Basis of Design Final Report
(Phase I Final Report)

11121.5402.01

Riser Lifecycle Monitoring System for Integrity Management

Contract 11121-5402-01

February 18, 2015
Judith Guzzo, Principle Investigator, and Team:
Uttara Dani, Lynn DeRose, Brandon Good, Jeff Lemonds, Shaopeng Liu,
Mahadevan Balasubramaniam, Glen Koste, John Carbone, Niloy Choudhury,
Michael Dell’Anno, Renato Guida, Richard Zinser
M. Volk (consultant)

GE Global Research
One Research Circle
Niskayuna, NY 12309
www.geglobalresearch.com

Acknowledgement Statement
This material is based upon work supported by the Department of Energy, and RPSEA, under RPSEA Subcontract 11121-5402-01 under DOE Prime Contract DE-AC-07NT42677.
# Table of Contents

Table of Contents ..........................................................................................................................................................3
Table of Figures .............................................................................................................................................................5
Table of Tables ...............................................................................................................................................................6
List of Acronyms............................................................................................................................................................7
Executive Summary.....................................................................................................................................................8

Task 5- Overall RLMS System Design Using TRL 5 & 6 Subsystems .................................................................9
Subtask 5.1 – Voice of the Customer .................................................................................................................................9
    Summary of Approach ................................................................................................................................................9
    Preliminary QFD Results & Proposed Preliminary Solution Design .........................................................10

Subtask 5.2 – Preliminary System Design & Risk Analysis for Key Subsystems ...........................................13
    Summary of System Design Requirements based on VOC ........................................................................13
    Summary of Failure Modes and Effects Analysis .....................................................................................15

Subtask 5.2.1 RFID Subsystem for Asset Identification for RLMS .................................................................17
    Initial Design Criteria ........................................................................................................................................17
    Technical Approach ........................................................................................................................................18
    Results from Sub-System Laboratory Validation ...................................................................................19

Subtask 5.2.2 Subsea Sensing & Acoustic Telemetry Subsystem for RLMS ................................................23
    Initial Design Criteria for Subsea Platform in RLMS System ...............................................................23
    Technical Approach ........................................................................................................................................23

Subtask 5.3 — Design & Conduct Subsystem Laboratory Validation ........................................................35
    Summary of Technical Approach ..................................................................................................................35

Subtask 5.3.1 Subsystem Laboratory Testing and Validation .................................................................35
    Subsystem Functionality Test ..........................................................................................................................35
    Test Results: ADC Range ..................................................................................................................................37
    Vibration Calibration Test Results .................................................................................................................38
    Lab Scale Vibration & Structural Testing .......................................................................................................38
    Test Results ......................................................................................................................................................41
    Conclusions ......................................................................................................................................................43

Subtask 5.2.3 Vibration & Fatigue Analysis Methodology for RLMS .............................................................43
    Motivation ......................................................................................................................................................43
    Initial Design Criteria ....................................................................................................................................44
    Technical Approach ........................................................................................................................................45
Results: Damage Rate Calculations & Verification Methodology .................................................. 46
Subtask 5.2.4 Software Management Subsystem for RLMS ....................................................... 47
  Initial Design Criteria .............................................................................................................. 47
  Technical Approach ............................................................................................................... 48
  Results ................................................................................................................................. 48
Task 6 – Alternative Technology Development for RLMS Communication Subsystem .......... 50
  Summary .......................................................................................................................... 50
  Motivation ...................................................................................................................... 51
  Fiber Optic Acoustic Telemetry Overview ......................................................................... 52
  Feasibility Testing .......................................................................................................... 53
  Lab Test Results Summary ............................................................................................ 53
  Comparison and Conclusions ......................................................................................... 55
Cost Benefit Analysis for RLMS ............................................................................................ 56
  Approach ....................................................................................................................... 56
  Preliminary Results ....................................................................................................... 58
Final Phase II Recommendations ......................................................................................... 64
Table of Figures

Figure 1. Translation of Customer Needs into Initial System Design Requirements for Riser Monitoring System .................................................................................................................................................... 12
Figure 2. Pareto of Prioritized System Requirements for Riser Monitoring System .......................... 12
Figure 3. System Design for RLMS based on VOC ........................................................................... 13
Figure 4. System Requirements for RLMS to Design Specifications for Subsea Sensing & Acoustic Platform ......................................................................................................................... 14
Figure 5. Pareto of Functional System Requirements for Subsea Sensor Platform .......................... 15
Figure 6. Output Summary from FMEA on RLMS ........................................................................... 16
Figure 7. Lab Picture of Handheld Read Distance for Trac-ID ............................................................ 19
Figure 8. RFID Tag Attachment Orientation ...................................................................................... 19
Figure 9. Schematic of RFID Lab Test Results for 915 MHz Solution ........................................... 20
Figure 10. Reading Position at the Top of 915 MHz Tag, E133 ............................................................ 21
Figure 11. 45° Reading Position at the Top of 915 MHz Tag, E133 .................................................... 21
Figure 12. 90° Reading Position at the Top of 915 MHz Tag, E133 .................................................. 22
Figure 13. Reading Position at the Side of Tag BDAE ....................................................................... 22
Figure 14. Subsea Platform System Architecture ............................................................................... 24
Figure 15. Block Diagram of Subsea Platform Sensor Data Acquisition Software .............................. 25
Figure 16. ITC 3013 Hemispherical transducer (dimensions in inches) ............................................. 26
Figure 17. Micro-Modem electronics assembly, 3x5x2.5 inches ....................................................... 27
Figure 18. Baffle assembly for a 10 kHz directional transducer (dimensions in inches) ................. 28
Figure 19. Power spectrum from drillship Stena Forth in Baffin Bay, Greenland .......................... 29
Figure 20. Spectrogram of Acoustic Navigation Signals from the Stena Forth ................................ 29
Figure 21. Power budget distribution under normal operating condition ....................................... 31
Figure 22. Model showing baffled transducer protruding from a ship hull ...................................... 33
Figure 23. Saddle support drawing for pressure housing attachment to riser joint .......................... 34
Figure 24. Attachment mechanism (a) with the saddle support and (b) close-up view .................. 34
Figure 25. Actual attachment mechanism of pressure housing to pipe section .............................. 34
Figure 26. System functionality test setup block diagram ............................................................... 36
Figure 27. Subsea Platform Laboratory Test Setup ............................................................................. 37
Figure 28. Voltage and ADC readings from lab testing .................................................................... 37
Figure 29. Test results from Test 2 .................................................................................................... 38
Figure 30. Test setup. (a) Accelerometer placed inside pressure housing for vibration testing; (b) test conceptual design .................................................................................................................. 39
Figure 31. Pendulum test setup. (a) Pressure housing only; (b) pressure housing strapped onto riser pipe sample; (c) close-up view of (a); (d) close-up view of (b) .................................................. 40
Figure 32. Reference accelerometer placements .................................................................................. 41
Figure 33. Time-domain signal comparison (reference accelerometer at top-center of the pipe location): (a) X-axis; (b) Y-axis; (c) Z-axis; (d) X-Y-Z vector length ......................................................... 42
Figure 34. Frequency-domain signal comparison (reference accelerometer at top-center of the pipe location): (a) X-axis; (b) Y-axis; (c) Z-axis; (d) X-Y-Z vector length ......................................................... 42
Figure 35. Fatigue Damage Analysis Workflow .................................................................................. 45
Figure 36. Calculation of Current Intensities in Data-Matching ....................................................... 46
Figure 37. Methodology to Verify Fatigue Damage Calculation ....................................................... 47
Figure 38. 3DFAS System Architecture ................................................................. 48
Figure 39. RLMS Software System Architecture .................................................. 49
Figure 40. Lower TRL Fiber Optic Acoustic Telemetry Approach ....................... 50
Figure 41. Baseline RLMS Acoustic Telemetry .................................................... 51
Figure 42. Fiber Optic Acoustic Telemetry ............................................................ 52
Figure 43. Test Schematic .................................................................................... 53
Figure 44. Top View Of Test Setup During Final Tests With Acoustic Absorbers .... 53
Figure 45. BPSK BER Plot With 1m Coiled Fiber; Acoustic TX 2cm From Fiber Coil ... 54
Figure 46. BPSK BER For Various Configuration Of The Optical Fiber Receiver ... 54
Figure 47. BPSK BER for Different Distances Between The Transmitter And Receiver 55
Figure 48. Stages in the development of a CBA model ....................................... 57
Figure 49. Onshore vs. offshore discoveries ....................................................... 58
Figure 50. The growth of deepwater production over the last 20 years .............. 59

Table of Tables

<table>
<thead>
<tr>
<th>Table</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Table 1</td>
<td>Summary of Riser Inspection Criteria Potentially Impacted by RLMS</td>
<td>10</td>
</tr>
<tr>
<td>Table 2</td>
<td>Summary of Initial Customer Expectations for Riser Monitoring System</td>
<td>11</td>
</tr>
<tr>
<td>Table 3</td>
<td>Summary of High and Medium-High Priority Risks for RLMS</td>
<td>16</td>
</tr>
<tr>
<td>Table 4</td>
<td>FMEA Results for System Installation &amp; Maintenance</td>
<td>17</td>
</tr>
<tr>
<td>Table 5</td>
<td>Summary of RFID Systems for Lab Testing</td>
<td>18</td>
</tr>
<tr>
<td>Table 6</td>
<td>RFID Lab Test Results for 915 MHz Solution</td>
<td>20</td>
</tr>
<tr>
<td>Table 7</td>
<td>Battery needs during various lengths of drilling campaigns</td>
<td>31</td>
</tr>
<tr>
<td>Table 8</td>
<td>Voltage and ADC readings</td>
<td>37</td>
</tr>
<tr>
<td>Table 9</td>
<td>Quantitative assessment of signal fidelity</td>
<td>43</td>
</tr>
<tr>
<td>Table 10</td>
<td>Compare Baseline Acoustic Telemetry &amp; Fiber Optic Telemetry Approaches</td>
<td>55</td>
</tr>
<tr>
<td>Table 11</td>
<td>Offshore rig fleet</td>
<td>Error! Bookmark not defined.</td>
</tr>
<tr>
<td>Table 12</td>
<td>Initial Benefits to be quantified in Phase II</td>
<td>63</td>
</tr>
<tr>
<td>Table 13</td>
<td>Costs to be quantified in Phase II</td>
<td>64</td>
</tr>
</tbody>
</table>
List of Acronyms

RLMS  Riser Lifecycle Management System
API  Application Programming Interface
ADC  Analog-to-Digital Converter device
BER  bit error rate
BPSK  binary phase shift keying
BNC  Bayonet Neill-Concelman
CTQ's  Critical-to-Quality
CBM  Condition Based Maintenance
CBA  Cost-benefit analysis
COTS  Commercial-off-the-Shelf
DOE  Design of Experiments
3DFAS  3D Fracture Analysis System
FMEA  Failure Modes Risk Analysis
GoM  Gulf of Mexico
ID  Identification
MVP  minimum viable product
OOK  on-off keying
OS  Operating System
QFD  Quality Function Deployment
rms  root mean square
SME  Subject Matter Experts
VOC  Voice of the Customer
TRL  Technology Readiness Level
WTP  Willingness to Pay
VIV  Vortex-Induced Vibration
Executive Summary

The objective of this two-phase project is to develop an integrated, reliable, and commercially viable solution for a real-time, telemetry-based marine Riser Lifecycle Management System (RLMS). The long term vision of the project is an unsupervised drilling riser that is auto adaptive to the environment so that real time problem identification and corrective action can be taken to enhance operations. The specific focus is on subsea drilling riser integrity, to provide end users with tools to increase operating window in high current environments for **Real-time asset visibility** and (2) Reduce inspection and maintenance costs, toward performance-based inspections (re: condition based maintenance) for **long term lifecycle management** of their operations.

RLMS is an integrated system of hardware and software tools comprised of sensors located on select riser joints, wireless subsea communication between the vessel and select instrumented risers, and software for data collection, processing, riser fatigue analysis, visualization and alerts for enhanced operational decision-making for contractors and operators. The initial focus is on drilling risers but this technology could translate to production risers.

Summarized herein are results from Phase I of the program, which focus on the RLMS technical solution design, development, and risk retirement and involved collaboration with a group of industry participants (GE, TOI, DNV, BG Group). Initial end-user requirements for an integrated structural riser monitoring system design were obtained using Voice of the Customer (VOC). This information was collected from drilling contractors, an offshore classification society, and riser offshore engineering manufacturer subject matter experts. Using Six Sigma methodology, this VOC was then translated into preliminary system user requirements for a RLMS System, and functional design specifications for select subsystems.

