HVDC TRANSMISSION SYSTEM
FOR RURAL ALASKA APPLICATIONS
Phase II - Prototyping and Testing

May 2012
FINAL REPORT, Version 1.1
About the Cover Image:

The cover image is of a demonstration installation in Fairbanks of a guyed fiberglass pole similar in size, height, and construction to the poles considered in this study for overhead transmission in rural Alaska applications. The pole is a 12-inch-diameter, 60-foot-tall fiberglass structure supported by three micro-thermopiles. The pole’s four guys are anchored by two micro-thermopiles and two screw anchors set in silt-rich permafrost.
EXECUTIVE SUMMARY

Program Objectives

This report presents the achievements and findings of Phase II of the “High-Voltage Direct Current (HVDC) Transmission Systems for Rural Alaska” research and development (R&D) program. The goal of this program is to improve the economic viability of Alaska’s rural communities by providing more affordable electricity transmission alternatives. Phase II work was funded by the Denali Commission and completed by Polarconsult Alaska, Inc. (Polarconsult) under contract to the Alaska Center for Energy and Power (ACEP).

The effect of excessive energy costs continues to degrade the quality of life in Alaska’s rural communities and places these indigenous populations at severe risk. Nearly 80% of rural communities are dependent on diesel fuel for their primary energy needs. Some of the poorest households spent 47% of their income on energy in 2008, more than five times the amount in Anchorage (CWN, 2012).

HVDC interties will support more cost-effective development of local energy resources, such as wind, hydro, biomass, geothermal, hydrokinetic, gas, and coal. Reducing the cost of low-power (1 megawatt [MW] and less) interties by using HVDC systems can enable increased interconnection of rural communities to Alaska’s abundant energy resources.

HVDC interties will also benefit rural communities with reduced energy costs by building economics of scale in rural power grids and allowing utilities to consolidate bulk fuel facilities and diesel electric power plants into more efficient and lower-cost configurations.

As a result of ongoing advances in power electronics, small-scale HVDC interties are now feasible. This report has identified low-power overhead and submarine HVDC transmission systems as an economically superior alternative to conventional alternating current (AC) interties. Additional cost reductions can be realized by integrating HVDC systems with future expansion of broadband fiber-optic telecommunication networks. This synergistic opportunity between the telecommunications and electric industries is one of several reasons HVDC interties can help surmount the economic barriers facing Alaska’s rural communities.

Comparative analysis of HVDC transmission systems with conventional AC systems indicates significant technical and economic advantages of HVDC systems. In many rural Alaska applications, the use of HVDC systems will significantly lower intertie costs.

Phase II Objectives and Findings

Phase II of this R&D program follows the Phase I – Preliminary Design and Feasibility Analysis Final Report (Polarconsult, 2009). Phase I tasks included assessing converter technical feasibility and evaluating the economics of a low-power HVDC system sized for rural Alaska applications. Based on the favorable results of the Phase I project, the following Phase II objectives were established:

- Confirmation of the technical feasibility of the HVDC/AC power converter technology by designing, building, and testing a full-scale prototype of a 1-MW bidirectional power converter and key transmission system elements.
• Confirmation of the economic feasibility of the low-power HVDC system in rural Alaska applications by determining the commercial cost of the converter, the converter’s efficiency, and the estimated overall costs of an HVDC system.

• Development of cost estimates for HVDC transmission systems and comparison with conventional AC systems to quantify the benefits and savings of HVDC systems.

Phase II has demonstrated that the converter technology is technically viable and the transmission system is economically feasible. Key Phase II findings are:

• Low-power HVDC converter technology is expected to be commercially available at $250 per kilowatt per converter.

• Estimates of construction costs for a conceptual 25-mile overhead HVDC intertie indicate capital cost savings of approximately 30% compared with a conventional overhead AC intertie. Estimated life-cycle costs range from 79% to 107% of the life-cycle cost of an AC intertie.

• Longer overhead HVDC interties can expect capital cost savings of up to 40%.

• Phase II analysis also indicates that significant savings are possible for submarine cable and underground cable applications using HVDC systems. Estimated capital cost savings on a 25-mile low-power HVDC submarine cable intertie are over 50% compared to AC alternatives.

Based on Phase II findings, the benefits of low-power HVDC systems for Alaska are substantial, and continued development of this system is recommended.

**Opportunities and Barriers**

Based on analysis and study conducted during this Phase II project, Polarconsult has concluded that this HVDC technology presents the following opportunities for Alaska’s utility industry and rural communities:

• Less expensive rural electric interties, leading to lower-cost energy and increased energy independence for rural communities.

• Interconnection to currently stranded local energy resources.

• Interconnection cost savings by combining rural electric and telecommunications interties.

The successful commercialization and adoption of low-power HVDC technology in Alaska requires overcoming the following barriers:

• Completion of the commercial development and demonstration of the converter technology. Continued development of the prototype converters, culminating in independent testing of the converters and deployment on an Alaska utility system, is needed to prove that the converters are a commercially viable technology.

• Acceptance and use of low-power HVDC technology by Alaska’s utility industry. Continued involvement of in-state and international stakeholders with the ongoing development of this technology is considered necessary to surmounting this barrier.

• Development and demonstration of standards and control protocols for low-power multiterminal direct-current (MTDC) transmission networks, which are needed to build cost-effective regional HVDC power networks in rural Alaska.
Recommendations

Based on the conclusions and findings of this project, the following actions are recommended:

Phase III program activities:

- Continued development of the power converter technology to commercialize the existing prototype converter design. Solicitation of additional HVDC converter manufacturers is warranted to encourage diversity of suppliers and competition;
- Independent testing of the converters to validate efficiency and performance, followed by deployment on an Alaskan utility system to validate functionality and reliability in a commercial setting;
- Further development of MTDC transmission systems interconnection and control technologies; and
- Continued involvement of in-state stakeholders in the development of this technology.

Stakeholder actions:

- Incorporate low-power HVDC technology into Alaska’s regional and statewide energy plans and policies;
- Continue coordination with the State of Alaska to allow a project-specific waiver of the National Electrical Safety Code (NESC) to allow the use of single-wire earth return (SWER) circuits;
- Encourage planned rural power and telecommunications interties to incorporate HVDC technology in their economic and technical analysis, as well as their environmental and permitting review processes;
- Engage the telecommunications industry to raise awareness of the synergies possible between low-power HVDC transmission and fiber networks in rural Alaska; and
- Collaborate with international stakeholders to identify synergies and lessons learned from parallel technology development efforts. Coordinate on development of applicable policies/standards and identification of markets to help expedite the commercialization and reduce the costs of low-power HVDC systems.
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ACRONYMS AND TERMINOLOGY

°F degrees Fahrenheit
A, a, i amperes or amps
AC alternating current
ACEP Alaska Center for Energy and Power
ACSR aluminum conductor steel reinforced
ADNR Alaska Department of Natural Resources
AEA Alaska Energy Authority
AEL&P Alaska Electric Light and Power Company
AFI Arctic Foundations, Inc.
AKDOL Alaska Department of Labor
albedo The extent to which an object diffusely reflects light.
alternating current The form of electricity commonly used in homes and businesses in which the current and voltage oscillate at a frequency of 60 cycles per second. (The frequency in some nations is 50 cycles.)
Alumoweld A type of cable used in electrical systems. Each strand of the cable consists of a steel core with a layer of aluminum extruded over it during the pulling and drawing process. The steel core provides increased strength, and the aluminum exterior provides better corrosion protection and increased electrical conductivity.
amperes/amps A measure of the amount of electrical current flowing through a circuit (a typical household circuit is rated for 20 amperes).
AP&T Alaska Power and Telephone Company
APA Alaska Power Association
ASCE American Society of Civil Engineers
AVEC Alaska Village Electric Cooperative, Inc.
AVR automatic voltage reference
bandwidth A measure of the data transfer capability of a given communications method. Units of bandwidth can vary but are generally bits per second.
BEC Bethel Electric Utility
bipolar A type of direct current circuit that uses two wires to transmit energy. Bipolar circuits operate one wire (“pole”) at a positive potential and the second pole at a negative potential relative to ground (e.g., +/- 600,000 volts). These circuits normally also have an earth return pathway or a dedicated ground conductor that is used to compensate for any imbalance on the two poles and serves as a temporary return pathway if the negative or positive pole is out of service for any reason.
BSNC Bering Straits Native Corporation
A circuit provides an electrical pathway from a point of energy supply (e.g., a generator or battery) to a point of energy use (e.g., motor, lighting, etc.), and then back to the point of supply. Without a complete pathway from supply to use and back, the circuit will not function. The pathway can take many forms. Most commonly, it is made of metallic (copper or aluminum) wires, but it can also use water, the earth, or other materials. These other materials are most often used on the return pathway back to the point of supply, where the voltage differential relative to the surrounding environment is low.

A typically metallic wire or cable that is designed and fabricated to conduct electricity between two locations.

An electrical device that converts electricity from AC to DC and/or from DC to AC. “Converter” is a more general term for a rectifier or inverter.

A communications method that consists of sending pulses of light down glass fibers.
HEA  Homer Electric Association, Inc.
hertz  A unit of how rapidly something oscillates, rotates, or repeats. One hertz is equal to one complete cycle per second. Alternating current electrical systems in the U.S. operate at 60 hertz, or 60 cycles per second.

high-impedance  A fault or short circuit between a high-voltage wire and ground. An example of a high-impedance ground fault would be a conductor that falls to the ground without breaking, landing on ice or ice-rich soils. These soils are very poor conductors, thus little or no current may short circuit into the ground. Because the wire did not break, it can continue to transmit energy between the converters. This energized wire poses a hazard to any people or animals who happen upon it.

high-voltage direct current  Direct current electricity at a high voltage relative to the surrounding environment.

HMI  human-machine interface

hot work  Working on electrical equipment while it is energized.

HVDC  high-voltage direct current

IEC  International Electro-technical Commission

IEEE  Institute of Electrical and Electronics Engineers

IGBT  insulated gate bipolar transistor

inverter  An electrical device that can convert DC electricity into AC electricity.

IPEC  Inside Passage Electric Cooperative

KEA  Kodiak Electric Association, Inc.

kHz  kilohertz (1,000 hertz)

kilowatt  1,000 watts. One kW is the power consumed by ten 100-watt incandescent light bulbs.

kilowatt-hour  The quantity of energy equal to one kilowatt (kW) expended for one hour.

KoEA  Kotzebue Electric Association, Inc.

kV  kilovolt (1,000 volts)

kVA  kilovolt-ampere

kW  kilowatt (1,000 watts)

kWh  kilowatt-hour

LDE  Line Design Engineering, Inc.

LFL  line fault locator

LIDAR  light detection and ranging

litz wire  An electrical wire or cable made of multiple individually insulated strands of wire. Litz wire is used in high frequency AC applications and is designed to reduce power losses caused by skin effects and proximity effects that occur at high frequencies.

LVAC  low-voltage alternating current
MEA Matanuska Electric Association
MHRC Manitoba HVDC Research Centre
mm² square millimeters
MOD motor-operated disconnector
monopolar A direct current circuit that operates one leg of the circuit at an elevated voltage and the return leg at or near ground voltage. The return leg can use a metallic conductor or, in the case of earth or sea return systems, can use the earth or sea to complete the circuit. An HVDC SWER circuit is one type of monopolar circuit.
ms millisecond(s)
MSB Matanuska-Susitna Borough
MTDC multi-terminal direct current
MVA megavolt amperes (one million volt amperes)
MW megawatt(s) (1,000 kilowatts)
MWh megawatt-hours
NCC Nome Chamber of Commerce
NEA Naknek Electric Association, Inc.
NEC Nushagak Electric Cooperative, Inc.
NESC National Electrical Safety Code
NJUS Nome Joint Utility Service
NLP Nuvista Light and Power, Inc.
NRECA National Rural Electric Cooperative Association
NSB North Slope Borough
NWAB Northwest Arctic Borough
O&M operations and maintenance
OED City of Ouzinkie Electric Department
OMR&R Operation and Maintenance, Repair, Replacement, and Rehabilitation
OPGW optical ground wire
PCB printed circuit board
PCE Power Cost Equalization
PLC power line carrier
PPS Princeton Power Systems, Inc.
PSCAD Power Systems Computer Aided Design
psf pounds per square foot
R&D research and development
RCA Regulatory Commission of Alaska
rectifier An electrical device that can convert AC electricity into DC electricity.
RMS root-mean-square

root mean square

The root mean square voltage is the mean absolute voltage over any whole number of waveform oscillations. For a sinusoidal waveform (such as normal AC electricity), the root-mean-square (RMS) voltage is the peak voltage divided by the square root of 2. Nominal 120 volts alternating current (VAC) electricity thus has a peak voltage of about +/-170 volts relative to ground.

RUS Rural Utilities Service (USDA)

SAG Stakeholders Advisory Group

SCADA supervisory control and data acquisition

sea return A means of completing an electrical circuit by using the sea (or more generally rivers, lakes, and other water bodies) as a return path instead of a second wire. This approach is frequently used on submarine cables where the cost savings from not installing a second cable justify this approach. Sea return can be used for single-phase AC circuits or for DC circuits.

SEAPA Southeast Alaska Power Agency

SEC Southeast Conference

single-wire earth return Another term for an earth return or sea return circuit. The name emphasizes the fact that these types of circuits only require one wire, as compared with two or more wires for other types of circuits.

spur and belt A common method of climbing utility poles, trees, and similar objects. Special climbing spurs are strapped onto the feet and a large belt is fixed around the climber’s waist. The climber loops the belt around the pole and drives the spurs into the pole. The climber then “walks” up the pole with the spurs, and hitches the belt along the pole for support.

step potential A voltage gradient that occurs at the ground surface due to earth return currents. If the voltage gradient is high enough, it can pose a hazard to people or wildlife stepping in the vicinity.

stranded energy resources Energy resources located in remote, distant, or otherwise isolated areas “stranded” from either (1) integration into modern energy infrastructure and supply chains or (2) utilization by local population and industry centers.

SWAMC Southwest Alaska Municipal Conference

SWER single-wire earth return

transmission-class Refers to higher-voltage electrical systems. Definitions vary, but in Alaska AC systems operating above nominal 35 kV line-to-ground are generally classified as transmission-class. Most rural Alaska inerties function as transmission systems, but are operated at distribution-class voltages.

twisted pair A generic term for communications cable that uses multiple individually insulated wires. Each pair of wires is twisted together, hence the name.

TWMR transmission with metallic conductor-return path

UAF University of Alaska Fairbanks

USDA U.S. Department of Agriculture
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Term</th>
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<tr>
<td>V</td>
<td>volt</td>
</tr>
<tr>
<td>VAC</td>
<td>volts alternating current</td>
</tr>
<tr>
<td>VAR</td>
<td>volt-amperes reactive</td>
</tr>
<tr>
<td>VDC</td>
<td>volts direct current</td>
</tr>
<tr>
<td>VFT</td>
<td>variable frequency transformer</td>
</tr>
<tr>
<td>volt</td>
<td>A unit of electrical potential. Some typical voltages are car battery: 12 volts (DC); alkaline battery (AAA, C, D, etc.): 1.5 volts (DC); household electricity: 120 volts (AC RMS).</td>
</tr>
<tr>
<td>VSC</td>
<td>voltage source converter(s)</td>
</tr>
<tr>
<td>ZAE</td>
<td>Zarling Aero Consulting</td>
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1.0 INTRODUCTION

This report presents the achievements and findings of Phase II of the “High-Voltage Direct Current (HVDC) Transmission Systems for Rural Alaska” research and development (R&D) program.

The goal of this program is to improve the economic viability of Alaska’s rural communities by providing more affordable electricity transmission alternatives. The effect of excessive energy costs continues to degrade the quality of life in Alaska’s rural communities and places these indigenous populations at severe risk. Nearly 80% of rural communities are dependent on diesel fuel for their primary energy needs. Some of the poorest households spent 47% of their income on energy in 2008, more than five times the amount in Anchorage (CWN, 2012).

Reducing the cost of low-power (1 megawatt [MW] and less) interties by using HVDC systems can enable increased interconnection of rural communities to Alaska’s abundant energy resources. HVDC interties will support more cost-effective development of local energy resources, such as wind, hydro, biomass, geothermal, hydrokinetic, gas, and coal.

Phase II of this program was funded by the Denali Commission and completed by Polarconsult Alaska, Inc. (Polarconsult) under contract to the Alaska Center for Energy and Power (ACEP). This Phase II effort and final report follows the results of the Phase I R&D project, completed in 2009 and summarized in Phase I – Preliminary Design and Feasibility Analysis Final Report (Polarconsult, 2009). Phase I of this R&D program included evaluation of the technical and economic feasibility of the proposed HVDC system, including limited prototyping and testing of the converter technology.

Phase II of the HVDC Transmission System program included design, fabrication, and testing of full-scale prototypes of the converter and transmission system elements. The Phase II efforts involved the evaluation of design, efficiency, and functionality of the HVDC systems. Rural Alaska intertie alternatives were also investigated, which involved comparing HVDC transmission systems to the conventional alternating current (AC) alternatives. The Phase II findings were used to further develop construction cost estimates and refine the economic analysis of the technology developed in Phase I. Polarconsult is the prime contractor and author of both Phase I and II project reports.

As a result of ongoing advances in power electronics, small-scale HVDC interties are now feasible. This report has identified overhead and submarine HVDC transmission systems as economically superior alternatives to conventional AC interties.

Additional cost reductions can be realized by integrating HVDC systems with future expansion of broadband fiber-optic telecommunication networks. This synergistic opportunity between the telecommunications and electric industries is one of several reasons HVDC interties can help surmount the economic barriers facing Alaska’s rural communities.

Comparative analysis of HVDC transmission systems with conventional AC systems indicates significant technical and economic advantages of HVDC systems. In many rural Alaska applications, the use of HVDC systems will significantly lower intertie costs.

Based on the favorable findings, Polarconsult recommends continued work on this project through Phase III work activities, including demonstration of the HVDC system on an Alaska utility system.
1.1 REPORT ORGANIZATION

Phase II of this project addresses a wide range of technical disciplines and subject material. For brevity, the body of this report focuses on the key findings and conclusions that have resulted from this work. In-depth information pertaining to specific topics is included in the report’s appendices.

This report is organized as follows:

- The Executive Summary and the Acronyms and Definitions sections are included at the beginning.
- Section 1.0 introduces the report.
- Section 2.0 provides background information on Alaska’s rural energy issues and a brief explanation of the stakeholders’ roles in this phase of the project.
- Section 3.0 is a description of the HVDC transmission system, which includes a comparison of AC and HVDC transmission, overhead intertie alternatives, and submarine cable intertie alternatives.
- Section 4.0 discusses HVDC converter stations.
- Section 5.0 evaluates the design concepts for overhead interties.
- Section 6.0 contains the economic evaluation of Phase II.
- Section 7.0 provides the conclusions and recommendations for the Phase II prototyping and testing study.

In addition, this report contains the following appendices, which include reports generated by Polarconsult’s subcontractors for this project as attachments:

- Appendix A  HVDC Overview
- Appendix B  Economic Analysis
- Appendix C  Conceptual Design of Overhead HVDC Intertie Lines
- Appendix D  Conceptual Design for Submarine Cables
- Appendix E  SWER Circuits and HVDC System Grounding
- Appendix F  HVDC Power Converter Development
- Appendix G  HVDC System Protection, Controls, and Communications
- Appendix H  Candidate HVDC System Demonstration Projects
- Appendix I  Stakeholder Advisory Group Involvement and Meetings
- Appendix J  Bibliography
1.2 ACKNOWLEDGEMENTS

Polarconsult acknowledges and appreciates the support and contributions of the many individuals and entities that have participated in this project. Their support, insights, experience, and technical analysis remain invaluable to the continuing effort to bring lower-cost HVDC intertie systems to Alaskans.

Members of the team involved in the second phase of HVDC intertie development include:

- Denali Commission (Funding Agency)
- ACEP (Grant Management, Economic Analysis, Strategy)
- Polarconsult (Project Management, Strategic Vision, Design)
- Princeton Power Systems, Inc. (PPS) (Converter Development)
- University of Alaska Fairbanks (UAF)/Dr. Richard Wies (UAF Quality Control and Technical Review)
- Alaska Village Electric Cooperative, Inc. (AVEC) (Alaska Integration/Practicality)
- Stakeholders Advisory Group (Practicality/Industry Acceptance)
- Manitoba HVDC Research Centre (HVDC Expert)
- Line Design Engineering (Structural and Code Expert)
- Golder Associates (Geotechnical Expert)
- Almita, Inc. (Foundation Supplier)
- Arctic Foundations, Inc. (AFI) (Foundation Supplier)
- Zarling Aero Consulting (ZAE) (Thermal Soils Analysis)
- STG, Inc. (Rural Intertie Contractor)
- Cabletricity, Inc. (Submarine Cable/HVDC Expert)

In addition, the Stakeholders Advisory Group (SAG) members have played an instrumental role in this program by contributing their time and years of experience. The SAG was chaired by the Denali Commission and facilitated by ACEP. SAG members include:

- Alaska Department of Labor (AKDOL)
- Alaska Energy Authority (AEA)
- Alaska Power & Telephone Company (AP&T)
- Alaska Power Association (APA)
- AVEC
- Bering Straits Native Corporation (BSNC)
- Bethel Electric Utility (BEC)
- Copper Valley Electric Association, Inc. (CVEA)
- Golden Valley Electric Association, Inc. (GVEA)
- Homer Electric Association, Inc. (HEA)
- Inside Passage Electric Cooperative (IPEC)
- Institute of Northern Engineering (INE), UAF
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2.0 BACKGROUND

Energy costs throughout most of rural Alaska are significantly higher than in the state’s urban areas. Over the past decade, rural energy costs have escalated dramatically, to the point where life in many rural Alaskan communities is in a state of economic peril. The primary reasons for these high energy costs is rural Alaska’s dependence on diesel fuel for power generation and heating, the lack of economies of scale in rural communities, and the transportation challenges common in rural Alaska.

For most rural Alaskan communities, a diesel-electric plant is the power generation resource of choice since these plants and their supporting infrastructure such as bulk fuel facilities are readily adapted to the needs of rural localities. However, generating electricity with diesel fuel is expensive due to these communities’ small scale and geographic isolation. Consequently, rural Alaska has significantly higher energy costs compared to communities in or connected with Alaska's urban centers. The high cost of rural energy negatively affect both the quality and sustainability of life in rural Alaska.

Many power generation costs are beyond a community's control. The fuel price for these plants is determined by an increasingly volatile global energy market. In addition, a substantial component of the fuel cost is transportation. In recent years, the limited shipping and delivery windows caused by seasonal ice and low water conditions in many parts of the state have resulted in villages paying record prices for fuel. Interior communities, located near the upper limits of navigable waterways and thus susceptible to low water conditions, paid as much as $11 per gallon in 2010 (DCRA, 2010). Several rural communities frequently fly in fuel due to a lack of reliable barge access or service.

Alternatives to diesel generation often exist in the form of local energy resources such as hydro, wind, geothermal, tidal, solar, gas, coal, and biomass. However, many of these “stranded energy resources” are not economically viable due to the cost of the conventional AC electric transmission systems required to interconnect them and the prohibitively high cost to develop these local energy resources to serve small loads. HVDC interties can help surmount both of these barriers by lowering the cost to reach stranded energy resources and by reducing the cost to interconnect communities (ACEP, 2012).

Although commercial HVDC transmission technology has been available for over 50 years, it has been limited to large-scale transmission of tens to thousands of MWs of power. These systems are far too large and expensive to use for the interconnection of Alaska’s rural communities, which typically have loads measured in the hundreds to thousands of kilowatts (kWs). Currently, no commercially available HVDC converter system exists that is suitable for interconnecting these rural communities. However, innovative technologies in the power electronics industry have made the development of low-power, cost-effective converters feasible.

Polarconsult has investigated alternatives to AC interties and found that in many applications, HVDC transmission systems using innovative power conversion technologies offer the most economical solution to interconnect with stranded energy resources. Further, the replacement of a conventional overhead AC three- or four-wire transmission line with a one- or two-wire HVDC

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1 Rural Alaska for the purposes of this report refers to isolated communities off the main road system that have high energy costs due to their location, size, or other factors.
transmission line has significant cost advantages. The change in overhead infrastructure results in reduced structural loads, allowing fewer support structures per mile of transmission line. The decrease in materials and construction time is one of several reasons that overhead HVDC interties are less costly than AC interties. Submarine and buried HVDC interties can also be less costly than their AC alternatives.

2.1 PROGRAM OVERVIEW

The HVDC development effort consists of the following phases:

**Phase I – Preliminary Design and Feasibility Analysis (2008-2009)**

During Phase I, Polarconsult evaluated the technical and economic feasibility of the proposed HVDC system. Tasks included defining the HVDC system’s preliminary design parameters, defining design considerations for the transmission and converter components, and estimating costs for these systems. Phase I also included limited prototyping and successful testing of the converter technology.

**Phase II – Prototyping and Testing (2010-2012)**

Phase II included construction and testing of full-scale prototypes of the transmission and converter systems. This effort validated the design of these systems and validated the feasibility of the construction methods necessary to make the system a success in rural Alaska applications. The information from Phase II testing was used to refine the construction methods and develop cost estimates used in the economic analysis of the technology described in this report. This report is the final deliverable for Phase II.

**Phase III – Demonstration Project (Proposed)**

Phase III will include full testing of the converter system, including the manufacturer and third-party functional, compliance, and performance testing needed to move the converter technology from advanced prototypes to a commercial product. Phase III will also include a full-scale field demonstration of the HVDC technology on a utility system in Alaska. The specific project details are dependant on the candidate location selected for the intertie. Phase III is intended to be the final proof-of-concept project, to be followed by commercial deployment of the system.
2.2 **STAKEHOLDER ADVICE**

This project seeks to develop a highly innovative power transmission technology for deployment in rural Alaska applications. Because many aspects of this system mark a departure from accepted practice in rural power systems, widespread industry understanding, as well as acceptance, of this technology is considered critical to the success of this effort. Additionally, the overview and feedback of industry is considered critical to the successful development of the innovative systems needed for this HVDC technology.

The Denali Commission and ACEP recognized that the best means to achieve this understanding, acceptance, and feedback would be to directly engage the stakeholders and end-users of the proposed system in the development stages of the technology. To this end, a SAG was formed as part of the Phase II effort to familiarize and facilitate feedback from industry leaders on the development of this system.

The SAG is an advisory body comprised of representatives of Alaska’s rural electric utility industry and related professionals. The purpose of the SAG is to provide comments, feedback, review, and recommendations to the HVDC project. The SAG held the following three meetings over the course of the project:

- SAG Meeting # 1 – Fairbanks, Alaska – April 27, 2010;
- SAG Meeting # 2 – Anchorage, Alaska – January 14, 2011; and
- SAG Meeting # 3 – Anchorage, Alaska – October 25, 2011.

Several additional outreach activities occurred over the course of the project. These included:

- Southeast Conference Mid-Session Summit – Juneau, Alaska (March 2, 2010);
- Emerging Energy Technology Forum – Juneau, Alaska (February 14, 2011);
- Brown-Bag Work Session – Anchorage, Alaska (August 29, 2011); and

Appendix I provides the following detailed information regarding SAG meetings and discussions:

- List of SAG members;
- Summary of SAG role and policies;
- Summary of key informal correspondence between SAG members and Polarconsult over the course of the project;
- Handouts from the three SAG meetings; and
- Handouts from other meetings and outreach activities conducted over the course of the project.

Additional details associated with the SAG meetings and proceedings are presented in Appendix I. Transcripts of the SAG meetings are available upon request.
3.0 HVDC TRANSMISSION SYSTEM DESCRIPTION

HVDC transmission systems can take on a wide variety of configurations. This section describes those configurations relevant to low-power HVDC applications in rural Alaska applications.

- **Section 3.1** provides a general overview of the history of HVDC power transmission and the major components of an HVDC transmission system.
- **Section 3.2** provides a general overview of the different configurations of HVDC systems for power transmission applications.
- **Section 3.3** provides a comparison of HVDC and AC power transmission alternatives.
- **Section 3.4** provides a description of overhead line alternatives for AC and HVDC applications.
- **Section 3.5** provides a description of submarine cable line alternatives for AC and HVDC applications.

3.1 HVDC BACKGROUND

Thomas Edison pioneered the first utility-scale application of electric power in New York City in the 1880s with a direct current (DC) electric utility system. Concurrently, George Westinghouse was marketing an AC electric utility system invented by Nikola Tesla. AC was better suited to stepping up voltages, which is vital to economical electric transmission across town and between cities. By the 1890s, Westinghouse’s AC system had prevailed over Edison’s DC system, and AC became the industry standard.

In the 1950s, technological advances enabled DC systems to reenter the electric utility industry. With the commercialization of the mercury arc-valve, voltage transformation of DC and conversion between DC and AC electricity on a large scale became cost-effective. This allowed utilities to begin using HVDC transmission links in their systems.

Because of the high capital cost of these early HVDC converters, utility usage of HVDC remained limited to transmission functions. AC remained the industry standard for electricity generation, distribution, and consumption.

Today, HVDC converter technology has advanced to use high efficiency solid-state hardware, and HVDC links are used for electrical transmission throughout the world. The smallest available utility-grade HVDC systems are designed to transmit approximately 50 MW. As a result, the current commercially available HVDC converters are oversized and prohibitively expensive for Alaskan interties that typically require the transfer of less than 1 MW. Figure 3-1 is an image of a large HVDC station.

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2 “HVDC Lite,” distributed by ABB, is one example of the smaller utility-grade HVDC systems.
HVDC transmission systems include the following major components:

- **HVDC Converter Stations.** Each connection point between the HVDC transmission line and a load center requires an HVDC converter station. The converter station converts the HVDC electricity into AC electricity that can be moved through a local power grid and used. The converter station includes the power converters, grounding stations, communications and control systems, and protective equipment as required by the particular system design requirements. The power converters are discussed in Appendix F. The grounding stations are discussed in Appendix E.

- **HVDC Transmission Line.** The HVDC transmission line is the overhead wire, submarine cable, underground cable, or combination of these that connects the converter stations together and forms the transmission circuit. The configuration and design of the transmission line will depend on local conditions and system requirements. Overhead transmission line concepts are discussed in Appendix C. Submarine cable transmission line concepts are discussed in Appendix D.

- **Controls and Communications.** The HVDC transmission system requires a means of communicating between the converter stations and the control the system. The simplest control and communication scheme would use the DC line voltage as a control signal. This would be suitable for a point-to-point HVDC system that feeds power in one direction. Power reversal over the intertie would be possible with manual intervention. Control and communication options for HVDC systems are discussed in Appendix G.

![Figure 3-1 Typical Large HVDC Station](image-url)

5,000 MW +/- 800 kV HVDC Yunnan-Guangdong Converter Station. (TDW, 2012)
3.2 HVDC SYSTEM CONFIGURATIONS

The various system configurations for HVDC can be classified into three different categories, with several options within each category. The three categories and major options are shown below. Each category is described in more detail in the following sections.

Types of HVDC Utility Power Systems

**HVDC Application - How the HVDC technology is used:**
- Point-to-Point DC Power Transmission
- Multiterminal Direct Current (MTDC) Power Transmission

**HVDC Circuit - How the electricity is transported:**
- Monopolar with Single-Wire Earth Return (SWER)
- Monopolar with Metallic Return
- Bipolar

**Intertie Type - How the wires transporting the electricity are configured:**
- Overhead
- Submarine
- Underground

3.2.1 HVDC System Applications

There are three basic applications of HVDC technology in today's electric utility industry. These are:

- **Point-to-point power transmission.** The majority of HVDC systems in use today are point-to-point transmission systems. These transport bulk energy (100s or 1,000s of MWs) over long distances (100s or 1,000s of miles) more efficiently than AC transmission systems.

Point-to-point networks will be a significant application for the low-power HVDC technology being developed with this project.

- **Multiterminal power transmission.** MTDC networks are a more flexible and complicated application of HVDC transmission technology. Instead of the two terminals in a conventional point-to-point HVDC system, MTDC systems have more than two terminals and can route power to or from these terminals as needed. MTDC systems are currently receiving significant industry interest as technology evolves to handle these more complicated systems and regional grids demand the superior performance and enhanced capabilities that MTDC systems offer over AC transmission networks for certain applications. There are a handful of large-scale MTDC systems planned or in operation. Examples include the Quebec – New England MTDC system and the Sardinia – Corsica – Italy MTDC system.

Many regional energy solutions in rural Alaska using HVDC will be in the form of MTDC networks. The power converters developed for this project can support MTDC operation, provided suitable control systems and protective equipment are present. MTDC systems and control considerations are discussed in greater detail in Appendix G.

At the most abstract level, an electrical circuit requires two current pathways, normally metal wires. One wire goes from the power supply to the load, and a second wire goes from the load back
to the power supply. Both single-phase AC and DC circuits rely on this basic configuration. The wire
from the power supply to the load is usually at an increased voltage relative to ground, and so it is
insulated for safety and to prevent short circuits. The wire from the load back to the power supply
is usually at a much lower voltage relative to ground and is usually, but not always, insulated.

There are three types of HVDC circuits in use around the world. Each of these circuits may utilize
overhead wires, underground cables, submarine cables, or a combination of these. These three
circuits are listed on Figure 3-2 and described on the following pages.

**Figure 3-2 Three Types of Interties Used in HVDC Systems**

1. Monopolar with earth return (SWER)
2. Monopolar with return conductor
3. Bipolar

More complex HVDC circuit configurations normally incorporate elements of the simpler circuits
for efficiency, reliability, redundancy, and/or safety. For example, all bipolar HVDC systems include
earth electrodes and sometimes a ground conductor so they can operate either pole in monopolar
or monopolar SWER mode during maintenance or emergencies.

Generally, the more complex bipolar circuit configurations are used for large, important interties
where the increased reliability, efficiency, and power throughput capability justify the higher cost
of these systems.

### 3.2.1.1 Single Wire Earth Return (SWER) Circuits

SWER circuits use the subsurface geology as a return current pathway. Sea return circuits are
similar to earth return circuits. The only difference is that the sea, or any water body, is used as the
predominant return current pathway. Parallel pathways, such as the seabed, are also available for
current flow. The primary advantages offered by SWER circuits include:

- Lower costs (eliminate the second conductor).
- Higher efficiency (lower electrical losses).

The primary concerns associated with SWER circuits include:

- Avoiding accelerated “induced current” corrosion of buried metallic objects.
- As with all electrical systems, safety.

SWER circuits are widely used for utility transmission and distribution of electricity all over the
world. Numerous HVDC interties are SWER circuits, consisting of a single high-voltage cable and an
earth or sea return to complete the transmission circuit. Many of these are installed in climates and
conditions similar to Alaska, notably in Scandinavia. In many nations, single-phase AC SWER
circuits are accepted practice and are industry standard for serving rural areas.
Two single-phase AC SWER circuits have been successfully built and operated in Alaska. These AC SWER circuits demonstrate that SWER is a proven, beneficial, and appropriate technology for rural Alaska transmission applications.

3.2.1.2 **Monopolar HVDC Circuit Using SWER**

A monopolar HVDC intertie using SWER (see Figure 3-3) for the return pathway will generally be the lowest-cost alternative for HVDC power transmission in rural Alaska applications. This circuit configuration will consist of the following major components:

- AC/DC converter module in the generating village.
- High-voltage conductor. This can be an overhead line, buried cable, or submarine cable.
- DC/AC converter in the receiving village.
- Grounding electrodes in both villages to complete the intertie circuit using earth return.

![Figure 3-3 Monopolar HVDC Intertie Using SWER](image)

There are numerous examples of monopolar HVDC interties using SWER circuits. The 500-MW submarine HVDC link completed between Victoria and Tasmania, Australia, in 2006 is one example of a recently constructed SWER HVDC system. Bipolar and monopolar HVDC circuits are normally designed to operate in a monopolar SWER configuration when needed to maximize system reliability.
3.2.1.3 Monopolar HVDC Circuit with Return Conductor

A monopolar HVDC intertie with a return conductor (see Figure 3-4) is similar to a monopolar SWER HVDC intertie. The primary difference is that the earth return is replaced with a dedicated return conductor to minimize earth currents induced by the intertie. Often, such interties will still have the earth electrodes necessary to operate in SWER mode and will operate in SWER mode during maintenance or emergency situations. This HVDC circuit configuration includes the following major components:

- AC/DC converter module in the generating village.
- High-voltage conductor. This can be an overhead line, buried cable, or submarine cable.
- DC/AC converter in the receiving village.
- Return conductor. This can be an under-built line on the high-voltage poles, a separate cable, or incorporated into the same cable as the high-voltage conductor, such as a concentric neutral on an AC cable.
- Grounding electrodes in both villages. These will not normally be used to complete the intertie circuit, but they will be used during maintenance or emergencies.

Monopolar return conductors are warranted in areas where a SWER circuit is not viable or desirable. Generally, this is due to the risk of inducing corrosion in buried metallic utilities. The lack of suitable ground conditions for economical earth electrodes would also warrant use of a return conductor. Using a return conductor with the same electrical resistance as the high-voltage conductor will nearly double the conductor losses relative to a SWER transmission circuit.

Figure 3-4 Monopolar HVDC Intertie with Return Conductor (SWER-capable for Backup)
3.2.1.4  Bipolar HVDC Circuit

A bipolar HVDC intertie (see Figure 3-5) is generally the most costly and most reliable HVDC circuit configuration. It employs two parallel high-voltage conductors, one operated at positive voltage and the second at negative voltage. The system requires two converters at each end of the intertie (four total), compared to one converter per end for monopolar circuits (two total). Thus, the bipolar HVDC configuration includes these major components:

- Two AC/DC converter modules in the generating village. One (+) and one (–).
- Two high-voltage conductors. These could be overhead lines, buried cables, or submarine cables.
- A third neutral conductor to carry any current due to minor imbalance between the power transmission levels on the positive and negative poles. Some bipolar systems do not have a neutral conductor and instead rely on the grounding electrodes to balance the poles.
- Two DC/AC converters in the receiving village. One (+) and one (–).
- Grounding electrodes in both villages. These will not normally be used to complete the intertie circuit, but they will be used to balance the system and for SWER operation during maintenance or emergencies.

The additional costs of a bipolar HVDC intertie are largely due to the additional converters and the second high-voltage conductor. A bipolar HVDC intertie will be roughly twice as costly as a monopolar HVDC intertie, but with twice the capacity and increased reliability.

The principal advantage of a bipolar intertie compared to a monopolar intertie is increased reliability. If something breaks on one of the two poles, the other pole can be operated as a monopolar intertie. This will reduce the power transfer capability, but the intertie can continue to function.

For many rural Alaska applications, the additional cost of bipolar circuits is not justified. Operating backup diesel generators in villages would be more cost-effective than constructing a bipolar HVDC intertie.

Figure 3-5  Bipolar HVDC Intertie (SWER-capable for Backup)
3.2.2 HVDC Intertie Types

HVDC interties can be built using overhead wires, submarine cables, or underground cables. Combinations of these can be used for a single intertie. Overhead wire intertie options are discussed in Section 3.4 and Appendix C. Submarine cable intertie options are discussed in Section 3.5 and Appendix D. Underground cable options are discussed in Appendix G.
3.3 COMPARISON OF AC TO HVDC TRANSMISSION

The following abbreviated comparison is presented to illustrate when an HVDC intertie is anticipated to be a good alternative to a comparable AC intertie in rural Alaska applications. A more detailed comparison is presented in Appendices A and B.

**HVDC Advantages:**

- Lower per-mile overhead transmission line cost than AC lines;
- Ability to use underground or submarine cables for long distances;
- Better compatibility with migratory birds due to fewer overhead conductors (1 or 2 wires instead of 3 or 4 wires);
- Asynchronous connection; and
- Lower per-mile conductor energy losses.

**HVDC Disadvantages:**

- An HVDC converter is more expensive, requires more maintenance, and is less reliable than a comparable AC transformer;
- Converter costs are a barrier to serving loads along the transmission line route;
- Unconventional technology and limited equipment suppliers compared to AC;
- HVDC converters generally have higher energy losses than a comparable AC transformer; and
- HVDC interties may have fewer funding opportunities than conventional AC lines because they are uncommon.

**Implications:**

- If an intertie must employ long-distance submarine or buried cables, HVDC offers a technically superior solution to AC. AC cable interties are not technically feasible for long-distance transmission systems.
- Where both systems are technically feasible, the decision is largely economic. An HVDC intertie will have higher terminal costs and lower per-mile costs. Accordingly, an AC intertie is more cost-effective for short interties, and HVDC is more cost-effective for long interties. The longer the intertie, the greater the cost savings of an HVDC versus AC system. The economic crossover point is project specific but for the scale of interties under consideration in this report, it will generally occur at a distance of 6 and 31 miles.
- Since the HVDC converters developed under this program use new technology, and because it represents a departure from conventional AC transmission systems, substantial savings will be a factor in encouraging utilities to adopt this technology in lieu of proven but more costly intertie solutions.
- Most AC interties are overhead and may not be environmentally acceptable in many parts of Alaska. HVDC interties are either buried or have fewer wires and structures and may be more acceptable within refuges and other sensitive areas.
3.4 OVERHEAD INTERTIE ALTERNATIVES

3.4.1 Conventional AC Interties

The typical cost for constructing a conventional overhead distribution-class AC intertie in rural Alaska can range from as little as $100,000 per mile in areas with good logistic support and transportation infrastructure (road system, southeast) to over $600,000 per mile\(^3\) in rural parts of the state with challenging logistics and little or no transportation infrastructure (remote interior, northwest, or Yukon-Kuskokwim delta regions). Because of this prohibitive expense, relatively few rural interties have been built.

The high cost of rural overhead AC interties is the result of several factors. Two significant cost contributors common to many Alaskan interties projects are logistics and foundations. AC systems rely on multi-wire transmission lines; this leads to high materials costs and high loads placed on structures and foundations. The structures needed to support the multiple aerial wires of an AC system are costly. The resulting AC intertie usually has short spans, 250 to 400 feet being typical, thus resulting in many transmission components such as poles, hardware, wire, and foundations that must be purchased, shipped, installed, and maintained.

When the costs of shipping, geotechnical conditions, construction factors, logistics and environmental requirements are all factored in, conventional AC construction often results in a prohibitively expensive intertie. As a result, many rural communities are denied the opportunity to benefit from interconnection to each other or local energy resources.

3.4.2 HVDC Transmission Interties

Polarconsult has investigated alternatives to AC interties and found that in many applications, HVDC transmission systems offer the most economical solution.

