gas Services (December 1994).

Figure 14. Range of Maximum Transportation Rates for Corridors with Multiple Routes, 1991 and 1994

|                              | 1.40 |                                      | 100-Perc                             | ent Load Factor                  |  | High                                  |
|------------------------------|------|--------------------------------------|--------------------------------------|----------------------------------|--|---------------------------------------|
|                              | 1.20 |                                      |                                      |                                  |  | Low                                   |
| 1994 Dollars per Million Btu | 1.00 |                                      |                                      |                                  |  |                                       |
|                              |      |                                      |                                      |                                  |  |                                       |
|                              | 0.80 |                                      |                                      |                                  |  |                                       |
|                              | 0.60 |                                      |                                      |                                  |  |                                       |
|                              | 0.40 |                                      |                                      |                                  |  |                                       |
|                              | 0.20 |                                      |                                      |                                  |  |                                       |
|                              | 0.00 | 1991 1994<br>Gulf Coast<br>to Boston | 1991 1994<br>Appalachia<br>to Boston | 1991 1994<br>Canada<br>to Boston | 1991 1994<br>Gulf Coast<br>to New York | 1991 1994<br>Gulf Coast<br>to Detroit |

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1991: Foster Associates, Competitive Profile of U.S. Interstate Pipeline Companies (October 1991); 1994: Federal Energy Regulatory Commission (FERC) Automated System for Tariff Retrieval (FASTR); and Foster Associates, Competitive Profile of Natural Gas Services (December 1994).

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Under the capacity release program, a local distribution company (LDC) may assign to others some of its rights to capacity on the pipeline system. This would typically occur during the summer when there is no demand for space heating. If this reassignment of capacity results in new incremental load, the pipeline system will operate on a more uniform basis throughout the year, resulting in more efficient use of the existing pipeline capacity. Capacity release also permits more buyers to reach more sellers by making firm transportation available to shippers who may not otherwise be able to obtain service. For example, prior to capacity release, a shipper would not be able to contract for firm transportation service on a pipeline that was fully subscribed (all capacity was contracted for). However, under capacity release the shipper may be able to use released capacity to connect to the gas supply of its choice.

The revenue generated by capacity release decreases the total cost of pipeline transportation to low-load-factor customers.71 As discussed earlier, these customers pay reservation charges to hold space on the pipeline to meet their maximum requirement on any single day. These customers frequently underutilize this capacity, which causes their average cost of transportation to be relatively high. The revenue these customers receive for their released capacity offsets some of their transportation costs.

The capacity release market has grown steadily since its full activation on November 1, 1993. Pipeline capacity traded during the 1993-94 heating season (November 1993 through

Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Partian Rates for capacity release transportation represent an average 64 percent discount from the maximum firm transportation rate.72 reliable except for modest seasonal fluctuations during the winter months (Figure 16). This contrasts with the amount of capacity basis traded, which has increased steadily (Figure 17). The highly discounted price level may indicate that an abundance of capacity is available from releasing shippers.

The price for capacity release has a pronounced seasonal pattern in the Northeast Region (Figure 18), indicating a strong demand for capacity during winter periods. The prices for capacity release are at their highest levels during the winter season when capacity on pipeline systems is more likely to be constrained. LDC's, who comprise the bulk of the releasing shippers, must retain their capacity to supply gas to their residential and commercial heating-load customers. During the summer months, when pipeline capacity may be underutilized, released capacity is abundant and returns a much lower price. Alternatively, a consistent high average price for released capacity may suggest a consistent strong demand for the capacity. This may be the case in the Southeast Region where the 1994 average price for released capacity was more than three times the national average price (Table 11). The Southeast Region has an expanding gas market and only a few pipelines serving the area. Therefore, capacity may be constrained or there may be only limited released capacity in that region leading to the high prices for released capacity.

March 1994) amounted to 762 billion cubic feet. Capacity held by replacement shippers during the 1994-95 heating season was 1,570 billion cubic feet. Approximately \$568 million in revenue credits from November 1993 through March 1995 were generated by the capacity release market-\$528 million from released pipeline capacity and \$40 million from released storage capacity. Revenues from pipeline capacity released during the 1994-95 heating season increased in all regions compared with the 1993-94 heating season (Figure 15). For the Northeast Region, the revenues in the 1994-95 heating season totaled almost \$74 million, more than double the revenues generated during the 1993-94 heating season. Although the apparent growth in the capacity release market appears promising, its effectiveness at reducing the cost of firm transportation will depend on the unit price received for released capacity compared with that paid for firm transportation.

Rates for released capacity vary from region to region and tend to be significantly less than maximum firm transportation rates.

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Some LDC's with very low load factors may not be able to obtain the revenue crediting benefits from released capacity. The lowest load-

factor customers are generally thesmallest LDC's. Since they are often

served under one-part rates, they are not able to mitigate their costs through capacity release, because it only applies to customers receiving service under two-part rates.

The capacity release market not only reduces the cost of reserving capacity on the system, it also gives replacement shippers a generally low cost alternative to capacity obtained directly from the pipeline company. Before this market emerged, economies of scale limited competition on a corridor to a small number of pipelines. As a result of the emergence of the secondary market, a shipper now can potentially obtain capacity from an average of almost 70 holders of capacity rights on a given pipeline.73 The number of effective suppliers is probably substantially lower than 70 per pipeline. For example, the shippers may need some of the capacity for themselves; the delivery points of the potential releasing and acquiring shippers may not match; and the excess capacity may be upstream while the capacity desired

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Interstate Natural Gas Association of America, Gas Transportation Through 1994, August, 1995.

See Arthur De Vany and W. David Walls, "Natural Gas Industry Transformation, Competitive Institutions and the Role of Regulation," Energy Policy 1994, 22 (9) 755-763, footnote 31.

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Figure 15. Heating Season Revenues from Release of Pipeline Capacity

|         | Cent | ral  |             |      |           |
|---------|------|------|-------------|------|-----------|
| Western |      |      | M idw e s t | :    |           |
|         |      |      |             |      | Northeast |
| 56.7    | 14.2 | 22.6 | 9.0         |      |           |
|         |      |      |             | 11.9 | 73.7      |

25.6

|                   |       |       |     |           | 29.6 | 1 Mcf | age Cost of Acquiring<br>f of Capacity for 1 Day<br>cf-day) |         |
|-------------------|-------|-------|-----|-----------|------|-------|---|---------|
|                   |       |       |     | Southeast |      |       |   |         |
|                   |       |       |     |           |      |       | 1993-94   | 1994-95 |
|                   | South | hwest |     |           |      |       | Heating   | Heating |
|                   |       |       |     | 40.9      |      |       |   |         |
|                   |       |       |     |           |      |       | Season  | Season  |
| Capacity Release  |       |       |     |           |      | NE    | \$0.15  | \$0.16  |
| Revenues          |       |       |     |           |      |       |   |         |
|                   |       |       |     |           |      | SE    | \$0.40  | \$0.46  |
| (million dollars) |       |       |     |           |      |       |   |         |
|                   | 0.3   | 1.2   |     |           |      | MW    | \$0.13  | \$0.08  |
| 1993-94 Heating   |       |       |     |           |      | C     | \$0.13  | \$0.09  |
| Season            |       |       | 4.2 |           |      |       |   |         |
|                   |       |       |     |           |      | W     | \$0.15  | \$0.12  |
| 1994-95 Heating   |       |       |     |           |      |       |   |         |
|                   |       |       |     |           |      | SW    | \$0.07  | \$0.21  |
| Season            |       |       |     |           |      |       |   |         |

\$/Mcf = Dollars per thousand cubic feet.

Notes: Revenues used in price calculation exclude data with capacity release rates that are stated as a percent of effective maximum rates, capacity

transactions with incomplete data, and one transaction with inconsistent release rates. The excluded data account for about 10 percent of pipelin e capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas, derived from: capacity release transaction data provided by Pasha Publications,

 $\ensuremath{\mathsf{may}}$  be downstream. Nevertheless, the creation of a secondary

market in pipeline capacity represents a substantial increase in the degree of effective competition in the market for pipeline capacity. This creation of an intra-pipeline market in capacity preserves the scale economies inherent in transmission while effectively providing for a competitive and thus more efficient market in pipeline capacity.

Currently several transportation services compete with the capacity release market. These services include traditional interruptible transportation, short-term firm transportation offered by pipeline companies, and capacity obtained through gray market transactions.74 However, there is little doubt that the emerging capacity release market represents an important institutional innovation.

Natural Gas Prices and Markups, 1988-1994

While some transmission rates have declined as a result of changes in Federal policies, others have increased. A cursory analysis might conclude that recent policies have had a mixed effect on the cost of natural gas transmission. However, transmission rates, whether they represent maximum posted or actual transactions, do not fully reflect the impact of policy changes on the cost of moving gas from the wellhead to the citygate or to the burnertip. Recent policy has been to provide both producers and consumers of gas with more choices. Prior to the recent institutional changes, the combined merchant/ shipper status of the pipeline companies resulted in consumers of gas having very limited choices with respect to both gas supply and transmission. The choices currently available to market participants have affected the cost of moving gas in ways that are simply not captured in the tariff rate associated with moving gas from point A to point B. Under the new policies, gas

Short-term firm capacity is that portion of unused firm

transportation capacity on its system that a pipeline company decides to sell. The gray market is broadly viewed as transportation or storage that is bundled with gas and sold as a deregulated service by marketers and LDC shippers.

that previously moved from A to B may instead flow at lower overall cost from a new point. C to B.

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Table 11. Average Price for Released Pipeline

Capacity by Region, 1994

(Dollars per Thousand Cubic Feet per

Day)

| Northeast                    | Region  | Price<br>0.11        |
|------------------------------|---------|----------------------|
| Southeast                    |         | 0.45                 |
| Midwest<br>Central           |         | 0.09<br>0.14         |
| Western<br>Southwest<br>U.S. | Average | 0.11<br>0.12<br>0.13 |

Notes: Revenues used in price calculation exclude data with capacity release rates that are stated as a percent of effective maximum rates, capacity transactions with incomplete data, and one transaction with inconsistent release rates. The excluded data account for about 10 percent of pipeline capacity volumes traded. Also, revenues calculated for capacity transactions with volumetric rates assume 100-percent load factor use of capacity.

Source: Energy Information Administration, Office of Oil and Gas,

derived from: capacity release transaction data provided by Pasha Publications, Inc.

End-use, citygate, and wellhead prices can be used to estimate transmission and distribution markups to the various end-use sectors. The transmission markup represents the cost of moving gas from the wellhead to the citygate and is calculated as the difference between the citygate price and the wellhead price. The distribution markup represents the LDC's charge for delivering the gas from the citygate to the end user and is calculated as the difference between the retail price to onsystem end users and the citygate price.

The end-use price is the average retail price paid for gas by a single customer class or sector (e.g., residential, commercial, industrial, and electric utility). It includes the costs of the many transactions necessary to bring natural gas from the producing field to the burnertip, including the citygate price and the wellhead price. Between 1988 and 1994, end-use prices for all sectors fell, with the greatest declines experienced by the onsystem industrial and electric utility sectors, 15 and 19 percent respectively. The decline in end-use prices experienced by residential and commercial customers was considerably less, only 4 and 3 percent, respectively (Table 12).

Retail gas price data for the electric utility sector are the only

data that encompass both onsystem and offsystem purchases of gas by end users.75 They show clearly the benefits of enhanced competition and open access in the transportation markets. Not the

As a

customers

Price data for electric utilities are based on reports by the utilities themselves on their total gas purchases. Retail price data for the other 87

sectors are based on reports by pipeline companies and LDC's on their gas sales to these sectors and therefore do not include offsystem sales.

only can electric utility (and industrial) consumers obtain

transportation service at lower prices, they can also shop for the lowest priced gas supplies. As a result, real electric utility gas prices declined between 1988 and 1994, but experienced an

upturn in both 1992 and 1993 reflecting the increase in wellhead prices in those years.

The citygate price is the average delivered price of gas to the

LDC. It represents a weighted average of the delivered cost of

gas across all customer classes served by LDC sales. Between 1988 and 1994, the real citygate price declined 13 percent, from \$3.54 to \$3.08 per thousand cubic feet (Table 12). The

magnitude of the decline varies by region, with the price falling less than the average in the Northeast (9 percent) and more in the Midwest and West (19 and 18 percent, respectively).

The wellhead price is the price paid to the producer for the natural gas, in other words, the commodity cost. Between 1988 and 1994, the real natural gas wellhead price declined 11

percent, from \$2.05 to \$1.83 per thousand cubic feet (Figure 19 and Table 12).

Because of the different service requirements of the end-use sectors, the relative importance of each component of price varies substantially among the sectors (Figure 20).

For residential and commercial customers, most of  $% \left\{ 1\right\} =\left\{ 1\right\} =$ the end-use price is directly related to the costs of local distribution. For instance, the LDC markup accounted for 52 and 43 percent of the total price paid by the residential and commercial consumers, respectively. The costs of transportation services by pipeline companies accounted for 20 and 23 percent of the respective end-use prices, while the wellhead price accounted for 29 and 34 percent, respectively.76

The citygate price used in the calculation of these components

a weighted average of the delivered cost of gas across the customer classes served by LDC sales. Because it may include lower cost onsystem industrial and electric utility volumes, it may understate

delivered citygate price to the residential and commercial sectors. result, the distribution markup to residential and commercial

may be overstated, and the transmission markup may be understated. However, this problem is relatively minor given that approximately

percent of deliveries to the citygate in 1994 were accounted for by deliveries to residential and commercial customers.

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates Table 12. Average Natural Gas Prices and Price Changes, 1988 and 1994

| (1994 Dollars per Inousa | na Cubic Feet) |      |      |              |                |
|--------------------------|----------------|------|------|--------------|----------------|
|                          | Price          | 1988 | 1994 | Price Change | Percent Change |
| Wellhead                 |                | 2.05 | 1.83 | -0.22        | -11            |
| Citygate                 |                | 3.54 | 3.08 | -0.46        | -13            |
| End Use                  |                |      |      |              |                |
| Residential              |                | 6.64 | 6.41 | -0.23        | -3             |
| Commercial               |                | 5.62 | 5.43 | -0.19        | -3             |
| Onsystem Industrial      |                | 3.58 | 3.05 | -0.53        | -15            |

Electric Utility 2 83 2.28 -0.55 -19

Note: Industrial end-use price data represent onsystem sales only. The onsystem share of total sales to industrial consumer s declined from 43 percent in 1988 to 22 percent in 1994.

Sources: Energy Information Administration. 1988: Natural Gas Annual 1992, Vol. 2 (November 1993). 1994: Natural Gas Monthly (August 1995).

Figure 19. Wellhead and End-Use Prices by Sector, 1988-1994

Price 7.00 7-Year Average Residential 6.00 Commercial 1994 Dollars per Thousand Cubic Feet 5.00 4.00 Onsvstem Industrial 3.00 Electric Utility W ellhead 2.00 1.00

Note: Industrial end-use price data represent onsystem sales only. The onsystem share of industrial deliveries declined from 43 percent in 1988 to 22 percent in 1994.
Sources: Energy Information Administration. 1988: Natural Gas Annual 1992, Vol. 2 (November 1993). 1989-1994: Natural Gas Monthly

1990

1991

1992

1993

1994

1989

(August 1995).

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1988

0.00

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Figure 20. Components of End-Use Prices by Sector, 1994 (Dollars per Thousand Cubic Feet)

> Residential Commercial Total Price = \$6.41 Total Price = \$5.43

\$1.25

\$1.25 Transmission Markup \$1.83 \$1.83 (19.5%) Wellhead Price Transmission Markup Wellhead Price (28.5%) (23.0%) (33.7%)

\$3.33 \$2.35 Distribution Markup Distribution

Markup (52.0%) (43.3%)

Electric Utility
Total Price = \$2.28 Onsystem Industrial Total Price = \$3.05

\$1.83 \$1.83

Wellhead Price Wellhead Price (60.0%)(80.3%)

> \$1.22  ${\it Transmission} \ {\it and} \ \\$ Transmission and Distribution Markup Distribution Markup (19.7%)

(40.0%)

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! For the onsystem industrial and electric utility sectors, the wellhead price of natural gas is the largest component of the total end-use price. In 1994, the wellhead price accounted for 60 percent of the industrial price while the combination transmission and distribution charge accounted for the remaining 40 percent. In the electric utility sector, the wellhead price accounted for 80 percent of the 1994 end-use price while the transmission and distribution charge comprised the remaining 20 percent.

Before proceeding, it should be noted that as a result of data limitations, the end-use prices used to calculate the industrial and commercial transmission and distribution markups reflect only onsystem sales. As a result, the markups overstate the actual markups for these sectors (Figure 21). While this issue is a concern in the case of the commercial sector, where onsystem sales account for 78 percent of deliveries, it is an especially serious limitation in the industrial sector where the burnertip price reflects only 24 percent of the market.

Except for the commercial customers, combined transmission/distribution markups declined during the period 1988 through 1994 (Figure 22). Specifically, the markup for the

industrial sector fell by 20 percent, while the electric utility markup declined by 42 percent. The declines in these markups are no doubt largely attributable to the increase in transportation options available to these customer classes during this period.

In fact, average industrial retail prices have been lower than citygate prices as LDC's have attempted to prevent their industrial customers from bypassing their system with direct tie-ins to nearby pipelines. Loss of industrial customers, with their higher and less variable demands, would increase the LDC's unit cost of service. These higher rates would have to be covered by the residential and commercial customers remaining on the system. Therefore it may be to the advantage of all of its customers for LDC's to discount prices to those customers who contribute most to lowering the overall costs of the LDC.

The combined transmission/distribution markup for the residential and commercial sectors declined marginally in the 1988 through 1993 period, but rose modestly from 1993 to 1994. For these sectors, the combined transmission/ distribution markup in 1994 was within 3 cents of the level in 1988. While the total markup paid by these customers has remained roughly constant, the transmission component of the total markup (or the markup to citygate) declined 16 percent in real terms from 1988 to 1994 (Figure 23). This is striking given that some analysts believed that the switch to straight fixed-variable from modified fixed-variable rate design would

increase the average cost of transmission for these low-load-factor sectors. As discussed earlier in this chapter, a number of considerations put either upward or downward pressures on maximum taniff rates for pipeline transportation. A possible reason for the lower transmission markup to these sectors is that the higher reservation charges are being spread over a higher volume of deliveries. Also, the regulatory changes during the period may have permitted some LDC's to exploit previously unavailable lower cost transportation options.

In contrast to the transmission markup, the distribution markup for residential and commercial customers was roughly flat in real terms from 1988 through 1993, but increased substantially from 1993 to 1994 (Figure 23). The sharp increase in the distribution markup between 1993 and 1994 may reflect the higher costs incurred by LDC's who, with the unbundling of pipeline company services, have had to take responsibility for security of supply, including storage. Bypass by industrial customers and electric utilities may also have contributed to the increased LDC markups paid by residential and commercial customers in 1994.

Trends in Regional Prices: End-Use and Citygate

Changes in end-use prices between 1988 and 1994 varied greatly by geographic region (Figure 24). As at the national level, the regional changes were the greatest in the onsystem industrial and electric utility sectors. In most regions, real average prices declined by 10 percent or more in these sectors (1994 dollars).

The largest regional percentage change during the period was a 29-percent drop in the real price of natural gas to electric utilities in the Western Region. In 1988, the price of gas to electric utilities in the Western Region was \$3.52 per thousand cubic feet (1994 dollars), the highest of any region. Even after dropping to \$2.50 per thousand cubic feet in 1994, electric utilities in this region still paid the highest average price for natural gas of all the regions. The price change from 1993 to 1994 contributed significantly to the overall drop in prices during the period. From 1993 to 1994, electric utility gas consumption increased 30 percent in this region, possibly as a result of drought conditions in the Northwest that reduced the availability of hydroelectric power. The average price of gas to electric utilities fell by \$0.57 per thousand cubic feet (1994 dollars) or 19 percent from 1993 to 1994.

The largest actual price change (and second largest percentage change) also occurred in the Western Region, but in the onsystem industrial sector. The real average price of gas to industrial users fell \$1.20 per thousand cubic feet

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Figure 21. Transmission/Distribution Markups by Sector, 1988 and 1994

Transmission

5.00

Markup to Citygate

4.00

Thousand Cubic Feet

1994 Dollars per

3.00

Combined Transmission and Distribution Markup

2.00

\$1.49

\$1.25

5.00

(1994 Dollars per Thousand Cubic Feet)

1.00

\$4.59 \$4.58

Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Natural Gas Annual, Vol. 2 (November 1993); 1994:

Natural Gas Monthly (August 1995).