An initial framework for a cost-benefit analysis (CBA) is presented to evaluate all relevant costs and benefits of the RLMS solutions, with the goal to quantitatively assess whether oil and gas users, public and private enterprises, and government agencies would experience a net benefit from the proposed RLMS solution (the formal CBA will be done in Phase II).

For each RLMS subsystem, the initial design criteria based upon the VOC is first presented. This is followed by results of the failure modes risk analysis (FMEA), the technical approach and results from sub-system laboratory testing. The key RLMS subsystems (TRL 5-6) are Radio Frequency Identification (RFID) for automated asset identification, subsea sensing and acoustic telemetry for real time riser monitoring and data backhaul topside, vibration and fatigue analysis for fatigue damage estimation, and topside software and architecture for real-time advisory information for riser operations (Task 5). Operational considerations such as RLMS system installation and maintenance are considered as well.

A parallel path, lower TRL approach to the subsea acoustic communications was successfully demonstrated in Phase I using fiber optic acoustic telemetry (Task 6).
team achieved technology readiness progression from TRL 0 to TRL 2 (idea conception to proof of concept). The fiber optic acoustic telemetry design has the potential to reduce several of the risks of the baseline subsea telemetry design.

Lastly, formal recommendations for Phase II efforts are proposed, including field trial of a RLMS minimal viable product that addresses critical customer expectations and product risk retirement, final RLMS system design specifications, Cost Benefit Analysis and proposed commercialization path.

**Task 5- Overall RLMS System Design Using TRL 5 & 6 Subsystems**

**Subtask 5.1 – Voice of the Customer**

**Summary of Approach**

For the preliminary Riser Lifecycle Monitoring System (RLMS) design, the team identified key stakeholders for Voice of the Customer (VOC) input into a structural riser monitoring system for deepwater marine drilling. Initial VOC was obtained from drilling contractors, an offshore classification society, and riser offshore engineering manufacturer SME’s.

Anticipated benefits of this system include:

1. **Optimize Inspection and Maintenance costs through Performance-based Inspection** – Track the accumulated fatigue damage on a per-joint basis, to aid in joint rotation and optimize inspection schedule & estimate remaining useful life
2. **Increase operating window in high current environments** - enhanced visibility during operations to identify highly fatigued joints from high current events
3. **Easy to retrofit on existing installations** without impacting riser deployment
4. **Action-oriented and easy to understand software User Interface**

Innovation and key features of this system include:

1. **Intelligent Decisioning System for Continuous Calculation of Fatigue Damage and Key Performance Indicators** - to identify highly fatigued riser joints during operation and optimize riser configuration post extreme events.
   - Display real-time frequency and time measurements
   - Display fatigue damage rate and cumulative damage estimates
2. **Economical sensor node placement** – to reduce impact on riser running operations and address criteria in Cost-Benefit Analysis.
3. **Modular and open subsea platform approach** - for ease of installation, near real time data backhaul with acoustic telemetry and open sensor Input and Output for commercial-off-the-shelf (COTS) sensor integration.

The above features and benefits enable realization of a **Fleet Wide Lifecycle Management System** as a tool to enhance safety, optimize drilling operations and future equipment design and provide information to the industry (OEM’s, contractors, operators, regulatory) for data-driven inspection and maintenance of riser equipment.
Using Six Sigma methodology\(^1\), the VOC was then translated into preliminary system user requirements for RLMS, and functional design specifications for the Subsea Sensor Platform using a Quality Function Deployment (QFD) tool. This tool is a quantitative mechanism to translate customer needs into prioritized technical requirements and facilitates communications of Critical to Quality customer needs and design (CTQs) between the key stakeholders and reduces risk of program delays. This iterative process will be used to refine and validate the Riser Lifecycle Monitoring System (RLMS) user requirements and product functional design specifications during the remainder of the program (Phase I and II) with additional stakeholders and SME’s.

Objectives of the VOC are to obtain an understanding of the following:
- Current challenges during drilling operations
- Expected value & benefits, including Economics/Return on Investment (ROI)
- Actions that can be taken based on a near real time monitoring system
- System installation & maintenance needs (e.g. operationalization requirements)
- Expectations for system requirements/functionality

From this VOC, an initial framework for a cost-benefit analysis (CBA) of the proposed preliminary RLMS solution design has been developed. Working in conjunction with the GE team and the WPG, this effort is led by Dr. Michael Volk (see “Cost-Benefit Analysis” section of this report). The final analysis will be performed in Phase II.

**Preliminary QFD Results & Proposed Preliminary Solution Design**

A prioritized summary of customer needs from the VOC includes:

1. Impact Inspection and Maintenance (I&M) schedules
   - Condition based maintenance to optimize usage and I&M schedules
   - Data and documentation from OEM to extend 5 year inspection window
   - Performance based Inspection: Accurately measure, record & evaluate riser utilization & inspection criteria (see Table 1)

Table 1. Summary of Riser Inspection Criteria Potentially Impacted by RLMS

<table>
<thead>
<tr>
<th>Riser Inspection Criteria</th>
<th>Basis for Selective Inspection</th>
<th>Riser Usage Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Visual inspection of equipment</td>
<td>Verify operations</td>
<td>Operations log for riser history (e.g. Riser Stack-ups with joint position and dates)</td>
</tr>
<tr>
<td>Review riser monitoring data and resultant stress on individual riser joints (e.g. telescopic joint) from extreme events, such as VIV, loop currents or extreme vessel motion during operations</td>
<td>Identify extreme events (e.g. VIV, loop currents or heave surge/sway of vessel during operations)</td>
<td>Operating Conditions (e.g. Tension, mud-weight, drill string tension, current and wave)</td>
</tr>
</tbody>
</table>
2. Enhance Operations & Reliability
   - Increase operational window and monitoring of safety margins
   - Facilitate planning of riser configuration
3. Easily retrofit and install on existing risers
   - Minimal impact on operations
4. Real time loads & tension near wellhead
   - Risk aversion strategy to maintain integrity of well head
5. Cost effective
   - Translate benefits to ROI
6. Rugged, reliable & accurate system
   - Environmental deployment (e.g. at 10,000 ft), handling & storage conditions
7. Intuitive User Interface (UI) with actionable information
   - Intuitive software tool with real time critical information to operator

These prioritized customer expectations are summarized below in Table 2, and are used to construct the first House of Quality (House 1) which translates Customer Needs into RLMS System Requirements (Figure 2).

Table 2. Summary of Initial Customer Expectations for Riser Monitoring System

<table>
<thead>
<tr>
<th>Customer Expectations [Y’s/ WHAT’s]</th>
<th>Importance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enhance Operations &amp; Reliability</td>
<td>5</td>
</tr>
<tr>
<td>Impact I&amp;M schedules</td>
<td>5</td>
</tr>
<tr>
<td>Easily retrofit &amp; install on existing risers</td>
<td>5</td>
</tr>
<tr>
<td>Real time loads &amp; tension near wellhead</td>
<td>5</td>
</tr>
<tr>
<td>Cost effective</td>
<td>3</td>
</tr>
<tr>
<td>Rugged, reliable &amp; accurate system</td>
<td>5</td>
</tr>
<tr>
<td>Intuitive UI; Actionable information</td>
<td>3</td>
</tr>
</tbody>
</table>

5= high importance
3= medium importance
1= low importance
A Pareto diagram of prioritized system requirements for a RLMS System (Figure 2) highlights attributes key to a successful system design that will be accepted by the industry. This process will continue to be refined and validated by industry SME’s in Phase II.

![Figure 2. Pareto of Prioritized System Requirements for Riser Monitoring System](image)

Figure 1. Translation of Customer Needs into Initial System Design Requirements for Riser Monitoring System
Subtask 5.2 – Preliminary System Design & Risk Analysis for Key Subsystems

Summary of System Design Requirements based on VOC

Based on initial VOC and identification of initial System Design Requirements (Figure 1), the following enabling technical design elements for the RLMS solution are required:

1. **Radio-Frequency Identification (RFID)** to automate marine riser identification and enable topside riser analytics, riser pedigree & Condition Based Maintenance (CBM)
2. **Subsea Sensing and Communication** for marine riser monitoring and near real time tetherless data transmission, and to enable CBM. This approach relies on long range acoustic links from each sensor module to the drill ship.
3. **Vibration and Fatigue Analysis** for topside “surface” alerts during drilling operations and for estimated riser life prediction
4. **Topside Software** for data acquisition, RLMS analytics and intuitive user interface

Figure 3 summarizes these design elements, highlighting functionality of the Subsea Sensing and Acoustic Platform and the “underwater” and “surface” analytics. Detailed design elements, risk assessment and next steps in Phase I for each subsystem are described in subsequent sections of this report.

Figure 3. System Design for RLMS based on VOC

Note, a parallel path, lower TRL approach to the subsea acoustic communications was explored in Phase I of the program using fiber optic acoustic telemetry (Task 6). The fiber optic acoustic telemetry design has the potential to reduce several of the risks of the baseline subsea telemetry design, and is discussed in the “Task 6 – Alternative Technology Development for RLMS Communication Subsystem” section of this report.
The QFD process was used to translate output from House 1 (Figure 1) into Subsystem Product Design specifications. By example, this is shown for the Subsea Sensing and Acoustic Platform (Figure 4).

### House 2

#### Product Functionality

<table>
<thead>
<tr>
<th>System CTQs (Xs or HOWs)</th>
<th>Importance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wireless/acoustic communication from subsea to surface</td>
<td>H</td>
</tr>
<tr>
<td>Battery powered</td>
<td>M</td>
</tr>
<tr>
<td>Report extreme events, high tension stress occurrences along the riser</td>
<td>L</td>
</tr>
<tr>
<td>Measure acceleration and angle at selected locations on the riser</td>
<td>M</td>
</tr>
<tr>
<td>Monitor critical loads at critical locations, e.g., wellhead, stick joint, flex joint, etc.</td>
<td>M</td>
</tr>
<tr>
<td>Rugged system packaging that is resistant to tough handling: &quot;roughneck&quot; and withstand n.</td>
<td>L</td>
</tr>
<tr>
<td>Low overall/equivalent system supply current</td>
<td>M</td>
</tr>
<tr>
<td>Simple attachment mechanism, e.g., magnetic installation or ROV deployable</td>
<td>H</td>
</tr>
<tr>
<td>Interface to external existing sensors on the riser</td>
<td>M</td>
</tr>
<tr>
<td>Platform generic HW/SW design, not customized, suitable for various riser types</td>
<td>H</td>
</tr>
<tr>
<td>SW platform that allows customized SW development</td>
<td>H</td>
</tr>
<tr>
<td>Energy harvesting</td>
<td>L</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>180</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Importance</th>
<th>M</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>M</th>
<th>L</th>
<th>110</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>M</td>
<td>L</td>
<td>195</td>
</tr>
<tr>
<td>Energy</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>M</td>
<td>L</td>
<td>245</td>
</tr>
<tr>
<td>Power</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>H</td>
<td>M</td>
<td>L</td>
<td>260</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>135</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Importance</th>
<th>M</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>M</th>
<th>L</th>
<th>95</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sufficient system operation life</td>
<td>H</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Actionable info with varying information levels</td>
<td>H</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low cost ownership</td>
<td>H</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td><strong>54</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Importance</th>
<th>M</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>H</th>
<th>M</th>
<th>L</th>
<th>45</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rugged construction of system</td>
<td>L</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td><strong>27</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure 4. System Requirements for RLMS to Design Specifications for Subsea Sensing & Acoustic Platform
A Pareto diagram (Figure 5) of the prioritized Functional System Requirements for the Subsea Platform highlights functionality key to a successful RLMS system design that will be accepted by the industry. Again, this process will continue to be refined and validated by industry SME’s throughout the program.

Summary of Failure Modes and Effects Analysis

A Failure Modes and Effects Analysis (FMEA), or risk analysis, was performed by the team for the following six key categories: (1) RFID, (2) Subsea sensor package, (3) Subsea acoustic communication, (4) vibration and lifting analytics, (5) Topside data acquisition and software and (6) System installation and maintenance.

The team rated each risk by severity, probability and detectability, with the following definitions for each:

- **Sev** = **Severity** of consequences if failure mode activates
  - 1: minor performance loss
  - 2: results in partial system malfunction
  - 3: renders product unfit for service OR could cause injury OR dissatisfies customer

- **Prob** = **Probability** of occurrence of failure mode
  - 1: very low probability
  - 2: occasional occurrence
  - 3: very likely to occur

- **Detect** = **Detectability** of activation of failure mode
  - 1: defect is obvious or detection process can be automate
  - 2: detection requires manual inspection
  - 3: defect is not detectable OR difficult or expensive to detect

- **RPN** = Severity x Probability, with note of Detectability-rating
From the 66 risks identified (Figure 6), 3 emerged as high Probability and high Severity (red), and 14 risks emerged as medium or high Probability and medium or high Severity (orange). Risk mitigation plans were assigned to each potential failure mode.

