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Monte Carlo Simulation – A Key for a Feasible Gas Pipeline Design

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ABSTRACT

Gas pipeline projects are capital intensive and are exposed to many risks related to uncertainties of their main components such as capital investment (material and services) – Capex, operation and maintenance costs – Opex, construction and assembly – C&A schedule, C&A Costs and others. Such items need to be properly addressed to mitigate project risk otherwise they may impact negatively the project sustainability normally measured by the project net present value – NPV.

The availability of the compression system, if not properly addressed, may expose a gas pipeline project to undesirable risks. This paper will present a case study demonstrating how useful is Monte Carlo Simulation in association with Thermo-hydraulic simulation and economic evaluation in identifying and quantifying risks and in helping to define the optimum level of availability for the gas pipeline compression system. The installation of standby compressor station units helps achieving the necessary availability level to face contractual obligations related to transmission capacity.

Technical and economical evaluation are of fundamental importance to support the decision-making process in the design phase of a pipeline project. Monte Carlo Simulation is also used in the economical evaluation to provide accurate and reliable results.

The aforementioned approach impacts project positively while supporting transportation rate design and also defining pipeline capacity that Transporter will negotiate with the Local Distribution Companies (LDC's) on a firm contractual basis.

This paper presents a case study that uses all the above-mentioned technology.

INTRODUCTION

Credit for inventing the Monte Carlo method often goes to Stanislaw Ulam, a Polish born mathematician who worked for John von Neumann on the United States' Manhattan Project during World War II. The Monte Carlo method, as it is understood today, encompasses any technique of statistical sampling employed to approximate solutions to quantitative problems. <http://www.riskglossary.com/link/monte_carlo_method.htm> Accessed in: May 28, 2008.

According to Evans and Olson (1998) *Simulation* is the process of building a mathematical or logical model of a system or a decision problem, and experimenting with the model to obtain insight into the system's behavior or to assist in solving the decision problem. The authors define *Monte Carlo simulation*, basically, as a sampling experiment whose purpose is to estimate the distribution of an outcome variable that depends on several probabilistic input variables. Monte Carlo simulation is often used to evaluate the expected impact of policy changes and risk involved in decision making. Risk is often defined as the probability of occurrence of an undesirable outcome.

As a reference for applying Monte Carlo simulation in compressor station project selection Santos (2003) has evaluated the impact of Capex, Opex, and Construction and Assembly schedule on the economic sustainability of a project while comparing two different alternatives for implementing compressor stations in Petrobras gas pipeline network as described below:

(a) Compressor station as a Transporter asset: in this alternative Capex, Opex are Transporter responsibility. Transporter will keep the ownership of the compressor station asset.

(b) Compression service contract: in this alternative Capex and Opex are the responsibilities of a Service Provider Company that will be responsible for the installation, operation and maintenance of the compressor station and will be the owner of the asset. Transporter will pay for the compression service under a contractual relationship.

Monte Carlo simulation was of fundamental importance in supporting Petrobras final decision on contracting compression service in 2002 from a third party company instead of holding the ownership of the stations and being responsible for operation and maintenance thereof. The selected alternative was more economic and less risky. Since 2002 more than 18 compressor stations have been installed under compression service contracts.

The case study presented in this paper uses Monte Carlo simulation to help defining the optimum availability level for a gas pipeline project and also the project risk related to some important input variables (e.g. Capex, Opex and C&A Schedule).

METHODOLOGY

The methodology adopted for this case study considers the following steps:

1. A pipeline design from point A to point B for different diameters (four alternatives):
   - Thermo-hydraulic simulations;
   - Compressor stations quantity definitions based on predefined compressor ratio;
   - Compressor units selection based on overall thermodynamic efficiency and market availability;
2. Selection of the best pipeline alternative by comparing risk-free transportation rate (J-curves) with nominal pipeline capacities;
3. Availability study for the pipeline compression system using Monte Carlo simulation and different levels of compressor units redundancy for the pipeline compressor stations;
4. Rate design for the best alternative from item 2 incorporating risk analysis:
   - Availability study with Monte Carlo simulation;
   - Independent variables (e.g. Capex, Opex and C&A Schedule) with statistical distribution;
5. Feasibility study
6. Project's final decision.

THERMOHYDRAULIC SIMULATION

Three configurations for unavailable compressor units were simulated as explained below:

1. Failure of one compressor unit at one station
2. Failure of two compressor units at one station
3. Failure of one compressor unit at one station and failure of another one at a contiguous station (upstream or downstream)

Simulation Results Analysis

Compressor stations were modeled with two compressor units operating in parallel arrangement with standard flow of around 529.5 MMCFD each.

Unavailability of one compressor unit at one compressor station causes the remaining unit to shut down or stay in idle speed because one single unit does not have power enough to sustain the operation. As an example, the unavailability of station #2 causes pipeline capacity to drop to 915.7 that is 72.9% higher than one compressor unit design capacity of 529.5 MMCFD. Same situation happens with the unavailability of 2 (1+1) compressor units at contiguous stations. As an example, the unavailability of stations #2 and 3 causes pipeline capacity to drop to 792.8 MMCFD that is 49.7% higher than one compressor unit design capacity of 529.5 MMCFD.

Five different compressor station alternatives have been evaluated:

(a) Without stand-by compressor units;
(b) With 2 stand-by units (1 at station #3 and #6)
(c) With 3 stand-by units (1 at #2, #4 and #6)
(d) With 4 stand-by units (1 at # 1, #3, #5 and #7)
(e) With 7 stand-by units (1 at #1 to #7).

Thermohydraulic simulations capacity results due to unavailability of compressor units are summarized on Tables 3, 4, 5, 6 and 7.

MONTE CARLO SIMULATION

Monte Carlo simulation is based on a spreadsheet model where the uncertainties variables are modeled according to their statistical distribution and random number generation. While running the model all the uncertain (independent) variables will change randomically and in most of the cases independently as would happen in real life. When we have correlated variables, they are modeled accordingly. The software @Risk 4.5 with Microsoft Excel was used to run this case study models.

- Availability Study

In the availability study all gas pipeline compressor stations are modeled with their two compressor units in parallel arrangement and an availability value and statistical distribution is addressed to each compressor units. The model run more than 5000 iterations and then we evaluate the frequency of compressor units' failures that will be simulated Thermo-hydraulically to support the availability level evaluation and consequently the decision making on standby units to be installed.

- Economic Study

In the economic study all uncertain independent variables (e.g. Capex, Opex, pipeline capacity, C&A schedule) are addressed a statistical distribution with their expected values (e.g. in the case of triangle distribution: minimum, best guess and maximum values) as part of a spreadsheet used to evaluate the impact of those independant variables on the dependant variables such as NPV or IRR. Statistical distributions are then generated for the dependant variables that will support risk quantification and mitigation.