Electric

U tility

| Figure 22. Indices of Transmission/Distribution Markups by Sector, 1988-1994 |                                 |      |      |      |      |      |      |                               |       |                              |
|--|---------------------------------|------|------|------|------|------|------|-------------------------------|-------|------------------------------|
| 120  | Transmission Markup to Citygate |      |      |      |      |      |      |                               |       |                              |
| 100  |                                 |      |      |      |      |      |      |                               |       | Index                        |
| 1988 = 100   |                                 |      |      |      |      |      |      |                               |       | 21100.                       |
|  |                                 |      |      |      |      |      |      |                               |       |                              |
| 80   |                                 |      |      |      |      |      |      |                               |       |                              |
| 60   |                                 |      |      |      |      |      |      |                               |       |                              |
| 40   |                                 |      |      |      |      |      |      |                               |       |                              |
| 20   |                                 |      |      |      |      |      |      | 120                           |       |                              |
| 0  |                                 |      |      |      |      |      |      |                               |       |                              |
| 1988   |                                 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |                               |       |                              |
| Index 1988 = 100   |                                 |      |      |      |      |      |      |                               |       |                              |
|  |                                 |      |      |      |      |      |      |                               |       |                              |
|  |                                 |      |      |      |      |      |      | 80                            |       |                              |
|  |                                 |      |      |      |      |      |      | 60                            |       |                              |
| Distribution   |                                 |      |      |      |      |      |      | C o m b ined Transmission and |       |                              |
|  |                                 |      |      |      |      |      |      | 40                            |       | dential<br>ercial            |
|  |                                 |      |      |      |      |      |      | 20                            | Onsys | stem Industrial<br>ctricUtil |
| i t y  |                                 |      |      |      |      |      |      | a                             |       |                              |

Notes: Industrial markups reflect end-use prices for onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

1993

1988

1989

1990

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Natural Gas Annual, Vol. 2 (November 1993); 1989-1994: Natural Gas Monthly (August 1995).

1992

Energy Information Administration 59 Energy Policy Act Transportation Study:

Interim Report on Natural Gas Flows and Rates Figure 23. Indices of Residential and Commercial Distribution Markups and Citygate Transmission Markup, 1988-1994

Onsystem

1991

Industrial

80

Index 1988 = 100

60

Distribution Markup - Commercial 40 Distribution Markup - Residential Transmission Markup to Citygate

20

1988 1989 1990 1991 1992 1993 199/

Source: Energy Information Administration, Office of Oil and Gas, derived from: 1988: Natural Gas Annual, Vol. 2 (November 1993); 1989-1994: Natural Gas Monthly (August 1995).

Figure 24. Percentage Change in End-Use Prices by Sector and Region Between 1988 and 1994

10

0

(10)

Percent

(20)

(30) Residential Commercial Onsystem Industrial

Northeast Southeast

ElectricUtility

M idwest

(40)

Central

Notes: Changes were calculated in 1994 dollars. Industrial end-use price data represent onsystem sales only. The onsystem share of industrial deliveries was 43 percent in 1988 and 22 percent in 1994.

Source: Energy Information Administration, Office of Oil and Gas, derived from: Natural Gas Monthly (August 1995).

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(27 percent), perhaps because of competition from Canadian imports. The 1988 price of \$4.45 per thousand cubic feet

(1994 dollars) was the third highest in the onsystem industrial sector, and by 1994, the Western Region had only the fourth highest industrial gas prices. The average real price to industrial users fell by 10 to 16 percent in all other regions during the neriod.

The price changes were not as dramatic for residential and commercial users, but average real prices in these sectors did fall from 2 to 10 percent in every region, with two exceptions—residential prices in the Northeast and commercial prices in the Western Region. The price of natural gas to residential users rose \$0.47 per thousand cubic feet (6 percent) in real terms in the Northeast Region. Residential gas prices in the Northeast were higher than in any other region throughout the period and reached \$8.06 per thousand cubic feet in 1994. The largest decline in real residential prices occurred in the Midwest where real prices fell from \$6.15 per thousand cubic feet in 1988 to \$5.56 in 1994 (10 percent).

In the commercial sector, the largest real price drop also occurred in the Midwest. Commercial prices fell from \$5.51 to \$4.98 per thousand cubic feet during the period (10 percent) in this region. While the prices in most other regions fell from 2 to 10 percent, prices rose \$0.44 per thousand cubic feet, or 8 percent, to commercial users in the Western Region. This increase moved the Western Region from the third to the second highest priced region for commercial gas users between 1988

Between 1988 and 1994, citygate prices, the average delivered price of gas to the local distribution company, decreased

#### Conclusion

FERC Order 636, issued in 1992 and implemented in November 1993, probably had the most significant direct effect on transportation rates between 1988 and 1994. Specifically, Order 636 separated the pipeline's merchant/ shipper role; unbundled transportation, storage, and ancillary services; changed the method of computing transportation rates; and initiated a capacity release program that allows customers to reassign their capacity rights for a revenue credit. The costs to pipeline companies of complying with Order 636 and restructuring their operations (transition costs) have also affected rates. As of August 1995, \$2.7 billion in transition costs, for eventual recovery from pipeline customers, had been filed at FERC.

Southwest W estern United States

Prior to FERC Order 636, Order 436 (issued in 1985) initiated industry restructuring by encouraging pipeline companies to offer open access. Open access promoted producer competition, exerting downward pressure on wellhead prices. Other legislation and policies, such as the Clean Air Act Amendments, have indirectly affected transportation rates by expanding gas markets and/or encouraging conservation, Also, rates paid between 1991 and 1994 were strongly influenced by greater efficiency in operations, the cost of capacity additions, and take-or-pay costs incurred by pipeline companies.

#### Additional conclusions are:

! On average, customers are paying less (in real terms) for natural gas service in 1994, compared with 1988. This includes declines of 11 and 13 percent in the wellhead

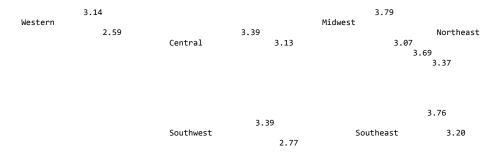
61

\$0.46 per thousand cubic feet, or 13 percent. Although the average citygate price may not broadly apply to any specific customer sector, it may indicate the regional cost to customers. Comparing 1994 and 1988 citygate prices across the regions, the price decrease ranged from \$0.26 per thousand cubic feet (8 percent) in the Central Region to \$0.72 per thousand cubic feet (19 percent) in the Midwest (Figure 25). For all but two regions (Northeast and Central), the decrease in the citygate price exceeded \$0.50 per thousand cubic feet, representing at least a 15-percent reduction since 1988. The smaller reduction in the Northeast probably reflects the costs associated with incremental pipeline capacity added between 1988 and 1994 as well as the great distance between this region and the major supply areas of both the United States and Canada. For each region, the decrease in citygate prices exceeded the average decrease in the wellhead price (\$0.22 per thousand cubic feet). This points to an overall reduction in the costs for interstate transmission. The relatively sharper declines in the Southeast (\$0.56 per thousand cubic feet), Midwest (\$0.72 per thousand cubic feet), and Southwest (\$0.62 per thousand cubic feet) may suggest that local distribution companies in these regions derive more direct benefits from reduced transportation costs.

and citygate prices, respectively, and an average decline of between of 3 and 19 percent in end-user prices. Residential and commercial prices generally declined the least, while electric utility prices declined the most. Onsystem industrial prices declined almost 15 percent between 1988 and 1994.

- ! Between 1988 and 1994, total transmission and distribution markups to the residential and commercial sectors remained fairly constant in real terms, while comparable prices to the onsystem industrial and electric utility sectors declined dramatically by 20 and 42 percent, respectively.
- ! Transmission costs, the cost of moving gas from the wellhead to the local distributor, decreased 16 percent in real terms between 1988 and 1994. However, the

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Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates
Figure 25. Citygate Prices by Region, 1988 and 1994
(1994 Dollars per Thousand Cubic Feet)



1988 Citygate Price 1994 Citygate Price

Source: Energy Information Administration (EIA), Office of Oil and Gas, derived from: a special extract from Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers."

decrease in the transmission component was almost completely offset by an average real price increase of 7 and 13 percent in the local distribution company markup for the residential and commercial sectors, respectively. Although total transmission and distribution markups to captive residential and commercial consumers have remained fairly constant in real terms, they may be benefiting from the increased competition in interstate transportation.

- ! The analysis of maximum allowable rates suggests that low-load-factor customers have benefited less than high-load-factor customers from the recent regulatory changes. Although both categories saw both increases and decreases in tariffs, in all cases the change was more advantageous to the high-load-factor customers.
- ! While other influences may have mitigated SFV's downward pressure on high-load-factor rates and upward pressure on low-load-factor rates, the change in rate design was the dominant influence in widening the gap between the rates paid by the two groups. Except for the change in rate design, other key determinants of

- firm rates would tend to have the same general impact on customers regardless of their load factors.  $\,$
- ! Comparing pre- and post-Order 636 rates in the corridors served by multiple pipelines suggests that transportation services offered by different pipeline companies may have been more comparable over the period. The variation among pipelines in a corridor is decreasing—with the decrease being more pronounced for low-load-factor customers. The comparison shows some convergence of rates between 1991 and 1994 for several of the corridors. One possible explanation is that increased competition and integration of the pipeline grid may have increased the comparability of services offered by pipeline companies. In addition, Order 636's directive to use a common rate design method for all pipeline companies may have led to more similarity in the rates offered by pipeline companies serving the same corridor.
- ! Total revenues generated by the capacity release program from November 1993 through March 1995 totaled \$568 million. Trading of capacity has increased significantly since the program began and currently represents 13 percent of the overall volumes moved to

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Energy Information Administration

Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates market. On average, capacity trades at a 64-percent in other regions possibly because discount from maximum rates.

in other regions possibly because of capacity constraints or the relative unavailability of released capacity in the region.

! The regional rates for released firm capacity vary significantly. Rates in the Southeast are higher than those

Energy Information Administration

Energy Policy Act Transportation Study: Interim Report on Natural Gas Flows and Rates

#### On the Estimation of Failure Rates of Multiple Pipeline Systems

http://cat.inist.fr/?aModele=afficheN&cpsidt=20474871 December 07, 2014

64

#### Rupture;

Departamento de Ingeniería Metalúrgica, IPN-ESIQIE, UPALM Edif. 7, Zacatenco, Mexico, Distrito Federal 07738, MEXIQUEColegio de Ciencia y Tecnología, Universidad Autónoma de la Ciudad de México, Mexico, Distrito Federal 09090, MEXIQUEIn this work, the statistical methods for the reliability of repairable systems have been used to produce a methodology capable to estimate the annualized failure rate of a pipeline population from the historical failure data of multiple pipeline systems. The proposed methodology provides point and interval estimators of the parameters of the failure intensity function for two of the most commonly applied stochastic models: the homogeneous Poisson process and the power law process. It also provides statistical tests for assessing the adequacy of the stochastic model assumed for each system and testing whether all systems have the same model parameters. In this way, the failure data of multiple pipeline systems are only merged in order to produce a generic failure intensity function when all systems follow the same stochastic model. This allows statistical and tolerance uncertainties to be addressed adequately. The proposed methodology is outlined and illustrated using real-life failure data of oil and gas pipeline systems. JPVTAS2008, vol. 130, n2, [Note(s): 021704.1-021704.8] (9 ref.) Anglais American Society of Mechanical Engineers, New York, NY, ETATS-UNIS (1974) (Revue) INIST-CNRS, Cote INIST: 6120 J, 35400019755538.0150

# 🔼 Oil and Gas Pipeline Design, Maintenance and Repair

http://eng.cu.edu.eg/users/aelsayed/Part%208%20%20Maintenance,%20%20Reliability%20and%20Failure%20Analysis.pdf December 07, 2014

PE 607: Oil & Gas Pipeline Design, Maintenance & Repair o Maintenance Plan • For each system, determine a maintenance strategy • For each system identified for ...

```
Oil and Gas Pipeline Design,
  Maintenance and Repair
             Dr. Abdel-Alim Hashem
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Part 8 : Maintenance, Reliability and
             Failure Analysis
       PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
                                  Contents
     Maintenance objective
     Maintenance plan
Maintenance strategies
     Corrective maintenance
     Failure modes
     Pro-active maintenance
     PdM techniques
     Reliability
     Maintenance and the construction codes
     Elements of failure analysis
               PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
         Maintenance Objective
• "Ensuring that physical assets continue to do
what their users want them to do" [Moubray]

"To preserve the system function" [Smith]

"Physical as-sets" are pipes, valves, active equipment (pumps, compressors, etc., also referred to as dynamic or rotating equipment),
  instrumentation, fixed equipment (vessels, heat
  exchangers, etc., also referred to as static equipment), in-line components (traps, strainers,
  etc.), insulation and supports.
              PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
  Maintenance Variety of Manners

    Maintenance information is ignored. Things are

  fixed as they break, time and again.
  Maintenance information is recorded as data,
   somewhere on a server, on a shelf or in a
  drawer.

    Maintenance data is converted into knowledge

  for a few, the maintenance mechanic and possibly the system engineer.
  Maintenance knowledge is converted into
  wisdom, by analysis, trending, and communication (in a clear and illustrated manner) to the whole organization.
            PE 607: Oil & Gas Pipeline Design, Maintenance & Repair &
               Maintenance Plan

    For each system, determine a maintenance strategy
    For each system identified for proactive maintenance,

  prepare a component list (pipe segments, valves, pumps,
   compressors, etc.).
• For each component, specify the required function, its
failure mode and failure cause.For each component failure cause, select the proper
   inspection technique, The objective here is to decide
what needs to be inspected, when, where and how.

• Determine the acceptance criteria that will be used to
  evaluate the inspection results and to determine the
   "fitness-for-service" of the system
               PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
                Maintenance Plan
• Plan and implement maintenance inspections, either on
  stream (on line) or during an outage (shutdown).
• Document results, intelligently, clearly, and succinctly.
  Illustrate with digital photographs. Record in a retrievable and sortable maintenance database. Maintain "system
   health reports".
• Issue clear recommendations, for example in three categories: green (ok as-is), yellow (plan for future
```

inspection, degradation is taking place but equipment is

```
fit-for-service till next inspection), or red (repair or
  replace).
               PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
      Maintenance Strategies
There are two maintenance strategies

1. A reactive approach (corrective
maintenance, running equipment to
failure, or near failure)

2. A proactive ap-proach (inspecting
    equipment and taking early steps to
    overhaul, repair or replace, before
    failure).
          PE 607: Oil & Gas Pipeline Design, Maintenance & Repair Y
        Maintenance Strategies
Systems of a proactive maintenance strategy
• Facility safety basis: systems essential to prevent
or mitigate credible accidents that would have
unacceptable consequences to the workers, the
  public or the envi-ronment.

    Production loss: systems essential to maintain an

  acceptable level of produc-tion throughput.
• Maintenance cost: systems with equipment that
  would be costly to replace, or would require long
             PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
        Maintenance Strategies
Systems of a proactive maintenance strategy
  include
  Risk of failure: systems at greater risk of failure,
   for example because of corrosion, operation at
  high pressure or temperature, operation beyond vendor recom-mendations, or based on past
   company or industry experience.

    Regulatory requirements: systems or
components that are required, by regula-tion, to
be periodically inspected or tested

              PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
       Corrective Maintenance
• Is reactive maintenance: run to failure, then
  repair or replace
  Quite common for non-essential systems

    Maintenance managers cite limited manpower
and budgets focused first on solving the day's

  emergencies as an impediment to predictive
  maintenance
• A recent survey reported corrective maintenance at 40% of the maintenance workload

    Well-implemented, corrective maintenance
yields a wealth of knowledge

            PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
   Corrective Maintenance Work
               Package
• Equipment make and model.
• As-found condition (photographs are
  recommended).
• Mechanics' opinion as to the likely cause
  of failure.
· Corrective action (and possibly
  recommendation to avoid recurrence).
          PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
                    Failure Modes
• Failure mode and failure cause should be
  captured in a standard format, and regularly
   sorted, analyzed and trended
• The objectives to understand failure cause, and
  take pre-emptive measures to avoid recurrence,
  optimize per-formance, reduce costs, and
improve safetyCompany may develop its own maintenance
  history software

    To help in documentation and sorting, each

  class of equipment would have a standard list of
   failure modes and failure causes
             PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
  Failure Mode 1 - Pumps Fails to
                  Start
Corresponding Failure Causes:
Loss of power.Internal binding.

    Failed bearing.

    Failed coupling.

• Open or shorted motor.
• Start circuit fails.
          PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
  Failure Mode 2 - Pump Delivers
           Inadequate Flow
Corresponding Failure Causes:
• Worn or broken impeller.
```

Worn wear ring.Discharge valve closed.