Replacing a conventional overhead AC three- or four-wire transmission line with a one- or two-wire HVDC transmission line has significant cost advantages. The change in overhead infrastructure results in reduced structural loads thus allowing fewer support structures per mile of transmission line. The decrease in materials and construction time is the primary reason overhead HVDC interties are more economically viable than AC interties.

A monopolar HVDC intertie designed as a SWER circuit needs only a single wire aloft, which significantly reduces the loads compared with a three- or four-wire AC intertie. Using a single wire profoundly simplifies the transmission line design, which translates to significant cost savings compared with an AC line.

Because SWER circuits induce a return current in the earth, they require special attention in the design and planning phase to avoid adverse effects from this earth current. The primary concerns are (1) the step potential\(^4\) in the immediate vicinity of the grounding stations and (2) accelerated corrosion of buried metallic objects in the vicinity of the return current pathways through the earth.

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\(^3\) See Section B.6.1 in Appendix B for cost basis information.

\(^4\) A voltage gradient that occurs at the ground surface due to earth return currents. If the voltage gradient is high enough, it can pose a hazard to people or wildlife stepping in the vicinity.
In most rural Alaska localities, these concerns can be readily addressed through proper planning and system design.

Because of these special factors, SWER circuits are not allowed by the National Electrical Safety Code (NESC), which is the applicable code for electric utility transmission and distribution systems. Polarconsult has discussed this HVDC system and concept in detail with the state code authority and finds that SWER circuits can be approved on a project-specific basis by issuance of a code waiver. There is precedent for code waivers being issued for SWER systems in Alaska. The use of SWER circuits is discussed further in Appendix E of this report.

As an alternative to using an earth return circuit, two-wire monopolar HVDC lines (using an overhead wire as the return circuit) also achieve a cost savings relative to AC interties although the savings will typically be less than for an HVDC SWER transmission line.

Bipolar HVDC interties require the use of two additional converters but can transfer twice the energy of a comparable monopolar system. In the event of a converter failure or loss of a conductor, a bipolar system can be configured to operate as a monopolar SWER or monopolar two-wire system. This offers significant reliability advantages; however, it also incurs the cost of the additional converters and second high-voltage conductor. The advantages of the increase in capacity and reliability are the primary reasons for use of bipolar systems.
3.5 **Submarine Cable Intertie Alternatives**

Another advantage of HVDC transmission over AC is its intrinsic ability to carry energy by buried or submarine cable over long distances without the technical limitations and additional equipment required for similar transmission by AC. Monopolar HVDC using a single cable can connect villages separated by lakes, bays, fjords, or lands where overhead transmission is not practical, cost-effective, or desirable. For this reason, low-power HVDC technology has significant implications for interconnecting communities in Alaska separated by water bodies, particularly in the southeast.

Cabletricity was retained by Polarconsult as a subconsultant to investigate submarine cables optimized for use with this HVDC system. Appendix D includes the Cabletricity report detailing results of their investigations.

The report begins with a description of the electrical system to which the cables will be connected, and then advances to the regional environment they must withstand and on to descriptions of submarine cable standards, cable designs, typical installation methods, and cost estimates for a case study.

Cabletricity evaluated submarine cables suitable for 1-MW monopolar HVDC interties at 50 kilovolts (kV), with potential upgrade of the converter stations to 5-MW service in a monopolar circuit. Cabletricity also evaluated the feasibility and cost of integrating optical fibers into the power transmission system to serve the communications needs of rural communities. To make this system practical, simplicity and reliability are critical design considerations.

Cabletricity’s investigations focused on single core insulated conductor submarine cables with earth or sea return that would be generally suitable for the rugged and deep inter-island and fjord crossings typical of southeast Alaska. The objective is to identify suitable conventional or innovative submarine cable designs to meet the overall project objectives where water crossings are required.
4.0 HVDC CONVERTER STATIONS

4.1 OVERVIEW

The HVDC converter stations will include the major components listed below:

- HVDC power converters such as those being developed by PPS;
- Converter enclosures, which may consist of dedicated enclosures or use of an existing building, such as an existing power plant;
- Protection, control, and switching equipment on the AC and HVDC sides of the converters;
- AC transformers, depending on the AC interface voltage and wiring; and
- Grounding stations, including the ground conductor from the converter station to the grounding station.

4.2 CONVERTER DEVELOPMENT OVERVIEW

Polarconsult subcontracted with PPS for the development of the HVDC power converters. PPS was tasked with the development of one full-scale and full-functionality 1-MW power converter, consisting of two 500-kilowatt (kW) modules. Development work included preparation of specifications, design, construction, and testing of the prototype converter.

The HVDC converter is a 1-MW power converter capable of bidirectional power conversion between three-phase 480 volts alternating current (VAC) and 50 kV HVDC. The converter capacity is appropriate to supply the electrical needs of most Alaska villages economically. In contrast, existing HVDC power converter systems are only available at much larger transmission capacities, starting at approximately 50 MW and extending up to 1,000s of MWs of capacity.

Each 500-kW PPS converter consists of two modules: an air-cooled low-voltage cabinet (Figure 4-1), and an oil cooled high-voltage tank (Figure 4-2). AC power cables connect to the low-voltage cabinet, which conditions the power and transforms it to a special high-frequency AC, which is transmitted to the high-voltage tank via power cable. The high-voltage tank transforms the high-frequency AC to 50 kV DC. The high-voltage tank has two bushings that output up to 500 kW at 50 kV DC. Either bushing can be grounded to produce a positive 50-kV HVDC output or a negative 50-kV HVDC output.

Multiple PPS HVDC converters can be “paralleled” to achieve higher power transmission capacities where needed. Based on Phase II development work, the price of a commercially produced 1-MW HVDC power converter is estimated to be $250,000. At least two 1-MW converters are needed for a complete 1-MW HVDC transmission system.

PPS has successfully demonstrated operation and power flow at the full 50 kV DC in both inverter (HVDC to AC) mode and rectifier (AC to HVDC) mode in a controlled test facility setting. These testing efforts validate the design and basic functionality of the converter.

In the course of testing, PPS identified two hardware problems that prevented full-power testing of the prototype converters. PPS has investigated these problems and identified the actions necessary to correct both problems. The problems and solutions are discussed in Appendix F.
The following figures illustrate the converter features:

- Figures 4-1 and 4-2 show the two basic modules that make up a complete 500-kW converter system. These are further discussed in Appendix F.
- Figure 4-3 shows the test setup for testing of the central resonant link circuit in the high-voltage DC transformer.
- Figure 4-4 shows the in-air high potential (hi-pot) test setup of the high-voltage DC transformer assembly. This test identified some insulation defects that were corrected. The test demonstrated that the DC transformer assembly will withstand the voltages experienced at full operating voltage of 50 kV DC.
- Figure 4-5 shows the dry system test setup and schematic. Before the DC transformer was immersed in oil, it was tested at low voltage in air to validate function and facilitate troubleshooting. This was primarily done for convenience, to avoid the delays and mess associated with repeatedly immersing the DC transformer in oil and removing it.
- Figure 4-6 shows a complete 500-kW converter module, consisting of the HVDC tank and the low-voltage alternating current (LVAC) cabinet.
- Figure 4-7 shows four high-voltage measurement probes used to monitor the voltages at different points in the DC transformer. The test showed excellent voltage sharing between the DC transformer stages, indicating that the system is performing in accordance with design. Uniform voltage sharing is a key success, as it means the power electronics components will not be subjected to uneven voltages stresses. Excessive voltage stresses could severely shorten the life of the components, reducing the reliability of the converter.
Figure 4-1  Low Voltage Alternating Current (LVAC) Enclosure: Mechanical Layout

Notes:
Cabinet size: 66"W x 42"D x 66"H;
Cabinet weight: Approximately 2,200 pounds.
Figure 4-2 HVDC Transformer Tank: Mechanical Layout

Notes:
Tank size: 88"W x 39"D x 59.25"H;
Tank weight with oil: 4,200 pounds.
Figure 4-3  Central Resonant Link Test Setup

Figure 4-4  Hi–Pot Test Setup for HVDC Transformer
Figure 4-5  Dry System Inverter Mode Test Schematic and Setup
Figure 4-6  System #1 HV Tank and LV Enclosure

Figure 4-7  System #1 Showing HV Measurement Probes
4.3  ADDITIONAL EQUIPMENT

4.3.1  Converter Enclosure

While the converter specifications permit the converters to be installed outdoors in most Alaska environments, it is assumed that the converters will be installed inside an enclosure. This will provide for a controlled operating environment and greater security for the converters, extending their useful service life.

The conceptual design assumes that a modular, prefabricated enclosure will be sent to the community with the two 500-kW power converter units already installed. This converter module will then be set in place on a suitable foundation.

In communities that will be primarily served by an HVDC intertie, it may be appropriate to locate the converters inside the existing powerhouse or other suitable existing structure. This would have the following advantages:

- The existing powerhouse may already have a suitable step-down transformer sized for the full community load;
- Waste heat from the converters would provide all or part of the heat for the power plant building; and
- Achieves project cost reduction by eliminating the need for a dedicated converter enclosure and purchasing or leasing land to site the converter.

4.3.2  Protection and Switchyard Equipment

Switchgear will be needed on the AC side of the converters to isolate and protect the converter from the AC grid and to monitor power flow between the converter and the grid.

Similar isolation, protection, and monitoring equipment is needed on the HVDC side of the converter. At a minimum, manual disconnect switches (nonload break), surge arrestors, and protective fuses are needed on the HVDC side. More automated control apparatus can also be used, but at increased cost.

4.3.3  AC Transformers

The grid interface on the power converters is three-phase 480-volt AC. In communities where the converter is connected directly to the 480-volt power plant bus, no transformer is required. In communities where the converter connects to the local distribution grid, a step-up transformer is required. The transformer will typically be a three-phase 480/12.47-kV transformer.

4.3.4  Grounding Stations

A grounding station will need to be provided at each HVDC converter station, regardless of the HVDC circuit configuration. The conceptual design of a 1-MW, 50-kV DC grounding station is presented in Appendix E (Figure E-1).
5.0 DESIGN CONCEPTS FOR OVERHEAD INTERTIES

The following summarizes design criteria developed for the conceptual design of the HVDC overhead intertie lines. Design criteria and conceptual designs are presented in detail in Appendix C.

5.1 OVERHEAD DESIGN APPROACH

The overhead intertie design concepts presented required consideration of typical site conditions, codes, utility and lender requirements, construction methodologies, standard design practices, and project economics. The following two design approaches for overhead HVDC interties have been evaluated, each with a capacity to supply 1 MW through a monopolar 50-kV DC system:

5.1.1 RUS Design Approach, Modified for HVDC Interties

The first conceptual design approach is based on the use of structures that are constructed in accordance with USDA RUS-type construction (RUS standard practice) for conventional 12.4/24.9-kV AC distribution lines. These RUS standard practices are currently used to develop AC interties throughout Alaska and are widely accepted by the utility industry. HVDC transmission requires fewer conductors than AC, resulting in reduced loads on the supporting structures. As a result, the conceptual designs developed using the RUS approach have longer ruling spans than typical AC lines. This results in fewer transmission structures for the HVDC intertie and an associated comparative reduction in construction cost.

5.1.2 Alaska-Specific Design Approach for HVDC Interties

The second conceptual design approach takes the logistic and technical challenges of construction in rural Alaska into consideration and focuses on methods to reduce construction costs without compromising performance or long-term maintainability. This design approach incorporates cost-saving features made possible through HVDC-specific design alternatives, materials, and construction methods. Design features of this concept include the use of guyed composite structures to allow significantly longer ruling spans than is possible with RUS standard practice. The reduced number of structures, less costly foundations, and reduced number of conductors all result in additional savings compared with interties built in accordance with RUS standard practices.

The following three HVDC transmission circuit configurations are considered for each of the HVDC conceptual design approaches:

- Monopolar single-wire transmission with earth-return path (SWER);
- Monopolar two-wire transmission with metallic conductor-return path (TWMR);
- Bipolar two-wire transmission (2-MW capacity).

---

5 In this report, the term “RUS standard practice” refers to overhead intertie line designs based on the methods and materials presented in RUS design manuals for transmission and distribution line construction, including but not limited to: REA, 1982, RUS, 1998, 2002, 2003a, 2003b, 2003c, and 2009.
Schematic figures are provided for each of these conceptual designs in Appendix C. Detailed reports that address various technical aspects of the assumed conditions and loadings used to develop these conceptual designs are provided as attachments to Appendix C.

5.2 Geotechnical Conditions

Based on the analysis described below, conceptual foundation design alternatives for a guyed pole utilize three thermoprobe micropiles for the pole base and helical anchors for the guys. The overhead system test site in Fairbanks, Alaska, features installations of both these prototype foundations.

5.3 Environmental Loads

Five standard NESC loading cases were analyzed for each conceptual design. These load cases are considered sufficient for most rural Alaska overhead intertie applications. Specific locations may be subject to higher and/or lower wind and/or ice loadings. Except where specifically stated otherwise, each of the conceptual designs presented in this section comply with the most stringent of these load conditions.

5.4 Construction, RUS Standard Practice

The conceptual designs of overhead intertie lines presented in this section have been developed to take advantage of the following factors:

- Alaska contractors, line crews, and utility line personnel are familiar with RUS standard practice materials, designs, and construction practices, thus they will be more familiar with the techniques and procedures for building, maintaining, and repairing these lines.
- Alaska already has many miles of RUS standard-practice distribution and transmission lines built and in service throughout the state. Utilities understand the performance record and issues with this type of line construction.
- Utility lenders, which includes RUS, understand and accept RUS standard construction practice, which can simplify obtaining funds for constructing new interties.

To take advantage of these factors, conceptual design for HVDC preserved RUS standard practice construction to the extent possible, modifying the pole top assembly to accommodate the conductor(s), insulator(s), and clearances for HVDC operation. The ruling span is also increased to take advantage of the fewer wires and reduced structure loads associated with the HVDC circuit configurations.

Structural analysis of conventional overhead HVDC transmission structures (adapted from RUS standard practice) was performed by Polarconsult. A conceptual design summary is presented in Appendix C for each of the line configurations proposed.

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6 Section 4.6 of the Phase I Final Report provides a summary of environmental loadings around Alaska (Polarconsult, 2009)
5.5 Construction, Alaska-Specific Concept

The conceptual designs of overhead intertie lines presented in this section have been developed to reduce construction costs on rural Alaska interties. Cost reduction is achieved through special attention to the factors listed below.

- Minimizing the reliance on heavy equipment that must be mobilized to a construction site. If lighter equipment or local equipment can be used for construction, mobilization costs will be less, reducing project costs.
- Maximizing the flexibility in construction methods and seasons. By designing for the use of smaller equipment, greater use of helicopters for construction support, and similar techniques, all-season construction becomes possible, providing increased flexibility for construction techniques and methods. This increased flexibility creates new opportunities to increase utilization of equipment, increase competition for line construction projects, and reduce project costs.

These factors have been incorporated into the conceptual design elements listed below.

- Use of taller structures and longer spans. Because HVDC circuits require only one or two wires, they can utilize longer spans than a comparable three- or four-wire AC circuit. Increasing spans reduces the number of structures and foundations for a given length of overhead line, which reduces costs. With this approach, taller structures are needed to maintain required clearances between the conductor and the ground.
- Use of glass-fiber-reinforced polymer (GFRP) poles instead of wood or steel poles. GFRP poles have been used for over 50 years in electric utility applications but have little to no history in Alaska’s electric utility industry. GFRP poles are lighter than wood or steel poles so they can be transported by a small helicopter such as a Hughes 500 or Bell UH-1 “Huey.” They are also rot-resistant and do not leach toxic preservatives into the soils around the pole. The Phase II project included demonstration of a field-friendly splice for GFRP poles, which permits tall poles to be shipped in parts and assembled in the field. This splice can also be used for field repair of damaged GFRP poles.
- Use of guyed structures in areas where geotechnical conditions prevent cantilevered poles from being directly buried in the soil. Accepted practice for such conditions is to drive a steel pile up to 40 feet deep and then fasten a wood pole to the steel pile. Installing the steel pile requires mobilizing a crane or other heavy equipment to the project site. A guyed structure can be installed in such conditions with a much smaller base foundation, as the guys carry most of the moment, and the structure base mostly carries compressive loads.

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7 Ibrahim, 2000.
5.6 TESTING OF OVERHEAD DESIGN CONCEPTS

The conceptual overhead designs described in Appendix C use commercially available and accepted materials, designs, and construction methods. Certain aspects of the conceptual designs presented represent innovations in overhead line design that do not have a proven record within the utility industry in Alaska conditions. In order to evaluate the performance of these components, they were installed at a test site in Fairbanks, Alaska. This section summarizes the objectives and installation of the Fairbanks Test Site. Details of the test program are presented in Appendix C.

5.6.1 Test Objectives

The primary test objectives of the Fairbanks Test Site are listed below.

- Demonstrate performance and assembly time of a splice for a constant-section GFRP utility pole.
- Demonstrate installation and performance of micro-thermopile pole foundations.
- Demonstrate installation and performance of micro-thermopile guy anchors.
- Demonstrate installation and performance of screw guy anchors.
- Demonstrate the installation and performance of the overall guyed GFRP pole structure.
- Demonstrate maintenance and operational characteristics.

5.6.2 Test Site

The test site is located on private property south of Farmer’s Loop Road and north of Creamers’ Field in Fairbanks. The site consists of warm ice-rich silty permafrost soils. The site has an organic layer consisting of deciduous shrubs and black spruce. Peat was present at depths of 1 to 5 feet below ground surface. The active layer in September 2011 extended to a depth of 3 feet, with standing water encountered within the vegetative mat near the surface. Geotechnical conditions at the site are characteristic of marginal warm permafrost conditions, as further described in Appendix C.

Figures 5-1 through 5-4 show the installation of innovative materials and systems at the test site in Fairbanks.
Figure 5-1 Installing Micro-Thermopile for Guy Anchor

Contractor GeoTek Alaska, Inc. drilling a hole for installation of a micro-thermopile at a 45-degree batter angle using a GeoProbe 8040 series drill rig. The micro-thermopile will serve as a guy anchor for the prototype guyed GFRP pole installation at the Fairbanks Test Site. (Polarconsult, 2011).
Contractor City Electric, Inc. installing the field splice for the prototype GFRP pole. 40-foot and 20-foot GFRP pole segments were spliced to create the 60-foot pole erected at the site. The splice slides over the pole segments and carries moment through contact between the pole and splice walls. Vertical loads are carried through the butt ends of the pole segments. No glue or adhesive is necessary for the splice to develop the full mechanical strength of the pole. The screws serve to prevent differential movement between the pole and splice. (Polarconsult, 2011)
Figure 5-3  Prototype GFRP Pole Foundation During Installation

Detail of prototype GFRP pole base at the Fairbanks Test Site. The adapter plate was adjusted during installation so the hinge is oriented in line with the guy anchor in the distance (orange flagging). This will allow use of the guy anchor to lower the pole with a winch if needed. (Polarconsult, 2011)
Figure 5-4 Prototype Pole at the Fairbanks Test Site

View of the prototype guyed GFRP pole installed at the Fairbanks Test Site. This photograph is taken at a distance of approximately 25 yards from the 60-foot-tall pole. The four guys and the pole splice are visible in this photograph. (Polarconsult, 2011)
6.0 SYSTEM ECONOMICS

The extreme variety of environmental and technical conditions found across rural Alaska results in a significant variation in intertie costs. The typical cost for constructing a conventional overhead distribution-class AC intertie in rural Alaska can vary from as little as $100,000 per mile to over $600,000 per mile in parts of the state with challenging logistics and little or no transportation. Intertie cost variations also affect submarine cables, underground cables, and other overhead intertie configurations. The details of system economics are presented in Appendix B.

6.1 COST COMPARISON OF AC AND HVDC OVERHEAD INTERTIES

Two distinct overhead HVDC intertie configurations have been compared to a conventional AC intertie to illustrate a range of HVDC intertie economics with different overhead designs. The two HVDC intertie configurations are:

- A two-wire monopolar HVDC intertie using RUS standard practice construction methods. This intertie configuration represents the upper range of estimated cost for an HVDC overhead intertie in rural Alaska applications.
- A monopolar SWER HVDC intertie using Alaska-specific construction methods. This intertie configuration represents the lower range of estimated cost for an HVDC overhead intertie in rural Alaska applications.

The estimated cost for HVDC interties in most rural Alaska applications is expected to fall between the costs cited for these two configurations.

6.1.1 Installation Cost Comparison

Figure 6-1 presents the estimated installed cost relative to the intertie length for three different kinds of interties built in rural Alaska conditions:

- A conventional rural Alaska intertie,
- A two-wire monopolar HVDC intertie using RUS-type construction methods, and
- A monopolar SWER HVDC intertie using Alaska-specific construction methods.

Additionally, Figure 6-1 illustrates the economic break-even length and relative increase in savings for longer HVDC interties. The points at which the AC “cost line” crosses either of the HVDC “cost lines” represents the economic break-even length. The estimated HVDC costs show a hypothetical range of installed costs anticipated for low-power (under 1 MW) rural Alaska HVDC systems.

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8 See Section B.6.1 in Appendix B for cost basis information.
Figure 6-1 Comparative Installed Cost: Overhead 1-MW HVDC and AC Interties

Note: This chart is based on the assumptions and comparative system costs presented in Appendix B. The break-even point will vary for every intertie project.
6.1.2 Life-Cycle Cost Comparison

Operating costs, maintenance costs, and electrical efficiency affect the long-term economic value of an intertie. Table 6-1 presents comparative life-cycle costs for hypothetical 25-mile-long overhead AC and HVDC interties in rural Alaska. A length of 25 miles was selected as it conservatively represents the savings anticipated for short HVDC interties. The estimated life-cycle cost for a 25-mile-long HVDC intertie ranges from 79% to 107% of the life-cycle cost of an AC intertie.

Table 6-1 Estimated Life-Cycle Costs for 25-mile Overhead AC and HVDC Interties

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Standard RUS AC Intertie</th>
<th>Monopolar Two-Wire HVDC Intertie (RUS Construction)</th>
<th>Monopolar SWER HVDC Intertie (Alaska-Specific Design)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Diesel ($/gallon [gal])</td>
<td>$7.00 per gallon</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generation Efficiency (kWh/gal)</td>
<td>13 kWh per gallon</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intertie Efficiency 4</td>
<td>97.7%</td>
<td>93.4%</td>
<td>94.5%</td>
</tr>
<tr>
<td>Net Annual Energy Transmission (kWh)</td>
<td>1,664,400</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Transmission Losses 4 (kWh)</td>
<td>38,300</td>
<td>133,000</td>
<td>114,000</td>
</tr>
<tr>
<td>Annualized Value of Transmission Losses ($)</td>
<td>$21,000</td>
<td>$71,000</td>
<td>$61,000</td>
</tr>
<tr>
<td>Intertie Design Life (years)</td>
<td>20 years</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intertie Annual Operations and Maintenance (O&amp;M) Costs</td>
<td>$40,000</td>
<td>$58,000</td>
<td>$54,000</td>
</tr>
<tr>
<td>Effective Discount Rate</td>
<td>3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Present Worth of Transmission Losses</td>
<td>$307,000</td>
<td>$1,063,000</td>
<td>$912,000</td>
</tr>
<tr>
<td>Present Worth of O&amp;M Costs</td>
<td>$595,000</td>
<td>$867,000</td>
<td>$796,000</td>
</tr>
<tr>
<td>Converter Stations Installed Cost</td>
<td>$20,000</td>
<td>$2,080,000</td>
<td>$1,160,000</td>
</tr>
<tr>
<td>Intertie Installed Cost</td>
<td>$9,480,000</td>
<td>$7,120,000</td>
<td>$5,340,000</td>
</tr>
<tr>
<td>Estimated Life-Cycle Cost</td>
<td>$10,402,000</td>
<td>$11,130,000</td>
<td>$8,208,000</td>
</tr>
<tr>
<td>HVDC Life-Cycle Cost as Percent of AC Life-Cycle Cost</td>
<td>107%</td>
<td>79%</td>
<td></td>
</tr>
<tr>
<td>Present Worth Savings (Cost) of HVDC vs. AC</td>
<td>($728,000)</td>
<td></td>
<td>$2,194,000</td>
</tr>
</tbody>
</table>

Notes:
1. “Alaska-Specific Design” refers to the design concepts presented in Appendix C of this report.
2. “RUS Construction” refers to standard RUS design and construction methods for AC interties, adapted to HVDC applications as described in Appendix C of this report.
3. All monetary values are in 2012 dollars.
4. Efficiency and loss information includes all transmission system components.
Figure 6-2 illustrates the economic break-even length and relative increase in savings for longer HVDC interties. The points at which the AC “cost line” crosses either of the HVDC “cost lines” represents the economic break-even length. The estimated HVDC costs represent a hypothetical range of life-cycle costs anticipated for low-power (under 1 MW) rural Alaska HVDC systems.

**Figure 6-2 Comparative Life-Cycle Cost: Overhead 1-MW HVDC and AC Interties**

Note: This chart is based on the assumptions and comparative system costs presented in Appendix B. The break-even point will vary for every intertie project.
6.2 Case Studies

The case studies in this section provide project-specific examples of the expected costs and resulting benefits of using HVDC systems to interconnect communities and resources. These case studies rely on existing information regarding the proposed intertie routes, loads, and related project information. Figure 6-3 presents a few of the many potential low-power HVDC project sites throughout Alaska.

For the purposes of this report, two specific HVDC project sites were selected for evaluation. The “Greens Creek – Hoonah” and the “Nome – Pilgrim Hot Springs” intertie projects are typical of the design approach and economics common to other HVDC Alaskan interties. Table 6-2 summarizes the case studies considered in this section.
### Table 6-2 Summary of Case Studies

<table>
<thead>
<tr>
<th>HVDC Intertie Case Study</th>
<th>Transmission Circuit</th>
<th>Intertie Type</th>
<th>HVDC Intertie Cost Estimate¹</th>
<th>AC Intertie Cost Estimate¹</th>
<th>Estimated HVDC Savings¹</th>
<th>Percent Capital Cost Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greens Creek – Hoonah</td>
<td>5-MW monopolar HVDC circuit with sea return²</td>
<td>Submarine Cable</td>
<td>$22.2 million</td>
<td>$49 million</td>
<td>$26.8 million</td>
<td>55%</td>
</tr>
<tr>
<td>Nome – Pilgrim Hot Springs</td>
<td>5 MW bipolar HVDC circuit</td>
<td>Overhead Line</td>
<td>$25.7 million</td>
<td>$36.3 million</td>
<td>$10.6 million</td>
<td>29%</td>
</tr>
</tbody>
</table>

**Notes:**

1. All cost estimates are presented in 2012 dollars.
2. The case study provides a submarine and overhead intertie capacity of 5 MW and converter station capacity of 2 MW. This provides an ample margin for load growth in Hoonah. The converter station capacity can be upgraded as needed in 500-kW increments up to 5 MW.

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**6.2.1 Green’s Creek – Hoonah Case Study**

An intertie between Greens Creek, on the Alaska Electric Light and Power Company (AEL&P) grid that serves Juneau, and the village of Hoonah, an isolated micro-grid operated by the IPEC, has been under consideration for over a decade. AEL&P and the IPEC have completed extensive studies and design work on this intertie. Studies identified a 25-mile-long AC submarine cable and approximately 4 miles of overhead line near Hoonah as the most economical means to complete this interconnection. The proposed intertie route is shown on Figure 6-4.

As the development of this project continued, the costs of the AC submarine cable have escalated, until the project was finally put on hold due to its excessive cost. Hoonah is currently exploring local hydropower resources to reduce its energy costs but continues to view an intertie as the best long-term solution for its energy needs.

This HVDC system represents a technological advance that can reduce the cost of the Greens Creek – Hoonah intertie and increase its economic feasibility as compared with Hoonah’s other energy options. The following subsections of this case study provide a high-level analysis of the merits of an HVDC intertie for Hoonah.

For the purposes of this case study, a 5-MW monopolar HVDC transmission circuit with sea return was selected to connect Hoonah with Green’s Creek. This circuit consists of 25 miles of submarine cable and 4 miles of overhead line. A monopolar circuit was selected because it is expected to be the least-cost intertie solution between Hoonah and Green’s Creek. Other potential configurations, such as a bipolar HVDC circuit utilizing two single-conductor cables, would be more expensive than the monopolar design selected.

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⁹ (Power Engineers, 2004)
The estimated capital costs include a 5-MW transmission circuit (submarine cable and overhead line), and 2-MW converter stations at Hoonah and Green's Creek. The converter stations can be upgraded to 5 MW by adding 500-kW converter modules as Hoonah's load increases. If Hoonah's load grows beyond 5 MW, a second submarine cable can be installed to provide a 10-MW bipolar transmission system.

**Figure 6-4  Greens Creek – Hoonah Intertie Route**

6.2.1.1 Economic Analysis

Table 6-3 presents the economic analysis for the Greens Creek – Hoonah intertie alternatives. The estimated installed cost for the HVDC intertie is $22.2 million, as compared to the cost of $49 million for a conventional AC intertie. The AC intertie cost estimate is based on the 2009 estimated cost of $37.5 million\(^\text{10}\) adjusted to 2012 dollars.

\(^{10}\) IPEC, 2009.
### Table 6-3 Estimated Cost for a Greens Creek – Hoonah HVDC Intertie

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preconstruction</td>
<td></td>
</tr>
<tr>
<td>Right-of-way acquisition, engineering, survey, permitting</td>
<td>$1,600,000</td>
</tr>
<tr>
<td>Administration/Management</td>
<td>$900,000</td>
</tr>
<tr>
<td>HVDC Converter Stations (power converters, sea electrodes, enclosures, AC and DC side station equipment)</td>
<td>$2,700,000</td>
</tr>
<tr>
<td>Submarine Cable Supply and Installation</td>
<td>$12,400,000</td>
</tr>
<tr>
<td>Overhead HVDC Line: Spaaski Bay to Hoonah</td>
<td>$900,000</td>
</tr>
<tr>
<td>Contingency (on entire project, 25%)</td>
<td>$3,700,000</td>
</tr>
<tr>
<td><strong>Total Estimated Cost</strong></td>
<td><strong>$22,200,000</strong></td>
</tr>
</tbody>
</table>

**Notes:** 1. A contingency of 25% is applied to the costs developed for this project based on the uncertainties associated with the project. A significant amount of work has already been done to characterize the bathymetry and sea floor conditions along the proposed cable route.
Table 6-4 presents estimated benefit-cost ratios for the Greens Creek – Hoonah intertie under several load growth scenarios. This analysis indicates a clear economic advantage to an HVDC intertie based on reasonable load growth forecasts for Hoonah.

### Table 6-4 Estimated Benefit-Cost Ratio of Greens Creek – Hoonah HVDC Intertie

<table>
<thead>
<tr>
<th>Item</th>
<th>Load Growth Scenario</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Existing Load</td>
<td>165% Growth</td>
<td>200% Growth</td>
<td></td>
</tr>
<tr>
<td>Annual Hoonah Energy Generation (kWh/yr) ¹</td>
<td>5,150,000</td>
<td>8,500,000</td>
<td>9,780,000</td>
<td></td>
</tr>
<tr>
<td>AEL&amp;P Avoided Cost of Energy (Juneau) ²</td>
<td>$0.06 per kWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IPEC Avoided Cost of Energy (Hoonah) ¹</td>
<td>$0.20 per kWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Intertie Outage Rate ³</td>
<td>2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annual Hoonah Savings ⁴</td>
<td>$707,000</td>
<td>$1,170,000</td>
<td>$1,340,000</td>
<td></td>
</tr>
<tr>
<td>IPEC Operation, Maintenance, Repair, Replacement and Rehabilitation (OMR&amp;R) Annual Costs ⁵</td>
<td>$90,000</td>
<td>$90,000</td>
<td>$100,000</td>
<td></td>
</tr>
<tr>
<td><strong>Net Annual Savings (Cost)</strong></td>
<td><strong>$617,000</strong></td>
<td><strong>$1,150,000</strong></td>
<td><strong>$1,340,000</strong></td>
<td></td>
</tr>
<tr>
<td>Intertie Life and Discount Rate</td>
<td>30 years, 3%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Present Worth of Annual Savings (Costs)</strong></td>
<td><strong>$12,070,000</strong></td>
<td><strong>$21,090,000</strong></td>
<td><strong>$24,500,000</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Estimated Installed Cost</strong></td>
<td><strong>$22,200,000</strong></td>
<td><strong>$22,200,000</strong></td>
<td><strong>$22,200,000</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Estimated Benefit-Cost Ratio</strong></td>
<td>0.54</td>
<td>0.95</td>
<td>1.10</td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
2. Approximate AEL&P energy cost. IPEC has capacity, so no demand or capacity charges are included.
3. Assumed value.
4. Annual savings are based on the differential cost of energy and do not consider economic benefits in Hoonah from lower cost energy, or effects to AEL&P of increased energy sales.
5. IPEC’s estimated operations, maintenance, repair, and routine replacement costs include costs for the converter stations, savings from decreased operation and overhaul of the diesel power plant in Hoonah, and a one-time cable repair event over the 30-year analysis period.
6. Hoonah’s peak loads under a 200% load growth scenario would exceed the 2-MW capacity of the intertie converter stations. Intertie throughput is reduced by 5% to reflect diesel generation in Hoonah.
6.2.2 Pilgrim Hot Springs – Nome

Pilgrim Hot Springs is a geothermal resource located approximately 60 miles north of Nome. It has been proposed as a power source to reduce Nome’s reliance on diesel fuel for electrical generation. ACEP is currently studying the Pilgrim Hot Springs geothermal resource to better characterize the resource’s potential for power generation and other applications. For purposes of sizing the transmission line from Pilgrim Hot Springs, an electrical generating capacity and transmission capacity of 5 MW is assumed, based on conversations with ACEP’s manager for the Pilgrim Hot Springs assessment project. The proposed transmission route is shown on Figure 6-5.

A bipolar HVDC circuit using overhead lines was selected for the HVDC intertie. The bipolar configuration was selected because it provides increased reliability compared to a monopolar line at a reasonable additional cost.

Conceptual power line costs for overhead AC and HVDC interties were estimated to evaluate the benefits of connecting Pilgrim Hot Springs to Nome using an HVDC intertie. The cost estimates indicate that an HVDC transmission line would cost 29% less than an AC transmission line.

A routing study was not performed as part of this case study. Power lines were routed along the existing road corridor. This is assumed to be the least-cost route for the power lines, as the road can be used to support the construction and long-term maintenance of the line. A routing study may identify other routes that are more favorable due to geotechnical, land status, environmental, or other factors.

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11 Personal communication with Marcus Mager, 2012.
Figure 6-5  Prospective Transmission Route from Pilgrim Hot Springs to Nome
6.2.2.1 Economic Analysis

Table 6-5 presents the economic analysis for the Pilgrim Hot Springs – Nome intertie alternatives. The estimated installed cost for the HVDC intertie alternative is $25.7 million, as compared to the cost of $36.3 million for a conventional AC intertie.

No information is available for the installed cost of a geothermal power plant at Pilgrim Hot Springs or the cost of the energy it would generate, so a benefit-cost ratio of the intertie alternatives was not evaluated.

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Installed Cost for Bipolar HVDC Intertie</th>
<th>Estimated Installed Cost for AC Intertie</th>
<th>Estimated HVDC Savings</th>
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<td><strong>$36,300,000</strong></td>
<td><strong>$10,600,000</strong></td>
<td><strong>29%</strong></td>
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Note:
1. A 30% contingency was applied to the costs for this project because no information was available for the transmission route. This lack of data creates risks due to factors such as land availability, geotechnical conditions, structural (wind and ice) loadings, and environmental (bird, wildlife, and aesthetics) factors.

Some of these risks are mitigated by the use of cost data for the robust conceptual designs (i.e., Alaska-specific construction) used for the HVDC system. The Alaska-specific conceptual design is assumed to be adequate for the expected geotechnical and structural conditions along the route. Environmental and land availability issues, which could require a longer route or departure from the road corridor, pose relatively greater risks than line design considerations. The net result of these factors results in the 30% contingency used for the case study economics.
7.0 CONCLUSIONS AND RECOMMENDATIONS

7.1 CONCLUSIONS

Phase II has demonstrated that the converter technology is technically viable and the transmission system is economically feasible. Key Phase II findings are:

- Low-power HVDC converter technology is expected to be commercially available at $250 per kilowatt per converter.
- Estimates of construction costs for a conceptual 25-mile overhead HVDC intertie indicate capital cost savings of approximately 30% compared with a conventional overhead AC intertie. Estimated life-cycle costs range from 79% to 107% of the life-cycle cost of an AC intertie.
- Longer overhead HVDC interties can expect capital cost savings of up to 40%.
- Significant savings are possible for submarine cable and underground cable applications using HVDC systems. Estimated capital cost savings on a 25-mile low-power HVDC submarine cable intertie are over 50% compared to AC alternatives.

Based on Phase II findings, the benefits of low-power HVDC systems for Alaska are substantial, and continued development of this system is recommended.

7.2 OPPORTUNITIES AND BARRIERS

Based on analysis and study conducted during this Phase II project, Polarconsult has concluded that this HVDC technology presents the following opportunities for Alaska’s utility industry and rural communities:

- Less expensive rural electric interties, leading to lower-cost energy and increased energy independence for rural communities.
- Interconnection to currently stranded energy resources.
- Interconnection cost savings by combining rural electric and telecommunications interties.

The successful commercialization and adoption of low-power HVDC technology in Alaska requires overcoming the following barriers:

- Completion of the commercial development and demonstration of the converter technology. Continued development of the prototype converters, culminating in independent testing of the converters and deployment on an Alaska utility system, is needed to prove that the converters are a commercially viable technology.
- Acceptance and use of low-power HVDC technology by Alaska’s utility industry. Continued involvement of in-state and international stakeholders with the on-going development of this technology is considered necessary to surmounting this barrier.
- Development and demonstration of standards and control protocols for MTDC transmission networks, which are needed to build cost-effective regional HVDC power networks in rural Alaska.
7.3 RECOMMENDATIONS

Based on the conclusions and findings of this project, the following actions are recommended.

Phase III program activities:

- Continued development of the power converter technology to commercialize the existing prototype converter design. Solicitation of additional HVDC converter manufacturers is warranted to encourage diversity of suppliers and competition;
- Independent testing of the converters to validate efficiency and performance, followed by deployment on an Alaskan utility system to validate functionality and reliability in a commercial setting;
- Further development of MTDC transmission systems interconnection and control technologies; and
- Continued involvement of in-state stakeholders in the development of this technology.

Stakeholder actions:

- Incorporate low-power HVDC technology into Alaska’s regional and statewide energy plans and policies;
- Continue coordination with the State of Alaska to allow a project-specific waiver of the NESC to allow the use of SWER circuits;
- Encourage planned rural power and telecommunications interties to incorporate HVDC technology in their economic and technical analysis, as well as their environmental and permitting review processes;
- Engage the telecommunications industry to raise awareness of the synergies possible between low-power HVDC transmission and fiber networks in rural Alaska; and
- Collaborate with international stakeholders to identify synergies and lessons learned from parallel technology development efforts. Coordinate on development of applicable policies/standards and identification of markets to help expedite the commercialization and reduce the costs of low-power HVDC systems.
APPENDIX A

HVDC OVERVIEW
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A.1 HIGH-VOLTAGE DIRECT CURRENT (HVDC) TECHNOLOGY

High-voltage direct current (HVDC) converter technology has advanced to use high-efficiency solid-state hardware, and HVDC links are utilized for electrical transmission throughout the world. While the technology has advanced considerably since the 1950s, utility application of HVDC remains limited to transmission functions. The smallest utility-grade HVDC systems are designed to transmit approximately 50 megawatts (MW) 12. Some notable HVDC installations include:

- **Swedish Mainland to Gotland Island:** 20 MW, 100 kilovolt (kV), monopolar submarine cable with sea return. Commissioned in 1956, this was one of the first HVDC interties installed in the world. This original system was decommissioned in 1987 13.
- **Pacific Intertie – Celilo, Oregon, to Sylmar, California:** 846-mile, 3,100 MW, 500 kV, bipolar overhead line. Commissioned in 1970.
- **British Columbia Mainland to Vancouver Island, Canada:** 45-mile, 682 MW, 260-280 kV, bipolar submarine and overhead system. The first pole was commissioned in 1968, and a second pole was commissioned in 1977 14.
- **Nelson River Bipolar System, Nelson River Hydro Complex to Southern Manitoba, Canada:** Two bipolar transmission systems operate between the hydropower projects along the Nelson River in northern Manitoba and Winnipeg in the southern part of the province. The first system is a 540-mile, 1,620 MW, 450 kV overhead bipolar circuit commissioned in 1977. The second is a 560-mile, 1,800 MW, 500 kV overhead bipolar circuit commissioned in stages between 1978 and 1985. Notably, both systems traverse permafrost terrain similar to that found in Alaska and can operate in SWER mode, moving 1,000s of amperes of current through earth-return 15.
- **Cross-Sound Cable, New Haven, Connecticut, to Long Island, New York:** 24-mile, 330 MW, 150 kV bipolar submarine cable. Commissioned in 2002, this cable uses ABB’s HVDC Lite technology. Both HVDC conductors and a fiber-optic telecommunications cable are bundled into a single cable to simplify installation 16.
- **England – France Cross Channel Intertie:** 38-mile, 160 MW, 100 kV bipolar submarine cable. The original system was commissioned in 1961 and replaced in 1986 by a larger system operating at 270 kV and 2,000 MW. A bipolar system was originally installed to reduce magnetic anomalies that could interfere with shipping.
- **Sardinia – Corsica – Italian Mainland, Italy:** 500 MW, 200 kV both earth and sea returns. The first 200 MW pole of this system was commissioned in 1965. A second 300 MW pole was installed in 1992. This system is unusual because it is a multipoint system (serving three load centers), unlike most HVDC interties, which transmit power between only two points.

---

12 “HVDC Lite,” distributed by ABB, is one example of the smaller utility-grade HVDC systems.
13 The original system used on-shore grounding grids to complete the transmission circuit via sea and/or seabed pathways. This first HVDC link was augmented by a second 150 MW monopolar HVDC link to the island in 1983, and a third 150 MW monopolar link in 1987. Today, these two newer circuits are operated together as a bipolar transmission link.
14 The first monopolar line is rated for 312 MW at 260 kV, and the second monopolar line is rated at 370 MW at 280 kV.
15 http://www.hydro.mb.ca/corporate/facilities/ts_nelson.shtml
16 Cross Sound Cable Connector Project Literature, www.abb.com
Five back-to-back HVDC converter stations\(^\text{17}\) interconnect the Texas grid and U.S. electric grid in neighboring states. Most of these stations were commissioned in the 1980s. Because of these stations, Texas has an asynchronous grid connection to the remainder of the Lower 48.