CASE STUDY

This case study is based on a pipeline project that goes from a gas supply receipt point to targeted market 1,000 miles distant delivering 1,059.4 MMSCFD (30 MMm3/d) of natural gas on firm contractual basis. Four pipeline alternatives have been considered as shown in Figure 1 and as described below:

Alternative I:

Pipeline diameter:	30”
Compressor stations quantity:	19

Alternative II:

Pipeline diameter:	32”
Compressor stations quantity:	13

Alternative III:

Pipeline diameter:	34”
Compressor stations quantity:	9

Alternative IV:

Pipeline diameter:	36”
Compressor stations quantity:	7

Technical Assumptions

Pipeline	
Diameter:	(alt. I, II, III, IV)
Length:	1000 miles
Design code:	ANSI B31.8
Max. Allowed Working Pres. – MAOP:	1440 PSIG
Pipe material:	API 5L X80
Pipe internal roughness (epoxy painted):	350 minches
Pipeline Inlet Pressure:	1420 psig
Minimum Pipeline Delivery Pressure:	498 psig
Pipeline overall heat transfer:	0.39 Btu/h.ft^2.F
Soil temperature:	61 to 86 F
Depth of cover:	3 feet
Compressor Station	
Maximum Compression ratio:	1.4
Suction and Discharge Header pressure drop:	7 psi
After cooler pressure drop:	14 psi
After cooler outside temperature:	122 F
Site elevation	0 feet
Site Temperature	82.4 F
Flow Equation:	Colebrook

ECONOMIC EVALUATION

To support the economic evaluation the following assumptions were considered:

Technical Assumptions

- Three sizes of compressor sets selected according to the power requirement of each gas pipeline alternative:
  - 15000 ISO hp
  - 10300 ISO hp
  - 7800 ISO hp
- Fuel consumption for all four alternatives based on 80% efficiency on the compressor side and 32% on turbine side.
- Without standby compressor unit at the compressor stations.
- J-curves developed based on the selection of the best available compressor set for each pipeline diameter versus compressor station quantity and at the maximum (nominal) capacity, as shown on Table 1.

Economic Assumptions

• Construction schedule:	2 years
• Pipeline material cost:	2000 US$/ton
• Pipeline C&A cost:	
– 30”:	25,100 US$/mile-inch
– 32”:	24,473
– 34”:	23,652
– 36”:	22,864
• Compressor Station Capex	
– (2) x 15000 ISO hp:	41.65 MMUS$
– (3) x 15000 ISO hp :	55.62
– (1) x 10300 ISO hp:	19.43
– (2) x 10300 ISO hp:	31.85
– (3) x 10300 ISO hp :	42.54
– (1) x 7800 ISO hp:	15.93
– (2) x 7800 ISO hp:	26.12
– (3) x 7800 ISO hp :	34.88
• O&M C. Sta. (without Fuel):	5% of C.Sta. Capex
• O&M Pipeline:	0.8% of Ppl. Capex
• Depreciation:	20 years
• Taxes:	40%
• Fuel price:	1.5 US$/MMBTU
• Discount rate:	12% a year
• Economic life:	20 years

First Economic Analysis

This first economic analysis for each pipeline alternative – without standby compressor units – and their respective capacity build up, as Table 1 and J-curves show in Figure 2 has the objective to help selecting the alternative that presents the lowest transportation rate. By adopting this criterion, Alternative III is the best. Considering that Alternative IV is the second-best and very close to Alternative III and having the advantage of future expansion capability it was selected as the best one and it is evaluated in more detail with regard to firm capacity, reliability level and risk exposure.

The alternatives' transportation rates are as follow:

1 - Alternative I, ND 30" : 1.5105 US$/MMBTU
2 - Alternative II, ND 32" : 1.4190
3 - Alternative III, ND 34" : 1.3857
4 - Alternative IV, ND 36" : 1.3887

The alternative IV allows future capacity expansion at lower Capex and Opex by increasing compressor ratio (from 1.3389 up to 1.40) increasing capacity from 1059 to 1112 MMSCFD. Also allows pipeline capacity expansion from 1059 to 1497 MMSCFD by doubling the compressor station quantity (from 7 to 14).

AVAILABILITY ANALYSIS

The purpose of the availability analysis is to define the level of redundancy to be adopted for the gas pipeline compression system. It takes into account the following information:

- Compressor unit availability (as shown on Table 2);
- Capex required for standby compressor units;
- Revenues from incremental pipeline firm capacity as a result of enhancing the overall compressor system availability.

Santos (2006) has presented the methodology adopted for the Bolivia-Brazil gas pipeline to define the availability level to be adopted for that pipeline compression system and Monte Carlo simulation proved to be of fundamental importance to achieve the goals. Santos (2008) also presents the impact of compression system availability level and risk effects on gas pipeline transportation rate (tariff).

A comprehensive and accurate survey on compressor station reliability and availability was carried out by EPRI (1998) and their findings, as presented on Table 2, provide input for the evaluation of this case study that uses gas turbine drivers and centrifugal compressors.

The availability value of 97.1% or 0.971 is taken into the Monte Carlo simulation model used for the gas pipeline alternative IV with 7 compressor stations with two running compressor units per station without standby compressor units. Four different compressor station configurations are evaluated as defined in the Thermohydraulic Simulation paragraph.

Monte Carlo and Thermo-hydraulic simulations for configurations (a), (b), (c), (d) and (e) were performed and the frequency of unavailable compressor units was quantified as well as pipeline capacity as shown on Tables 3, 4, 5, 6 and 7 and in Figure 3.

The table first column shows the unavailability configurations of 1 and 2 units per station and also 2 (1+1) units unavailable in contiguous stations. Second column shows the total frequency of occurrence of such unavailability measured in days per operating year. Third column shows resulting pipeline capacity at downstream end of the pipeline that can be maintained under the defined unavailability of compressor units. The wider fourth column shows the unavailability frequency of compressor units (1, 2 or (1+1)) at each compressor station as identified on the header (#1 to #7).

Gas pipeline overall availability is evaluated by dividing the average capacity by the nominal (firm contractual) capacity and then we get the following results for each alternative of standby compressor units installation.

(a) Without stand-by compressor units: 0.9456
(b) With 2 stand-by units (first 5 stations): 0.9594
(c) With 3 stand-by units (all the stations): 0.9661
(d) With 4 stand-by units (all the stations): 0.9764
(e) With 7 stand-by units (all the stations): 0.9994

ECONOMIC EVALUATION

Second Economic Analysis

The purpose of this second economic analysis is to quantify the benefit of increasing the availability level of the compression system by installing standby units at the compressor stations. This evaluation takes into account the firm contractual pipeline capacity that can be committed and potential losses of revenue and penalties from non-delivered firm contractual capacity.

Two distinct situations may happen that requires economic analysis to define the availability level to be adopted:

- **New gas pipeline project**: transportation rate of each configuration incorporates all Capex and Opex associated with the pipeline and standby compressor units and represents gas pipeline total cost of the transportation service on energy basis. Transportation rates are calculated for average capacities;
- **Existing gas pipeline**: transportation rate does not incorporate Capex and Opex associated with standby units. The approach is to invest in standby compressor units to

mitigate risk exposure to losses of revenue and contractual penalties as reflected by the NPV of each alternative. Transportation rate is constant and calculated for nominal (maximum) capacity.

New Gas Pipeline Projects

Configuration (a) - Without Standby Units

- System availability : 0.9456
- Nominal capacity : 1059 MMCFD
- Average potential capacity shortfall : 57.7 MMSCFD
- Average capacity : 1001.8 MMCFD
- Transportation rate : 1.4668
- Average PV of Potential losses : (411.6) MMUS$

Configuration (b) – With 2 Stand by Units

- System availability : 0.9594
- Nominal capacity : 1059 MMCFD
- Average potential capacity shortfall : 43.4 MMSCFD
- Average capacity : 1015.6 MMCFD
- Transportation rate : 1.4614
- Average PV of Potential losses : (309.1) MMUS$

Configuration (c) – With 3 Stand by Units

- System availability : 0.9661
- Nominal capacity : 1059 MMCFD
- Average potential capacity shortfall : 36.4 MMSCFD
- Average capacity : 1022.7 MMCFD
- Transportation rate : 1.4587
- Average PV of Potential losses : (258.5) MMUS$

Configuration (d) – With 4 Stand by Units

- System availability : 0.9764
- Nominal capacity : 1059 MMCFD
- Average potential capacity shortfall : 25.4 MMSCFD
- Average capacity : 1034.1 MMCFD
- Transportation rate : 1.4508
- Average PV of Potential losses : (179.3) MMUS$

Configuration (e) – With 7 Stand by Units

- System availability : 0.9994
- Nominal capacity : 1059 MMCFD
- Average potential capacity shortfall : 1.0 MMSCFD
- Average capacity : 1058 MMCFD
- Transportation rate : 1.4391
- Average PV of Potential losses : (7.4) MMUS$

The economic results above allow us to come to the following conclusions:

- Configuration (e) is the best one;
- Presents the lowest risk related to potential losses;
- Presents the lowest transportation rate;
- Is the most competitive alternative configuration.