Cavitation.Seal failure

```
• Casing cracked.
• Gasket leak.
• Clogged strainer.
• Shaft damage.
            PE 607: Oil & Gas Pipeline Design, Maintenance & Repair γε
  Failure Mode 3 - Pump Exhibits
Abnormal Condition
Corresponding Failure Causes:

    Excessive vibration.

· Leak of process fluid.
• Oil leaks.
• Excessive temperature.
• Unusual noise.
          PE 607: Oil & Gas Pipeline Design, Maintenance & Repair 10
A Second Level of Failure Causes
• The cause of the cause
• May be necessary to diagnose and correct
  the failure mode.
          PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
     An Example of Second Level Failure Causes
Failure Cause 1st Level - Excessive Vibration in Pump
Failure Cause 2nd Level:
Mechanical Cause:
• Unbalance.
• Eccentric rotor.
Bent shaft.Axial misalignment at shaft coupling.

    Angular misalignment at shaft coupling.

Loose foot.Rotor rubs against fixed part.
• Bearing wear
• Oil instabilities.
             PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
      An Example of Second Level
            Failure Causes
Failure Cause 1st Level - Excessive Vibration in
Centrifugal Pump
Failure Cause 2nd Level:
Mechanical Cause:
• Gear worn or broken.
Faulty motor.Belt drive misaligned.
Hydraulic Cause:
• Pressure pulsing from vane pass.

    Flow turbulence.

• Cavitation.
• Hydraulic resonance (Helmholtz oscillator)
              PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
       Pro-active Maintenance
    Preventive or Predictive Maintenance
    Inspection Checklists
            PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
         Preventive or Predictive
               Maintenance
• Where a system cannot be run to failure, it has to be part of the pro-active maintenance
  program.

    A choice must now be made between Preventive
Maintenance (PM) or Predictive Maintenance

    With PM, also referred to as Scheduled

  Maintenance [Patton], pre-determined maintenance activities take place at
  predetermined intervals; for example, replacing pump lube oil every X months, testing a relief
  valve every X years, etc
PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
Y.
Preventive Maintenance (PM)
• Also, referred to as Scheduled Maintenance [Patton],
  pre-determined maintenance activities take place at
   predetermined intervals

    For example, replacing pump lube oil every X months, testing a relief valve every X years, etc
    Based on several factors:

            Equipment failure history.

   - Vendor recommendations.
   - Industry practice, codes, standards.
    - Personnel experience.
    - Risk: likelihood and consequence of malfunction or
      failure.
              PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
 Predictive Maintenance (PdM)
• Given to the combina-tion of three
  activities: vibration analysis, thermography, and oil analysis
• Viewed in a much broader sense
```

```
• Based on the expert inspection and
   analysis - as quantitative as possible
   Involves more upfront effort and more
   expertise than PM
              PE 607: Oil & Gas Pipeline Design, Maintenance & Repair YY
              Inspection Checklists

    Use inspection checklists to guide and document the

   inspection

    Visual inspections supplemented by periodic surface

   inspections:

    - (typically liquid penetrant testing (PT) or magnetic particle testing (MT) or volumetric inspections
    - (typically ultrasonic testing (UT) or radiographic

       testing (RT)

    Based on the system's or component's risk
    Degradation of piping and equipment supports (steel or
   concrete structures) must be determined case by case, applying the rules of the construction codes and
                 PE 607: Oil & Gas Pipeline Design, Maintenance & Repair Yr
   Illustrative Example for PdM
Heat Exchanger
                                 Valves
                                                                                                   Vertical
                                                                                                   Vessel
           6 " pipe
                                                  2" Bleed
                        Support
                                                  pipe
               PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
                                                                                                           ۲ ٤
               PdM Techniques
• The system consists of 6" pipe, from a vertical
   vessel to horizontal heat exchanger, with two
welded manual valves, a support and a spring
hanger (line hot in service); and a 2" branch line
with a threaded manual valve

• The maintenance plan follows the outline of
• Maintenance strategy: predictive because the system is essential to operations
               PE 607: Oil & Gas Pipeline Design, Maintenance & Repair Yo
 Component List, Function, Failure
      Mode and Failure Cause
Piping 6" and 2", needs to remain leak tight
- Failure mode would be loss of pressure boundary
- Failure causes: corrosion or fatigue cracking Manual
       valves, normally open, must be able to close for
       isolation
Manual valves, normally open, be able to close for isolation

- Failure mode would be loss of operability (hand wheel cannot be turned), loss of leak tightness if closed,
       loss of pressure boundary through body, bonnet,
       packing, joints

    Failure causes: corrosion buildup, corrosion of wall,
packing wear, debris at valve seat, wear of valve disk

       or plug.
                  PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
 Component List, Function, Failure
Mode and Failure Cause
Vertical vessel must remain leak tight. No overpressure.
      Failure mode would be loss of pressure boundary (leak) or rupture by overpressure.
     - Failure causes: corrosion, failure of pressure relief
valve to open and discharge at set pressure
Heat exchanger must operate at nominal and full flow, need
to maintain heat transfer. No overpressure.

    Failure mode: tube leak, shell and heads leak, head
flange leak, overpressure.

      Failure causes: corrosion (thinning, cracking or
 plugging), inadequate flange gasket, bolts or assembly torque, tube vibration in cross flow, failure of pressure relief valve to open and discharge at set pressure

PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
Component List, Function, Failure
      Mode and Failure Cause
Supports, must maintain pipe in position, variable spring needs to remain within travel range.
     - Failure mode: support fails, pipe dislodges,
       and spring motion exceeds travel allowance.

    Failure causes: corrosion, impact (such as
water hammer) or vibration, wear of support

       parts, external damage
Inspection locations and techniques
    - Piping and vessels: visual inspection of
       equipment and supports
               PE 607: Oil & Gas Pipeline Design, Maintenance & Repair
 Component List, Function, Failure
      Mode and Failure Cause
Inspection locations and techniques
     - Valves: many facilities overhaul valves on a
       rotating schedule (preventive maintenance PM)
       Supports: on critical systems, support
       members and anchor bolts visually inspected,
    for evidence of damage
- Acceptance criteria for the integrity of the
```

```
pressure boundary of piping, ves-sels, heat
       exchangers and valve bodies are based on
       fitness-for-service procedures,
             PE 607: Oil & Gas Pipeline Design, Maintenance & Repair Y9
                                   Reliability
• There are basically three methods to gain knowledge
from maintenance ac-tivities.

• The first method is to investigate a failure or malfunction
   in the field, as it happens.
• The advantage of this approach is that a lot of first hand
   information can be gathered regarding failure mode and
   failure cause.
• The shortcoming is the diffi-culty to generalize the
  findings.

    The second method is to qualitatively review his-torical

  maintenance records, particularly corrective maintenance, for a class of equipment over a period of
                 PE 607: Oil & Gas Pipeline Design, Maintenance & Repair \ensuremath{\text{r}}\cdot
  Some Examples of Mean Failure
Tanks and Vessels
• Tank leakage IE-7/hour
• Vessel ruptures 5E-9/hour

Heat exchanger tube leak 1 E-6/hour
1/4" leak in vessel or storage tank 4E-5/year

4" leak in vessel or storage tank 1E-5/year
Rupture of vessel 6E-6/year

• Rupture of storage tank 2E-5/year
              PE 607: Oil & Gas Pipeline Design, Maintenance & Repair r)
  Some Examples of Mean Failure \,
                Rates
Pipe and Fittings:
• Leak of metallic straight pipe 0.0268E-6/hour
• Leak of metallic fittings 0.57E-6/hour
• Flange gasket leak 1 E-7/hour

Plugged strainer 3E-6/hour
1/4" leak in 3/4" pipe 1E-5/year-ft
1/4" leak in 6" pipe 4E-7/year-ft

• 1/4 leak in o pipe larger than 16" 6E-8/year-ft
• Rupture of %" pipe 3 E- 7/year - ft
• Rupture 6" pipe 8E-8/year-ft
• Rupture pipe larger than 16" E-8/year-ft
                PE 607: Oil & Gas Pipeline Design, Maintenance & Repair rr
  Some Examples of Mean Failure
                Rates
Valves:
Solenoid valve fails open 3E-6/hourSolenoid valve fails closed 3E-6/hour

    Solenoid Vaive fails closed 3E-6/hour
    Solenoid fails to respond 2.83E-3/demand
    Motor operator fails to respond 5.58E-3/demand
    Air operator fails to respond 2.2E-3/demand
    Safety relief fails to open 3E-3/day
    Safety relief fails to reclose 3E-3/day
    Check valve leaks through E-6/hour

• Check valve leaks through 3.18E-6/hour
                PE 607: Oil & Gas Pipeline Design, Maintenance & Repair rr
  Some Examples of Mean Failure
                Rates
Pumps and Compressors:
• Compressor fails 1430E-6/hour
• Pump motor fails to start lE-2/demand
• Centrifugal pump motor fails to start 18.6E-3/demand
• Centrifugal pump motor fails to furl at rated speed
    920E-6/hour
  Centrifugal pump motor fails while running 292E-6/hour
• Pump overspeed 3E-5/hour
• Pipe leak 3E-9/hour-foot
• Pipe rupture IE-I0/hour-foot
                PE 607: Oil & Gas Pipeline Design, Maintenance & Repair τε
   Elements of Failure Analysis
• Data Collection
```

• Visual Examination, Macrofractography and

• Metallography and Microfractography

• Chemical Analysis

Mechanical Tests

• Stress and Fracture Analysis

Improvements

PE 607: Oil & Gas Pipeline Design, Maintenance & Repair  $\tau \circ$ Shear and Tension Overload

PE 607: Oil & Gas Pipeline Design, Maintenance & Repair "T Tension, Shear and Tearing Failures

PE 607: Oil & Gas Pipeline Design, Maintenance & Repair TA

#### The History of Oil Pipeline Spills in Alberta, 2006-2012

http://www.seankheraj.com/?p=1257 December 07, 2014

According to the Globe and Mail, this rupture, which occurred along a pipeline operated by Pace Oil & Gas, ... This measurement of pipeline failure rate, ...

[This article was updated on June 8, 2012]

Late Thursday evening on June 7, 2012, the Sundre Petroleum Operators Group, a not-for-profit society, notified Plains Midstream Canada of a major oil pipeline failure near Sundre, Alberta that spilled an early estimate of between 1,000 and 3,000 barrels of light sour crude oil (~159-477 cubic metres) into Jackson Creek, a tributary of the Red Deer River. The river is one of the province's most important waterways, providing drinking water for thousands of Albertans.

This recent spill occurred just weeks after another oil pipeline burst in Alberta in late May, spilling an estimated 22,000 barrels of oil and water (~3,497 cubic metres) across 4.3 hectares of muskeg in the northwest part of the province near Rainbow Lake. According to the Globe and Mail, this rupture, which occurred along a pipeline operated by Pace Oil & Gas, Ltd., "ranks among the largest in North America in recent years," and certainly in the province of Alberta. A couple of weeks after the accident, the company downgraded the estimate to 5,000 barrels of sweet crude oil with no water (~795 cubic metres).

These recent spills are considerably smaller in volume of liquid hydrocarbons released than last year's 28,000 barrel (~4,452 cubic metres) spill on the Rainbow pipeline operated by Plains Midstream Canada near Little Buffalo, Alberta. While the 2011 Plains Midstream oil pipeline rupture may have been the largest single spill event in recent memory, the entire oil pipeline network in Alberta has spilled nearly equivalent volumes of liquid hydrocarbons every year since 2006.

As my brief history of oil pipeline spills in Alberta from 1970 to 2005 demonstrated, the problem of pipeline ruptures is endemic to the industry. Now with over 399,000 kilometres of pipelines under the authority of the province's Energy Resources Conservation Board, industry specialists and regulators not only know that this system has never been free from oil spills, but that a spill-free system is an impossible goal. The recent history of pipeline ruptures in Alberta since 2006 further underlines these realities.

At 1:46am on October 10, 2006, the Rainbow Pipe Line Company became aware of a crude oil spill on its pipeline 20 kilometres southeast of Slave Lake. Roughly 7,924 barrels of oil (~1,260 cubic metres) poured into a series of ponds near the northern Alberta town, despoiling wildlife habitat on what one local news outlet ironically referred to as "Black Tuesday." Darin Barter from the Alberta Energy Utilities Board tried to reassure Albertans that the incident was anomalous. According to the CBC, Barter "said it is rare for pipelines to fail in Alberta." The EUB press release also stressed this point, insisting that "[p]ipeline failures in Alberta are rare."

The alleged rarity of such oil pipeline spills was probably of little solace to the residents and tourists who enjoyed the recreational benefits of life on Glennifer Lake. In mid-June 2008, Pembina Pipeline Corporation accidentally leaked 177 barrels of oil (28.1 cubic metres) into the Red Deer River, eventually resulting in a large oil slick on the surface of Glennifer Lake. While the volume of the spill was considerably smaller than the 2006 Rainbow Pipeline spill, the location of the rupture in a river and lake made this incident more threatening to human lives. As Pembina's district superintendent Sandy Buchan told the Red Deer Advocate, "Anytime you are putting oil into the river and you are affecting people's drinking water, you need to take it very seriously." Pembina instructed local resorts on Glennifer Lake to turn off their drinking water intakes to avoid human consumption of the contaminated water. From June 18 to 27, the company trucked in drinking water to service the community throughout the course of the emergency until the David Thompson Health Region declared the water safe for drinking again. The day after Pembina discovered the oil spill, the Energy Resources Conservation Board once again tried to reassure Albertans about the infrequency of pipeline failures in the province and issued a press release which emphasized that the rate of pipeline ruptures "was at a record low 2.1 failures per 1000km of pipeline in 2007." This measurement of pipeline failure rate, however, is somewhat misleading in terms of the environmental impact of oil pipeline spills.

The ERCB has used the ratio of the number of pipeline failure incidents to the total length of the province's pipeline network as a metric to illustrate the safety of the system. For example, in its 2011 field surveillance and operations summary, the ERCB boasts that the failure rate "was 1.6 per 1000km in 2010." Furthermore, of the 1,174 liquid pipeline releases in 2010, 94 per cent "had no impact on the public." This metric for measuring the safety of the pipeline system does not, in fact, measure frequency since frequency is measurement of time, not a measurement of distance. As such, it makes more sense to look at the number of pipeline failures per year. In 2010, there were 20 crude oil pipeline failures and 241 multi-phase pipeline failures (carries crude oil and gas). According to the ERCB, these pipeline failures released 3400 cubic metres of liquid hydrocarbons or roughly 21,000 barrels of oil. If we consider just the crude oil pipeline failures in 2010, there were an average of 1 pipeline failure every 18.25 days. If we include multi-phase pipeline failures, that's 1 every 1.4 days.

The trouble, of course, is that the ratio of pipeline failures to total distance of the network and the vague description of "impact on the public" does not adequately convey the environmental risks of large oil pipeline networks. The environmental impact of oil pipeline spills is obscured under this rubric.

The ratio of number of pipeline failures to the total length of the network disguises three important measurements of the environmental impact of oil spills: volume, product type, and location. While the rate of individual pipeline ruptures has declined in Alberta since 2006, this rate includes all substances, including water, and does not convey the volume of individual spills. When considered by product type, between 2006-2010 there have been 109 failures on crude oil pipelines and 1,538 failures on multi-phase pipelines, which carry a combination of crude oil and gas. By volume, the quantity of liquid hydrocarbon spills on Alberta's pipeline network is staggering. From 2006-2010, the pipeline network leaked roughly 174,213 barrels of oil (~27,700 cubic metres). In 2010 alone, more than 21,000 barrels (~3,400 cubic metres) were spilled across the network, nearly the equivalent of the most recent oil spill near Little Buffalo.

As the 2008 pipeline failure on the Red Deer River and Glennifer Lake demonstrated, when it comes to the environmental impact of oil spills, it is all about location. Even a relatively small spill in a critical body of water can have enormously detrimental effects on people and wildlife. The cost of cleaning such spills can also vary greatly by location. Unfortunately, the ERCB data from the field surveillance and operations summaries do not include geographic data to assess environmental effects of oil pipeline spills.

To keep track of the recent historical geography of oil pipeline spills in Alberta, I have created the following map below. The map includes rough geographic data about major oil pipeline spills in Alberta from 2006 to 2012. The spatial distribution of these major oil pipeline spills reveals, perhaps, why these events so quickly fade from public discourse and popular memory. All but two of the substantial oil spills since 2006 occurred north of Edmonton, away from the province's major urban centres. As such, most ordinary Albertans have never personally witnessed the environmental consequences of these pipeline failures. The relatively small leak of crude oil into the Red Deer River in 2008 drew a lot of public and news media attention because of its proximity to the city of Red Deer and a popular tourist destination. Similarly, the most recent spill on Jackson Creek is likely to draw considerable attention. Had the May 2012 Pace Oil & Gas spill in northwest Alberta near Rainbow Lake occurred to the south in a more populous (and popular) location, such as Banff National Park, it almost certainly would have attracted greater national media attention. The

geography of oil pipeline spills then has political consequences that must also be considered when assessing extension of the pipeline network.

A more accurate measurement of the environmental impact of oil pipeline spills should include information about volume, product type, and location. Only then can Canadians understand the environmental history of oil pipelines and reasonably assess future plans to expand the network.

Please let me know in the comments if I have missed any major spills on the map below.

#### Gas Pipeline Failure

http://www.oilcoalgas.com/gas/gas-pipeline-failure.php December 07, 2014

Natural Gas; Oil Fired; Coal Fired; Nuclear Power Generation; Power Distribution; ... Pipeline Failure Investigation Reports resulting from four gas pipeline failures.

The following provides summaries of the Pipeline and Hazardous Materials Safety Administration (PHMSA) Pipeline Failure Investigation Reports resulting from four gas pipeline failures. These are not intended to provide a comprehensive study of gas pipeline failures,. These summaries are only intended to give a few real-life examples of what can happen.

The complete reports are available online at: See Complete Report »

On November 3, 2011 a pipeline failed at the Artemas Compressor Station in Bedford County, PA. The failure resulted in the release of natural gas and resulted in a fire. Property damage was limited to the compressor station, and the main office structure and several outbuildings were destroyed due to the heat and flames. There was no damage to public property. There were no injuries or fatalities as a result of this incident.

What had failed was a two inch manual drain line, located at the bottom of Filter Separator-A. The drain pipe wall had thinned as a result of internal corrosion. The pressure in the filter separator at the time of failure was 1,940 psig. This was below the 2,400 psig Maximum Allowable Operating Pressure (MAOP) for the filter separator.

The corrosion in the drain line was caused by fluid collecting and remaining stagnant in the manual dump drain line for lengthy periods of time. The fluids would be drained when the dump valve was manually operated, but this was done infrequently. The separator was equipped with an automatic dump system which resulted in the manual dump valve only being operated occasionally.

According to the laboratory analysis the stagnant fluid led to internal corrosion and wall thinning in the failed section of piping. The internal corrosion was only found in the manual dump piping. There was no indications of internal corrosion in the piping associated with the automatic dump system.

To prevent similar damage in other manual dump valves, all manual dump valves will be operated weekly, during the winter season, to remove fluids and solids. Where applicable, the heat tracing on liquid removal devices will be inspected once per week during the winter season.

Tennessee Gas Pipeline Company (TGP) provides transportation of natural gas for industrial and commercial deliveries from South Texas to the East Coast through several systems. The failure described here occurred in the 100 System.

The 100 System has 4,600 miles of multiple pipelines running from Texas to West Virginia. On December 8, 2010 a release of natural gas in the discharge header area of Station 17 at East Bernard, TX was detected. The failed pipe was a dead leg 24 inch diameter, half-inch wall, X-40 lateral that connected to the station discharge header piping.

The MAOP of the piping is 750 psig. The failure occurred at a pressure of 720 psig.

The failure was a sudden rupture that left a 100 foot by 25 foot hole around the pipeline. Approximately a twelve foot section of the pipe was thrown 295 feet from the hole. No injuries or fire resulted from this failure. All damages were contained within Station 17.

The station ESD was activated immediately when the incident occurred. Approximately 9 miles of 30â pipeline was blown down to secure the location, taking about 6 hours.

The investigation revealed that a dead leg was established in 2000 when a 24-inch high pressure pipeline was sold and disconnected from the TGP system. Inspection during the disconnecting process revealed no internal corrosion issues. The disconnect resulted in approximately 40 feet of isolated pipe without any gas flow. This abandoned connection became a dead leg in the piping at the station and was the point of failure for the rupture.

The failure mechanism that led to the pipeline rupture was identified as internal microbiologically induced corrosion (MIC). An 83.6% wall loss was measured. There were obvious indications of residual moisture gathering in the dead leg, contributing to internal corrosion and a thinning of the pipe wall. The final conclusion was that the moisture in the pipe promoted the growth of microbiological organisms which resulted in corrosion. Evaluation of all other dead leg segments of pipe in the Station yard found no additional areas affected.

At approximately 5:08 pm on November 30, 2010 Tennessee Gas Pipeline Co. (TGP) reported a release of natural gas due an unknown cause on their pipeline downstream of Station 40, Natchitoches, Louisiana.

A failed 30-inch pipe was found approximately 1.4 miles downstream of the compressor station. A 50 inch long, straight circumferential crack had occurred in a wrinkle bend. Wrinkle bends were common in construction when the pipeline was installed in 1948. The failure was sudden, leaving a 15â hole around the pipeline. There was no fire or injuries associated with this failure. The section of pipeline was isolated and the system was blown down by approximately 4:40 pm.

The pipeline MAOP is 750 psig and was operating normally at approximately 671 psig when the failure occurred.

An analysis of the pipe failure was done with the following conclusions:

A pipeline technician, assigned to take annual cathodic protection readings, noticed bubbles in standing water within the pipeline right-of-way. The area is crisscrossed with small diameter crude oil gathering pipelines and this resulted in uncertainty about the source of the bubbles.

The source of the bubbles was found to be a leak in the Transco 24-inch "A Pipeline." Production supplying the "A Pipeline" was shut-in and the valve segment isolated. Excavation revealed that the gas was coming from a small external corrosion anomaly located on the pipeline at approximately the 5 oâclock position. Additional isolated corrosion pits in the pipe near the leak site required that about 30 feet of the pipe be replaced.

A metallurgical evaluation determined that the probable cause of the failure was microbiologically induced corrosion (MIC). The analysis also indicated that the coal tar coating near the leak was degraded. This most likely was caused by hydrocarbon liquids leaking from a deteriorated gathering pipeline that crossed above the Transco "A Pipeline." The leaking hydrocarbons would have created an environment conducive to the growth of sulfate reducing bacteria.

Transco had recently changed the cathodic protection on this segment of the pipeline from using the -850mV with consideration for IR drop to the 100 mV depolarization criterion. A close-interval survey (CIS) performed in 2009 did not indicate any areas where the 100mV criterion was not being met.

While MIC is a different failure mechanism than traditional electrochemical corrosion, research has found that 200 to 300 mV of polarization may protect carbon steel from corrosion caused by sulfate reducing bacteria. Higher polarization potentials may be required to accomplish this protection depending on the specific environment around the pipeline. While there was no indication that Transco was not meeting the required cathodic protection requirements of Part 192, the level of cathodic protection potentials maintained on the âA Pipelineâ apparently were not of a high enough level to inhibit MIC.

#### **Pipeline Capacity and Utilization**

http://www.eia.gov/pub/oil\_gas/natural\_gas/analysis\_publications/ngpipeline/usage.html December 07, 2014

Natural Gas Pipeline Capacity & Utilization Overview | Utilization Rates | Integration of Storage ... The systemwide pipeline flow rate, ...

Integrating storage capacity into the natural gas pipeline network design can increase average-day utilization rates. This integration involves moving not only natural gas currently being produced but natural gas that has been produced earlier and kept in temporary storage facilities.

On the other hand, during periods of high demand for natural gas transportation services, usage on some portions of a pipeline system may exceed 100% of certificated capacity. Certificated capacity represents a minimum level of service that can be maintained over an extended period of time, and not the maximum throughput capability of a system or segment on any given day.

Utilization rates below 100% do not necessarily imply that additional capacity is available for use. A pipeline company that primarily serves a seasonal market, for instance, may have a relatively low average utilization rate especially during the summer months. But that does not mean there is unreserved capacity on a long-term basis.

Most companies try to schedule maintenance in the summer months when demands on pipeline capacity tend to be lower, but an occasional unanticipated incident may occur that suspends transmission service.