- Three Gorges Dam to Shanghai, China: 530-mile, 3,000 MW, 500 kV, bipolar overhead line. Four HVDC lines are planned between Three Gorges and China’s eastern coastal regions. The first bipolar circuit was commissioned in 2003 and the second in 2006.
- Victoria to Tasmania, Australia: 500 MW, 400 kV, monopolar submarine cable with sea return. Commissioned in 2005.
- Sweden to Germany, Baltic Cable: 600 MW, 450 kV, with earth return via deep hole electrodes. Commissioned in 1993.

HVDC links can be superior to high-voltage alternating current (AC) links for several key reasons:

- HVDC links are less costly and/or more efficient than AC links under certain circumstances.
- Long interties utilizing insulated cables (as for submarine applications) are possible with HVDC electricity, but prohibitively difficult with AC electricity due to cable capacitance and reactive power losses.
- HVDC links provide an asynchronous connection between AC electrical grids. Analogous to a clutch on a mechanical system, an HVDC intertie allows each AC system to operate at its own phase and frequency and still allow power transfer between the systems. This can increase the stability of both AC grids.
- For a given power transfer requirement, HVDC interties can require less right-of-way than comparable AC interties. They can also have a variety of other regulatory, permitting, or environmental advantages compared to AC interties.

Because of the high cost of the converter systems necessary to convert HVDC to a more readily used AC waveform, HVDC is generally limited to transmission applications. Accordingly, most or all utility HVDC systems in use today are point-to-point transmission lines, with no intermediate take-off points or substations for communities en route.

For the small-scale rural Alaska HVDC applications considered in this study, there is still an economic barrier due to the cost of the HVDC converters (estimated at $250,000 per MW in 2012 dollars). For example, a remote lodge or fish camp likely cannot justify the cost to tap the HVDC line, but most villages can.

As HVDC interties are considered for rural Alaska applications, utilities may desire to extend AC distribution as an underbuild or overbuild on an overhead HVDC line. Similarly, other utilities may desire to utilize the overhead structures to co-locate their cables. This practice is possible so long as applicable code requirements and safety provisions are followed. It may be desirable to use conventional construction in the immediate vicinity of villages to facilitate colocation of multiple utility cables, transitioning to a different, optimized overhead structure for HVDC once away from the village.

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\(^{17}\) The five HVDC systems are the 220-MW back-to-back North DC Tie, 600-MW back-to-back East DC Tie, 36 MVA back-to-back EGPS DC Tie, 150 MVA back-to-back RAIL DC Tie, and 80 MVA Laredo variable frequency transformer (VFT) Tie. [www.ercot.com](http://www.ercot.com).
A.2 SINGLE-WIRE EARTH RETURN (SWER) CIRCUITS

In its simplest form, an electrical circuit requires two current pathways, typically wires. One wire goes from the power supply to the load, and a second wire goes from the load back to the power supply. Both single-phase AC and DC circuits rely on this basic configuration. The wire from the power supply to the load is usually at an increased voltage relative to ground, and so it is insulated for safety and to prevent short circuits. The wire from the load back to the power supply is usually at a much lower voltage relative to ground and thus is usually but not always insulated.

In single-wire earth return (SWER) circuits, the wire that serves as the second current pathway from the load back to the power supply is replaced with a suitable, convenient, and safe current pathway. In the most general case, this “non-wire” pathway can be a car or truck chassis, the metal handle of a flashlight, the earth, natural water bodies, or other objects that can safely complete the electrical circuit.

Sea return circuits are similar to earth return circuits. The only difference is that the sea, or any water body, is used as the predominant return circuit pathway. Parallel pathways, such as the seabed, are also available for current flow.

A.2.1 Why Use SWER?

The primary advantages offered by SWER circuits include:

- Lower costs (eliminate the second conductor).
- Higher efficiency (lower electrical losses).

The primary concerns associated with SWER circuits include:

- Avoiding corrosion of buried or submarine metallic objects in the vicinity of the SWER circuit.
- As with all electrical systems, safety.

SWER circuits are widely used for utility transmission and distribution of electricity all over the world. Numerous HVDC interties are SWER circuits, consisting of a single high-voltage cable and an earth or sea return to complete the transmission circuit. Many of these are installed in climates and conditions similar to Alaska, notably in Scandinavia. In many nations, single-phase AC SWER circuits are accepted practice and are industry standard for serving rural areas.

Nations and jurisdictions that use SWER AC circuits to serve their rural areas economically include the following 18, 19.

- Australia (over 100,000 miles in service)
- Cambodia (Electricite’ du Cambodge)
- New Zealand
- Vietnam
- Laos (Electricite’ du Laos)
- South Africa (Eskon Distribution)

---


At least two single-phase AC SWER circuits have been successfully built and operated in Alaska. These AC SWER circuits demonstrate that SWER is a proven, beneficial, and appropriate technology for rural Alaska transmission applications.

A.3.1 Bethel – Napakiak AC SWER Line

In 1981, a 10.5-mile 14.4 kV single-phase AC SWER line was constructed to connect the small village of Napakiak to the City of Bethel. This line used bipod structures to suspend a 7#8 Alumoweld conductor.

This line was constructed at a cost of $23,000 per mile (1980 $) and operated successfully for many years. Arguably, the line had two shortcomings, neither related to its SWER operation: (1) the structural design of the line relied upon the conductor to provide longitudinal support to the bipod poles between dead ends, and on at least one occasion a conductor break caused a series of structures to fall down; and (2) over time, the load in Napakiak exceeded the line’s capacity. However, the line was an unqualified success at demonstrating that SWER can reduce the costs of power transmission in rural Alaska.

Common misperceptions about this line have given it a negative reputation, which is often incorrectly attributed to its “innovative” SWER design. The line did suffer high losses, but these can be attributed to unmetered loads in Napakiak and the poor condition of the distribution system in Napakiak.

The Alaska Energy Authority replaced the Bethel-Napakiak line with a conventional three-phase line in 2010. The installed cost of this replacement was approximately $344,000 per mile in 2012 dollars, approximately three times greater than the inflation-adjusted cost of the original line 20.

A.3.2 Kobuk – Shungnak AC SWER Line

A 10-mile single-phase AC SWER line was constructed to connect the village of Shungnak to Kobuk in northwestern Alaska. The line and the SWER system worked successfully; however, the support structures were constructed of local spruce trees, and eventually the bases rotted. Like the Bethel – Napakiak SWER line, this line also successfully demonstrated SWER viability in permafrost regions. In 1991, this 10-mile line was replaced with a conventional three-phase 7.2/12.4 kV AC line with poles attached to driven steel H-piles at a cost of $1.1 million, or about $110,000 per mile in 1991 dollars 21.

A.3.3 Future of SWER in Alaska

The transition of most Alaska villages to three-phase distribution systems has diminished the value of single-phase AC SWER interties. AC phase converters would be necessary to interface the intertie with one or both village grids. In addition, the national electrical codes adopted by the State of Alaska do not allow the use of SWER circuits for routine power transmission or distribution. Perhaps because of these factors, there is currently a general lack of interest in SWER technology in Alaska.

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20 AEA, 2007; (DC, 2010).
Despite such factors, SWER circuits remain a proven and cost-effective option for rural Alaska applications, and they warrant serious consideration. Coupled with HVDC, SWER offers cost and technical advantages that have the potential to revolutionize rural power transmission in Alaska.

Affordable energy is a vital underpinning of creating a sustainable economic base for Alaska's rural areas. Affordable transmission is key to achieving affordable energy, and the coupling of SWER and HVDC presents the brightest opportunity for achieving affordable transmission in Alaska. Accordingly, the future of SWER in Alaska is very promising.

### A.4 HVDC FOR ALASKA

The list of existing HVDC projects in Section A.2 illustrates the fact that today's commercial HVDC technology remains limited to large-scale transfer of electricity, normally measured in the 100s or 1,000s of megawatts. Such technology has very limited application in Alaska, as our largest utility grid, along the rail belt, has a peak load of well under 1,000 MW. Most rural loads are measured in the 100s of kW.

The lack of commercial HVDC technology in the kilowatt class necessary for rural Alaska applications means that the numerous benefits offered by HVDC transmission are not presently available to Alaska's rural communities. The key objective and impetus for this project is to lower the cost of rural Alaska interties by extending the reach of commercially available HVDC technology down to the kilowatt class needed to serve Alaska's rural energy transmission needs.

The applications for this technology in Alaska are numerous and include:

- Connecting Bethel and nearby villages with a wind farm along the Bering Sea coast.
- Connecting villages along the Yukon River such as Koyukuk, Nulato, Ruby, and Kaltag with the proposed Toshiba nuclear battery in Galena.
- Connecting 25 southwestern communities to a proposed 25-MW geothermal plant near King Salmon.
- Connecting North Slope communities such as Atqusuk with Barrow to share in the low-cost electricity derived from Barrow's gas fields.
- Developing the geothermal resource at Pilgrim Hot Springs and transmit the power to Nome via HVDC intertie.
- Completing connections in the Southeast Intertie via an affordable HVDC submarine cable.

### A.3.9 Design Considerations for Small Alaska HVDC Interties

Many of the technical aspects of designing and building small HVDC interties in Alaska are much the same as for building interties anywhere. The single dominating factor that sets construction in rural Alaska apart is logistics. Most projects have little or no support infrastructure, ranging from the basics such as modern lodging for workers to availability of transportation infrastructure, heavy equipment, skilled labor, and so on.

Many major construction projects address the logistical challenges of rural Alaska by importing everything necessary to get the job done by conventional means. This works, but is very costly.

A different solution to the logistics challenge is to tailor the design to use available local resources to the extent possible. This is a very challenging proposition, but the rewards – lower construction costs – are substantial. In general terms, designing for Alaska logistics means:
- Use materials and equipment that are readily shipped by common transportation methods, such as small cargo aircraft\textsuperscript{22}. Use materials and construction methods that can utilize small, low ground pressure equipment to enable construction during summer or autumn thawed conditions.

- Use materials and construction methods that employ locally available equipment for transport and construction as much as possible.

- Reduce the amount of construction and fabrication required in the field and on the line. Pre-manufacture and preassemble before shipping to the villages or in the villages before shipping to the field to reduce costs and increase quality.

- Optimize the construction and assembly methods to employ locally available labor.

\textsuperscript{22} The largest cargo aircraft suitable for Alaska logistic planning is a Hercules C-130, but many village airstrips cannot accommodate a Hercules. A more universal cargo aircraft for remote Alaska projects is a Sherpa SD-330 or similar small cargo aircraft.
APPENDIX B

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B.1 INTRODUCTION

The extreme variety of environmental and technical conditions found across rural Alaska results in a significant variation in intertie costs. The typical cost for constructing a conventional overhead distribution-class alternating current (AC) intertie in rural Alaska can vary from as little as $100,000 per mile in areas with good logistic support geotechnical conditions and transportation infrastructure (road system, southeast) to over $600,000 per mile in parts of the state with challenging logistics and little or no transportation infrastructure (remote interior, northwest, or Yukon-Kuskokwim delta regions).

Intertie cost variations also affect submarine cables, underground cables, and other overhead intertie configurations.

This appendix provides the following economic analyses:

- Comparative present worth analysis of conceptual AC and high-voltage direct current (HVDC) interties;
- Case studies of Alaska HVDC interties;
- Estimated costs for conceptual HVDC interties; and
- Baseline costs for rural Alaska AC interties.

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23 See Section B.6.1 for information on the cost basis of rural Alaska AC interties.
B.2 ECONOMIC ANALYSIS

This section evaluates comparative costs for conceptual AC and HVDC interties. Because HVDC interties incur the added expense of converter stations, short HVDC interties (under approximately 6 to 31 miles) will generally not be cost-effective compared with AC interties, depending on project-specific conditions.

As the intertie length increases, the lower per-mile cost of the transmission line offsets the additional cost of the power converters. HVDC interties shorter than a certain economic “break-even” length will be more costly than a comparable AC intertie. The relative savings possible with an HVDC transmission system increases for intertie lengths above this break-even length.

Based on specific project conditions, and on the assumptions and analysis described herein, the conceptual break-even length for overhead interties is approximately 6 to 22 miles on an installed-cost basis, and 12 to 31 miles on a life-cycle cost basis. The conditions and assumptions used to develop these economic break-even length estimates are provided in this appendix.

B.2.1 Comparative Cost: AC versus HVDC Overhead Interties

Two distinct HVDC intertie configurations have been compared to a conventional AC intertie to illustrate the difference in project economics. The two HVDC intertie configurations are:

- A two-wire monopolar HVDC intertie using U.S. Department of Agriculture (USDA) Rural Utilities Service (RUS)-type construction methods. This intertie configuration represents the upper range of estimated cost for an HVDC overhead intertie in rural Alaska applications.
- A monopolar single-wire earth return (SWER) HVDC intertie using Alaska-specific construction methods. This intertie configuration represents the lower range of estimated cost for an HVDC overhead intertie in rural Alaska applications.

The cost for HVDC interties in most rural Alaska applications are expected to fall between the cost estimates cited for these two configurations.

B.2.2 Installation Cost Comparison

Figure B-1 presents the estimated installed cost relative to the intertie length for three different kinds of overhead interties built in rural Alaska conditions:

- A conventional rural Alaska intertie,
- A two-wire monopolar HVDC intertie using RUS-type construction methods, and
- A monopolar SWER HVDC intertie using Alaska-specific construction methods.
In addition, Figure B-1 illustrates the economic break-even length, and relative increase in savings for longer HVDC interties. The points at which the AC “cost line” crosses either of the HVDC “cost lines” represents the economic break-even length. The estimated HVDC costs represent a hypothetical range of installed costs anticipated for low-power (under 1 megawatt [MW]) rural Alaska HVDC systems.

**Figure B-1   Comparative Installed Cost: Overhead 1-MW HVDC and AC Interties**

Note: This chart is based on the assumptions and comparative system costs presented in Appendix B. The break-even point will vary for every intertie project.
B.2.3 Life-Cycle Cost Comparison

Operating costs, maintenance costs, and efficiency affect the long-term economic value of an intertie. Table B-1 presents comparative life-cycle costs for hypothetical 25-mile-long overhead AC and HVDC interties in rural Alaska. A length of 25 miles was selected as it represents the savings possible using a relatively short HVDC intertie. The estimated life-cycle cost for a 25-mile-long HVDC intertie ranges from 79% to 107% of the life-cycle cost of an AC intertie.

Table B-1 Estimated Life-Cycle Costs for 25-mile Overhead AC and HVDC Interties

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<th>Monopolar Two-Wire HVDC Intertie (RUS Construction(^2))</th>
<th>Monopolar SWER HVDC Intertie (Alaska Specific Design(^1))</th>
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<td>Intertie Efficiency(^4)</td>
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</tr>
<tr>
<td>Intertie Annual O&amp;M Costs</td>
<td>$40,000</td>
<td>$58,000</td>
<td>$54,000</td>
</tr>
<tr>
<td>Effective Discount Rate</td>
<td></td>
<td>3%</td>
<td></td>
</tr>
<tr>
<td>Present Worth of Transmission Losses</td>
<td></td>
<td>$307,000</td>
<td>$1,063,000</td>
</tr>
<tr>
<td>Present Worth of O&amp;M Costs</td>
<td>$595,000</td>
<td>$867,000</td>
<td>$796,000</td>
</tr>
<tr>
<td>Converter Stations Installed Cost</td>
<td>$20,000</td>
<td>$2,080,000</td>
<td>$1,160,000</td>
</tr>
<tr>
<td>Intertie Installed Cost</td>
<td>$9,480,000</td>
<td>$7,120,000</td>
<td>$5,340,000</td>
</tr>
<tr>
<td><strong>ESTIMATED LIFE-CYCLE COST</strong></td>
<td><strong>$10,402,000</strong></td>
<td><strong>$11,130,000</strong></td>
<td><strong>$8,208,000</strong></td>
</tr>
<tr>
<td><strong>HVDC LIFE-CYCLE COST AS PERCENT OF AC LIFE-CYCLE COST</strong></td>
<td></td>
<td>107%</td>
<td>79%</td>
</tr>
<tr>
<td><strong>PRESENT WORTH SAVINGS (COST) OF HVDC VS. AC</strong></td>
<td></td>
<td>($728,000)</td>
<td><strong>$2,194,000</strong></td>
</tr>
</tbody>
</table>

Notes:
1. "Alaska-Specific Design" refers to the design concepts presented in Appendix C of this report.
2. "RUS Construction" refers to standard RUS design and construction methods for AC interties, adapted to HVDC applications as described in Appendix C of this report.
3. All monetary values are in 2012 dollars.
4. Efficiency and loss information includes all transmission system components.
Figure B-2 illustrates the economic break-even length, and relative increase in savings for longer HVDC interties. The points at which the AC “cost line” crosses either of the HVDC “cost lines” represents the economic break-even length. The estimated HVDC costs represent a hypothetical range of life-cycle costs anticipated for low-power (under 1 MW) rural Alaska HVDC systems.

**Figure B-2 Comparative Life-Cycle Cost: Overhead 1-MW HVDC and AC Interties**

Note: This chart is based on the assumptions and comparative system costs presented in Appendix B. The break-even point will vary for every intertie project.
B.3 COST ANALYSIS BASIS

B.3.1 Generation and Load Assumptions

The following generation and load assumptions are used as the basis of the cost analysis:

- Energy transmitted over all intertie configurations is assumed to be generated by a diesel-electric plant operating at a constant efficiency of 13 kilowatt-hours (kWh) per gallon;
- The price of diesel is assumed to be $7.00 per gallon; and
- No escalator is applied to the price of fuel over time.

B.3.2 System Efficiency Assumptions

The following circuit path is assumed for the AC intertie case:

- Generation at 480 volts alternating current (VAC) in community “A”;
- Step up to 7.2/12.47 kilovolts (kV) AC at the power plant in community “A”; and
- Transmission at 7.2/12.47 kV AC to the receiving community “B.”

The following circuit path is assumed for the HVDC intertie cases:

- Generation at 480 VAC in community “A,”
- Conversion from 480 V AC to 50 kV direct current (DC) at the community “A” power plant,
- Transmission at 50 kV DC to the receiving community “B,”
- Conversion from 50 kV DC to 480 VAC at the power plant in community “B,” and
- Step-up from 480 VAC to 7.2/12.47 kV AC in community “B.”

The following additional assumptions have been made:

- Both load paths include a single 480 V to 7.2/12.47 kV AC transformer; the comparative analysis does not need to consider losses in this transformer.
- Intertie line losses are based on the operating voltages and conductors described in Appendix C for each intertie configuration.
- Two different HVDC converter efficiencies were used to characterize the range of comparative economics for HVDC interties:
  - The RUS-based HVDC intertie case uses a converter efficiency of 96.2%, which is the efficiency published by Princeton Power Systems, Inc. (PPS) for the prototype converter at 50% load (see Appendix F).
  - The Alaska-specific HVDC intertie case uses a higher converter efficiency of 97.2%. This hypothetical efficiency results in improved comparative economic performance.
- Transmission system losses are valued based on the avoided cost of fuel. All other utility costs are assumed to be fixed and not affected by transmission system losses.

B.3.3 Operation, Maintenance, and Repair Assumptions

An annual budget of $7,500 to $12,300 per converter is provided for maintenance, repair, and scheduled components replacement. For HVDC interties, the $12,300 figure is used for the RUS-based HVDC intertie case, and $7,500 is used for the Alaska-specific HVDC intertie case. The $7,500 per converter
maintenance, repair, and replacement budget is based on the expected life and replacement cost of major components. These components include the power electronics boards, controller, and other major items that are expected to require replacement during the 20-year life of the system. See Appendix F for details on converter component life and replacement costs.

An annual maintenance and repair budget of $1,500 per mile is assumed for all three overhead intertie configurations.

**B.3.4 Economic Assumptions**

A discount rate of 3% has been applied to bring future cash flows (line losses; Operation and Maintenance, Repair, Replacement, and Rehabilitation [OMR&R] costs) to present values. For purposes of this comparative analysis, a project life of 20 years is used for all interties, and no salvage value, disposal, or replacement cost are considered at the end of the 20-year life.

**B.3.5 Installed Cost Assumptions**

The range of installed costs developed for the converter stations in Section B.5 was used for the comparative economic analysis. For HVDC interties, an installed cost of $1,040,000 per station is used for the RUS-based HVDC intertie case, and $580,000 is used for the Alaska-specific HVDC intertie case.

The range of installed costs for the three intertie configurations are based on the estimated intertie costs presented in the following sections of this appendix.
B.4 CASE STUDIES

The case studies in this section provide project-specific examples of the expected costs and resulting benefits of using HVDC systems to interconnect communities and resources. These case studies rely on existing information regarding the proposed intertie routes, loads, and related project information.

Table B-2 summarizes the case studies considered in this section.

<table>
<thead>
<tr>
<th>HVDC Intertie Case Study</th>
<th>Transmission Circuit</th>
<th>Intertie Type</th>
<th>HVDC Intertie Cost Estimate1</th>
<th>AC Intertie Cost Estimate1</th>
<th>Estimated HVDC Savings1</th>
<th>Percent Capital Cost Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greens Creek – Hoonah</td>
<td>5-MW monopolar HVDC circuit with sea return2</td>
<td>Submarine Cable</td>
<td>$22.2 million</td>
<td>$49 million</td>
<td>$26.8 million</td>
<td>55%</td>
</tr>
<tr>
<td>Nome – Pilgrim Hot Springs</td>
<td>5 MW bipolar HVDC circuit</td>
<td>Overhead Line</td>
<td>$25.7 million</td>
<td>$36.3 million</td>
<td>$10.6 million</td>
<td>29%</td>
</tr>
</tbody>
</table>

Notes:
1. All cost estimates are presented in 2012 dollars.
2. The case study provides a submarine and overhead intertie capacity of 5 MW, and converter station capacity of 2 MW. This provides ample margin for load growth in Hoonah. The converter station capacity can be upgraded as-needed in 500 kW increments up to 5 MW.

B.4.1 Green’s Creek – Hoonah Case Study

An intertie between Greens Creek, on the Alaska Electric Light and Power, Inc. (AEL&P) grid that serves Juneau, and the village of Hoonah, an isolated micro-grid operated by the Inside Passage Electric Cooperative, Inc. (IPEC) has been under consideration for over a decade. AEL&P and IPEC have completed extensive study and design work on this intertie. Studies identified a 25-mile-long AC submarine cable and approximately 4 miles of overhead line near Hoonah as the most economical means to complete this interconnection. 24 The proposed intertie route is shown on Figure B-3.

As the development of this project continued, the costs of the AC submarine cable have escalated, until the project was finally put on hold due to its excessive cost. Hoonah is currently exploring local hydropower resources to reduce its energy costs but continues to view an intertie as the best long-term solution for its energy needs.

This HVDC system represents a technological advance that can reduce the cost of the Greens Creek – Hoonah intertie and increase its economic feasibility as compared with Hoonah’s other energy options. The following subsections of this case study provide a high-level analysis of the merits of an HVDC intertie for Hoonah.

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24 (Power Engineers, 2004)
For purposes of this case study, a 5-MW monopolar HVDC transmission circuit with sea return was selected to connect Hoonah with Green’s Creek. This circuit consists of 25 miles of submarine cable and 4 miles of overhead line. A monopolar circuit was selected because it is expected to be the least-cost intertie solution between Hoonah and Green’s Creek. Other potential configurations, such as a bipolar HVDC circuit utilizing two single-conductor cables, would be more expensive than the monopolar design selected.

The estimated capital costs include a 5 MW transmission circuit (submarine cable and overhead line), and 2 MW converter stations at Hoonah and Green’s Creek. The converter stations can be upgraded to 5 MW by adding 500 kW converter modules as Hoonah’s load increases. If Hoonah’s load grows beyond 5 MW, a second submarine cable can be installed to provide a 10 MW bipolar transmission system.

![Diagram of Greens Creek – Hoonah Intertie Route](image)
B.4.1.1 **Conceptual Design Basis**

**B.4.1.1.1 Load**

Hoonah’s annual kWh generation is approximately 5,000 to 5,500 megawatt-hours (MWh). The peak load in Hoonah is estimated at 1,200 kW.  

An initial intertie power capacity of 2,000 kW would serve 100% of the community’s existing needs and provide a 67% margin for future load growth (for handling peak load).

**B.4.1.1.2 Conceptual Intertie Design**

A monopolar HVDC intertie circuit with sea-return is considered for the conceptual design of the Greens Creek – Hoonah intertie. The intertie has an initial capacity of 2,000 kW, but the proposed submarine cable can be operated at 5,000 kW by installing additional modular power converters and related upgrades at either end of the HVDC system. A higher-capacity upgrade to 10 MW is possible through further converter station expansion and installation of a second cable to form a bipolar HVDC system. The initial HVDC system would consist of the following major components:

- An HVDC converter station at Hawk Inlet on the Greens Creek end of the intertie with a rated capacity of 2,000 kW. This station would require a 69-kV to 480-volt (V) step-down transformer, four 500-kW HVDC converter modules, a sea return electrode rated for 40 amperes of current, and associated controls and protective equipment.
- 25 miles of monopolar HVDC submarine cable. This cable would have a rated capacity of 5 MW at 50 kV DC (100 amperes). This cable would include a 35 square millimeter (mm²) copper conductor, a cross-linked polyethylene dielectric, an extruded lead alloy sheath, and two layers of counter-laid galvanized steel armor wire. A fiber-optic bundle is assumed to be included either in the cable construction or within one of the armor wire positions to facilitate broadband communications.
- A submarine cable landing station at Spasski Bay near Hoonah. This station would house the shore end of the submarine cable and transition to an overhead HVDC conductor. The station would also include a second sea-return electrode to complete the sea-return circuit.
- A 3.5-mile overhead monopolar HVDC transmission line with metallic return from Spasski Bay to the existing Hoonah powerhouse. This two-wire overhead line would have one wire at +50 kV DC and the second wire close to earth potential.
- A second 2,000-kW HVDC converter station adjacent to the existing Hoonah powerhouse. This station would house the four 500-kW HVDC power converters and an AC transformer to converter the 480 VAC output to 4,160 VAC to interface with the power plant bus voltage.

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25 AEA, 2010a; AEA, 2010b

26 See Figure 2 in Attachment D-1 to Appendix D of this report.
### B.4.1.2 Economic Analysis

Table B-3 presents the economic analysis for the Greens Creek – Hoonah intertie alternatives. The estimated installed cost for the HVDC intertie is $22.2 million, as compared to the cost of $49 million for a conventional AC intertie. The AC intertie cost estimate is based on the 2009 estimated cost of $37.5 million\(^{27}\) adjusted to 2012 dollars.

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preconstruction</td>
<td>$1,600,000</td>
</tr>
<tr>
<td>Right-of-way acquisition, engineering, survey, permitting</td>
<td></td>
</tr>
<tr>
<td>Administration/Management</td>
<td>$900,000</td>
</tr>
<tr>
<td>HVDC Converter Stations (power converters, sea electrodes, enclosures, AC and DC side station equipment)</td>
<td>$2,700,000</td>
</tr>
<tr>
<td>Submarine Cable Supply and Installation</td>
<td>$12,400,000</td>
</tr>
<tr>
<td>Overhead HVDC Line: Spaaski Bay to Hoonah</td>
<td>$900,000</td>
</tr>
<tr>
<td>Contingency (on entire project, 25%) (^1)</td>
<td>$3,700,000</td>
</tr>
<tr>
<td><strong>Total Estimated Cost</strong></td>
<td><strong>$22,200,000</strong></td>
</tr>
</tbody>
</table>

**Notes:** 1. A contingency of 25% is applied to the costs developed for this project based on the uncertainties associated with the project. A significant amount of work has already been done to characterize the bathymetry and sea floor conditions along the proposed cable route.

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\(^{27}\) IPEC, 2009.
Table B-4 presents estimated benefit-cost ratios for the Greens Creek – Hoonah intertie under several load growth scenarios. This analysis indicates a clear economic advantage to an HVDC intertie based on reasonable load growth forecasts for Hoonah.

<table>
<thead>
<tr>
<th>Item</th>
<th>Existing Load (kWh/yr)</th>
<th>165% Growth (kWh/yr)</th>
<th>200% Growth (kWh/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Hoonah Energy Generation</td>
<td>5,150,000</td>
<td>8,500,000</td>
<td>9,780,000</td>
</tr>
<tr>
<td>AEL&amp;P Avoided Cost of Energy (Juneau)</td>
<td></td>
<td></td>
<td>$0.06 per kWh</td>
</tr>
<tr>
<td>IPEC Avoided Cost of Energy (Hoonah)</td>
<td></td>
<td></td>
<td>$0.20 per kWh</td>
</tr>
<tr>
<td>Intertie Outage Rate</td>
<td></td>
<td></td>
<td>2%</td>
</tr>
<tr>
<td>Annual Hoonah Savings</td>
<td>$707,000</td>
<td>$1,170,000</td>
<td>$1,340,000</td>
</tr>
<tr>
<td>IPEC Operation, Maintenance, Repair, Replacement and Rehabilitation (OMR&amp;R) Annual Costs</td>
<td>$90,000</td>
<td>$90,000</td>
<td>$100,000</td>
</tr>
<tr>
<td><strong>Net Annual Savings (Cost)</strong></td>
<td><strong>$617,000</strong></td>
<td><strong>$1,150,000</strong></td>
<td><strong>$1,340,000</strong></td>
</tr>
<tr>
<td>Intertie Life and Discount Rate</td>
<td>30 years, 3%</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Present Worth of Annual Savings (Costs)</strong></td>
<td><strong>$12,070,000</strong></td>
<td><strong>$21,090,000</strong></td>
<td><strong>$24,500,000</strong></td>
</tr>
<tr>
<td>Estimated Installed Cost</td>
<td>$22,200,000</td>
<td>$22,200,000</td>
<td>$22,200,000</td>
</tr>
<tr>
<td>Estimated Benefit-Cost Ratio</td>
<td>0.54</td>
<td>0.95</td>
<td>1.10</td>
</tr>
</tbody>
</table>

Notes:
2. Approximate AEL&P energy cost. IPEC has capacity, so no demand or capacity charges are included.
3. Assumed value.
4. Annual savings are based on the differential cost of energy and do not consider economic benefits in Hoonah from lower cost energy, or effects to AEL&P of increased energy sales.
5. IPEC’s estimated operations, maintenance, repair, and routine replacement costs include costs for the converter stations, savings from decreased operation and overhaul of the diesel power plant in Hoonah, and a one-time cable repair event over the 30-year analysis period.
6. Hoonah’s peak loads under a 200% load growth scenario would exceed the 2-MW capacity of the intertie converter stations. Intertie throughput is reduced by 5% to reflect diesel generation in Hoonah.
B.4.2 Pilgrim Hot Springs – Nome

Pilgrim Hot Springs is a geothermal resource located approximately 60 miles north of Nome. It has been proposed as a power source to reduce Nome’s reliance on diesel fuel for electrical generation. ACEP is currently studying the Pilgrim Hot Springs geothermal resource to better characterize the resource’s potential for power generation and other applications. For purposes of sizing the transmission line from Pilgrim Hot Springs, an electrical generating capacity and transmission capacity of 5 MW is assumed, based on conversations with ACEP’s manager for the Pilgrim Hot Springs assessment project. The proposed transmission route is shown on Figure B-4.

A bipolar HVDC circuit using overhead lines was selected for the HVDC intertie. The bipolar configuration was selected because it provides increased reliability compared to a monopolar line at a reasonable additional cost.

Conceptual power line costs for overhead AC and HVDC interties were estimated to evaluate the benefits of connecting Pilgrim Hot Springs to Nome using an HVDC intertie. The cost estimates indicate that an HVDC transmission line would cost 29% less than an AC transmission line.

28 Personal communication with Marcus Mager, 2012.
B.4.2.1 Conceptual Design Basis

A routing study was not performed as part of this case study. The intertie route is assumed to follow the approximately 70-mile road corridor from Nome to Pilgrim Hot Springs. This is assumed to be the least-cost route for the power lines, as the road can be used to support the construction and long-term maintenance of the line. A routing study may identify other routes that are more favorable due to geotechnical, land status, environmental, or other factors.

For this analysis, the transmission route distance is assumed to be 60 miles.
B.4.2.1.1 Load

Nome's average annual electricity usage is approximately 3,500 kW, and monthly peak demand is between 4 and 10 MW. The assumed size of the Pilgrim Hot Springs geothermal power plant is assumed to be 5 MW. The intertie is therefore assumed to have a capacity of 5 MW and operate at between 2 and 5 MW, depending on instantaneous demand in Nome.

B.4.2.1.2 Conceptual AC Intertie Design

The conceptual design for the AC intertie is a three-wire 69-kV AC overhead line set on 45-foot wood poles with a ruling span of 400 feet. All poles are assumed to be fastened to steel pile foundations for moment support and to resist frost jacking forces.

The AC transmission system would consist of the following major components:

- A 5-MW geothermal power plant at Pilgrim Hot Springs generating at 4,160 V.
- A substation and switch yard to increase voltage from 4,160 V to 69 kV.
- An approximately 60-mile-long overhead intertie from Pilgrim Hot Springs to Nome.
- A substation and switchyard in Nome to isolate Nome from the transmission line and step down the voltage from 69 kV to 12.47 kV for distribution in Nome.

B.4.2.1.3 Conceptual HVDC Intertie Design

The conceptual design for the HVDC intertie is a bipolar circuit operating at +50 and –50 kV DC. The two circuits would be supported on a guyed glass-fiber-reinforced polymer (GFRP) pole fitted with a cross arm and suspension insulators. A ruling span of 1,000 feet is assumed. The design is similar to that shown on Figure C-9.

The HVDC transmission system would consist of the following major components:

- A 5-MW geothermal power plant at Pilgrim Hot Springs generating at 480 V. It may be preferable to instead generate at 4,160 V and have a step-down transformer to the 480 V interface voltage to the power converters.
- A bipolar HVDC converter station consisting of two banks of five 500-kW power converters. Each bank would form a 2.5-MW pole on the bipolar transmission system.
- An approximately 60-mile-long bipolar HVDC transmission line from Pilgrim Hot Springs to Nome.
- A second bipolar HVDC converter station in Nome.
- An AC transformer to step up the AC output from the converters from 480 V up to 7.2/12.47 kV for distribution in Nome.
B.4.2.2 Economic Analysis

Table B-5 presents the economic analysis for the Pilgrim Hot Springs – Nome intertie alternatives. The estimated installed cost for the HVDC intertie alternative is $25.7 million, as compared to the cost of $36.3 million for a conventional AC intertie.

No information is available for the installed cost of a geothermal power plant at Pilgrim Hot Springs or the cost of the energy it would generate, so a benefit-cost ratio of the intertie alternatives was not evaluated.

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Installed Cost for Bipolar HVDC Intertie</th>
<th>Estimated Installed Cost for AC Intertie</th>
<th>Estimated HVDC Savings</th>
<th>Percent Cost Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preconstruction Activities <em>(right-of-way acquisition, design, survey, permitting)</em></td>
<td>$3,400,000</td>
<td>$3,400,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Administration/Management</td>
<td>$1,000,000</td>
<td>$1,300,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Converter Station Construction</td>
<td>$4,600,000</td>
<td>$3,000,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Overhead Intertie Construction</td>
<td>$10,800,000</td>
<td>$20,200,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Contingency (30%) ¹</td>
<td>$5,900,000</td>
<td>$8,400,000</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total Estimated Cost</strong></td>
<td><strong>$25,700,000</strong></td>
<td><strong>$36,300,000</strong></td>
<td><strong>$10,600,000</strong></td>
<td><strong>29%</strong></td>
</tr>
</tbody>
</table>

Note:

¹ A 30% contingency was applied to the costs for this project because no information was available for the transmission route. This lack of data creates risks due to factors such as land availability, geotechnical conditions, structural (wind and ice) loadings, and environmental (bird, wildlife, and aesthetics) factors.

Some of these risks are mitigated by the use of cost data for the robust conceptual designs (i.e., Alaska-specific construction) used for the HVDC system. The Alaska-specific conceptual design is assumed to be adequate for the expected geotechnical and structural conditions along the route. Environmental and land availability issues, which could require a longer route or departure from the road corridor, pose relatively greater risks than line design considerations. The net result of these factors results in the 30% contingency used for the case study economics.
B.5 DETAILED HVDC INTERTIE COST INFORMATION

B.5.1 Overhead Intertie Cost Detail

This report considers different overhead design concepts for HVDC interties. This section presents a range of estimated costs for these concepts.

The two-wire monopolar intertie adapted from standard RUS practice is estimated to have the highest installed cost. In contrast, the monopolar SWER intertie based on Alaska-specific design concepts is estimated to have the lowest installed cost.

Table B-6 presents a breakdown of the estimated installed costs for 25-mile overhead interties in rural Alaska using the design cases and concepts presented in Appendix C.
### Table B-6 Estimated Cost for a 25-mile Overhead HVDC Intertie

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Monopolar SWER, Alaska Specific Construction</th>
<th>Two-Wire Monopolar HVDC, RUS –Based Construction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Per-Mile Cost</td>
<td>Project Cost</td>
</tr>
<tr>
<td>Preconstruction</td>
<td>$58,000</td>
<td>$1,450,000</td>
</tr>
<tr>
<td><em>Right-of-way acquisition, design, survey, permitting</em></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Administration/Management</td>
<td>$13,000</td>
<td>$325,000</td>
</tr>
<tr>
<td>Materials (intertie only)</td>
<td>$48,000</td>
<td>$1,200,000</td>
</tr>
<tr>
<td>Converter Stations (on per-mile basis)</td>
<td>$62,000</td>
<td>$1,550,000</td>
</tr>
<tr>
<td>Shipping</td>
<td>$15,000</td>
<td>$375,000</td>
</tr>
<tr>
<td>Mobilization/Demobilization</td>
<td>$37,000</td>
<td>$925,000</td>
</tr>
<tr>
<td>Labor</td>
<td>$67,000</td>
<td>$1,675,000</td>
</tr>
<tr>
<td><strong>Total Cost</strong></td>
<td><strong>$300,000</strong></td>
<td><strong>$7,500,000</strong></td>
</tr>
</tbody>
</table>

**Note:**

Line item costs include an embedded 25% contingency.
B.5.2 Submarine Cable Intertie Cost Detail

A number of site-specific factors influence the cost of submarine cable applications for HVDC applications in Alaska. These are the following:

- Cable laying vessels are specialized equipment that must be mobilized to Alaska. Mobilizing these vessels to Alaska is costly and project dependant. Mobilization costs result in short submarine interties being significantly more expensive on a per-mile basis than long submarine interties.
- Marine traffic influences submarine intertie costs. Shallower cable routes must consider commercial fishing activity, anchoring, and related marine traffic that may pose a hazard to the cable.
- The seafloor conditions along the cable route also influence costs. Steep slopes, rugged exposed rock, or unstable slopes will tend to increase costs or project risk.
- The depth of the cable route will influence costs. Deeper routes require stronger, heavier, and more costly cables, which in turn can require larger, more expensive cable laying vessels.

As a result, a generic per-mile cost of low-power submarine cables is not meaningful without consideration of the project-specific factors.

B.5.3 Underground Cable Intertie Cost Detail

A number of site-specific factors will strongly influence the technical feasibility and cost of underground cable applications for low-power HVDC applications in Alaska. These are the following:

- Presence of ground susceptible to frost cracking or polygonal cracking. These ground cracks can impose large tension forces on cables and cause mechanical failure of the cable, resulting in electrical faults.
- Geotechnical conditions along the cable route will influence the cost of cable installation.
- Steep terrain or other local conditions may prevent use of underground cable.

Estimated costs for HVDC interties using underground cables are presented in Table B-7.
Table B-7  Estimated Costs for a 25-mile Underground HVDC Intertie

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Per-Mile Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preconstruction Right-of-way acquisition, design, survey, permitting</td>
<td>$45,000</td>
</tr>
<tr>
<td>Administration/Management</td>
<td>$13,000</td>
</tr>
<tr>
<td>Materials (intertie only)</td>
<td>$80,000</td>
</tr>
<tr>
<td>Converter stations (on per mile basis)</td>
<td>$62,000</td>
</tr>
<tr>
<td>Shipping</td>
<td>$20,000</td>
</tr>
<tr>
<td>Mobilization/Demobilization</td>
<td>$10,000</td>
</tr>
<tr>
<td>Labor</td>
<td>$20,000</td>
</tr>
<tr>
<td><strong>Total Cost</strong></td>
<td><strong>$250,000</strong></td>
</tr>
</tbody>
</table>

Note: Line item costs include an embedded 25% contingency.

The estimated costs in Table B-7 are based on the following assumptions:

- Terrain and conditions are suitable for use of a track-mounted trencher such as a Ditch Witch RT115 Quad, which can cut a trench through frozen ground during the winter months over most terrain;
- 1/0 full concentric neutral jacketed 35-kV AC cable with ethylene propylene rubber (EPR) dielectric in a 2-inch duct;
- A water blocking antifreeze gel compound is used;
- A fiber-optic cable in duct is installed in the same trench;
- Limited brushing is necessary to clear the route;
- Cable reels are spotted along the line with a helicopter; and
- The cable installation depth is a minimum of 18 inches.

B.5.4  Converter Station Cost Detail

The HVDC converter stations will include the major components:

- HVDC power converters;
- Converter enclosures, which may consist of dedicated enclosures or use of an existing building, such as an existing power plant;
- Protection and switching equipment on the AC and HVDC sides of the converters;
- AC transformers, depending on the AC interface voltage and wiring; and
- Grounding stations, including the ground conductor from the converter station to the grounding station.

The estimated installed component costs for a 1-MW monopolar HVDC converter station is presented in Table B-8. The range of costs is based on the presence of existing infrastructure and project-specific conditions.
### Table B-8 1-MW HVDC Converter Station Cost Estimate

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-MW HVDC Power Converter</td>
<td>$220,000 to $280,000</td>
</tr>
<tr>
<td>Converter Enclosure</td>
<td>$40,000 to $160,000</td>
</tr>
<tr>
<td>AC-Side and HVDC-Side Protective and Switching Equipment</td>
<td>$100,000 to $190,000</td>
</tr>
<tr>
<td>1-megavolt amperes (MVA) AC Transformer (7.2/12.4 kV – 480 V)</td>
<td>$0 to $30,000</td>
</tr>
<tr>
<td>Grounding Station</td>
<td>$100,000 to $170,000</td>
</tr>
<tr>
<td>Contingency (25%)</td>
<td>$120,000 to $210,000</td>
</tr>
<tr>
<td><strong>Total, 1-MW HVDC Converter Station</strong></td>
<td><strong>$580,000 to $1,040,000</strong></td>
</tr>
</tbody>
</table>

### B.5.4.1 Converter Cost Detail

Based on Phase II development efforts, PPS estimates that the commercial cost of the HVDC power converters will be $250,000 +/- 10% per 1-MW power converter. PPS states that as manufacturing volumes increase, the per-converter cost should decrease. PPS forecasts a 5% to 10% discount at 10 units and a 20% to 30% discount at 100 units. See Appendix F for a more detailed discussion of converter costs.