Existing Gas Pipeline

For an existing pipeline and assuming the nominal pipeline capacity has been contracted as firm capacity without standby compressor units all the associated costs (Capex and Opex) for the installation of standby compressor units are considered as new investments that are not included in the transportation rate.

Configuration (a) - Without Standby Units

- System availability : 0.9456
- Nominal capacity : 1059 MMCFD
- Average capacity : 1001.8 MMCFD
- Transportation rate at nominal capacity : 1.3888 US$/MMBTU
- Average PV of Potential losses : (389.7) MMUS$

Configuration (b) – With 2 Stand by Units

- System availability : 0.9594
- Nominal capacity : 1059 MMCFD
- Potential capacity shortfall : 43.4 MMSCFD
- Average capacity : 1015.6 MMCFD
- Transportation rate at nominal capacity : 1.3888 US$/MMBTU
- Average PV of Potential losses : (293.7) MMUS$
- Average PV of avoided losses : 96.0 MMUS$
- Capex PV for stand by units : 20.2 MMUS$
- NPV : 75.8 MMUS$

Configuration (c) – With 3 Stand by Units

- System availability : 0.9661
- Nominal capacity : 1059 MMCFD
- Potential capacity shortfall : 36.4 MMSCFD
- Average capacity : 1022.7 MMCFD
- Transportation rate at nominal capacity : 1.3888 US$/MMBTU
- Average PV of Potential losses : (246.1) MMUS$
- Average PV of avoided losses : 143.6 MMUS$
- Capex PV for stand by units : 30.3 MMUS$
- NPV : 113.3 MMUS$

Configuration (d) – With 4 Stand by Units

- System availability : 0.9764
- Nominal capacity : 1059 MMCFD
- Potential capacity shortfall : 25.4 MMSCFD
- Average capacity : 1034.1 MMCFD
- Transportation rate at nominal capacity : 1.3888 US$/MMBTU
- Average PV of Potential losses : (171.6) MMUS$
- Average PV of avoided losses : 218.1 MMUS$
- Capex PV for stand by units : 40.5 MMUS$
- NPV : 177.6 MMUS$

Configuration (e) – With 7 Stand by Units

- System availability : 0.9994
- Nominal capacity : 1059 MMCFD
- Potential capacity shortfall : 1.0 MMSCFD
- Average capacity : 1058 MMCFD
- Transportation rate at nominal capacity : 1.3888 US$/MMBTU
- Average PV of Potential losses : (7.1) MMUS$
- Average PV of avoided losses : 382.6 MMUS$
- Capex PV for stand by units : 70.8 MMUS$
- NPV : 311.8 MMUS$

The economic results above allow us to come to the following conclusions:

- Configuration (e) is the best one;
- Mitigates risk related to potential losses;
- Presents the highest NPV.

Conclusions from Second Economic Analysis

Installation of standby units for existing or new pipeline projects presents significant economic benefits to Transporter.

The Tables 8 and 9 show Monte Carlo simulation results for new and existing pipeline projects with 90% confidence interval for the variables.

Monte Carlo simulation – in association with thermohydraulic simulation and economic analysis – is very powerful in providing information to support the decision making process.

Risk Evaluation

For a new gas pipeline project and once selected the best gas pipeline alternative and also defined the compression system availability level, as previously described in this paper, the next step is to perform the risk evaluation.

The risk evaluation is performed by using a spreadsheet model and a risk simulator. For this case study it was used *Microsoft Excel* and *@Risk 4.5*.

The economic model follows the traditional approach and the assumptions as defined previously in this paper. The only additional thing is to define the statistical distribution to be adopted for the selected independent variables (Pipeline capacity, Capex, Opex and C&A Schedule) and their volatility (variance, standard deviation or even minimum, maximum and best guess values over the average).

The independent uncertainty variables and their statistical distributions for the purpose of this paper (see Figures 4, 5, 6 and 7) were assumed as follows.

- Pipeline Capacity: [from MC availability study]
- Capex: [Lognormal (95%, 100%, 120%)]
- Opex: [Lognormal (95%, 100%, 120%)]
- C&A Schedule: [Triangle (90%, 100%, 125%)]

Risk Evaluation Results

The simulation result shows the NPV – the dependant variable – behavior as shown in Figure 8. As seen from Figure 8 the NPV distribution has a probability of 0.8328 of being between 0 and a negative value of 328.72 MMUS$.

An easy approach to protect against this risk would be to increase the transportation rate from 1.4391 to 1.6518 that gives a positive NPV of 328.72 MMUS$ without incorporating the independent variables uncertainties as previously described but the drawback of doing this is that it turns the project less competitive. A better approach comes from the NPV tornado diagram analysis.

Figure 9 presents a Tornado Diagram that comes from the risk evaluation simulation. It presents a sensitive regression that shows the independent variables that are most responsible for the NPV volatility. This diagram shows how a change of one standard deviation of one independent variable affects the project dependant variable (NPV) under analysis. This helps to identify which independent variable (or variables) will be subject to special care to narrow down its (or their) volatility and therefore allowing risk mitigation.

Conclusions

By applying the methodology presented in this paper and getting at the stage of quantifying project risk as measured by the dependant variable as consequence of the volatility of the selected independent variables we can then have a more accurate view of the project sustainability and take actions to mitigate then.

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TABLES

Table 1 – Pipeline Alternatives I, II, III and IV – Thermohydraulic Results

Pipeline Alternative	Nominal Diameter ND	Capacity PPL End Point MMCFD	Pipeline Length	Discharge Pressure (At Comp. Flange)	Compression Ratio (Pd/Ps)	Station Quantity	Total Required Power	Mean Required Power per Station	Fuel required	Comp. Unit size
	inches	(MMCMD)	miles	psig	-	Qty.	hp	hp	MMCFD	HP ISO
I	30	503 (14.26)	1000	1420	1.4000	3	24,563	8,188	5.0996	1 x 10300
		611 (17.30)			1.4000	5	49,935	9,987	10.3673	2 x 7800
		811 (22.97)			1.4000	10	137,246	13,725	28.4943	2 x 7800
		1059 (30.00)			1.3859	19	345,971	18,209	71.8288	3 x 7800
II	32	424 (12.02)	1000	1420	1.4000	1	6,915	6,915	1.5081	1 x 7800
		594 (16.83)			1.4000	3	28,994	9,665	6.3231	2 x 7800
		775 (21.93)			1.4000	6	76,647	12,774	16.7154	2 x 7800
		1059 (30.00)			1.3836	13	229,400	17,646	47.6265	3 x 7800
III	34	355 (10.04)	1000	1420	-	0	-	-	-	-
		605 (17.12)			1.4000	2	19,664	9,832	4.2883	2 x 7800
		772 (21.87)			1.4000	4	50,393	12,598	10.9899	2 x 7800
		1059 (30.00)			1.3854	9	155,752	17,306	32.3362	3 x 7800
IV	36	411 (11.65)	1000	1420	-	0	-	-	-	-
		576 (16.30)			1.4000	1	9,370	9,370	2.0435	2 x 7800
		805 (22.78)			1.4000	3	39,243	13,081	8.5582	2 x 7800
		1059 (30.00)			1.3389	7	106,289	15,184	22.0670	2 x 10300