Natural gas pipeline companies prefer to operate their systems as close to full capacity as possible to maximize their revenues. However, the average utilization rate (flow relative to design capacity) of a natural gas pipeline system seldom reaches 100%. Factors that contribute to outages include:

Storage is usually integrated into or available to the system at the production and/or consuming end as a means of balancing flow levels throughout the year. Trunklines serving markets with significant storage capacity have greater potential for achieving a high utilization rate because the load moving on these pipelines can be leveled. To the extent that these pipelines serve multiple markets, they also can achieve higher utilization rates because of the load diversity of the markets they serve. Trunklines, which are generally upstream (closer to) the natural gas production fields and storage areas, may sometimes exhibit peak period utilization rates exceeding 100% because they are occasionally capable of handling much larger volumes than indicated by the operational design certificated by FERC. Utilization on the grid systems, which are closer to the consuming market areas and downstream of the storage fields, is more likely to reflect a seasonal load profile of the market being served. The grid-type systems usually operate at lower average utilization levels than trunklines and usually show marked variation between high and low flow levels, reflecting seasonal service and local market characteristics. There are several ways that natural gas pipeline system utilization may be estimated, as demonstrated in the following cases: As a measure of the average-day natural gas throughput relative to estimates of system capacity at State and regional boundaries The systemwide pipeline flow rate, which highlights variations in system usage relative to an estimated system peak throughput level The latter measure is a good indication of how well the design of the system matches current shipper peak-day needs. For example, when a pipeline shows a comparatively low average usage rate (based on annual or monthly data) yet shows a usage rate approaching 100 percent on its peak day, it indicates that the system is called upon and is capable of meeting its shipper's maximum daily needs. Nevertheless, a large spread between average usage rates and peak-day usage rates may indicate opportunities to find better ways to utilize off-peak unused capacity. In some cases, utilization rates exceeding 100 percent may be an artifact of the data that obscures the true operational status of the pipeline. In some instances the sum of individual transportation transactions may exceed pipeline capacity even though physically the pipeline may not be full. For example, suppose a segment from points A to D (with points B and C between A and D) has a capacity of 200 million cubic feet (MMcf) per day. Suppose further that this segment handles a 100 MMcf per day transaction from A to B, a second of 100 MMcf per day from B to C, and a third of 100 MMcf per day from C to D. The pipeline company will report transportation volumes of 300 MMcf per day, even though its capacity is 200 MMcf per day but is only 50 percent utilized on any one segment.

#### Oil Pipeline Failure

http://www.oilcoalgas.com/oil/oil-pipeline-failure.php December 07, 2014

Oil Pipeline Failure. ... The following provides summaries of five oil pipeline failures as reported to the Pipeline and Hazardous Materials Safety Administration ...

The following provides summaries of five oil pipeline failures as reported to the Pipeline and Hazardous Materials Safety Administration (PHMSA). These summaries are not intended to be a comprehensive study of oil pipeline failures,. These summaries are only intended to give a few real-life examples of what can happen.

A farmer installing drain tile struck and ruptured the 10-inch Buckeye Line 803 in Cayuga County, New York. Approximately 595 barrels of gasoline were released. This pipeline runs approximately 95 miles from the Auburn Terminal to the Rochester Terminal. The pipeline location was properly marked. The farmer had been in contact with local Buckeye personnel during the installation of the drain tile in his field adjacent to Buckeyeâs pipeline. The farmer had been instructed by Buckeye not to dig in the pipeline right-of-way, which extends approximately 25 feet from the centerline of the pipeline. On the day of the incident, the farmer was plowing the field perpendicular to the pipeline, and failed to stop the tractor and raise the tile-plow out of the ground prior to proceeding over the pipeline. After hitting the pipeline, the farmer called Buckeye to report that he had hit the pipeline and that gasoline was escaping from the pipe. Buckeye personnel arrived at the site within 15 minutes to begin the emergency response. On the day of the incident, Line 803 was not flowing product and was shut in due to an unrelated leak at the Auburn Tank Farm that had been found earlier the same morning.

Buckeye was in the process of pumping Ultra Low Sulfur Diesel (ULSD) fuel from their Coraopolis Terminal to their Midland Terminal in Shippingport, PA. The pressure at the site at the time of failure was 462 psig which was below the MAOP of 1,147 psig. A resident reported a spray of product that could be seen rising above the trees in a wooded area behind a gypsum plant. Buckeye responded and determined that their line 820 that was leaking. The leak was caused by an external corrosion pit. Approximately 300 barrels of diesel fuel were spilled. It was estimated that 238 barrels were recovered. The spill followed the natural terrain from the leak to a stormwater drainage canal located behind the gypsum plant. The leaking product was contained in the drainage canal and prevented from entering the Ohio River. Buckeye isolated the line and the leaking segment was drained into tank trucks located at the Midland Terminal. The leak was repaired by cutting out and replacing a 10-foot section of pipe with new pipe. The pipeline was returned to full operation on March 23rd. The cause of the leak may have been related to an April 2010 washout near the leak location. Approximately 2 feet of pipe was exposed, but it was likely that low pH water directly contacting the exposed segment of pipeline caused the localized external pitting corrosion. The corrosion was limited to the section of exposed piping where the coating had become disbonded.

On the evening of December 1, 2010, Chevron Pipe Line Company (CPL) shut down their Number 2 pipeline because of erratic supervisory control and data acquisition (SCADA) information following restart of the line after a planned shutdown. Because this pipeline experienced åslack lineå phenomena, CPLås leak detection system often would trigger false alarms. SCADA controllers could not reliably recognize an actual release below a certain threshold. The Number 2 pipeline delivers crude oil to the Chevron Salt Lake City refinery. The pipeline transports crude oil from Rangely, Colorado to the Salt Lake City refinery. It crosses Wolf Creek Pass and then quickly descends into the Salt Lake Basin. After shutting down the pipeline field teams were sent out to patrol the line. A release of crude oil was found at the Chevron Red Butte Block Valve installation, adjacent to the

University of Utahâs arboretum and 100 yards uphill from Red Butte Creek. A damaged 6-inch valve, that "stubbed" off of the Number 2 pipeline in the Red Butte block valve vault, was the source of the leak. The failed valve was water injection valve for a water test conducted in June 2010. The valve is located in a below-grade open vault. The released crude oil filled the vault, spilled out of the fenced area and flowed down hill toward Red Butte Creek. The low temperatures that night congealed the crude making it more viscous. The crude oil did not reach the creek. The failed valve was in the closed position at the time of the release. Analysis of the valve showed that ice had formed inside the valve, forcing an opening between the bonnet and valve body. Due to the pipelineâs topography, and the fact the leaky valve was immediately upstream of the mainline block valve, oil continued to flow out the ruptured 6-inch valve even after the shut down. The final spill amount was 500 barrels, of which 250 were recovered. The investigation showed that the OEM's winterization recommendations had not been followed and the water had not been flushed from the valve. In addition, there was no formal winterization plan in place for identifying and correcting this type of circumstance., and the procedure for the water test was developed without adequate communication. As a result operations personnel were not aware that water was isolated in the valve after commissioning. The investigation also revealed CPL did not have an adequate leak detection system on the Number 2 crude line. In 2007 CPL had performed a study to identify potential improvements to the leak detection system, but had not implemented any of the recommendations at the time of the leak.

A flange gasket failed resulting in the release of 1,700 barrels of Vacuum Gas Oil (VGO) from the Sunoco FM-1 pipeline. The oil flowed into an open in-ground valve pit and the surrounding area in the West Yard of the refinery in Philadelphia, PA. The failed flange gasket was downstream of a main line valve in a dead leg of pipe leading to the FM-1 pig trap. A loss of pipe support and leakage through a closed valve contributed to the failure. There were no fatalities or injuries, and the incident did not result in a fire, explosion or evacuation.

AS was normal practice, Mid-Valley employees had manually lined up the manifold valves to receive a shipment of crude oil into the #7 tank. Upon start up, crude oil was observed gushing from the soil in the manifold area. The flow was stopped and the release was identified as having come from one of several buried lines within the manifold area. An inspection of the manifold area indicated that a buried dead-leg section of the manifold piping that delivered crude oil to tanks # 13 and #14 was releasing product. The section of manifold piping had an MOP of 275 psig, and was operating at less than 150 psig when the release occurred. 198 barrels of crude oil were estimated to have been released and 196 barrels were recovered. Mid-Valley isolated the underground section of the manifold piping and installed blind flanges to isolate it from the above ground header. Once the spill was controlled, approximately 25 feet of 8" buried header was excavated for evaluation and/or removal. It was determined that two localized spots of internal corrosion were the source of the leak. Mid-Valley determined that crude oil feed to tanks #13 and #14 was not essential to their operations and they chosen to not replace this section of the header.

#### Analysis Of Oil Pipeline Failures In The Oil And Gas

http://the-printableform.rhcloud.com/analysis-of-oil-pipeline-failures-in-the-oil-and-gas-/ December 07, 2014

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#### Pipeline failure causes

http://www.corrosion-doctors.org/Pipeline/Pipeline-failures.htm December 07, 2014

Pipeline Failure Causes . ... rupture of previously damaged pipe, and vandalism. The data show that for hazardous liquid pipelines and gas transmission pipelines, ...

There are many causes and contributors to pipeline failures. The U. S. Department of Transportations Research and Special Programs Administration, Office of Pipeline Safety (RSPA/OPS) compiles data on pipeline accidents and their causes. (reference 76)

This combined data for 2002-2003 indicate that outside force damage contributes to a larger number of pipeline accidents and incidents than any other category of causes, if all accidents involving hazardous liquid, natural gas transmission, and natural gas distribution pipelines are considered together. When hazardous liquid pipeline data is considered separately, corrosion contributes to a higher number of accidents than other categories.

Outside force damage can include the effects of: earth movement, lightning, heavy rains and flood, temperature, high winds, excavation by the operator, excavation by a third party, fire or explosion external to the pipeline, being struck by vehicles not related to excavation, rupture of previously damaged pipe, and vandalism. The data show that for hazardous liquid pipelines and gas transmission pipelines, the largest portion of outside force damage results from excavation damage. This may occur when excavation activity occurring near the pipeline causes an accidental hit on the line. The range of excavation damage runs from damage to the external coating of the pipe, which can lead to accelerated corrosion and the potential for future failure, to cutting directly into the line and causing leaks or, in some cases, catastrophic failure.

Following are tables and graphs based on recent RSPA/OPS statistics, showing the causes of pipeline accidents. Information on OPS Safety Initiatives that address these significant failure causes may be found here.

#### Notes

- (1) The failure data breakdown by cause may change as OPS receives supplemental information
- on accidents.
- (2) Sum of numbers in a column may not match given total because of rounding error.

Note that corrosion (external and internal) is the most common cause of natural gas transmission pipeline incidents in 2002-2003.

Note that over 60% of natural gas distribution pipeline incidents were caused by outside force damage in 2002-2003. These incidents can include damage from excavation by the operator or by other parties, as well as damage from natural forces.

#### Seam weld failure in a petroleum pipeline

http://www.dnv.com/industry/oil\_gas/publications/updates/pipeline\_update/2012/01\_2012/CASE\_STUDY\_Seam\_weld\_failure\_in\_a\_petroleum\_pipeline.asp\_December 07, 2014

There are more than 2.5 million miles of oil and gas pipelines in the United States. ... Seam weld failure in a petroleum pipeline Have a look at what I found on DNV ...

There are more than 2.5 million miles of oil and gas pipelines in the United States. These pipelines typically contain longitudinal seam welds in each pipe joint and girth welds that connect the individual joints to form the pipeline. Both types of welds are prone to failure from time independent and/or time dependent failure mechanisms.

While some smaller diameter pipelines are seamless, most pipelines are manufactured by forming flat plate or skelp into a tubular form and completing a longitudinal seam weld. Both submerged arc welding and autogenous welding processes are used for weld completion.

Submerged arc welded line pipe is manufactured by first forming a flat plate or skelp into a tubular shape (can) in a set of presses, followed by weld completion. Prior to forming the can, the edges are typically beveled. Historically, single submerged arc welding (SSAW) and double submerged arc welded (DSAW) processes have been used but, currently, the DSAW process is the only submerged arc welding process that is approved in API 5L. In SSAW line pipe, the edges are joined by a single pass submerged arc weld made from the outside surface onto a backing shoe located at the ID surface. DSAW line pipe is formed in a similar manner except one pass is made from the OD surface followed by a pass from the ID surface, or vice versa. Filler weld material is used in both processes. One variation of this process is used to produced spiral welded DSAW line pipe; in which skelp is helically wound and welded to produce a spiral weld.

Historically, there have been several different autogenous welding processes for longitudinal seam welds including furnace lap welding, furnace butt welding, electric flash welding (EFW) and electric resistance welding (ERW). ERW currently is the dominant autogenous welding process for pipe manufacturing. ERW line pipe is manufactured by forming plate or skelp into a tubular shape and heating the two adjoining edges with electric current and forcing them together mechanically. An autogenous bond is formed between the molten edges. Upset material at the weld is trimmed on the OD and ID surfaces.

Various types of defects can be produced in these welds and the defects typically are unique to the specific welding procedure. Some of these defects are too small to be detected in the mill and are never an integrity problem for the pipelines. Other defects that are not detected at the mill can fail during the initial hydrostatic test of a pipeline, or grow in service by fatigue, stress corrosion cracking, or other mechanisms, resulting in a service leak or failure. Because of differences in the metallurgy at the weld and the base metal of the pipe, the welds can also be prone to environmentally induced failure mechanisms such as preferential corrosion.

This case study describes a rupture of seam weld during a hydrostatic pressure test. The pipeline that failed was comprised of 16-inch diameter by 0.312-inch wall thickness, API 5L X52 line pipe that contained an ERW longitudinal seam. The pipeline transported refined petroleum products. The maximum operating pressure (MOP) on this line segment was 1,408 psig, which corresponds to 69.4% of the specified minimum yield strength (SMYS). The failure occurred during initial pressurization at a test pressure of 1,390 psig, which corresponds to 98.7% of the MOP and 68.5% of the SMYS. The normal operating pressure at the failure location ranged from 1,000 to 1,100 psig (71.0 to 78.1% of MOP).

The pipeline was installed in 1965 and was externally coated with coal tar. The coating was not intact near the failure. The pipeline had an impressed current cathodic protection system that was commissioned around 1965. This pipeline segment was previously hydrostatically tested in the fall of 1965. The hydrostatic test lasted 24 hours and the maximum pressure was 1,760 psig (125% of MOP and 86.8% of SMYS).

The pipe section was visually examined and photographed in the as-received condition. Transverse base metal and cross weld samples were removed from the pipe section for mechanical (Charpy V-notch and tensile) testing. Samples for chemical analysis of the steel were removed from the base metal. Magnetic particle inspection (MPI) was performed where the coating was removed to identify defects at or near the seam weld. Transverse metallographic samples were removed from the seam, at and away from the failure origin. The samples were mounted, polished, and light photomicrographs were taken to examine the morphology and steel microstructure. Samples were removed from the failure origin to analyze the morphology of the fracture surface in the scanning electron microscope.

The results of the analysis indicated that the rupture initiated at an ID connected pre-existing hook crack. This and all hook cracks are slightly offset from the bond line of the ERW seam. No evidence of in-service growth by fatigue was found, although the quality of the fractography was poor as a result of corrosion of the fracture surfaces that occurred after the rupture. The tensile properties of the line pipe steel and the steel chemistry were typical of the vintage and grade and met the API 5L specifications in place at the time of manufacture. The microstructure and Charpy toughness properties of the steel also were typical for the vintage and grade.

#### The History of Oil Pipeline Spills in Alberta, 2006-2012

http://activehistory.ca/2012/06/the-history-of-oil-pipeline-spills-in-alberta-2006-2012/ December 07, 2014

This measurement of pipeline failure rate, ... Had the May 2012 Pace Oil & Gas spill in northwest Alberta near Rainbow Lake occurred to the south in a more populous ...

The History of Oil Pipeline Spills in Alberta, 2006-2012

Late Thursday evening on June 7, 2012, the Sundre Petroleum Operators Group, a not-for-profit society, notified Plains Midstream Canada of a major oil pipeline failure near Sundre, Alberta that spilled an early estimate of between 1,000 and 3,000 barrels of light sour crude oil (~159-477 cubic metres) into Jackson Creek, a tributary of the Red Deer River. The river is one of the province's most important waterways, providing drinking water for thousands of Albertans.

This recent spill occurred just weeks after another oil pipeline burst in Alberta in late May, spilling an estimated 22,000 barrels of oil and water (~3,497 cubic metres) across 4.3 hectares of muskeg in the northwest part of the province near Rainbow Lake. According to the Globe and Mail, this rupture, which occurred along a pipeline operated by Pace Oil & Gas, Ltd., "ranks among the largest in North America in recent years," and certainly in the province of Alberta. A couple of weeks after the accident, the company downgraded the estimate to 5,000 barrels of sweet crude oil with no water (~795 cubic metres).

These recent spills are considerably smaller in volume of liquid hydrocarbons released than last year's 28,000 barrel (~4,452 cubic metres) spill on the Rainbow pipeline operated by Plains Midstream Canada near Little Buffalo, Alberta. While the 2011 Plains Midstream oil pipeline rupture may have been the largest single spill event in recent memory, the entire oil pipeline network in Alberta has spilled nearly equivalent volumes of liquid hydrocarbons every year since 2005.

As my brief history of oil pipeline spills in Alberta from 1970 to 2005 demonstrated, the problem of pipeline ruptures is endemic to the industry. Now with over 399,000 kilometres of pipelines under the authority of the province's Energy Resources Conservation Board, industry specialists and regulators not only know that this system has never been free from oil spills, but that a spill-free system is an impossible goal. The recent history of pipeline ruptures in Alberta since 2006 further underlines these realities.

At 1:46am on October 10, 2006, the Rainbow Pipe Line Company became aware of a crude oil spill on its pipeline 20 kilometres southeast of Slave Lake. Roughly 7,924 barrels of oil (~1,260 cubic metres) poured into a series of ponds near the northern Alberta town, despoiling wildlife habitat on what one local news outlet ironically referred to as "Black Tuesday." Darin Barter from the Alberta Energy Utilities Board tried to reassure Albertans

that the incident was anomalous. According to the CBC, Barter "said it is rare for pipelines to fail in Alberta." The EUB press release also stressed this point, insisting that "[p]ipeline failures in Alberta are rare."

The alleged rarity of such oil pipeline spills was probably of little solace to the residents and tourists who enjoyed the recreational benefits of life on Glennifer Lake. In mid-June 2008, Pembina Pipeline Corporation accidentally leaked 177 barrels of oil (28.1 cubic metres) into the Red Deer River, eventually resulting in a large oil slick on the surface of Glennifer Lake. While the volume of the spill was considerably smaller than the 2006 Rainbow Pipeline spill, the location of the rupture in a river and lake made this incident more threatening to human lives. As Pembina's district superintendent Sandy Buchan told the Red Deer Advocate, "Anytime you are putting oil into the river and you are affecting people's drinking water, you need to take it very seriously." Pembina instructed local resorts on Glennifer Lake to turn off their drinking water intakes to avoid human consumption of the contaminated water. From June 18 to 27, the company trucked in drinking water to service the community throughout the course of the emergency until the David Thompson Health Region declared the water safe for drinking again. The day after Pembina discovered the oil spill, the Energy Resources Conservation Board once again tried to reassure Albertans about the infrequency of pipeline failures in the province and issued a press release which emphasized that the rate of pipeline ruptures "was at a record low 2.1 failures per 1000km of pipeline in 2007." This measurement of pipeline failure rate, however, is somewhat misleading in terms of the environmental impact of oil pipeline spills.

The ERCB has used the ratio of the number of pipeline failure incidents to the total length of the province's pipeline network as a metric to illustrate the safety of the system. For example, in its 2011 field surveillance and operations summary, the ECRB boasts that the failure rate "was 1.6 per 1000km in 2010." Furthermore, of the 1,174 liquid pipeline releases in 2010, 94 per cent "had no impact on the public." The trouble, of course, is that this measurement of pipeline failure rate and vague description of "impact on the public" does not adequately convey the environmental risks of large oil pipeline networks. The environmental impact of oil pipeline spills is obscured under this rubric.

The ratio of number of pipeline failures to the total length of the network disguises three important measurements of the environmental impact of oil spills: volume, product type, and location. While the rate of individual pipeline ruptures has declined in Alberta since 2006, this rate includes all substances, including water, and does not convey the volume of individual spills. When considered by product type, between 2006-2010 there have been 109 failures on crude oil pipelines and 1,538 failures on multi-phase pipelines, which carry a combination of crude oil and gas. By volume, the quantity of liquid hydrocarbon spills on Alberta's pipeline network is staggering. From 2006-2010, the pipeline network leaked roughly 174,213 barrels of oil (~27,700 cubic metres). In 2010 alone, more than 21,000 barrels (~3,400 cubic metres) were spilled across the network, nearly the equivalent of the most recent oil spill near Rainbow Lake.

As the 2008 pipeline failure on the Red Deer River and Glennifer Lake demonstrated, when it comes to the environmental impact of oil spills, it is all about location. Even a relatively small spill in a critical body of water can have enormously detrimental effects on people and wildlife. The cost of cleaning such spills can also vary greatly by location. Unfortunately, the ECRB data from the field surveillance and operations summaries do not include geographic data to assess environmental effects of oil pipeline spills.

