



## Strategy and Technology for Operators, Contractors and Partners

### Advanced Pipeline Designs to Increase Hydrocarbon Flow

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#### ABSTRACT

The 24 inch MEDGAZ high pressure deepwater pipeline runs for 210 km along the seabed of the Mediterranean Sea, transporting natural gas from the Beni Saf Compressor Station (BSCS) on the coast of Algeria to the Offshore Pressure Regulation Station (OPRT) at Almería on the coast of Spain and into the Enagas transportation network. The pipeline reaches a maximum depth of 2,155 m as it crosses the Mediterranean.

This paper presents key aspects of the flow assurance studies carried out during the FEED and detailed engineering phases of the project with particular attention to the requirements for a deepwater natural gas pipeline. Moreover the particular requirements for deepwater pipeline commissioning and operation are discussed.

Medgaz has relied on the use of modeling systems from the early design phases of the project where steady state and transient simulators were used to aid in the design and in the verification of the expected hydraulic performance of the pipeline. This paper presents modeling of the pipeline with a focus on those elements and modules not often found in pipeline simulation.

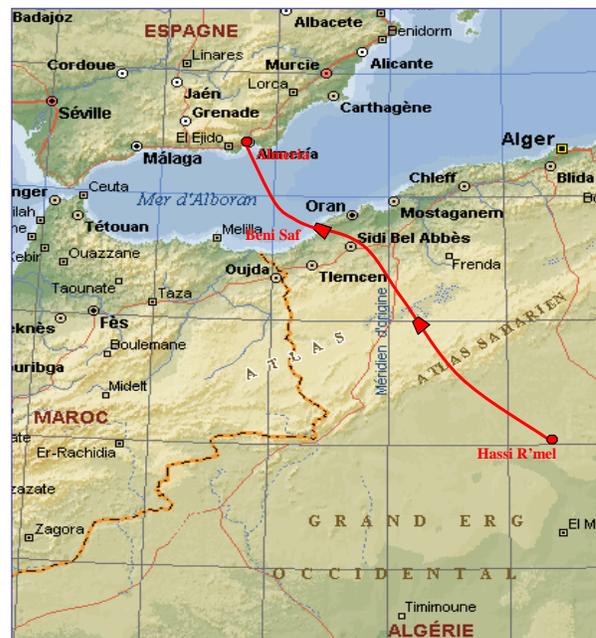


Figure 1. MEDGAZ Pipeline Route <sup>(1)</sup>

#### THE MEDGAZ PIPELINE

The MEDGAZ pipeline is a very strategic project for Algeria, Spain and the rest of Europe. This direct link between Northern Africa and Southern Europe will contribute to the security of gas supply within Europe. Additionally, international agencies such as the Observatoire Méditerranéen de l'Énergie have concluded that it is the most cost effective way to provide energy to southern Europe. The MEDGAZ pipeline will also help Europe achieve important objectives of the Kyoto Protocol by providing clean energy as authorities have pledged an increased use of natural gas for electricity generation.

The project was launched in 2001 by CEPSA and SONATRACH. The feasibility study was executed during 2002 - 2003 followed by marine survey campaigns, geotechnical investigations, geohazard investigation and front end engineering design. Permits and financing were secured in 2006. Detailed engineering and construction commenced in 2007 and the pipeline was put in to commercial operation in May 2011. Current MEDGAZ partnership comprises:-

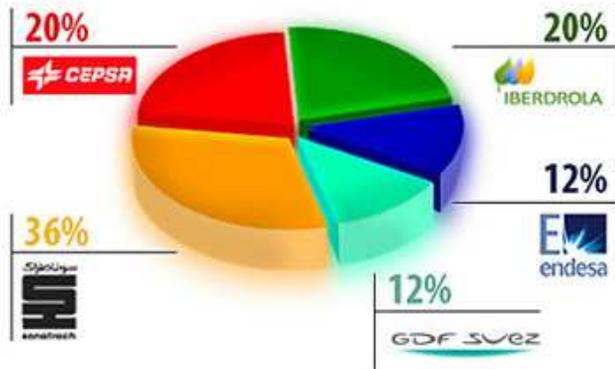


Figure 2. MEDGAZ Partnership Structure

The origin of the natural gas supply is the Hassi R'Mel pipeline hub and gas fields, about 550 km from Beni Saf. Gas delivered to Medgaz for onward transportation to Europe is treated and blended at Hassi R'Mel to a sales quality.

The principal features of the MEDGAZ system are outlined below:

- Capacity to supply 8 billion m<sup>3</sup>/year of gas to the Iberian Peninsular and Europe via one 24 inch diameter submarine pipeline.
- The offshore pipeline directly connects the Algerian gas fields and Spanish gas network across the Mediterranean (Alboran Sea) at a maximum depth of 2155 m and an approximate length of 210 km (Fig. 3).
- Two onshore terminals assure the safe and efficient transportation of gas:
  - BSCS: Beni Saf Compressor Station, near Sidi Djelloul in Algeria
  - OPRT: Offshore Pipeline Receiving Terminal, near Almería in Spain
- Onshore connecting pipelines (operated by others):
  - Algerian section: 550 km.
  - Spanish section: 285 km.
- Phase 1 of the project for installation of a single east pipeline to transport 8 BCM/Y is complete. Phase 2 of the project will involve installation of a second west offshore pipeline plus expansion of onshore facilities to increase capacity to 16 BCM/Y.

The pipeline route is characterized by:

- non-steep continental slopes on either side of the Alboran Sea;
- quaternary clay soil for the major part of the route;
- stable sea-bed conditions.
- Maximum water depth 2155m (49% > 1000m)
- 19 curvature points
- 5 crossings of telecommunications cables (all at water depth greater than 1000m )
- 1 geological fault crossing : Yusuf Fault
- Critical zone KP71 – KP77: Slopes <14 degrees
- More than 95% of the route: slopes less than 4 degrees
- Critical zone KP71 – KP77: Habibas escarpment

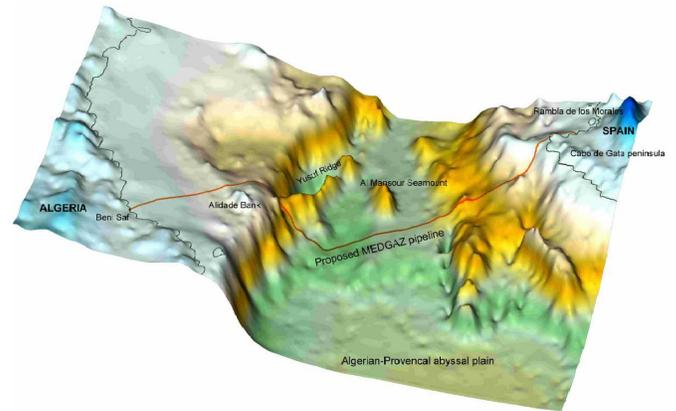


Figure 3. MEDGAZ Marine Pipeline Route

### The Marine Pipeline

Technical Data:

- Length = 210 km
- Diameter = 24"
- Capacity = 8 BCM/Year
- Maximum depth = 2,155 m
- Design Pressure = 220 barg
- Upper design temperature = 60° C
- Lower design temperature = -5° C
- Design Code = DnV F101
- Steel Grade X70 = SAWL 485 I DUF
- Pipe Thickness = 22.9 / 28.5 / 29.9 mm

The pipeline is laid on the seabed throughout most of its route and buried at nearshore approaches. An external anti-corrosion multi-layer polypropylene coating is applied for the entire pipeline length. External concrete coating is applied in shallow waters. The pipeline is applied with an internal flow coating.