Table 2 – Compressor Station Units Reliability and Availability

Compressor Station Unit	Reliability	Availability
Electric motor + Centrifugal compressor	99.4	98.9
Gas turbine + Centrifugal compressor	98.2	97.1
Gas motor + Reciprocating compressor	97.1	94.3

Table 3 – Failure Analysis Capacity Results and Unavailability Frequency of Compressor Units – Without Standby Units

Unavailable Compressor Units per Station	Frequency (days/year)	Capacity, MMCFD	Compressor Station No. # / Unavailability Frequency (days/year)						
			#1	#2	#3	#4	#5	#6	#7
0	241.57	1059							
1	114.86	909	19.36						
		916		18.57					
		915			17.14				
		912				15.21			
		903					15.79		
		882						14.29	
		819							14.50
2	2.29	909	0.29						
		916		0.36					
		915			0.29				
		912				0.36			
		903					0.29		
		882						0.36	
		819							0.36
			1&2	#2&3	#3&4	#4&5	#5&6	#6&7	
1 + 1 (At 2 contiguous Stations)	6.29	786	0.79						
		793		0.79					
		788			1.71				
		776				1.14			
		748					0.86		
		670						1.00	
Total days	365.00								
Average Capacity		1002							
Nominal Capacity		1059							
Availability		0.9456							

Table 4 - Failure Analysis Capacity Results and Unavailability Frequency of Compressor Units – With 2 Standby Units

Unavailable Compressor Units per Station	Frequency (days/year)	Capacity, MMCFD	Compressor Station No. # / Unavailability Frequency (days/year)						
			#1	#2	#3	#4	#5	#6	#7
0	271.21	1059							
1	90.00	909	19.64						
		916		19.36					
		915			0.29				
		912				16.79			
		903					17.00		
		882						0.21	
		819							16.71
2	1.64	909	0.29						
		916		0.36					
		915			0.00				
		912				0.36			
		903					0.29		
		882						0.00	
		819							0.36
			1&2	#2&3	#3&4	#4&5	#5&6	#6&7	
1 + 1 (At 2 contiguous Stations)	2.14	786	0.79						
		793		0.00					
		788			0.00				
		776				1.29			
		748					0.00		
		670						0.07	
Total days	365.00								
Average Capacity		1016							
Nominal Capacity		1059							
Availability		0.9594							

Table 5 - Failure Analysis Capacity Results and Unavailability Frequency of Compressor Units – With 3 Standby Units

Unavailable Compressor Units per Station	Frequency (days/year)	Capacity, MMCFD	Compressor Station No. # / Unavailability Frequency (days/year)						
			#1	#2	#3	#4	#5	#6	#7
0	287.14	1059							
1	76.50	909	20.50						
		916		0.36					
		915			19.57				
		912				0.29			
		903					18.64		
		882						0.29	
		819							16.86
2	1.21	909	0.29						
		916		0.00					
		915			0.29				
		912				0.00			
		903					0.29		
		882						0.00	
		819							0.36
1 + 1 (At 2 contiguous Stations)	0.14		1&2	#2&3	#3&4	#4&5	#5&6	#6&7	
		786	0.00						
		793		0.00					
		788			0.00				
		776				0.07			
		748					0.00		
		670						0.07	
Total days	365.00								
Average Capacity		1023							
Nominal Capacity		1059							
Availability		0.9661							

Table 6 - Failure Analysis Capacity Results and Unavailability Frequency of Compressor Units – With 4 Standby Units

Unavailable Compressor Units per Station	Frequency (days/year)	Capacity, MMCFD	Compressor Station No. # / Unavailability Frequency (days/year)						
			#1	#2	#3	#4	#5	#6	#7
0	305.57	1059							
1	58.36	909	0.29						
		916		20.43					
		915			0.29				
		912				19.00			
		903					0.21		
		882						17.79	
		819							0.36
2	1.07	909	0.00						
		916		0.36					
		915			0.00				
		912				0.36			
		903					0.00		
		882						0.36	
		819							0.00
1 + 1 (At 2 contiguous Stations)	0.00		1&2	#2&3	#3&4	#4&5	#5&6	#6&7	
		786	0.00						
		793		0.00					
		788			0.00				
		776				0.00			
		748					0.00		
		670						0.00	
Total days	365.00								
Average Capacity		1034							
Nominal Capacity		1059							
Availability		0.9764							

Table 7 - Failure Analysis Capacity Results and Unavailability Frequency of Compressor Units – With 7 Standby Units

Unavailable Compressor Units per Station	Frequency (days/year)	Capacity, MMCFD	Compressor Station No. # / Unavailability Frequency (days/year)						
			#1	#2	#3	#4	#5	#6	#7
0	362.71	1059							
1	2.29	909	0.29						
		916		0.36					
		915			0.29				
		912				0.36			
		903					0.29		
		882						0.36	
		819							0.36
2	0.00	909	0.00						
		916		0.00					
		915			0.00				
		912				0.00			
		903					0.00		
		882						0.00	
		819							0.00
1 + 1 (At 2 contiguous Stations)	0.00		1&2	#2&3	#3&4	#4&5	#5&6	#6&7	
		786	0.00						
		793		0.00					
		788			0.00				
		776				0.00			
		748					0.00		
		670						0.00	
Total days	365.00								
Average Capacity		1058							
Nominal Capacity		1059							
Availability		0.9994							