To keep track of the recent historical geography of oil pipeline spills in Alberta, I have created the following map below. The map includes rough geographic data about major oil pipeline spills in Alberta from 2006 to 2012. The spatial distribution of these major oil pipeline spills reveals, perhaps, why these events so quickly fade from public discourse and popular memory. All but two of the substantial oil spills since 2006 occurred north of Edmonton, away from the province's major urban centres. As such, most ordinary Albertans have never personally witnessed the environmental consequences of these pipeline failures. The relatively small leak of crude oil into the Red Deer River in 2008 drew a lot of public and news media attention because of its proximity to the city of Red Deer and a popular tourist destination. Similarly, the most recent spill on Jackson Creek is likely to draw considerable attention. Had the May 2012 Pace Oil & Gas spill in northwest Alberta near Rainbow Lake occurred to the south in a more populous (and popular) location, such as Banff National Park, it almost certainly would have attracted greater national media attention. The geography of oil pipeline spills then has political consequences that must also be considered when assessing extension of the pipeline network.

A more accurate measurement of the environmental impact of oil pipeline spills should include information about volume, product type, and location. Only then can Canadians understand the environmental history of oil pipelines and reasonably assess future plans to expand the network.

Please let me know in the comments if I have missed any major spills on the map below.

Sean Kheraj a regular contributor to Activehistory.ca and is an assistant professor of Canadian and environmental history at York University. He blogs at http://seankheraj.com

#### Analysis Of Oil Pipeline Failures In The Oil And Gas

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, Aspo is a network of scientists and others, having an interest in determining the date and impact of the peak and decline of the world's production of oil and gas.

#### **Pipelines**

http://www.aer.ca/rules-and-regulations/by-topic/pipelines December 07, 2014

About 415 000 kilometres of Canada's oil and gas pipelines operate solely within Alberta's boundaries and fall under the jurisdiction of the AER.

About 415 000 kilometres of Canadaâs oil and gas pipelines operate solely within Albertaâs boundaries and fall under the jurisdiction of the AER. Certain rate-regulated gas transmission pipelines fall under the jurisdiction of the Alberta Utilities Commission, for which the AER conducts field inspections and provides incident response. Oil and gas pipelines that cross provincial or federal borders are regulated by the National Energy Board.Â

The AER ensures that the design, construction, operation, and maintenance - including discontinuation and abandonment of regulated pipelines - complies with Albertaâs Pipeline Act, Pipeline Regulation, and applicable Canadian Standards Association (CSA) standards. The AER's pipeline-inspection program considers pipeline fluid characteristics, location, line size, failure history, and the companyâs compliance history. Pipelines with greater potential risks are given a higher inspection priority.

The AER also conducts comprehensive incident investigations after serious incidents occur to determine the cause of a pipeline failure and what can be done to prevent a similar situation in the future.

Report 2013-B: Pipeline Performance in Alberta, 1990â2012Â is a comprehensive analysis of pipeline data for Alberta on amounts and types, incident statistics, and incident rates.

Please see the Pipeline Safety Review webpage for the report, video, feedback, as well as organizational responses.

Compliance Assurance

Manual 005: Pipeline Inspections identifies noncompliance events. Noncompliance with the requirements may result in the licensee of the pipeline or duty holder receiving a response from the AER in accordance with the processes described in Directive 019: Compliance Assurance.

Below is additional information related to pipeline regulation in Alberta.

#### Analysis Of Oil Pipeline Failures In The Oil And Gas

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#### Oil and Gas Accidents, Oil and Gas Law

http://www.lawyersandsettlements.com/lawsuit/oil-and-gas-accidents.html December 07, 2014

... mishaps while raising pipeline, oil rig and ... the fatality rate among oil and gas extraction ... if there is a product failure using Propane vs Natural Gas.

Oil and Gas workers are subject to some of the most hazardous industrial conditions in the US. Serious injuries and fatalities occur too often from an oil accident or gas accident. Oil and gas attorneys ensure that gas and oil companies are held accountable for oil drilling accidents and oil field accidents. When an oil and gas worker is injured, the severity and duration of injuries are far worse than in other industry sectors, and recovery times often take twice as long. Oil and gas accidents typically occur for the following reasons: Given the amount of people employed by the gas and oil industry and the dangerous nature of oil and gas drilling, it is almost inevitable that accidents will occur. Oil and gas accidents can involve explosions, mishaps while raising pipeline, oil rig and derrick safety violations and other incidents, including: Hydraulic fracturing (also called fracking), which is used to extract natural gas from rock formations, is thought to be linked to cancer and other serious, chronic illnesses. It is important to seek advice from oil and gas attorneys because determining liability can often be difficult, and Worker's Compensation may not cover all the expenses associated with long term serious injuries. An oil and gas lawyer can review your employment documents thoroughly to determine any indemnification clauses that may waive the liability of the employer, contractor or other third party. In 2006, almost a half million people in the US were working in jobs related to the oil and gas industry and the gas extraction industry employed about 400,000 workers on both offshore and land drilling and workover rigs, comprising the largest part of the US mining industry. The oil and gas industry is growing but at the same time increases in oil and gas activity correlate with an increase in the rate of fatal occupational injuries, particularly when inexperienced workers are not sufficiently trained in safety and precautionary measures. The most common types of injuries are burns, brain injury, spinal injury and fractures. From 2000 – 2009, pipeline accidents accounted for 2,554 significant incidents, 161 fatalities, and 576 injuries in the US. There are nearly 500,000 miles of oil and gas transmission pipelines that crisscross the US. These lines often carry hazardous materials with the potential to cause public injury and environmental damage in rural and urban areas. According to an investigation in the Austin American- Statesman, from 1984 - 2000 pipeline related fatalities occurred in more than 40 states. According to the Bureau of Labor Statistics, about 600 oil field and rig workers died on the job between 2002 and 2007. During that period, the number of deaths per year rose by around 70 percent, from 72 victims in 2002 to 125 in 2006 and a preliminary count of 120 in 2007.During 2003-2007, the fatality rate among oil and gas extraction workers was nearly eight times that for all U.S. workers.Drilling oil and gas wells industries had a rate of 4 cases of nonfatal injuries and illnesses per 100 equivalent full-time workers. The rate for injuries and illnesses by size of business was: Nearly half of all fatal injuries were attributed to highway motor-vehicle crashes and workers being struck by machinery or equipment. Gas explosion injuries, fires, chemical burns and dangerous falls or falling objects or equipment-- workers are often hit on the head or back by tools or equipment—are just a few of the dangers occurring on a regular basis in the oil and gas industry. The highest numbers of oil and gas extraction occupational fatalities occurred in Texas (38 percent), Louisiana (12 percent), Oklahoma (11 percent), Wyoming (8 percent), and New Mexico (5 percent). Among the states where most of the fatalities occurred, New Mexico (45.2 per 100,000) and Wyoming (58.5 per 100,000) had the highest average annual fatality rates, compared with Oklahoma (33.3 per 100,000), Louisiana (29.2 per 100,000), and Texas (25.3 per 100,000). Currently, there is a major boom in the natural gas sector in the US, resulting in a huge need for workers in Rocky Mountain states like Wyoming, and the new Mackenzie gas project is expected to employ thousands of workers. But with more employment, higher fatality rates are likely to occur. The oil and gas industry is rife with inexperienced workers who work longer working hours (more overtime), and many rigs include older equipment with fewer safeguards. According to a recent report, "Assault on America: A Decade of Petroleum Company Disaster, Pollution, and Profit", from 2000 to 2010, the oil and gas industry accounted for hundreds of deaths, explosions, fires, seeps, and spills. This report, which includes a full List of Oil Disasters from January 2000 - June 2010, demonstrates that the BP incident is not isolated but an industry pattern that places profit ahead of communities, local economies, and the environment. In this video, Tim Warman, National Wildlife Foundation, discusses how the oil and gas industry must be held more accountable by removing the liability cap. Oil companies make trillions of dollars in revenue—more than enough to cover oil and gas accident lawsuits. Gas explosions can also occur in the home; they can be caused a defective product or combination of defective products; or minimal or no public or consumer information on the safe handling and use of propane or natural gas. Approximately 26 million people use propane: it is also very dangerous. More than 100 million people use natural gas. You are four times more likely to be involved in a fire or explosion using Propane (LP Gas) vs Natural Gas (Methane). You are 13 times more likely to be severely injured or burned with Propane vs. Natural Gas. You are more than 100 times more likely to be killed or severely injured if there is a product failure using Propane vs Natural Gas. April 2: Seven workers were killed in a fire at Tesoro Corp's Washington oil refinery. Federal investigators say the victims were likely engulfed in"a firewall" that ignited within seconds April 19: A worker was killed at Motiva's oil refinery in Port Arthur, Texas in a construction crane accident. Motiva now has two fatalities since 2007 at this refinery while it has been attempting to expand production. April 20: Possibly the worst environmental disaster in U.S. history, BP's Deepwater Horizon Oil Spill stemmed from an explosion that killed 11 rig workers and injured 17.On Jan 11, 2011, the White House oil spill commission's final report on the oil disaster contained recommendations including raising the liability cap for drillers and creating an independent safety agency. The panel made the following recommendations: Texas Oil and Gas production is booming and is expected to reach an all-time high by 2016, mainly due to Texas oil and gas drilling. Greater production means a greater increase in jobs, but rapid development—particularly in South Texas oil and gas-- means that more workers are subject to injury. Texas oil and gas lawyers are increasingly seeing more accident and injury claims as oil and gas companies increase their rigs, often with unskilled well drilling and well maintenance workers. Combined with the physical demands of the job and long shifts (roughnecks often work 72 hour shifts), workplace accidents are bound to occur. Furthermore, some companies are in such a hurry to increase production that they may fail to disregard OSHA safety standards or fail to properly maintain equipment. Common causes of oil and gas accidents include inadequate safety training and disregard for safety measures, defective equipment and improperly maintained equipment. While injuries are covered by Workers Compensation, the Texas law of oil and gas ensures that companies and contractors are held responsible should negligence occur. OSHA safety standards protect drilling rig workers both onshore and offshore, but companies often disregard rules and regulations. Federal statistics count 1,300 drilling rig injuries in the Gulf of Mexico from 2006-2010, and 41 worker fatalities. (Eleven deaths were the result of the BP Deepwater Horizon explosion and 15 deaths at the Texas refinery explosion in Texas City.) According to the Bureau of Labor Statistics, in 2008 Texas had more fatalities in the oil and gas extraction industry (41) than any other state. The Eagle Ford Shale, a gas basin extending through 30 counties-- including Hood, Johnson, Parker, Tarrant, and Wise Counties-- is one of the largest oil and gas reserves ever found in Texas. The formation produces from various depths between 4,000 and 12,000 feet and is benefiting from "high liquids yields across much of the play." The state of Texas reported that natural gas production at the Eagle Ford shale has increased ten-fold from 2009 to 2010. Along with oil and gas prices, controversial Eagle Ford Shale drilling methods, i.e., Hydro Fracking and horizontal drilling, have resulted in a rapid expansion of oil and gas companies (more than 24 oil and gas companies are currently in the Eagle Ford Shale Patch). According to Mark Sundland, drilling manager for Anadarko Petroleum, horizontal/directional drilling and hydraulic fracturing "has put Eagle Ford in a class by itself". Hydro-fracking also poses public health concerns. Environmental groups are concerned that the fracking water may pollute drinking water. Fracking requires millions of gallons of chemically treated water that is mixed with sand, to blast through the shale, which then releases gas or oil. Even one well can require millions of gallons of water. The EPA has investigated fracking's effects on drinking water in other parts of the US and is now looking at the Eagle Ford Shale. With this oil and gas boom comes an increase in workers, some of whom are unskilled and untrained in safety procedures. (Recently OSHA opened an investigation following a Sept 2011 accident where two people were hospitalized after an oil rig explosion on the Eagle Ford Shale.) Most oil and gas injuries are avoidable yet safety is often secondary to oil and gas profits. In 2008, 31-year-old Larry Mullins Jr., an employee at Nabors Drilling USA, was working on a drill site location and was crushed by oilfield equipment being positioned by a tandem truck in a rig move in Wise County, Texas. In April 2010, the Mullins family settled an oilfield accident lawsuit for \$9.5 million dollars. In 2007 the Usumacinta jack-up oil rig was positioned over the Kab-101 platform. Strong winds forced the jack-up off location, causing it to collide with the Kab-101 platform and rupture the platform's production tree. Twenty-two workers lost their lives as a result of the emergency evacuation in storm-force conditions. The leaking hydrocarbons ignited twice, causing major fire damage to both the Usumacinta and the Kab-10.In 1998 an employee of Marine Drilling Company was working on an offshore jackup rig when a piece of equipment severed his hand. A lawsuit was filed against Mar- Dril, Inc, Storm Drilling Company

Freeport- McMoran and Directional Wireline Services, and an out of court settlement for the offshore drilling rig accident was reached. Oil and gas accidents generally occur at work sites where the employer and/or employee is negligent, therefore injuries and death are covered by workers' compensation. But if a third party is involved (i.e., someone or some other entity, such as a defective product, not associated with your employer) a claim will likely exist and you should get advice from a gas and oil attorney who is experienced with the following: If you or a loved one has sustained an oil and gas injury, you should seek legal help. An oil and gas attorney can review your accident against safety regulations to help uncover what happened, and who is responsible, to ensure that you obtain suitable compensation for your workplace accident injuries. If you or a loved one has suffered damages in this case, please click the link below and your complaint will be sent to a lawyer who may evaluate your claim at no cost or obligation.

#### **Stress Engineering Services**

http://www.stress.com/capabilities/pipelines/ December 07, 2014

... Oil & Gas; News & Media ... Stress Engineering helps operators across the continent expand pipeline ... From pipeline failure analysis to integrity management ...

The pipeline infrastructure of North America is not only being expanded aggressively, but is aging at the same time. Stress Engineering helps operators across the continent expand pipeline networks safely, repair them effectively, and reduce failure-related downtime significantly. From pipeline failure analysis to integrity management challenges, we know how to solve pipeline problems.

Our system assignments are diverse: High-pressure interstate gas pipelines. Oil and hydrocarbon products pipelines. Local distribution (LDC) gas lines. We bound the problem, defining its parameters, interpolating between stress points. We use advanced finite element analysis and modeling, materials engineering, burst testing, field instrumentation, and monitoring expertise to help our customers guard against catastrophic failure and maintain mechanical integrity.

We evaluate pipeline failure or the potential for failure, determining for our customers the safe limits of prospective operations. We analyze mechanical damage from gouges to dents, define the safest conditions, identify roadblocks to long-term operation, and help ensure they are accounted for before installation or repair.

Above all, we are an experienced, hands-on technological and problem-solving resource for transportation infrastructure operators, not just in High Consequence Areas (HCAs), but in wide open spaces across the continent.

# Regulatory Basics for Oil Pipelines - Federal Energy ...

http://www.ferc.gov/help/pub-ref-rm/oil-ratemaking.pdf December 07, 2014

FERC Tariffs and Market Development (Central Group) Analyzes oil pipeline tariff and rate change filings. Advises Commission on filings, initial decisions.

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AOPL Workshop
Regulatory Basics for Oil Pipelines
            September 16, 2009
 Discussion Outline
Part I: Who regulates oil pipelines?
Part II: Procedures for filing tariffs.
Part III: The two major rate-setting methodologies.
                 Part I
Federal Energy Regulatory Commission
          The federal authority
              responsible for
          regulating oil pipelines
FFRC
Introduction
Also regulates the electric, hydro, gas industries.
Part of the Executive Branch.

② An independent agency.

Extensive Congressional oversight.
\ensuremath{\mathbb{P}} Funded by the fees charged to the entities it regulates
As of 2009, regulated 141 oil pipelines.

☑ FERC departments important to oil pipeline industry:

  ☑ Office of Energy Markets & Reliability
☑ Office of Enforcement

☑ Office of Administrative Litigation

FFRC
Organizational Chart
FERC
Commissioners as of Sept. 2009
                      Suedeen
                                 Philip
          Jon
                                            Marc
                       Kelly
                                 Moeller
                                            Spitzer
       Wellinghoff
                        D
       Chairman
                                   R
                                              R
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Serve 5-Year Terms.Equal vote on regulatory matters.No more than 3 Commissioners of the same political party.
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Appointed by the President with the consent of