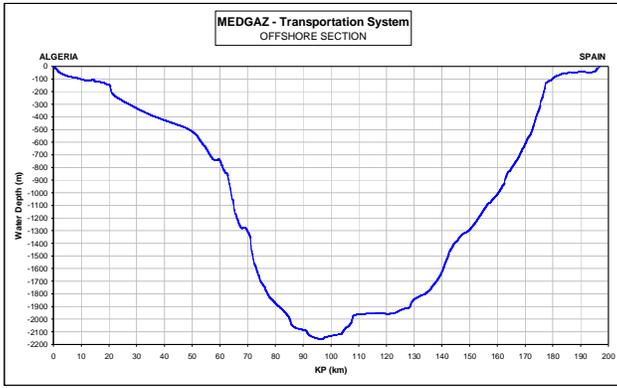


Figure 4. Pipeline Elevation Profile

### The Beni Saf Compressor Station

The MEDGAZ compressor station at Beni Saf raises pressure of natural gas received from the Hassi R'Mel fields for onward transportation to Europe. Facilities are installed for compression to the high pressures required to deliver flow through the marine pipeline to arrive at the receiving terminal at Spanish pipeline grid conditions. In addition BSCS is equipped with gas filtration, gas cooling, on line analysers and pipeline flow measurement. Custody transfer measurement is performed in the neighbouring upstream Sonatrach onshore pipeline arrival terminal.

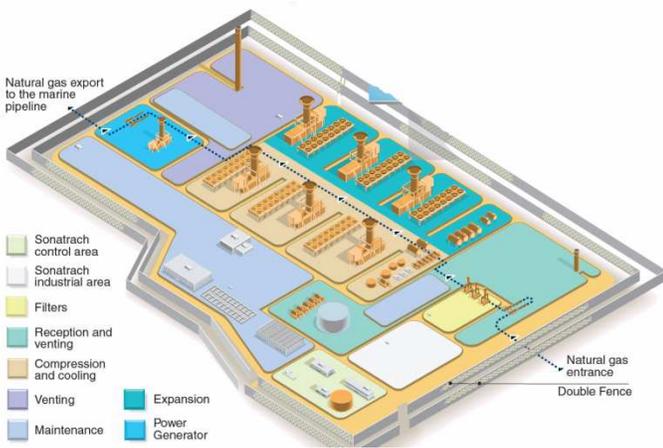


Figure 5. Beni Saf Compressor Station (BSCS)

### The Offshore Pipeline Receiving Terminal

The function of the normally unmanned Offshore Pipeline Receiving Terminal (OPRT) in Almería is to regulate the gas pressure and temperature to meet Spanish grid entry conditions. Under normal transportation conditions gas arriving at OPRT is filtered and delivered directly to the Spanish network via pressure regulation and overpressure protection facilities.

Temperature regulation is necessary in situations when gas enters the terminal at high pressure such as a pipeline depacking. In these cases gas is diverted to a heating facility installed upstream of pressure regulation to compensate for the Joule-Thomson process at the control valves.

OPRT is also equipped with on line analysers and pipeline flow measurement. Custody transfer measurement is performed in the neighbouring downstream Enagas flow metering & regulation station.



Figure 6. Offshore Pipeline Receiving Terminal (OPRT)

### Central Control Room

Operation of the pipeline system is supervised and monitored from a remote Central Control Room (CCR) located in Almería, Spain. The CCR is equipped with the SCADA, Online Pipeline Simulator, Pipeline Leak Detection System and a Machinery & Asset Management System for remote condition monitoring.

## DESIGN BASIS

**JP KENNY LTD** were appointed to provide the technical supervision of the pipeline FEED studies and to direct the flow assurance work. A basis of design was established considering:-

- Transportation of sales quality natural gas
- Pipeline diameter fixed at 24"
- Optimisation of pipeline transportation capacity
- Avoid risk of hydrate formation
- Avoid condensation of water
- Avoid condensation of hydrocarbons
- Avoid requirement for continuous heating of gas at the receiving terminal

Although pipeline diameter was fixed at 24" there existed flexibility to adjust pipeline thickness in order to maximize internal diameter and moderate gas arrival temperature at pipeline exit in Spain. An assessment of fuel saving in compression power versus additional pipe material CAPEX to provide justification for optimization. This work together with preliminary flow assurance established a pipeline design capacity of 28.5 MCM/day. Subsequent flow assurance is described as follows.

An important activity was to establish the design basis for pipeline dewatering for the construction and pre-commissioning phases. This considered the need of a contingency plan for wet buckle during pipelay and also for evacuation of hydrotest water.

## STEADY STATE HYDRAULIC ANALYSIS

Steady state hydraulic analysis was performed in HYSYS. A model was developed to represent the pipeline route, pipeline construction (internal & external coatings), burial conditions and marine & onshore environmental conditions.

Equation of State	Peng Robinson
Pipe flow Correlation	OLGAS2000_2P
Density	Peng Robinson
Viscosity	Mod. NBS (Ely and Hanley)
Enthalpy	Peng Robinson
Entropy	Peng Robinson
Heat Capacity	Peng Robinson
Thermal Conductivity	Misc, Thodos & Chung
Vapour Isentropic Coefficient	Peng Robinson
Friction Factor	Colebrook-White

Table 1: Base Case Marine Conditions

Subsequently the model was developed in Pipeline Studio for verification of results.

## Base Case

Data used for the steady state base cases is presented below:

- Design flowrate = 28.5 MCM/day
- OPRT Arrival pressure = 82 barg
- BSCS discharge temperature = 50 °C
- Algerian Ambient onshore (ground) temperature: 16°C
- Spanish Ambient onshore (ground) temperature: 15°C
- Nearshore Sea velocity = 0.2 m/s
- Pipe roughness: 12.5 μm
- Pipeline partially buried: 200mm burial in seabed
- Minimum Sea Temperature (deep water): 13°C

Some further information

Position	Burial condition
0 – 2.5 KP	Buried 1.2m (TOP)
2.5 - 168.6 KP	Resting on seabed - assumed sinking 200mm into seabed
168.6 - 178.2 KP	Buried flush <sup>1</sup> with seabed
178.2 – 206.7 KP	Resting on seabed - assumed sinking 200mm into seabed
206.7 – 207.1 KP	Buried 1.2m (TOP)
207.1 - 208.1 KP	Onshore buried 1.2m (TOP)

Table 2: Base Case Burial Conditions

Position	Sea conditions
Landfall - 20 KP	Velocity of seawater (current) = 0.2 m/s
20 - 170 KP	Velocity of seawater (current) = 0.05 m/s
170 KP - landfall	Velocity of seawater (current) = 0.2 m/s
Landfall - 21 KP	Sea temperature = 16°C
21 - 178 KP	Sea temperature = 13°C
178 - 206 KP	Sea temperature = 14°C
206-landfall	Sea temperature = 15°C

Table 3: Base Case Marine Environmental Conditions

The results from both HYSYS and Pipeline Studio models verified the maximum capacity design basis and provided pipeline conditions for lower transportation cases as summarised as follows:-

Case	Flow (MCM/day)	BSCS exit P (barg)	OPRT arrival Temp. (°C)
Design case	28.5	199	3
8 BCM/Y	22.9	166	7
7 BCM/Y	20.0	150	9
6 BCM/Y	17.1	136	11