<table>
<thead>
<tr>
<th>Probability</th>
<th>Severity</th>
<th>Sev</th>
<th>Prob</th>
<th>Detect</th>
<th>RPN</th>
</tr>
</thead>
<tbody>
<tr>
<td>H</td>
<td>L</td>
<td>4</td>
<td>6</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>M</td>
<td>M</td>
<td>6</td>
<td>10</td>
<td>8</td>
<td></td>
</tr>
<tr>
<td>L</td>
<td>L</td>
<td>6</td>
<td>7</td>
<td>16</td>
<td></td>
</tr>
</tbody>
</table>

Figure 6. Output Summary from FMEA on RLMS

Table 3 provides the details for the 17 High and Medium-High Priority Risks. These are the focus for Phase I and Phase II of the program. Detailed discussion for key subsystems is discussed in subsequent sections of this document.

**Table 3. Summary of High and Medium-High Priority Risks for RLMS**

<table>
<thead>
<tr>
<th>Risk / Failure Mode</th>
<th>Sev</th>
<th>Prob</th>
<th>Detect</th>
<th>RPN</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>HIGH PRIORTY (3 Risks)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>System Installation &amp; Maintenance</td>
<td>Batteries run out during drilling campaign</td>
<td>3</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Acoustic Communication</td>
<td>buoyancy module blocks acoustic link</td>
<td>3</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>Acoustic Communication</td>
<td>Transducer beam pattern not appropriate</td>
<td>3</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>Acoustic Communication</td>
<td>excessive acoustic noise from working enviroment</td>
<td>3</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td><strong>MED HIGH PRIORTY (14 risks)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vibration &amp; Lifing Analytics</td>
<td>Data screening not accurate</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Vibration &amp; Lifing Analytics</td>
<td>Ocean currents only measured to a certain depth</td>
<td>2</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Vibration &amp; Lifing Analytics</td>
<td>Unavailability of real time ocean current/velocity measurements</td>
<td>2</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>Vibration &amp; Lifing Analytics</td>
<td>Complex components (BOP, LMRP) not modeled or fidelity is too low</td>
<td>2</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>TopSide Data Acquisition System and Software</td>
<td>No data in Historian</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>TopSide Data Acquisition System and Software</td>
<td>Bad data in Historian</td>
<td>2</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>System Installation &amp; Maintenance</td>
<td>HW system leaking saltwater</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>System Installation &amp; Maintenance</td>
<td>broken cabling</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Acoustic Communication</td>
<td>Transducer beam pattern not appropriate</td>
<td>3</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>Acoustic Communication</td>
<td>No certification to perform field testing</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Subsea Sensor Package</td>
<td>not enough sensor sampling data for analytics</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Subsea Sensor Package</td>
<td>sensors installed to insensitive location</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Subsea Sensor Package</td>
<td>can't reliably detect events of interest by customer (e.g. real time tension near wellhead)</td>
<td>2</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>RFID</td>
<td>modification of riser for tag (e.g. drill holes)</td>
<td>2</td>
<td>3</td>
<td>1</td>
</tr>
</tbody>
</table>
Since System Installation & Maintenance is not one of the five technical areas discussed in this document, the FMEA is shown below (Table 4). The FMEA is an iterative process which will be updated and refined in Phase II by the WPG.

Table 4. FMEA Results for System Installation & Maintenance

<table>
<thead>
<tr>
<th>Risk / Failure Mode</th>
<th>Sev</th>
<th>Prob</th>
<th>Detect</th>
<th>Safety Issue?</th>
<th>RPN</th>
<th>Risk Mitigation Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Batteries run out during drilling campaign</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>9</td>
<td>Create procedure for power loss &amp; replacement.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Develop/Optimize the battery model</td>
</tr>
<tr>
<td>HW system leaking saltwater</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>6</td>
<td></td>
<td>Robust sensor node packaging design and testing</td>
</tr>
<tr>
<td>Broken cabling</td>
<td>3</td>
<td>2</td>
<td>2</td>
<td>6</td>
<td></td>
<td>SOP with customer &amp; HW certification</td>
</tr>
<tr>
<td>Sensor package interferes with riser deployment</td>
<td>5</td>
<td>1</td>
<td>1</td>
<td>5</td>
<td></td>
<td>Sensor packaging design with O&amp;G Chief engineer</td>
</tr>
<tr>
<td>Batteries run out after 1 drilling campaign</td>
<td>1</td>
<td>3</td>
<td>2</td>
<td>3</td>
<td></td>
<td>Create procedure to evaluate power state (e.g. visual, etc) &amp; process for device or battery replacement</td>
</tr>
<tr>
<td>Hardware disconnects</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>3</td>
<td></td>
<td>SOP for HW setup and training plan for HW I&amp;M</td>
</tr>
<tr>
<td>Don't meet regulatory requirements/certification for field trial</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>3</td>
<td></td>
<td>Review cert. requirements with customer &amp; DNV</td>
</tr>
<tr>
<td>Modem function unreliable or impaired without firmware updates</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
<td>Create procedure for firmware updates</td>
</tr>
<tr>
<td>Dead subsea modem</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td></td>
<td>SOP for predeployment testing of modems</td>
</tr>
</tbody>
</table>

Subtask 5.2.1 RFID Subsystem for Asset Identification for RLMS

RFID technology will be utilized to identify each riser section for the drill string and to enable topside riser alerts and analytics (condition-based maintenance). RFID is an enabler to automate processes such as riser string reading and configuration, and enable the analytics and riser pedigree/utilization. Complete hardware and software solutions are not readily available on the market today for this application (e.g. stationary readers for automated reading during string deployment). Some development work thus far has been done by riser or drill pipe manufacturers, and they are selling the technology as part of their commercial riser systems.

Since RFID technology is relatively mature and has lower technical risk compared to other RLMS sub-systems (e.g. vibration and fatigue analytics), the objective for this RLMS sub-system is to evaluate existing ruggedized RFID hardware for riser identification and incorporate the tag data into the overall RLMS being developed.

Initial Design Criteria

The following are initial design criteria for the RFID subsystem based on the customer CTQ's identified in Table 2:

1. RFID Reader will be handheld and dockable
2. RFID Reader battery life will last for an entire drilling campaign (3 - 6 months)
3. RFID Reader will be ruggedized and water resistant
4. RFID Tags will attach to the riser without requiring modifications to the riser
5. RFID Tags will withstand 5,200 PSI and 32-34°F
6. RFID Tags will be passive
7. RFID Tags will read from 2ft away
8. RFID Tag placement will not interfere with riser operations
9. Riser joints will be scanned manually during staging before proceeding to spider

Technical Approach

The RFID system will consist of a handheld reader and RFID tags attached to each riser section. The tags will be attached to each riser before the riser string assembly process is started. Each riser will be associated with the tag’s unique digital identification (ID) number and stored in the backend system. At the beginning of the riser string assembly process, the handheld will be used to start a new riser string “build list”. The rig worker will use the handheld to scan each riser section as it is being selected to add to the riser string. The handheld will add the scanned tag to the riser string build list. At the end of the riser assembly process, the handheld will have a complete build list of the riser sections and the order they are connected. The handheld will be docked and the riser string build list will be uploaded to the onsite workstation.

After an extensive analysis of RFID Commercial-off-the-Shelf (COTS) technology based on the above design criteria and the risk assessment, three RFID systems were down selected for purchase and lab testing (Table 5). Each system is from a different RFID frequency family (125 kHz, 13.56 MHz, 915 MHz) and will be tested and validated against the design criteria. Using a trade-off matrix for quantitative assessment, the highest performing system will be implemented in the final solution.

Table 5. Summary of RFID Systems for Lab Testing

<table>
<thead>
<tr>
<th>Frequency</th>
<th>Tag Vendor</th>
<th>Tag Type</th>
<th>Reader &amp; Hand Held (HH)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13.56 MHz</td>
<td>Info-Chip</td>
<td>Attachable Embeddable</td>
<td>Bluetooth Reader &amp; secondary HH</td>
</tr>
<tr>
<td>125 KHz</td>
<td>Trac-ID</td>
<td>Embeddable</td>
<td>M3 Handheld with LF Reader</td>
</tr>
<tr>
<td>915 MHz EPC</td>
<td>TROI</td>
<td>Attachable</td>
<td>Motorola Reader</td>
</tr>
</tbody>
</table>
Results from Sub-System Laboratory Validation

Based on the initial design criteria and FMEA, the 13.56MHz solution was eliminated because the read distance required physical contact with the tag and did not meet the 2 foot read range requirement. Next, the 125KHz solution was tested and also eliminated due to the insufficient read distance of 2 inches compared to the 2 foot requirement. Tag placement required modification to the riser to embed the tag in the riser pipe, which is not desirable for installation (see Figure 7).

![Figure 7. Lab Picture of Handheld Read Distance for Trac-ID](image)

Lastly, the 915 MHz tags were tested in the lab at GE Global Research. A summary of the testing methodology is as follows:

- A steel pipe section was obtained as a test bed to mimic a riser section (20 inch diameter, 2 ft length)
- Two 915 MHz RFID tags were attached to the pipe oriented perpendicular to each other (Figure 8). The tags were attached according to the manufacturer’s specified recommendation using a 2 part epoxy.

![Figure 8. RFID Tag Attachment Orientation](image)
• Tag ID: E133 was placed on the pipe to avoid the pipe curvature; Tag ID: BDAE was placed on the pipe to maximize the pipe curvature and test for antenna de-tuning.
• Readings were taken with the handheld reader at angles of 0°, 45° and 90° to the tag; at positions (1) from straight at the tag, or “Top” and (2) from the side of the tag.
• Readings were taken at 1 foot intervals until the tag could not be read and then the read distance was taken at 6” intervals.

Lab test results from the 915 MHz solution are summarized below in a schematic diagram (Figure 9) and in Table 6.

![Figure 9. Schematic of RFID Lab Test Results for 915 MHz Solution](image)

Table 6. RFID Lab Test Results for 915 MHz Solution

<table>
<thead>
<tr>
<th>Tag ID</th>
<th>Position</th>
<th>Angle (degrees)</th>
<th>Read Distance (Ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>E133</td>
<td>Top</td>
<td>0</td>
<td>3.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>45</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>90</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>Side</td>
<td>0</td>
<td>2.0</td>
</tr>
<tr>
<td>BDAE</td>
<td>Top</td>
<td>0</td>
<td>3.5</td>
</tr>
<tr>
<td></td>
<td></td>
<td>45</td>
<td>2.0</td>
</tr>
<tr>
<td></td>
<td></td>
<td>90</td>
<td>0.17</td>
</tr>
<tr>
<td></td>
<td>Side</td>
<td>0</td>
<td>2.0</td>
</tr>
</tbody>
</table>

Tag ID: E133, optimally placed on the riser pipe to avoid curvature, could be read up to 3 feet 6 inches when the handheld was in the optimal Top position to the tag (Figure 10).
At a 45° angle to the tag antenna, there is some loss of signal strength and the tag could only be read up to 2 feet away from the pipe (See Figure 11).

At 90° to the tag, worst case antenna orientation, the tag was read but only 6 inches away (see Figure 12).
From the side, the tag could be read up to 2 feet away.

Tag ID: BDAE, placed on the pipe to maximize curvature, performed similarly from the optimal top position except when read from the side. As expected, the antenna was detuned by the pipe curvature and could only be read from a distance of 2 inches (Figure 13).
Subtask 5.2.2 Subsea Sensing & Acoustic Telemetry Subsystem for RLMS

Initial Design Criteria for Subsea Platform in RLMS System

The primary customer expectations (Table 2) and the system design requirements (Figure 3) drive the system CTQs and define the initial design criteria for the Subsea Platform:

1. **Real-time or near real-time condition monitoring and alerts**
2. A **Modular Platform**, integrating Commercial Off-The-Shelf (COTS) motion sensors (accelerometer + gyro), interfaces for additional sensor data acquisition, processing capability for customized edge computation and analytics, wireless communication, storage for data backup when wireless not present, battery, & marinized housing
3. "**Plug-and-go** and **battery powered**, eliminating the requirement of auxiliary cabling, and minimally impacting existing operations
4. **Open Operating System (OS) environment** on the processor, allowing customized software application development for interfacing with additional sensors, performing signal processing, and edge analytics.

These features, in addition to an integrated RLMS, differentiate the proposed Subsea Platform from existing products.