FERC Commissioners

the Senate.

```
FFRC
Office of Energy Markets & Reliability
Principal advisor to the Commission on regulatory
  issues.
② Oversees energy market structure and performance.

☑ Oversight of compliance of market participants with the

  Commission's rules.
Conducts analytical studies of energy markets.
☑ OEMR Division Key to Oil Pipelines:
☑ Division of Tariffs and Market Development (Central Group)
  1 of 6 divisions under OEMR
FERC
Tariffs and Market Development (Central Group)

☑ Analyzes oil pipeline tariff and rate change filings.
\ensuremath{\mathbb{D}} Advises Commission on filings, initial decisions, rehearings, complaints, & declaratory orders.
Directs companies to perform oil pipeline statutory
  depreciation studies.
Analyzes oil pipeline market-based rate applications.
\ensuremath{\mathbb{D}} Often assists pipelines in complying with regulations
  (e.g. ensuring tariffs meet all of the pertinent requirements).
    FFRC
    Office of Enforcement
② Oversees compliance of market participants with the
     Commission's rules for market activity.
    Reports on the state of the energy markets, analyzing market activities and trends.
    Advises the Commission on accounting and financial
    matters affecting energy markets.

Oversees compliance with the Uniform System of
     Accounts.
    OE Divisions Key to Oil Pipelines:
Division of Financial Regulation
     Division of Audits
FERC
OE: Division of Financial Regulation
Provides guidance to the Commission concerning its
  financial accounting
\ensuremath{\mathbb{P}} Reviews new or proposed accounting standards
  made by authoritative accounting bodies to
  determine effect on regulated industries.
\ensuremath{\mathbb{Z}} Prepares and coordinates necessary revisions and/or amendments to the Commission's Uniform
  System of Accounts.

☑ Administers financial forms Nos. 1, 2, 2-A, 6, 3Q,

  6Q, etc.
  FERC
  Form No. 6

☑ What is the Form 6?

      Required Annual Report of Oil Pipeline Companies who are
      regulated by the Federal Energy Regulatory Commission as set forth
      in the Interstate Commerce Act
\ensuremath{\mathbb{D}} Who uses the Form 6?
     FERC and Other Regulatory Commissions, Shippers, Carriers, AOPL, Bureau of Economic Analysis

    Purpose of the Form 6:

      To collect comprehensive financial and operational information
      about oil pipeline companies subject to the jurisdiction of the FERC 

General Corporate Information
      Financial Statements
      Plant Statistical Data

☑ Allowed Cost-of-Service (Page 700)

Filing Dates
  ☑ Year-End (Form 6)- April 18th
  \ensuremath{\mathbb{D}} Quarterly (Form 6-Q) (70 days after the quarter ends)
FERC
OE: Division of Audits
\ensuremath{\mathbb{D}} 
 Performs financial and operational audits of industry
  participants.
  Performs audits on a random basis.
  \ensuremath{\mathbb{B}} Authority to audit all FERC regulation related records
\ensuremath{\mathbb{B}} Represents the Commission and explains and advocates its legal and policy positions.
\ensuremath{\mathbb{P}} Advises the Commission on compliance related matters.
FERC
Offices Involved in Rate Cases
2 Office of Administrative Litigation (OAL)
  Resolves disputes through settlement.

    Litigates unresolved issues at hearing.

  Commission Staff and lawyers represent the public interest.

☑ Office of Administrative Law Judges (OALJ)

  Resolves contested cases as directed by the Commission,
either through impartial hearing and decision or through
     negotiated settlement.
  Conducts fair and impartial investigations as directed by
     the Commission.
  Performs various alternative dispute resolution (ADR) as
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directed by the Commission. Part II Rate-Setting Procedures Initial Rates Indexed Rates Grandfathered Rates Settlement Rates Market-Based Rates Cost-of-Service Rates Rate-Setting Procedures Introduction Water Recourses (CFR 18)

B FERC & DOE regulations: Volume I, parts 1 to 399. Chapters pertinent to oil pipelines: Subchapter P - Regulations under the Interstate Commerce Act (ICA), Parts 340-350 ☑ Subchapter Q - Accounts under the ICA, Parts 351-352 ☑ Subchapter R - Approved Forms, ICA, Parts 356-357 ☑ Where are regulations specific to tariff filings located? 18 C.F.R. § 340
 □ Tariffs must be filed 30 days prior to taking effect, 18 C.F.R. §341.2 ☑ Neither the filing date nor the effective date are counted in the 30 days

B Short notice exception ☑ Tariff must be formatted in conformance with regulations, 18 C.F.R. 6341.3 Tariff Rate Types Initial Rates (18 C.F.R. §342.2) ☑ A carrier must justify an initial rate for a new service by: a) Filing a cost-of-service to support such rate, or b) Filing a sworn affidavit that the rate is agreed to by at least one non-affiliated shipper who intends to use the service in question (a negotiated rate). Tariff Rate Types Indexed Rates 18 C.F.R. §342.3  $\ensuremath{\mathbb{D}}$  A rate may be changed, at any time, to a level not to exceed the ceiling level.  $\ensuremath{\mathbb{B}}$  The current period ceiling level equals the product of the previous index year's ceiling level and the most recent index published by the Commission. Index published prior to June 1 of each year. Tariff Rate Types Grandfathered Rates Section 1803(a) of the Energy Policy Act of 1992 ("EPAct") deems just and reasonable "any rate in effect for the 365-day period ending on the date of the enactment of this Act ... if the rate in effect... has not been subject to protest, investigation or complaint during such period.  ${\ensuremath{\mathbb P}}$  A grandfathered rate can be challenged if: "a substantial change has occurred after" October 24, 1992, "in the economic circumstances of the oil pipeline which were a basis for the rate," or
"a substantial change has occurred after" October 24,
1992, "in the nature of the services provided which
were the basis of the rate." Tariff Rate Types Settlement Rates 18 C.F.R. §342.4  $\ensuremath{\mathbb{D}}$  A carrier may change a rate without regard to the ceiling level if the proposed change has been agreed to, in writing, by each person who, on the day of the filing of the proposed rate change, is using the service covered by the rate. Tariff Rate Types Market-Based Rates 18 C.F.R. §342.3 Carrier must demonstrate that it lacks significant market power in the in the origin market and the destination market. Filing requirements established in 18 C.F.R. §348. These filing requirements require a relatively lengthy application. If the application is approved, the carrier may set rates at whatever level the market will bear. Chris Lyons and I will be giving a presentation discussing market-based rates in significant depth at  $\mathsf{X}\mathsf{X}$ Tariff Rate Types Cost-of-Service Rates 18 C.F.R. §342.4 
☑ Carrier must show that there is a substantial divergence between the actual costs experienced by the carrier and the rate resulting from the application of the index such that the rate at the ceiling level would preclude the carrier from being able to charge a just and reasonable rate within the meaning in the Interstate Commerce Act. ☑ Filing requirements established in 18 C.F.R. §346 ☑ More on cost-based rates to come...

Cost-of-Service Rates Cost-of-Service Introduction

PART III

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☑ Types of Cost-of-Service Methodologies:

  Depreciated Original Cost ("DOC")
Trended Original Cost ("TOC")

② COS Methodology Prescribed by the Commission: The

  Opinion No. 154-B Cost-of-Service Methodology

Issued June, 1985
Utilizes a TOC rate base
  {\ensuremath{\mathbb R}} Has been modified and clarified by subsequent
     decisions.
Cost-of-Service
Depreciated Original Cost
     Operating Expenses
Return of Rate Base (Depreciation)
     Return on Rate Base
     Amortization of Allowance for Funds Used
     During Construction ("AFUDC")
     Income Tax Allowance
     Cost of Service (Revenue Requirement)
Cost-of-Service
Operating Expenses
Salaries and Wages

    Materials and Supplies
    Outside Services

Pensions and Benefits

☑ Insurance

② Oil Losses and Shortages
☑ Taxes other than Income Taxes
☑ Allocated Overhead
Allocated Overhead

☑ For pipelines that are subsidiaries of a larger
corporation, allocated overhead can represent a
significant component of the COS.

☑ The Commission generally uses a three factor

approach consisting of revenue, plant and payroll to

   allocate overhead.
\ensuremath{\mathbb{B}} Other approaches are permissible. \ensuremath{\mathbb{B}} The critical issue is that the allocation methodology
  match cost with causation.
Cost-of-Service
Depreciation
Depreciation Example:
  Beginning of Year 1 Rate Base = 1000
Estimated Life = 20 years
   Year 1 Depreciation Expense = (1000 / 20) = 50
\ensuremath{\mathbb{P}} Group Method of Depreciation: a number of similar or
   related assets are included in a group to which a single
   composite depreciation rate is applied.
Cost-of-Service
Rate Base
     Carrier Property in Service
     Accumulated Depreciation
Allowance for Funds Used During Construction
          ("AFUDC")
     Accumulated Amortization of AFUDC
     Working Capital Allowance
Accumulated Deferred Income Taxes ("ADIT")
     DOC Rate Base
Cost-of-Service
Accumulated Deferred Income Tax
   Calculation of ADIT
                                    Year 1 Year 2 Year 3 Year 4
   Tax Depreciation
                                        33.3 33.3 33.3
   Book Depreciation
                                         25.0 25.0 25.0
                                                                    25.0
                                          8.3 8.3 8.3 (25.0)
4.2 4.2 4.2 (12.5)
4.2 8.3 12.5
  Timing Difference
Deferred Income Taxes
   ADIT
                                      Assumptions
                                  Property
                                  Book Depreciation
                                                                    25%
                                  Tax Depreciation
                                                                    33%
                                  Income Tax Rate
                                                                    50%
                                  Equity % ROE
                                                                   100%
                                                                    10%
Cost-of-Service
Return on Rate Base
   Debt % x Cost of Debt
+ Equity % x Nominal Equity Rate of Return
= Weighted Cost of Capital
Average DOC Rate Base
x Weighted Cost of Capital
= Return on DOC Rate Base
Cost-of-Service
Allowance for Funds Used During Construction
   Average Monthly Construction Work in Progress ("CWIP")
  Balance
x Weighted Cost of Capital
= AFUDC
```