Table 4: Base Case summary of Results

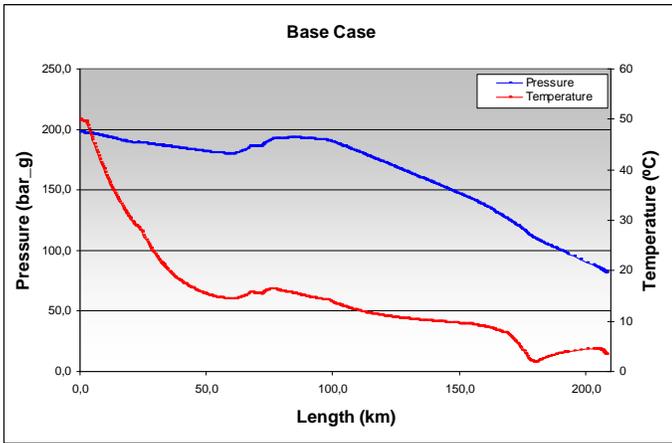


Figure 7. Base case Pipeline Design Condition

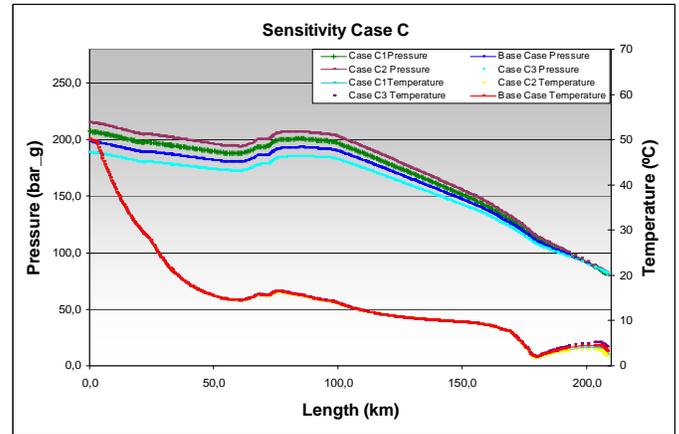


Figure 9. Pipeline Rugosity Sensitivity Case

**Sensitivity Cases**

Sensitivity cases were examined to assess influence of the following:-

- Pipeline delivery pressure
- Pipeline inlet temperature
- Operating temperature limits
- Gas molecular weight
- Seawater temperature
- Sea current
- Pipeline burial conditions
- Concrete coating length
- Pipe roughness

With the exception of rugosity the sensitivity cases revealed minor impact in hydraulics (example below). Major variations in pipeline internal roughness result in very significant changes in pressure drop.

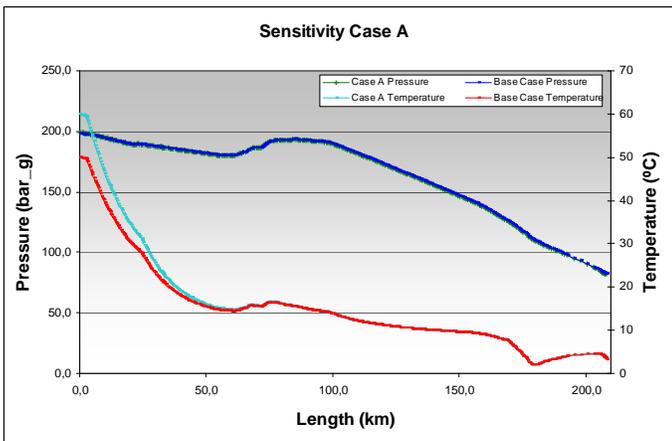


Figure 8. BSCS Outlet Temperature Sensitivity Case

**Conclusions**

- BSCS discharge pressure required at design condition is calculated as 199 barg with a resulting arrival temperature at OPRT arrival of 3 °C.
- Increasing BSCS discharge temperature 10 °C results in a 1 bar increment in the pipeline pressure drop. OPRT arrival temperature remains at 3°C.
- Reducing sea current velocity to 50% shows no influence in pipeline pressure drop nor OPRT arrival temperature.
- Pipeline pressure drop and OPRT arrival temperature are very sensitive to major changes (increase or reduction) in pipeline internal absolute roughness. For example an of internal roughness of 40 μm (equivalent to considering bare steel) is demonstrated by Case C2 to require a BSCS discharge pressure of 215 barg.
- Pressure drop and OPRT arrival temperature show a very slight sensitivity to the pipeline burial. Comparison of 200 mm and 400 mm burial depth in seabed show negligible impact on pipeline process conditions.
- OPRT arrival temperature shows a slight sensitivity (maximum 2 °C) to changes of +/- 5% in gas molecular weight. Pressure drop changes are negligible.
- Extending 10km the length of the concrete coated section has no influence neither in pressure drop nor in OPRT arrival temperature.
- Considering minimum sea temperature 12°C (1°C lower than in base case) results in a slight reduction (1 bar) of required BSCS discharge pressure

## DYNAMIC HYDRAULIC ANALYSIS

Dynamic hydraulic analysis was performed using the pipeline model constructed for steady state work as the basis plus equipment, controllers & valves at the pipeline boundary. Objective of the analysis was to:-

- Define design requirements during start-up, changes in flow, emergency shut-in, and blow down.
- Examine pipeline settling out conditions
- Examine pipeline depacking
- Define design basis for gas heating facility at receiving terminal
- Study the flow/pressure control interface with Spanish grid
- Assess pipeline survival time at various cases

The models used the following:-

- Peng-Robinson EOS in the whole model for prediction of physical properties.
- Aspen HYSYS dynamics version 2004 for BSCS
- Aspen HYSYS dynamics version 2004 for OPRT
- Aspen ProFES version 2004 for the marine pipeline and linked to BSCS & OPRT HYSYS models.
- Aspen ProFES version 2004 for the downstream Spanish onshore pipeline and linked to OPRT HYSYS models.

The model has subsequently been compared with Pipeline Studio.

### Results

Figure 10 shows transient simulation results for an instantaneous stop of flow at OPRT, such as closing a station battery limit ESD valve. The valve starts to close at time = 0 seconds. Pressure then starts to increase. The compressors at BSCS are forced to trip after 2 hour 8 minutes when maximum allowable incidental pressure (MIP = 231 barg) is reached in the pipeline. Peak pressure arise at KP 102,5. At that moment BSCS pressure reaches 212 barg.

The resulting pipeline settle-out pressure of 176 barg is reached in approximately 7 hours after shutting off the flow into OPRT. The highest pressure encountered at OPRT is 185 barg at 2½ hours after closing the inlet valve to OPRT. It is noted that the outlet pressure from BSCS is stable for nearly an hour after shutting off the flow at OPRT.

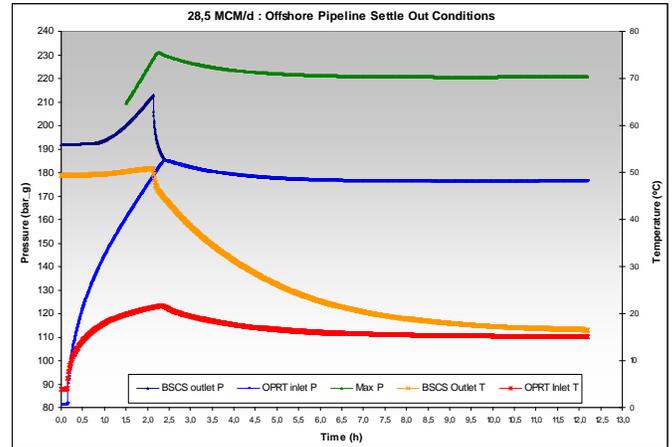


Figure 10. Pipeline Settling Out at Design Flow

Table 5 and Figure 11 represent the re-start case considering the maximum pipeline settle out condition and a downstream pressure in the Spanish onshore pipeline of 45 barg. Due to the large initial differential pressure difference across OPRT there is a high degree of gas cooling due to the Joule-Thompson effect. This simulation has been used to dimension the OPRT gas heating facility on the basis of establishing a flow increasing ramp to depack the pipeline within one shift (an 8 hour period) while maintaining OPRT outlet temperature above 0° C.