### B.5.4.2 Converter Enclosure Cost Detail

Estimated costs assume that a modular, prefabricated enclosure will be sent to the community with the two 500-kW power converter units already installed. This converter module will then be set in place on a suitable foundation. Estimated costs are listed in Table B-9.

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Converter Enclosure</td>
<td>$68,000</td>
</tr>
<tr>
<td>Foundation</td>
<td>$30,000</td>
</tr>
<tr>
<td>Labor</td>
<td>$27,000</td>
</tr>
<tr>
<td>Shipping</td>
<td>$35,000</td>
</tr>
<tr>
<td><strong>Total, 1-MW HVDC Converter Enclosure</strong></td>
<td><strong>$160,000</strong></td>
</tr>
</tbody>
</table>
In communities that will be primarily served by an HVDC intertie, it may be appropriate to locate the converters inside the existing powerhouse or other suitable existing structure. This would have the following advantages:

- The existing powerhouse would already have a step-down transformer sized for the full community load,
- Waste heat from the converters would provide all or part of the heat for the power plant building, and
- This would achieve project cost reduction by eliminating the need for a dedicated converter enclosure and the need to purchase or lease land to site the converter.

**B.5.4.3 Switchgear and Switchyard Equipment Cost Detail**

Switchgear is required on the AC side of the converters for isolation and protection purposes. Depending on the desired degree of system automation, the switchgear may also interface between the converter controls and the power plant controls to allow remote dispatch of generators and the HVDC power converter.

Similar isolation, protection, and monitoring equipment is needed in the HVDC switchyard on the HVDC side of the converter. At a minimum, manual disconnect switches (nonload break), surge arrestors, and fuses are required. Current and voltage sensors are needed on the HVDC line as well.

Estimated switchgear and switchyard costs are presented in Table B-10.

**Table B-10 Switchgear and Switchyard Cost Detail**

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Estimated Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Switchgear Section (Fuses, Disconnect Switches [load break])</td>
<td>$25,000 to $35,000</td>
</tr>
<tr>
<td>HVDC Manual Disconnect Switch (nonload break)</td>
<td>$2,000 to $20,000</td>
</tr>
<tr>
<td>HVDC Surge Arrestor</td>
<td>$10,000 to $15,000</td>
</tr>
<tr>
<td>HVDC Fuse</td>
<td>$2,000 to $8,000</td>
</tr>
<tr>
<td>AC and DC Sensors</td>
<td>$30,000 to $48,000</td>
</tr>
<tr>
<td>Other Materials</td>
<td>$12,000 to $16,000</td>
</tr>
<tr>
<td>Shipping</td>
<td>$5,000 to $18,000</td>
</tr>
<tr>
<td>Labor</td>
<td>$14,000 to $20,000</td>
</tr>
<tr>
<td><strong>Total, 1-MW HVDC Converter Station Switchgear and Switchyard</strong></td>
<td><strong>$100,000 to $190,000</strong></td>
</tr>
</tbody>
</table>
B.5.4.4  AC Transformer Cost Detail

The grid interface on the power converters is three-phase 480-V AC. In communities where the converter is connected directly to the 480-V power plant buss, no additional transformer is required. In communities where the converter connects to the local distribution grid, a step-up transformer is required. The transformer is assumed to be a three-phase 480/12.47 kV transformer.

B.5.4.5  Grounding Station Cost Detail

A grounding station will need to be provided at each HVDC converter station, regardless of the HVDC circuit configuration. The conceptual design of a 1-MW 50 kV DC grounding station is presented in Appendix E. Estimated costs for this station are presented in Table B-11, and include 1 mile of overhead line between the converter station and the grounding station.

Costs for grounding stations will depend on the local geotechnical conditions, the distance between the converter and grounding stations, and other factors.

Table B-11  HVDC Grounding Station Cost Detail

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Conceptual Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Site Investigations</td>
<td>$26,000 to $33,000</td>
</tr>
<tr>
<td>Materials</td>
<td>$25,000 to $45,000</td>
</tr>
<tr>
<td>Labor</td>
<td>$34,000 to $46,000</td>
</tr>
<tr>
<td>Equipment</td>
<td>$7,000 to $12,000</td>
</tr>
<tr>
<td>Shipping</td>
<td>$8,000 to $34,000</td>
</tr>
<tr>
<td>Total, 1-MW HVDC Grounding Station</td>
<td>$100,000 to $170,000</td>
</tr>
</tbody>
</table>
B.6  DETAILED AC INTERTIE COST INFORMATION

This section presents cost baselines for remote Alaska AC interties to allow comparison to the HVDC alternatives presented in this report. Cost baselines for AC intertie projects were developed using two methods. The first method was to develop conceptual cost estimates considering unit costs for labor, materials, mobilization, etc. The second method was to review, where available, the actual costs of recent relevant AC intertie projects in Alaska. For both methods, two types of interties were analyzed:

1. **Overhead intertie lines in arctic and subarctic regions of western Alaska.** These regions present some of the greatest geotechnical and logistical challenges; therefore, they tend to have the highest installed costs for overhead interties.

2. **Submarine cable interties in rural Alaska.** For many parts of Alaska, and in particular the southeast, submarine cables are the only viable means of building a power intertie.

The cost baselines are summarized in Table B-12.

<table>
<thead>
<tr>
<th>Type of AC Electric Intertie</th>
<th>Cost Baseline by Unit Cost/Quantity Method</th>
<th>Cost Baseline from Recent Project Experience</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Interties</td>
<td>$440,000 per mile</td>
<td>$450,000 per mile +/- 50%</td>
</tr>
<tr>
<td>Submarine Cable Interties</td>
<td>N/A</td>
<td>$1,300,000 per mile +/- 35%</td>
</tr>
</tbody>
</table>

Notes:

1. Intertie power capacity will affect cost. See subsequent notes for the specific types of interties considered to develop these conceptual costs.
2. Interties are standard RUS three-phase 14.4/24.9 kV construction, using steel pile foundations.
3. Interties are single-bundled three-conductor armored cable.
B.6.1 Cost Baselines for Overhead AC Interties

B.6.1.1 Cost Baseline for Overhead AC Interties Using Unit Costs and Quantities

A cost baseline for typical AC transmission systems has been estimated for 10-mile and 25-mile intertie concepts. These concepts are based on a standard four-wire three-phase 14.4/24.9 kV RUS power line using driven steel pile foundations. The estimated installed costs are presented in Table B-13.

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>10-Mile Intertie</th>
<th>25-Mile Intertie</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Per-Mile Cost</td>
<td>Project Cost</td>
</tr>
<tr>
<td>Preconstruction</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Right-of-way acquisition, design, survey,</td>
<td>$61,000</td>
<td>$610,000</td>
</tr>
<tr>
<td>permitting</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Administration/Management</td>
<td>$18,000</td>
<td>$180,000</td>
</tr>
<tr>
<td>Materials</td>
<td>$71,000</td>
<td>$710,000</td>
</tr>
<tr>
<td>Shipping</td>
<td>$36,000</td>
<td>$360,000</td>
</tr>
<tr>
<td>Mobilization/Demobilization</td>
<td>$136,000</td>
<td>$1,360,000</td>
</tr>
<tr>
<td>Labor</td>
<td>$111,000</td>
<td>$1,110,000</td>
</tr>
<tr>
<td><strong>Total Cost</strong></td>
<td><strong>$440,000</strong></td>
<td><strong>$4,400,000</strong></td>
</tr>
</tbody>
</table>

The per-mile cost of overhead AC interties decreases as the intertie gets longer. This is influenced by the following factors:

- The scope and complexity of environmental, right-of-way, design, and permitting issues for the project.
- The quality of access corridors along the intertie route. The estimated costs assume that per-mile labor costs are independent of intertie length.
- The construction plan and schedule. The estimated costs assume that per-mile mobilization/demobilization costs decrease slightly with increasing intertie length.

This report finds that per-mile costs for typical overhead AC interties decrease approximately 10% as the intertie length increases from 10 to 25 miles. Further, an additional decrease of 5% occurs from 25 to 50 miles. Costs are constant on a per-mile basis from 50 to 100 miles.
### Cost Baseline for Overhead AC Interties Using Comparable Project Costs

Construction cost data compiled for seven remote overhead intertie lines built in western Alaska over the past 20 years are presented in Table B-14. The lines selected are considered representative of the most difficult logistical and geotechnical conditions common in Alaska. Based on Table B-14, the conceptual per-mile cost for a remote Alaska overhead AC intertie is $450,000 per mile, +/-50% (2012 $).

The cost data are presented as a general cost baseline for remote Alaska overhead interties.

<table>
<thead>
<tr>
<th>Intertie Project</th>
<th>Installed Cost</th>
<th>Year Built</th>
<th>Length (miles)</th>
<th>Per-Mile Cost (2012 $)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kobuk – Shungnak 3</td>
<td>$1.1M</td>
<td>1991</td>
<td>11</td>
<td>$276,500</td>
</tr>
<tr>
<td>Toksook Bay – Tununak 4,5</td>
<td>$2.0M</td>
<td>2005</td>
<td>6.6</td>
<td>$440,200</td>
</tr>
<tr>
<td>Nunapitchuk – Old Kasigluk – Akula Hts. 5,6</td>
<td>$1.9M</td>
<td>2006</td>
<td>4.2</td>
<td>$594,400</td>
</tr>
<tr>
<td>Toksook Bay – Nightmute 7,8</td>
<td>$6.9M</td>
<td>2009</td>
<td>18</td>
<td>$495,800</td>
</tr>
<tr>
<td>Bethel – Napakiak 5,9</td>
<td>$3.1M</td>
<td>2010</td>
<td>10.5</td>
<td>$344,400</td>
</tr>
<tr>
<td>Brevig Mission – Teller 10</td>
<td>$4.7M</td>
<td>2011</td>
<td>6.8</td>
<td>$730,200</td>
</tr>
<tr>
<td>Emmonak – Alakanuk 11</td>
<td>$2.9M</td>
<td>2011</td>
<td>11</td>
<td>$267,300</td>
</tr>
</tbody>
</table>

**Average Cost per Mile, 2012 Dollars:** $449,800

**Average Cost per Mile, (Excluding Highest and Lowest-Cost Projects):** $430,300

**Notes:**

1. Installed costs are in nominal dollars at the time of construction. Due to the limited detail and variety of sources for cost data, it is not always possible to discern if costs for a given project include preconstruction, construction, shared mobilization with separate but concurrent projects, and similar complicating factors. Adjusting for these unknown factors may increase or decrease the project cost that is presented in the table.
2. Project costs are adjusted to 2012 dollars using a custom escalator based on Alaska labor costs and commodity prices relevant to overhead intertie construction.
3. Estimated cost for the project. The project consisted of replacing an AC SWER intertie with a conventional RUS AC intertie (Petrie, personal communication, 2012).
4. The project consisted of a new overhead AC intertie (Denali Commission, 2008b).
5. Entire intertie was set on H-pile or round pile foundations (Denali Commission, 2008a, 2008b, and 2010).
6. The project consisted of replacing an existing overhead AC intertie with a new overhead AC intertie. The cost was reduced by $300,000 for step-down transformers for services along the intertie route that are not part of the “intertie” cost (Denali Commission, 2008a).
7. The project consisted of a new overhead AC intertie (Denali Commission, 2009).
8. Approximately 30% of intertie is set on steel pile foundations (Denali Commission, 2009).
9. The project consisted of replacing an AC SWER intertie with a conventional RUS AC intertie (Denali Commission, 2010).
10. The project consisted of a new AC intertie including overhead, underground, and submarine cable segments. Cost includes preconstruction and budgeted construction (Denali Commission, 2011).
11. This is the estimated cost for a proposed intertie built in 2011. The intertie project shared mobilization costs with concurrent installation of wind turbines in Emmonak (AVEC, 2008).
B.6.2 Cost Baseline for Submarine Cable AC Interties

Construction cost data were compiled for three AC submarine power cables installed or proposed in Alaska over the past 15 years; these data are presented in Table B-15. Very few “low-power” AC submarine cables have been built in Alaska – the cables in Table B-15 each have a capacity of 10 to 15 MW. These lines were reviewed because they are the smallest submarine cables with available cost data. The indicated conceptual per-mile cost for a AC submarine intertie in Alaska is $1,300,000 per mile, +/- 35% (2012 $).

Submarine cable costs are project dependent and have a significant cost variability. Short cable projects in particular can be expected to have significantly higher per-mile cost due to the fixed mobilization cost of specialized cable-laying vessels.

The cost data provide a general cost baseline for remote Alaska submarine power cables.

<table>
<thead>
<tr>
<th>Intertie Project</th>
<th>Installed Cost 1</th>
<th>Year Built/Proposed</th>
<th>Length (miles)</th>
<th>Per-Mile Cost (2012 $) 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Haines – Skagway 3</td>
<td>$5.86M</td>
<td>1998</td>
<td>15</td>
<td>$880,000</td>
</tr>
<tr>
<td>Homer – South Katchemak Bay 5</td>
<td>$2.5M</td>
<td>2001</td>
<td>4.5</td>
<td>$1,200,000</td>
</tr>
<tr>
<td>Green’s Creek – Hoonah 4</td>
<td>$37.5M</td>
<td>2009</td>
<td>29</td>
<td>$1,700,000</td>
</tr>
</tbody>
</table>

Average Cost per Mile, 2012 Dollars: $1,300,000

Notes:
1. Installed costs are in nominal dollars at the time of construction. Due to the limited detail and variety of sources for cost data, it is not always possible to discern if costs for a given project include preconstruction, construction, shared mobilization with separate but concurrent projects, and similar complicating factors. Adjusting for these unknown factors may increase or decrease the project cost that is presented in the table.
2. Project costs are adjusted to 2012 dollars using a custom escalator based on Alaska labor costs and commodity prices relevant to power line construction.
3. The Haines-Skagway cable has a maximum depth of 1,500 feet and a rated capacity of 15 MW (INEEL, 1998).
4. The Green’s Creek – Hoonah cable has not been built due to its cost. Installed costs are the most recent estimates available. This cable route includes depths to 2,600 feet. Costs include approximately 4 miles of overhead line (IPEC, 2009).
5. The Homer – South Katchemak Bay cable has a maximum depth of 600 feet and a rated capacity of approximately 12 MW (AJOC, 2001).
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APPENDIX C

CONCEPTUAL DESIGN OF
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C.1 INTRODUCTION

The conceptual overhead transmission line design alternatives presented in this appendix required consideration of site-specific conditions, codes, utility and lender requirements, construction methodologies, standard design practices, and project economics.

Two conceptual design approaches for overhead high-voltage direct current (HVDC) interties have been evaluated, each with a capacity to supply 1 megawatt (MW) at 50 kilovolts (kV) DC: (1) U.S. Department of Agriculture (USDA) Rural Utilities Service (RUS) design approach, modified for HVDC interties; and (2) Alaska-specific design approach for HVDC interties. Each is described below.

C.1.1 Rural Utilities Service (RUS) Design Approach, Modified for HVDC Interties

The first conceptual design approach is based on the use of structures that are constructed in accordance with the RUS standard practices for conventional 12.4/24.9 kilovolt (kV) alternating current (AC) distribution lines. These RUS standard practices are currently used to develop AC interties throughout Alaska and are widely accepted by the utility industry. HVDC transmission requires fewer conductors than AC, resulting in reduced loads on the supporting structures. As a result, the conceptual designs developed with the RUS approach have longer ruling spans than typical AC lines. This results in fewer transmission structures for the HVDC intertie and an associated comparative reduction in construction cost.

C.1.2 Alaska-specific Design Approach for HVDC Interties

The second conceptual design approach takes the logistic and technical challenges of construction in rural Alaska into consideration and focuses on methods to reduce construction costs without compromising performance or long-term maintainability. This design approach incorporates cost-saving features made possible through HVDC-specific design alternatives, materials, and construction methods. Design features of this concept include the use of guyed composite structures to allow significantly longer ruling spans than is possible with RUS standard practice. The reduced number of structures, less costly foundations, and reduced number of conductors all result in additional savings compared with interties built to RUS standard practices.

The following three HVDC transmission circuit configurations are considered for each of the HVDC conceptual design approaches:

- Monopolar single-wire transmission with earth-return path (SWER);
- Monopolar two-wire transmission with metallic conductor-return path (TWMR);
- Bipolar two-wire transmission.

Schematic figures are provided in this appendix for each of these conceptual designs. Detailed reports that address various technical aspects of the assumed conditions and loadings used to develop these conceptual designs are provided as attachments to this appendix.

---

29 In this report, the term “RUS standard practice” refers to overhead intertie line designs based on the methods and materials presented in RUS design manuals for transmission and distribution line construction, including but not limited to: REA, 1982, RUS, 1998, 2002, 2003a, 2003b, 2003c, and 2009.
C.2 DESIGN CRITERIA FOR OVERHEAD INTERTIE LINES

The following design criteria has been developed as a basis for the conceptual design of the HVDC overhead intertie lines.

C.2.1 Geotechnical Conditions

Based on the analysis described below, conceptual foundation design alternatives for a guyed pole utilize three thermoprobe micropiles for the pole base and helical anchors for the guys. The conceptual foundation design alternatives are presented on Figures C-9 through C-11. The overhead system test site includes installation of both of these prototype foundations, as well as thermoprobe micropiles and screw anchors to restrain the guy wires.

Polarconsult contracted with Golder Associates, Inc. (Golder) to identify and characterize the most common geotechnical conditions that pose the greatest technical and economic challenges for rural Alaska overhead intertie lines as currently designed.

In summary, Golder identified three conceptual geotechnical conditions representing the greatest economic challenge for rural Alaska overhead interties. These are summarized below.

**Profile “A”:** Icy, “warm” permafrost comprised primarily of low-plasticity mineral silt below an active layer with higher organic content. The permafrost temperature in the upper 15 feet beneath the active layer would have a maximum temperature (occurring in late autumn) of 31.0 to 31.5 °F. The active layer is assumed to be approximately 3.5 feet thick, consisting of organic soils and surface peat. Surface vegetation in the project footprint is assumed to remain undisturbed by line construction. This profile is intended to represent a generic geotechnical profile in the lower Yukon and Kuskokwim areas.

**Profile “B”:** Warm and degrading permafrost, primarily low- to moderate-plasticity mineral silt with elevated pore water salinity. Taliks or thin unbonded soil layers may be present in the frozen soil matrix within 15 to 20 feet below grade. Temperatures are expected to average 31.5 to 31.8 °F in the uppermost 15 feet below the active layer. Degrading permafrost conditions are expected below the active layer in some areas along the intertie alignment. Surface vegetation in the project footprint is assumed to remain undisturbed by line construction. This profile is intended to represent a generic geotechnical profile along coastal areas of western Alaska.

**Profile “C”:** Thawed or unfrozen mineral soil, generally sandy with silt contents of 20% to 40% total dry weight. Highly degraded permafrost with significant thawed zones is present below the active layer. Soil moisture contents represent saturated conditions and no significant pore water salinity is present. A higher organic content active layer is present, with grasses, brush, and trees for vegetation. The active layer is approximately 5 feet. This profile is intended to represent a generic geotechnical profile along the permafrost margin in interior Alaska or inland areas with significant permafrost degradation.

C.2.2 Environmental Loads

The following loadings were analyzed for each conceptual design:

- **Case 1:** National Electrical Safety Code (NESC) 250B = ½ inch of ice, 4 pounds per square foot (psf) wind.
- **Case 2:** NESC 250C = no ice, 120 mph wind.
Case 3: NESC 250D = ¼ inch of ice, 80 mph wind.
Case 4: High ice = 1 inch ice, no wind, 30 degrees Fahrenheit (°F).
Case 5: No ice or wind.

These load cases are considered sufficient for many rural Alaska overhead intertie applications. Specific locations may be subject to higher and/or lower wind and/or ice loadings. Except where specifically stated otherwise, each of the conceptual designs presented in this section comply with the most stringent of these load conditions.

Section 4.6 of the Phase I Final Report provides a summary of environmental loadings around Alaska (Polarconsult, 2009)
C.3 CONCEPTUAL DESIGN OF OVERHEAD HVDC TRANSMISSION, RUS STANDARD PRACTICE

The conceptual designs of overhead intertie lines presented in this section have been developed to take advantage of the following factors:

- Alaska contractors, line crews, and utility line personnel are familiar with RUS standard practice materials, designs, and construction practices, thus they will be more familiar with the techniques and procedures for building, maintaining, and repairing these lines.
- Alaska already has many miles of RUS standard-practice distribution and transmission lines built and in service throughout the state. Utilities understand the performance record and issues with this type of line construction.
- Utility lenders, which includes RUS, understand and accept RUS standard construction practice, which can simplify obtaining funds for constructing new interties.

To take advantage of these factors, conceptual design for HVDC preserved RUS standard practice construction to the extent possible, modifying the pole top assembly to accommodate the conductor(s), insulator(s), and clearances for HVDC operation. The ruling span is also increased to take advantage of the fewer wires and reduced structure loads associated with the HVDC circuit configurations.

Structural analysis of conventional overhead HVDC transmission structures (adapted from RUS standard practice) was performed by Polarconsult. A conceptual design summary is presented in the following sections for each line configuration.

C.3.1 Conventional AC Intertie Design

Conventional AC intertie designs for low-power (under 1 MW) rural Alaska AC intertie lines are considered in this study for the following reasons:

1. The majority of existing rural Alaska interties are built per RUS standard practice. Thus, this conventional AC overhead line configuration is the baseline for comparisons of capital cost, electrical efficiency, and other metrics by which the HVDC intertie systems are evaluated in this report.

2. The RUS standard practice construction that is used for most AC intertie lines in rural Alaska has been used in this report as the basis for conceptual design of conventionally built HVDC intertie lines.

Most rural Alaska AC intertie lines are designed and constructed per RUS standard practice, which typically uses direct-burial cantilevered wood poles. Many intertie lines, such as those in the Yukon-Kuskokwim region, cannot use direct-burial cantilevered wood pole designs due to the adverse geotechnical conditions. In these problem areas, the wood pole is commonly attached to a steel pile driven to a depth of as much as 40 feet to provide an adequate foundation for the cantilevered pole. The wood poles are typically 35 to 45 feet in length, depending on the site conditions and line design.

The poles support a standard RUS tangent pole-top assembly as presented on Figure C-1. The conceptual design data for this type of line construction is provided in Table C-1.

---

31 See RUS, 1998; RUS, 2005.
Figure C-1  Tangent Pole for Conventional AC Intertie Line

<table>
<thead>
<tr>
<th>ITEM</th>
<th>MATERIAL</th>
<th>VC1.11P QTY</th>
<th>VC1.12P QTY</th>
</tr>
</thead>
<tbody>
<tr>
<td>c</td>
<td>Bolt, machine, 5/8&quot; x req'd length</td>
<td>3 3</td>
<td>1 1</td>
</tr>
<tr>
<td>d</td>
<td>Washer, square, 2 1/4&quot;</td>
<td>5 5</td>
<td>2 2</td>
</tr>
<tr>
<td>g</td>
<td>Crossarm, 3 5/8&quot; x 4</td>
<td>1 1</td>
<td>2 2</td>
</tr>
<tr>
<td>i</td>
<td>Bolt, carriage, 3/8&quot; x 4&quot;</td>
<td>2 2</td>
<td>1 1</td>
</tr>
<tr>
<td>j</td>
<td>Screw, lag, 1/2&quot; x 4&quot;</td>
<td>1 3</td>
<td>1 1</td>
</tr>
<tr>
<td>bs</td>
<td>Bolt, single, upset</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>cm</td>
<td>Insulator, spool, 3&quot;</td>
<td>1 1</td>
<td>1 1</td>
</tr>
<tr>
<td>cu</td>
<td>Brace, 28&quot;</td>
<td>2 2</td>
<td>2 2</td>
</tr>
<tr>
<td>ea</td>
<td>Insulator, post type (24.9/14.4 kV)</td>
<td>3 3</td>
<td>3 3</td>
</tr>
<tr>
<td>eb</td>
<td>Bracket, pole top</td>
<td>1 1</td>
<td>1 1</td>
</tr>
<tr>
<td>ec</td>
<td>Bracket, offset neutral</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>ek</td>
<td>Locknuts</td>
<td>6 6</td>
<td>6 6</td>
</tr>
</tbody>
</table>

**DESIGN PARAMETERS:**

MAXIMUM LINE ANGLES:
5" = Small Conductors
2" = Larger than #1/0

**SINGLE SUPPORT ON CROSSARM (TANGENT) (POST INSULATORS)**

3 - PHASE PRIMARY
24.9/14.4 kV
VC1.11P
VC1.12P

Image Credit: RUS, 1998
### Table C-1  Conceptual Design Data for Conventional AC Intertie Line

<table>
<thead>
<tr>
<th>I. GENERAL INFORMATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>PROJECT: CONCEPTUAL 1 MW HVDC LINE</td>
</tr>
<tr>
<td>LINE IDENTIFICATION: RUS STD. AC CONSTRUCTION</td>
</tr>
<tr>
<td>VOLTAGE: 14.4 / 24.9 KV AC</td>
</tr>
<tr>
<td>TYPE</td>
</tr>
<tr>
<td>THREE PHASE AC DIST LINE &lt; 1 MW</td>
</tr>
<tr>
<td>TYPE OF TANGENT STRUCTURE: WOOD POLE</td>
</tr>
<tr>
<td>BASE POLE: 35 FT CLASS 1</td>
</tr>
<tr>
<td>DESIGNED BY: POLARCONSULT ALASKA (CONCEPT DESIGN)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SUMMARY OF CONCEPTUAL DESIGN DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>THREE-PHASE 14.4 / 24.9 KV AC INTERTIE</td>
</tr>
<tr>
<td>STANDARD RUS CONSTRUCTION</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>II. CONDUCTOR DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>SIZE: 1/0 (raven)</td>
</tr>
<tr>
<td>STRANDING: 6/1</td>
</tr>
<tr>
<td>MATERIAL: ACSR</td>
</tr>
<tr>
<td>DIAMETER (IN): 0.398</td>
</tr>
<tr>
<td>WEIGHT (LBS/FT): 0.145</td>
</tr>
<tr>
<td>RATED STRENGTH (LBS): 4,380</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>III. DESIGN LOADS</th>
</tr>
</thead>
<tbody>
<tr>
<td>NESC LOADING DISTRICT: HEAVY</td>
</tr>
<tr>
<td>TRANSMISSION (LBS/FT)</td>
</tr>
<tr>
<td>COMMON NEUTRAL (LBS/FT)</td>
</tr>
<tr>
<td>a. ICE (IN.): (vertical) 0.5 in. radial 0.5 in. radial</td>
</tr>
<tr>
<td>b. WIND ON ICED COND (PSF): (transverse) 4.0 psf 4.0 psf</td>
</tr>
<tr>
<td>c. CONSTANT K: (resultant + K) 0.3 psf 0.3 psf</td>
</tr>
<tr>
<td>EXTREME ICE (NO WIND): (vertical) 1.0 in. radial 1.0 in. radial</td>
</tr>
<tr>
<td>EXTREME WIND (NO ICE): (transverse) 120 mph 30.6 psf 120 mph 30.6 psf</td>
</tr>
<tr>
<td>EXTREME ICE + WIND: ICE: (vertical) 0.25 in. radial 0.25 in. radial</td>
</tr>
<tr>
<td>WIND: (transverse) 80 mph 13.6 psf 80 mph 13.6 psf</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IV. SAG &amp; TENSION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>RULING SPAN: 250 ft.</td>
</tr>
<tr>
<td>SOURCE OF SAG/TENSION DATA: SOUTHWIRE SAG10</td>
</tr>
<tr>
<td>TRANSMISSION</td>
</tr>
<tr>
<td>COMMON NEUTRAL</td>
</tr>
<tr>
<td>TENSIONS (% RATED STRENGTH)</td>
</tr>
<tr>
<td>INITIAL</td>
</tr>
<tr>
<td>NESC a. UNLOADED TEMP: 60 F lbs: 1,333 642 lbs: 1,333 642</td>
</tr>
<tr>
<td>30%</td>
</tr>
<tr>
<td>NESC b. LOADED TEMP: 0 F lbs: 2,190 lbs: 2,190</td>
</tr>
<tr>
<td>50%</td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F lbs: 2,488 lbs: 2,488</td>
</tr>
<tr>
<td>HIGH WIND (NO ICE) TEMP: 60 F lbs: 1,875 lbs: 1,875</td>
</tr>
<tr>
<td>UNLOADED LOW TEMPERATURE TEMP: -20 F lbs: 1,868 lbs: 1,868</td>
</tr>
<tr>
<td>SAGS (FT)</td>
</tr>
<tr>
<td>NESC DISTRICT LOADED TEMP: 0 F lbs: 3.61 lbs: 3.61</td>
</tr>
<tr>
<td>UNLOADED HIGH TEMP lbs: 3.56 lbs: 3.56</td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F lbs: 5.93 lbs: 5.93</td>
</tr>
<tr>
<td>LOADED 1/2&quot; ICE, NO WIND TEMP: 32 F lbs: 3.73 lbs: 3.73</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>V. CLEARANCES</th>
</tr>
</thead>
<tbody>
<tr>
<td>MINIMUM CLEARANCES TO BE MAINTAINED AT:</td>
</tr>
<tr>
<td>EXTREME ICE LOADING</td>
</tr>
<tr>
<td>CLEARANCES IN FEET</td>
</tr>
<tr>
<td>RAILROADS</td>
</tr>
<tr>
<td>HEIGHT</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>VI. RIGHT OF WAY</th>
</tr>
</thead>
<tbody>
<tr>
<td>WIDTH: 30 FT. AT EXTREME WIND, FINAL SAG, AREAS WITH TYP. STRUCTURES ADJ. TO ROW</td>
</tr>
<tr>
<td>WIDTH: 35 FT. AT EXTREME WIND, FINAL SAG, CLEARANCE TO VEGETATION AT LINE ELEV.</td>
</tr>
</tbody>
</table>
C.3.2 Monopolar Single-Wire Transmission with Earth-Return Path (SWER), Conventionally Built

The RUS standard practice for an AC line construction (Figure C-2) can be adapted for a monopolar SWER HVDC line. The necessary changes are listed below:

- Elimination of the four (or three) conductors, insulators, and the cross-arm assembly.
- Addition of a single conductor rated for the structural loads and electrical requirements of the line. Aluminum conductor steel reinforced (ACSR) 4/0 Penguin was selected for the conceptual design.
- Add a single line post insulator rated for nominal 50 kV DC and the structural loads from the conductors. A 115 kV AC NGK polymer line post insulator (#L4-SN321-15U) was selected for the conceptual design.
- Increase the ruling span between the poles from 250 feet (typical for AC lines) to 500 feet.

A tangent pole-top assembly for a conventionally built monopolar HVDC SWER intertie is shown on Figure C-2. The conceptual design data for this type of line construction is provided in Table C-2.

---

32 The insulator design is considered conservative and is anticipated to be adequate for most regions of Alaska. Insulators rated at a lower voltage may be appropriate for some intertie lines.
Figure C-2 Conventional Tangent Pole for Monopolar SWER HVDC Intertie Line

**DESIGN SUMMARY**

- **Ruling Span:** 500 ft.
- **Min. Ground Clearance:** 19 ft.
- **Design Basis:** NESC Heavy, Class 250B
- **Stringing Tension:** 25% (2100 LBS)

**ITEM**

<table>
<thead>
<tr>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. <strong>Conductor</strong> (e.g., 4/0 ACSR &quot;PENGUIN&quot;)</td>
</tr>
<tr>
<td>b. <strong>Conductor Grip</strong> (e.g., Preformed #CCS-2100 or equal)</td>
</tr>
<tr>
<td>c. <strong>115VAC Polymer Line Post Insulator</strong> (e.g., NGK L4-NX221-15U, or equal)</td>
</tr>
<tr>
<td>d. <strong>Transmission Insulator Bracket</strong> (e.g., Hubbell WP10115, WP10135, or equal)</td>
</tr>
<tr>
<td>e. <strong>Pole</strong> (e.g., wood, fiberglass, or as req’d)</td>
</tr>
<tr>
<td>f. <strong>Foundation Assembly</strong> (e.g., direct burial, steel pile, or as req’d)</td>
</tr>
</tbody>
</table>

**NOTES**

This conceptual design is suitable strictly for planning purposes only, and is not to be used as final design or for construction.

**ELEVATION VIEW**

**CONCEPTUAL DESIGN FOR 50 KV MONOPOLAR SWER HVDC LINE (HUS CONSTRUCTION)**

*Polarconsult Alaska, Inc.*

**PROJECT**

HVDC TRANSMISSION SYSTEM FOR RURAL ALASKAN APPLICATIONS - PHASE II - PROTOTYPING AND TESTING

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## Table C-2  Conceptual Design Data for Conventionally Built Monopolar SWER HVDC Intertie Line

### I. GENERAL INFORMATION

**PROJECT:** CONCEPTUAL 1 MW HVDC LINE  
**LINE IDENTIFICATION:** RUS STD. AS HVDC SWER  
**VOLTAGE:** 50 KV HVDC  
**TYPE**  
MONOPOLAR HVDC SWER  
**TYPE OF TANGENT STRUCTURE:** WOOD POLE  
**BASE POLE:** 35 FT CLASS 1  
**DESIGNED BY:** POLARCONSULT ALASKA (CONCEPT DESIGN)

### II. CONDUCTOR DATA

**SIZE:** 4/0 ‘PENGUIN’  
**STRANDING:** 6/1  
**MATERIAL:** ACSR  
**DIAMETER (IN):** 0.563  
**WEIGHT (LBS/FT):** 0.291  
**RATED STRENGTH (LBS):** 8,350

### III. DESIGN LOADS

**NESC LOADING DISTRICT:** HEAVY  
**TRANSMISSION (LBS/FT):** COMMON NEUTRAL (LBS/FT)

<table>
<thead>
<tr>
<th>a. ICE (IN): (vertical)</th>
<th>0.5 in. radial</th>
<th>(NONE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>b. WIND ON ICED COND (PSF): (transverse)</td>
<td>4.0 psf</td>
<td></td>
</tr>
<tr>
<td>c. CONSTANT K: (resultant + K)</td>
<td>0.3 psf</td>
<td></td>
</tr>
<tr>
<td>EXTREME ICE (NO WIND): (vertical)</td>
<td>1.0 in. radial</td>
<td></td>
</tr>
<tr>
<td>EXTREME WIND (NO ICE): (transverse)</td>
<td>120 mph</td>
<td>31.1 psf</td>
</tr>
<tr>
<td>EXTREME ICE + WIND:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ICE: (vertical)</td>
<td>0.25 in. radial</td>
<td></td>
</tr>
<tr>
<td>WIND: (transverse)</td>
<td>80 mph</td>
<td>13.8 psf</td>
</tr>
</tbody>
</table>

### IV. SAG & TENSION DATA

**RULING SPAN:** 500 ft  
**SOURCE OF SAG/TENSION DATA: SOUTHWIRE SAG10**  
**TENSIONS (% RATED STRENGTH)**  
**TRANSMISSION / COMMON NEUTRAL**

<table>
<thead>
<tr>
<th>NESC</th>
<th>INITIAL</th>
<th>FINAL</th>
<th>INITIAL</th>
<th>FINAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. UNLOADED TEMP: 60 F</td>
<td>lbs: 1,999</td>
<td>1,142</td>
<td>(NONE)</td>
<td></td>
</tr>
<tr>
<td>24%</td>
<td>14%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>b. LOADED TEMP: 0 F</td>
<td>lbs: 4,175</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>50%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F</td>
<td>lbs: 4,962</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HIGH WIND (NO ICE) TEMP: 60 F</td>
<td>lbs: 3,915</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UNLOADED LOW TEMPERATURE TEMP: -20 F</td>
<td>lbs: 3,013</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**SAGS (FT)**

| NESC DISTRICT LOADED TEMP: 0 F | | | 9.71 |
| UNLOADED HIGH TEMP TEMP: 212 F | | | 11.32 |
| MAXIMUM ICE TEMP: 30 F | | | 14.06 |
| LOADED 1/2" ICE, NO WIND TEMP: 32 F | | | 10.44 |

### V. CLEARANCES

**MINIMUM CLEARANCES TO BE MAINTAINED AT:**  
**EXTREME ICE LOADING**

<table>
<thead>
<tr>
<th>CLEARANCES IN FEET</th>
<th>RAILROADS NA</th>
<th>ROADS 21.7</th>
<th>CULTIVATED AREAS (REMOTE AREAS) 21.7</th>
<th>ADD'L ALLOWANCE 5.0</th>
</tr>
</thead>
</table>

### VI. RIGHT OF WAY

| WIDTH: | 40 FT. | AT EXTREME WIND, FINAL SAG, AREAS WITH TYP. STRUCTURES ADJ. TO ROW |
| WIDTH: | 45 FT. | AT EXTREME WIND, FINAL SAG, CLEARANCE TO VEGETATION AT LINE ELEV. |
C.3.3 Monopolar Two-Wire Transmission with Metallic Conductor-Return Path (TWMR), Conventionally Built

The standard RUS design for an AC line can be adapted for a monopolar HVDC line with metallic return. Necessary adaptations are listed below:

- Eliminate the four (or three) conductors, insulators, and the cross-arm assembly.
- Increase the ruling span for the intertie line from a typical 250 feet up to 500 feet.
- Add one cantilevered line post insulator rated for nominal 50 kV DC and the structural loads from the conductors. 115 kV AC NGK polymer line post insulators (#L4-SN321-23) were selected for the conceptual design.
- Add one offset neutral bracket for the metallic return conductor.
- Add two conductors rated for the structural loads and electrical requirements of the line. ACSR 4/0 Penguin was selected for the conceptual design for both high-voltage conductors.

A tangent pole-top assembly for this conceptual design is shown on Figure C-3. The conceptual design data for this type of line construction is provided in Table C-3.
Figure C-3 Conventional Tangent Pole for Monopolar HVDC with Metallic Return

**DESIGN SUMMARY**

- **RULEING SPAN:** 500 FT.
- **MIN. GROUND CLEARANCE:** 19 FT.
- **DESIGN BASIS:** NESC HEAVY, CLASS 250B
- **STRINGING TENSION:** 25% (2100 LBS)

**ITEM** | **DESCRIPTION**
--- | ---
- **a:** CONDUCTOR (e.g., 4/0 ACSR ‘penguin’)
- **b:** CONDUCTOR GRIP (e.g., Preformed #CGS-2100 or equal)
- **c:** 115VAC POLYMER LINE POST INSULATOR (e.g., NGK L4-SN321-16U, or equal)
- **d:** TRANSMISSION INSULATOR BRACKET (e.g., Hubbell WP10115, WP10135, or equal)
- **e:** POLE (e.g., wood, fiberglass, or as req’d)
- **f:** OFFSET NEUTRAL BRACKET (e.g., Hubbell C2060004 or equal)
- **g:** 3” SPIGOT INSULATOR (e.g., Hubbell DE495 or equal)
- **h:** FOUNDATION (e.g., direct burial, steel pile, or as req’d)

**NOTES**

This conceptual design is suitable strictly for planning purposes only, and is not to be used as final design or for construction.
Table C-3  Conceptual Design Data for Conventionally Built Monopolar HVDC with Metallic Return

<table>
<thead>
<tr>
<th>SUMMARY OF CONCEPTUAL DESIGN DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>MONOPOLAR HVDC INTERTIE - TWMR CIRCUIT (METALLIC RETURN)</td>
</tr>
<tr>
<td>STANDARD RUS CONSTRUCTION</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>I. GENERAL INFORMATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>PROJECT: CONCEPTUAL 1 MW HVDC LINE</td>
</tr>
<tr>
<td>LINE IDENTIFICATION: RUS STD. AS HVDC TWMR</td>
</tr>
<tr>
<td>VOLTAGE: 50 KV HVDC</td>
</tr>
<tr>
<td>TYPE</td>
</tr>
<tr>
<td>MONOPOLAR HVDC - METALLIC RETURN</td>
</tr>
<tr>
<td>TYPE OF TANGENT STRUCTURE: BASE POLE:</td>
</tr>
<tr>
<td>WOOD POLE</td>
</tr>
<tr>
<td>45 FT CLASS 1</td>
</tr>
<tr>
<td>DESIGNED BY: POLARCONSULT ALASKA (CONCEPT DESIGN)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>II. CONDUCTOR DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>SIZE:</td>
</tr>
<tr>
<td>TRANSMISSION</td>
</tr>
<tr>
<td>COMMON NEUTRAL</td>
</tr>
<tr>
<td>4/0 'PENGUIN'</td>
</tr>
<tr>
<td>4/0 'PENGUIN'</td>
</tr>
<tr>
<td>STRANDING:</td>
</tr>
<tr>
<td>6/1</td>
</tr>
<tr>
<td>MATERIAL:</td>
</tr>
<tr>
<td>ACSR</td>
</tr>
<tr>
<td>ACSR</td>
</tr>
<tr>
<td>DIAMETER (IN):</td>
</tr>
<tr>
<td>0.563</td>
</tr>
<tr>
<td>0.563</td>
</tr>
<tr>
<td>WEIGHT (LBS/FT):</td>
</tr>
<tr>
<td>0.291</td>
</tr>
<tr>
<td>0.291</td>
</tr>
<tr>
<td>RATED STRENGTH (LBS):</td>
</tr>
<tr>
<td>8,350</td>
</tr>
<tr>
<td>8,350</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>III. DESIGN LOADS</th>
</tr>
</thead>
<tbody>
<tr>
<td>NESC LOADING DISTRICT: HEAVY</td>
</tr>
<tr>
<td>TRANSMISSION (LBS/FT)</td>
</tr>
<tr>
<td>COMMON NEUTRAL (LBS/FT)</td>
</tr>
<tr>
<td>a. ICE (IN.): (vertical) 0.5 in. radial 0.5 in. radial</td>
</tr>
<tr>
<td>b. WIND ON ICED COND (PSF): (transverse) 4.0 psf 4.0 psf</td>
</tr>
<tr>
<td>c. CONSTANT K: (resultant + K) 0.3 psf 0.3 psf</td>
</tr>
<tr>
<td>EXTREME ICE (NO WIND): (vertical) 1.0 in. radial 1.0 in. radial</td>
</tr>
<tr>
<td>EXTREME WIND (NO ICE): (transverse) 120 mph 32.2 psf 120 mph 32.2 psf</td>
</tr>
<tr>
<td>EXTREME ICE + WIND: ICE: (vertical) 0.25 in. radial 0.25 in. radial</td>
</tr>
<tr>
<td>WIND: (transverse) 80 mph 14.3 psf 80 mph 14.3 psf</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IV. SAG &amp; TENSION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>RULING SPAN: 500 ft.</td>
</tr>
<tr>
<td>SOURCE OF SAG/TENSION DATA: SOUTHWIRE SAG10</td>
</tr>
<tr>
<td>TRANSMISSION</td>
</tr>
<tr>
<td>INITIAL</td>
</tr>
<tr>
<td>COMMON NEUTRAL</td>
</tr>
<tr>
<td>INITIAL</td>
</tr>
<tr>
<td>NESC a. UNLOADED TEMP: 60 F lbs: 1,999 1,142</td>
</tr>
<tr>
<td>24% 14%</td>
</tr>
<tr>
<td>NESC b. LOADED TEMP: 0 F lbs: 4,175</td>
</tr>
<tr>
<td>50% 50%</td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F lbs: 4,982</td>
</tr>
<tr>
<td>50% 50%</td>
</tr>
<tr>
<td>MAXIMUM WIND (NO ICE) TEMP: 60 F lbs: 3,983</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>UNLOADED LOW TEMPERATURE TEMP: -20 F lbs: 3,013</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>SAGS (FT)</td>
</tr>
<tr>
<td>NESC DISTRICT LOADED TEMP: 0 F</td>
</tr>
<tr>
<td>9.71</td>
</tr>
<tr>
<td>UNLOADED HIGH TEMP TEMP: 212 F</td>
</tr>
<tr>
<td>11.32</td>
</tr>
<tr>
<td>MAXIMUM WIND TEMP: 30 F</td>
</tr>
<tr>
<td>14.06</td>
</tr>
<tr>
<td>LOADED 1/2&quot; ICE, NO WIND TEMP: 32 F</td>
</tr>
<tr>
<td>10.44</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>V. CLEARANCES</th>
</tr>
</thead>
<tbody>
<tr>
<td>MINIMUM CLEARANCES TO BE MAINTAINED AT: EXTREME ICE LOAD</td>
</tr>
<tr>
<td>CLEARANCES IN FEET</td>
</tr>
<tr>
<td>RAILROADS NA</td>
</tr>
<tr>
<td>ROADS 21.7</td>
</tr>
<tr>
<td>CULTIVATED AREAS (REMOTE AREAS) 21.7</td>
</tr>
<tr>
<td>ADD'L ALLOWANCE 5.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>VI. RIGHT OF WAY</th>
</tr>
</thead>
<tbody>
<tr>
<td>WIDTH: 50 FT. AT EXTREME WIND, FINAL SAG, AREAS WITH TYP. STRUCTURES ADJ. TO ROW</td>
</tr>
<tr>
<td>WIDTH: 45 FT. AT EXTREME WIND, FINAL SAG, CLEARANCE TO VEGETATION AT LINE ELEV.</td>
</tr>
</tbody>
</table>
C.3.4 Bipolar Two-Wire Transmission, Conventionally Built

The standard RUS design for an AC line can be adapted for a bipolar HVDC line. Necessary adaptations are listed below:

- Eliminate the four (or three) conductors, insulators, and the cross-arm assembly.
- Increase the ruling span for the intertie line from a typical 250 feet up to 500 feet.
- Add two cantilevered post insulators rated for nominal 50 kV DC and the structural loads from the conductors. A 115 kV AC NGK polymer line post insulator (#L4-SN321-15U) was selected for the conceptual design.
- Add two conductors rated for the structural loads and electrical requirements of the line. ACSR 4/0 Penguin was selected for the conceptual design for both the high-voltage and metallic-return conductors.