Average AFUDC Balance x Useful Life Factor = Amortization of AFUDC Cost-of-Service

```
Equity Portion of Return on DOC Rate Base
    Amortization of Equity AFUDC
    Taxable Elements of Return
    Net-to-Tax Multiplier
    Income Tax Allowance
Income Tax Rate*
÷ (1.0 - Income Tax Rate)
= Net-to-Tax Multiplier
*Generally based on the statutory marginal tax rate for corporations
Cost-of-Service
DOC Recap
    Operating Expenses
Return of Rate Base (Depreciation)
Return on Rate Base
    Amortization of Allowance for Funds Used
    During Construction ("AFUDC")
Income Tax Allowance
    Cost of Service (Revenue Requirement)
Cost-of-Service
Trended Original Cost (TOC)

    Variation of DOC.

Stores inflation adjustment in Rate Base and recovers as
"Deferred Return" over life of assets.

Applies Real Return on Equity ("ROE")1/ to "equity" portion of Rate Base and Cost of Debt ("COD") to debt
  portion of Rate Base.

☑ Trends portion of Rate Base funded by equity to reflect

  inflation as measured by the CPI-U.
Cost-of-Service
Nominal Equity Rate of Return
                                       TOC
                    Inflation
                                    Rate Base
      DOC
     Cost of
                     Real
                                     TOC
                     Rate
     Service
                      of
                                    Cost of
                    Return
                                    Service
Cost-of-Service
Calculation & Amortization of Deferred Return
     Trending Base (Equity Rate Base)
  x Inflation Factor
  = Deferred Return
   Deferred Return
  x Useful Life Amortization Factor
  = Amortization of Deferred Return
Cost-of-Service
Opinion No. 154-B
Issued June of 1985.
Adopts the trended original cost rate base ("TOC")
for oil pipelines wishing to establish or change their
        tariff rates by filing a cost-of-service.
Provides for a transition from the previous valuation
       rate base methodology, referred to as the "starting rate base," ("SRB").
Advocates use of the pipeline's actual capital
        structure.

    Case-by-case determination of many issues.

    FERC Opinion No. 154-B, as modified and clarified by subsequent decisions
Cost-of-Service
Starting Rate Base
    Intended to provide transition from prior methodology.
    One-time calculation as of December 31, 1983.
    SRB Formula:
        (Debt % x Net Original Cost)
     + (Equity % x Net Reproduction Cost New)
= Starting Rate Base
     Starting Rate Base ("SRB")
- DOC Rate Base
     = SRB Write-Up
Cost-of-Service
Starting Rate Base Write-Up
    SRB Write-Up is included in Opinion No. 154-B
    Rate Base.
    SRB Write-Up is amortized.
    Amortization of SRB Write-Up is excluded from
     Cost of Service.
    Carrier's Return On Rate Base includes a return
    on the unamortized SRB.
    SRB Write-Up is included in Trending Base when
    computing Deferred Return.
Cost-of-Service
Rate Base Components
  DOC Rate Base
+ SRB Write-Up
- Accumulated Amortization of SRB Write-up
+ Deferred Return
- Accumulated Amortization of Deferred Return
= 154-B TOC Rate Base
Cost-of-Service
Income Tax Allowance
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= Subtotal
x Net-to-Tax Multiplier
 = Income Tax Allowance
Cost-of-Service
Base & Test Periods
\ensuremath{\mathbb{D}} A base period must consist of 12 consecutive months of
  actual experience adjusted to eliminate non-recurring items. Carrier may include appropriate normalizing
   adjustments in lieu of non-recurring items.
A test period must consist of a base period adjusted for
changes in revenues and costs which are known and
  measurable with reasonable accuracy at the time of
filing and which become effective within nine months
after the last month of available actual experience
   utilized in the filing. For good cause shown, the
  Commission may allow reasonable deviation from the prescribed test period.  \\
   See 18 C.F.R. §346.2.
☐ Take-Aways on COS
☐ The calculations contain a number of variables that
   function in tandem.
Some of the required inputs involve data going back
  over 25 years.
\ensuremath{\mathbb{D}} The higher the quality of the data the more
   successful a cost-based rate filing will be.
Questions?
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+ Amortization of Deferred Return

# Pipelines, Failure and Success, 1861-1864

http://www.petroleumhistory.org/OilHistory/pages/Pipelines/failure.html December 07, 2014

Pipelines, Failure and Success, ... (Oil & Gas Journal, ... A two inch wrought iron pipeline to carry refined oil from Plumer to the Allegheny River ...

According to a notation in the Derrick's Handbook of Petroleum for Dec. 1861: "Victory M. Thompson built the Erie City Oil Works at the corner of Ninth and Chestnut/ Walnut Streets. The oil was pumped to the refinery, about half a mile from the depot, at which it was left by car." This pipeline was ahead of those which were later laid in the producing fields. According to a notation treating on pipelines in the Derrick's Handbook of Petroleum for Feb. 19, 1863: "Barows [Barrows] & Co. of Tarr Farm have for some time been conveying oil from the [Densmore wells] to their refinery, a distance of 800 to 1000 feet by this means and the plan was said to work admirably." This pipeline was actually laid in the fall of 1862 under the direction of James Hutchinson, engineer (some sources state that the name was Hutchings). It operated by siphon, a satisfactory method for short distances. The Barrows refinery was south of the Densmore wells, just over the line in the adjacent Blood Farm. A two-inch cast iron pipeline conceived by the Hutchinson and Foster Company was reported as follows: "A two-inch iron pipe was laid in 1863 from the Tarr Farm to the Humboldt refinery at Plumer, an oil line distance of two and a half miles. The oil was forced through this by powerful pumps" (Derrick Handbook of Petroleum, Feb. 19, 1863). This 1863 line had to climb about 500 feet to get over the ridge on the east side of the valley separating Plumer from the flats of Tarr Farm. Three pumps were utilized on the route, one on the Tarr Farm flats and the other two on the Tarr Farm flank of the ridge (west flank). The projectors found that the pumps and the cast iron pipes could not handle the job. This was attributed to poor pipes, leaky lead joints that came unjointed and faulty pump machinery (Giddens, 1938). The affair was referred to as being an "experimental" project. The teamsters, however, foresaw this experiment as the beginning of the end, a threat to their control of the hauling of oil, and they tore up the ill-fitting pipes. In spite of the problems which led to failure of the 1863 line, it was felt that this effort at Tarr Farm showed that a pipeline with pumps was a feasible manner of transporting crude oil, at least theoretically. The advance of the pipeline industry depended on correcting the obvious problems, and they were by no means insurmountable. Hutchinson kept on going at full speed after the 1863 Tarr Farm - Plumer mechanical failure and put down a three mile fourinch cast iron pipeline on the west side of Oil Creek from the Sherman well area (north Pioneer) upstream to the Oil Creek RR depot at Miller Farm. This was done in 1863-64 under the name of the Western Transportation Company. Tall 10 inch diameter air chambers were cast into the pipes every 100 feet to "equalize pressure" (Redwood, 1913), but the pumps jarred the lead-socketed joints loose and much oil was lost. The air chambers which jutted up from the pipe made it look like "an ornamental iron fence" (Oil & Gas Journal, Derrick, 1934). The teamsters finally dug it up and tore it up and the pieces of the demolished line laid along the creek bank for several years. In the winter of 1863-64 Hutchinson and Company, regardless of the destructive stance of the teamsters, laid another line made of three- inch cast iron pipes (five inch according to A.M. Johnson, 1956, and McLaurin, 1896) from the prolific Noble well on the east side of Oil Creek upstream to Shaffer farm on the west side, a distance of about three miles (Giddens, 1938). A newly constructed depot and terminal of the Oil Creek Railroad was the objective at Shaffer. McLaurin (1896) states that this illfated line was laid via a pipeline charter granted by the Legislature to the Western Transportation Company in 1864. This charter was to become immensely important in the annals of pipeline development and history. However, in popular terms of the day this was the pipeline that bore the reputation of leaking "like a fifty cent umbrella". A two inch wrought iron pipeline to carry refined oil from Plumer to the Allegheny River (three miles) was conceived and laid by a refiner at Plumer in 1863-64. It was said to be successful (McLaurin, 1896). To sum up these early pipelines through 1864, only three were successful: the 1861 line from a depot to a refinery in the city of Erie, a 1000 foot siphon line which carried oil from a well to a nearby refinery in Oil Creek Valley, and a two-inch line which carried refined product from Plumer to the Allegheny River. It is said that the short siphon line would not have worked over a greater distance, hence was not used in other circumstances (Johnson, 1956).

# MITIGATION MEASURES OF OIL PIPELINES IN CASE OF POWER FAILURE

http://www.arpapress.com/Volumes/Vol12Issue2/IJRRAS 12 2 16.pdf December 07, 2014

MITIGATION MEASURES OF OIL PIPELINES ... as pressure and gas flow rate, ... down or power failure at an intermediate location, ...

IJRRAS 12 (2) • August 2012

www.arpapress.com/Volumes/Vol12Issue2/IJRRAS\_12\_2\_16.pdf

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MITIGATION MEASURES OF OIL PIPELINES

IN CASE OF POWER FAILURE

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# ABSTRACT

This work is to investigate the operations at various upset conditions due to power failure of the 1506-km Heglig-Portsudan pipeline. A simulator, developed at the Department of Oil/Gas Storage & Transportation, China University of Petroleum-Beijing, can simulate the existing long-distance waxy crude pipeline, exactly as it is configured in the field. For non-Newtonian flow, the fluid rheological consistency, K (Pa.sn) and the flow behaviour index n are evaluated experimentally. Those two parameters were required to be introduced into the software to assess their effects on surge scenarios.

Some surge cases of loss of communication were reviewed. Consequently, it is of great important that the operator should review some practical mitigation measures as well as the capacity of SCADA (Supervisory Control and Data Acquisition) system to ensure that the system has resources to accommodate normal and abnormal operations.

Key Words: simulator, non-Newtonian, rheological properties, surge, SCADA.

#### 1. INTRODUCTION

There is a general concern regarding the pipeline transportation of the waxy crude oils at temperatures below the pour point and at various scenarios of operations. More importantly, this study is of practical significance in safe design and operation of pipelining the waxy crudes, it helps not only minimizing many risks which might encounter in the long-distance oil pipelining systems but also handling the expected problems arises when pumping the waxy crudes.

A pressure surge may produce even greater consequences. Excessive surge may move a pipe off its supports or rupture a pipeline, leading to significant repair or replacement costs. In the worst scenario, a major pipeline failure may cause injures to people and require a massive cleanup. Specifically, unexpected power failure or shut down scenarios may lead to great changes of transportation materials, operating parameters or equipments of pump stations; which in turns will induce surge in oil transfer pipeline. To conduct a dynamic surge analysis, a simulator has been developed. In addition, a set of input data is used to describe the specific pipeline system and its operation. In China, the most complicated long-distance-crude-oil-pipeline technically and operationally is the China West Crude Oil Pipeline. The shear and thermal history of three PPD- beneficiated waxy crude oils transported through this pipeline were simulated by using a stirred vessel and with the energy dissipation of viscous flow as the shear simulation parameter. The comparisons of flow properties of the crude oils obtained from field tests with experimental simulation show that the gel points and viscosities from simulation are in agreement with the field data.[1]

Based on the characteristic method, Jing Gong and Wang [2] established a numerical calculation and simulated the pressure variation process, when a valve at the terminal station was accidentally closed in a product pipeline. Further research combining the boundary condition of relief system was carried out.

Bruce and Gerald [3] have found that integrating data analysis, safety devices and controller training were the best tools to control surge.

Anindya, et al. [4] conducted a numerical simulation to analyze transients in gas flow and pressure in a horizontal straight pipe. The numerical results showed that depending upon the pipe dimensions and operating variables such as pressure and gas flow rate, transient effects in the pipeline may last for a long time and/or over significant length of pipe. The simulations predicted an initial surge in gas flow rate greater than the final steady-state value if the pressure drop across the pipe is increased.

An orientation visit [5] to Heglig Central Processing Unit was done by the author, it was well stated that two Pour Point Depressants (PPD) Products which were suggested by Chinese partner had provided acceptable values of pour point and viscosity with a slight difference. But, field test was strongly suggested to verify laboratory results as well as to determine the true effects of different blends in the real pipeline. On the other hand, Dafan & Zheming [6] investigated the variation of the rheological properties of Da Qing waxy crude with their thermal history and their

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time effect. They found, experimentally, that such properties were very sensitive to heat treatment. Also, it was denoted that, the structural strength of Da Qing crude varied with heat treatment.

More experimental works had been done at the Laboratory of Oil Rheology, China University of Petroleum, Beijing. It has been quite clear that Da Qing waxy crude is similar to Sudan waxy crude. However, the best heat treatment temperature for Da Qing crude oil was 60°C and reheating the crude was found to be of great importance. Whereas, heating the Nile Blend up to 90°C was quite acceptable. Nevertheless, still heating to 80°C may be considered for operating cost reduction regardless of other shortcomings.

# 2. MATERIALS AND METHODS

The major purpose of the current work was to further investigate the problems encountered pipeline transportation of the Nile blend in case of unexpected power failure. This research was, mainly, adopting methods to utilize a software simulator and carry out laboratory techniques that are capable of providing essential data and analyses necessary for assessing the important mitigation measures for safe operations of Heglig-Portsudan pipeline. The crude sample to be studied was brought by the Pipeline Science Research Institute of China National Petroleum Corporation (CNPC), Lang Fang. The sample was too waxy, refer to table 1 & 2. Due to high solidification temperature, high viscosity at low temperature and high yield strength, novel oil transporting technology methods have to be studied and developed.

Table 1 The main physical properties of the crude sample

The wax content (approximately)

The Wax Appearance Temperature

Average inlet temperature

Heat capacity

Fluid density

The viscosity at 28°C and 10 s-1

The kinematic viscosity at 28°C and 10 s-1

Oliver 23% by weight

57°C

60°C

2100 J/kg.°C

843 kg/m3

The viscosity at 28°C and 10 s-1

Oliver 25%

Oliver 25%

Oliver 25%

Oliver 25%

Oliver 25%

Oliver 25%

The kinematic viscosity at 28°C and 10 s-1

Oliver 25%

Olive

Table 2 The base value for control set points of Heglig-Portsudan pipeline
Minimum suction pressure station #1 490kPa
Minimum suction pressure at all other stations 280kPa
Max. Allowable operating pressure (MAOP) under 9724kPa
normal condition

Max. Allowable operating pressure under upset condition
Discharge pressure controller
Discharge pressure shutdown high (DPSH)
Discharge pressure shutdown high high (DPSHH)

9724+10%(9724) = 10696kPa 9724-1%(9724) = 9627kPa 9724+5%(9724)= 10210kPa with 30 sec delay 9724+7.5%(9724)= 10453kPa with no delay

In the experimental setup carried out at the laboratory of rheology, China University of Petroleum-Beijing, the viscometer VT500 with a Phoenix P2 circulator has been selected as the main device. The viscometer VT500 is a combination of viscometer (VT) with a power supply VS500 with DOS-based application. A Phoenix P2 circulator was used as temperature controller .The measurements have been carried out at different heat treatment and shear conditions. Depending on those measurements, the values of the fluid rheological consistency, K (Pa.sn) and the flow behaviour index n were introduced into the software.

# 3. RESULTS AND DISCUSSION

The prediction of pressure surges is of economic importance in pipeline transportation where the pressure must be maintained within narrow limits to prevent damage of pipe and/or devices.

maintained within narrow limits to prevent damage of pipe and/or devices.

In the current work, the main cause of the pressure surges was the unexpected power failure. When the pump shuts down or power failure at an intermediate location, e.g. at station#3, the rotational inertia of the motor-pump system continues to transfer energy to the liquid until the pump head has decreased to zero. The pump impeller rotates as the flow continues through the pump. The rotational inertia of the motor-pump system and the efficiency of energy transfer from the impeller to the fluid both contribute to determine the rate of run-down (the rate the motor and pump slow down when the electrical energy is disconnected).

pump slow down when the electrical energy is disconnected).

The outcome of this case study, fig.1 & Fig.2 indicated that to what extent the mitigation measures should be taken to keep the MAOP within the limit. However, the maximum value displayed at station#1, 10.6MPa, is safe when compared to the MAOP (Maximum Allowable Operating Pressure) under abnormal condition, i.e. 10.696MPa.

Fig. 1 The transient.

#### Fig. 2 Maximum & Minimum Pressure Curves.

The power failure at station#3 can cause large pressure surges. A low pressure surge travels downstream as the pump head decreases. The flow rate and velocity downstream decrease as the new pressure gradient is established. Pump shutdowns also affect the flow upstream of the third station; i.e. a high pressure travels upstream as the flow velocity decreases, fig.3-a and fig.3-b.

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Fig.3-a Transient Curves at the 2nd Station.

#### Fig. 3-b Transient Curves at the 2nd Station (Modified).

Since the accident of surge here happens as a result of a power failure at station#3; therefore an effective mean of mitigation should be taken. This can be done by two levels of controls. Firstly, the oil can be released by means of PRV (Pressure Relief Valve). As the time goes the amount of oil released from the line is increased to keep the pressure within the allowable limits. Secondly, by considering a similar case in which the degree of opening of the adjusting valves should be set, separately, to a low value at the upstream of the station. In contrary, the adjusting valves at the downstream stations are to be kept to higher values.

The most successful mitigation measure considered is the bypass relief valves, which are better to be substituted by high integrity pressure sensors. In general, there were no surge pressure violations if relief bypass were used, and the

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pipeline was able to establish a steady-state flow rate. In addition to hardware control in these situations, the operator needs a comparatively low cost method for simulating surge pressures while working off-line.

# 4. WHAT WOULD HAPPEN TO HEGLIG PIPELINE IN THE ABSENCE OF SCADA

The worst condition of the sub-cases was when SCADA is out of service and the PRVs (Pressure Relieve Valves) were not in place while pumping the chemically untreated sample. The maximum pressure at stations #3, #4, and#6 were 12, 12, and 9.6MPa, respectively. A loss of communication with PRVs was taken place when Heglig-Portsudan Pipeline was simulated without SCADA, therefore acceptable means of minimizing the upset situations should be provided as suggested below. However, with PRVs and SCADA in service, a better quick response to mitigation is provided which results in reducing the maximum pressure recorded at stations #4 and #5 to their limit of 6 and 6.6MPa, respectively. Other modified set points can be shown in table 3.

On the other hand, without PRVs the role of SCADA was obvious in creating signals to other pump controls trying to maintain the pressures to their set points while surge accident was happening; significant reduction in the maximum limits of pressure were maintained at the terminal station, i.e. the surge accident start point. The maximum pressure recorded at stations #4, #6, and #7 were 11.4, 5.4 and 7.8MPa, respectively. Those values can be compared to 12, 9.6, 14.4MPa, respectively, when SCADA was out of service. Again, the purpose of getting optimal surge control measures was accomplished through adjusting the relief system on time as a major outcome of the simulator.

Nevertheless, surge generated by power cut off could be more destructive and the induced surge pressure would be much higher, so controlling surge of this kind is indispensable. Test looping for rheological investigations and/or computer programming for graphical simulations were few methods to assess the possible mitigation measures. However, in implementing this, several issues such as various failure scenarios and control measures should be looked into seriously as suggested above.

| I.                    |           | Table 3 Th<br>St.#1 | e Modified S<br>St.#2 | et points at<br>St.#3 | Various Pump<br>St.#4 | Stations<br>St.#5 | St.#6 | St.#7 |
|-----------------------|-----------|---------------------|-----------------------|-----------------------|-----------------------|-------------------|-------|-------|
| Param                 | eter      |                     |                       |                       |                       |                   |       |       |
| Pressure<br>Adjusting | Inlet     | -                   | 0.28                  | 0.28                  | 0.28                  | 0.28              | 0.28  | 4.47  |
|                       | Outlet    | 9.60                | 9.60                  | 6.90                  | 6.90                  | 6.9               | 6.90  | -     |
| Pressure<br>Releasing | Inlet     | -                   | 2.4                   | 2.4                   | 2.4                   | 2.4               | 2.4   | 5.24  |
| •                     | Outlet    | 10.80               | 9.20                  | 9.7                   | 9.70                  | 9.70              | 9.70  | -     |
| Pressure<br>Shutdown  | Inlet     | -                   | 0.20                  | 0.20                  | 0.20                  | 0.20              | 0.20  | -     |
|                       | Outlet    | 11.20               | 9.40                  | 9.7                   | 9.80                  | 10.20             | 9.80  | -     |
| High<br>Pressure      | Inlet     | -                   | 0.039                 | 0.039                 | 0.039                 | 0.039             | 0.039 | -     |
| Open/Close            | Outlet    | 11.40               | 10.9                  | 9.9                   | 10.00                 | 10.40             | 10.1  | -     |
| Flow R                | ate       |                     |                       |                       |                       |                   |       |       |
| (+Inlet)              | (-Outlet) | +2066               | -66                   | -330                  | -                     | -                 | -     | -     |

Note: The Modified Set Points are indicated with Bold. Various failure conditions and control measures by virtue of a computer simulator in its full version have to be considered in more details.

# 5. CONCLUSIONS

In parallel with SCADA system implementation, a simulator working on off-line basis is of great interest in terms of safety, cost and productivity. However, the suggested mitigation measures were proved to be more practical tool control for sophisticated systems such as Heglig-Portsudan pipeline.

# 6. ACKNOWLEDGEMENT

As far as the experimental works are concerned, the authors should mention the Pipeline Sc. Research Inst. of CNPC, Lang Fang Pipeline Institute (廊坊管道局) , teachers and students at the Laboratory of Oil Rheology,

China University of Petroleum, Beijing. Also, our utmost gratitude to Xudong Sun, the director of the International Office & his staff whose sincerity and encouragement we will never forget.

#### 7. APPENDICES

7.1 THE GENERAL FEATURE OF THE SIMULATOR: The figure below shows the Main Menus of the Input Data of the simulator which designed and developed at the Department of Oil/Gas Storage & Transportation, China University of Petroleum-Beijing,

### 7.2 HEGLIG-PORTSUDAN CRUDE OIL PIPELINE.:

The construction of the 1540 kilometer export pipeline to Port Sudan is the most important achievement of GNPOC for the development of the whole Sudan famous basin and indeed the country as a whole. ( Note: The Greater Nile Petroleum Operating Company (GNPOC) consortium comprises China National Petroleum Corporation (CNPC),

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Malaysia's Petronas, Sudan's Sudapet, and India's Oil and National Gas Corporation (ONGC). ONGC acquired its interest from Canada's Talisman in March 2003.)

Below, a map which shows the SEVEN pump stations, starting from the first station at Heglig and the terminal at Portsudan. Parts of the route through the northern desert and the Red Sea Hills were notoriously rocky and difficult to excavate. The pipe has been exposed to fluctuating extremes of heat and cold in the desert atmosphere. Better quality pipe was used in these sections to survive the thermal stresses of expansion and contraction. The pressure inside the pipes is highest near the pump stations, and these sections also used the strongest pipes. Also, the pipeline was exposed to ground movement, from flood erosion, for example, as well as organised attacks. Breaks could occur anywhere, and safety features were done successfully all along the route by the GNPOC under supervision of the Sudan Ministry of Energy & Mining.

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# GAIL pipeline fire due to collective failure: Oil ministry probe report

http://articles.economictimes.indiatimes.com/2014-09-10/news/53770208\_1\_gail-pipeline-fire-pipeline-route-pngrb December 07, 2014

... year was a result a collective failure of the system, an oil ... corrosion rate in the pipeline," the ... natural gas pipeline in ...

GAIL's Tatipaka-Kondapalli pipeline, which was built in 2001 to move dry natural gas to Lanco Power Plant, transported gas as also water and condensate coming from ONGC's wells. Water and condensate corroded the pipeline, leading to gas and condensate leaking to surface where a lighting of a stove led to a blast and subsequent fire on June 27.

NEW DELHI: The devastating fire at state-run GAIL India Ltd's pipeline in Andhra Pradesh that killed 22 persons in June this year was a result a collective failure of the system, an oil ministry probe has concluded.

An inquiry committee, headed by the ministry's Joint Secretary (Refineries) Rajesh Kumar Singh, in its report blamed "inadequate systems/approach" for the accident.

The agreement between producer ONGC and transporter GAIL does not provide for the quality of gas to be supplied as is the case in several marginal and isolated fields in Krishna Godavari and Caurvey basins as also Gujarat and North East.

Putting separators to strip gas of liquids before transportation may not be economically viable at all places due to small quantities of fuel being produced from these fields.

An audit by pipelines regulator PNGRB in August 2011 too did not make any observation in connection to composition of gas and associated issues.

The report said there was "no evidence of any efforts" by Nagpur-based Petroleum and Explosives Safety Organisation (PESO) to enforce putting up of Gas Dehydration Unit to drain out water and liquids.

The pipeline was also audited by OISD and there has been no observation on wet gas content.

The report said it was difficult to establish individual culpability.

Besides installation of dehydration facility for removal of water and condensate prior to feeding natural gas in the pipeline, it recommended through inspection of the pipelines and putting up of leak detection system.

Also, patrolling using modern gadgets should be carried out in the pipeline route.

It also recommended that "GAIL should complete an internal enquiry of managerial failures at different levels and fix responsibility for the lapses pointed out herein."

"Comprehensive procedure shall be developed for repair of pipeline in case of leak," it said, adding GAIL must develop proper supervisory and control systems for maintaining the health of pipelines.

The state government on its part did not act on GAIL's representations for removal of encroachment along the pipeline route.

"GAIL has apparently flouted the declaration to the statutory authority as well as the declared design basis by not providing GDU at Tatipaka and Mori. Absence of GDU contributed to increasing the internal corrosion rate in the pipeline," the report said.

Wet gas contains free water, carbon dioxide and sulphur which induced internal corrosion in the pipeline.

The panel said the explosion, followed by a major fire, was due to leakage of condensate and gas which was probably continuing from the night before the incident. The condensate formed vapour cloud with gas pockets, and triggered a major fire when a tea vendor lighted the stove.

# An Overview of Corrosion Mechanisms and Mitigation Strategies for Oil and Gas Pipelines

http://www.hindawi.com/journals/isrn/2012/570143/ December 07, 2014

Advances in Asset Management ... Internal corrosion is the largest cause of pipeline failure in oil and gas ... A study of the influence of gas flow rate on ...

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Effective management of assets in the oil and gas industry is vital in ensuring equipment availability, increased output, reduced maintenance cost, and minimal nonproductive time (NPT). Due to the high cost of assets used in oil and gas production, there is a need to enhance performance through good assets management techniques. This involves the minimization of NPT which accounts for about 20–30% of operation time needed from exploration to production. Corrosion contributes to about 25% of failures experienced in oil and gas production industry, while more than 50% of this failure is associated with sweet and sour corrosions in pipelines. This major risk in oil and gas production requires the understanding of the failure mechanism and procedures for assessment and control. For reduced pipeline failure and enhanced life cycle, corrosion experts should understand the mechanisms of corrosion, the risk assessment criteria, and mitigation strategies. This paper explores existing research in pipeline corrosion, in order to show the mechanisms, the risk assessment methodologies, and the framework for mitigation. The paper shows that corrosion in pipelines is combated at all stages of oil and gas production by incorporating field data information from previous fields into the new field's development process.

The oil and gas industry is an asset intensive business with capital assets ranging from drilling rigs, offshore platforms and wells in the upstream segment, to pipeline, liquefied natural gas (LNG) terminals, and refineries in the midstream and downstream segments. These assets are complex and require enormous capital to acquire. An analysis of the five major oil and gas companies (BP, Shell, ConocoPhillips, Exxonmobil, and Total) shows that plant, property, and equipment on average accounts for 51% of the total assets with a value of over \$100 billion [1]. Considering the huge investment in assets, oil and gas companies are always under immense pressure to properly manage them. To achieve this involves the use of different optimization strategies that is aimed at cost reduction and improved assets reliability [2].

Due to the growth in the demand of oil and gas around the world, companies are developing new techniques to reach new reservoirs in the offshore and onshore arena [3]. This is putting pressure on most of the facilities with the attendant cost of maintenance soaring [1]. The continuous utilization and the ageing of facilities have resulted in record failures in the oil and gas plants. Research shows that between 1980 and 2006, 50% of European, major hazards of loss containment events arising from technical plants failures were primarily due to ageing plants mechanism caused by corrosion, erosion, and fatigue [4, 5].

A study shows that corrosion cost in US rose above 1\$ trillion in 2012 accounting for about 6.2% of GDP hence, the largest single expense in the economy [6]. In the oil and gas company, corrosion accounts for over 25% of assets failure [7] and is found to be prevalent in every stage of the production cycle. Oxygen which plays a dominant role in corrosion is normally present in producing formation water. During drilling operation, drilling mud can corrode the well casing, drilling equipment, pipeline, and the environment. Water and CO produced or injected for secondary recovery can cause severe corrosion of completion strings, while the acids used to reduce formation damage around the well or to remove scale can attack metals [8]. The formation water and injected water used for the oil recovery are a potential source of pipeline corrosion during transportation of the oil from the wells to the loading terminals. Mechanical static equipment like valves, tanks, vessels, separators, and so forth are susceptible to a different kind of corrosion however, pipelines are more prone to corrosion due to the presence of CO, HS, HO, bacteria, sand, and so forth in the fluid.