Table 8 – Alternative IV (e) Risk Results Summary for a New Gas Pipeline Project

Name		Min	Mean	Max	x1	p1	x2	p2	x2-x1	p2-p1
Without stand-by compressor units	Units									
Capacity	MMCFD	670	1,001.8	1,059	819	5%	1,059	95%	241	90%
Capacity Loss	MMCFD	(390)	(57.7)	-	(241)	5%	-	95%	241	90%
Loss of revenue	MMUS$	(520)	(205.8)	-	(346)	5%	(84)	95%	262	90%
Penalty	MMUS$	(520)	(205.8)	-	(346)	5%	(84)	95%	262	90%
PV of losses (Revenue + Penalty)	MMUS$	(1,041)	(411.6)	-	(692)	5%	(169)	95%	523	90%
With 2 stand-by compressor units (#3 and 6)										
Capacity	MMCFD	670	1,016.0	1,059	819	5%	1,059	95%	241	90%
Capacity Loss	MMCFD	(390)	(43.4)	-	(241)	5%	-	95%	241	90%
Loss of revenue	MMUS$	(431)	(154.5)	-	(283)	5%	(47)	95%	236	90%
Penalty	MMUS$	(431)	(154.5)	-	(283)	5%	(47)	95%	236	90%
PV of losses (Revenue + Penalty)	MMUS$	(862)	(309.1)	-	(565)	5%	(93)	95%	472	90%
Recovered capacity	MMCFD	(390)	14.2	390	(156)	5%	177	95%	333	90%
Avoided loss of revenue	MMUS$	(304)	50.5	472	(129)	5%	227	95%	356	90%
Avoided penalty	MMUS$	(304)	50.5	472	(129)	5%	227	95%	356	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(608)	101.0	944	(257)	5%	455	95%	712	90%
With 3 stand-by compressor units (#2, 4 and 6)										
Capacity	MMCFD	670	1,023.0	1,059	903	5%	1,059	95%	156	90%
Capacity Loss	MMCFD	(390)	(36.4)	-	(156)	5%	-	95%	156	90%
Loss of revenue	MMUS$	(530)	(129.2)	-	(249)	5%	(30)	95%	219	90%
Penalty	MMUS$	(530)	(129.2)	-	(249)	5%	(30)	95%	219	90%
PV of losses (Revenue + Penalty)	MMUS$	(1,059)	(258.5)	-	(499)	5%	(60)	95%	439	90%
Recovered capacity	MMCFD	(390)	21.3	390	(156)	5%	177	95%	333	90%
Avoided loss of revenue	MMUS$	(318)	75.4	470	(98)	5%	248	95%	346	90%
Avoided penalty	MMUS$	(318)	75.4	470	(98)	5%	248	95%	346	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(636)	150.8	940	(195)	5%	496	95%	691	90%
With 4 stand-by compressor units (#1, 3, 5, 7)										
Capacity	MMCFD	819	1,034.1	1,059	882	5%	1,059	95%	177	90%
Capacity Loss	MMCFD	(241)	(25.4)	-	(177)	5%	-	95%	177	90%
Loss of revenue	MMUS$	(367)	(89.6)	-	(189)	5%	(12)	95%	177	90%
Penalty	MMUS$	(367)	(89.6)	-	(189)	5%	(12)	95%	177	90%
PV of losses (Revenue + Penalty)	MMUS$	(735)	(179.3)	-	(378)	5%	(25)	95%	353	90%
Recovered capacity	MMCFD	(241)	32.3	390	(148)	5%	177	95%	325	90%
Avoided loss of revenue	MMUS$	(181)	113.9	497	(43)	5%	270	95%	313	90%
Avoided penalty	MMUS$	(181)	113.9	497	(43)	5%	270	95%	313	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(363)	227.8	994	(86)	5%	541	95%	627	90%
With 7 stand-by compressor units (#1 to #7)										
Capacity	MMCFD	819	1,058.4	1,059	1,059	5%	1,059	95%	-	90%
Capacity Loss	MMCFD	(241)	(1.0)	-	-	5%	-	95%	-	90%
Loss of revenue	MMUS$	(132)	(3.7)	-	(30)	5%	-	95%	30	90%
Penalty	MMUS$	(132)	(3.7)	-	(30)	5%	-	95%	30	90%
PV of losses (Revenue + Penalty)	MMUS$	(264)	(7.4)	-	(60)	5%	-	95%	60	90%
Recovered capacity	MMCFD	(241)	56.6	390	-	5%	241	95%	241	90%
Avoided loss of revenue	MMUS$	(79)	198.2	511	77	5%	336	95%	259	90%
Avoided penalty	MMUS$	(79)	198.2	511	77	5%	336	95%	259	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(157)	396.5	1,021	155	5%	672	95%	517	90%

Table 9 – Alternative IV (e) Risk Results Summary for an Existing Gas Pipeline

Name		Min	Mean	Max	x1	p1	x2	p2	x2-x1	p2-p1
Without stand-by compressor units	Units									
Capacity	MMCFD	670	1,001.8	1,059	819	5%	1,059	95%	241	90%
Capacity Loss	MMCFD	(390)	(57.7)	-	(241)	5%	-	95%	241	90%
Loss of revenue	MMUS$	(493)	(194.8)	-	(328)	5%	(80)	95%	248	90%
Penalty	MMUS$	(493)	(194.8)	-	(328)	5%	(80)	95%	248	90%
PV of losses (Revenue + Penalty)	MMUS$	(986)	(389.7)	-	(655)	5%	(160)	95%	495	90%
With 2 stand-by compressor units (#3 and 6)										
Capacity	MMCFD	670	1,016.0	1,059	819	5%	1,059	95%	241	90%
Capacity Loss	MMCFD	(390)	(43.4)	-	(241)	5%	-	95%	241	90%
Loss of revenue	MMUS$	(410)	(146.9)	-	(269)	5%	(44)	95%	224	90%
Penalty	MMUS$	(410)	(146.9)	-	(269)	5%	(44)	95%	224	90%
PV of losses (Revenue + Penalty)	MMUS$	(819)	(293.7)	-	(537)	5%	(88)	95%	449	90%
Recovered capacity	MMCFD	(390)	14.2	390	(156)	5%	177	95%	333	90%
Avoided loss of revenue	MMUS$	(289)	48.0	449	(122)	5%	216	95%	338	90%
Avoided penalty	MMUS$	(289)	48.0	449	(122)	5%	216	95%	338	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(578)	96.0	897	(244)	5%	432	95%	676	90%
NPV for 2 stand-by units	MMUS$	(598)	75.8	877	(265)	5%	412	95%	676	90%
With 3 stand-by compressor units (#2, 4 and 6)										
Capacity	MMCFD	670	1,023.0	1,059	903	5%	1,059	95%	156	90%
Capacity Loss	MMCFD	(390)	(36.4)	-	(156)	5%	-	95%	156	90%
Loss of revenue	MMUS$	(504)	(123.0)	-	(237)	5%	(29)	95%	209	90%
Penalty	MMUS$	(504)	(123.0)	-	(237)	5%	(29)	95%	209	90%
PV of losses (Revenue + Penalty)	MMUS$	(1,008)	(246.1)	-	(475)	5%	(57)	95%	418	90%
Recovered capacity	MMCFD	(390)	21.3	390	(156)	5%	177	95%	333	90%
Avoided loss of revenue	MMUS$	(303)	71.8	447	(93)	5%	236	95%	329	90%
Avoided penalty	MMUS$	(303)	71.8	447	(93)	5%	236	95%	329	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(605)	143.6	894	(186)	5%	472	95%	658	90%
NPV for 3 stand-by units	MMUS$	(636)	113.3	864	(216)	5%	442	95%	658	90%
With 4 stand-by compressor units (#1, 3, 5, 7)										
Capacity	MMCFD	819	1,034.1	1,059	882	5%	1,059	95%	177	90%
Capacity Loss	MMCFD	(241)	(25.4)	-	(177)	5%	-	95%	177	90%
Loss of revenue	MMUS$	(352)	(85.8)	-	(181)	5%	(12)	95%	169	90%
Penalty	MMUS$	(352)	(85.8)	-	(181)	5%	(12)	95%	169	90%
PV of losses (Revenue + Penalty)	MMUS$	(703)	(171.6)	-	(362)	5%	(24)	95%	338	90%
Recovered capacity	MMCFD	(241)	32.3	390	(148)	5%	177	95%	325	90%
Avoided loss of revenue	MMUS$	(174)	109.0	476	(41)	5%	259	95%	300	90%
Avoided penalty	MMUS$	(174)	109.0	476	(41)	5%	259	95%	300	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(347)	218.1	952	(83)	5%	517	95%	600	90%
NPV for 4 stand-by units	MMUS$	(388)	177.6	911	(123)	5%	477	95%	600	90%
With 7 stand-by compressor units (#1 to #7)										
Capacity	MMCFD	819	1,058.4	1,059	1,059	5%	1,059	95%	-	90%
Capacity Loss	MMCFD	(241)	(1.0)	-	-	5%	-	95%	-	90%
Loss of revenue	MMUS$	(125)	(3.5)	-	(29)	5%	-	95%	29	90%
Penalty	MMUS$	(125)	(3.5)	-	(29)	5%	-	95%	29	90%
PV of losses (Revenue + Penalty)	MMUS$	(251)	(7.1)	-	(57)	5%	-	95%	57	90%
Recovered capacity	MMCFD	(241)	56.6	390	-	5%	241	95%	241	90%
Avoided loss of revenue	MMUS$	(76)	191.3	493	75	5%	324	95%	250	90%
Avoided penalty	MMUS$	(76)	191.3	493	75	5%	324	95%	250	90%
PV of avoided losses (Revenue + Penalty)	MMUS$	(152)	382.6	986	150	5%	649	95%	499	90%
NPV for 7 stand-by units	MMUS$	(223)	311.8	915	79	5%	578	95%	499	90%