A tangent pole-top assembly for this conceptual design is shown on Figure C-4. The conceptual design data for this type of line construction is provided in Table C-4.
Figure C-4  Conventional Tangent Pole for Bipolar HVDC Intertie Line

**Design Summary**

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>Conductor (e.g., 4/0 ACSR 'PENGUIN')</td>
</tr>
<tr>
<td>b</td>
<td>Conductor Grip</td>
</tr>
<tr>
<td>c</td>
<td>115VAC Polymer Line Post Insulator</td>
</tr>
<tr>
<td>d</td>
<td>Insulator Base</td>
</tr>
<tr>
<td>e</td>
<td>Pole</td>
</tr>
<tr>
<td>f</td>
<td>Foundation Assembly (e.g., direct burial, steel pile, or as req’d)</td>
</tr>
</tbody>
</table>

**NOTES**

This conceptual design is suitable strictly for planning purposes only, and is not to be used as final design or for construction.

**Elevation View**
Table C-4  Conceptual Design Data for Conventionally Built Bipolar HVDC Intertie Line

### I. GENERAL INFORMATION

<table>
<thead>
<tr>
<th>PROJECT:</th>
<th>CONCEPTUAL 2 MW HVDC LINE</th>
</tr>
</thead>
<tbody>
<tr>
<td>LINE IDENTIFICATION:</td>
<td>RUS STD. AS BIPOLAR HVDC</td>
</tr>
<tr>
<td>VOLTAGE:</td>
<td>+/- 50 KV HVDC</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TYPE</th>
<th>BIPOLAR HVDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>TYPE OF TANGENT STRUCTURE:</td>
<td>WOOD POLE</td>
</tr>
<tr>
<td>BASE POLE:</td>
<td>40 FT CLASS 1</td>
</tr>
</tbody>
</table>

| DESIGNED BY: | POLARCONSULT ALASKA (CONCEPT DESIGN) |

### II. CONDUCTOR DATA

<table>
<thead>
<tr>
<th>TRANSMISSION + 50 kVDC</th>
<th>TRANSMISSION - 50 kVDC</th>
</tr>
</thead>
<tbody>
<tr>
<td>SIZE:</td>
<td>4/0 'PENGUIN'</td>
</tr>
<tr>
<td>STRANDING:</td>
<td>4/0 'PENGUIN'</td>
</tr>
<tr>
<td>MATERIAL:</td>
<td>ACSR</td>
</tr>
<tr>
<td>DIAMETER (IN):</td>
<td>0.563</td>
</tr>
<tr>
<td>WEIGHT (LBS/FT):</td>
<td>0.291</td>
</tr>
<tr>
<td>RATED STRENGTH (LBS):</td>
<td>8,350</td>
</tr>
</tbody>
</table>

### III. DESIGN LOADS

<table>
<thead>
<tr>
<th>NESC LOADING DISTRICT:</th>
<th>HEAVY</th>
</tr>
</thead>
<tbody>
<tr>
<td>TRANSMISSION (LBS/FT)</td>
<td>TRANSMISSION (LBS/FT)</td>
</tr>
<tr>
<td>a. ICE (IN.): (vertical)</td>
<td>0.5 in. radial</td>
</tr>
<tr>
<td>b. WIND ON ICED COND (PSF): (transverse)</td>
<td>4.0 psf</td>
</tr>
<tr>
<td>c. CONSTANT K: (resultant + K)</td>
<td>0.3 psf</td>
</tr>
<tr>
<td>EXTREME ICE (NO WIND): (vertical)</td>
<td>1.0 in. radial</td>
</tr>
<tr>
<td>EXTREME WIND (NO ICE): (transverse)</td>
<td>120 mph</td>
</tr>
<tr>
<td>EXTREME ICE + WIND:</td>
<td></td>
</tr>
<tr>
<td>ICE: (vertical)</td>
<td>0.25 in. radial</td>
</tr>
<tr>
<td>WIND: (transverse)</td>
<td>80 mph</td>
</tr>
</tbody>
</table>

### IV. SAG & TENSION DATA

<table>
<thead>
<tr>
<th>TRANSMISSION</th>
</tr>
</thead>
<tbody>
<tr>
<td>INITIAL</td>
</tr>
<tr>
<td>INITIAL</td>
</tr>
<tr>
<td>NESC</td>
</tr>
<tr>
<td>a. UNLOADED</td>
</tr>
<tr>
<td>lbs:</td>
</tr>
<tr>
<td>24%</td>
</tr>
<tr>
<td>b. LOADED</td>
</tr>
<tr>
<td>lbs:</td>
</tr>
<tr>
<td>50%</td>
</tr>
<tr>
<td>MAXIMUM ICE</td>
</tr>
<tr>
<td>lbs:</td>
</tr>
<tr>
<td>50%</td>
</tr>
<tr>
<td>HIGH WIND (NO ICE)</td>
</tr>
<tr>
<td>lbs:</td>
</tr>
<tr>
<td>50%</td>
</tr>
<tr>
<td>UNLOADED LOW TEMPERATURE TEMP: -20 F</td>
</tr>
<tr>
<td>50%</td>
</tr>
<tr>
<td>SAGS (FT)</td>
</tr>
<tr>
<td>NESC DISTRICT LOADED</td>
</tr>
<tr>
<td>9.71</td>
</tr>
<tr>
<td>UNLOADED HIGH TEMP</td>
</tr>
<tr>
<td>11.32</td>
</tr>
<tr>
<td>MAXIMUM ICE</td>
</tr>
<tr>
<td>14.06</td>
</tr>
<tr>
<td>LOADED 1/2&quot; ICE, NO WIND</td>
</tr>
<tr>
<td>10.44</td>
</tr>
</tbody>
</table>

### V. CLEARANCES

<table>
<thead>
<tr>
<th>MINIMUM CLEARANCES TO BE MAINTAINED AT:</th>
<th>EXTREME ICE LOADING</th>
</tr>
</thead>
<tbody>
<tr>
<td>CLEARANCES IN FEET</td>
<td>RAILROADS</td>
</tr>
<tr>
<td>TRANSMISSION CLR. TO GROUND</td>
<td>NA</td>
</tr>
</tbody>
</table>

### VI. RIGHT OF WAY

| WIDTH: | 50 FT. | AT EXTREME WIND, FINAL SAG, AREAS WITH TYP. STRUCTURES ADJ. TO ROW |
| WIDTH: | 45 FT. | AT EXTREME WIND, FINAL SAG, CLEARANCE TO VEGETATION AT LINE ELEV. |
C.4 CONCEPTUAL DESIGN OF OVERHEAD HVDC TRANSMISSION, ALASKA-SPECIFIC METHODS

The conceptual designs of overhead intertie lines presented in this section have been developed to reduce construction costs on rural Alaska interties. Cost reduction is achieved through special attention to the factors listed below.

- Minimizing the reliance on heavy equipment that must be mobilized to a construction site. If lighter equipment or local equipment can be used for construction, mobilization costs will be less, reducing project costs.
- Maximizing the flexibility in construction methods and seasons. By designing for the use of smaller equipment, greater use of helicopters for construction support, and similar techniques, all-season construction becomes possible, creating new opportunities to increase utilization of equipment, increase competition for line construction projects, and reduce project costs.

These factors have been incorporated into the conceptual design elements listed below.

- Use of taller structures and longer spans. Because HVDC circuits require only one or two wires, they can utilize longer spans than a comparable three- or four-wire AC circuit. Increasing spans reduces the number of structures and foundations for a given length of overhead line, which reduces costs. With this approach, taller structures are needed to maintain required clearances between the conductor and the ground.
- Use of glass-fiber-reinforced polymer (GFRP) poles instead of wood or steel poles. GFRP poles have been used for over 50 years in electric utility applications but have little to no history in Alaska’s electric utility industry. GFRP poles are lighter than wood or steel poles so they can be transported by a small helicopter such as a Hughes 500 or Bell UH-1 “Huey.” They are also rot-resistant and do not leach toxic preservatives into the soils around the pole. The Phase II project included demonstration of a field-friendly splice for GFRP poles, which permits tall poles to be shipped in parts and assembled in the field. This splice can also be used for field repair of damaged GFRP poles.
- Use of guyed structures in areas where geotechnical conditions prevent cantilevered poles from being directly buried in the soil. Accepted practice for such conditions is to drive a steel pile up to 40 feet deep and then fasten a wood pole to the steel pile. Installing the steel pile requires mobilizing a crane or other heavy equipment to the project site. A guyed structure can be installed in such conditions with a much smaller base foundation, as the guys carry most of the moment, and the structure base mostly carries compressive loads.

The following sections describe conceptual designs using these Alaska-specific methods for the following types of HVDC circuits:

- Monopolar SWER;
- Monopolar TWMR;
- Bipolar two-wire transmission.

In all cases, the conceptual designs presented in the following sections comply with the design criteria, load factors, and strength factors set forth in Section C.2 of this appendix and by RUS.34

34 RUS, 2009
C.4.1 Monopolar Single-Wire Transmission with Earth-Return Path (SWER, Alaska-Specific Design)

The Alaska-specific conceptual design for a monopolar HVDC line consists of the following elements:

- Single 19#10 Alumoweld conductor installed at a ruling span of 1,000 feet.
- A single line post insulator rated for nominal 50 kV DC and the structural loads from the conductors. A 115 kV AC NGK polymer line post insulator (#L4-SN321-15U) was selected for the conceptual design.\(^{35}\)
- A 14-inch-diameter, 0.375-inch wall, 50-foot-tall GFRP pole. This pole can be increased to 70 feet if needed without modification for spans up to 1,500 feet or for increased ground or terrain clearances.
- Four guys attached to the pole top installed at a 45-degree angle to the conductor and a 45-degree angle to ground.
- Guy anchors consisting of two flights of 8-inch screw anchors driven 10 to 15 feet into the ground.
- A pole base foundation consisting of three 1½-inch by 25-foot thermoprobe micropiles installed to a depth of 20 feet. The remaining 5 feet serve as the thermoprobe radiator.

A tangent pole-top assembly for this monopolar HVDC SWER intertie conceptual design is shown on Figure C-5. The conceptual design data for this type of line construction is provided in Table C-5.

---

\(^{35}\) The insulator design is considered conservative and is anticipated to be adequate for most regions of Alaska. Insulators rated at a lower voltage may be appropriate for some intertie lines.
Figure C-5  Alaska-Specific Tangent Pole for Monopolar SWER HVDC Intertie Line

**FIG. a - MONOPOLAR HVDC TANGENT POLE, EARTH RETURN - PLAN VIEW**

**FIG. b - MONOPOLAR HVDC TANGENT POLE, EARTH RETURN - ELEVATION VIEW**
# Conceptual Design Data for Alaska-Specific Monopolar SWER HVDC Intertie Line

## I. GENERAL INFORMATION

<table>
<thead>
<tr>
<th>PROJECT</th>
<th>CONCEPTUAL 1 MW HVDC LINE</th>
</tr>
</thead>
<tbody>
<tr>
<td>LINE IDENTIFICATION</td>
<td>AK SPECIFIC HVDC SWER DES.</td>
</tr>
<tr>
<td>VOLTAGE</td>
<td>50 KV HVDC</td>
</tr>
<tr>
<td>TYPE</td>
<td>MONOPOLAR HVDC SWER</td>
</tr>
<tr>
<td>TYPE OF TANGENT STRUCTURE</td>
<td>BASE POLE: GUYED FRP POLE</td>
</tr>
<tr>
<td>BASE POLE</td>
<td>45 FT FRP POLE</td>
</tr>
<tr>
<td>DESIGNED BY</td>
<td>POLARCONSULT ALASKA (CONCEPT DESIGN)</td>
</tr>
</tbody>
</table>

## II. CONDUCTOR DATA

<table>
<thead>
<tr>
<th>SIZE</th>
<th>TRANSMISSION (LBS/FT)</th>
<th>COMMON NEUTRAL (LBS/FT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>19#10 ALUMOWELD (NONE)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>STRANDING</th>
<th>ALUMOWELD</th>
</tr>
</thead>
<tbody>
<tr>
<td>DIAMETER (IN)</td>
<td>0.509</td>
</tr>
<tr>
<td>WEIGHT (LBS/FT)</td>
<td>0.449</td>
</tr>
<tr>
<td>RATED STRENGTH (LBS)</td>
<td>27,190</td>
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## III. DESIGN LOADS

### NESC LOADING DISTRICT: HEAVY

<table>
<thead>
<tr>
<th>a. ICE (IN.)</th>
<th>TRANSMISSION (LBS/FT)</th>
<th>COMMON NEUTRAL (LBS/FT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(vertical)</td>
<td>0.5 in. radial</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>b. WIND ON ICED COND (PSF)</th>
<th>(transverse)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.0 psf</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>c. CONSTANT K</th>
</tr>
</thead>
<tbody>
<tr>
<td>(resultant + K)</td>
</tr>
<tr>
<td>0.3 psf</td>
</tr>
</tbody>
</table>

### EXTREME ICE (NO WIND): (vertical)

| (vertical)                  | 1.0 in. radial        |

### EXTREME WIND (NO ICE): (transverse)

<table>
<thead>
<tr>
<th>(transverse)</th>
</tr>
</thead>
<tbody>
<tr>
<td>120 mph</td>
</tr>
</tbody>
</table>

### EXTREME ICE + WIND:

<table>
<thead>
<tr>
<th>ICE</th>
<th>(vertical)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.25 in. radial</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>WIND</th>
<th>(transverse)</th>
</tr>
</thead>
<tbody>
<tr>
<td>80 mph</td>
<td></td>
</tr>
</tbody>
</table>

## IV. SAG & TENSION DATA

<table>
<thead>
<tr>
<th>RULING SPAN</th>
<th>1,000 ft.</th>
</tr>
</thead>
<tbody>
<tr>
<td>SOURCE OF SAG/TENSION DATA</td>
<td>SOUTHWIRE SAG10</td>
</tr>
</tbody>
</table>

### TRANSMISSION TENSIONS (% RATED STRENGTH)

<table>
<thead>
<tr>
<th>NESC</th>
<th>INITIAL</th>
<th>FINAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. UNLOADED TEMP: 60 F</td>
<td>lbs: 8,071</td>
<td>lbs: 6,798</td>
</tr>
<tr>
<td></td>
<td>30%</td>
<td>25%</td>
</tr>
<tr>
<td>b. LOADED TEMP: 0 F</td>
<td>lbs: 11,246</td>
<td></td>
</tr>
<tr>
<td></td>
<td>41%</td>
<td></td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F</td>
<td>lbs: 12,637</td>
<td></td>
</tr>
<tr>
<td>HIGH WIND (NO ICE) TEMP: 60 F</td>
<td>lbs: 10,075</td>
<td></td>
</tr>
<tr>
<td>UNLOADED LOW TEMPERATURE TEMP:</td>
<td>lbs: 9,736</td>
<td></td>
</tr>
<tr>
<td>SAGS (FT)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NESC DISTRICT LOADED TEMP: 0 F</td>
<td>15.97</td>
<td></td>
</tr>
<tr>
<td>UNLOADED HIGH TEMP TEMP: 212 F</td>
<td>13.73</td>
<td></td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F</td>
<td>23.85</td>
<td></td>
</tr>
<tr>
<td>LOADED 1/2&quot; ICE, NO WIND TEMP: 32 F</td>
<td>15.02</td>
<td></td>
</tr>
</tbody>
</table>

## V. CLEARANCES

<table>
<thead>
<tr>
<th>MINIMUM CLEARANCES TO BE MAINTAINED AT: EXTREME ICE LOADING</th>
</tr>
</thead>
<tbody>
<tr>
<td>CLEARANCES IN FEET</td>
</tr>
<tr>
<td>TRANSMISSION CLR. TO GROUND NA RAILROADS ROADS</td>
</tr>
<tr>
<td>21.7 CULTIVATED AREAS (REMOTE AREAS) ADD'L ALLOWANCE 5.0</td>
</tr>
</tbody>
</table>

## VI. RIGHT OF WAY

<table>
<thead>
<tr>
<th>WIDTH</th>
</tr>
</thead>
<tbody>
<tr>
<td>60 FT</td>
</tr>
<tr>
<td>AT EXTREME WIND, FINAL SAG, AREAS WITH TYP. STRUCTURES ADJ. TO ROW</td>
</tr>
<tr>
<td>70 FT</td>
</tr>
<tr>
<td>FOOTPRINT OF 4-GUYED STRUCTURE, GUYS AT 45 DEGREES TO LINE</td>
</tr>
<tr>
<td>95 FT</td>
</tr>
<tr>
<td>FOOTPRINT OF 4-GUYED STRUCTURE, GUYS IN LINE AND NORMAL TO CONDUCTOR.</td>
</tr>
<tr>
<td>55 FT</td>
</tr>
<tr>
<td>AT EXTREME WIND, FINAL SAG, CLEARANCE TO VEGETATION AT LINE ELEV.</td>
</tr>
</tbody>
</table>
C.4.2 Monopolar Two-Wire Transmission with Metallic Conductor-Return Path (TWMR), Alaska-Specific Design

The Alaska-specific conceptual design for a monopolar HVDC line (Figure C-6) can be adapted for a two-wire monopolar HVDC line with metallic return. The necessary changes are listed below:

- Increase the GFRP pole height from 50 feet to 65 feet. No change is needed in the pole section or material under the load cases listed in Section C.2.
- Addition of a second 19#10 Alumoweld conductor supported by an offset bracket 15 feet below the top of the pole. At this attachment point, this second conductor will have adequate clearance from the guys, ground, and the high-voltage conductor under all load conditions listed in Section C.2 of this appendix.
- Maintain the ruling span at 1,000 feet.

A tangent pole-top assembly for a conventionally built two-wire monopolar HVDC intertie is shown on Figure C-6. The conceptual design data for this type of line construction is provided in Table C-6.
Figure C-6  Alaska-Specific Tangent Pole for Monopolar Metallic-Return Intertie Line

**Figure C-6**  Alaska-Specific Tangent Pole for Monopolar Metallic-Return Intertie Line

**FIG. a - MONOPOLAR HVDC TANGENT POLE, METALLIC RETURN - PLAN VIEW**

**FIG. b - MONOPOLAR HVDC TANGENT POLE, METALLIC RETURN - ELEVATION VIEW**
Table C-6  Conceptual Design Data for Alaska-Specific Monopolar Metallic-Return Intertie Line

| I. GENERAL INFORMATION |  |
|------------------------|  |
| PROJECT: CONCEPTUAL 1 MW HVDC LINE |  |
| VOLTAGE: AK SPECIFIC HVDC SWER DES. 50 KV HVDC |  |
| TYPE: MONOPOLAR HVDC WITH METALLIC RETURN |  |
| TYPE OF TANGENT STRUCTURE: BASE POLE: GUYED FRP POLE 65 FT FRP POLE |  |
| DESIGNED BY: POLARCONSULT ALASKA (CONCEPT DESIGN) |  |

| SUMMARY OF CONCEPTUAL DESIGN DATA |  |
|-----------------------------------|  |
| MONOPOLAR HVDC OVERHEAD INTERTIE TMWR CIRCUIT (METALLIC RETURN) |  |
| ALASKA-SPECIFIC CONSTRUCTION |  |

<table>
<thead>
<tr>
<th>II. CONDUCTOR DATA</th>
<th>TRANSMISSION</th>
<th>COMMON NEUTRAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>SIZE: 19#10 ALUMOWELD</td>
<td>19#10 ALUMOWELD</td>
<td></td>
</tr>
<tr>
<td>STRANDING: 19#10</td>
<td>19#10</td>
<td></td>
</tr>
<tr>
<td>MATERIAL: ALUMOWELD</td>
<td>ALUMOWELD</td>
<td></td>
</tr>
<tr>
<td>DIAMETER (IN): 0.509</td>
<td>0.509</td>
<td></td>
</tr>
<tr>
<td>WEIGHT (LBS/FT): 0.449</td>
<td>0.449</td>
<td></td>
</tr>
<tr>
<td>RATED STRENGTH (LBS): 27,190</td>
<td>27,190</td>
<td></td>
</tr>
</tbody>
</table>

| III. DESIGN LOADS |  |
|-------------------|  |
| NESC LOADING DISTRICT: HEAVY | TRANSMISSION (LBS/FT) | COMMON NEUTRAL (LBS/FT) |
| a. ICE (IN.): (vertical) 0.5 in. radial | 0.5 in. radial |  |
| b. WIND ON ICED COND (PSF): (transverse) 4.0 psf | 4.0 psf |  |
| c. CONSTANT K: (resultant + K) 0.3 psf | 0.3 psf |  |
| EXTREME ICE (NO WIND): (vertical) 1.0 in. radial | 1.0 in. radial |  |
| EXTREME WIND (NO ICE): (transverse) 120 mph 34.0 psf | 120 mph 34.0 psf |  |
| EXTREME ICE + WIND: ICE (vertical) 0.25 in. radial | 0.3 in. radial |  |
| WIND: (transverse) 80 mph 15.1 psf | 80 mph 15.1 psf |  |

<p>| IV. SAG &amp; TENSION DATA |  |
|------------------------|  |
| RULING SPAN: 1,000 ft. |  |
| SOURCE OF SAG/TENSION DATA: SOUTHWIRE SAG10 |  |</p>
<table>
<thead>
<tr>
<th>TENSIONS (% RATED STRENGTH)</th>
<th>TRANSMISSION</th>
<th>COMMON NEUTRAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>NESC a. UNLOADED TEMP: 60 F</td>
<td>lbs: 8,071 6,798</td>
<td>8,071 6,798</td>
</tr>
<tr>
<td></td>
<td>30% 25%</td>
<td>30% 25%</td>
</tr>
<tr>
<td>NESC b. LOADED TEMP: 0 F</td>
<td>lbs: 11,246</td>
<td>11,246</td>
</tr>
<tr>
<td></td>
<td>41% 41%</td>
<td>41% 41%</td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F</td>
<td>lbs: 12,637 12,637</td>
<td></td>
</tr>
<tr>
<td>HIGH WIND (NO ICE) TEMP: 60 F</td>
<td>lbs: 10,075 10,075</td>
<td></td>
</tr>
<tr>
<td>UNLOADED LOW TEMPERATURE TEMP: -20 F</td>
<td>lbs: 9,736 9,736</td>
<td></td>
</tr>
<tr>
<td>SAGS (FT)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NESC DISTRICT LOADED TEMP: 0 F</td>
<td>15.97 15.97</td>
<td></td>
</tr>
<tr>
<td>UNLOADED HIGH TEMP TEMP: 212 F</td>
<td>13.73 13.73</td>
<td></td>
</tr>
<tr>
<td>MAXIMUM ICE TEMP: 30 F</td>
<td>23.85 23.85</td>
<td></td>
</tr>
<tr>
<td>LOADED 1/2&quot; ICE, NO WIND TEMP: 32 F</td>
<td>15.02 15.02</td>
<td></td>
</tr>
</tbody>
</table>

| V. CLEARANCES |  |
|----------------|  |
| MINIMUM CLEARANCES TO BE MAINTAINED AT: EXTREME ICE LOADING |  |
| CLEARANCES IN FEET RAILROADS ROADS CULTIVATED AREAS (REMOTE AREAS) ADD’L ALLOWANCE |  |
| TRANSMISSION CLR. TO GROUND: NA | 21.7 | 21.7 | 5.0 |  |

| VI. RIGHT OF WAY |  |
|------------------|  |
| WIDTH: 60 FT. FOR EXTREME WIND, FINAL SAG, AREAS WITH TYP. STRUCTURES ADJ. TO ROW |  |
| WIDTH: 100 FT. FOOTPRINT OF 4-GUYED STRUCTURE, GUYS AT 45 DEGREES TO LINE |  |
| WIDTH: 135 FT. FOOTPRINT OF 4-GUYED STRUCTURE, GUYS IN LINE AND NORMAL TO CONDUCTOR. |  |
| WIDTH: 60 FT. FOR EXTREME WIND, FINAL SAG, CLEARANCE TO VEGETATION AT LINE ELEV. |  |
C.4.3 Bipolar HVDC Intertie Line, Alaska Specific Design

The Alaska-specific conceptual design for a monopolar HVDC line (Figure C-7) can be adapted for a two-wire bipolar HVDC line. The necessary changes are listed below:

- Increase the GFRP pole height from 50 feet to 55 feet. No change is needed in the pole section or material.
- Eliminate the post-top insulator and add two 8-foot-long cross-arms. A Powertrusion #SH2096100N or equal was selected for the conceptual design.
- Install two suspension insulators off each end of the cross-arm. A 115-kV AC NGK suspension insulator #251-SE510-EE or equal was selected for the conceptual design.
- Use 19#10 Alumoweld as the conductor for both the positive and negative poles of the circuit.
- Maintain the same span length of 1,000 feet.

A tangent pole-top assembly for an Alaska-specific bipolar two-wire HVDC intertie is shown on Figure C-7. The conceptual design data for this type of line construction is provided in Table C-7.
Figure C-7  Alaska-Specific Tangent Pole for Bipolar HVDC Intertie Line

FIG. a - BIPOLAR HVDC TANGENT POLE (OR ALTERNATE MONOPOLAR HVDC TANGENT POLE, METALLIC RETURN) - PLAN VIEW

FIG. b - BIPOLAR HVDC TANGENT POLE (OR ALTERNATE MONOPOLAR HVDC TANGENT POLE, METALLIC RETURN) - ELEVATION VIEWS
Table C-7  Conceptual Design Data for Alaska-Specific Bipolar HVDC Intertie Line

<table>
<thead>
<tr>
<th>I. GENERAL INFORMATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>PROJECT: CONCEPTUAL 1 MW HVDC LINE</td>
</tr>
<tr>
<td>LINE IDENTIFICATION: AK SPECIFIC HVDC SWER DES.</td>
</tr>
<tr>
<td>VOLTAGE: 50 KV HVDC</td>
</tr>
<tr>
<td>TYPE: BIPOLAR HVDC</td>
</tr>
<tr>
<td>Bipolar HVDC Intertie: Alaska-Specific Construction</td>
</tr>
<tr>
<td>Type of Tangent Structure: Guyed FRP Pole</td>
</tr>
<tr>
<td>Base Pole: 55 FT FRP Pole</td>
</tr>
<tr>
<td>Designed By: Polarconsult Alaska (Concept Design)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>II. CONDUCTOR DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size: 19#10 Alumoweld</td>
</tr>
<tr>
<td>Stranding: 19#10 19#10</td>
</tr>
<tr>
<td>Material: Alumoweld</td>
</tr>
<tr>
<td>Diameter (in): 0.509</td>
</tr>
<tr>
<td>Weight (lbs/ft): 0.449</td>
</tr>
<tr>
<td>Rated Strength (lbs): 27,190</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>III. DESIGN LOADS</th>
</tr>
</thead>
<tbody>
<tr>
<td>NESC Loading District: Heavy</td>
</tr>
<tr>
<td>Transmission (lbs/ft)</td>
</tr>
<tr>
<td>Common Neutral (lbs/ft)</td>
</tr>
<tr>
<td>a. Ice (in.): (vertical) 0.5 in. radial 0.5 in. radial</td>
</tr>
<tr>
<td>b. Wind on Iced Cond (psf): (transverse) 4.0 psf 4.0 psf</td>
</tr>
<tr>
<td>c. Constant K: (resultant + K) 0.3 psf 0.3 psf</td>
</tr>
<tr>
<td>Extreme Ice (No Wind): (vertical) 1.0 in. radial 1.0 in. radial</td>
</tr>
<tr>
<td>Extreme Wind (No Ice): (transverse) 120 mph 32.3 psf 120 mph 32.3 psf</td>
</tr>
<tr>
<td>Extreme Ice + Wind:</td>
</tr>
<tr>
<td>Ice: (vertical) 0.25 in. radial 0.3 in. radial</td>
</tr>
<tr>
<td>Wind: (transverse) 80 mph 14.3 psf 80 mph 14.3 psf</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IV. SAG &amp; TENSION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ruling Span: 1,000 ft.</td>
</tr>
<tr>
<td>Source of Sag/Tension Data: Southwire SAG10</td>
</tr>
<tr>
<td>Transmission</td>
</tr>
<tr>
<td>Common Neutral</td>
</tr>
<tr>
<td>Tensions (% Rated Strength)</td>
</tr>
<tr>
<td>NESC</td>
</tr>
<tr>
<td>a. Unloaded Temp: 60 F lbs: 8,071 6,798</td>
</tr>
<tr>
<td>30% 25% 30% 25%</td>
</tr>
<tr>
<td>b. Loaded Temp: 0 F lbs: 11,246</td>
</tr>
<tr>
<td>41% 41%</td>
</tr>
<tr>
<td>Maximum Ice Temp: 30 F lbs: 12,637</td>
</tr>
<tr>
<td>41%</td>
</tr>
<tr>
<td>High Wind (No Ice) Temp: 60 F lbs: 10,075</td>
</tr>
<tr>
<td>Unloaded Low Temperature Temp: -20 F lbs: 9,736</td>
</tr>
<tr>
<td>Sag (ft)</td>
</tr>
<tr>
<td>NESC District Loaded Temp: 0 F</td>
</tr>
<tr>
<td>15.97</td>
</tr>
<tr>
<td>Unloaded High Temp Temp: 212 F</td>
</tr>
<tr>
<td>13.73 13.73</td>
</tr>
<tr>
<td>Maximum Ice Temp: 30 F</td>
</tr>
<tr>
<td>23.85 23.85</td>
</tr>
<tr>
<td>Loaded 1/2&quot; Ice, No Wind Temp: 32 F</td>
</tr>
<tr>
<td>15.02 15.02</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>V. CLEARANCES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum Clearances to be Maintained at: Extreme Ice Loading</td>
</tr>
<tr>
<td>Clearances in Feet</td>
</tr>
<tr>
<td>Railroads: NA</td>
</tr>
<tr>
<td>Roads: 21.7</td>
</tr>
<tr>
<td>Cultivated Areas (Remote Areas): 21.7</td>
</tr>
<tr>
<td>Add'1 Allowance: 5.0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>VI. RIGHT OF WAY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Width: 60 FT. for Extreme Wind, Final Sag, Areas with TYP. Structures Adj. to ROW</td>
</tr>
<tr>
<td>Width: 95 FT. for Footprint of 4-Guyed Structure, Guys at 45 Degrees to Line</td>
</tr>
<tr>
<td>Width: 125 FT. for Footprint of 4-Guyed Structure, Guys in Line and Normal to Conductor.</td>
</tr>
<tr>
<td>Width: 55 FT. for Extreme Wind, Final Sag, Clearance to Vegetation at Line Elev.</td>
</tr>
</tbody>
</table>
C.4.4 Conceptual Design Analysis

The conceptual design of overhead transmission structures and foundations considered methods for construction, long-term operation, maintenance, repair, and replacement of the HVDC transmission infrastructure.

C.4.4.1 Construction Methods

The cost-reduction potential of HVDC on rural Alaska projects may be realized using optimized construction methods.

The use of lightweight overhead structures and foundations allows significant latitude for the construction and maintenance of the lines. The use of helicopters to stage the materials and construction equipment becomes possible.

Conventional AC transmission line construction is typically performed in the winter to support the heavy equipment required for construction. This equipment often includes large pile-driving or drilling machines that can only be operated on frozen ground. The resulting winter construction schedule, combined with summer mobilization of the equipment, contributes significantly to the high cost of AC interties.

AC transmission structures and foundations are usually based on a cantilever pole design. For the low-strength geotechnical conditions found in much of rural Alaska, this design approach is inefficient compared to the use of axially loaded guyed structures proposed in the HVDC conceptual design.

The HVDC construction approach can utilize Hughes 500 or Bell UH-1 type helicopters, which are commonly available in Alaska. These helicopters have a sling capacity of approximately 1,000 and 3,000 pounds, respectively. The HVDC composite pole structures, guy wires, screw foundations, thermoprobe foundations, and other transmission components can be readily staged by these helicopters. Installation equipment and other construction tools are available in sizes that can be lifted by helicopter.

In addition, this construction approach involves the use of tracked, low-ground-pressure vehicles with attachments optimized for the installation of the HVDC foundations and erection of the composite pole structures. The ideal vehicle would be similar to a hydraulically driven BB Carrier. The BB Carrier was a predecessor of Nodwell tracked vehicles, but much smaller 36. The hydraulic drive system can be used to power drills, winches, spades, impact drivers, and other onboard equipment used for line construction 37.

C.4.4.2 Recommended Construction Approach

The following narrative sets forth the general construction approach recommended for the conceptual overhead HVDC intertie design presented herein. Preferred construction methods for any specific intertie will differ from this approach and will affect construction costs.

1. Identify and procure property rights to the intertie alignment. Standard practices for this effort are appropriate and are not duplicated here.

---

36 The BB Carrier was manufactured in the late 1950s and early 1960s by Bombardier. It is no longer in production and is quite rare today. It featured a gross vehicle weight of about 2,000 pounds, a payload capacity of about 1,000 pounds, and a ground pressure of less than one psi. Its drive train used a planetary transmission, maintaining power to both tracks during turns, which reduced the tendency of these vehicles to damage fragile tundra vegetation.

37 A 20,000 to 30,000-ft-lb hydraulic impact driver head on a small boom would be useful for driving foundation screw anchors.
2. Send an engineering crew and survey party to survey the line and determine pole locations in the field. Surveying and preliminary line design may be completed beforehand by remote methods (e.g., light detection and ranging [LIDAR] survey). The engineering crew will conduct geotechnical testing at each pole site to determine the type of foundation required. As appropriate, the engineering crew may adjust pole locations based on encountered conditions.

3. Order and ship materials to the project site. Depending on the project, one or both villages will be used as the base of operations. It may be cost-effective to preassemble pole or foundation units prior to shipping to the site.

4. Prepare and install pole foundations. Depending on the project, pole foundations may be shipped ready to install or may require some assembly in the village. Once ready to deploy to the field, the foundations for each pole (pole base and three guy foundations) will be airlifted to the pole site by helicopter. A small low-ground-pressure vehicle will be used to install the foundations. Depending on the terrain, this stage may occur during the late winter or summer months. The ground vehicle will remain in the field, and personnel and consumables will be transported to the vehicle daily by air. This will reduce transit times.

5. Prepare and assemble poles. This will occur in one or both villages and may include splicing the poles, attaching the pole top and base hardware, attaching the post insulator and stringing blocks, and attaching the guy wires and hardware. An assembled pole will be packaged in a manner suitable for airlift and clearly labeled so it is deployed to the proper foundation.

6. Pole installation. Each assembled pole will be airlifted by helicopter to the pole's foundation. The pole will be spotted on the ground by the helicopter and a ground crew. The ground crew will use an A-frame and their small, low-ground-pressure vehicle to erect the pole using two of the guy anchors as hoist points. Alternatively, the helicopter could be used for faster erecting and securing of the pole. Once the pole is erected, plumbed, and guys tensioned, the crew will drive to the next foundation site. Depending on helicopter logistics, it may be cost-effective to employ two ground crews for this activity. Ground crews and consumables will be mobilized to the line daily by helicopter.

7. Stringing and setting the conductor. The stringing line will be deployed by helicopter. Once in place, the conductor will be staged by helicopter and deployed by ground crews. A Hughes-500 can lift approximately 2,000 feet of conductor at a time. Once the conductor is strung, ground crews will ascend each pole to set, tension, and fix the conductor. Armor wrap and vibration dampers will be installed at this time.

C.4.5 Maintenance Methods

This section discusses the conceptual maintenance and repair methods that are appropriate for the long-span, tall-pole HVDC SWER overhead intertie. While some topics may be generally applicable to the maintenance and repair of overhead interties, this discussion focuses on and is specific to this particular intertie design concept.

Fiberglass poles cannot be climbed using the spur-and-belt method commonly employed to climb wood poles. Instead, a pulley and cable or rope system would be an integral part of the fiberglass pole. The pulley would be installed in the pole top, and the cable would travel down the pole interior. The line crew is envisioned to use a harness and winch apparatus to attach to the pole apparatus and use this system to lift a lineman to the pole top for maintenance.
This approach offers several advantages compared with conventional pole climbing methods.

- The equipment and inherent safety of the approach enables less experienced crews to ascend the poles.
- Pole-top maintenance is easier or possible during colder weather or adverse conditions.
- Ascent, descent, and top-site work is faster because the crew is not as fatigued.
- Work is less physically demanding, reducing the likelihood of fatigue-related accidents.
C.5 CONCEPTUAL DESIGN ANALYSIS

The majority of the design analysis for the overhead transmission concepts presented in this study follows established design practices that are found in industry literature. This section discusses specific aspects of the conceptual design of HVDC systems that are unique to Alaska and warrant more detailed discussion.

C.5.1 Structural Design

Polarconsult contracted with Line Design Engineering, Inc. (LDE) for assistance in the structural and code analysis of Alaska-specific overhead HVDC transmission structure design concepts.

C.5.2 Foundation Design

Polarconsult tasked Golder with developing conceptual foundation designs for the representative soils and geotechnical conditions discussed in this report. Golder proposed three foundation design concepts that provide economical foundation options for supporting guyed power poles in the representative geotechnical conditions. These are summarized below.

- **Passively cooled thermoprobe micropiles**, installed under the pole to receive compressive loads. Arctic Foundations, Inc. (AFI) was identified as an experienced manufacturer of such foundation systems.

- **Small-diameter helical anchors**, installed under the pole to receive compressive loads or installed at the guys to receive tension loads. Thermopiles could be installed adjacent to these anchors to decrease temperatures in the bearing soils, which will increase the anchor strength.

- **Smaller-diameter (4- to 6-inch) vertical piles** for both poles and guys, installed with impact hammers using smaller tracked rigs. Thermopiles could be installed adjacent to these anchors to decrease temperatures in the bearing soils and increase pile strength.

Existing conventional foundation methods were maintained for conventional intertie line construction. This consists of either direct burial of a wood pole in suitable soils or fastening a wood pole to a driven steel pile in the more difficult geotechnical conditions.

For guyed power poles, a set of three 1½-inch-diameter thermoprobe micropiles installed to a depth of 20 feet with a 5-foot radiator section above ground are used as the conceptual design for the pole base, and helical anchors are used as the conceptual design for the pole guys.

C.5.3 Analysis of Thermoprobe Performance

Polarconsult contracted with Zarling Aero Engineers (ZAE) to model the seasonal thermal performance of a passive cooling element such as a thermoprobe micropile. ZAE modeled a warm permafrost condition analogous to Golder’s geotechnical Profile “C” using thick and thin organic layers and current climate data for marginal permafrost in the Fairbanks area. Thermoprobes with thermal conductances of 1.0 British thermal unit (Btu)/hr-ft-°F and 2.0 Btu/hr-ft-°F were considered. ZAE also evaluated the effect of placing a 4-inch-thick layer of rigid insulation on the ground surface within 4 feet of the thermoprobe.