Owing to the increasing cost of pipeline corrosion management in the oil and gas industries [1], operators are becoming more concerned about corrosion management planning at all phases of production. Corrosion information from existing field data is being incorporated into design information for new oil and gas field [9, 10] in a bid to develop appropriate corrosion management methodologies that will enhance the design life of the pipelines and optimize production. To reduce the risk of microbiologically influenced Corrosion (MIC) and other associated corrosions like stress corrosion cracking (SCC), hydrostatic testing of carbon steel pipes should be carried out in such a manner that enhances the future pipeline service conditions by using the right source of water, ensuring proper degree of filtration, ensuring limited exposure period to temperature and eliminating air packets [11]. Though bacteria in the biofilm are responsible for pitting of a pipeline in a MIC however, the impact of the flow velocity of the constituent fluid influences the mass transfer rate thereby affecting the biofilm formation, hence, inhibiting the activities of sulphate reducing bacteria, (SRB) present in the fluid [12]. This flow attribute has significant impact in MIC in oil and gas pipeline.

Considering the fact that the CO and H S induced corrosion rate can reach up to 6 mm/yr and 300 mm/yr, respectively, [13] in oil and gas pipelines, sophistication in inspection and monitoring techniques is therefore necessary for quick mitigation. The increased trend in in-line inspection and online data acquisition has helped in quicker data acquisition, analysis, and decision making regarding corrosion in pipelines. The enhanced research knowledge of the behaviour of these corrodents (CO and H S, acetic acid, etc.) at different operating conditions [14–17] has given rise to numerous mechanistic, statistical, and empirical models [18–23] which have contributed immensely in the inspection and monitoring, selection of inhibitors, and materials selection for pipelines design.

Since corrosion is a dominant factor contributing to failures and leaks in pipelines [24], to aid industry experts in managing the integrity of pipelines therefore involves a layout of the developments in the management strategies. This involves the recognition of the conditions contributing to the corrosion incident and identifying effective measures that can be taken to mitigate against them. To facilitate best practices in pipeline integrity management therefore, requires a framework that utilizes good policies and procedures in inspection, data collection, and interpretation for corrosion control.

Corrosion is a naturally occurring phenomena commonly defined as the deterioration of a substance (usually metal) or its properties because of a reaction with its environment [25]. Corrosion of materials is inevitable due to the fundamental need of lowering of Gibbs energy [26]. Every material is trying to achieve a lower energy state hence the ability to corrode in order to get to a low energy oxide state. Though this is the case with all materials, the major focus of experts however, is to achieve an equilibrium position between the materials and the environment thereby controlling corrosion.

Modern corrosion science has its roots in electrochemistry and metallurgy. Whereas electrochemistry contributes to the understanding of materials via corrosion, metallurgy provides information about the behaviour of the material and their alloys hence provide a medium for combating the degradation on them. The type of corrosion mechanism and its rate of attack depend on the nature of the environment (air, soil, water, etc.) in which

the corrosion takes place. Whereas some environmental condition can help to mitigate the rate of corrosion, others help to increase it hence, industrial wastes and products can either be corrosion inhibitor or catalyst. For instance, CO, HS, temperature, mass flow rate, pH, formation water, and so forth contribute in no small measure to the rate of corrosion in oil and gas pipeline [14, 16, 17, 27]. The existence of anodic cathodic sites on the surface of a piece of metal implies that the difference in electrical potential is found on the surface. This potential difference has the tendency of initiating corrosion. If an oil and gas pipeline passes through a zone of clay soil (where the oxygen concentration is low) to gravel (where the oxygen concentration is high), the part of the pipeline in contact with the clay becomes anodic and suffers damage. Though this problem is extensively addressed with the cathodic protection [26], concentration cell may also be formed where there are differences in metal ion concentration.

Although most metals are crystalline in form, they generally are not continuous single crystal but rather are collections of small grains of domains of localized order in which microcrystal forms as the liquid cools and solidifies. In the final states, the crystals have different orientation with respect to one another. The edge of the domain form grain boundaries which are an example of planar defects in metal. These defects are usually sites of chemical reactivity. The boundaries are also weaknesses, the places where stress corrosion cracking begins. The metallic surface exposed to an aqueous electrolyte usually possesses site for oxidation (anodic reaction) that produces electrons in the metal and reduction (cathodic reaction) that consumes the electrons produced by the anodic reaction [25, 26]. These sites make up a corrosion cell. The anodic reaction (Figure 1) involves the dissociation of metal to form either soluble ionic product or an insoluble compound of metal usually an oxide. For cathodic reaction (Figure 2), oxygen gas generated could be reduced or water is reduced to produce hydrogen gas. The simultaneous reaction of the anodic and cathodic reactions produces the electrochemical cell.

In completely oxygen-free water, the cathodic reaction that takes place is the reaction of hydrogen ion to form hydrogen gas as shown in (1): 2 H + + 2 e - → H 2 (g) (1) When significant amounts of oxygen are present in the system, the cathodic reaction that takes place is shown in (2): 2 H + + 1 202 + 2

# Multi Criteria Decision Analysis framework for risk ...

http://www.citg.tudelft.nl/fileadmin/Faculteit/CiTG/Over de faculteit/Afdelingen/Afdeling Waterbouwkunde/sectie waterbouwkunde/people/personal/gelder/publications/papers/doc/042.r December 07, 2014

to provide a theoretical minimum failure rate for the life of the pipeline. ... paper, it is the determination of risk of failure of oil and gas pipelines.

Reliability, Risk and Safety - Ale, Papazoglou & Zio (eds) © 2010 Taylor & Francis Group, London, ISBN 978-0-415-60427-7

Multi Criteria Decision Analysis framework for risk management of oil and gas pipelines

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ABSTRACT: Oil and gas pipelines are subject to different degrees of failure and degradation during damage, and design imperfections. One or a combination of these failure mechanisms could eventually lead to rupture, carrying huge human, financial, and environmental loss. Hence, the need for reliable and cost effective risk management processes becomes more imperative. This paper proposes a decision based method for risk management of oil and gas pipelines. The method is based on a Multi Criteria Decision Analysis (MCDA) framework, utilizing an Analytic Hierarchy Process (AHP) to prioritize oil and gas pipelines for design, construction, inspection and maintenance. A case study application on pipelines in Nigeria is used to demonstrate the proposed methodology. The methodology is an improvement in the existing qualitative risk assessment of pipelines. Furthermore, with enhanced accuracy in risk assessment, considerable cost savings in the inspection and maintenance planning of the pipeline may be achieved.

# INTRODUCTION

#### 1.1 Background

Integrity maintenance of pipelines is a major challenge of service companies, especially those involved in the transmission of oil and gas. Two major factors have been the driving force behind this challenge. These are the need to minimize costs of installation, service and maintenance, and second is risk minimization. Safety analysis (or risk assessment) of pipelines entails the study of the probability of its failure and any associated consequences in terms of economic loss, human hazards, and degradation of the environment. Pipeline leakage or burst could be disastrous, having catastrophic influence on human and marine lives and huge economic loss. Pipeline disasters have been recorded in both developed and developing countries, including Venezuela, UK, Russia, Canada, Pakistan, Nigeria, and India (Dey et al. 2004 & Al-Khalill et al. 2005), necessitating the development of more effective risk management strategies.

and their risk analysis could be simplified by using an hierarchical approach, (Huipeng Li 2007). However, little has been achieved on hierarchical risk analysis of petroleum pipelines, as an aid to decision analysis, which is required in making inspection and maintenance decisions. Analytic hierarchy process is a promising method for this application. AHP, developed by Saaty fundamentally works by using opinions of experts in developing priorities for alternatives and the criteria used to judge the alternatives in a system, (Saaty 1980). The outcome is a relative scale which gives managers a rational basis for decision making. It has found applications in diverse industries, such as agriculture, (Quresh and Harrison 2003), oil and gas, (Al-Khalill et al. 2005 & Cagno et al. 2000), and the public sector, (Dey 2002). In this paper, a systematic risk-based approach to risk management of oil and gas pipelines is presented. The method is based on a multi criteria decision analysis framework, utilizing an analytical hierarchy process to prioritize operating pipeline for design, construction, inspection and maintenance.

Transmission pipelines are complex in nature,

Ideally, most pipeline operators ensure that during the design stage, safety provisions are created to provide a theoretical minimum failure rate for the life of the pipeline. While in operation, operators often used subjective estimate to carry out their routine based maintenance. However, subjective risk estimate is prone to inaccuracies with sometimes an unreliable outcome.

The overall objective, sub-objectives, attributes and decision alternatives are represented in an hierarchy.

Three different oil and gas pipelines operated by the Nigerian National Petroleum Company (NNPC) have been used as a case study. Their failure factors and historical failure records were obtained from literatures and historical records from the company. The failure factors are listed

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as the sub-objective factors in the MCDA. They have been grouped and identified as external interference, corrosion, operational error, structural defects and other minor failures. Each subobjective factor is further divided into attribute(s), as appropriate. For example, corrosion is a sub-objective factor which is further divided into external and internal corrosion. The selected crude oil and gas pipelines are the decision alternatives which will be prioritized for design, construction,

inspection and maintenance.

In the methodology, AHP is used to estimate the probability of failure of pipelines by combining historical failure data of the pipeline with pairwise comparison carried out by experts. The expected values of consequences of pipeline failures are obtained from typical cost of failures. Risk is then estimated by the product of probability and consequences. Web-HIPRE version 1.22 (Mustajoki and Hämäläinen 2000), is used to analyze the results and to carry out a sensitivity analysis.

Scientifically, the approach will be valuable to oil and gas companies in prioritizing the inspection and maintenance activities of their oil and gas pipelines. The methodology could also prove valuable in arriving at a design, redesign, construction and monitoring decisions.

### RESEARCH METHODOLOGY

#### The analytic hierarchy process 2.1

Analytic hierarchy process is used in the decision making to estimate the likelihood of an event, by establishing relative importance of each contributing factors. The analytical hierarchy process consists of the following basic steps:

# Procedures

# 2.2.1 Problem formulation

The ultimate goal of the AHP is defined. In this paper, it is the determination of risk of failure of oil and gas pipelines. After the goal definition, contributing factors to the failure are then identified. If applicable, these factors are further divided into 1 or 2 sub factors.

2.2.2 Selection of decision alternatives Identification of decision alternatives is very important in the AHP. The conclusion on the decision alternatives is the outcome of the AHP. In this paper, three oil and gas pipelines are selected as the  $\,$ decision alternatives. The goal of the AHP there-

fore is to compare these pipelines risk wise, and to rank them based on the level of risk expected.

2.2.3 Collection of information Required features for the pipelines are divided into physical data, construction data, operational data, inspection data and Failure history. This information is documented for the hierarchical analvsis.

# 2.2.4 Hierarchy

The next step is the development of an hierarchy (value tree), which consists of the goal of the risk assessment, the failure factors and sub factors, if applicable and the decision variables.

# 2.2.5 Expert elicitation

In the last step of the analytical hierarchy process, data of the pipelines are presented to a number of experts who will carry out a pairwise comparison of the pipelines with respect to each risk factor. The outcome of the comparison is a matrix that ranks the pipelines in order of likelihood of failure. The experts were required to rank each factor against another using the Saaty scale 1-9. Table 1 below gives an explanation of the Saaty scale.

For example, if two criteria are judged to have the same level of risk, the pairwise comparison score will be 1. A score of 9 is given if one criterion is assumed to be extremely stronger than the other. Intermediate judgments of 2, 4, 6 and 8 are selected when a conclusion cannot be reached from the scores of 1, 3, 5 and 7 as defined in Table 1.

### 2.2.6 Consistency check AHP provides the possibility of checking the logi-

cal consistency of the pairwise matrix by calculating the Consistency Ratio (CR). AHP judgment is acceptable if CR is less than 0.1. Given a weight vector,

| Table 1. Saaty scale of decision preference.  |       |
|---|-------|
| Judgment Explanation  | Score |
| Equally Two attributes contribute   | 1     |
| equally to the objective Moderately Slightly favour one attribute over another                          | 3     |
| Strongly Strongly favour one attribute over another   | 5     |
| Very strongly Strongly favour one attribute<br>with demonstrated importance<br>over another             | 7     |
| Extremely Evidence favouring one attribute over another is of the highest possible order of affirmation | 9     |
| Intermediate The intermediate values are  | 2, 4, |
| judgment used when compromise is needed   | 6, 8  |

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Other measures of consistency have been defined.

For example, (Mustajoki and Hämäläinen, 2000)

give a Consistency Measure (CM) of between 0 to 1 using the Multi Attribute Value Theory inherent in the Web-HIPRE software. A CM of

0.2 is considered acceptable.

CM

Consistency Measure is calculated using,

rij r(i,j) £ n( n

§w1 ¶

"w2 · Obtained from a decision matrix,

©п,

§ a11 a12 a1n ¶

"a21 a22 a2 n · · "@ a31 a32 a3n ⋅

The consistency of the decision matrix is calcu-

# 1) i j (1 r(i, j ))(1 r(i, j ))

lated as follows:

Multiply matrix  ${\bf A}$  by the weight vector  ${\bf w}$  to give vector, B

(6)

a11w1 a12w2 a1nwn a21w1 a22w2 a 2 n wn h2 bn

a31w a32w a3nwn Divide each element of vector, B with the corresponding element in the weight vector w to give a new vector

hmax is the average of the elements of vector  $\mathbf{c}$ :

Consistency Index is then calculated using.

1

n

where n is order of the decision matrix and hmax is obtained from equation (3) above.

Using equation (4), Consistency Ratio is calculated as,

3

where RI is the random index and its value is obtained from Table 2 below.

Table 2. Random index table. 4

7

8

6

A total of six pipeline experts participated in the expert judgment study on risk assessment of the pipelines. The affiliations of the experts are in the following organisations: Shell International, Chevron Exploration, BJ Services, Nigeria Petroleum Development Company, Nigeria National Petroleum Company, and SBM Offshore. Attributes of the pipelines and an historical failure records sheet containing defining characteristics of the pipelines were made available to the experts

with a questionnaire.

# 3.2 Construction of hierarchy

A hierarchy tree of the three pipelines is con-

structed using Web-HIPRE software, version 1.22. The tree (Figure 1) contains information on the

goal (failure of pipeline), criteria (failure factors) and sub-criteria (sub division of failure factors). The decision alternatives are the three pipelines under consideration.

# Results of pairwise comparison 3.3.1 Individual expert comparison Individual expert opinion on the pairwise comparison of factors responsible for pipeline failures are separately collected using a questionnaire that was made available to each expert. The outcome of the comparison is the pairwise matrix for the failure likelihood of the pipelines, based on the judgment of each expert. As expected, the outcome varied from one expert to another, since a consensus vote does not apply in this case.

# 3.3.2 Group judgment

The individual expert comparison is combined

group wise using the geometric mean method (GMM), (Aczel and Saaty 1983). In the geometric ment a(i, j), and r(i, j ) is the inverse of r (i, j ). CM gives an indication of the size of the extended region formed by the set of local preferences, when

wiarij wjforalli, j $\{1, z, n\}$ .

- (1) CASE STUDY
  - 3.1 Background information
    The AHP methodology of Risk Management has been illustrated by a case study of oil and gas pipelines in Nigeria. A summary of the character-istics of the pipelines is given in Table 3 below. The
- goal of the research is to conduct a risk assessment given pipelines using the AHP methodology.

  This is achieved by determining the relative con-(2) of

tribution of different failure factors to the overall pipeline failure. The failure factors indentified for this study are: corrosion, external interference, structural defects, operational error and others. We

arrived at these factors based on literature review, the historical record of failures from company (3) database, and feedback from company experts.

Table 3. Summary of the attributes of pipelines. Pipeline

Attribute EL ΔR ΑZ Primary service Gas Crude oil Crude oil Year of commission 1989 1996 2002 (5) Type of coating Concrete Polykene Polykene Length 340 km 18 km 4 km Diameter 24p 4p бр Design pressure 100 bar 207 bar 207 bar 26.8nC Operating temperature 33.4nC 33.4nC Material Carbon Carbon Carbon steel steel steel 9 Climate Tropical Tropical Tropical Age of coating 25 yrs 25 yrs 21 yrs 600MCFd 1380bbls 1080bbls

(4)

mean method, the group judgment for the pairwise comparison is obtained by taking the geometric mean of the individual judgments. GMM is particularly suitable for aggregating group preference

especially where conflicting responses could arise.
For n parties, the geometric mean of judgments
from entries for the matrices of pairwise comparison is calculated as:

Where:

G aijs : The group judgment for criterion i with crite-

ioo j of issue s.

aijks : Judgment of individual k (k  $\,$  1,  $\,$  z,  $\,$  N) for

criterion i with criterion j of issue s.

Os: Ordening of all criteria of issue s.

The result of the pairwise comparison for the

group is shown in Table 4 below.

Figure 2. Distribution of factors responsible for pipeline failures. The figure shows external interference as

the leading cause of pipeline failure followed by corrosion, with relative likelihood of failure of 0.607 and 0.214  $\,$ respectively.

Figure 3. Factors responsible for failures of EL, AB and

AZ pipelines. The figure shows EL as the most vulnerable among the three pipelines. The most pronounced failure factor for each pipeline is also shown. For example, for EL pipeline it can be seen that external corrosion is the next most significant failure factor after external interference. While for AZ pipeline it is internal corrosion.

Figure 1. Hierarchy tree for EL, AB and AZ pipeline.

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Table 4. Pairwise ranking of failure criteria and likelihood of failure of EL, AB and AZ pipelines.

|                       |            |                                       |                | Pipeline       |                         |                         |
|-----------------------|------------|---------------------------------------|----------------|----------------|-------------------------|-------------------------|
| Factors               | Likelihood | Sub-Factors                           | Likelihood     | EL             | AB                      | AZ                      |
| External interference | 0.607      | Sabotage<br>Mechanical damage         | 0.525<br>0.081 | 0.271<br>0.051 | 0.179<br>0.019          | 0.076<br>0.011          |
| Corrosion             | 0.214      | External corrosion Internal corrosion | 0.153<br>0.061 | 0.093<br>0.009 | 0.019<br>0.041<br>0.021 | 0.011<br>0.018<br>0.031 |
| Structural defects    | 0.066      | Construction defect Materials defects | 0.045<br>0.021 | 0.023<br>0.006 | 0.021<br>0.014<br>0.007 | 0.009                   |
| Operational error     | 0.069      | Equipment failure<br>Human error      | 0.050<br>0.019 | 0.009<br>0.003 | 0.007<br>0.018<br>0.007 | 0.024<br>0.009          |
| Others                | 0.044      | numan error                           | 0.044          | 0.023          | 0.011                   | 0.010                   |

### 3.4 Sensitivity analysis

The graphs below (Figures 4-8) show the sensitivity of each of the failure factors to the likelihood of failure of the pipelines. In the sensitivity analysis, the influence of changes on the overall model is investigated. The final priorities of the likelihood of failures of the pipelines depend greatly on the weights attached to the failure criteria. Similarly, the likelihood of failure of each pipeline is influenced by the weights attributed to each failure criterion. Hence, some changes in the relative weights of

the failure criteria could lead to significant changes

in the final ranking. Sensitivity analysis therefore gives good information on the robustness of the model

The likelihood of failure due to external interference is increased by 20% to see how this affects the ranking of failures of EL, AB and AZ pipelines. This change results in about 3% increase and 10% decrease in the weights of EL and AZ pipeline respectively. AB pipeline has an increase of 2% in weight. The result is displayed in Figure 4. Similarly in Figure 5, a 70% decrease in the weight of operational errors leads to about 3% increase in the likelihood of failure of EL pipeline and a 5% decrease in the weight of AZ pipeline, with about 1% decrease in the weight of AZ pipeline, with about 1% decrease in the weight of AB pipeline. In addition, the weight of corrosion and structural defect is further increased by 50% and 60% respectively, and the weight of minor failures (others) is decreased by 75% to capture the sensitivity. The outcomes are represented in Figures 6 to 8 below.

# 4 RISK MANAGEMENT OF PIPELINES

4.1 Inspection and maintenance strategy
Part of the risk management strategies is to formulate an appropriate inspection and maintenance
strategy for the three pipelines. Table 5 gives some
possible strategy (ies) for each failure factor.

Figure 4. Sensitivity of pipeline failure to external

interference when the likelihood of failure due to external interference is increased by 20%, from 0.61 to 0.73.

Figure 5. Sensitivity of pipeline failure to operational error when the weight of operational error is decreased by 70%.

Figure 6. Sensitivity of pipeline failure for a 50% increase in the likelihood of failure due to corrosion.

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also be explained by the poor coating condition of the pipeline. The result presented in Figure 9 shows EL pipeline as the most vulnerable pipeline among the three pipelines. To reduce the likelihood to external interference more patrolling is suggested, while efficient pipe coating is recommended in order to reduce external corrosion.

The study reveals that AB pipeline is more liable to "external interference" than AZ pipeline, but not as liable as EL pipeline. Also, on "internal corrosion", AB seems to be more liable than EL pipeline, but better than AZ pipeline. On "Materials

defect", the three pipelines generally have the same level of failure expectation. The similarity on the expected failure due to materials defect is expected because the three pipelines are all made of the same material, carbon steel. For AB pipeline, an intelligent pigging survey (IPS) is recommended to reduce its high likelihood to internal corrosion, and regular patrolling is also recommended to reduce its likelihood to external interference.

AZ pipeline has the highest likelihood of "internal corrosion", "equipment failure" and "human error". The investigation from the pipeline operator confirmed that the pipeline has suffered previously from internal corrosion and human failure. It is however interesting to note that if all the failure factors are considered, the likelihood of failure of pipeline AZ is much better than that of EL and AB pipe-

Figure 7. Sensitivity of pipeline failure due to structural

defect when the weight is increased by 60%.

Figure 8. Sensitivity of pipeline failure for a 75% decrease in the weight of failure for other minor failures.

Maintenance strategy for nineline failures.

| Table 3. Maintenance sci | racegy for pipeline railures:                   |
|--------------------------|---|
| Sub-Factors              | Maintenance strategy                            |
| Sabotage                 | Patrolling                                      |
| Mechanical damage        | Pipeline Marking/Improved<br>Right of Way (ROW) |
| External corrosion       | Pipe coating                                    |
| Internal corrosion       | Intelligent pigging survey                      |
| Construction defect      | Reconstruction/ Replacement                     |

Equipment failure Replacement of faulty eauipments Human error Operator training

Materials defects

EL pipeline is undoubtedly the most vulnerable among the 3 pipelines, having the highest likelihood of failure. The expected vulnerability of EL pipeline to external interference and external corrosion is much higher than expected for AB and AZ pipelines. EL pipeline is located in the Niger-Delta region of Nigeria, with a high likelihood of third party interference and sabotage due to the restive nature of the region. The high tendency to external corrosion could

lines. Therefore, AZ pipeline can be considered the least vulnerable among the three pipelines, as represented in Figure 9 and Table 4. This is due partially to the least likelihood of AZ pipeline to external interference, which has very high consequences. To reduce its operational error, immediate replacement of faulty equipments and retraining of operators is recommended. Intelligent pigging survey is also rec-

ommended to mitigate internal corrosion.

#### 4.2 Expected failure cost

For the three pipelines, the severity of failure was

estimated from historical failure costs available

from database of the pipeline company. In addition,

Figure 9. Ranking of pipelines according to likelihood of failure. Likelihood: EL 0.488, AB 0.317, and AZ 0.196.

Table 6. Inspection and maintenance strategy for failure factors.

Replacement of pipelines

|   |                     | EL pipeline        |                                      | AB pipeline        |                                      | AZ pipeline       |                                      |
|---|---------------------|--------------------|--------------------------------------|--------------------|--------------------------------------|-------------------|--------------------------------------|
|   | Sub-Factors         | Likeli-<br>hood    | Severity<br>of failure<br>('\$000 m) | Likeli-<br>hood    | Severity<br>of failure<br>('\$000 m) | Likeli-<br>hood   | Severity<br>of failure<br>('\$000 m) |
| External interference                             | Sabotage            | 0.271              | 2,200                                | 0.179              | 800                                  | 0.076             | 1,000                                |
|   | Mechanical damage   | 0.051              | 1,000                                | 0.019              | 400                                  | 0.011             | 500                                  |
| Corrosion   | External corrosion  | 0.093              | 300                                  | 0.041              | 120                                  | 0.018             | 120                                  |
|   | Internal corrosion  | 0.009              | 200                                  | 0.021              | 80                                   | 0.031             | 100                                  |
| Structural defects                                | Construction defect | 0.023              | 80                                   | 0.014              | 30                                   | 0.009             | 35                                   |
|   | Materials defects   | 0.006              | 20                                   | 0.007              | 10                                   | 0.008             | 15                                   |
| Operational error                                 | Equipment failure   | 0.009              | 800                                  | 0.018              | 400                                  | 0.024             | 400                                  |
|   | Human error         | 0.003              | 400                                  | 0.007              | 200                                  | 0.009             | 200                                  |
| Others  |                     | 0.023              | 100                                  | 0.011              | 55                                   | 0.010             | 55                                   |
| Likelihood of no failure<br>Expected failure cost |                     | 0.512<br>\$689,560 | 0                                    | 0.683<br>\$167,095 | 0                                    | 0.805<br>\$99,145 | 0                                    |

pipeline experts that participated in the AHP were asked to utilize their previous experience to esti-

asked to utilize their previous experience to esti-mate the severity of failure based on the unique characteristics of each pipeline. In Table 6, the likelihood of failure obtained from the AHP result in Table 4 is combined with the severity of failure to calculate the expected fail-ure cost for each pipeline.

It can be concluded from the results that the expected failure cost of EL pipeline is much higher than for AB and AZ pipeline. Moreover, AB pipeline has a higher likelihood of failure as compared to AZ pipeline. The expected failure cost calculation further indicates that allocating equal maintenance resources to the three pipelines will be a wrong and ineffective maintenance strategy. Therefore, in the allocation of maintenance resources, EL pipeline; with the highest expected failure cost should receive more attention than the other two pipelines. In addition, AB pipeline will require more maintenance resources than AZ pipeline.

# CONCLUSIONS

A decision based model has been presented for risk management of oil and gas pipelines. The model uses available data and structured expert judgment to predict the probability of failure and severity of failure of oil and gas pipelines. The work has made a unique contribution to the application of Analytic hierarchy process in prioritizing oil and gas pipelines for maintenance. The geometric mean method is applied to arrive at a group consensus by combining individual responses of experts on pipeline failures. The software, Web-HIPRE used was found suitable to model the case study, and to express the sensitivity of the failure factors.

Company (NNPC) and National Petroleum Development Company (NPDC) for their generous supply of data used in this study. All the experts that participated in this research are also

The case study of petroleum pipelines in Nigeria revealed some interesting conclusions, which shows that location plays a significant role in pipeline integrity. Similar works (Dey et al. 2004 & Al-Khalill et al. 2005) have concluded that corrosion is the most significant failure criterion of petroleum pipelines in India and Saudi Arabia. However, for the Nigerian case study, external interference is found to be the most important failure criterion, representing 60% of the entire failure criteria. The high likelihood of failure by external interference obtained is due to the influence of sabotage acts on the petroleum pipelines. Therefore, increasing security around the pipelines would help to improve their reliability.

Concentrating on most relevant failure factors is cost efficient as it helps the concentration of maintenance resources on most relevant failure factors. The management will also find this approach to be beneficial in formulating an inspection and maintenance policy for the company's assets. For the pipe-lines, the outcome of the decision analysis could also prove useful in formulating individual and societal risk acceptance criteria (Vrijling et al. 2004).

The participation of experts with working knowledge of the pipelines reduces the subjective nature of the AHP method, although subjectivity has not been totally eliminated. In future work, a structured expert calibration technique will be applied to further reduce subjectivity. Also, the accuracy of the severity of failure estimated could be further improved with more data from the pipeline operator.

# ACKNOWLEDGMENT

The authors would like to acknowledge the management of the Nigerian National Petroleum

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appreciated for their useful contributions.

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