Note that the detailed specifications will depend on the overall design of the entire RLMS system, considering both the Subsea Platform and the vibration and fatigue analysis, with the goal of optimizing the system battery life and analysis performance.

**Technical Approach**

**Overview**

This section focuses on the design details of the subsea sensing and acoustic subsystem, including the system architecture and design (hardware and software), acoustic communication, power consumption analysis, installation and attachment mechanism.

**System Design - Hardware**

The Subsea Platform uses a modular design approach, aiming to provide a “plug-and-go” system for easy installation and minimal impact on existing operations. The platform consists of the following seven components, as seen in the system hardware architecture (Figure 14), where COTS components are leveraged as much as possible:

- **Acoustic Modem** and **Transducer**. The subsea platform will integrate an acoustic modem with transducer attached to enable underwater wireless communication to the topside of a drilling vessel. The subsea platform leverages the acoustics for data transmission from the subsea platform to the topside data center, as well as for platform management and control when needed. Micro-Modem 2, a small-footprint, low-power acoustic modem developed by the Acoustic Communications Group at the Woods Hole Oceanographic Institution (WHOI), is being evaluated for
integration in the Subsea Platform. A COTS acoustic transducer was selected from those on the market by considering the specific beam pattern design in the actual ocean environment.

- **Battery.** A rechargeable Li-ion battery will be used to power the subsea platform and eliminate the use of auxiliary cabling. A detailed and scalable battery model was developed to estimate and optimize the Subsea Platform battery life. Various aspects of the RLMS system specifications have been factored into the model, such as the sensor data sampling interval, sampling duration, and sampling rate, as well as the selection of the acoustic transmission power level, transmission rate, etc. Depending on the choice of the above system specifications and the intended battery life, the battery model will output the estimated battery size/capacity, and vice versa.

- **Sensors and Sensor Interfaces.** Each subsea platform will consist of two motion sensors: one triaxial accelerometer and one triaxial gyroscope (angular rate sensor). Together with the vibration and fatigue algorithms (Subtask 5.2.3), it is expected that loads and stresses at different sections of the risers and related fatigue levels will be calculated using the motion sensor data. Both the accelerometer and gyroscope are COTS components with high sensitivity for the low vibration conditions of drilling risers. The Subsea Platform will also have additional sensor interfaces such as serial/RS232 connections, I2C/SPI digital interfaces, analog-to-digital conversion I/O, etc., that are open to end users to connect existing field sensors to provide real-time visibility for topside control.

![Figure 14. Subsea Platform System Architecture](image)

- **Microprocessor.** A single board computer will serve as the “edge intelligence” of the subsea platform, and will control the acquisition of the sensor data, perform signal
processing and/or algorithms on the collected data as needed, manage the acoustic communication protocol, provide data backup/storage, and power management. The open Operating System (OS) on the microprocessor will provide spaces for users to develop customized software applications, e.g., user specific analysis on the sensor data. The microprocessor will also host flash memory allowing secondary data backup and storage in case of situations when the acoustic link is down.

**System Design – Software**

The software development in the Phase I approach was primarily focused on sensor data acquisition using the microprocessor in WHOI’s acoustic system. The microprocessor is the commercial-off-the-shelf (COTS) Gumstix Overo FE COM, which uses Texas Instruments OMAP3530 processor with ARM Cortex-A8 architecture, and runs Linux operating system (OS)\(^1\). Our software is developed on the Linux OS running on the Gumstix hardware system.

Python is used as the programming language for software development. Python is a widely used open-source programming language, which provides Application Programming Interface (API) functions to interact with OS file system and hardware. The Python APIs were leveraged for accelerometer data collection based on the specifications of our hardware system. Specifically, Python API packages NumPy and SciPy\(^2\), were used for basic data analytics in the Subsea Platform software.

For sensor data collection, the software has the following functionalities: 1) read analog signal from a specified analog-to-digital converter (ADC) port; 2) collect signal samples together with recording time stamps; 3) accept user input for various sampling frequency, ADC port number and output file name; 4) enable user control to stop data acquisition and record data at any time. The software flow chart is illustrated as a block diagram in Figure 15.

![Block Diagram of Subsea Platform Sensor Data Acquisition Software](image)

**Figure 15. Block Diagram of Subsea Platform Sensor Data Acquisition Software**

---

2. [www.scipy.org](http://www.scipy.org)
**Acoustic Communication**

Acoustics provides a promising means for transmitting moderate amounts of data from remote undersea sensors to the surface for many applications. While cabled connections should always be considered if possible, the expense of either running or tapping into existing cables can be prohibitive. Fortunately, recent advances in acoustic communications have made small sensor networks feasible and cost-effective for many applications.

**Acoustic Propagation**

Acoustic waves travel efficiently through sea water with attenuation proportional to the square of the range, and absorption that depends on the carrier frequency. Selection of a carrier frequency is a trade-off between losses that increase with frequency, available bandwidth that also scales with frequency (higher is better), and transducer size (lower frequencies correspond to larger transducers). For distances in seawater of 1 to 5 km carrier frequencies of 10 to 30 kHz are typically used, employing bandwidths of 1 to 5 kHz. The transducers capable of generating signals at these frequencies are typically 5-7 inches in diameter, and 5 to 12 inches tall, depending on the configuration and design (e.g. omni, hemispherical or conical beam). An example of a 10 kHz hemispherical transducer is shown in Figure 16. In this example, the transducer is manufactured by ITC, and the 0.75 inch tall backing plate is made by Woods Hole Oceanographic Institution (WHOI) and provides a means for a right-angle connection.

![Figure 16. ITC 3013 Hemispherical transducer (dimensions in inches)](image)

**Acoustic Modem Hardware**

A complete acoustic modem system includes a transducer as described above, plus signal processor and power amplifier. Typically the transducer is used both as a transmitter and a receiver, though not simultaneously. Thus underwater acoustic communications is single-duplex, in contrast to terrestrial wired or radio communications. An example of acoustic modem hardware designed and manufactured by WHOI is shown in Figure 17. The electronics are compact, about 3 by 5 inches, though the size of the amplifier portion of the system (the bottom circuit board) varies with frequency. The example shown here is used at 25 kHz and 10 kHz. Higher output power is possible with larger electronics. This hardware is capable of transmitting and receiving signals at different carrier frequencies, bandwidths and data rates.
Typical bandwidths of 1-5 kHz allow (typically) 1-5 kbps maximum burst rate, i.e. the throughput is equal to the bandwidth, though in practice this is not always achieved because of noise levels, range or frequency-dependent fading due to multi-path interference. To improve reliability under adverse conditions, the modem can be configured for a variety of data rates, ranging from approximately equal to the bandwidth, to approximately one-tenth of the bandwidth. Under adverse conditions (high noise, long-range, extensive multi-path), the lower data rates are often required.

**Multipath and Background Noise**

The vertical acoustic channel offers the most benign propagation environment possible, and acoustic modems generally achieve their best data rates when operating vertically. High rates are enabled by direct-path propagation without boundary interaction or multiple paths from source to receiver that arrive at different times, thus creating time spread. While adaptive equalization helps to mitigate the effects of different arrivals, propagation over a single path is preferred. The vertical link single-path propagation is enabled by use of highly directional transducers with narrow flashlight beams.

The use of narrow beam transducers also helps to reject noise, in particular noise from behind the transducer. An example of a commercial transducer with a custom WHOI baffle is shown in Figure 18. The baffle material is a sandwich of lead composite disks that attenuates approximately 10 dB per inch at 20 kHz. The use of this baffle reduces the amount of noise from sources outside the main beam to negligible levels. Proper baffling and mounting can have a huge effect on performance, and should be employed whenever possible.

The baffle will have the most improvement on the receiver mounted just below the drill ship. The noise from the drilling machinery on the ship will be primarily from above and from the side, and the narrow beam from the transducer will be able to reject much of that noise. The noise level can be so high that it will still have an impact, but it will be reduced to the extent that it is out of the beam.
Acoustic Environment around a Drill Ship

The acoustic environment in the vicinity of a drill ship is known to be highly variable and during operations the noise level can be significant. However, the fact that multiple types of acoustic positioning and navigation systems are used extensively on drill ship reliably and accurate demonstrate that it is possible to employ acoustic communications in the vicinity. However, relevant question such as the following need to be addressed in Phase II of the program in order to achieve a reliable communication: (1) what data rates and how reliable are communications under a drill ship, and (2) how much power is required to reach a given (ideally high) level of reliability?

An example of the acoustic noise in the vicinity of a drillship is shown in Figure 18 as taken from (Kyhn, et al., 2011). The measurements are made using a hydrophone suspended 90 m deep below a small boat that is offset from the drillship at different ranges. While the measured noise levels are not guaranteed to be the same on all drill ships, they may be representative of the typical acoustic environment around such a vessel. Key points surmised from Figure 18 include:

- The predominant body of noise is at low frequencies and increases over ambient of 20-30 dB are typical from 100 Hz to 3000 Hz
- The noise tapers toward ambient at approximately 20 kHz
- Acoustic navigation signals are present from 20 to 30 kHz
- The characteristics of the noise are different between drilling (left figure) and maintenance (right figure) activities, but the noise increases over ambient are still approximately 20 dB for both activities with higher levels at certain frequencies

A basic conclusion is that the noise from this particular drill ship tapers off just below the band where the acoustic navigation starts. This is very promising for the proposed communications system and demonstrates that operators of the navigation systems have

---

looked at this issue as well, and have moved to frequencies that are as high as feasible to avoid the low frequency noise.

Figure 19. Power spectrum from drillship *Stena Forth* in Baffin Bay, Greenland (Kyhn et al, 2011)

An example of acoustic signals from a navigation system is shown below in Figure 20. The interrogation signals from the ship are the first two signals at 21.5 and 23 kHz, which appear to be very scattered and spread in time. This is most likely because the direct path is a low-amplitude side-lobe of the transmission, and the rest of the signal is actually scattered off the bottom. The other signals, which are the responses from the bottom transponders, show higher amplitude initial arrivals, but are also followed by extensive multipath that is most likely reflected from the surface and the bottom before being received by the recording vessel 800 meters away.

Figure 20. Spectrogram of Acoustic Navigation Signals from the *Stena Forth*

As mentioned above, the fact that acoustic navigation and positioning systems operate effectively in this very noisy environment bodes well for acoustic communications. However, dynamic positioning is done using very high amplitude pings, and each ‘ping’ is similar to transmission of a bit of information. The proposed system will need to be capable of hundreds of bits per second to be efficient, and will need to be more power efficient on a per ping basis. Furthermore, the acoustic navigation systems cannot be interfered with
because they are essential for positioning of the drilling vessel. Therefore the communications must be interleaved in frequency or in time.

There is potential for the RLMS acoustic communications to interfere with the dynamic positioning system in several different ways:

- Transmissions from the ship (interrogations) will be very close to the communications receiver and will be very high amplitude even if they are not in exactly the same frequency band. They will likely saturate the communications receiver for a brief period, potentially causing a few bit errors. However, depending on the duration of the interference this will be compensated for by the error-correction of the modem.
- Responses from the bottom transponders to the surface will be in the beam of the communications receiver. Thus they have the potential to interfere if the frequencies overlap or are close.

These risks will be mitigated in Phase II of the program.

**Power Consumption**

One potential high risk and failure mode (with RPN > 6) from the system installation and maintenance perspective is the battery capacity in the subsea platform to last a full drilling campaign. It is therefore critical to understand the power consumption of the subsea platform and model its power budget under various operating conditions.

The total power budget of the platform consists of transmission (Tx), sleep, sampling, receiving (Rx) and computation power budgets. Details of each power budget are as follows:

- **Tx Power Budget** models the battery capacity needed per drilling campaign for acoustic data transmission from the subsea platform on the riser joint to the topside acoustic receiver. It is a factor of data size per transmission, transmission interval, transmission power consumption of the acoustic modem, and the power consumption of the processor (which interfaces with and commands the acoustic modem) and peripheral circuitry.
- **Sleep Power Budget** is the battery capacity needed by the platform being quiescent during the drilling campaign.
- **Sampling Power Budget** models the battery capacity needed for the processor to acquire sensor data through analog-to-digital conversion (ADC) module per drilling campaign, and it depends on the number of sensors, data acquisition interval (how often to sample) and duration (how long to sample per each interval), sampling frequency (how many to sample per each duration), power consumptions of the processor, ADC and peripheral circuitry. It is noted that the determination of the sampling frequency, acquisition interval and duration is also affected by the vibration and fatigue analysis methodology. The number of sensor data points may affect the accuracy of the vibration and fatigue analysis. Thus, determining the
power budget for sampling needs is critical to the fatigue analysis, and hence the accuracy which acceptable to the application and/or the industry standard.