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38 Representative publications include RUS, 2001; RUS, 2003a; RUS, 2009; Naidu, 1996; KZK, 2006; Skrotzki, 1980; Southwire, 2008; and Thrash, 2007.

39 The 1.5-inch-diameter, 25-foot-long thermoprobes installed at the Fairbanks Test Site (see Section C.6 of this appendix) have an estimated thermal conductance of 0.3 Btu/hr-ft-°F (AFI, 2011).
ZAE repeated this analysis with warmer climate conditions to forecast the performance of the thermoprobes under a warming climate in the 2060 to 2069 decade. The results of these analyses are summarized in Table C-8. ZAE’s technical analysis and report is included as Attachment C-1 to this appendix.

Table C-8 presents the following model results that directly pertain to the structural performance of the thermoprobes:

1. Maximum depth of the active layer (occurs in late fall). This defines how much of the upper portion of the thermoprobe is in thawed, structurally weak soils that provided limited lateral support to the thermopile. For structural analysis, this portion of the thermoprobe is assumed to be an unsupported column that must be stiff enough to transfer compressive loads from the top of the thermoprobe down to the permafrost region without buckling.

2. Average maximum temperature of the permafrost 1 foot from the thermopile in early fall (maximum annual temperature). This defines the minimum strength of the soil around the thermoprobe and the bearing strength of the thermopile to resist both compressive and tension loads.

The results of ZAE’s analysis (Table C-8) are explained below. It is important to emphasize that these results are specific to the soil parameters, thermoprobe performance, and climate conditions modeled. Other model inputs may produce significantly different results.

1. Under the geotechnical conditions modeled, a 4-inch layer of rigid foam insulation installed at the surface and extending radially out from the thermoprobe for 4 feet can reduce the maximum depth of the active layer by 1 to 2 feet. Due to the modest structural benefit, expected cost, and difficulty of installing and maintaining such an insulation assembly, this insulation element is not included in the conceptual foundation designs.

2. Under all geotechnical conditions modeled, the thermoprobe lowers the soil temperature immediately surrounding the thermoprobe throughout the year. This effect is most pronounced during the winter months when the thermoprobe is extracting heat from the soil and cools the soil by up to 5 °F surrounding the thermoprobe. This cold bulb persists through the summer, resulting in an end-of-summer residual thermal anomaly of a few 1/10ths °F in the soil surrounding the thermoprobe. This result significantly enhances the compressive and tension capacity of the thermoprobe during the winter and spring months and produces a lesser (and decreasing) enhancement through the summer and into fall. The thermoprobe immediately starts cooling the surrounding soils upon the return of freezing nighttime conditions in the late fall.
### Table C-8 Summary of Results from Thermoprobe Modeling by ZAE

<table>
<thead>
<tr>
<th>Existing Climate Conditions (Fairbanks, 1971 – 2000)</th>
<th>Thermoprobe conductance = 1.0 Btu/hr-ft-°F</th>
<th>Thermoprobe conductance = 2.0 Btu/hr-ft-°F</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Thin Organic Layer</td>
<td>Thin Organic Layer</td>
</tr>
<tr>
<td></td>
<td>Thick Organic Layer</td>
<td>Thick Organic Layer</td>
</tr>
<tr>
<td>4” Surface Insulation</td>
<td>6.5 feet</td>
<td>6.5 feet</td>
</tr>
<tr>
<td>No Surface Insulation</td>
<td>3 feet</td>
<td>3 feet</td>
</tr>
<tr>
<td>4” Surface Insulation</td>
<td>6.5 feet</td>
<td>6.5 feet</td>
</tr>
<tr>
<td>No Surface Insulation</td>
<td>3 feet</td>
<td>3 feet</td>
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<tr>
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<th>Thermoprobe conductance = 2.0 Btu/hr-ft-°F</th>
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</table>

See the full ZAE report, Attachment C-1 to this appendix, for more detailed information.

1. Temperature at 11 feet from thermoprobe, which is the limit of the model graphics in the report.

NA: Not analyzed.
C.5.3.1 Thermoprobe Conceptual Design

AFI developed conceptual thermopile designs based on the structural loads given for the Alaska-specific intertie structures. The design and fabrication sheets for the AFI thermopile are included as Attachment C-2.

Pole foundations using either a single 3-inch thermopile or a set of three 1½-inch thermopiles are both practical. 1½-inch thermopiles can be installed by smaller equipment than a 3-inch pile, although the material cost and installation time will both be somewhat higher than for a single 3-inch thermopile. On some projects, the use of smaller equipment is expected to result in sufficient savings in spite of the increased material and labor costs.

Figures C-9 through C-11 present the adapter plate developed to mate a GFRP pole to three 1½-inch thermopiles. Figure C-8 below shows the prototype installation of this pole foundation design installed at the foundation test site in Fairbanks. The Fairbanks testing is described in greater detail in Section C.6 of this appendix.

Figure C-8 Prototype Micro-Thermopile Tripod Pole Foundation
Figure C-9  Shop Drawing of Prototype GFRP Pole Base Adapter for Micro-Thermopile Foundation (Sheet 1 of 3)
Figure C-11 Shop Drawing of Prototype GFRP Pole Base Adapter for Micro-Thermopile Foundation (Sheet 3 of 3)
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C.5.3.2  Screw Anchor Conceptual Design

Based on the conceptual design analysis prepared by Golder, screw anchors fitted with two flights of 8-inch helices and driven to a depth of 10 to 15 feet below the ground surface will be suitable for anchoring most guys. In the conceptual soils presented by Golder, these anchors can be installed with a torque of 10,000 to 15,000 foot-pounds. Guys at angle structures or dead ends may require two or more anchors. Representative screw anchors are shown on Figure C-12.

Figure C-12  Galvanized Screw Anchors with 8-Inch Flights

Pallet of galvanized screw anchors with 8-inch flights. Similar anchors are suitable for restraining guys for Alaska-specific transmission structures in many challenging soils. (Polarconsult, 2011; Photograph courtesy of Alaska Foundation Technology, Inc.)
C.5.4 Electrical Design

C.5.4.1 Conductor

A 1-MW transmission capacity at 50 kV DC equates to a nominal peak ampacity of 20 amperes. Overload or fault conditions are higher. The economically allowable conductor losses on the HVDC line were set at 3% losses at 100% nominal capacity. For a 25-mile, 1-MW, two-wire monopolar intertie, this is approximately equivalent to 1.5 ohms per conductor-mile. The required conductor resistance is the same for a monopolar SWER transmission circuit, provided that the grounding grids and earth return pathway have a total resistance equal to or less than 37.5 ohms.

The structural requirements of the conductor are part of a larger technical and economic analysis of the overhead system design. For rural Alaska intertie lines, longer spans and fewer foundations will generally result in lower overall capital costs. This design decision calls for stronger conductors to withstand the higher stresses from environmental loads and taller poles to maintain ground clearances under maximum sag conditions.

For conventionally built HVDC intertie design concepts, these design considerations resulted in the selection of a 4/0 ACSR Penguin conductor for all HVDC circuit configurations.

For Alaska-specific HVDC intertie design concepts, these design considerations resulted in the selection of a 19#10 Alumoweld conductor for all HVDC circuit configurations.

C.5.4.2 Insulators

Insulators in DC applications are more susceptible than AC insulators to the accumulation of contamination on the insulator sheds. This is due to the presence of a static electric field around the high-voltage conductor, which attracts charged particles toward the conductor. This attraction of charged particles results in more particles landing on and contaminating the insulator than occurs on comparable AC systems. This is because the alternating electric field around an AC conductor does not impart a net attraction to charged particles.

Periodic rains and other weather events can dislodge these particles from the insulator sheds. Various special coatings can also help to repel particles. If the insulator provides a sufficiently long leakage path to accommodate the accumulated contamination, then no action is required. In some climates, it is necessary to wash the insulators periodically. This can be done from suitably equipped helicopters or line trucks.

On most rural Alaska intertie lines, washing insulators would be cost prohibitive, and when possible, the insulators should be designed to withstand long-term accumulation of contamination. Design guidance for HVDC insulators indicate that insulators rated for 34.5 to 42 kV AC service are adequate for 50 kV DC, depending on the degree of environmental contamination and self-cleaning conditions that exist along the intertie route.40

Due to the wide range of environmental conditions present in Alaska, a very conservative conceptual insulator design has been adopted to provide a substantial allowance for insulator contamination. In discussions with insulator manufacturers, insulators rated for 115 kV AC have been selected for the conceptual design. This provides a leakage path length that is more than 2.7 times the published guidance for HVDC transmission insulators. Specific projects may be able to realize some cost savings by using

---

lower-voltage insulators if they are distant from coastal regions (salt spray), active rivers (blowing dust), glaciers (blowing dust), arid regions (lack of cleansing rains), and similar geographic or climatic characteristics.

Most HVDC lines are bipolar systems with two high-voltage conductors (Figure C-13). A typical economic design solution for a two-conductor overhead intertie line uses suspension insulators. In a monopolar SWER overhead system, the most economical design calls for a line post insulator atop a single structure.

**Figure C-13 Typical Bipolar HVDC Transmission Line Using Suspension Insulators**


At the spans, voltages, and environmental loads considered for this application, a composite line post with a 3.5-inch-diameter pultruded fiberglass core and silicone sheds are necessary to withstand the vertical, lateral, and longitudinal mechanical loads placed on the insulator. An insulator such as part no. L4-SN321-15U manufactured by NGK, Inc. or similar products are suitable for this application. Certain load conditions, such as unbalanced shedding of 1-inch radial ice on a 1,000-foot span, exceed the rated structural capacity of this insulator.
For specific projects, this limitation can be addressed in several ways (e.g., less stringent design loads, reduced insulator margin, shorter spans, etc.). Manufacturers are developing stronger line post insulators (4.0- and 4.5-inch cores) that will be adequate for all load combinations considered in this study. It is estimated that these will be commercially available by 2014 or thereafter.

Alternate insulator configurations can also be used to circumvent the structural limitations of existing line post insulators. Figures C-14 through C-16 present two potential insulator configurations that use suspension insulators to reduce the loadings on a line post insulator. These configurations can be adapted for use on any of the conceptual overhead designs presented in this appendix. Suspension insulators are less costly than the line post insulators; however, these more complicated assemblies will require more labor to install.

Figure C-14  Typical Tangent Structure Using Post Insulators

Cantilevered wood pole tangent structure for an AC transmission line. Post insulators are used to carry all three-phase conductors. The post-top insulator carries longitudinal and lateral forces in bending, and the two side insulators carry vertical and longitudinal forces in bending. These applications are similar to those shown on Figure C-3 and Figure C-4.
Figure C-15  Typical Angle Structure Using Suspension and Post Insulators

Guyed steel pole angle structure for an AC transmission line. Suspension insulators are used to carry the conductor tension, and a post insulator is used to hold the conductor off of the support structure. Available post insulators are not strong enough to be used as a post-top insulator (as on Figure C-4 or C-14) in this type of application. (Polarconsult, 2012)
Cantilevered wood pole tangent structure for a 115 kV AC transmission line. Note the use of a suspension insulator in tension and post insulator in compression to carry the weight of the conductor. The base of the post insulator is hinged to allow some longitudinal movement of the conductor. The post insulator also carries most of the lateral wind loads on the conductor. This insulator configuration can be used for single- or double-wire HVDC circuit configurations. A back guy could be used to reduce the net moment on the pole and foundation. (Polarconsult, 2012)
C.6  TESTING OF OVERHEAD DESIGN CONCEPTS

Most elements of the conceptual overhead designs described in this appendix utilize commercially available and accepted materials, designs, and construction methods. Certain components of the conceptual designs presented in Section C.5 represent innovations in overhead line design that do not have a proven record within the utility industry. In order to evaluate the performance of these components, they were installed at a test site in Fairbanks, Alaska. This section describes the objectives and installation of the Fairbanks Test Site.

C.6.1  Test Objectives

The primary test objectives of the Fairbanks Test Site are listed below.

1. Demonstrate performance and assembly time of a splice for a constant-section GFRP utility pole.
2. Demonstrate installation and performance of micro-thermopile pole foundations.
3. Demonstrate installation and performance of micro-thermopile guy anchors.
4. Demonstrate installation and performance of screw guy anchors.
5. Demonstrate the installation and performance of the overall guyed GFRP pole structure.

C.6.2  Test Site

The test site is located on private property off Farmer’s Loop Road north of Creamers' Field in Fairbanks. The site consists of warm ice-rich silty permafrost soils. The site has an organic layer consisting of deciduous shrubs and black spruce. Peat was present at depths of 1 to 5 feet below ground surface. The active layer in September extended to a depth of 3 feet, with standing water encountered within the vegetative mat near the surface.

Geotechnical conditions at the site are characteristic of marginal warm permafrost conditions, generally consistent with conceptual geotechnical profile “C” developed by Golder and described in Section C of this appendix.

C.6.3  Installation

Key items installed at the test site are described in this section.

C.6.3.1  Soil Temperature Probes

The site has two soil temperature monitoring probes. Each probe is a ¾-inch PVC pipe inserted into a drill hole that extends to 25 feet below grade. One hole is located adjacent (1.0 foot away) to the micro-thermopile tripod pole foundation and will be used to monitor the thermal effects of the thermopiles and vegetation clearing. The second hole is located approximately 50 feet away in an undisturbed black spruce stand and will be used to collect baseline soil temperature data.

C.6.3.2  Glass-Fiber-Reinforced Polymer (GFRP) Pole

The site has one 60-foot-tall guyed glass-fiber-reinforced polymer (GFRP) pole. The GFRP pole has a round section, is 12 inches in diameter, and has a 0.5-inch wall. The GFRP pole is manufactured by Powertrusions, Inc. The GFRP pole consists of a 40-foot and 20-foot section connected by a full moment-carrying slip-on external splice. The splice does not require any glue or solvent to develop bearing or moment capacity. Bearing is carried by physical contact of the butt-ends of the pole segments. Moment is
carried through mechanical contact between the pole and splice walls. The splice is held in place by #14 ¼-inch-diameter x 1½-inch-long zinc plated Teks hex washer head screws driven around the perimeter of the splice into each pole segment. The pole at the Fairbanks site is in compression. Power line poles subject to uplift would need to design the splice connection for tension loads.

C.6.3.3 GFRP Pole Foundation

The GFRP pole foundation is a micro-thermopile tripod with an adapter piece to fit the pole onto the micro-thermopiles. Shop drawings of the adapter piece are presented on Figure C-9 through C-11. The adapter piece:

- Features an integral hinge assembly to raise or lower poles in the field,
- Provides generous tolerances for batter angles and placement of the micro-thermopiles, and
- Provides full flexibility in orientation of the hinge angle relative to the tripod angle (so the pole can be raised or lowered in line with a guy anchor regardless of how the pole foundation micro-thermopiles are oriented.

C.6.3.4 Guys

The GFRP pole is secured by four 3/8-inch extra-high-strength (EHS) guy lines set at 90 degrees to each other and 45 degrees to ground. The guys and guy hardware is conventional. A FUTEK model LSB4000 load cell is rigged into one guy wire on each axis to measure guy wire tension.

C.6.3.5 Guy Anchors

Four different guy anchors are installed at the Fairbanks site.

1. A 25-foot-long by 1½-inch-diameter micro-thermopile, installed at a 45-degree angle to the ground surface (directly in-line with the guy). This anchor resists guy tension solely with skin friction. The anchor is installed with the top 5 feet above ground as the radiator section.
2. A 25-foot-long by 1½-inch-diameter micro-thermopile, installed at a 70-degree angle to the ground surface. This reduced angle from vertical is easier to install but places a moment on the micro-thermopile.
3. A standard 8-inch double-flight screw anchor. The screw anchor was driven 15 feet below ground surface at a 45-degree angle, placing the anchor flights approximately 10 feet below grade.
4. A standard 6-inch swamp anchor. The swamp anchor is screwed into the soil by a drive rod that is then withdrawn. The anchor attaches to the guy wire via a ground cable. This type of anchor is less susceptible to frost heave than the three other anchors described above.

C.6.4 Monitoring

Polarconsult will continue to monitor the installation at the test site for performance.

1. Monitor seasonal fluctuations in soil thermal profiles to establish baseline thermal profiles and the performance of the micro-thermopiles.
2. Monitor guy wire tensions and differential elevations of guy wires and pole foundation to identify creep in the foundations.
Figure C-17  Installing Micro-Thermopile for Guy Anchor

Contractor GeoTek Alaska, Inc. drilling a hole for installation of a micro-thermopile at a 45-degree batter angle using a GeoProbe 8040 series drill rig. The micro-thermopile will serve as a guy anchor for the prototype guyed GFRP pole installation at the Fairbanks Test Site. (Polarconsult, 2011).
Figure C-18  Setting Micro-Thermopile Guy Anchor with Sand Slurry Backfill

Setting micro-thermopile guy anchor with a sand slurry. (Polarconsult, 2011)
Contractor GeoTek Alaska, Inc. drilling a hole for installation of a micro-thermopile at a 45-degree batter angle using a GeoProbe 8040 series drill rig. The micro-thermopile will serve as a guy anchor for the prototype guyed GFRP pole installation at the Fairbanks Test Site. (Polarconsult, 2011).
Figure C-20  Micro-Thermopiles Staged at Fairbanks Test Site for Installation of Prototype Foundations

1½-inch-diameter by 25-foot-long micro-thermopiles used for pole base and guy anchor systems for a prototype guyed GFRP pole installed at the Fairbanks Test Site. Three micro-thermopiles are used at the pole base, and one each for two of the four guy anchors. (Polarconsult, 2011)
Figure C-21  Micro-Thermopile Tripod for Prototype Pole Foundation

Micro-thermopile tripod for prototype pole foundation. The fourth pipe at left is a soil temperature monitoring well that is used to monitor the thermal-affected zone around the thermopiles. There is a second soil temperature monitoring probe located approximately 40 feet from the pole base (not shown in photo) that is used to establish the baseline thermal profile of the site. (Polarconsult, 2011)
Contractor City Electric, Inc. installing a helical screw anchor with two 8-inch flights. The anchor was driven 15 feet into the ground at a 45-degree batter angle. The anchor will be used to secure one of the four guys on the prototype GFRP pole installed at the Fairbanks Test Site. (Polarconsult, 2011)
Figure C-23  Guy Attached to Micro-Thermopile Foundation

Guy wire supporting the installed prototype GFRP pole at the Fairbanks Test Site. The guy anchor is a micro-thermopile installed at a 20-degree batter angle. This guy wire includes a load cell to monitor guy wire tension. The load cell reader is attached to the cell and is visible in the photo (black and yellow device below the guy wire). Polarconsult, 2011.)
Figure C-24  Assembling the Prototype GFRP Pole Splice

Contractor City Electric, Inc. installing the field splice for the prototype GFRP pole. 40-foot and 20-foot GFRP pole segments were spliced to create the 60-foot pole erected at the site. The splice slides over the pole segments and carries moment through contact between the pole and splice walls. Vertical loads are carried through the butt ends of the pole segments. No glue or adhesive is necessary for the splice to develop the full mechanical strength of the pole. The screws serve to prevent differential movement between the pole and splice. (Polarconsult, 2011)
Figure C-25   Installed GFRP Pole, Micro-Thermopiles, and Adapter Plate

Detail of prototype GFRP pole base at the Fairbanks Test Site. The custom-designed base plate accommodates the variable angle and location of the three micro-thermopiles and includes a hinge so the pole can be lowered if needed. The base plate allows for adjustment of the hinge orientation during installation so a guy anchor can be used to winch the pole down. (Polarconsult, 2011)
Figure C-26  Prototype GFRP Pole Foundation During Installation

Detail of prototype GFRP pole base at the Fairbanks Test Site. The adapter plate was adjusted during installation so the hinge is oriented in line with the guy anchor in the distance (orange flagging). This allows use of the guy anchor to lower the pole with a winch if needed. (Polarconsult, 2011)
Figure C-27  Prototype Pole at the Fairbanks Test Site

View of the prototype guyed GFRP pole installed at the Fairbanks Test Site. This photograph is taken at a distance of approximately 200 yards from the 60-foot tall pole. (Polarconsult, 2011)
Figure C-28  Prototype Pole at the Fairbanks Test Site

View of the prototype guyed GFRP pole installed at the Fairbanks Test Site. This photograph is taken at a distance of approximately 25 yards from the 60-foot tall pole. The four guys and the pole splice are visible in this photograph (Polarconsult, 2011)
APPENDIX C ATTACHMENTS

Attachment C-1:
Zarling Aero Consulting (ZAE) Thermal Analysis of Thermopile
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Thermal Analysis of Pin Piles for a HVDC Transmission System

for Polarconsult Alaska Inc.

John Zarling, Ph.D., P.E.
Zarling Aero and Engineering
1958 Raven Dr.
Fairbanks, Alaska 99709
February 2012
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Thermal Analysis of Pin Piles for a HVDC Transmission System

John P. Zarling, Ph.D., P.E.

1.0 Introduction

Polarconsult Alaska Inc. of Anchorage, Alaska has been developing and designing a high voltage direct current power transmission system for use in rural Alaska. This system requires transmission lines and as part of the transmission system power poles are needed. Polarconsult envisions installing guyed light-weight poles. Pole and guy anchors will frequently be installed in permafrost soils and therefore poles and anchors are required to resist both thaw settlement as well as frost heave.

Polarconsult Alaska requested a thermal analysis be conducted of small diameter piles referred to as pin piles in this report. Two soil conditions were specified – a thin and a thick organic surface layer overlying a saturated organic and non-organic silt layers. It was assumed the installation of the pin piles would result in minimal disturbance to the original ground surface. Polarconsult Alaska further specified that Fairbanks, Alaska climate data be used in the modeling.

Discussions with Arctic Foundations Inc. of Anchorage, Alaska led to the proposal of using thermal probe (heat pipe or thermosyphon) type anchors. It was further determined that the depth of embedment of the anchors would be about 20 feet below the bottom of the active layer to resist design loads.

2.0 Analytical Methodology

Preliminary thermal modeling of the ground temperature regime surrounding a pin pile heat pipe anchor was done using the numerical model, TEMP/W. TEMP/W is a two-dimensional non-steady-state heat conduction finite element code using triangular and quadrilateral elements and was developed by GeoSlope International of Calgary, Alberta. This code accounts for phase change in soils and their frozen and thawed thermal properties. Inputs to this model include thermal properties of the soils and boundary conditions at the surfaces of the region being studied. Two dimensional planar and axisymmetric geometries can be modeled with this code.

2.1 Region of Analysis

The region analyzed is shown in Figure 1. It extends 20 feet horizontally from the vertical axis of the pin pile and 65 feet downward from the ground surface. Because of the symmetry about the vertical axis, the solution yields three dimensional thermal
contours about the pin pile. The horizontal extent at the surface is undisturbed natural vegetation. A 3-inch outside diameter pin pile was modeled for the non thermal probe cases and a line thermal probe condition was used to model the thermal probe cases. Affects of placing a layer of insulation lying on the ground surrounding the pin pile was also analyzed.

Figure 1. Upper 25 feet of region with vertical line of symmetry creating an axisymmetric region when rotated about vertical axis.

2.2 Soil Profiles and Thermal Properties

Thermal properties of the soils were based on soil types, dry densities and moisture contents. Thermal conductivities were calculated using Kersten’s equations, Andersland and Lydanyi (2004). Standard calculation procedures were used to determine volumetric specific heats. Unfrozen moisture contents of the soils were calculated using the parameters for Fairbanks silt, see Andersland and Ladanyi (2004), and for peat, see Romanovsky and Osterkamp (2000) and Farouki (1986). Soil properties for the thin and thick organic layer cases are presented in Table 1.
2.3 Boundary Conditions

The n-factor approach was used to establish the ground surface boundary conditions. N-factors for freezing and thawing are defined as

\[ n_f = \frac{SFI}{AFI} \]

and

\[ n_t = \frac{STI}{ATI} \]

where AFI, ATI, SFI and STI are the air and surface freezing and thawing indices, respectively. If the air freezing and thawing indices and n-factors are known, then the surface freezing and thawing indices can be determined using the above equations.

Values of frozen and thawed thermal conductivities of upper soil layers along with the surface indices affect the existence of permafrost. This condition can be expressed as

\[ n_f \cdot AFI \cdot k_f > n_t \cdot ATI \cdot k_t \]

for the existence of permafrost, where \( k_f \) and \( k_t \) are the frozen and thawed thermal conductivities of the upper soil layer. This approach was used to establish appropriate n-factors for an initial condition of warm permafrost.

It was assumed that the study sites were underlain with warm permafrost prior to construction and the installation of the pin piles. To achieve this condition for the undisturbed ground surface, freezing and thawing n-factors equal to \( n_f = 0.28 \) and \( n_t = 0.85 \) for the thick organic case and \( n_f = 0.35 \) and \( n_t = 0.85 \) for the thin organic case were used. A 20-year simulation was performed using these n-factors to establish a steady response to the transient surface boundary condition. Permafrost temperatures at depth of about 31.2°F were the result of these simulations. These temperature profiles were used as the initial condition for modeling the affects of installing the pin piles.
### Soil Profile and Properties for Thick Organic Layer

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### Soil Profile and Properties for Thin Organic Layer

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<tr>
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<td>0.85</td>
<td>1.18</td>
<td>39.1</td>
<td>28.3</td>
</tr>
</tbody>
</table>

Table 1. Soil characteristics and thermal properties.
Surface temperatures for the simulations are calculated based on the air temperatures and surface n-factors as

\[ T_{\text{surf}} = 32 - n_f (32 - T_{\text{air}}) \]  if \( T_{\text{air}} \leq 32^\circ\text{F} \)

and

\[ T_{\text{surf}} = 32 + n_f (T_{\text{air}} - 32) \]  if \( T_{\text{air}} > 32^\circ\text{F} \)

A zero heat flux boundary condition was applied along the bounding vertical line on the left side of the sketch below the bottom end of the pin pile and along the line forming the right side of the sketch shown in Figure 1. The central vertical axis is a line of symmetry and therefore no heat flows normal to this line. The right side boundary was assumed to have one dimensional vertical heat flow and it is therefore also a zero heat flow boundary.

The boundary condition along the bottom of the sketch in Figure 1, at the 65-foot depth, was a specified geothermal heat flux determined by multiplying the nominal geothermal gradient by the thermal conductivity of the soil at the base of the region.

### 2.4 Climate Data

The Western Regional Climate Center, WRCC, web site was used to access climate data for this study. The 1971-2000 climate normal data for Fairbanks were downloaded and the average daily temperatures were calculated from the 30-year average high and low temperatures reported for each day of the year. The mean annual air temperature and amplitude of the annual temperature variation were calculated from these data. This resulted in the following equation to represent the average air temperature variation for Fairbanks.

\[ T(t) = 27.75 - 36 \cos \left( \frac{2\pi(t - 9)}{365} \right) \]

Where the mean annual temperature is 27.75°F, the amplitude of the annual temperature variation is 36°F, and the phase lag measured from January 1 is 9 days. Figure 2 shows the reported data compared to the results of the sinusoidal function. Freezing and thawing indices for the 1971-2000 climate normal are

\[ \text{AFI} = 5,154 \text{°F - days} \quad \text{ATI} = 3,574 \text{°F - days} \]

There was no climate change modification included in the thermal simulations.
2.5 Thermal Probe – Heat Pipe Performance

It is typical to describe the heat pipe total conductance, $C_{hp}$, and the unit length conductance, $C_{hp}^*$, as measures of its performance. Total conductance of the heat pipe is defined as the heat flow caused by the temperature difference between the evaporator section surface and ambient air at the finned (condenser) section. The unit length conductance is based on the length of the evaporator section or embedded section and total conductance. In equation form, these conductances, $C_{hp}$ and $C_{hp}^*$, are defined as

$$Q = C_{hp} (T_{evap} - T_{air})$$

or

$$C_{hp} = \frac{Q}{(T_{evap} - T_{air})}$$

and

$$C_{hp}^* = \frac{C_{hp}}{L_{evap}}$$

where $C_{hp}$ is the total heat pipe conductance, BTU/hr-F

$C_{hp}^*$ is the unit length conductance, BTU/hr-ft-F

$Q$ is the heat flow rate, BTU/hr

$T_{evap}$ is the evaporator surface temperature,

$T_{air}$ is the ambient air temperature,
$L_{evap}$ is the evaporator or embedded length of heat pipe

The largest component to the total thermal resistance of the heat pipes are usually the outside surface area of their condenser sections. It is the thermal performance of these typical finned sections that largely determines the heat pipe's total conductance. Larger finned areas result in increased total conductance. Changing the evaporator length changes the heat pipe's unit conductance for a fixed fin area as defined above. It is common to measure or calculate the heat pipes total conductance and then calculate its unit length conductance based on the depth of embedment.

### 2.6 Model Calibration

The n-factors were varied to yield permafrost temperatures of about 31.2°F which is characteristic of warm permafrost temperatures of interior Alaska.

### 3.0 Results Based on Recent Climate Normal

Results of the finite element thermal simulations are shown in Appendix 1. Isotherms are presented for thin and thick organic layers with and without insulation and pin pile thermal probe unit conductances of 1.0 BTU/hr-ft-F° and 2.0 BTU/hr-ft-F° and at four times during the year: early winter, mid winter, spring and early fall (end of summer).

The lowest soil temperatures occur with the higher unit conductance and the ground surface insulated.

### 4.0 Climate Change

Polarconsult Alaska requested additional finite element modeling of the thermal pin piles accounting for projected 50-year climate change in interior Alaska. A source of climate change projections is SNAP which is described below (referenced from SNAP web page) and was used as a basis for future climate warming.

SNAP, Scenarios Network for Alaska Planning, is a collaborative organization linking the University of Alaska, state, federal, and local agencies, and NGOs. SNAP’s mission is to provide timely access to management-relevant scenarios of future conditions in Alaska. Primary products of the network are (1) datasets and maps projecting future conditions for selected variables, and (2) rules and models that develop these projections, based on historical conditions and trends.

SNAP climate projection maps were created by taking the mean values of outputs from all five of the best-performing IPCC Global Circulation Models. These models were the highest ranked out of fifteen total models for performance in three overlapping northern
zones: Alaska, latitudes 60°N to 90°N, and latitudes 20°N to 90°N. Models were assessed according to how closely their outputs for the recent past matched climate station data for temperature, precipitation, and sea level pressure. Based on predicted mid-level future atmospheric emissions, interior Alaska is predicted to experience a 0 to 3 C° mean annual air temperature rise by the 2080-89 decade. For modeling purposes, it was assumed a 1.5 C° (2.7 F°) increase in the mean annual temperature would occur over the next 50 years.

4.1 Thermal Modeling

The same finite element thermal model described in the report was used but with an increased mean annual air temperature of 2.7 F°. The first step was to run a simulation for 20 years to establish a steady response to the revised climate condition without the thermal pin piles installed. Then, using the resulting soil temperatures as the initial condition, an additional 10 years of simulation was performed with the thermal pin piles and with and without insulation placed on the ground surface. Results are presented on the following pages for both the thick and thin organic layers, with and without insulation, using a thermal pin pile conductance of 1.0 BTU/hr-ft-F. The figures presented in Appendix 2 show isothermal contours for four times during the year: spring, early fall (end of summer) when the depth of thaw at the surface is the greatest, early winter when the active layer is freezing-back, and mid winter.

5.0 Results Based on Climate Change

Climate warming had minimal affect on the thickness of the active layer for the thick organic case, however the active layer increased by about two feet for the thin organic case. Permafrost temperatures at depth warmed from 0.2 to 0.3 F° for both thick and thin organics layers. These results are based on simulation scenario that was used. Because of the unfrozen moisture content of the underlying silts, warming of the permafrost is a slow process which is reflected in the small temperature changes at depth.

6.0 Limitations

Because interior Alaska is underlain with discontinuous permafrost with widely varying soil and surface conditions, results presented in this report only provide insight to the resulting thermal regime based on the conditions used and/or assumed in performing these simulations.
7.0 References


Appendix 1 - Results Based on Recent Climate Normal
Thin organic layer, four-inch thick insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F
Thin organic layer, no insulation on ground and thermal pile unit conductance is 1.0 BTU/hr-ft-F
Thick organic layer, four-inch thick insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F
Thick organic layer, no insulation on ground and thermal pile unit conductance is 1.0 BTU/hr-ft-F.
Thin organic layer, four-inch thick insulation and thermal pile unit conductance is 2.0 BTU/hr-ft-F.
Thin organic layer, no insulation on ground and thermal pile unit conductance is 2.0 BTU/hr-ft-F
Thick organic layer, four-inch thick insulation and thermal pile unit conductance is 2.0 BTU/hr-ft-F.
Thick organic layer, no insulation on ground and thermal pile unit conductance is 2.0 BTU/hr-ft-F
Appendix 2 - Results Based on Climate Change
Thin organic layer, four-inch thick insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F
Thin organic layer, no insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F

Spring  End of Summer  Early Winter  Mid Winter

October 9, 2011
Thick organic layer, four-inch thick insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F

Spring

End of Summer

Early Winter

Winter

October 9, 2011
Thick organic layer, no insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F

Spring

End of Summer

Early Winter

Mid Winter

October 9, 2011
Attachment C-2:
Arctic Foundations, Inc. (AFI) Shop Drawings
Attachment C.2.1  Arctic Foundations, Inc. (AFI) Shop Drawing for Pile

NOTES:

1) All pressure retaining welds are full penetration v-groove welds. Welding procedure specifications are qualified in accordance with ASME Section IX. Welding is performed by welders qualified per ASME Section IX.

2) The brass valve to steel connection is silver brazed per AFI standard procedure.

3) Coat upper twelve feet of anchor with H.B. Fuller IF-1074 fusion bond epoxy over 3 mils flame sprayed aluminum applied per AWS C2.2. Extend the 3 mils of flame sprayed aluminum applied per AWS C2.2 down the anchor shaft an additional 2 feet. Brush blast mill finish off bearing zone of anchors.

4) Charge Thermoprobes with R-744 per AFI standard procedure.

5) Materials are AFI standard for the intended service.

6) Build 5 units as shown hereon.

SPECIAL INSTRUCTIONS:

Weld the top 5" pup onto the unit after the valve has been installed and pressure tested. Then, drill 3 each 1/8" drainage holes equally spaced around the pipe at the lower end of the 5" pup.

Prior to finishing, grind all girth welds smooth to the diameter of the pipe.
Attachment C.2.2  Arctic Foundations, Inc. (AFI) Shop Drawing for Guy Anchor

Thermoprobe Guy Anchor
1 1/2" sch 40 Pipe

Grade

Drilled Hole w/ Anchor
Cemented using Fondt
No-Shrink Grout

9 ft Anchor = 20' + active zone

Insulate surface as required to ensure the anchor has proper embedment in frozen soil.

Thermal conductance of the anchor as shown (5' stick-up) is approximately 7.5 Btu/h°F at an average winter airspeed of 5 mph.

The standard anchor is installed in a 4' drilled hole as shown. Dead end anchors are installed in 6' drilled holes. The 5 kip dead end anchor is embedded 20' plus the active zone. The 5.5 kip dead end anchor is embedded 39' plus the active zone.
APPENDIX D

CONCEPTUAL DESIGN FOR SUBMARINE CABLES
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APPENDIX D ATTACHMENT

Attachment D-1:
Cabletricity HVDC Transmission Systems for Rural Alaska Applications DC Power Cables for 1–5 MW Converters
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HVDC Transmission Systems for
Rural Alaskan Applications

DC Power Cables for 1 to 5 MW Converters

Submitted to:

Polarconsult Alaska Inc.

by:

Cabletricity Connections Ltd.

February 7, 2012

Cabletricity Report 2012-2
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This report was prepared by:

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1. Introduction

Polarconsult Alaska Inc. has a contract with the Alaska Center for Energy and Power at the University of Alaska Fairbanks, to investigate "HVDC Transmission Systems for Rural Alaskan Applications Phase II – Prototyping and Testing".

Cablelectricity was retained by Polarconsult as a subconsultant to investigate submarine cables optimized for use with this HVDC system. This report explains results of the investigations.

The overall project consists of developing an innovative high voltage direct current (HVDC) power transmission system operating at 50 kV dc and transmitting 1 MW of electrical power. Later the capacity may be expanded to 5 MW. The complete system is intended to reduce costs of energy in remote Alaskan villages by lowering the costs of intertices and/or local energy resource developments. It is also desirable to integrate optical fibers into the power transmission system to serve the communications needs of remote communities. To make this system practical, simplicity and reliability are critical design considerations.

Three possible transmission systems are contemplated for rural Alaskan applications:

- Single bare conductor overhead line with earth return
- Single core insulated conductor cable on land with earth return
- Single core insulated conductor submarine cable with earth or sea return

This report discusses submarine cable solutions for the rugged and deep inter-island and fjord crossings typical of southeast Alaska. The objective is to identify suitable conventional or innovative submarine cable designs to meet the overall project objectives where water crossings are required. The report begins with a description of the electrical system to which the cables will be connected, then advances to the regional environment they must withstand and on to descriptions of submarine cable standards, cable designs, typical installation methods and cost estimates for a case study.

2. Electrical System Requirements for Submarine Cables

The submarine cable system must withstand the following electrical duties.

- Nominal continuous voltage: 50 kV dc
- Highest continuous voltage: 55 kV dc
- Nominal continuous current, Ie: 20 to 100 A dc
- Maximum ac ripple on dc voltage: 5 %
- Basic Impulse Level: ? kV peak
- Fault current: 23 to 115 A
- Fault current duration: 10 seconds ?

3. Site Environmental Conditions for Envisioned Submarine Cable Applications

- Maximum ground temperature: 14 °C
- Minimum ground temperature: 0 °C
- Maximum air temperature: 35 °C

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DC Cables for 1 to 5 MW Converters
Minimum air temperature -35 °C
Maximum water temperature 14.0 °C
Minimum water temperature 2.0 °C
Maximum water current velocity ~2 m/sec
Maximum water depth 670 m (2,200') (in Hoonah study area)

Sea bottom conditions from the tidal zone to deepest sections are typically very rugged with steeply sloping rock outrops. There can be underwater cliff features and unstable debris slopes often leading to a soft sediment bottom.

4. Industry Standards for DC Power Submarine Cables

There are no comprehensive U.S. national or international standards for power submarine cables, regardless of whether ac or dc, laminar insulations or extruded insulations. The closest North American standard for medium voltages is ICEA S-93-639\(^2\), which includes brief prescriptive armour constructions for ac cables with extruded insulations, but without mechanical tests to prove adequacy for laying.

For high voltage ac applications, custom project specifications are developed by cable engineering specialists, usually referring to base documents IEC 141-1\(^3\) for fluid-filled laminar insulations, or IEC 60840\(^4\) for extruded insulations not exceeding 150 kV.

For high voltage laminar dc insulations (i.e. mass-impregnated cables), the base document is a Cigre Electra No. 189 magazine article\(^5\). For high voltage extruded dc insulations, the base document is Cigre Technical Brochure 219\(^6\).

In order to prove adequate performance for submarine cable applications, custom project specifications require the above IEC and Cigre documents be extended to include additional mechanical tests described in the relevant Cigre Electra No. 171 magazine article\(^7\). Although the article says: “The field of application are primarily meant for cables having a rated voltage \(U_r\) higher than 36 kV ac or 100 kV dc.”, it appears that diligent engineering would also extend the same principles to lower voltages as considered for this application.

5. Specifications for DC Power Submarine Cables for This Application

Considering all of the above, it is recommended that dc submarine cables for this application meet the requirements of Cigre Technical Brochure 219, IEC 60840 and Electra No. 171. This should


\(^3\) IEC 141-1, Tests on oil-filled and gas-pressure cables and their accessories – Part 1: Oil-filled, paper-insulated, metal sheathed cables and accessories for alternating voltages up to and including 400 kV, International Electrotechnical Commission, 1993.

\(^4\) IEC 60840 Edition 4, Power cables with extruded insulation and their accessories for rated voltages above 30 kV up to 150 kV – Test methods and requirements, International Electrotechnical Commission, 2011.

\(^5\) Cigre Working Group 21.02, Recommendation for Tests of Power Transmission DC Cables for a Rated Voltage up to 800 kV, Electra No. 189, April 2000.

\(^6\) Cigre Working Group 21-01, Technical Brochure 219, Recommendations for testing DC extruded cable systems for power transmission at a rated voltage up to 260 kV, Cigre, February 2003.

\(^7\) Cigre Working Group 21-02, Recommendations for mechanical tests on sub-marine cables, Electra No. 171, April 1997.
not cause difficulties for cable suppliers who have already developed dc cables with extruded insulation for high voltage applications, and have already passed the same tests for equal or more onerous conditions. However, cable suppliers who haven't already subjected their cables to the above test regimes would need to do them, increasing their initial supply costs. This will be discussed later when reviewing budgetary quotes from potential suppliers.

It is noteworthy that the above cable standards and recommendations are not prescriptive, describing every detail of how cables should be constructed, but rather functional, describing the tests that must be successfully passed in order to prove adequate in-service performance. That theme is also followed in this report, whereby we do not intend to describe detailed construction of candidate cables, but rather general designs and tests to prove performance. The requirement to pass (or to prove having passed) the above tests unfortunately detracts from applying novel designs or adapting similar designs, for example from the telecommunications submarine cable industry, which will be discussed below. It is expected that requiring compliance with these standard tests will make the resulting cable system significantly easier for utilities to finance and permit. The decreased risk associated with this requirement is also expected to result in a higher reliability cable system and reduced likelihood of very costly cable repair events.

6. Investigation Methodology – Requests for Information from Cable Suppliers

As part of the investigation, five power submarine cable suppliers were contacted and requested to provide budgetary estimates for a generic 50 kV dc, 1 MW design submarine cable. Alternates were requested for single wire and double wire armor, the latter typically required for installations greater than about 200 m deep. Three suppliers were selected because of their published information about high voltage dc cable development programs, and two were selected because of a history of providing medium voltage submarine cables from North American factories. There are presently no suppliers of high voltage submarine cables (ac or dc) with factories in North America.

Replies were received from all five suppliers, although with considerable variation in completeness and interest. Results showed low interest from the North American suppliers. This is interpreted to be due to the following possible factors.