Parameter	Value
Pressure upstream (after settle-out)	176 barg
Pressure downstream (after settle-out)	45 barg
Temperature in Marine pipeline	13-16° C
Temperature in onshore pipeline	15° C
Minimum allowable temp at outlet from OPRT	0° C
Maximum heating duty	12,6 MW

Table 5: Re-start Condition

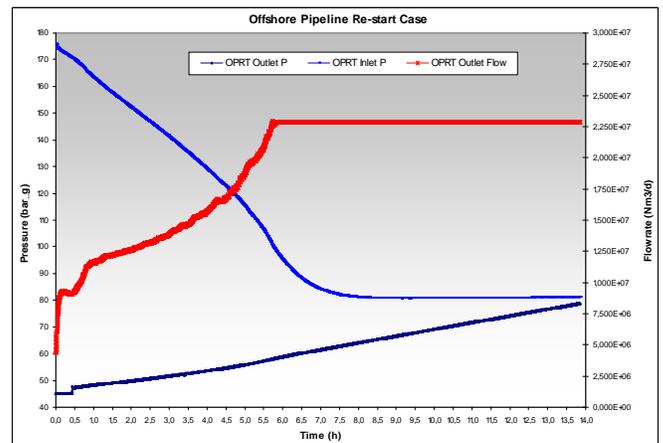


Figure 11. Re-start Condition from Max Settle Out

## Conclusions

- The dynamic simulations have not revealed any critical issues associated with transient behaviour of the marine pipeline and onshore facilities at BSCS or OPRT.
- The settling out analysis indicates the requirement to set the BSCS discharge high-pressure shutdown trip to 212 barg
- The pipeline restart case has shown that the flow can be re-started and ramped up to 8 BCM/y in 6 hours.
- A maximum heater duty of 12.6 MW is suitable to meet the restart objective.
- Examination of the ENAGAS flow control requirement has shown that it is possible to accommodate  $\pm 10\%$  control of flow in the short term (1 hour) from a steady state condition without the need for gas heating. In case of a reduction flow for an extended period exceeding one hour then it will be necessary to put gas heating into operation.

## HYDRATE FORMATION CONTROL

Design basis for the MEDGAZ pipeline is the transportation of dry sales quality natural gas. Hydrate Formation Control studies were carried out for flow assurance with the following objectives:-

- Examine conditions that may cause hydrate formation in the offshore pipeline;
- Assess upsets and incidental events that might cause hydrate formation in the offshore pipeline;
- Establish a hydrate prevention and mitigation philosophy.

The basis for the hydrate formation control studies includes gas flowrates, composition range, pipeline and environmental data as defined for the above mentioned hydraulic analyses studies. In addition the following cases have been considered with respect to water content in the gas supply:-

- 40 ppm water: expected concentration
- 80 ppm water: maximum specification limit
- 160 ppm water: off specification gas

Hydrates consist of a water lattice in which light hydrocarbon molecules are embedded resembling dirty ice. Hydrates normally form when a gas stream is cooled below its hydrate formation temperature in the presence of free water, i.e. the gas is below the water dew point temperature. The two major conditions that promote hydrate formation are thus:

- High gas pressure and low gas temperature
- The gas is at or below its water dew point with “free water” present

Secondary conditions such as high gas velocity, agitation and the formation of a nucleation site may also promote hydrate formation.

Hydrate formation is undesirable because the crystals might cause plugging of flow lines, valves and instrumentation. This can reduce line capacity and could cause physical damage to equipment. In MEDGAZ application the consequence of pipeline blockage would be severe operational disruption.

## Results

The initial study work was carried by **RAMBØLL OIL & GAS**. Figure 12 shows the hydrate formation curve together with the water dew point curves for 3 different cases considered of water content in the gas (40 ppm, 80 ppm and 160 ppm), see dashed lines. The pipeline operation conditions are also included (for each of the flowrate cases, see continuous lines) in order to evaluate whether hydrate formation will occur in the pipeline.

Formation of hydrates may occur at temperatures and pressures below the hydrate formation curve provided free water is present in the gas. The water dew point curves determine below which temperatures there will be free water in the gas and therefore hydrate formation will actually occur. As shown in Figure 12 the pipeline operation pressures and temperatures are such that hydrate formation will occur close to OPRT (Spanish end of pipeline), for all flowrate cases should free water is present.

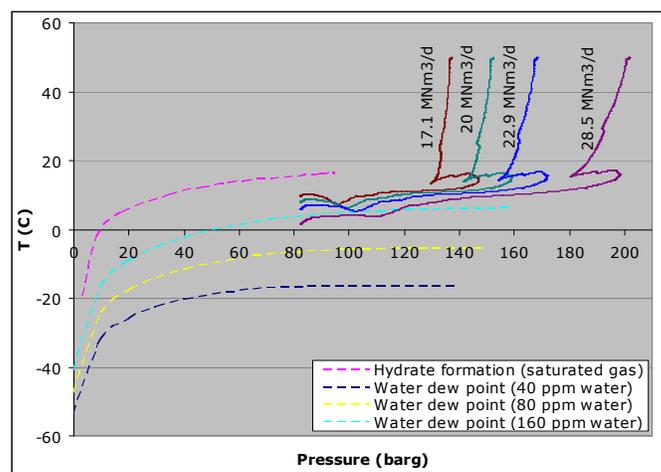


Figure 12. Pipeline Operating Conditions, Hydrate Formation & Water Dew Point Curves

From Figure 12 it can be observed that hydrate formation may occur at the design flowrate (28.5 MCM/d) if the amount of water in the gas reaches 160ppm off specification, moreover the maximum capacity 8 BCM/Year (22.9 MCM/day) case is

very close to the water dew point curve. At the lower flow cases the margin in temperature is only 2-3°C at 160 ppm of water). The risk of hydrate formation therefore needs to be considered in the case of off specification gas.

In the cases with 80 ppm limit the lowest pipeline operating temperatures (for any of the cases considered) are well above the water dew point curves (at least 8°C) and therefore the risk of hydrate formation is negligible.

**Conclusion**

Pipeline operating conditions with specification compliant gas are considered to provide sufficient safe temperature margin to avoid risk of hydrate formation. However, transportation of gas which exceeds water content specification limit poses the risk of hydrate formation at the OPRT end of the pipeline.

**Off Specification gas**

Further study was carried out to examine the operating limits should water content in the gas supply exceed the 80 ppm specification limit. Cases in the range 100 -160 ppm were examined. Figure 13 shows the water dew point curves for the gas when considering 100, 120, 140 and 160 ppm of water (see dashed lines). These are shown together with the pipeline operating conditions (for each of the flowrate cases, see continuous lines) in order to determine for which water content of the gas hydrate formation is an issue.

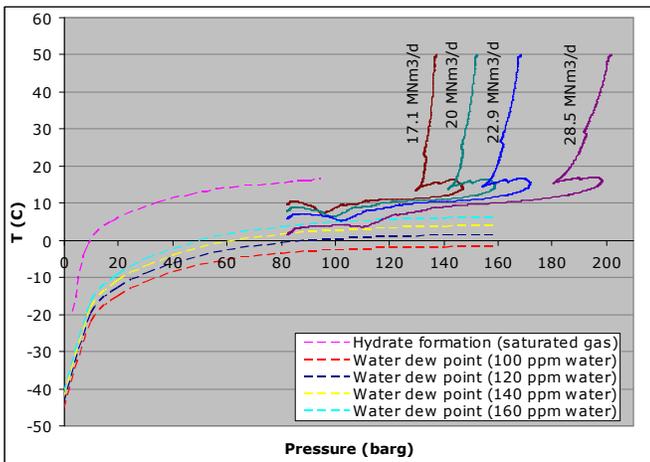


Figure 13 Pipeline Operating Conditions, Hydrate Formation & Water Dew Point Curves

Figure 13 shows that hydrates may form at the design rate when the water content exceeds 140 ppm. For other flow cases, the temperature margin needs to be analysed to identify the cases with risk of hydrate formation. It is recognised that there is the possibility of hydrate formation as gas temperature

approaches the predicted water dew point.