- **Rx Power Budget** is the battery capacity needed for receiving data/command from the topside receiver, and it is a factor of the Rx duration, interval, power consumption of the acoustic modem during receiving mode, and power consumption of the processor and peripheral circuitry.

- **Computation Power Budget** models the battery capacity needed for the processor to perform certain computation tasks on the acquired sensor data, e.g., calculation of representative signal features from the data, frequency-domain transformation, etc., which are needed for the vibration and fatigue analysis methodology. The power budget then depends on the particular computation tasks (computation complexity), number of the data points needed by the computation, number of computation occurrences, and power consumption of the processor and peripheral circuitry during the computation.

Figure 21 shows the distribution of the power budget of each component under a normal operating condition. It is seen that the Tx and sampling power budgets take the majority of the total needed battery capacity. Table 7 shows the total battery needs for drilling campaigns over period of 3, 4 and 6 months, respectively.

![Figure 21. Power budget distribution under normal operating condition](image)

**Table 7. Battery needs during various lengths of drilling campaigns**

<table>
<thead>
<tr>
<th>Days in Operation</th>
<th>Total Energy Needed (Wh)</th>
<th>Number of Batteries</th>
<th>Total Battery Weight (kg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>90</td>
<td>872.58</td>
<td>9</td>
<td>1.9</td>
</tr>
<tr>
<td>120</td>
<td>1163.45</td>
<td>12</td>
<td>2.6</td>
</tr>
<tr>
<td>180</td>
<td>1745.17</td>
<td>18</td>
<td>3.9</td>
</tr>
</tbody>
</table>
**Installation & Attachment Mechanism**

**Subsea Platform**
The approach for the installation location and attachment mechanism of the subsea platform to the riser is as follows. Initially, it will be mounted in the area between the flange and the buoyancy module that encases the pipe. The use of band clamps removes the need to modify the pipe, and allows quick disconnect and removal of the units whether aboard ship or at the depot where the riser pipes are stored and maintained. The space for the subsea node is very limited, and it must fit into an area where the pipe sections are joined together. Furthermore, there are constraints on placement of any additional equipment into the area because it cannot interfere with the joining operation as the pipe sections are assembled and then lowered.

The position and beam width of the transducer is critical to ensuring that the signal from the sensors is received at the surface. The ship is a very small target at ranges of several thousand feet, so only a very narrow beam is required to illuminate the ship overhead, though there must be a direct line of sight from the transducer to the bottom of the drill ship. Thus, the critical aspect of the transducer placement is ensuring that there is a direct path to the surface. The transducer cannot be recessed under the buoyancy module, but must be outside of it so that the signal is not blocked. This risk will be mitigated through controlled testing with a mock-up in Phase II of the program to determine the exact position of the transducer relative to the foam.

**Surface/Topside System**
The topside system includes the acoustic modem and transducer, plus a control computer that handles the modem interface and data transfer to a back-end computer that provides advisory information to the drilling contractor. The acoustic modem is located in the hull of the vessel. Hence, a long cable may be necessary to connect the modem to the control room. This interface can be serial-over-Ethernet if the ship’s network extends to the space where the modem is mounted, or it can be serial using RS-422 (a specification for a long-distance bidirectional digital data link).

Placement of the topside modem is critical, and it is one of the more challenging aspects of integrating the system on to a drill ship. As mentioned previously, several acoustic systems have been successfully integrated onto drill ships, and thus the acoustic modem should be possible to integrate as well. The acoustic modem receiver on the drill ship should be located on a pipe below the hull. This is the same approach used for mounting acoustic navigation and positioning systems. An example of such with the transducer retracted is shown in Figure 22. This mounting method for the acoustic transducer is commonly used for both Kongsberg HiPaP® tracking arrays and for Sonardyne tracking heads.
The beam pattern of the topside transducer can be very narrow. Two approaches are commonly used to create a narrow beam. One is to use a large physical area, and the other is to crimp the beam via baffling as shown in Figure 18. A combination of the two is also possible. Pending a final selection of the carrier frequency for the communications system, both options will be considered, including a hybrid approach. While a beam pattern of only a few degrees is necessary to cover the area below the ship, it is impractical to fabricate a transducer that has a beam pattern narrower than approximately 30° and still have it fit in standard hull openings.

**Attachment Mechanism Design for Testing**

For lab testing, a simple strapping mechanism was designed to attach the housing of the RLMS Subsea Platform to a riser joint. A band and buckle system from HCL Fasteners Corp. was selected. Materials from this system are fabricated from a high strength composite polymer and have been utilized in various subsea clamping and strapping applications.

To ensure proper attachment and sensor signal quality of the RLMS Subsea Platform, a “saddle” support (see Figure 23) was designed as the interface between the subsea platform pressure housing and the riser joint. Figure 24 is the drawing of the attachment with the saddle support, and Figure 25 shows the actual attachment.

A finite element analysis was performed on the design of the saddle support to validate the structural integrity under loading conditions. Experiments in the laboratory have been performed to evaluate any potential effect (or no effect) of the mechanical structure of the proposed attachment mechanism on output signal fidelity of the accelerometer inside the pressure housing. Please refer to later sections of this report for details on the experiments and test results.
Figure 23. Saddle support drawing for pressure housing attachment to riser joint

(a)
(b)

Figure 24. Attachment mechanism (a) with the saddle support and (b) close-up view

Figure 25. Actual attachment mechanism of pressure housing to pipe section
Subtask 5.3 — Design & Conduct Subsystem Laboratory Validation

Summary of Technical Approach

In Phase I of the program, a series of laboratory performance and validation tests were performed on the RLMS subsea sensing subsystem, while tests for the acoustic telemetry subsystem in water will be performed in Phase II. This lab testing focused on evaluating the platform functionality, sensor data acquisition, sensor signal fidelity, and the installation and attachment mechanism.

Subtask 5.3.1 Subsystem Laboratory Testing and Validation

Subsystem Functionality Test

The primary objective of this test is to validate the functionality of the subsea sensing subsystem, including: (1) sensor data acquisition and (2) acoustic communication. Note the acoustic communication test is performed in air, and is mainly for testing the functionality of the acoustic modem and associated software control.

A laboratory test setup was first prepared for the subsystem functionality testing, as shown in the block diagram in Figure 26. To streamline lab testing, one “subsea” acoustic modem and one “surface” modem have been assembled in a benchtop modem box, between which BNC connectors are used to simulate a perfect “acoustic” channel. Real acoustic environments can be simulated by adding artificial noise into the BNC cable. A processor is connected to the “subsea” modem through serial connection. A digital accelerometer and gyroscope are connected to the processor via the I2C interface, and an analogy accelerometer is connected through the ADC port 3. A laptop containing the acoustic communication protocol is connected to the “surface” modem via serial port. The laptop also hosts the user interface for topside data collection and display. Figure 27 shows the actual lab test setup, where (a) shows the test setup connection, (b) and (c) show the inside components of the setup, and (d) shows the analog accelerometer connection to ADC port 3 via a BNC connector. The program Putty was used to log into the Linux system of the Gumstix processor. A Python program was developed, as described in previous section, to record the sensor data from the accelerometer. The sensor data was then transmitted to the “surface” modem through the simulated acoustic interface.
Figure 26. System functionality test setup block diagram
Test Results: ADC Range

The working range of the analog-to-digital converter (ADC) device is tested by using a power supply as the analog input signal and using Python code described earlier to record ADC output, i.e., the digital readings. The voltages and the ADC readings from Python code are listed in Table 8, and the corresponding data points showing a linear fit (Figure 28).

Table 8. Voltage and ADC readings

<table>
<thead>
<tr>
<th>Voltage</th>
<th>0.025</th>
<th>0.1</th>
<th>0.2</th>
<th>0.3</th>
<th>0.5</th>
<th>1.04</th>
<th>1.52</th>
<th>2.00</th>
<th>2.20</th>
<th>2.40</th>
<th>2.47</th>
<th>2.53</th>
</tr>
</thead>
<tbody>
<tr>
<td>ADC</td>
<td>36.6</td>
<td>106.1</td>
<td>215.8</td>
<td>307.8</td>
<td>505.6</td>
<td>1049.6</td>
<td>1528.6</td>
<td>2008.08</td>
<td>2213.7</td>
<td>2415.8</td>
<td>2489.5</td>
<td>2500</td>
</tr>
</tbody>
</table>

Figure 27. Subsea Platform Laboratory Test Setup

Figure 28. Voltage and ADC readings from lab testing
It is seen that the ADC readings are from 36 to 2500, which approximately correspond to voltage 0 to 2.5 V. For any voltage input greater than 2.5 V, the ADC output remains 2500. For very low voltage input, like 0.025 V, the ADC reading does not follow the same linear relationship as in range 0.5 V to 2.5 V, but this bias is acceptable considering that small voltage is probably outside the working range of our vibration sensors.

**Vibration Calibration Test Results**

The objective of this test was to validate the sensor data acquisition of the subsystem under a vibrating condition. In this test, the accelerometer was attached to a handheld mechanical shaker with the Z-axis of the accelerometer along the shaker vibrating direction. The handheld shaker generates an approximate 1-g peak acceleration output profile at a frequency of about 159.2 Hz. The Z-axis was connected to the ADC port 3 of the Gumstix, and acceleration data was recorded during the test. The shaker was stationary at the beginning of the test, and then turned on and off twice. Figure 29 shows the collected sensor data points. It is seen that the recorded data clearly captures the test sequence that the readings keep a constant level when the shaker was off and oscillate during two time periods: from sample index 345 to 474, and from index 689 to 1119. These two time periods correspond to the times when we the shaker was turned on. The cut-off effect was also observed clearly, since the acceleration exceeded the working range of the ADC module (0 to 2500).

![Figure 29. Test results from Test 2](image)

**Lab Scale Vibration & Structural Testing**

**Test Objective**
The main goal of the vibration tests is to (1) evaluate the fidelity of the accelerometer signal output under simulated vibrating environment of a drilling riser in the field, and (2) evaluate the installation and attachment mechanism of the subsea platform (pressurized housing with modem, sensors, microprocessor, and saddle and band/buckle system).
**Test Setup**

The accelerometer was placed inside the pressure housing of subsea sensing platform, which was in turn strapped onto a steel pipe of 20-inch diameter that simulates the drilling riser pipe, as shown in Figure 30 (a) and (b). The pressure housing and/or the riser pipe sample was connected to a crane through two thin rods forming a pendulum which would swing at a frequency around 0.5 Hz and less than 1 Hz. Such frequency is within the frequency range of the riser under vortex-induced vibrations (at normal circumstances).

Two separate pendulum tests were conducted (Figure 31). In the first pendulum test, the pressure housing (with the accelerometer inside) was attached to the crane alone. Three uniaxial accelerometers placed perpendicular to each other were then attached to the side of the pressure housing as references, as shown in Figure 314 (a) and (c). For the second pendulum test, the pressure housing was strapped onto the riser pipe sample, which was in turn connected to the crane. A reference triaxial accelerometer was attached to the riser pipe sample directly, as shown in Figure 31 (b) and (d). For the second test, the reference accelerometer was placed at four different locations, as shown in Figure 32 (top, bottom, left, and right of the pipe with respect to the pressure housing). These tests were repeated four times. To conduct the test, the pressure housing and/or the riser pipe sample were physically lifted at a very small angle and then allowed to swing freely. The signals of both the accelerometer inside the housing and the reference accelerometer were sampled using a data acquisition unit simultaneously.

![Figure 30. Test setup. (a) Accelerometer placed inside pressure housing for vibration testing; (b) test conceptual design](image)

39
Figure 31. Pendulum test setup. (a) Pressure housing only; (b) pressure housing strapped onto riser pipe sample; (c) close-up view of (a); (d) close-up view of (b)
Figure 32. Reference accelerometer placements

Test Results

The vector length of the X, Y, and Z axis of both accelerometers were calculated, and compared against each other in both time and frequency domains. Statistical measures such as cross correlation coefficient, root mean square error (RMSE) were computed for assessing the signal fidelity.