- They mainly produce submarine cables with ethylene propylene rubber insulation (EPR), which has inherently shorter insulation extrusion lengths (the maximum continuous cable length without splices).
- Installing splices to join extrusion lengths interrupts the production process, adds to costs, and may affect long term reliability.
- They have limited in-house capacity to apply armor wires to the extruded cable cores, which means that spliced cable cores would need to be shipped to a third party portside contractor to splice onto other long cable cores, before applying armor wires to them, which adds to costs.
- They had not yet started the test program for dc cables described in section 5 above, which is an expensive commitment.
- As a result they presumably concluded that they couldn't compete with other cable suppliers who may not have the proximity advantage, but already have all the necessary equipment in place, and have completed industry standard tests, to assure profitable

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Oceaner Inc. has a near portside cable factory for making complex umbilical cables with single or double wire armor, located near Panama City, Florida. Simplex Wire & Cable (bought by Tyco Laboratories in 1974) used to armor submarine telecom cables at their Portsmouth, NH factory, but it is apparently no longer available. Prysmian had an armoring machine at their St. Jean, Quebec cable factory, but it has been closed down.
manufacturing of continuous, long length, armored submarine cables at an in-house portside factory.

It is noteworthy that cable factories made specifically for producing land cables are typically not easily convertible to making long length submarine cables because they are designed to produce, move, test and store completed cables within the factory in relatively short lengths on reels. By comparison, submarine cable factories typically have multiple turntables to manage long lengths throughout the various stages of production, from conductor stranding, to insulating, degassing, shielding/sheathing, jacketing, armoring, testing and storage prior to shipment, approximately as shown in Figure 1.

![Manufacturing flow diagram for submarine extruded cables](image)

Figure 1. Manufacturing flow diagram for submarine extruded cables (Credit: Prysmian, from Cigre 2010 paper B1-105)

Although all five suppliers were encouraged to propose innovative designs for the relatively unconventional application (20 A at 50 kV dc for 1 MW), all responses from the three offshore suppliers were based on scaled-down versions of their conventional test-proven HV dc cables using polymer insulation, such as cross-linked polyethylene (XLPE).

7. Conventional DC Cable Design Recommended for this Application

For high voltage dc applications up to 320 to 400 kV, the trend is toward more use of extruded polymer insulations, usually consisting of XLPE compounds developed specifically for dc applications.

Mass-impregnated laminar insulation cables have proven to have very high reliability and remain popular, especially above 350 kV.

Elastomer insulations (ethylene propylene rubber – EPR) have not been fully developed for dc power cable applications, although some investigations have been carried out to show possibilities for medium voltage dc, particularly if conductor temperatures are relatively low, as
would be the case for this application. One of the three offshore suppliers offered a 50 kV dc submarine cable with EPR insulation, subject to further testing.

Pressurized fluid-filled laminar insulations are declining in popularity for dc mainly because of limits to distances (40 to 50 km) that can be adequately pressurized under all operating conditions.

All types of laminar insulations would be uneconomic for this application. XLPE is considered to be the most practical extruded insulation, for the same reasons as mentioned above for HV cables. EPR may be a possibility for some existing North American suppliers who specialize in it, if willing to do the industry-standard tests described in section 4 above, and arrange for subcontracted arminging.

7.1 Detailed Conventional DC Cable Design

Figure 2 describes an example cable proposed by one supplier with a single layer of steel armor wires for relatively shallow water applications (less than about 200m). The design is subject to change after getting detailed information on actual installation conditions. The industry standard tests described in section 5 have apparently been completed for cables of equal or higher stresses, but confirmation is needed. Other cable manufacturers have recently published technical papers or given presentations at technical conferences describing development of similar polymer insulation dc cables, although not all for submarine applications.

![Cross-section of 50 kV dc, 35 mm² copper conductor, single wire armor submarine cable](image)

Figure 2: Cross-section of ±50 kV dc, 35 mm² copper conductor, single wire armor submarine cable (Credit: LS Cable)

---

10 M. Mammen, M. L. Paupardin, B. Poisson; Development of a 270 kV XLPE Cable System for DC Operation, Paper A.2.4, Jicable '11, June 2011.
13 M. Jeroensei, A. Gustafsson, M. Bergkvist; HVDC Light cable system extended to 320 kV; Cigré 2010, July 2010.
14 T. Nakajima; HVDC Cable Development: Presentation to Cigré AORC B1 Shanghai Meeting, Sept. 23, 2011

DC Cables for 1 to 5 MW Converters
Table 1: Description of Figure 2 cable components (Credit: LS Cable)

Table 2: Description of Figure 2 cable electrical and mechanical data (Credit: LS Cable). Cable weight in air/water is approximately 10.6 kg/m.

The conductor size was based on controlling the electric stresses in the insulation and managing tensions during laying. Ampacity would be much more than the required 20 A for 1 MW or 100 A for 5 MW dc transmission, resulting in relatively cool conductor and insulation and less concerns about space charge accumulation and temperature-stress inversion effects. It’s noteworthy that the cable insulation is protected from moisture ingress with a lead alloy sheath, which was also recommended by other suppliers.

This cable design could be modified by replacing several armor wires (item 9) with stainless steel tubes containing optical fibers for communication purposes. Some designs have included multiple tubes spaced around the circumference to provide redundancy in case of laying or abrasion damage. Other designs include stainless steel tubes with optical fibers or ribbons placed over the lead alloy sheath (item 6) and under the PE anti-corrosion layer jacket (item 7). Final designs would depend on supplier preferences and ease of repairs. Aside from communications, the fibers assist with location of cable faults due to external aggression, since if they were also damaged, Optical Time Domain Reflectometry (OTDR) can provide more accurate location than conventional Time Domain Reflectometry (TDR) using electrical impulses applied to the central conductor. Figure 3 shows a single core cable with optical fibers integrated into the armor. Figure 4 shows a single core cable with an optical fiber element integrated over the sheath and under the jacket.


Figure 3: Power cable with integrated optical fiber element within armor wires (Credit: J-Power Systems/Sumitomo)

Figure 4: Power cable with integrated optical fiber element over sheath and under jacket (Credit: Nexans)

Figure 5 describes a similar conventional cable design, but with two counter-helically applied layers of steel armor wires. The advantage is better abrasion and impact resistance, as well as ability to withstand the higher laying tensions arising from deep water installations (say above 200 m) due to a torsion-balanced design. This provides much better control over helix formation during DC Cables for 1 to 5 MW Converters.
laying, which can result in cable looping and irreversible kinking damage, if laying tensions are not well managed. Double counter-helical armor helps to avoid cable elongation and helix formation.

Figure 5: Cross-section of ±50 kV dc, 35 mm² copper conductor, double wire armor submarine cable (Credit: LS Cable)

<table>
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<th>Details</th>
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<th>Diameter (mm)</th>
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<td>1</td>
<td>Conductor</td>
<td>Stranded and compacted circular copper, Watertight:</td>
<td>Approx. 1.0</td>
<td>11</td>
</tr>
<tr>
<td>2</td>
<td>Conductor screen</td>
<td>Extruded semi-conducting compound</td>
<td>Approx. 0.9</td>
<td>23</td>
</tr>
<tr>
<td>3</td>
<td>Insulation</td>
<td>Extruded cross-linked polyethylene (XLPE)</td>
<td>Nom. 2.0</td>
<td>21</td>
</tr>
<tr>
<td>4</td>
<td>Insulation screen</td>
<td>Extruded semi-conducting compound</td>
<td>Approx. 0.9</td>
<td>23</td>
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<tr>
<td>5</td>
<td>Water blocking layer</td>
<td>Semi-conducting swelling tape(s)</td>
<td>Approx. 0.9</td>
<td>1</td>
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<tr>
<td>6</td>
<td>Metallic sheath</td>
<td>Lead alloy sheath</td>
<td>Nom. 2.6</td>
<td>8</td>
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<td>7</td>
<td>FE sheath</td>
<td>Extruded semi-conducting polyethylene</td>
<td>Nom. 2.7</td>
<td>33</td>
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<tr>
<td>8</td>
<td>Armor bedding</td>
<td>Polypropylene yarn with bitumen</td>
<td>Approx. 0.8</td>
<td>37</td>
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<tr>
<td>9</td>
<td>Wire armor</td>
<td>Galvanized steel wires with bitumen</td>
<td>6.0 m</td>
<td>50</td>
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<tr>
<td>10</td>
<td>Serving</td>
<td>Polypropylene yarn with black/yellow barber pole pattern</td>
<td>Approx. 4.0</td>
<td>75</td>
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*Note 2) Over the armor bedding, suitable separation tape(s) may be applied.

Table 3: Description of Figure 4 cable components (Credit: LS Cable)

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<th>Items</th>
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<td>Conductor resistance</td>
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<tr>
<td>2</td>
<td>Capacitance</td>
<td>μF/km</td>
<td>Max. 0.229</td>
</tr>
<tr>
<td>3</td>
<td>Max. pulling tension</td>
<td>kN</td>
<td>190</td>
</tr>
<tr>
<td>4</td>
<td>Min. bending radius during installation</td>
<td>m</td>
<td>1.9</td>
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Table 4: Description of Figure 4 cable electrical and mechanical data (Credit: LS Cable). Cable weight in air/water is approximately 17/12 kg/km.

thus allowing cable laying with lower residual tensions on the sea bottom, shorter free spans and less susceptibility to vortex induced vibration. A disadvantage in some cases is that cables with

DC Cables for 1 to 5 MW Converters
double counter-helical armor cannot be coiled and therefore must be shipped on large reels or turntables, and must use cable laying vessels observing the same restrictions.

There can be high confidence that conventional submarine power cables similar to the above, with integrated optical fibers for telecommunications purposes, can be successfully used for this application.

8. Possible Innovative DC Cable Designs for this Application

Several alternatives to the use of conventional dc power submarine cables were explored, as described below.

8.1 Armorless Submarine Cable Designs

A suggestion was made that armorless submarine cables might be suitable for this application. Although they have been used for some ac transmission cable applications in very shallow water (less than 10 m) the underwater distribution cables have been used on an emergency basis for 25 kV ac repair until new armored submarine cables could be delivered for permanent replacement, armorless cables are rarely used for power cable applications. As an example, the Electra No. 171 Recommendations for Mechanical Tests on Submarine Cables implicitly assumes that submarine power cables are armored.

![Diagram of Armorless cable](image)

Figure 6: Armorless telecommunication submarine cable, analogue type SD. (Credit: Footnote 18)

Figure 6 shows typical construction of an analogue armorless cable developed by the telecommunications industry in the 1960s. Cables were usually laid in pairs for bi-directional

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17 J H Cooper, M J Polasek; Planning and installation of the 138 kV South Padre Island submarine cable; IEEE Transactions on Power Delivery, Volume 8, Issue 4, p 1675-1681, October 1993.

coaxial communications with spaced repeaters powered by an applied voltage and current from the cables.

Basic construction featured a central strength member comprised of high tensile strength steel strands, over which a copper tape was folded and longitudinally seam-welded using automated tungsten inert gas welding techniques. The seamless copper tube was then swaged down tightly against the steel, to prevent distortion due to very high water pressures in deep water, as well as to prevent water ingress and steel corrosion. Low-loss polyethylene insulation was applied over the inner copper conducting tube and a second copper tube applied over the insulation to form a coaxial system, followed by a high density polyethylene outer jacket. The result was a relatively light and torsion-free design capable of being laid in very deep water with a smooth bottom. They were not considered suitable for waters shallower than say 1,000 m, where exposed to mechanically hazardous conditions, such as fishing gear and anchors, rugged bottoms and possible slope instability. For those more onerous situations the deep water armorless cable was spliced onto single or double armored cables, as shown in Figure 7. They featured a solid copper conductor to provide the ductility required for the conductor to elongate when the armor wires were subjected to tensile loads and constant cable elongation.

![Diagram of armored telecommunication submarine cable]

*Figure 7: Armored telecommunication submarine cable, analogue type SD (Credit: Footnote 18)*

Due to the very rugged bottom conditions and active fishing in many Alaskan waters, armorless designs are not recommended for this application. Since the armored telecom designs shown in Figure 7 begin to resemble the conventional power cable designs shown in Figures 1 and 2, indications are that power cable solutions are optimum, especially considering the importance of compliance with industry standard testing protocols.

18 B W Lerch, J W Phelps; Armorless Cable Manufacturer; Bell System Technical Journal, July 1964.
8.2 Modified Telecommunications Cables for 50 kV DC

It was suggested that there could be some advantages to using modified fiber optic telecommunications submarine cables for this 50 kV application, somewhat similar to those described in Appendix A. The notion arose from the knowledge that some are designed with high density polyethylene insulation to withstand dc voltages up to 15 kV and with current-carrying components rated at up to 1.6 A\(^2\). The idea was that their integral optical fibers could serve the communications needs of remote communities, while with increased insulation and conductor modifications, they could perhaps also meet the required 50 kV dc power transmission requirements.

Like submarine power cables, modern submarine telecommunication cables must also comply with industry standards\(^{21}\). Since most now use optical fibers, the standards focus on light transmission performance, as well as mechanical performance. They do not provide much detail, however, on insulation performance for the power system used to drive repeaters. In order to raise the voltage from about 15 kV dc to the required 50 kV dc, a fundamental change would be required to the insulation system, from the unshielded conductor and insulation of telecom cables to the semi-conducting shielding system required for higher voltage power cable applications (items 2 and 4 in Figures 1 and 2). There also needs to be some assurances that the insulations can withstand space charge accumulation typical of dc voltages applied to extruded insulations. This could require a change in compounding formulation, similar to that commonly used by European dc cable manufacturers and supplied by Borealis\(^{22}\), as well as changes in extrusion processes. Existing telecom cable specifications are silent on this requirement and therefore would be inadequate.

We have concluded that specifying a 50 kV dc power submarine cable as a hybrid between the Cigré-IEC based testing protocols described in section 5 above, and the ITU protocols described in this section, would be impractical, would not achieve interest from suppliers for a relatively uncommon product, and would not lead to an optimum solution for this application. We therefore see no value in further pursuing alternate designs to those described in section 6, if the 50 kV dc transmission voltage is to be retained. However, if the transmission voltage could be reduced to 15 kV dc, and current increased to about 67 A, 1 MW transmission could be achieved with existing telecommunication cable designs already proven to be capable of 15 kV dc, provided the conductor cross-sectional area could be increased and temperatures kept within limits. Further investigations are recommended if considered worthy of pursuit.

9. Cost Effective Cable Transportation, Installation and Repair

9.1 Transportation

For a large high voltage submarine cable project it is often efficient to use the same vessel to transport the submarine cables as to lay them. Examples of two such vessels are shown in Figures 8 and 9.


\(^{21}\) ITU-T G.971; General features of optical fibre submarine cable systems; International Telecommunications Union, July 2010.

However, for lower voltage cables they would probably not be economic, so the other options are either to ship the cables by freighter on large reels or drums, wound onto a turntable or coiled into the hold of a freighter. Total route length is an obvious determinan of which method to use, since reel and drum capacities are limited, and the ability to coil is affected by whether the cables have single or double wire armor.

Figure 10 shows cables being transferred from cable factory onto a freighter and Figure 11 shows transfer onto a lay-barge near the site.
Figure 9: Transfer of Single Wire Armor Collable Cable from Cable Factory to Freighter
(Credit: Nexans/Alcatel)

Figure 11: Transfer of Single Wire Armor Collable Cable from Freighter to Lay Barge at Site
(Credit: Nexans/Alcatel)

This method is anticipated for most Alaskan applications using long length 50 kV dc cables. If non-collable double armor cables were used for long, deep installations, temporary turntables would need to be installed in the freighter and cables trans-spooled to a similar turntable on the lay barge.
9.2 Installation

Installation costs would be minimized if regionally available cable laying vessels were used. For relatively short installations where laying accuracy down or over rugged underwater terrain is not required, or water currents are relatively low, a modified bow-loading transporter could be used. An example of a vessel equipped with a power reel and available in the Pacific Northwest, is shown in Figures 12 and 13. Tugboat assistance would also be needed during laying.

Figure 12 and 13: Transporter suitable for laying 50 kV dc submarine cables for short, shallow, sheltered applications – deck view (Credit: Cabletricity and BC Hydro)

Figures 13: Transporter suitable for laying 50 kV dc submarine cables for short, shallow, sheltered applications – profile view (Credit: Cabletricity and BC Hydro)

Alternatively, for longer cable lengths in deeper waters and rugged underwater terrain where precision cable laying is needed, a vessel with dynamic positioning capabilities and four outboard thrusters, similar to shown in Figures 14 and 15 (and cover page), would be appropriate.
Figure 14. DP cable laying barge ‘ITB 45’ stationed in Pacific Northwest (credit: Cabletricity)

Figure 15. ‘ITB 45’ Plan and Cross-section (credit: ITB Marine Projects)

As an example, the ITB 45 is capable of laying cables from a pan, reel or basket transferred from a freighter to its turntable, or laying cables coiled in a tank on its deck. Equipped with suitable linear cable engine braking systems, it would be capable of managing tensions corresponding to DC Cables for 1 to 5 MW Converters.
over 200 m water depth with work-class ROV touchdown monitoring. It would also be capable of performing repairs under similar circumstances. Other similar DP lay-barges are available.

10. Cost Estimates for a Typical Alaska Project

A link from Hawk Inlet on Admiralty Island to Spasski Bay on Chichagof Island was selected as an example for estimating 50 kV dc submarine cable costs. The village of Hoonah, with a load of about 4 MW and presently powered by expensive diesel generators lies west of Spasski Bay and would be supplied by an overhead line from it. A 69 kV ac source from AEL&P’s Douglas Island supply is assumed to be available directly above the Greens Creek Mine ore ship loading dock in Hawk Inlet. Approximate route length is 38 km and maximum water depth is 670 m. Detailed studies have been done by others for a conventional 69 kV ac supply to Hoonah and a marine desktop study was completed in 2007.

Figure 16 shows the NOAA chart for the route area.

![Figure 16: Excerpt from NOAA Chart 17300 showing possible cable route (depths in fathoms)](image)

10.1 General Description of Bathymetry

The following has been extracted from the footnote 23 reference.

"Hawk Inlet is a six mile long by half mile wide North-South trending embayment with the entrance located at the south end where it joins with Chatham Strait. Hawk Inlet is over 250 feet deep in the center section and shoals to less than 40 feet over a saddle feature near the entrance. A broad section of mudflats bounds the south side of the channel leaving the navigable channel on the North side less than 800 feet wide. To the south of the channel is a 100 foot deep hole which may be a byproduct of the high current velocities associated with the ebb tide.

Moving in to Chatham Strait from Hawk Inlet the bottom slopes gently toward the west for approximately one mile to the 200 foot contour. To the west of this point the slope increases to approximately 1:5 (20% grade, 11.3°) to about the 1300 foot contour at which point the slope lessens significantly to a westward grade of only 3% (3.100, < 2°). At approximately the 1600 to 1700 foot contour a very steep slope is encountered which drops 1:1 (100% grade, 45°). The base of this steep slope is the basin of the main channel in Chatham Strait at a depth of 2200 feet. There is a broad rise of a few hundred feet farther to the west, beyond which is a narrow trench or channel feature which drops 100 to 200 feet relative to the surrounding depths. This is also the general area (approximately one mile NE of Pt. Augusta) where the main channel of Icy Strait comes in from the NW to intersect with Chatham Strait. Continuing around Pt. Augusta and entering the Icy Strait channel the bottom bathymetry remains relatively flat at a depth of 1500 feet for a distance of nearly two miles. Just north of Pt. Augusta and east of Whitestone Harbor the contour map depicts numerous small closed contours which are believed to be artifacts in the NOAA data from the early multibeam data from the BSSS system used by the NOAA ship Davidson in the 1980’s. The validity of these features will need to be ascertained with additional survey data. The Icy Strait channel turns to the northwest with the bottom continuing to be relatively flat. Approximately two miles north of Whitestone Harbor there appears to be a bifurcation in the steep slope which has been bounding the west side of the channel along Chichagof Island. This break occurs between the 1300 foot and 600 foot contours in the form of a narrow channel. The bottom approximately two miles off the north side of Chichagof Island rises gently toward the west from 500 feet at the top of the channel shoulder to the shoreline at Spasski Bay at a rate of approximately 1:7 (1.4% grade, < 1°).

10.2 Geology and Seismology

The following has also been extracted from the footnote 23 reference, and describes hazardous site conditions for the eastern half of the route. It was researched and described in a report produced by Dr. Gary Carver of Carver Geologic Inc. in Kodiak, Alaska included as an attachment to the footnote 23 reference.

“In general, it describes an area comprised of a variety of rock types from differing geologic origins which were merged together through the action of plate tectonics. The accreting regions form generally north south trending bands that decrease in age toward the west. The accreted material has been deformed and fractured through a variety of geologic processes including: faulting, tectonic uplift, volcanic activity and glaciations amongst other things. The area contains significant faulting; however, the major Chatham Strait Fault, which runs in a north-south direction across the proposed route, appears to be inactive based on seismic monitoring over the past 20 years. In addition, GPS observations which monitor crustal motion seem to show fairly even velocity vectors on either side of the fault, which may indicate less build up of the stresses needed for significant fault movement.

The surficial rocks along the proposed cable route are Silurian aged (400 – 425 m.y.) sedimentary rocks such as Graywacke and mudstone turbidites, toward the western half of the route near Point Augusta, and Triassic to Ordovician (210 – 500 m.y.) aged sedimentary and volcanic rocks to the east on Admiralty Island. These older rocks on Admiralty Island include some which have undergone regional metamorphism. Reports referring to the Greens Creek area indicate that the rocks at the south side of the entrance to Hawk Inlet are predominantly amphibolites and along the east shoreline of Hawk Inlet is comprised of sedimentary formations.

Conditions are very favorable for high rates of erosion and corresponding deposition of unconsolidated material in the deep waters of SE Alaska. These conditions include: high rates of

DC Cables for 1 to 5 MW Converters.
uplift, fractured rocks, regional seismic activity, harsh weather conditions, steep terrain and plentiful sources for running water. The deposition of unconsolidated material along the steep slopes of Chatham and Icy Straits may present potential slide hazards for the submarine cable. Detailed multibeam data along the channel slopes along with subbottom data acquisition will be helpful in evaluating the locations of built up unconsolidated material along the proposed route."

10.3 Basis for Cost Estimates

With knowledge of the above site conditions, double counter-helical steel wire submarine cable is appropriate considering the 670 m water depths, very steep inclines with potential for underwater slides, high water currents and ore ship anchor hazards in the narrow confines of Hawk Inlet. An existing telecommunications submarine cable in Hawk Inlet must also be avoided during laying (Southeast Alaska Cable, SEAFAST). Power cable laying with a specialized barge equipped with dynamic positioning, outboard thrusters and a work class ROV, such as shown in Figures 14 and 15 would be needed to help optimize final cable position on the sea bottom. Cable burial or protection with flexible concrete mattresses and/or rock dumping is recommended for the Hawk Inlet area. The cable would have integral optical fibers for telecommunications between cable ends.

Cable supply cost estimates for double armor cable were derived from the range of budgetary costs received (or not received) from the five suppliers contacted, which were:

Supplier 1: $69/m FOB factory
Supplier 2: $130/m FOB Factory, Type testing needed
Supplier 3: $1,000/m FOB factory
Supplier 4: Did not respond with price
Supplier 5: Did not respond with price

None of the suppliers provided costs for integral optical fibers. Supplier 3’s price was clearly an outlier. A conservative approach was followed by averaging the remaining prices, which resulted in a cost of $100/m for double armor cable. It should allow for integral optical fibers.

Supplier 1 quoted $45/m FOB factory for single layer armor cables. Supplier 2 did not quote for a single armor layer, but assuming the same cost reduction ratio as Supplier 1, their cost could be about $85/m. Averaging Supplier 1 and 2 would yield a price for single armor cable of approximately $65/m.

It is believed that Supplier 1 presently has industry standard qualification tests underway and Supplier 3 is known to have completed them. Supplier 2 stated that Type tests would be needed for the proposed insulation type. Suppliers 4 and 5 had not done the required tests.

Quotations for past projects have indicated that optical fiber elements can be integrated into power submarine cables for approximately $20/m. This is included in the average unit costs described above.

10.4 Cost Estimate Results

Detailed cost estimates are included in Appendix B and summarized in table 5. The following assumptions were made.

1. Costs are in 2012 US Dollars.
2. Cable is single conductor, 35 mm² copper conductor, 50 kV dc XLPE insulation, lead alloy sheath, PE jacket, double armour submarine cable.
3. Cable costs based on copper at $7,500/tonne and lead at $2,000/tonne.
4. Cable is 38 km long, maximum 670 m deep.
5. Cable is supplied from a cable factory in Asia or Europe and shipped to site by freighter, then transferred to a specially equipped cable laying barge.
6. Submarine cable is buried 1.0 m deep to 3m water depth below MLW, except in Hawk Inlet where it is buried 3.0 m deep.
7. Cable is directly buried 1.0 m deep on land.
8. Cable is laid during summer months using a barge with dynamic positioning (DP) thrusters.
9. Costs for AC-DC converters not included.
10. Costs for overhead line taps and extensions to new near-shore cable terminals not included.
11. Estimate accuracy is ±25%.
12. No contingencies are applied. 15% is recommended.
13. Interest During Construction not included.
14. Duties and taxes not included.

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<th>Cable Cost Component</th>
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<td>EPC Contractor's Supply</td>
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<td>Total EPC Contractor Costs</td>
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<td>Total EPC Contractor and Owner's Costs</td>
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Table 5: Submarine cable system cost estimate for Hawk Inlet to Spasski Bay 50 kV dc link

11. Conclusions

Investigations showed that it would be more practical to provide 50 kV dc cables with a 1 to 5 MW rating from suppliers of conventional power submarine cables, who had already completed a development and qualification test program for high voltage dc transmission cables. Suppliers of telecom cables would need to begin custom development activities and industry standard testing programs for custom cables, passing costs on to customers. Ultimately they probably wouldn’t be able to compete with the established power cable producers who had already completed their development and testing programs for similar but larger cables. An exception would be if telecom cables with 15 kV dc ratings could use modified conductors to carry approximately 67 A in order to meet the 1 MW minimum rating requirement, and converter designs could be modified accordingly. Further investigations would be required, in order to confirm adequacy and identify benefits.

North American power cable suppliers are not presently equipped to provide the 50 kV dc submarine cables in long lengths and did not appear interested in expanding facilities for what they may have perceived to be a small market.

Several offshore suppliers are willing to provide the required power cables at what is judged to be a reasonable cost. More could be interested if a specific project was described with an indication of permitting approvals and financial commitments to proceed to completion.

DC Cables for 1 to 5 MW Converters
Optical fibers can be relatively easily integrated into conventional power submarine power cables, as proven by existing installations. Customizing telecom cables to transmit 1 MW at 50 kV dc would not be as easy or economical.

Based on budgetary quotations from power cable suppliers, costs for a suitable cable with double wire armor and integrated optical fiber elements were estimated to be about $100/m, FOB freighter at factory. For shallower water installations with smooth terrain and low water currents, single armor cable could be suitable, at a price of about $80/m FOB freighter at factory.

For most installations in Alaskan coastal waters, use of specialized laying barges appears to be adequate and would be a more cost-effective solution than using large dedicated cable transportation and laying vessels, which are presently in short supply. Suitable lay-barges are available in the Pacific Northwest. Smaller, less expensive 'transporters' would be adequate for smaller projects, whereas large lay-barges with dynamic positioning systems would be more appropriate for longer, deeper, more complex projects.

Mobilization and demobilization costs for large submarine cable lay barges can be as high as the costs to lay the cables, so there could be considerable savings if multiple projects were combined or coordinated for approximately the same time period.

Cost estimates for a Hawk Inlet to Spasski Bay submarine cable system to ultimately supply Hoonah were approximately $12.4M.

12. Appendices
Appendix A – Telecommunications Submarine Cable Brochure

Alcatel OALC4
Fiber Optic Cable for Repeted Submarine Systems

A Complete Cable Product Range
Alcatel submarine product portfolio includes a full range of fiber optic submarine cables, one of them being the OALC4 cable family.

The OALC4 cable has been specifically designed for repeted systems, benefiting from our past extensive experience in the conception and development of submarine fiber optic cables.

Reliable Cable Design
The cable design is based on a laser welded stainless steel tube, housing up to 12 fibers in a stress-free environment to ensure a long service life.

The fibers have a defined excess length relative to the tube, which is filled with a water-blocking compound.

The composite conductor is composed of the steel tube fiber structure protected by a high-strength jacket, which is formed from 24 close tolerance steel wire surrounded by a semi-voided and stranded copper tube.

Longitudinal water tightness is provided by a water-blocking material within the jacket.

The composite conductor is insulated with high-density polyethylene which provides four times more abrasion resistance than conventional materials. This insulated structure is our lightweight cable (LW) design used for deep-sea deployment.

The OALC4 cable can be used at any sea depth between 0 and 3000 meters. OALC-4 armored cables use the deep-sea lightweight cable (LW) structure as the inner core, and provide additional external protection with various numbers and diameters of armored steel armour wires according to the application water depth, survival topology and the degree of protection required.

Benefits to Our Customers
The OALC4 cable offers exclusive benefits to our customers:
- Best optical performance by using steel tube technology
- Greater abrasion performance with high-density polyethylene
- Further hydrogen resistance owing to a double barrier (copper tube plus steel tube)
- Adaptable static resistance (1.6 and 1.2 km/km).

In addition, our cable features a lower weight and a smaller diameter than similar products on the market and offers a number of extra benefits for the customer:
- Handling is easier, so the risk of damage is reduced
- Storage capacity is increased both in volume and in weight (i.e. storage capacity is 40% more in volume and 50% more in weight)
- Shorter and less costly marine installation schedule as the shrinkable cable storage tanks can hold more cable per lay
- Reduced shipping and storage costs for the customer’s space cable.

Key Features:
- Up to 12 fibers
- Maximum deployment depth, 3000 m
- Double barrier against hydrogen
- High density polyethylene
- Adaptable static resistance
- High reliability over 25 years
- High yield to cable levels
- Complete range of accessories

DC Cables for 1 to 5 MW Converters
Technical Summary

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<th>Performance</th>
<th>LW</th>
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<th>DAH</th>
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Characteristics:
- Outer diameter: mm 17
- Weight in air: kg/m 0.5
- Weight in water: kg/m 0.27

Notes:
1. HTTS: nominal tensile strength
2. HOPA: nominal operating tensile strength
3. HTTS: nominal permanent tensile strength
4. LTS: ultimate tensile strength

OALC4 Global Submarine Cable References

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<td>Mad Nautus</td>
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www.alcatel submarine
For more information, please contact Alcatel submarine.

DC Cables for 1 to 5 MW Converters

22
Appendix B – Cost Estimate for Hawk Inlet to Spasski Bay 50 kV dc Submarine Cable

Hawk Inlet - Hoonah 50 kV dc Submarine Cable Cost Estimate

**Assumptions:**
1. Costs are in 2012 US Dollars.
2. Cable is single conductor, 35 mm² copper conductor, 50 kV dc XLPE insulation, lead alloy sheath, PE jacket, double armour submarine cable.
3. Cable costs based on copper at $7,500/tonne and lead at $2,000/tonne.
4. Cable is 38 km long, maximum 670 m deep.
5. Cable is supplied from a cable factory in Asia or Europe and shipped to site by freighter and transferred to a specialty equipped cable laying barge.
6. Submarine cable is buried 1.0 m deep to 3 m water depth below MLW, except in Hawk Inlet where it is buried 3.0 m deep.
7. Cable is directly buried 1.0 m deep on land.
8. Cable is laid during summer months using a barge with dynamic positioning (DP) thrusters.
9. Costs for AC-DC converters not included.
10. Costs for overhead line taps and extensions to new near-shore cable terminals not included.
11. Estimate accuracy is ±25% to ±50%.
12. No contingencies are applied. 15% is recommended.
13. Interest During Construction not included.
14. Duties and taxes not included.

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<th>Item</th>
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<th>Unit Price</th>
<th>Extended Price</th>
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<td>Design, QA, factory testing, submittals, and drawings for factory and project site work (lump sum)</td>
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<td>Supply 1/4 50 kV dc, 35 mm² copper conductor, XLPE insulation, lead alloy sheath, double armor submarine cable (m), F.O.B freighter at factory</td>
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<td>S-5</td>
<td>Supply 3-phase line disconnects at new cable terminals (each)</td>
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<td>S-6</td>
<td>Supply materials for site prep, ground grid and fencing for new cable terminals (lump sum)</td>
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<td>S-7</td>
<td>Supply 50 kV station class composite lightning arresters (each)</td>
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<td>Supply HDPE conduits for cable terminal approaches through inter-tidal zone (ea)</td>
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<td>5,000</td>
<td>10,000</td>
</tr>
<tr>
<td>S-9</td>
<td>Supply fiber optic cable termination panels (each)</td>
<td>0</td>
<td>2,000</td>
<td>0</td>
</tr>
<tr>
<td>S-10</td>
<td>Supply spare submarine cable (m)</td>
<td>4,000</td>
<td>100</td>
<td>400,000</td>
</tr>
<tr>
<td>S-11</td>
<td>Supply spare submarine cable turnable or reel (m)</td>
<td>1</td>
<td>10,000</td>
<td>10,000</td>
</tr>
<tr>
<td>S-12</td>
<td>Spare cable termination (each)</td>
<td>1</td>
<td>2,000</td>
<td>2,000</td>
</tr>
<tr>
<td>S-13</td>
<td>Supply spare rigid cable joint (each)</td>
<td>2</td>
<td>10,000</td>
<td>20,000</td>
</tr>
<tr>
<td></td>
<td><strong>Subtotal - Supply</strong></td>
<td></td>
<td></td>
<td>4,260,000</td>
</tr>
<tr>
<td>Contractor Installation</td>
<td>Quantity</td>
<td>Unit Price</td>
<td>Extended Price</td>
<td></td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------------</td>
<td>----------</td>
<td>------------</td>
<td>----------------</td>
<td></td>
</tr>
<tr>
<td>Shipping, handling and delivery to site of cable and other supply items to Juneau by freighter, including waiting and return time (days)</td>
<td>30</td>
<td>50,000</td>
<td>1,500,000</td>
<td></td>
</tr>
<tr>
<td>Mobilize/demobilize DP cable laying barge and installation crews at Juneau area site (lump sum)</td>
<td>1</td>
<td>2,500,000</td>
<td>2,500,000</td>
<td></td>
</tr>
<tr>
<td>Transfer cable from freighter to laying barge (days)</td>
<td>2</td>
<td>125,000</td>
<td>250,000</td>
<td></td>
</tr>
<tr>
<td>Install armored submarine cable (days)</td>
<td>4</td>
<td>125,000</td>
<td>500,000</td>
<td></td>
</tr>
<tr>
<td>Install cable termination support structures (each)</td>
<td>2</td>
<td>5,000</td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td>Bury cable 3.0 m deep through Hawk Inlet (m)</td>
<td>2,000</td>
<td>500</td>
<td>1,000,000</td>
<td></td>
</tr>
<tr>
<td>Install line disconnects at new cable terminals (each)</td>
<td>0</td>
<td>10,000</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Install materials for site prep, ground grid and fencing for new cable terminals (lump sum)</td>
<td>0</td>
<td>1,000,000</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Install 50 kV dc terminations complete with armor clamps (each)</td>
<td>2</td>
<td>2,000</td>
<td>4,000</td>
<td></td>
</tr>
<tr>
<td>Install 50 kV dc kV station class composite lightning arresters (each)</td>
<td>2</td>
<td>2,000</td>
<td>4,000</td>
<td></td>
</tr>
<tr>
<td>Install cable trenches from MHW to cable terminals (m)</td>
<td>200</td>
<td>500</td>
<td>100,000</td>
<td></td>
</tr>
<tr>
<td>Install HDPE conduits and trench through inter-tidal zone at cable terminal approaches (each)</td>
<td>2</td>
<td>100,000</td>
<td>200,000</td>
<td></td>
</tr>
<tr>
<td>Install spare submarine cable turntable (lump sum)</td>
<td>1</td>
<td>10,000</td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td>ROV monitoring during cable laying (days)</td>
<td>4</td>
<td>25,000</td>
<td>100,000</td>
<td></td>
</tr>
<tr>
<td>Divers during cable laying (days)</td>
<td>4</td>
<td>6,000</td>
<td>20,000</td>
<td></td>
</tr>
<tr>
<td>Testing and Commissioning (lump sum)</td>
<td>1</td>
<td>20,000</td>
<td>20,000</td>
<td></td>
</tr>
<tr>
<td><strong>Subtotal - Installation</strong></td>
<td></td>
<td></td>
<td>6,218,000</td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL Contractor Costs</strong></td>
<td></td>
<td></td>
<td>11,276,000</td>
<td></td>
</tr>
<tr>
<td><strong>Owner's Engineering, Project Management and Permitting costs (10% of 'TOTAL contractor costs')</strong></td>
<td></td>
<td></td>
<td>1,127,600.00</td>
<td></td>
</tr>
<tr>
<td><strong>TOTAL Contractor and Owner costs</strong></td>
<td></td>
<td></td>
<td>12,403,600.00</td>
<td></td>
</tr>
</tbody>
</table>
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APPENDIX E

SWER CIRCUITS AND HVDC SYSTEM GROUNDING
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E.1 SINGLE-WIRE EARTH RETURN (SWER) CIRCUITS

The most economical applications of low-power high-voltage direct current (HVDC) systems in Alaska will use monopolar circuits with single-wire earth return (SWER). Alaska has adopted the National Electric Safety Code (NESC) to regulate the design and installation of utility grade electric systems. The NESC does not allow the use of SWER circuits. This rule is based on considerations of life safety (avoidance of step potential hazards) and economics, as DC SWER circuits can cause accelerated corrosion of nearby buried metal infrastructure such as pipelines.

SWER circuits are successfully used on AC and DC circuits in many international jurisdictions. In many rural Alaska applications, the use of HVDC SWER circuits is a safe and appropriate technology that can save significant costs. There is a process to obtain waivers to the NESC rules that will permit the installation of SWER circuits. Two AC SWER systems built in the 1980s successfully obtained such waivers.

Polarconsult subcontracted with the Manitoba HVDC Research Centre (MHRC) to prepare a letter report summarizing the technical and code issues associated with the appropriate use of SWER circuits. That report is included as Attachment E-1 to this appendix.

E.2 SYSTEM GROUNDING

A conceptual design for a low-power HVDC grounding station suitable for use with the proposed HVDC transmission system is included in the attachment to this appendix.
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APPENDIX E ATTACHMENTS

Attachment E-1:
HVDC Ground Electrode Overview
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Engineering Support Services for

HVDC Ground Electrode Overview
Alaska HVDC Transmission Project – Phase II

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File # 475.00
Rev: 0.0
Date: March 31, 2011

Original Sealed by
L. Recksiedler
April 6, 2011
# 3288
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1. **Executive Summary and Background**

PolarConsult Alaska Inc. has contracted Manitoba HVDC Research Centre, a division of Manitoba Hydro International Ltd. (MHI) in Winnipeg, Canada to provide technical support for an Alaskan HVDC Distribution Initiative and project. MHI has been directly contacted by State of Alaska, Electrical Inspection Department (the Client) in January 2011 to provide technical background on Single Wire Earth Return (SWER) systems HVDC systems that utilize ground electrodes and several specific questions. This report is in direct response to those queries.

The report summarizes the following items:

- Introduction to HVDC system configurations with respect to earth or sea electrodes
- Describes the type of ground currents that are in operation
- Description of ground electrodes
- HVDC Electrodes and AC SWER systems in USA and world
- Safety Considerations
- Regulations and Codes in the USA and world
- Observation and Answers to Questions raised and Conclusions.

**Conclusions**

- It is recognized that Single Wire Earth Return (SWER) whether it is AC or DC can provide a low cost method of providing grid power to remote locations with small loads.
- SWER projects have been installed safely throughout the world.
- The National Electric Safety Code (NESC) C2 2007 of the United States does not normally allow for the return current to be continuous but only temporary for maintenance or emergencies.
- The NESC C2 2007 does allow for exceptions where granted by the administrative authority as long as the installation is safe. Thus existing SWER AC system have been approved by exception. The administrative authority in the regulation is defined as “The government authority exercising jurisdiction over the application of the Code”.

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2. Introduction

HVDC transmission is a mature technology and has been around since the 1950’s. This form of electrical transmission is best suited to transfer bulk power over long distances, in undersea/buried cables or back to back schemes between asynchronous AC systems. HVDC schemes are either monopolar (one high voltage conductor) or bipolar (two high voltage conductors).

The most cost effective way of designing a monopole scheme is to construct it with a high voltage conductor and sea or earth electrodes to return the current. [1] If a sea or earth return is not desirable then a dedicated metallic conductor is required for the return current and this is known as a “metallic return”. In the case of a bipolar scheme, if one conductor faults, the remaining high voltage conductor can remain in-service utilizing the electrode for return current making the link more reliable as only up to 50% of the power is lost.

Current return through the earth saves the cost of the metallic conductor, smaller transmission towers are required and the power losses are less. In one case, the metallic conductor is 14.0 ohms whereas the earth return is 1.0 ohm, thus the losses are approximately 1/15 using the earth return as compared to using a dedicated conductor.

Earth electrodes thus play an important function for both monopolar and bipolar HVDC Schemes. EPRI a large USA based research firm has produced a detailed design manual for HVDC earth electrodes [8]. This information is now available as IEC/PAS – (CIGRE) 62344 [2] [3].
3. Types of Ground Currents

There are three types of ground currents that must be recognized and managed as required. These types are listed below.

3.1. AC Currents

AC currents are normally are 50 or 60 Hz in frequency. These currents concentrate on the surface of a conductor in what is commonly known as the ‘skin effect’. AC distribution systems can be configured as a Single Wire Earth Return (SWER) where the current continuously returns through the earth. The second consideration in earth return systems is fault conditions. When a fault occurs on a grounded transmission or distribution line, the fault current returns to the AC substation via earth (and ground wire if available) for a period of approximately 50 to 500 milliseconds. This AC fault current is normally cleared by tripping the AC breakers. The fault currents can be very high in some systems, some in the 20 000 to 50 000 Amperes range.

Stray currents during normal and faulted operations have been measured. These stray currents in rural areas have been well documented and their effects on livestock are well known. While there are numerous papers on this subject only one is referenced here. [4]

3.2. Geomagnetically Induced Currents (GIC)[5]

GIC’s are “quasi DC current” with a frequency of approximately 0.2 Hz. They are produced by “sun spots” which are really solar flares emitting large amounts of radiation energy from the sun. Thus charged particles stream away from the sun towards the earth in what is known as the solar wind. These particles tend to accumulate at the Arctic and Antarctic poles in a large auroral oval which can be seen as the Northern Lights. GIC currents start to flow in the earth. While the GIC’s can occur at any time, periods of high intensity occur in cycles of 11 years and 100 years respectively.