Table 6 presents an assessment of the risk of hydrate formation for the cases represented in Figures 12 & 13 considering a safety margin criteria.

Flow rate (MNm3/d)	Water content				
	80 ppm DESIGN	100 ppm	120 ppm	140 ppm	160 ppm
17.1	No hydrates	No hydrates	Risk of hydrates	Risk of hydrates	Below safety margin
20	No hydrates	Risk of hydrates	Risk of hydrates	Below safety margin	Below safety margin
22.9	No hydrates	Risk of hydrates	Risk of hydrates	Below safety margin	Below safety margin
28.5	Risk of hydrates	Risk of hydrates	Below safety margin	Hydrates	Hydrates

No hydrates	No hydrates formed (?T > 10°C)
Risk of hydrates	Hydrates not formed and within safety margin (4 < ?T < 10°C)
Below safety margin	Hydrates not formed but no safety margin available (?T = 0 - 4°C)
Hydrates	Hydrates will be formed (?T = 0°C)

Table 6 Hydrate formation risk for flow / water content cases

**GERGWater Sensitivity Analysis**

In support of the Hydrate Formation Control study a sensitivity analysis was carried by **GDF SUEZ** on water dew point calculations when gas compositions and different physical models and/or correlation methods are used. The analysis calculated the WDP curves for Water Content between 40 -160 ppm water for two different gas compositions using two different methods:-

- (1) GERGWater<sup>6</sup>
- (2) GPSA Method used in the previous work

Moreover, analysis was also made to determine which constituents trigger a change in the WDP temperature.

For lean, sweet gases containing over 70% methane and small amounts of heavy hydrocarbons. Generalized pressure-temperature correlations are suitable for many applications, such as the GPSA method. The method is valid over a pressure range of 28.6 to 689.5 barg; WDP temperature range -40<sup>0</sup> C to 0<sup>0</sup> C and water content 10 to 100 mg/Sm<sup>3</sup>.

The GERGWater correlation is the result of a task group founded by GERG to develop a method for calculating WDP and WC of natural gases. The correlation was developed at the Institut fur Technische Thermodynamik und Kaltetchnik of the Universitat Karlsruhe, and the final monograph published in 2000.

It is reported that WDP can be predicted by the GERGWater

correlation with an accuracy of better than  $\pm 2$  K in the pressure range 5 to 100 bar and temperature range of  $-25^{\circ}\text{C}$  to  $+20^{\circ}\text{C}$ . GERGWater application range has subsequently been extended from  $-25^{\circ}\text{C}$  to  $+20^{\circ}\text{C}$  over 1 to 300 bar in pressure however no accuracy is stated.

Results of the analysis are summarised in Table 6. It can be seen that predicted GSPA WDP values are lower in all cases

Pressure	50 barg		100 barg		140 barg	
	Rambøll	GERGWater	Rambøll	GERGWater	Rambøll	GERGWater
Software						
40 ppm	-18.8	-13.8	-16.4	-7.3	-16.4	-4.8
80 ppm	-9.8	-6.5	-6.1	0.0	-5.6	2.7
160 ppm	-0.2	1.5	4.8	8.8	5.9	11.6

Table 7 GPSA (Rambøll values) versus GERGWater: WDP temperature prediction

Main findings of the GDF SUEZ study work were:-

- GERGWater WDP values higher than predicts e.g. by PR EOS
- GERGWater predicts hydrate for “any” flow case above 120 ppm
- GPSA, PR (unmodified) and standard reference data under predicts WDP when comparing to GERG Water
- WDP is not sensitive to range of concentrations for the gas specification range.

A plot of the various WDP temperature prediction methods for 80 ppm WC is presented in Figure 14 with an additional curve for GERGWater prediction for 130 ppm WC.

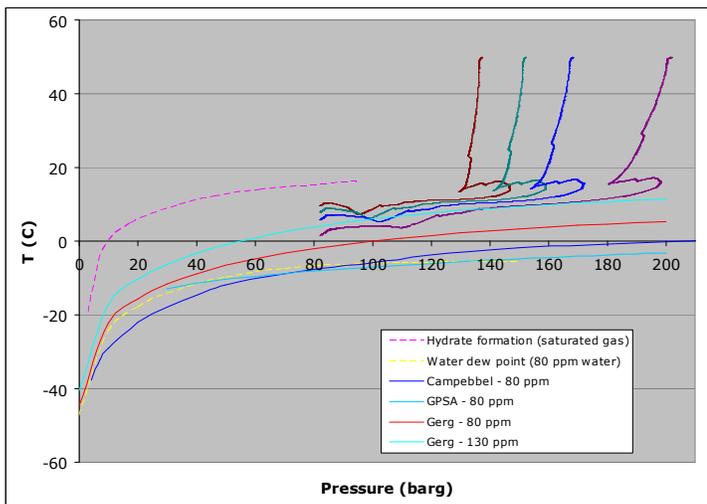


Figure 14 Comparison of WDP Temp Prediction Methods

The assessment of hydrate formation risk was revised to consider the GERGWater predictions and the findings are presented in Table 8.

Flow rate (MNm <sup>3</sup> /d)	Water content				
	80 ppm DESIGN	100 ppm	120 ppm		
17.1	No hydrates	Risk of hydrates	Risk of hydrates		
20	No hydrates	Risk of hydrates	Below safety Margin		
22.9	Risk of hydrates	Below safety Margin	Below safety Margin		
28.5	Below safety Margin	Below safety Margin	Hydrates		

No hydrates	No hydrates formed ( $\Delta T > 8^{\circ}\text{C}$ )
Risk of hydrates	Hydrates not formed and within safety margin ( $2 < \Delta T < 8^{\circ}\text{C}$ )
Below safety margin	Hydrates not formed but no safety margin available ( $\Delta T = 0 - 2^{\circ}\text{C}$ )
Hydrates	Hydrates will be formed ( $\Delta T = 0^{\circ}\text{C}$ )

Table 8 Revised Hydrate formation risk for GERGWater

### Hydrate Formation Mitigation Philosophy

The formation of hydrates should be avoided since they do not dissociate at the same conditions as they are formed. Significantly higher temperature and/or lower pressure are required and even at the right conditions, hydrate dissociation is a slow process.

The of hydrate inhibitors has not been recommended for the Medgaz pipeline in continuous operation nor in response to upstream upset. Accumulation in pipeline due to deep water pipeline profile is likely to cause slugging. Moreover it is doubtful that the injected inhibitor could effectively reach the affected pipeline section. Injection of inhibitor to be considered as a last resort remedial action in case of hydrate formation.

The mitigation philosophy established for hydrate formation to be managed by manipulation of pipeline operating conditions. This is considered to be an effective measure for steady state continuous operation and also response to transient upstream upsets. The corrective action in case of an off-spec gas where free water may appear and therefore hydrate formation would occur, is to reduce the flow to a safe level, i.e. approximately to 17.1 MCM/day if the water content is up to 140 ppm or to approximately 22.9 MCM/day if the water content is up to 120 ppm. These flow reductions decrease the pressure drop in the pipeline thereby increasing the pipeline outlet temperature.

## Recommendations

- (1) The initial phase of pipeline operation is likely to be at reduced capacity which means operation with a wide margin from the water dew point curve. This period of operation will allow validation of pipeline hydraulic analysis and on line calibration of the simulator. More accurate prediction of operation risk areas for higher flowrates can be made at this time.
- (2) Obtain feed forward information from Sonatrach on gas quality in the upstream Algerian onshore pipeline delivery when water content exceeds 80ppm. This will provide operator with time to manipulate pipeline operating condition.