Figures 33 and 34 show an example of the signal comparisons in time- and frequency-domains between the reference and the accelerometer inside the pressure housing for X, Y, Z, and the vector length, respectively. It is seen that the signals generally match relatively well between each other in both the time- and frequency-domain. The amplitude differences observed in the figures were naturally due to the mounting distances between the reference accelerometer and the one inside the pressure housing. In the example shown in the figures, the reference accelerometer was placed at the top center of the pipe (refer to Figure 32 for accelerometer locations).
Figure 33. Time-domain signal comparison (reference accelerometer at top-center of the pipe location): (a) X-axis; (b) Y-axis; (c) Z-axis; (d) X-Y-Z vector length

Figure 34. Frequency-domain signal comparison (reference accelerometer at top-center of the pipe location): (a) X-axis; (b) Y-axis; (c) Z-axis; (d) X-Y-Z vector length
Conclusions

Table 9 summarizes the quantitative assessment of the signal fidelity of the accelerometer placed inside the pressure housing against the reference. It is seen that these statistical measures confirm the matching of the two signals. Based on these results, it can be concluded that the test results have demonstrated the fidelity of the accelerometer signal outputs for adequately and correctly measuring drilling riser motions.

Table 9. Quantitative assessment of signal fidelity

<table>
<thead>
<tr>
<th>Reference Accelerometer Location</th>
<th>Time Domain</th>
<th>Frequency Domain</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Correlation</td>
<td>RMSE (g)</td>
</tr>
<tr>
<td>Top center</td>
<td>0.9922</td>
<td>0.0020</td>
</tr>
<tr>
<td>Bottom center</td>
<td>0.9692</td>
<td>0.0026</td>
</tr>
<tr>
<td>Left</td>
<td>0.9808</td>
<td>0.0018</td>
</tr>
<tr>
<td>Right</td>
<td>0.9884</td>
<td>0.0028</td>
</tr>
</tbody>
</table>

Subtask 5.2.3 Vibration & Fatigue Analysis Methodology for RLMS

The objective of this subtask is to develop the framework for a generic riser life-cycle reliability model for marine drilling risers that predict riser life based on fatigue. The Riser Lifecycle Monitoring System (RLMS) will include state-of-the-art methodology for predicting fatigue damage based on data from real-time sensor measurements. Fatigue damage rate estimates will be updated frequently in order to adequately capture events that produce above-average fatigue damage.

The prediction algorithms discussed herein incorporate dynamic vibration models and a limited number of sensor nodes to estimate the fatigue damage. Using advanced data analytics, a state-of-the-art approach is employed to predict real-time damage rates in marine riser strings. The vibratory stresses and the associated damage rates in risers resulting from a current profile extending from the ocean surface to the ocean floor is estimated using the commercial code Shear7.  

Motivation

The prediction and monitoring of fatigue damage that arises from vortex-induced vibrations (VIV) of drilling risers is complex and a challenging problem in harsh deepwater drilling environments. Although multiple sources of fatigue damage exist, VIV and waves are responsible for the majority of the fatigue damage observed in deepwater drilling risers. Severe and prolonged undersea currents can result in VIV in which the drilling riser vibrates in a direction perpendicular to the dominant current direction. Unlike shallow environments, deepwater drilling requires high top tension to maintain lateral stability of the riser string. This high tension interacts with the stresses produced by strong currents

---

3 [http://web.mit.edu/shear7/shear7.html](http://web.mit.edu/shear7/shear7.html)
to potentially result in the BOP stack/conductor system vibrating near or at one of its resonant frequencies. In addition, high top-tensions frequently need to be applied to the riser, yet precise quantification of the stresses produced by the cable tension is difficult. Load-sharing between the main pipe and auxiliary lines can cause mismatches in tension that magnify bending stresses at joints. High hoop stresses exist due to mud weight in the riser which can vary over time -- this affects the hydrodynamic response which is predicted by empirical models that have precision issues. This, in turn, can result in increased rates of fatigue damage that increase the susceptibility of the overall system to fatigue failure. Other conditions also contribute to stress and fatigue, including hang-off deflection, vessel drift, and lateral displacements during riser installation; all of these should be considered in a comprehensive life prediction model.

The ability to estimate fatigue damage rates from real-time sensor measurements and/or its derivatives, e.g. root mean square (rms) acceleration (ft/sec²), can do much to alleviate concerns regarding the aforementioned uncertainties and to provide damage predictions that can be used with confidence when making decisions regarding inspection and maintenance actions.

**Initial Design Criteria**

Based on the Initial Customer Metrics for a Riser Monitoring System (see Table 2), it is expected that the RLMS system will provide continuous updates on key parameters related to the “health” of the riser string. These data will assist the rig operator with decision-making processes that affect drilling operations. The top-level parameters that will be continuously updated to address the customer metrics include:

- Maximum fatigue damage level in the riser assembly
- Average and maximum fatigue damage rates during the past day, week and month
- Planned and recommended time to the next inspection
- Remaining useful life based on accumulating fatigue predictions vs. design specs
- Estimated time-history of the axial force on the wellhead

The continuous availability of such data will offer the rig operator an enhanced view of the effects of the current drilling operations on riser life metrics and will assist on decision-making processes related to performance-based inspection and maintenance. Several of these processes and related scenarios are discussed here, with many more arising in practice. Of primary importance is the identification of critical riser joints – those which are “aging” faster than expected from a fatigue standpoint. These joints will be identified and highlighted in visual displays and subsequently flagged for scrutiny during upcoming maintenance cycles. The system will display a plot of the highest level of fatigue damage rate, compared to expected design life, in the riser assembly and will recommend revisions to the next inspection date if the fatigue damage history warrants such action.
Technical Approach

The fatigue damage analysis workflow used in this generic riser life-cycle reliability methodology is shown in Figure 35. The workflow can be broadly divided in three steps, the first being the **Inputs** which consists of riser configuration (modal data from the global riser analysis), the associated digital Radio Frequency Identification (RFID) data from each riser joint as the riser configuration is built, and the measured accelerometer data. The second step is the **Analysis** which consists of generating the transfer function (algorithm) for as-built configuration, calculating the fatigue damage along the drilling riser, and updating the database (DB) and user interface (UI) with damage rates and remaining useful life. The third step is the **Output** which consists of the recommendations for inspecting particular riser segments in case of a significant event, such as a VIV occurrence, or unanticipated discrepancies in load sharing in the riser system, such as on the well head. Recommended actions from the RLMS advisory system may involve, for example, swapping riser segments in low-fatigue portions of the riser string with ones from the high-fatigue regions for the subsequent drilling campaign. Such operations changes could result in extension of the inspection and maintenance period.

![Figure 35. Fatigue Damage Analysis Workflow](image)

In Step A.2, a neural network model, combined with an optimization algorithm, is used to develop transfer functions that will estimate the ocean current velocities along the length of the marine drilling riser. The inputs to the neural network model are current intensities, and the outputs of the model are acceleration features at locations along the riser string.
where the sensor nodes containing motion sensors are attached. An optimization algorithm is used to match predicted acceleration from the neural network model with measured acceleration features in order to back-calculate the current intensities. The current intensities are then input into Shear7 to estimate fatigue damage rates. When a new riser configuration is specified, neural network models are automatically run by generating a space-filling Design of Experiments (DOE) that covers a wide range of current profiles and current intensities representative of the flows that occur in the geographical regions in which upcoming drilling campaigns will be conducted. The data set for the DOE is split into three parts: one for training the neural network model, one for cross-validation and tuning of the model’s internal parameters, and one for validation. The neural network models include the effects of the specific riser geometry, material properties, top-tension levels, and mud weights.

Results: Damage Rate Calculations & Verification Methodology

The neural network model discussed in the previous section calculates acceleration features at each sensor location on the riser string based on current intensities, which are initially unknown. Periodically, acceleration data is collected from accelerometers located along the riser string, and the acceleration features are calculated. A constrained optimization problem is performed that minimizes the sum of the squares of the differences between the predicted and the measured acceleration features: Step A.2 (see Figure 36). This process yields a set of current intensities at the sensor locations that would result in the observed acceleration features. Once the current intensities are known, the Shear7 code is run to calculate stresses and damage rates for each component in the riser string. Damage increments are then calculated by assuming constant damage rates during the period of time over which the sensor data was taken (typically a duration on the order of minutes). The total damage for each component is updated and entered into a database.

Figure 36. Calculation of Current Intensities in Data-Matching

Verification of the methodology of fatigue damage calculation is summarized in Figure 37. To verify the transfer function and the optimization algorithm described above, a typical current velocity profile was first created (Step 1). Next, the Root Mean Square (RMS) Acceleration and Damage Rates at each sensor location (total 9 sensors) were calculated in
Shear7 using the current profile (Step 2). The neural network model was then used to predict the RMS acceleration at each sensor location (Step 3). The optimization algorithm was then used to minimize the sum of squares of the differences between the actual and predicted RMS accelerations to obtain the predicted current velocity profile (Step 4). That profile was then run through Shear7 to generate predicted damage rates (Step 5). Verification of the method is contingent on good agreement between the actual and predicted damage rates, which agreed to within 10% for the dozen verification cases that were considered.

Figure 37. Methodology to Verify Fatigue Damage Calculation

Subtask 5.2.4 Software Management Subsystem for RLMS

Initial Design Criteria

The subsea structural monitoring system should provide sensor measurement data for real-time estimation of actual loads (e.g., tension, bending moments) and motions (e.g., displacements, inclinations, angles) in selected locations of the marine drilling riser. It is desired to have relevant data from existing rig system (e.g., mud weights, top tensions, and environmental data) integrated with the subsea data. It is desired to have results of analysis of all relevant data should be presented to the rig crew in near real-time in an intuitive view, such that the rig crew can optimize the rig and riser operation, compare the status with operating limits, and take necessary action to avoid exceeding the specified operating limits. It is desired to have raw data stored in a redundant database for post retrieval, processing and analysis.
Technical Approach

The initial prototype version of the Riser Lifecycle Monitoring System (RLMS) software was built using a mature GE engineering software tool, 3DFAS (3D Fracture Analysis System). 3DFAS is a software engineering tool widely used across GE for fracture mechanics. Due to its ease-of-use and streamlined user interface design methodology, it was selected for development of the prototype RLMS Software, “RiserHealth”, for real time operational visibility and fatigue life assessment of deep water risers.

As a result of ease and speed in which other tools can be built upon the 3DFAS software foundation, the decision was made to use 3DFAS for the foundation of the prototype of the RLMS system under development in this project. All of the 3DFAS software objects for model representation, data I/O, and visualization of results are readily applicable to the subsystems in the RiserHealth tool. The use of these objects has enabled rapid development and new idea testing for riser life assessment.

As background, 3DFAS evolved as an efficient and easy-to-use software framework for fracture mechanics based analysis of cracks in engineering structures. This tool facilitates the process of inserting cracks into either solid geometric models or finite element meshes. The model is then discretized and a stress and fracture analysis is performed to obtain stress intensity values along the crack fronts. This allows the analyst to determine whether or not a crack in a component will propagate under design loading.

Development of 3DFAS began in 2003 and continues today. During development, the tool has undergone approximately 12 formal reviews under GE’s Software Tools Center of Excellence. It was built using C++ and Microsoft’s foundation classes. A diagram of the 3DFAS system architecture is shown in Figure 38.

![3DFAS System Architecture](image)

Figure 38. 3DFAS System Architecture

Results

4 McNeill, Scot et. al “Subsea Wellhead and Riser Fatigue Monitoring in a Strong Surface and Submerged Current Environment”, OTC-25403-MS, Houston, TX, 2014.
The continuous availability of sensor data will offer the rig operator an enhanced view of the effects of the current drilling operations on riser life metrics and will assist on decision-making processes related to performance-based inspection and maintenance. A high-level view of the architecture of the RLMS system is shown in Figure 39. The use of the system is simple and effective, involving essentially just five steps, some of which are repeated in the continuous monitoring phase. The first step involves the specification of the initial riser configuration via a file that contains the unique ID (RFID) of each of the joints in the riser assembly. Once specified, the system retrieves geometric data (length, weight, inertia, etc.), material properties (Young’s modulus, S-N curves for fatigue calculation, etc.) and buoyancy data on the riser components from a master database and builds an analytic model for vibration analysis. At that point, the model can be viewed, and sensor locations displayed (Step 2). The remaining three steps perform analysis using the periodic sensor measurements and provide the rig operator with displays of high-level results related to the instantaneous state of fatigue damage in the riser assembly. Each time the riser configuration changes, such as when joints are repaired or interchanged, or when the assembly is moved to a shallower area and fewer joints are needed, the riser configuration file must be updated (Step 3). The riser components with the highest damage at any point in time can be viewed in Step 4 and the state of the health of the riser string is displayed in Step 5. Detailed information, such as RMS stress and acceleration values, and ocean current velocities can also be displayed for each riser component.