FIGURES

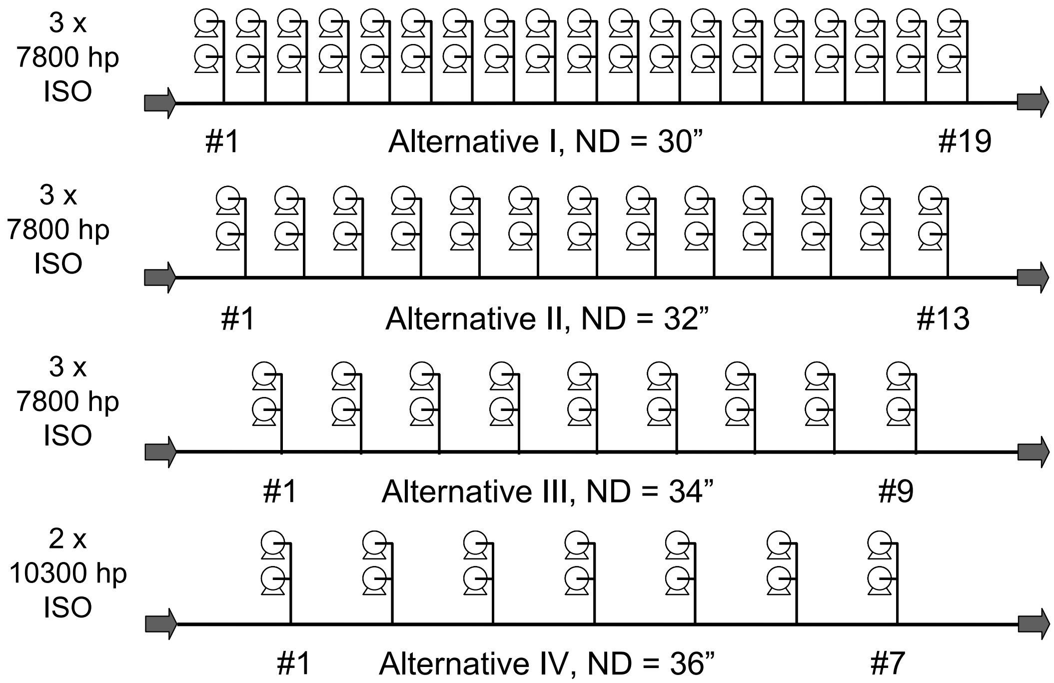

Figure 1 – Case Study – Gas Pipeline Alternative I, II, III and IV

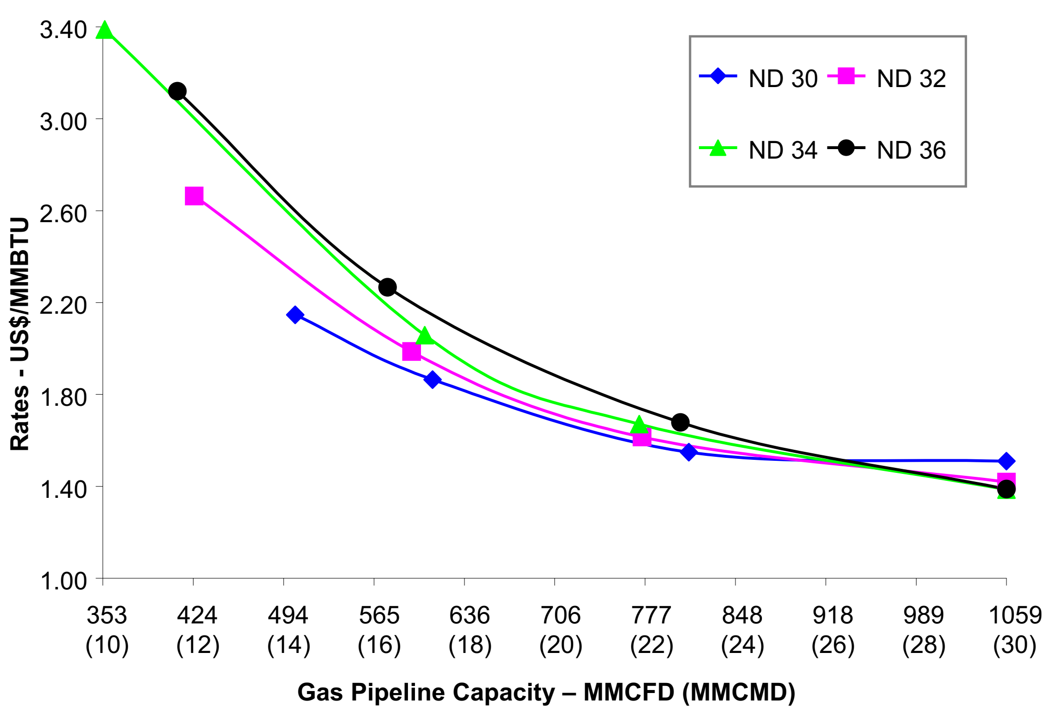

Figure 2 – J-Curves for Alternative I, II, III and IV - Without Standby Compressor Units