## HYDROCARBON DEW POINT STUDY

**GDF SUEZ** supported MEDGAZ on the flow assurance by carrying out a Hydrocarbon Dew Point (HCDP) Study with the objectives:-

- To develop a HCDP curve for a similar Algerian Gas Composition calculated the from GDF SUEZ gas database to assess project specification.
- Sensitivity analysis where the variation of the C6+ constituents will show how the hydrocarbon dew-point temperature can shift.
- Establish a method to implement in the Pipeline Online Simulator to calculate HCDP from the on line gas chromatograph measurements (i.e. measured hydrocarbon components From C<sub>1</sub> to C<sub>6</sub>.)

A set of HCDP curves developed by GDF Suez for a range of typical Algerian gas are shown on Figure 15. The curves indicate that the average Algerian gas composition (blue line) is within the project specification (i.e. HCDP maximum temperature limit of 0<sup>0</sup> C). The closest pipeline operating point (OPRT arrival condition) is annotated on the graph and a reasonable (safe) margin can be observed.

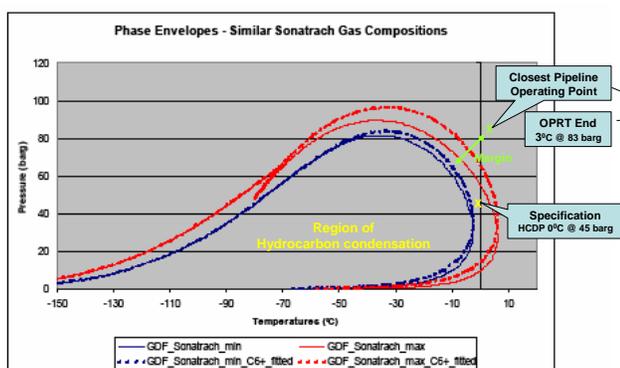


Figure 5.2 : Phase envelopes calculated with the GDF SUEZ Similar Sonatrach and the fitted C<sub>6</sub>, GDF SUEZ Similar Sonatrach gas compositions (minimum and maximum)

Figure 15 Typical Algerian Gas Hydrocarbon Phase Envelope

It is known that for some light hydrocarbon mixtures there is a linear relationship between the log[concentration] and the carbon number. This means, that as the concentrations of C<sub>3</sub>, C<sub>4</sub> and C<sub>5</sub> are known (data available from the installed on-line gas chromatograph), it is possible to calculate by extrapolation the concentrations of fractions C<sub>6</sub> up to C<sub>13</sub>, thus “splitting” the C<sub>6+</sub> fraction. GDF SUEZ determined this linear regression for a similar Algerian Gas composition and made sensitivity analysis to provide the input data for the Online Simulator software.

## PIPELINE DEWATERING STUDY

An issue which distinguishes deepwater transmission pipelines from conventional water depth systems is the dewatering requirement. Provision of a dewatering facility is normally considered necessary at the construction phase as contingency should a wet buckle occur during pipelay causing accidental flooding. During subsequent pre-commissioning a facility is needed to evacuate hydrotest water. Removal of water is conventionally achieved by compressed air. In the case of the Medgaz pipeline an unusually high delivery pressure is required to overcome the hydrostatic head resulting from the 2,155 water depth.

A study was carried during FEED to examine construction risks, hydrotest needs and alternative design configurations for dewatering facilities. The study included an evaluation of the possible use of permanent facilities to be installed at the pipeline compressor station with the provision of a temporary facility.

### Provision of Temporary Air Compression Facility

Temporary air compression spreads have been employed on previous deepwater pipeline projects. These facilities are extensive requiring a large number of air compressors units with ancillary equipment, require a sizeable footprint and entail high cost to mobilize throughout the construction and pre-commissioning phases. Enquiries outlining the Medgaz pipeline dewatering duty were issued to potential contractors and a preliminary engineering study was made to define the basic design configuration and equipment.

### Use of Permanent Facilities for Dewatering

A conceptual engineering study was made to examine various alternatives to integrate the permanent pipeline compressors in a dewatering configuration. The potential turbo-compressor suppliers were consulted to assess capability to adapt their units to the dewatering duty. The following main design aspects were identified:-

- The permanent compressors could be arranged in series to deliver the flow requirement from around 50 barg up to maximum required dewatering pressure.
- A temporary compressor, reciprocating type, would be needed to raise feed air up to 50 barg.
- It was considered that gas would not be available from the upstream pipeline at the pre-commissioning stage. Therefore the turbine drives for permanent compressors would need to be adapted to dual fuel (natural gas and diesel).
- Air cooling requirement would exceed duty of the permanent BSCS air coolers. Additional cooling would be necessary. Use of sweater was considered a possibility.
- Temporary water separators would be required at air discharge.

### Evaluation of Alternatives

It seemed possible to establish a technical solution using permanent facilities however it was recognised that an extensive FEED would be necessary to demonstrate viability. Based on a preliminary scheme the estimated cost compared favourably with provision of a temporary facility.

A risk analysis was made. Findings were that the solution to permanent facilities for dewatering would have a high risk of impacting the project schedule with consequences to interfere with progress of both offshore and onshore contractor. The logistics and interface management would be a challenge and require extensive planning. It was therefore concluded to proceed with provision of temporary facilities as a proven method for deepwater pipeline dewatering.

### Temporary Air Compressor Station used at Medgaz

Following an initial engineering phase Weatherford's Temporary Air Compression Spread (TACS)<sup>2</sup> was selected by the Offshore Contractor as the temporary facility for pipeline dewatering. A scope of work was established to cover Wet Buckle Contingency, Pipeline Flooding, Dewatering, Pipeline Drying, Inerting and Testing. The TACS configuration comprising major equipment listed below rated for dewatering air discharge pressure of 250 barg:-

- 56 FEED air compressors
- 28 boosters
- 2 scrubbers
- 16 air driers
- 4 molecular sieves
- Fuel system

The facility was installed next to OPRT at the Spanish end of

the pipeline as the final offshore construction plan was to lay the pipeline from Spain to Algeria. Figure 16 shows an aerial view of the facility.



Figure 16. Temporary Air Compressor Station (TACS)

## ONLINE SIMULATOR

The use of models has been instrumental during the design and pre-operation phases of the MEDGAZ pipeline project. Models have been used to validate the design parameters, estimate conditions for the formation of hydrates, plan detailed specific operations, review operational sequences and train operators. It was recognised that an online pipeline simulator would be an essential tool for operation of the pipeline.

**ENERGY SOLUTIONS INTERNATIONAL** were selected to provide the **Online Simulator** as part of a suite of advanced applications also including **Pipeline Leak Detection System, Offline Model, Stations Simulation Models and Operator Trainer**.

Medgaz have integrated the Online Pipeline Simulator in the Central Control Room SCADA. Functionality includes:-

- Real-time Pipeline Model
- Dew Point & Hydrate Formation Tracking
- Look-ahead Pipeline Model
- Survival Pipeline Model
- Predictive Pipeline Model

The model has been developed and validated with input from FEED studies in particular the basis for hydrate formation prediction and hydrocarbon dew point tracking.

### Dew Point and Hydrate Formation Tracking Module

One of the most critical functions of the online modeling system at MEDGAZ is to calculate dew points and alert the operator when there is possibility of hydrate formation anywhere in the marine pipeline. Look-ahead models will notify operators in advance of possible hydrate formation so that they can take corrective action.

The Fluid Monitoring module of the online modeling system uses gas composition information from the DCS system to keep track of “batches” of gas as any of the components changes by more than a configurable percentage.