Figure 39. RLMS Software System Architecture
Task 6 – Alternative Technology Development for RLMS Communication Subsystem

Summary

In Task 6 of Phase I of the Riser Lifecycle Monitoring System for Integrity Management Program, the team has successfully demonstrated the feasibility of an alternative, lower Technology Readiness Level (TRL) fiber optic acoustic design for subsea telemetry, as shown in Figure 40. The team achieved technology readiness progression from TRL 0 to TRL 2 (idea conception to proof of concept). This approach has the potential to reduce several of the risks of the baseline subsea telemetry design which relies on long range acoustic links from each sensor module to the drill ship. To demonstrate the feasibility of the fiber optic acoustic telemetry approach, data transmission experiments were conducted in a 1.5m water tank lined with acoustic absorbers. The bit error rate results and power budget calculations indicate that the number of batteries required at each sensor node could be reduced by at least a factor of two compared to the baseline approach. The fiber optic acoustic telemetry design also reduces the risk of interference due to buoyancy modules on the riser string and drill ship noise.

Figure 40. Lower TRL Fiber Optic Acoustic Telemetry Approach
Motivation

The acoustic telemetry feature of the Riser Lifecycle Monitoring System (RLMS) enables real-time advisory information for riser operations. The baseline acoustic telemetry design employs an acoustic transmitter/receiver (TX/RX) at each remote sensor module which will transmit data to a TX/RX mounted below the drill ship as shown in Figure 41. In the preliminary design phase, several high priority risks associated with the baseline acoustic telemetry design were identified, as summarized below.

Figure 41. Baseline RLMS Acoustic Telemetry

The RLMS transmitters must use high power (50 Watt driver power) acoustic transmission to communicate several kilometers distance to the drill ship. The sensor transmitters must be mounted and aimed carefully towards the topside TX/RX considering curvature of the riser string. The mounting must minimize reflections and multipath effects due to the large-diameter buoyancy modules located directly above the sensor module locations. Since each of the many transmitted signals can reach the receiver topside simultaneously, time-multiplexing must be used to keep the sensors from interfering with each other. This can be accomplished by using fixed scheduling or a two-way link and handshaking which requires more power and impacts data throughput. The topside receiver needs to be mounted below the drill ship, e.g., on a pole, to minimize interference, primarily from the thrusters used for positioning the ship. Although successful deployment of the baseline acoustic telemetry approach is still expected and planned in Phase II with a risk mitigation plan in place to address each technical challenge, research into an alternative, lower TRL approach was performed as Task 6 of Phase I for additional risk mitigation.

---

Fiber Optic Acoustic Telemetry Overview

The alternative approach utilizes optical fiber deployed within existing umbilical cables running down the riser string. This optical fiber is used as a distributed acoustic receiver by terminating the fiber on the drilling rig with a coherent optical time domain reflectometer (C-OTDR). This type of system is also known as a distributed acoustic sensor or “DAS”. The instrument sends light pulses down the fiber and analyzes light which is scattered or reflected back up the fiber to measure sound pressure waves impacting and straining the fiber. It is a single-ended system so the fiber can be unconnected at the bottom of the riser string. As with the baseline approach, fiber optic acoustic telemetry will offer continuous monitoring with untethered sensor modules.

The fiber optic telemetry solution is shown in Figure 42. Lower power transmitters (2.5 Watts, see results below) on the remote sensors can be used since the signal is only traveling a few 10s of centimeters to the BOP umbilical. The sensor transmitters can be mounted perpendicular to the riser so the buoyancy modules will not interfere with signal transmission. Since acoustic levels are low, the sensors are separated by many 10s of meters, and DAS has very little crosstalk, so no special multiplexing scheme is required. The RLMS transmitters can transmit at the same time and the signals are easily separated topside. For the fiber optic acoustic telemetry solution, a fiber in the umbilical must be routed on the drill ship back to the BOP control room which terminates the other lines within the umbilical. No hardware below the ship is required and the effect of drill ship noise will be minimized. The Task 6 effort included system testing to verify performance and to quantify the power savings and data rates achievable.

Figure 42. Fiber Optic Acoustic Telemetry

---


**Feasibility Testing**

A schematic of the test setup is shown in Figure 43. Using a Signal Generator, digital signals were impressed on carriers and transmitted through a TX hydrophone to the RX fiber sensing cables. Five different fiber sensing cable arrangements were tested simultaneously leveraging the multiplexing capabilities of DAS. Data was recorded by the commercial DAS and Hydrophone acquisition systems and saved in files which were later processed to measure the bit error rates (BER). Figure 44 is a photo of the actual laboratory test set up.

![Figure 43. Test Schematic](image)

**Lab Test Results Summary**

In order to test the reliability of the system data transmission, the BER was measured for on-off keying (OOK) and binary phase shift keying (BPSK) modulation formats as well as various bit rates.

Figure 45 shows BER for BPSK modulation for different bit rates as a function of the root mean square (rms) electrical power used to drive the transducer. The acoustic transducer
was 2cm from the fiber. The optical receiver was a coiled 1m section. Colored solid circles indicate BER runs where no error was observed for 4000 received bits, which corresponds to a BER of \( \sim 3.25 \times 10^{-4} \) with a confidence level of 95%. Figure 46 shows the BER plots for the five different configurations tested. The acoustic transducer was placed at a distance of 2cm from the fibers. The best BER performance was from the 5m coiled configuration.

![Figure 45. BPSK BER Plot With 1m Coiled Fiber; Acoustic TX 2cm From Fiber Coil](image1)

![Figure 46. BPSK BER For Various Configuration Of The Optical Fiber Receiver](image2)

Figure 47 plots the effect of distance between the acoustic transducer and optical fiber on the BER performance. As the distance increases 10 times (from 2cm to 20cm) the power requirement to achieve the same BER increases about 10 times (15mW to 150mW).
Using the information and insight gained from the above results, it can be inferred that the root-mean-square power needed to achieve a BER of 1x10^{-3} for a straight 1.5m long fiber section will be 2.5W using BPSK scheme, 100kHz sampling frequency for the DAS, and 500bps bit-rate.

**Comparison and Conclusions**

From the experimental results, one can conclude that about 2.5 Watts electrical drive power is required to transmit to the hydrophone for the fiber optic acoustic telemetry system at 500 bits/s. In comparison, 50 Watts electrical drive power is required for the traditional long range acoustic system at 100 bytes/s. From the system level power budget, this translates to about 50% savings in battery power. Table 10 summarizes the differences between the two approaches.

**Table 10. Compare Baseline Acoustic Telemetry & Fiber Optic Telemetry Approaches**

<table>
<thead>
<tr>
<th>Telemetry Parameter</th>
<th>Baseline Acoustic Telemetry</th>
<th>Fiber Optic Acoustic Telemetry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acoustic transmitter drive power (Watts)</td>
<td>50</td>
<td>2.5</td>
</tr>
<tr>
<td>Number of batteries for 180 days of operation</td>
<td>12</td>
<td>6</td>
</tr>
<tr>
<td>Bit rate (bytes/second)</td>
<td>100</td>
<td>62.5</td>
</tr>
<tr>
<td>Deployment Approach</td>
<td>RX on pole below rig</td>
<td>Instrument in control room</td>
</tr>
<tr>
<td>Risk of impact from drilling rig noise</td>
<td>Medium (if on long pole)</td>
<td>Low</td>
</tr>
<tr>
<td>Risk of signal degradation due to buoyancy module blockage and riser sway</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Multiplexing approach for multiple RLMS sensors</td>
<td>Fixed time-slot multiplexing or handshaking</td>
<td>&gt;10m separation of RLMS sensors</td>
</tr>
<tr>
<td>Total data throughput per sensor w.r.t. single sensor throughput</td>
<td>Reduced by number of sensors ~1/N</td>
<td>No reduction in throughput with multiple nodes</td>
</tr>
<tr>
<td>Maturity of technology</td>
<td>Field Qualified (TRL5/6)</td>
<td>Validated System Concept (TRL2)</td>
</tr>
</tbody>
</table>
To summarize, in Task 6 of Phase I of the program, the team has successfully demonstrated the technical feasibility of using the fiber optic approach for subsea telemetry (progressed technology from TRL 0 to TRL 2), and quantified the benefits for power consumption and deployment. The main drawback is the immaturity of this approach relative to the baseline.

**Cost Benefit Analysis for RLMS**

A critical part of this program is a Cost vs. Benefit Assessment (CBA) to quantitatively assess whether oil and gas users, public and private enterprises, and government agencies would experience a net benefit from the proposed RLMS solution. This effort is being led by Dr. Michael Volk, in conjunction with the GE team and WPG. The methodology entails the systematic estimation of all benefits and costs for the RLMS solution. Note the framework for the CBA is being developed in Phase I to ensure the team gathers critical information (e.g. hardware, software, labor costs, and potential benefits) relevant to the analysis, and the formal CBA will be performed in Phase II. Assuming that the benefits are higher than the costs, then an overall benefit is achieved through implementation of the project.

**Approach**

CBA considers both gains and losses to all members of the community, including offshore oil and gas users, public and private enterprises, and government agencies, who are affected by the project. This analysis will not concentrate solely on the financial implications of a project but other tangible and intangible externalities that must be assessed. In developing a CBA model for this project, the following key elements of the appraisal will to be identified:

- **Comparison of Monitoring System Implementation Options**: Scenario A: Benchmark or base case or “without-project” scenario which represents the current level of service. This will be compared with the Scenario B: “with-project” scenario that contains the current cost to the Riser Lifecycle Monitoring System Provider (RLMSP).

- **Estimated costs** over the planning period including operating expenditure (opex), capital expenditure (capex), social and environmental costs. This involves identifying and quantifying the cost to the RLMSP of the intervening mechanisms that will provide improvements to all the aspects of riser lifecycle monitoring identified from a customer focus group. Both tangible and intangible costs will be identified.

- **Estimated benefits** for a RLMS, customers, and society as a whole over the planning period (expressed in terms of monetary benefits, cost savings or both). This involves identifying and deriving customer benefit, in monetary terms, of these improvements in aesthetic service provision through a large – scale customer willingness to pay survey. Both tangible and intangible benefits will be identified.

- **A risk and sensitivity analysis** to integrate risk and uncertainty into the framework.

- Planning period/horizon in years for the appraisal

- A discount rate to convert future values to present values
A workflow of the typical phases to conduct a CBA is summarized in Figure 48. For this program, four key tasks were completed in Phase I.

![Image](image.jpg)

**Figure 48. Stages in the development of a CBA model**

In *Task 1 of the CBA*, a framework was developed for the cost benefit analysis. This consisted of defining the market place, i.e., the exploration companies as well as the drilling contractors/vessels. Globally, the Gulf of Mexico (GoM) is one of the most important regions for energy resources and existing infrastructure thus making the Gulf one of the unrivaled basins of the world because of its geology, commercial potential of discoveries, and the existing pipeline network as well as production infrastructure. These aspects provide the Gulf significant advantages over almost anywhere else in the world. For this reason, the cost benefit analysis as well as the field test will focus on the GoM.

*Task 2 of the CBA* focused on riser monitoring issues. The issues identified were: sensor failure/fiber breaks, robustness, redundancy, sufficient battery life, strong loop currents, integrity, negative perceptions, visualization, data transmission, fatigue damage, uncertain market and geo-political events.

In *Task 3 of the CBA*, the framework to quantify the two scenarios was outlined (base case or without-project vs the RLMS or with-project scenario).

In *Task 4 of the CBA*, the initial costs and benefits were identified. This included both tangible and intangible costs and benefits.
Preliminary Results

**Task 1 of CBA - Develop Framework for Cost benefit Analysis** This task encompasses quantifying the market place as well as the participants. The participants will be operators and drilling contractors.

*The Market Place* - The average U.S. well produces about 10 barrels of oil a day. The average offshore deepwater well, in contrast, produces thousands of barrels per day. The reserves discovered offshore significantly outweigh those onshore as shown in Figure 49 below.

![Figure 49. Onshore vs. offshore discoveries](image)

As noted below, deepwater is greater than 5,000 feet but less than 7,500 feet. Deeper than 7,500 feet is ultra deepwater. As will be noted later, the focus of this study will be water depths > 5000 feet.

<table>
<thead>
<tr>
<th>Category</th>
<th>Depth Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>ULTRA DEEPWATER</td>
<td>&gt; 7,500 FT</td>
</tr>
<tr>
<td>DEEPWATER</td>
<td>5,000 – 7,500 FT</td>
</tr>
<tr>
<td>MIDWATER</td>
<td>450 – 5,000 FT</td>
</tr>
<tr>
<td>JACKUPS</td>
<td>0 – 450 FT</td>
</tr>
</tbody>
</table>

Because of the large reserves and the production potential, there are four offshore frontiers where oil rigs are focusing their efforts: Brazil, West Africa, the Gulf of Mexico and the Arctic. The focus for the marketplace for this study will be the Gulf of Mexico.
The Gulf of Mexico

The Gulf of Mexico, with more than 3,400 offshore production facilities, hardly seems like a new drilling frontier. But the experts believe there is much more oil out there—further from shore, in deeper water and in older geological formations. Estimates by IHS CERA suggest that the Gulf still holds nearly 13 billion barrels of recoverable deepwater oil. In the Gulf the hottest spot is something called the Lower Tertiary. It’s vastly different from any other deepwater reservoir. BP’s Macondo well was in a geological formation called the Miocene, 25 million years old or less. The Lower Tertiary formation, farther south, is close to 60 million years old. The Lower Tertiary lies about 200 miles (322 kilometers) off the Gulf Coast and extends from Alabama to Mexico.