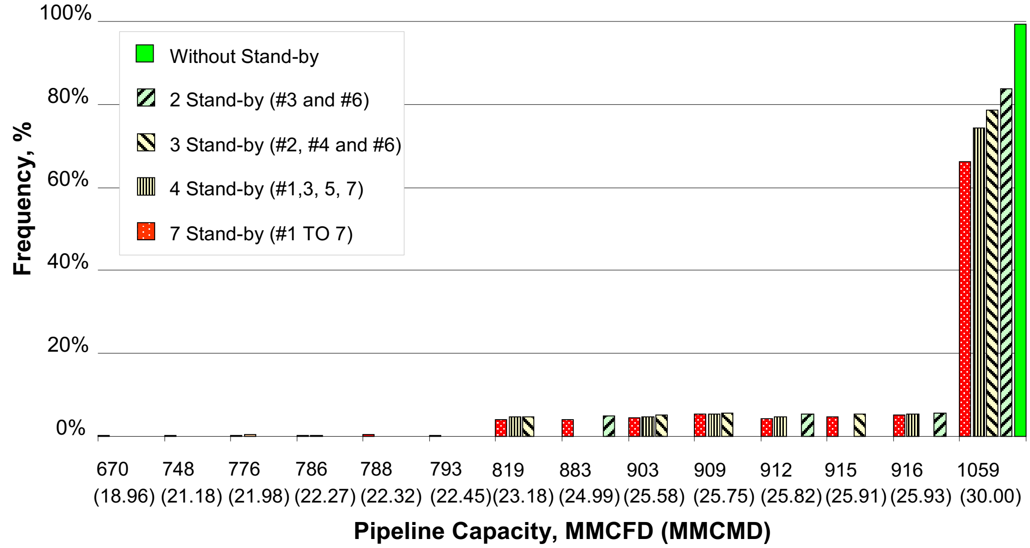

Figure 3 – Capacity Frequency and Availability

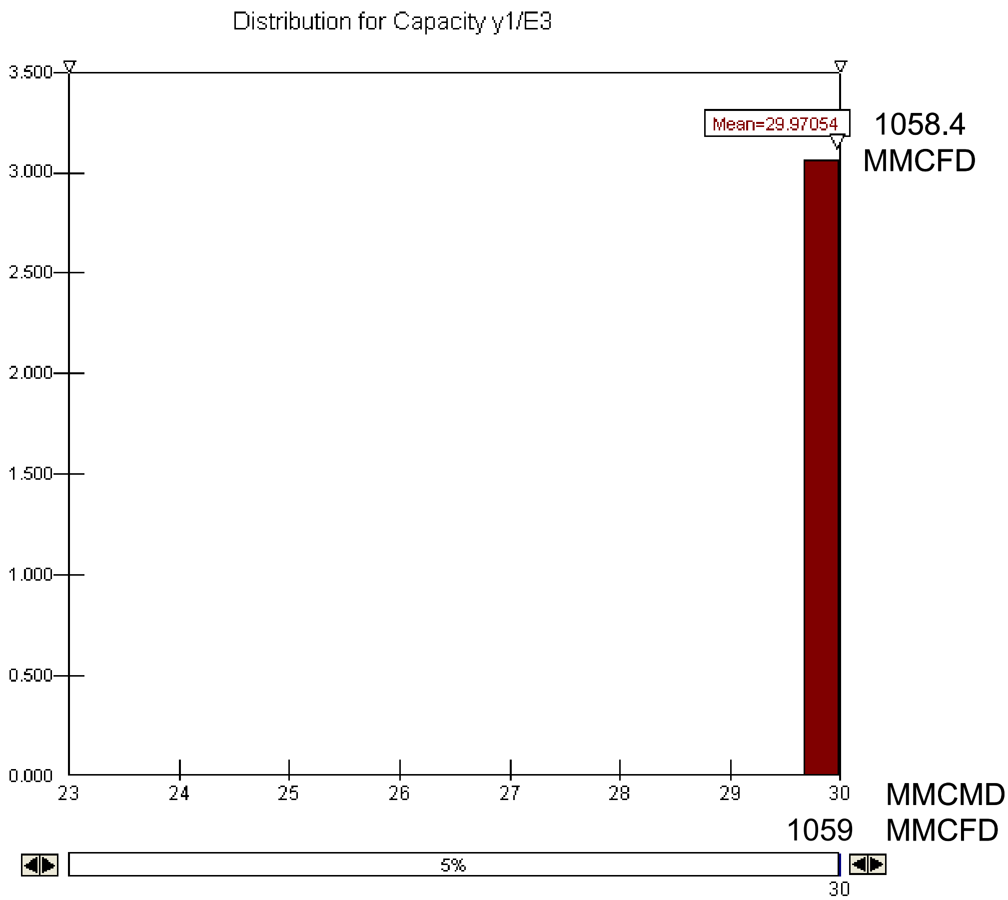

Figure 4 - Pipeline Capacity Frequency Distribution – With 7 Standby Compressor Units

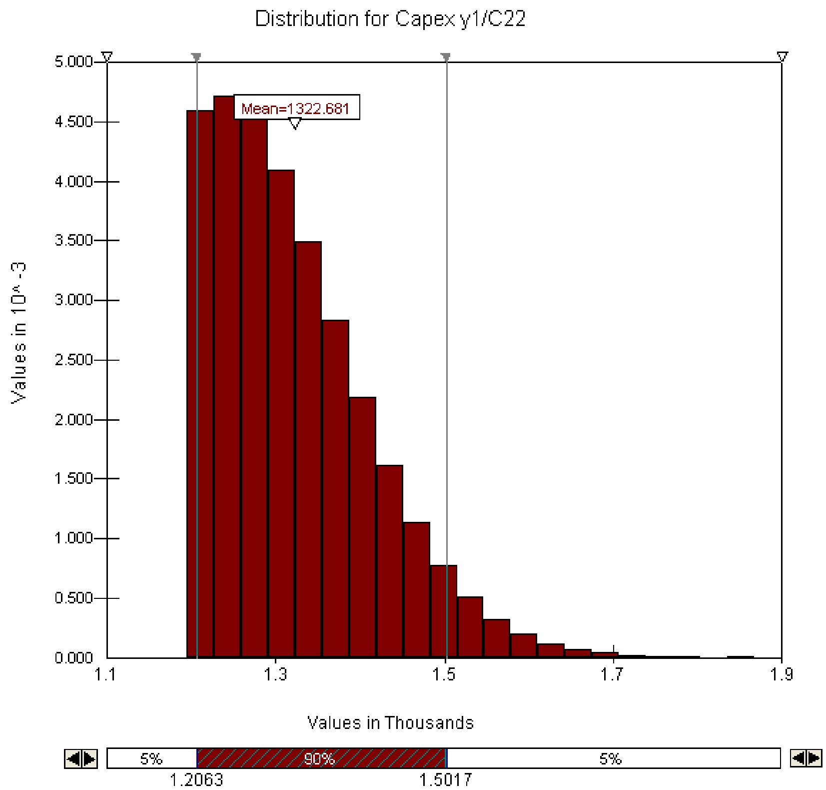

Figure 5 - Capex Statistical Distribution – Pipeline Alternative with 7 Standby Compressor Units

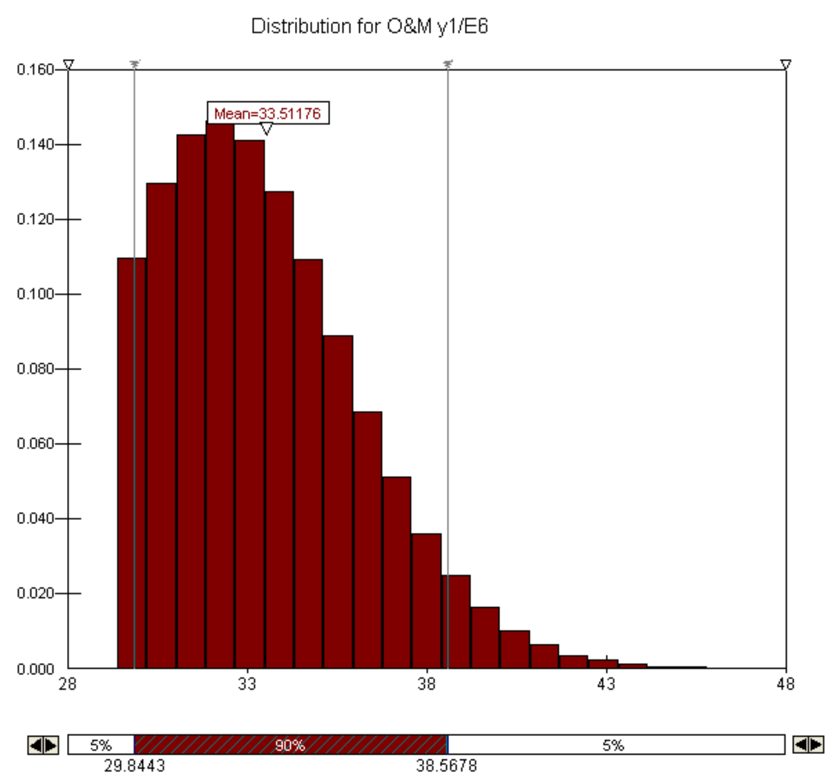

Figure 6 - Opex Statistical Distribution – Pipeline Alternative with 7 Standby Compressor Units