For each batch, the system calculates three curves:

- Water Dew Point curve
- Hydrocarbon Dew Point curve
- Hydrate Formation curve

The solution uses a proprietary generalized fluid properties package (PVTPro) that supports a number of equations of state (and correlations for other fluid properties). This has been used in other models with the primary functionality of providing density, heat capacity, heating value and viscosity, and their derivatives.

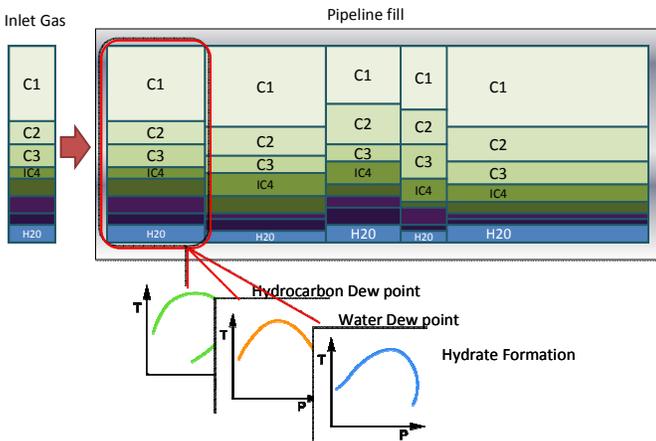


Figure 17 - Gas Tracking

The Hydrocarbon Dew Curve is generated using the standard technique of using the fugacity coefficient and phase equilibrium with fluid properties calculated using the Peng-Robinson equation of state<sup>1</sup>.

The Hydrate Formation Curve is calculated using the API k-method for Hydrate temperature prediction<sup>2</sup>. The data in the tables provided is curve fitted and then interpolated based on composition.

The Water Dew point Curve is calculated using the GPSA method<sup>5</sup>.

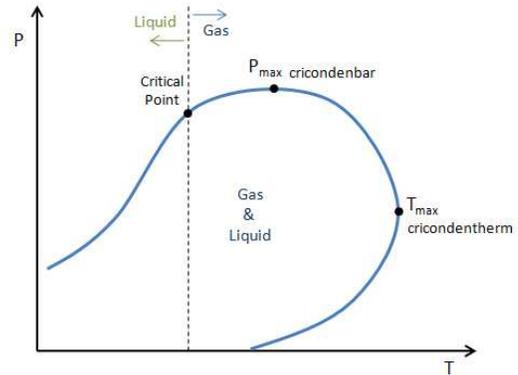


Figure 18 - Typical Natural Gas Hydrocarbon Dew Point Curve

In order to validate the solution from the online simulation system, a series of offline simulations were carried out using the same composition and input data used in the hydrate formation risk analysis performed by a third party as part of the FEED study of the pipeline. The simulations were performed at various operating conditions as per design, and the results were compared with the hydrate formation risk analysis report.

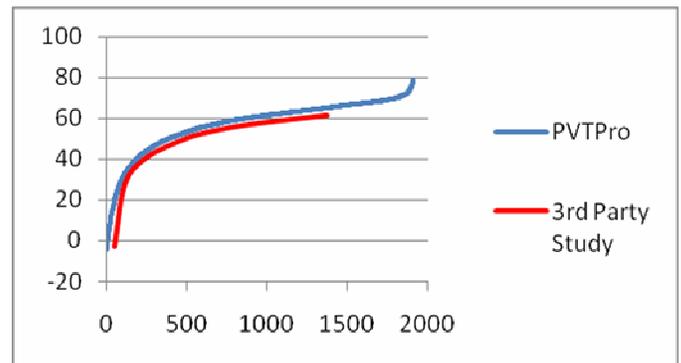


Figure 19 – Hydrate formation curve comparison

The results show a close match between the data from the third party study and the data produced by the online simulation system.

### Leak Detection System

As in any other pipeline transporting natural gas or hazardous materials, the leak detection system is a component of the overall monitoring and control system.

MEDGAZ opted to use model-based leak detection as the method of choice. In this case, two models with opposing boundary conditions (pressure-flow and flow-pressure) are implemented. The signals generated from the difference between the model values and the measurement values at the end points of the marine pipeline are processed using a statistical analysis called SALD which is based on the Sequential Probability Ratio Test (SPRT).

This method, based on the classic hypothesis testing with two alternative hypotheses evaluated through a threshold scheme, allows calculation of typical Unexpected Flows (UF) and Unexpected Pressure (UP) responses based on model calculated and measured values.

SALD also calculates the response quality to determine if a given sample is valid.

In order to determine the expected performance of the leak detection system an analysis was performed. Since no live or archive data was available at the time of the study, model-simulated data was used. The following diagram explains the methodology used:

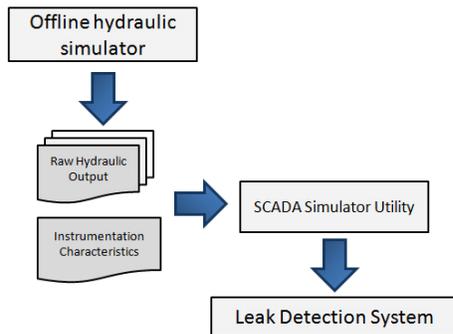


Figure 20 - Methodology for simulating SCADA data

The SCADA Simulator Utility applies realistic errors to the model-generated data to make sure the effects of those errors are analyzed. This utility simulates time skews, instrument dead-band, drift, repeatability, resolution, linearity and other instrument errors.

Some characteristics make the MEDGAZ project unique. For example, the sub-sea pipeline has an elevation profile that

reaches elevations below 6,500 ft (1980 m) deep. Under these conditions there are pipeline sections where the external pressure will be higher than the internal pressure. Figure A1 in appendix A depicts this issue. It can be seen that negative pressure values are reached between approximately 51 miles and 80 miles (82 km and 128.7 km). This example has 2,715 psig (187.2 barg) at the inlet conditions and 1,185 psig (81.7 barg) at the outlet.

Any leak in the area where the hydrostatic pressure (green curve) is greater than the gas pressure (red curve) would lead to the potential ingress of water to the pipeline. It was not possible to simulate leaks within this area of negative differential pressure.

The offline analysis concluded that the model-based SALD methodology met the performance criteria set out by MEDGAZ.

It was also concluded that accurate thermal modeling is important to achieve optimal performance.

Dead-bands imposed on pressure transmitters could have a significant impact on the false alarm rate. It has been recommended to minimize the use of dead-bands as much as possible, especially on pressure instruments.

### Operation Simulator model

The objective of the Operation Simulator Model is to be able to reproduce most of the typical operations within the BSCS and OPRT stations.

The interesting aspect of this model is that it pays particular attention to the expected reactions of the devices within the station. This makes it particularly challenging for models traditionally used in simulation of pipelines and not in simulation of station devices.

The Operation Simulator Model required modeling of the devices in a level of detail not often found in these types of models. Furthermore, the model included the implementation of specific control systems to mimic the functions of the DCS.

The following section highlights how this model was implemented and the most challenging tasks of such an implementation. In subsequent sections of this paper we explain how these models have been used and will be used in the upcoming months in preparation for the startup of the pipeline.