Summary of the Market place and participants: According to the IEA, at least 10% of the world’s remaining recoverable conventional oil and gas resources lie below the ocean’s surface in deep water. They are projected to become a vital part of the future energy mix as deep water oil and gas production is expected to increase significantly from current levels to about 8.7 million barrels of oil equivalent (BOE) by 2035.

As shown in Figure 50 below, deepwater production has grown from 10% of the total GoM production to where it is now around 80% of the total GoM production over the past 20 years.

![Figure 50. The growth of deepwater production over the last 20 years](image)

Globally, the Gulf of Mexico is one of the most important regions for energy resources and existing infrastructure making the Gulf “one of the unrivaled basins of the world” because of its geology, commercial potential of discoveries, the existing pipeline network as well as production infrastructure. These aspects provide the Gulf significant advantages over almost anywhere else in the world. For this reason, the cost benefit analysis as well as the field test will focus on the GoM.
**The Drilling Market – Rig classification and overall fleet numbers:** Rigs are generally classified as one of eight main rig types. As of August 2014, 74 drilling companies provide a total of 1,496 rigs of which 867 are actually contracted (57.96%), and the others are either cold stacked, ready stacked, under inspection, undergoing a work over, en route to a new destination or under construction.

**Expected Participants, Marketplace and Rig Opportunity**

Expected participants in the study will be the major players in the development of deepwater oilfield reservoirs in the GoM (e.g. ExxonMobil, Chevron, Royal Dutch Shell and BP). Amerada Hess, Anadarko and ConocoPhillips will also be considered. Sensitivity studies will be conducted by including global reserves. Current estimates are 191 billion barrels of which 48 BBO are in Brazil, 20 BBO in West Africa, 13 BBO in GoM and 90 BBO in the Arctic. This will add ENI, Petrobras, Repsol, Statoil, Total, Tullow and Woodside Petroleum to the market place participants.

Since the study will focus on water depths > 5000 feet, as of September, 2014 the study would utilize 32 drillships and 27 semisubmersibles. These two groups are the companies that make-up the market place for this study. In Phase II we will seek input from them for the CBA.

**Task 2 of CBA – Riser Monitoring Challenges**

As the search for oil and gas extends into deeper and more difficult environments, the safety, ecological and technical challenges associated with drilling operations become ever greater. For the drilling industry to realized advantages of riser monitoring and adapt to enabling state-of-the art technology, riser monitoring systems must address the following challenges:

- **Sensor failure/fiber breaks** - the sensors must be simple, accurate, robust and well-packaged, easy to install at critical points on the riser
- **Robustness** - they are manhandled relatively regularly for connection and disconnection – the sensors must not interfere with its running and retrieval or normal drilling operations.
- **Redundancy** - given the harsh surroundings on the rig and in service, there also needs to be a degree of redundancy built into the system, something that takes considerable practical experience to engineer effectively.
- **Sufficient Battery life** - System health parameters such as battery life must be transmitted.
- **Loop currents too strong forcing rig to move off location** - In the Gulf of Mexico (GoM), high loop currents can delay drilling and completion operations and the resulting cost to operators is high. This places a high priority on better understanding how drilling risers actually behave while subjected to high currents. This is amplified in importance when considering that for six months of the year high currents can occur in combination with GoM hurricane activity.
Integrity - Prone to vortex-induced vibration (VIV) risers accumulate fatigue. Negative perceptions - Perception that riser monitoring projects were R&D focused.

Visualization - The data is of little use without the processing capability to provide users with meaningful parameters that can be compared with key operating limits.

Data Transmission - Getting the data back to the surface - There is a vital need to improve the performance of the existing systems in terms of data-rate, noise immunity, operational range, and power consumption, since portable high-speed, long range, compact, low-power systems are desired.

Fatigue damage - Given that VIV is such an important issue for deepwater risers of all kinds, there is a need to monitor the extent of the effect and the associated fatigue damage to the riser.

Uncertain market - the near-term market for ultra-deepwater drilling units remains challenging and is uncertain about how deepwater drilling rates will develop, driven by reduced exploration drilling that has led to a slower growth rate in overall upstream spending.

Geo-political events - Sanctions by the EU and the US have already impacted the behavior of giant firms like XOM. Sanctions in the market in the future could also impact drill rig utilization.

Task 3 of CBA - The Strategies - Base case or “without-project” vs. the RLMSP or “with-project” scenario

Base case or without project scenario: In the base case no monitoring is conducted. Because a riser is very long, even vibration of high order mode may occur. If vortex shedding at a frequency of 1 to a several Hz causes resonance of a riser, safety problems such as fatigue damage may arise from VIV. VIV has recently been attracting attention, and major international oil companies such as Shell (Netherlands), BP (UK), Chevron (U.S.), and Petrobras (Brazil), as well as classification societies such as DNV (Norway) and academic institutions, have been cooperatively promoting studies. There is considerable disparity between predictions of marine riser vortex-induced vibration (VIV) fatigue damage, and often the agreement between computer models and observed VIV-related damage is inaccurate by orders of magnitude. Resulting problems for deepwater riser design are the need for large safety factors on fatigue damage predictions and the use of expensive vortex-suppression devices (e.g. helical strakes). Understanding is especially limited for long risers, which may be excited in multiple and higher modes.

With project scenario - Riser Lifecycle Monitoring System (RLMS) for Integrity Management: The RLMS system real-time monitoring and data acquisition tool will offer several significant benefits. The system will improve understanding of the relationship between riser response and environmental loading, thus increasing confidence and assurance to maximize drilling uptime. In addition, it will help drillers reduce unnecessary costs and operational downtime by optimizing maintenance and inspection activities and provide an important operational safety tool, supplying critical information needed to improve decision making.
Task 4 of CBA - Cost and Benefit Quantification

In this task of the CBA, the costs and benefits will be quantified. Costs are either one-off, or may be ongoing. Benefits are most often received over time. The effect of time is built into the analysis by calculating a payback period. Typically, companies require a payback over a specified period of time. In its simple form, cost-benefit analysis is carried out using only financial costs and benefits. A more sophisticated approach to cost/benefit measurement models are to include also includes financial value on intangible costs and benefits. The latter approach will be utilized in this study.

It can difficult to place monetary values on non-financial benefits such as health benefits or aesthetic benefits. For example, it is not possible to quantify or estimate in real monetary terms the value of an elimination of potential spills or the value of human lives potentially saved due to improvements in riser lifecycles. This is because a market does not exist, or market prices are not directly observable or easy to estimate. Many riser lifecycle monitoring benefits cannot be directly measured through the market system; therefore non-market methods have been developed to assess them. Consequently, a number of economic valuation tools and techniques can be employed to estimate the value that is placed on these non-market goods.

In our study, the Choice Experiment approach will be used to quantify the costs and benefits. In this approach, a survey respondent will be presented with two or more options for service levels and associated price, and will be asked to state a preference option. Respondents make a choice among a number of options each with defined attributes. A monetary value is included as one of the attributes so that when individuals make their choices, they implicitly make trade-offs between both the level of the attributes in the different alternatives along with the costs associated with each one. Different service levels and prices are specified in a number of experiments to provide the variation that is necessary for identifying an estimate of the marginal utilities of each attribute. A series of experiments is presented to each respondent, with the experiments varying over respondents. Respondents’ choices reveal their willingness to pay (WTP) for improved service. Statistical analysis of the responses, using discrete choice models, provides estimates of the WTP.

Benefits: As summarized in Table 12, both the tangible and intangible benefits of the RLMS will be quantified. Examples of initial tangible benefits include:

- **Enhanced safety and risk management** - improved safety through reduction in unplanned incidents and maximizing the time available in the event of an emergency disconnect situation
- **Ability to operate in increasingly deeper and harsher offshore environments** - greater productivity by optimizing the vessel position, increasing operating windows, enabling longer drilling operations and increasing confidence to drill during high currents with less risk of VIV
- **Increased operating window** - longer asset lifetime through reduced stress and wear on critical riser components with optimal riser management

62
• **Increased operational efficiency** - improved decision making on the drill floor and automated software to verify and/or replace manual calculations during operations
• **Reduced costs through optimization of riser maintenance and inspection programs** – potential to extend the current 5 year I&M cycle of risers.

Examples of indirect, or intangible, benefits are summarized below:
• **Increased sales**
• **Repeat customer business**
• **Employee retention**
• **Enhance process of securing deepwater drilling permits**

Table 11. Initial Benefits to be quantified in Phase II

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>I Tangible Benefits</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operate in increasingly deeper and harsher offshore environments</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reduced likelihood of event occurrences</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Enhance safety and risk management</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Increased operating window</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reduced service and maintenance costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Optimized engineering design of future risers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Industry accepted solution</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Tangible Benefits</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| II Intangible Benefits | | | | | | |
| Increased sales | | | | | | |
| Repeat Customer Business | | | | | | |
| Happier employees | | | | | | |
| **Total Intangible Benefits** | | | | | | |

**Costs:** Both tangible and intangible costs of the RLMS will be quantified; examples of such costs are summarized in Table 13. In this analysis, four main tangible costs are: (1) development costs, (2) testing costs to validate the RLMS, (3) capital costs for the RLMS system itself, and (3) operating costs for the system once installed. The base case costs are then only the daily drilling rate for the drillships and semisubmersibles. The development costs include design, testing and integration an optimized RLMS system (key subsystems include RFID, subsea sensing and communications, vibration and fatigue analysis, and the industrial internet software). Testing costs include RLMS system level open water and field testing. Examples of CAPEX costs include the onshore service center/office space, the satellite costs for data transmission, and RLMS HW/SW on the vessel. The last category is the operating costs for the RLMS (e.g. labor, materials, shipping, maintenance and training).

Examples of intangible costs include the cost of adjusting an established routine, possible loss of business during implementation, market saturation or penetration, cost of time spent on the project and a drilling downturn. Imperfect processes could result in downtime to replace or cause the operator to move on without the RLMS service. New routines take
time to implement because crews need to be familiarized with a new way of doing things. Some companies may be hesitant to implement the RLMS until proven.

Table 12. Costs to be quantified in Phase II

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>I Tangible Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. CAPEX</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>a) Drilling vessel and riser components</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b) Data Transmission</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c) Onshore service center/office space</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Testing</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. OPEX</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. Development Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>II Intangible Costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Imperfect processes</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of adjusting an established routine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Possible loss of business during implementation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market penetration or penetration</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of time spent on project/energy spent</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Drilling downtime</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Influence or ones reputation</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

All costs and benefits will be evaluated in Phase II at present values using an appropriate discount rate and ten year planning horizon of the analysis. A “risk assessment” will be included in the analysis to deal with the uncertainty from investment projects. A sensitivity analysis will also be conducted to quantify forecasting uncertainty and to assess project risks. The proposed approach will test combinations of key variables in three scenarios: a pessimistic scenario, most probable or base scenario, and an optimistic scenario. This approach can be then be used to test the robustness of the analysis and allow for uncertainty about future cash flows.

**Final Phase II Recommendations**

In summary, based upon Phase I efforts, formal recommendations for Phase II include:

- Subtask 5.3 — Design and conduct sub-system laboratory validation and sub-scale rig testing (Subtask 5.3.2 — Sub-Scale Rig Testing)
- Task 7.0 - Conduct RLMS System Field Trial
  - Subtask 7.1 — Define Field Trial Test Plan *(Operator, Test Site, Equipment Deployment/ Installation, Safety, Regulatory, and Documentation Requirements)*
  - Subtask 7.2 — Develop Pilot Charter (e.g., team, schedule, costing)
  - Subtask 7.3 — Develop Final Design Specifications for Field Trial
  - Subtask 7.4 — Conduct Pilot and Analyze Results
  - Subtask 7.5 — Integrated Field Trial Results Report and Final Presentation
- Task 8.0 – Business Model Analysis and Cost vs. Benefit Assessment
- Task 9.0 – Define Integrated Generic Solution for Industry: Final Design Specifications for Integrated Deepwater RLMS