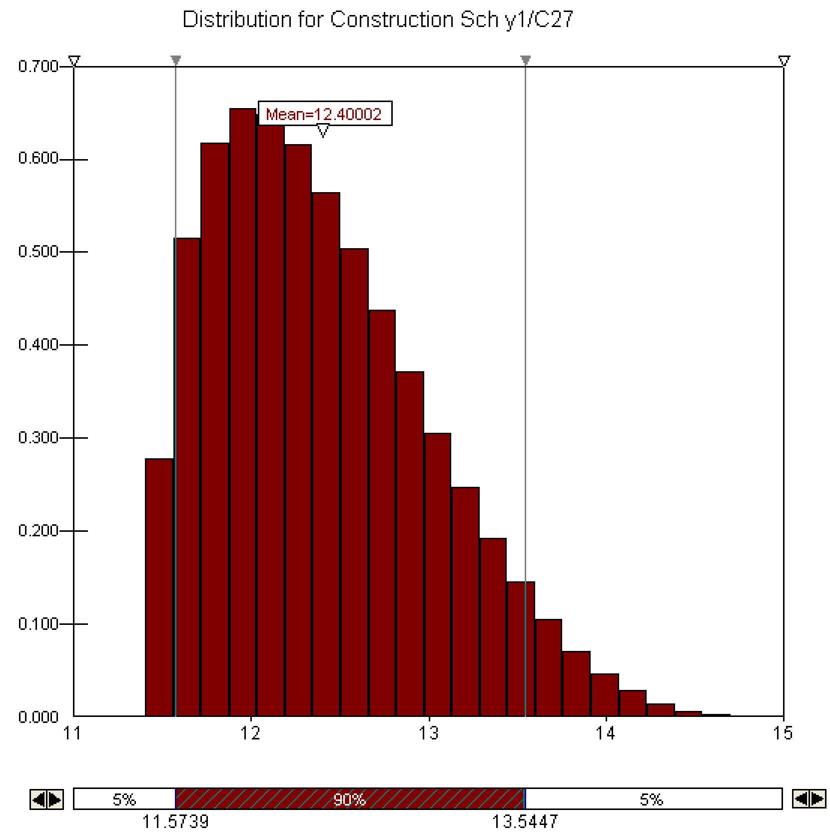

Figure 7 - Construction and Assembly Schedule – Pipeline Alternative with 7 Standby Compressor Units

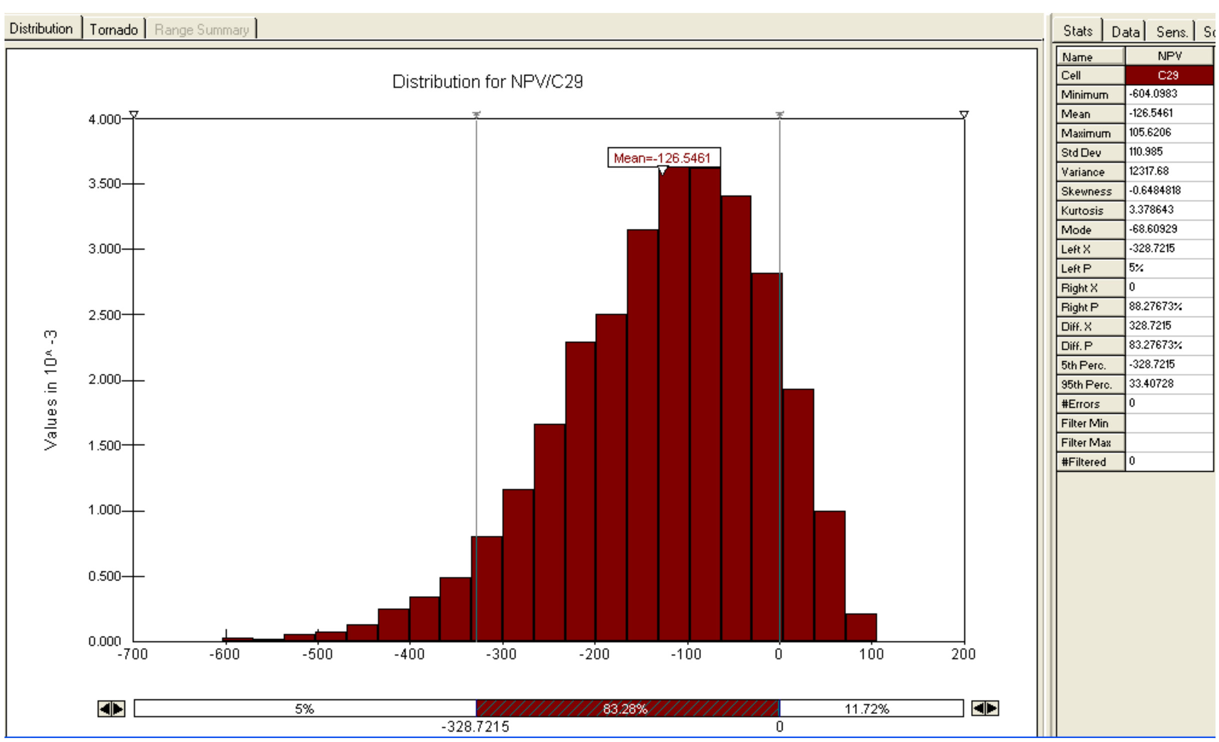

Figure 8 - NPV Distribution - Pipeline Alternative with 7 Standby Compressor Units

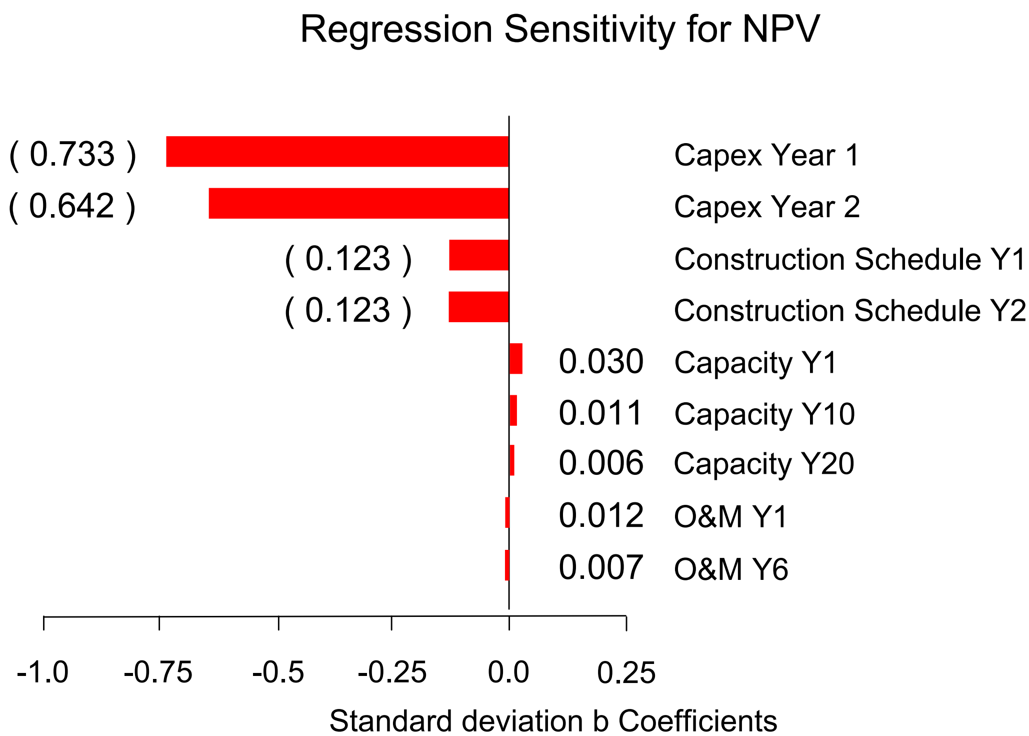

Figure 9 - Tornado Diagram - Pipeline Alternative with 7 Standby Compressor Units