### The BSCS Station Model

The BSCS station model is composed of the following elements:

- Sonatrach Supply
- Inlet filters
- Compressor trains with associated valves and coolers
- Outlet valves
- Venting delivery and associated valves

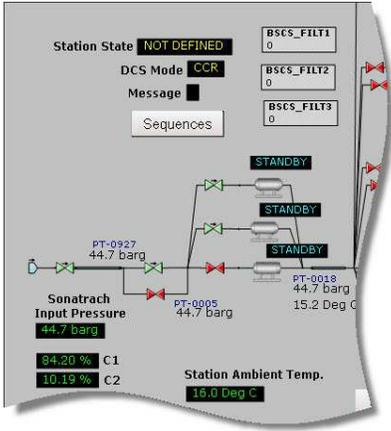


Figure 21 - BSCS Inlet and Filters

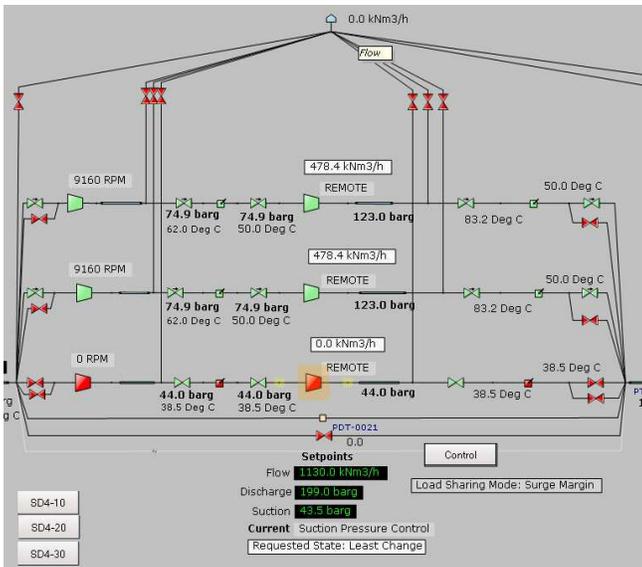


Figure 22 - BSCS Compressor Train and Venting System

A number of small pipes have been modeled inside the station to simulate the piping inside the station. The volumes of these pipes are important for the simulation of certain operations that involve pressurization or blow-down of the station.

**Compressor Models**

BSCS includes 3 compression trains, each with a two-stage centrifugal compressor and turbine. Since the model did not include a model for two-stage compressors, each compressor was simulated as two centrifugal compressors in series with

the corresponding coolers at the discharge side.

In order to simulate both units rotating simultaneously on the same axis, a simple but effective control scheme was implemented: the main station controller acts on the first stage unit indicating whether to increase speed, decrease speed or maintain the speed. The first-stage unit then calculates the proper speed to follow the main station controller commands. This first-stage unit speed is then transferred to the second-stage unit as a speed set-point. In this way, the second unit is constantly following the speed of the first unit, reproducing the effect of both units rotating at the same speed.

Each compressor model contains a recycle control system and a turbine model that allows the calculation of power and fuel consumption.

**Compressor Control System**

The station master control model includes a multi-variable control (flow, discharge pressure and suction pressure) and a load-sharing algorithm.

The multi-variable controller selects the process variable that is closest to the associated set-point. At the same time the controller is looking to balance the load between running units by maintaining the same distance from the operating point to the surge line.

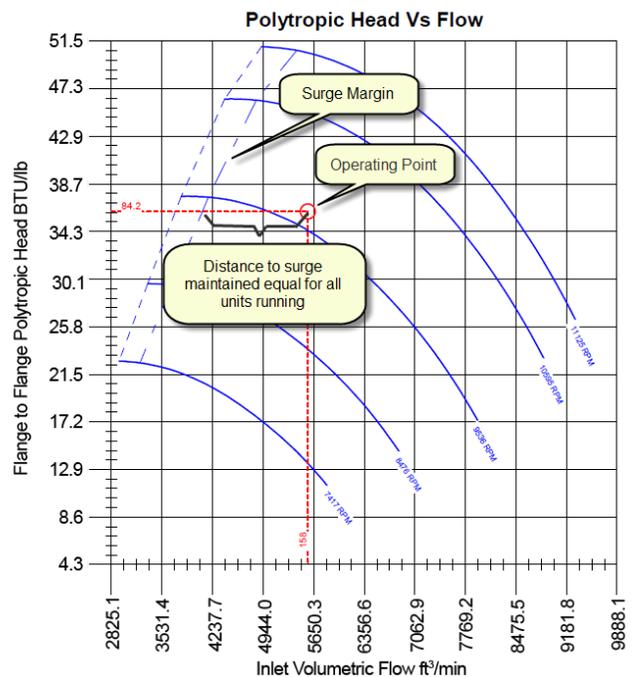


Figure 23 – Load Sharing Philosophy

### ***The OPRT Model***

The OPRT model comprises the following elements:

- Inlet valves
- Filters
- Gas Heating System
- Regulator Train
- Outlet Valves
- Enagas Delivery
- Venting delivery and associated valves

As in BSCS, small pipes have been configured to model the volumes within the station which are important for pressurization, purge and blow-down operations.

### ***The Pressure Regulation Control Loop***

A complex control loop has been implemented at OPRT in order to ensure Spanish grid entry conditions are achieved for under steady state and transient operating conditions, i.e. gas delivery pressure does not exceed 80 barg and gas delivery temperature does not drop below 0<sup>o</sup> C. The loop includes flow, pressure and temperature controllers plus a flow ramp generator to cater for the different operating modes, in particular the heating demand during depacking from the extreme high pipeline settle out pressure of 180 barg as determined by dynamic hydraulic analysis.

One of the abnormal conditions is when the pipeline is shutdown and the pressure at the OPRT station can reach 180 barg as determined by the dynamic hydraulic analysis studies. To restart pipeline a “depacking” operation must be performed which requires heating the gas to avoid extreme cold temperatures due to the Joule-Thomson process created when regulating from such high pressures.

A complex control loop has been implemented to ensure none of the critical variables exceed the permissible limits: maximum delivery pressure, maximum flow through the heaters and minimum delivery temperature.

This implementation has proven to be useful to test the design of the control loops and also to tune the PID controllers.

### **Trainer simulator model**

The Trainer Simulator is based on the same model implementation as the Operation Simulator model described in the previous section. However, some additional features were added to suit the MEDGAZ requirements of using this model to train the control room operators under a realistic environment which is as close as possible to the real DCS consoles.

The Trainer Simulator model includes automatic operation sequences and a set of DCS-like screens that mimic the operator’s console with similar schematics, buttons, dialogs, etc.

In order to systematically evaluate the operator’s performance, the trainer simulator includes a scoring system that allows the instructor to define goals and limits. If the operator reaches the goals, he or she gets positive points. If limits are violated, he or she gets negative points. At the end of the session all goals and limits are tallied to calculate the final score of the session.

### **Pipeline Commissioning**

Some simulations were performed with the offline model to predict the initial gas sweeping, gas to estimate the times for filling and pressurisation operations.

The analysis demonstrated a time of 16 hours to completely sweep the total volume of nitrogen from the pipeline system and a 1 day initial pressurisation period.

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## ACRONYMS / ABBREVIATIONS

BCM	: Billion Cubic Meters
BSCS	: Beni Saf Compressor Station
CCR	: Central Control Room
DCS	: Distributed Control System
DnV	: Det Norske Veritas
EOS	: Equation of State
FEED	: Front End Engineering Design
GERG	: Groupe Européen de Recherches Gazières
HCDP	: Hydrocarbon Dew Point
HP	: High Pressure
KP	: Kilometre Point
LP	: Low Pressure
MCM	: Million Cubic Meters
OPRT	: Offshore Pipeline Receiving Terminal
PLDS	: Pipeline Leak Detection System
PR EOS	: Peng Robinson Equation Of State
SALD	: PLDS statistical analysis process
SCADA	: Supervisory Control And Data Acquisition
SPRT	: Sequential Probability Test Ratio
TACS	: Temporary Air Compression Spread
UF	: Unexpected Flows
UP	: Unexpected Pressures
WC	: Water Content
WDP	: Water Dew Point

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