GIC’s can cause corrosion problems in pipelines, railway tracks, ships, marine structures, bridges and long culverts or other long metal structures. These industries have come up with ways of combatting these GIC’s by adding insulating blocks to make the sections shorter (insulating between sections), by using insulating coatings, and applying cathodic protection systems. Cathodic protection is a technique used to control the corrosion of a metal surface by making it the cathode of an electrochemical cell. A galvanic anode is designed to be more negative than the object
being protected and this prevents the corrosion of the protected object. Another method of protection is to use a DC power source or pulse rectifier when the galvanic anodes cannot deliver enough current economically. This is typically the case for pipelines which are very long [6].

GIC’s can also get into the neutrals of transformers causing damage (generally shell type transformers), into transmission lines causing voltage instability and protection trips. It can also affect communications systems. These industries have a variety of GIC mitigation methods that cater for these system impacts.

3.3. DC Currents

DC currents occupy the entire cross section of a conductor and thus are more efficient than AC. DC operates at a frequency of zero Hertz and thus is not subject to inductive and capacitive losses. DC currents tend to go deep into the earth because the electrodes are large and far apart [9].

DC fault currents are normally limited to 3.0 times the load current due to the high impedance used in the equipment and equipment is in series rather than parallel. This is due to the Thyristor Valves which must be controllable for line faults. As newer Thyristors and other electronic devices have higher fault current capabilities this value will likely rise. Thus for a 2,000 Ampere load current; the fault current is 6,000 Amperes DC maximum. For the typical 1 MW converter at 50 kV DC, the load current would be about 20 Amperes and thus the expected fault current is to be in the 60 Ampere range.

For multi-terminal converters, the maximum DC current will depend on how many converters are delivering power into the system versus the ones taking power. The converters taking power from the DC transmission line do not provide any DC fault contribution.

In addition, DC fault currents are rapidly limited by very fast acting controls to the maximum load current in the DC line. As a backup protection the fault current can be interrupted by opening the AC breakers within 50 to 200 milliseconds.

4. HVDC Ground Electrodes

HVDC ground electrodes have been around for about 45 years. It is important to keep the step and touch potentials near the electrode sites within safe limits. This has usually been possible without having to resort to area fencing and other mitigation measures.
4.1. Location of Electrodes

It is important to find areas with good moisture availability. Also, it is important to find good shallow and deep low resistivity earth structure or layers. Advancements in the area of resistivity measurements have made this task easier and more predictable. For the shallow layers high resolution multi-electrode DC resistivity imaging techniques are used which can provide the electrical resistivity of structures up to depths of a few hundred meters [1]. For deeper layers, the Magnetotelleric Technique (MT) is used. MT can be used to determine the electrical resistivity of structures up from depths of a few hundred meters to depths of several hundreds of kilometers.[1]

Electrodes have been installed in Northern locations with permafrost and moraines. A good example is the Radisson electrode in the Northern region of Manitoba Canada which is 900 km North of Winnipeg which is installed in a moraine area and has been in-service since 1973; the Henday electrode which was installed in a permafrost prone area and has been in-service since 1978. Both electrode sites operate without any problems.

4.2. Types of Electrodes

The resistivity profile of the earth layers will determine the type of ground electrode used. One type is the vertical or borehole arrangement where a number of holes are drilled and the electrodes buried deep into the earth. This arrangement is used for deeper conducting layers and where space is limited. The other arrangement is a horizontal design where the electrode is buried below the frost line and tends to be either linear, ring shaped, or star shaped.

5. HVDC Electrodes in the World and the USA

There are 36 HVDC schemes in the world with ground or sea electrodes with two electrodes each. Of the 36 HVDC Schemes operating, 23 have ground electrodes.

In the USA, there are four Bipolar HVDC Schemes with electrodes as listed below:

1. The CU HVDC scheme was built in 1979 and transmits power between the Coal Creek terminal near Underwood North Dakota and the Dickinson terminal near Minneapolis, Minnesota.

2. The IPP Intermountain HVDC scheme was built in 1986 and transmits power from Utah to Los Angeles, California.

3. The Pacific Intertie HVDC scheme was built in the early 1970's and transmits power between The Dalles, Oregon and Los Angeles, California. The Los
Angeles end is a sea electrode where The Dalles end is a ground electrode. Plans are underway to upgrade these electrodes to a higher operating current rating.

4. The Square Butte HVDC scheme was built in 1977 and transmits power between Center, North Dakota and the Arrowhead terminal near Duluth, Minnesota.

6. Safety – Step and Touch Potentials/Voltage

Step voltage is the voltage difference across the step of a person or the difference across the front and back legs of an animal. Touch voltage is the voltage difference between an object that a person may touch such as a building and the ground surface at the person’s feet. The permissible step and touch voltages which a person may be subjected to at the electrode site is based on IEEE Standard 80 – Guide for Safety in AC Substation Grounding.

The maximum potential gradient at the electrode site is typically less than 20 V/m. The maximum potential gradient at one utility’s HVDC electrode sites is less than 10 V/m at 1,800 Amperes DC which is considered safe for both humans and animals. Because of this, the sites are not fenced nor are any other mitigation means necessary. Increasing the burial depth of the electrode is another means to reduce the surface potential gradient.

7. Regulations

7.1. United States

The National Electric Safety Code (NESC), Accredited Standards Committee C2 – 2007 prohibits the continuous use of ground as a sole current carrying conductor (Section 314 C 4a). The regulation does allow for bipolar systems for limited period of time for maintenance or during emergencies operation in the monopolar ground return mode (Section 314 C 4b). It does not specify what conditions constitute an emergency, or any time limit for maintenance or emergency.

Another section, 092 – Point of connection of grounding conductor, provides an exception in A2 “Exception: Where the stations are not geographically separated as in back to back converter stations, the neutral of the system should be connected to ground at one point only.”

Another section, 013 Application – A New Installations and extensions – 1, States that these rules apply to all new installations and extensions, except that they may be waved or
modified by the administrative authority. When so waved or modified, safety shall be provided in other ways.” This section appears to allow the administrative authority to make an exception provided it is safe to do so.

7.2. Canada and the rest of the world

Regulations in Canada have not been fully researched as the focus of this report was for United States based jurisdictions. There are no known regulations in Canada preventing ground electrodes and they are being considered for some HVDC schemes currently under development. As for the rest of the world there have been nine out of sixteen HVDC schemes built with ground or sea electrodes since the year 2000. These have been located in China, Greece, Italy, India, and Namibia.

In Canada, one utility has ground electrodes that are designed to operate for 30 to 40 days at maximum current of up to 4,000 Amperes for maintenance or emergencies and has operated one set of electrodes for an extended period of time without any problems and up to 2,000 Amperes.

SWER AC has been used successfully in many parts of the world for up to 80 years in New Zealand. It is commonly applied in areas with large geographic areas and sparse populations such as Australia, New Zealand and the province of Saskatchewan, Canada. [7]

7.3. Practical Considerations

Sometimes environmental concerns are real and require changes to the system design and other times there is only a perceived concern but both can cause delays and costs in the licensing process. In some cases, environmental opposition has caused some HVDC Schemes to include a metallic return conductor or to cancel the entire project. Therefore, a well prepared information strategy is recommended ahead of any public consultations on the HVDC Electrodes.
8. Observations

The four HVDC Schemes in the USA are Bipolar Schemes, thus the National Electric Safety Code (NEC) C2 appears to allow them to operate normally.

- Although not explicitly stated as a safety or corrosion concern, the National Electric Safety Code (NESC) C2 does allow bipolar HVDC schemes to operate in the monopolar mode for maintenance and emergencies with no time limit.

- It is possible to design a HVDC ground electrode to safely meet the step and touch voltage requirements outlined in the IEEE Standard 80. Issues with corrosion can also be mitigated. As GIC's also can cause corrosion, utilities such as pipelines and railways are already equipped to handle this.
Questions

1. What is the intent of the rule which does not allow the earth normally as the sole conductor for any part of the circuit?

**Answer:** It is not clear what the intent is of this rule but in the case of AC there has been issues with stray currents affecting animals particularly in rural farming communities. The Code does allow Single Wire Earth Return AC systems by exception as they exist in the upper Midwest States. The Code does allow bipolar HVDC schemes to operate monopolar for maintenance and emergencies with no time limit. During this time the sole conductor for the return current is the earth. This period of time is normally a few minutes to a few days but could be a several weeks in an emergency. The Bipolar schemes existed when this legislation was created in 1993 and it appears to be written to accommodate them. There does not appear to be any safety issues involved as the Bipolar schemes are allowed to operate for days and weeks at a time during emergencies and maintenance.

2. To what extent does the use of a SWER circuit pose a safety hazard to people and animals? [Step potential]

**Answer:** A SWER-dc circuit electrode must be designed to limit the touch and step potentials to a safe potential gradient. Because dc fault currents are much less that ac fault currents and dc currents want to go deep in the earth it is generally easier to design for a DC electrode than SWER-ac and AC substations. Generally no additional mitigation measures such as fencing the electrode site and applying crushed rock on the surface are required. Whereas in a normal AC substation this is required and many utilities also require insulated footwear to work in the AC substation as a backup measure.

3. Are there SWER systems in use in the U.S.? If so, how have the NESC rules been addressed?

**Answer:** There are no SWER-dc systems in use in the U.S. SWER-AC systems are used in distribution circuits in some areas of the Midwest which is defined as Minnesota, Wisconsin and Michigan. In 1981 a high power 8.5 mile SWER AC line was installed from a coal plant Bethel to Napakiak in Alaska U.S. Experience here has shown that the electrode has to be buried below the frost level. [10]

NESC rules are written such that each SWER line must be approved by exception.

4. Have installation standards been established for SWER systems?

9. Conclusions

- It is recognized that Single Wire Earth Return (SWER), whether AC or DC can provide a low cost method of providing grid power to remote locations with small loads.
- SWER projects have been installed safely throughout the world.
- The National Electric Safety Code (NESC) C2 2007 of the United States does not normally allow for the return current to be continuous but only temporary for maintenance or emergencies.
- The NESC C2 2007 does allow for exceptions where granted by the administrative authority as long as the installation is safe. Thus existing SWER AC system have been by exception. The administrative authority in the regulation is defined as “The government authority exercising jurisdiction over the application of the Code”.
10. References


Attachment E-2:
Grounding Station Figure
Figure E-1  Grounding Station

**FIG. a - EARTH RETURN - PLAN VIEW**
SCALE: AS SHOWN

**FIG. b - POWER CENTER ELEVATION**
SCALE: AS SHOWN

**FIG. c - ELECTRODE STRING DETAIL**
SCALE: AS SHOWN

**FIG. d - EARTH RETURN - ELEVATION VIEW**
SCALE: AS SHOWN
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APPENDIX F

HVDC POWER CONVERTER DEVELOPMENT
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F.1 CONVERTER DEVELOPMENT

F.1.1 Introduction

The high-voltage direct current (HVDC) converter developed under this project is a 1-megawatt (MW) power converter capable of bidirectional power conversion between three-phase 480 volts alternating current (VAC) and 50 kilovolts (kV) HVDC. The converter capacity is appropriate to supply the electrical needs of most Alaska villages. In contrast, existing HVDC power converter systems are only cost effective at much larger transmission capacities, starting at approximately 50 MW and extending up to 1,000s of MWs of capacity.

Multiple HVDC converters can be “paralleled” to achieve higher power transmission capacities where needed. Based on Phase II development work, the price of a commercially produced 1-MW HVDC power converter is estimated to be $250,000. At least two 1-MW converters are needed for a complete 1-MW HVDC transmission system.

This appendix presents Princeton Power Systems, Inc.’s (PPS’s) final deliverables for converter specification, design, and test plan under Phase II of the HVDC technology development program (Attachment F-1).

PPS has successfully demonstrated operation of the prototype converters at the full 50 kV DC and power flow in both inverter (HVDC to AC) mode and rectifier (AC to HVDC) mode in a controlled test facility setting. These testing efforts validate the design and basic functionality of the converter.

In the course of testing, PPS identified two hardware problems that prevented full-power testing of the prototype converters. PPS has investigated these problems and identified the actions necessary to correct both problems. The problems and solutions are discussed in Attachment F-1 to this appendix.

PPS is continuing to work on the hardware modifications needed to correct the prior technical problems. Due to the long lead-time to obtain suitable replacement insulated gate bipolar transistor (IGBT) switches, the converter modifications and testing are not expected to be completed until late 2012. PPS will issue a supplemental report detailing the results of final Phase II testing when testing is completed. This supplemental report and the fully operational converters will be PPS’s final deliverable under Phase II of this research and development (R&D) project.

F.1.2 Converter Sizing Analysis

The electrical load characteristics of rural Alaskan communities that are the target of this project were evaluated. The capacity of the HVDC intertie system was based on the likely peak loads and load duration profiles of the selected communities.

The duration of peak loads provides an economic basis for design capacity of the intertie. In general, the intertie is designed to minimize the line losses at peak loads. The load duration profile for Hooper Bay is presented on Figure F-1. This profile is representative of rural Alaskan communities with a peak load of 760 kW, and will generally apply to other communities. Some communities, such as those with fish processors, will have load profiles different than that shown on Figure F-1.
The peak loads of rural Alaska communities participating in the Power Cost Equalization (PCE) program were reviewed to determine the appropriate power capacity for the HVDC interties considered for this study. The distribution of peak loads is presented on Figure F-2.

Based on this analysis, a 1-MW power intertie is an appropriate conceptual capacity for the majority of rural Alaska interties. For maximum reliability and flexibility, the power converter specifications call for a 1-MW unit comprised of two 500-kW modules operating in parallel. The converter modules can be connected to operate in parallel, thus providing additional capacity up to a few MWs where necessary. Interities designed for more than a few MWs may warrant reevaluation of the AC interface voltage (480 volts [V] for the 500-kW power converter module).

---

41 Data generated for Hooper Bay using the Alaska Village Electric Load Calculator (NREL, 2005)
Figure F-2  Peak Loads in Alaska Villages (2007 – 2009)

(2) 1 MW HVDC CONVERTERS USED FOR BIPOLAR INTERTIE, ADEQUATE FOR 82% OF COMMUNITIES.

1 MW HVDC CONVERTER, ADEQUATE FOR 76% OF COMMUNITIES.

1 MW HVDC CONVERTER WITH 500KW MODULE FAILURE, ADEQUATE FOR 60% OF COMMUNITIES.

Source: 2009 Power Cost Equalization Data, Alaska Energy Authority
F.1.3 Converter Test Results

In the course of testing the prototype converters, PPS has successfully demonstrated operation at the full 50 kV DC and power flow in both inverter (HVDC to AC) mode and rectifier (AC to HVDC) mode. In the course of testing, PPS identified two hardware problems that prevented completion of Phase II testing of the prototype converters, including demonstration of full power operation. PPS has investigated these problems and identified the actions necessary to correct both problems. The problems and solutions are summarized below.

F.1.3.1 Fiber Optic Triggering System in High-Voltage Tank

A fiber optic network is used to trigger the solid-state IGBT switches inside the high-voltage tank. Testing revealed problems with the triggering timing and reliability of this triggering system. Investigation determined that the lenses used in the fiber optic system exhibit excessively high signal loss, causing the observed timing and reliability issues. PPS has identified and tested different lenses and is proceeding to replace the lenses in both prototype converter modules to solve this problem.

F.1.3.2 IGBT Switches in High-Voltage Tank

The IGBT switches in the high-voltage tank were found to enter thermal runaway when the prototype converter is operated at low-power levels in inverter (HVDC to AC) mode. Investigation has determined that these switches do not perform in accordance with the manufacturer's specifications. Consultations with the manufacturer has not produced an acceptable remedy, and PPS has concluded that these IGBTs cannot be used for this application. PPS has identified alternate IGBTs that meet the technical and economic criteria of this project, and is proceeding to upgrade the converters with these switches. Because the switches operate at a different voltage than the original switches and have a different form factor, redesign of the high-voltage stage boards is necessary.

Because of the hardware problems identified, PPS has not yet completed converter testing. Final testing is pending receipt of new IGBTs.

Figure F-3 shows a simplified schematic illustrating the current development status of the converter's basic functional modes.
Figure F-3  Simplified Schematic Illustrating Technical Progress

Legend:
- Green arrow: Function has been verified
- Blue arrow: Functions have been proven in other PPS products
- Red arrow: Function has issues
APPENDIX F ATTACHMENTS

Attachment F-1:
PPS HVDC Power Converter Report
HVDC Transmission System for Rural Alaska Applications, Phase II – Prototyping and Testing


Final Report (Rev. 1.7)
March 2012

Prepared by:
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POWER SYSTEMS

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Revision History

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Project Information

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| Main Author[s]: | Mark Holveck – mholveck@princetonpower.com  
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Rik Aspinall – raspinall@princetonpower.com |
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<td>ADC</td>
<td>Amperes, direct current</td>
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<td>A/D</td>
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<td>A rms</td>
<td>Amperes, root mean square</td>
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<td>direct current</td>
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<td>Equipment Under Test</td>
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<td>F, uF</td>
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<td>General Purpose Interface Bus</td>
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<tr>
<td>L-G</td>
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<td>L-L</td>
<td>Line to line</td>
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<td>L-N</td>
<td>Line to neutral</td>
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<tr>
<td>Imd</td>
<td>Total Harmonic Distortion Current</td>
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<td>LVAC</td>
<td>low-voltage alternating current</td>
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<tr>
<td>m, M</td>
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<td>m³/hr</td>
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<td>mA</td>
<td>milli-ampere</td>
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<td>mean time between failures</td>
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<td>SPL</td>
<td>Sound pressure level</td>
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<tr>
<td>TCP/IP</td>
<td>Transmission control protocol / internet protocol</td>
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<tr>
<td>THD</td>
<td>Total Harmonic Distortion</td>
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<tr>
<td>UART</td>
<td>universal asynchronous receiver/transmitter</td>
</tr>
<tr>
<td>UL</td>
<td>Underwriters Laboratories, Inc.</td>
</tr>
<tr>
<td>VAC</td>
<td>volts alternating current</td>
</tr>
<tr>
<td>VAR</td>
<td>volt-amperes reactive</td>
</tr>
<tr>
<td>VDC</td>
<td>volts direct current</td>
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<td>( V_{\text{nom}} )</td>
<td>Volts, nominal</td>
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SECTION 1: INTRODUCTION

Polarconsult Alaska, Inc. of Anchorage, Alaska, has been provided funding by the Denali Commission to develop a high voltage direct current power transmission system for use in rural Alaska. Princeton Power Systems, Inc. (PPS) is a critical subcontractor in this technology development program, responsible for development of the power converter technology.

The converter design, incorporating several unique power electronics technologies, enables the construction of HVDC transmission interties in rural Alaska at a significantly lower cost than conventional alternating current (AC) transmission interties. This cost savings improves the economics of building interties in rural Alaska, enabling greater interconnection of rural communities and improved economies of scale in rural power generation. These factors will result in lower electric costs in the communities served.

The HVDC converter is a one-megawatt (MW) power converter capable of bidirectional power conversion between three-phase 460 volts alternating current (VAC) and 50 kilovolts (kV) HVDC. The converter capacity is appropriate to economically supply the electrical needs of most Alaska villages. In contrast, existing HVDC power converter systems are only cost effective at much larger transmission capacities, starting in the tens of MWs and extending up to 1,000s of MWs of capacity.

Multiple PPS HVDC converters can be “paralleled” to achieve higher power transmission capacities where needed. Based on Phase II development work, the price of a commercially produced one MW HVDC power converter is estimated to be $250,000. At least two one MW converters are needed for a complete one MW HVDC transmission system.

Phase I of this development program (2007 – 2009) was managed for the Denali Commission by Alaska Village Electric Cooperative, Inc. (AVEC), an electric cooperative that serves 54 of Alaska’s remote villages and communities. Phase I included preliminary design and feasibility analysis of the overall HVDC transmission system. In Phase I, PPS successfully designed, constructed, and tested a limited functionality bench top demonstration unit to determine that the proposed power converter technology met the basic functional, technical, efficiency, and economic criteria for the overall transmission system.

Phase II of this development program (2010 – 2012) was managed for the Denali Commission by the Alaska Center for Energy and Power (ACEP) at the University of Alaska Fairbanks’ Institute for Northern Engineering. Phase II includes prototyping and testing of the key technology aspects of the full HVDC power transmission system. In Phase II, PPS has successfully specified, designed, modeled, and constructed a prototype one megawatt HVDC converter.

In the course of testing the prototype converters, PPS has successfully demonstrated operation at the full 50 kV DC, and power flow in both inverter (HVDC to AC) mode and rectifier (AC to HVDC) mode. In the course of testing, PPS identified two hardware problems that prevented completion of Phase II testing of the prototype converters, including demonstration of full power operation. PPS has investigated these problems and identified the actions necessary to correct both problems. The problems and solutions are summarized below.

Fiber Optic Triggering System in High Voltage Tank
A fiber optic network is used to trigger the solid state insulated gate bipolar transistors (IGBTs) switches inside the high voltage tank. Testing revealed problems with the triggering timing and reliability of this fiber system. Investigation determined that the lenses used in the fiber optic system exhibit excessively high signal loss, causing the observed timing and reliability issues. PPS has identified and tested different lenses, and is proceeding to replace the lenses in both prototype converters to solve this problem.

**IGBT Switches in High Voltage Tank**

The IGBT switches in the high voltage tank were found to enter thermal runaway when the prototype converter is operated at low power levels in inverter mode. Investigation has determined that these switches do not perform in accordance with the manufacturer's specifications. Consultations with the manufacturer have not produced an acceptable remedy, and PPS has concluded that these IGBTs cannot be used for this application. PPS has identified alternate IGBTs that meet the technical and economic criteria of this project, and is proceeding to upgrade the converters with these switches. Because the switches operate at a different voltage than the original switches and have a different form factor, redesign of the high voltage stage boards is necessary.

This report presents PPS' final deliverables for converter specification, design, and test plan under Phase II of the HVDC technology development program. Because of the hardware problems identified, PPS has not yet completed converter testing. Testing is on hold pending completion of the corrective actions for the two problems identified in testing.

PPS continues to work on the hardware modifications needed to correct these two problems. Due to the long lead time for the new IGBT switches, the converter modifications and testing is not expected to be completed until late 2012. PPS will issue a supplemental report detailing the results of final Phase II testing when testing is completed. This supplemental report and the fully operational converters will be PPS' final deliverable under Phase II.
SECTION 2: HVDC CONVERTER DESIGN

1.0 SPECIFICATIONS

1.1 HVDC CONVERTER APPLICATION AND OPERATION

The HVDC converter is a 1-MW power converter capable of bidirectional power conversion between three-phase 480 VAC and 50 kV HVDC. The converter will change AC power to DC power and back again to AC at the receiving community. It is also possible to scale this system to transfer larger amounts of power.

1.2 PERFORMANCE SPECIFICATIONS

The following tables have been taken from the “1MW Alaska HVDC System Specification” (Revision 1.1, September 19, 2011) document prepared by PPS. These tables encompass the set of specifications that describe the HVDC converter to be used in a 1-MW, 50-kV HVDC link to provide bidirectional power flow between remote villages in Alaska. All aspects of the converter design are addressed in these tables.

<table>
<thead>
<tr>
<th>Performance</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous Apparent DC Power</td>
<td></td>
<td>1</td>
<td></td>
<td>MW</td>
<td>Rated (60 °C)</td>
<td>PIFR: Table 4-1</td>
</tr>
<tr>
<td>Allowable Overload</td>
<td></td>
<td></td>
<td>120</td>
<td>%</td>
<td>For 10 seconds</td>
<td>Industry standard</td>
</tr>
<tr>
<td>Converter Unit Start-up Time</td>
<td></td>
<td></td>
<td>1</td>
<td>seconds</td>
<td></td>
<td>Polarconsult review</td>
</tr>
<tr>
<td>Converter Power Flow Direction Change Time</td>
<td></td>
<td></td>
<td>1</td>
<td>seconds</td>
<td>Power reversal from either AC supplied or DC supplied</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Transient Response</td>
<td></td>
<td></td>
<td>300</td>
<td>μs</td>
<td>Response to 10%-90% power step</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Peak Efficiency Target</td>
<td></td>
<td></td>
<td>97</td>
<td>%</td>
<td>At 30% Power</td>
<td>PIFR: Table 3-2</td>
</tr>
</tbody>
</table>

Table 1: Overall Performance
<table>
<thead>
<tr>
<th>Software</th>
<th>Spec (P1FR: 3.2.1.1 [With Correction])</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid-tied Mode (Receiving Village)</td>
<td>DC to AC (Receiving Village) where additional generation source is present</td>
</tr>
<tr>
<td>Microgrid Mode (Receiving Village)</td>
<td>DC to AC (Receiving Village) where additional generation source is not present</td>
</tr>
<tr>
<td>Rectifier Mode (Transmitting Village)</td>
<td>AC to DC conversion</td>
</tr>
</tbody>
</table>

**Table 2: Operating Modes**

<table>
<thead>
<tr>
<th>DC Interconnection</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Unit</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC Voltage</td>
<td>45</td>
<td>50</td>
<td>55</td>
<td>kV</td>
<td></td>
<td>Phase 1 Final Report – August 2009, P1FR: Table 4-1</td>
</tr>
<tr>
<td>DC Current</td>
<td>18.18</td>
<td>20.00</td>
<td>22.22</td>
<td>ADC</td>
<td>Rated power (1 MW)</td>
<td>Calculated from DC Voltage</td>
</tr>
<tr>
<td>DC Voltage Regulation</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>%</td>
<td></td>
<td>PPS Design</td>
</tr>
<tr>
<td>DC Voltage Ripple</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>%</td>
<td></td>
<td>PPS Design</td>
</tr>
<tr>
<td>DC Current Ripple</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>%</td>
<td>External inductance may be required to meet this specification</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Overcurrent Protection Requirement</td>
<td>-</td>
<td>-</td>
<td>28</td>
<td>A</td>
<td>Software-based protection will limit DC fault energy*</td>
<td>P1FR: 4.4.3: Fuses only to be used where probability of opening is very low</td>
</tr>
<tr>
<td>Lightning Protection</td>
<td>-</td>
<td>-</td>
<td></td>
<td></td>
<td>External surge protection by customer</td>
<td></td>
</tr>
<tr>
<td>Rated Voltage</td>
<td>-</td>
<td>-</td>
<td>60</td>
<td>kV</td>
<td>IEC 60099-4 is a minimum, but additional tests may be performed depending on construction (e.g., CIGRE 33/14-05, IEC TS 60071-5)</td>
<td>PPS Requirement</td>
</tr>
</tbody>
</table>

* Overcurrent protection will only operate to prevent continuously feeding a DC fault by ceasing operation. Stored energy in the capacitor will still be liable to discharge into DC fault.

**Table 3: HVDC Electrical Specifications**
<table>
<thead>
<tr>
<th>AC Interconnection - Grid-tied</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Phase Voltage</td>
<td>432</td>
<td>460</td>
<td>526</td>
<td>V&lt;sub&gt;me&lt;/sub&gt;, L-L</td>
<td>UL-1741:2005 (IEEE 1547)</td>
<td></td>
</tr>
<tr>
<td>AC Line Current</td>
<td>1127</td>
<td>1240</td>
<td>1378</td>
<td>A&lt;sub&gt;me&lt;/sub&gt;, L-N</td>
<td>Max is derived from rated DC output power (1 MW) at min AC voltage (432 V) with 97% efficiency</td>
<td></td>
</tr>
<tr>
<td>AC Frequency</td>
<td>57</td>
<td>60</td>
<td>60.5</td>
<td>Hz</td>
<td>UL-1741:2005 (IEEE 1547)</td>
<td></td>
</tr>
<tr>
<td>Grid-tied Power Factor (PF)</td>
<td>±0.08</td>
<td>1</td>
<td>-</td>
<td>PF</td>
<td>When power &gt; 20% rated</td>
<td></td>
</tr>
<tr>
<td>Grid-tied Total Harmonic Distortion</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>% (f&lt;sub&gt;fund&lt;/sub&gt;)</td>
<td>Percent fundamental</td>
<td></td>
</tr>
<tr>
<td>Allowable Voltage Imbalance</td>
<td>-</td>
<td>-</td>
<td>12</td>
<td>%</td>
<td>Voltage unbalance tested in IEEE 1547.1 abnormal voltage</td>
<td></td>
</tr>
<tr>
<td>Overcurrent Protection Requirement</td>
<td>-</td>
<td>-</td>
<td>800</td>
<td>A</td>
<td>Thermal-magnetic breaker with shunt bhp installed for each 500-kW unit</td>
<td></td>
</tr>
<tr>
<td>Surge Protection (Line-Ground) Voltage</td>
<td>-</td>
<td>400</td>
<td>480</td>
<td>V&lt;sub&gt;cr&lt;/sub&gt;, VPR</td>
<td>Operating voltage VPR per UL 1449 3rd ed.</td>
<td></td>
</tr>
<tr>
<td>Surge Protection (Line-Ground) Withstand Current</td>
<td>-</td>
<td>-</td>
<td>140</td>
<td>kA</td>
<td>8/20 ms surge pulse (NEMA LS-1)</td>
<td></td>
</tr>
<tr>
<td>Surge Protection (Line Line)</td>
<td>-</td>
<td>-</td>
<td>510</td>
<td>V</td>
<td>10/350 lightning pulse (IEC 61643-1)</td>
<td></td>
</tr>
</tbody>
</table>

* Additional site-specific lightning protection may be required to be installed by the customer.

**Table 4: AC – Grid-tied Operation**
### Table 5: AC – Microgrid Operation

<table>
<thead>
<tr>
<th>Control Power</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage</td>
<td>-</td>
<td>120</td>
<td>-</td>
<td>V_{lim} L-L</td>
<td>4,200 lbs per 500 kW HV tank</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Current</td>
<td>-</td>
<td>-</td>
<td>15</td>
<td>A</td>
<td>Per 500 kW tank</td>
<td>PPS Design</td>
</tr>
</tbody>
</table>

Table 6: External Control Power (Required for “Black Start”)
<table>
<thead>
<tr>
<th>Packaging</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight</td>
<td>-</td>
<td>-</td>
<td>2x4200</td>
<td>lbs</td>
<td>4,200 lbs per 500 kW HV tank</td>
<td>P1FR. 4.2</td>
</tr>
<tr>
<td>Lid Assembly Weight</td>
<td>-</td>
<td>-</td>
<td>700</td>
<td>lbs</td>
<td>Per 500 kW tank</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Max Lateral Dimension</td>
<td>-</td>
<td>-</td>
<td>88Wx38D</td>
<td>inches</td>
<td>Per 500 kW HV tank</td>
<td>P1FR. 4.2</td>
</tr>
<tr>
<td>Max Height</td>
<td>-</td>
<td>-</td>
<td>59.25</td>
<td>inches</td>
<td>Per 500 kW HV tank</td>
<td>P1FR. 4.2</td>
</tr>
<tr>
<td>Vertical Clearance</td>
<td>-</td>
<td>-</td>
<td>120</td>
<td>inches</td>
<td>Does not include lifting harness or crane height</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Endosure Rating</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>IEC 1/NEMA 4</td>
<td>Industry standard</td>
</tr>
<tr>
<td>HVDC Power Interface</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Top entry</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Power Interface to LV Endosure</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1000W/8kHz/700A, with bus termination on top of tank</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Cooling Method</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Mineral oil, natural convection</td>
<td>PPS Design</td>
</tr>
</tbody>
</table>

Table 7: HVDC Tank Assembly Mechanical Specifications
<table>
<thead>
<tr>
<th>Packaging</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight</td>
<td>-</td>
<td>-</td>
<td>2,200</td>
<td>lbs</td>
<td>Per 500 kV LV Enclosure</td>
<td>P1FR: 4.2</td>
</tr>
<tr>
<td>Max Dimension Lateral</td>
<td>-</td>
<td>-</td>
<td>88'H x 88'W x 42'D</td>
<td>inches</td>
<td>Per 500 kV LV Enclosure</td>
<td>P1FR: 4.2</td>
</tr>
<tr>
<td>Conduit Entry - 480 VAC</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
<td>600 V, with top entry</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Power Interface to HV Tank</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
<td>1000 V/8 kHz/700 A, with bus termination on top of enclosure</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Control Interface to HV Tank</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
<td>From top entry:</td>
<td>PPS Design</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>- 9x1-mm fiber optic</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>- 24V control power</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>- Current sensor feedback</td>
<td></td>
</tr>
<tr>
<td>Environmental Class</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
<td>NEMA 3R for enclosure and 4 for controls sub-enclosure</td>
<td>Industry Standard</td>
</tr>
<tr>
<td>Cooling Method LVAC Bridge</td>
<td>-</td>
<td>-</td>
<td>6 x 200</td>
<td>m³/hr</td>
<td>Forced air cooling</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Cooling Method LVDC Bridge</td>
<td>-</td>
<td>-</td>
<td>4 x 280</td>
<td>m³/hr</td>
<td>Forced air cooling</td>
<td>PPS Design</td>
</tr>
</tbody>
</table>

Table 8: LV Enclosure Mechanical Specifications
Table 9: Environmental Considerations

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local HMI</td>
<td>• LCD Display</td>
</tr>
<tr>
<td></td>
<td>• Touchscreen pushbuttons</td>
</tr>
<tr>
<td></td>
<td>• Local/Remote control</td>
</tr>
<tr>
<td>Local FC (on front door below HMI)</td>
<td>• Ethernet via RJ45 Connector #1</td>
</tr>
<tr>
<td>Remote Users via Web</td>
<td>• Ethernet via RJ45 Connector #2</td>
</tr>
<tr>
<td>External User Interface</td>
<td>• 2x Analog input, 0-10 VDC</td>
</tr>
<tr>
<td></td>
<td>• 2x Analog output, 0-10 VDC &amp; 4-20 mA</td>
</tr>
<tr>
<td></td>
<td>• 2x Digital input</td>
</tr>
<tr>
<td></td>
<td>• 2x Digital output</td>
</tr>
</tbody>
</table>

Table 10: Communications Interface Specifications

* No secondary oil containment required. Fire detection/protection for the oil-filled indoor transformer tank will be covered under the building maintenance and fire protection policies and procedures.
<table>
<thead>
<tr>
<th>External Signal Interface</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Analog Input Range</td>
<td>0</td>
<td>-</td>
<td>10</td>
<td>VDC</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Impedance</td>
<td>100</td>
<td>-</td>
<td>-</td>
<td>kΩ</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Input Quantity</td>
<td>-</td>
<td>-</td>
<td>2</td>
<td>-</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Input Mapping</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Power command, converter mode</td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Output Range</td>
<td>0</td>
<td>-</td>
<td>10</td>
<td>VDC</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Output Current</td>
<td>-</td>
<td>-</td>
<td>20</td>
<td>mA</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Output Range (Mode)</td>
<td>4</td>
<td>-</td>
<td>20</td>
<td>mA</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Output Impedance</td>
<td>-</td>
<td>-</td>
<td>500</td>
<td>Ω</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Quantity</td>
<td>-</td>
<td>-</td>
<td>2</td>
<td>-</td>
<td></td>
<td>PPS Standard</td>
</tr>
<tr>
<td>Analog Mapping</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Power command, DC link voltage, AC Line Voltage, AC Line Current</td>
<td>PPS Standard</td>
</tr>
</tbody>
</table>

Table 11: External I/O Interface Specifications
### Table 12: Functional Specifications

The system will have a Java-based GUI. The GUI will be accessible through a TCP/IP connection over Ethernet using a standard Web browser.

The interface will contain the following pages:

- **Login**: The login page will contain fields for a user name and password. There will be three user levels available: ‘User’, (not password protected), one for a general user ‘Maintenance’ and one for (PPS) personnel ‘Factory’.

- **Configuration**: This page will contain a list of all configuration parameters in the system. The parameters will be organized in submenus.

- **Set System Clock**: This page will allow a user to set the system clock that is used to generate time stamps for diagnostic purposes.

- **Control/Status**: This page will contain "On" and "Off/Reset" buttons, as well as high-level monitoring values such as voltages, currents, power, and temperatures.

- **Save/Load Profile**: This page will allow a user to save all configuration parameters into a file or load them back into the system.

- **Change Password**: This page will allow a user to change the password.

- **Data Log**: This page will allow a user to download the diagnostic data to a personal computer.
### Table 13: Safety Features

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inrush Current Protection</td>
<td>Capacitor Precharge System from AC Side</td>
</tr>
<tr>
<td>Unintentional Island Detection (at Transmitting Village)</td>
<td>Current Vector Variation, (meets UL-1741)</td>
</tr>
</tbody>
</table>

### Table 14: Security Protection

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Security</td>
<td>Protected access levels</td>
</tr>
<tr>
<td></td>
<td>• User (no password)</td>
</tr>
<tr>
<td></td>
<td>• Maintenance (password #1)</td>
</tr>
<tr>
<td></td>
<td>• Factory (password #2)</td>
</tr>
</tbody>
</table>

The type of communications that will be used will be determined on a project-specific basis, and will depend on the cost, reliability, technical limitations, and logistics of the available options. Typical options will include:

- **Use of existing communications networks** (fiber optic, copper, microwave, or satellite networks).
- **Including a dedicated communications circuit** with the HVDC transmission system (fiber optic or copper circuit).
- **Using a carrier-type transmitter system** to induce a communications signal onto the power conductor.

The communication protocol of the units would be Modbus from the unit to a Distributed Network Protocol 3 converter box, which would then transmit in International Electrotechnical Commission (IEC) 61850 or other standard industry communication protocol.
<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Operating Faults</td>
<td>• Over/Undervoltage (UL compliant)</td>
</tr>
<tr>
<td></td>
<td>• Over/Underfrequency (UL compliant)</td>
</tr>
<tr>
<td></td>
<td>• Overcurrent</td>
</tr>
<tr>
<td></td>
<td>• AC Overload</td>
</tr>
<tr>
<td>DC Operating Faults</td>
<td>• Over/Under Voltage</td>
</tr>
<tr>
<td></td>
<td>• Over Current</td>
</tr>
<tr>
<td></td>
<td>• DC Overload</td>
</tr>
<tr>
<td>Line Faults (dead short)</td>
<td>• DC</td>
</tr>
<tr>
<td></td>
<td>• + to - Bus Fault</td>
</tr>
<tr>
<td></td>
<td>• AC</td>
</tr>
<tr>
<td></td>
<td>• 1 Phase Line-to-Line Fault</td>
</tr>
<tr>
<td></td>
<td>• Bolted Fault (all 3 phases faulted)</td>
</tr>
<tr>
<td>AC Ground Faults (dead short)</td>
<td>• 1 Line to Ground Fault</td>
</tr>
<tr>
<td></td>
<td>• 2 Lines to Ground Fault</td>
</tr>
<tr>
<td></td>
<td>• All 3 Phases to Ground Fault</td>
</tr>
<tr>
<td>Internal Operating Faults</td>
<td>• High-Voltage Stage Trigger Failure</td>
</tr>
<tr>
<td></td>
<td>• DC Bus Overvoltage</td>
</tr>
<tr>
<td></td>
<td>• DC Bus Overcurrent</td>
</tr>
<tr>
<td></td>
<td>• Overtemperature</td>
</tr>
<tr>
<td></td>
<td>• Low Temperature</td>
</tr>
<tr>
<td>Software Faults</td>
<td>• Boot-up Fault</td>
</tr>
<tr>
<td></td>
<td>• Calibration Load Fault</td>
</tr>
<tr>
<td></td>
<td>• Grid Synchronization Fault</td>
</tr>
<tr>
<td>Communication Faults</td>
<td>• Analog Signal Loss</td>
</tr>
<tr>
<td></td>
<td>• Front Panel Interface Communication Loss</td>
</tr>
<tr>
<td>User-generated Faults</td>
<td>• User-defined Trip</td>
</tr>
<tr>
<td></td>
<td>• External Trip</td>
</tr>
<tr>
<td></td>
<td>• Maximum Number of Retries</td>
</tr>
</tbody>
</table>

Table 15: Fault Protection
### Table 16: Standard Compliance

<table>
<thead>
<tr>
<th>Item</th>
<th>Conditions/Notes</th>
<th>Source/Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installation</td>
<td>The NESC covers utility facilities up to the service point (of the load). The unit should be installed per Section 12 - Installation and maintenance of equipment.</td>
<td>ANSI/IEEE C2-2007 (“The NESC”): Section 1-011 Scope (E) FFIR: 3.1.5</td>
</tr>
<tr>
<td>Inverter Mode – Grid-tied</td>
<td>When acting as a Distributed Resource (providing power to an energized grid), inverter will comply with IEEE 1547.1 Section 5 Type Test criteria and disconnect AC at PCC if abnormal conditions detected.</td>
<td>PPS Design</td>
</tr>
<tr>
<td>Inverter Mode – Microgrid</td>
<td>Inverter will monitor voltage and frequency limits set by IEEE 1547.1 Section 5.2 and 5.3 and notify user when local demand causes supply to go outside these limits.</td>
<td>PPS Design</td>
</tr>
</tbody>
</table>

### Table 17: Maintenance Frequency

Recommended routine maintenance activities for the oil-filled high voltage transformer tank include:

- Regular service will check high-voltage (HV) transformer tank oil quality, pressure, and possible leaks at oil sampling device.
- Oil sampling/service will be notified for oil replacement/leaks repair.
- See Web site [www.weidmann-diagnostics.com](http://www.weidmann-diagnostics.com) for a prospective service provider.
### Table 18: List of Least Replaceable Units

<table>
<thead>
<tr>
<th>Unit</th>
<th>MTBF (Yrs.)</th>
<th>MTTR (Hrs.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDC Bridge (single unit)</td>
<td>25</td>
<td>6</td>
</tr>
<tr>
<td>HF Transformer</td>
<td>50</td>
<td>6</td>
</tr>
<tr>
<td>LVAC Bridge</td>
<td>25</td>
<td>3</td>
</tr>
<tr>
<td>LVDC Bridge</td>
<td>25</td>
<td>3</td>
</tr>
<tr>
<td>LV Bridge Blowers</td>
<td>4</td>
<td>1.5</td>
</tr>
<tr>
<td>Control Components</td>
<td>5</td>
<td>3</td>
</tr>
</tbody>
</table>

#### 2.0 DESIGN

PPS follows extensive design procedures for the development of new products that meet specifications and provide simple and cost-effective solutions to design problems. The design process starts with the development of performance specifications that meet application and performance expectations. The selection of power electronics topology and control algorithms is the next step before verifying these concepts through computer-based simulations and analyses. Once the concept is verified, the design of hardware and software begins along with developing hardware and software design documentation. Detail designs follow the design documentation that produces the detail parts drawings, subassembly/final assembly drawings, bill of materials (BOM), wiring diagrams, and wire harnesses. The design goes through a Preliminary Design Review and Final Design Review before procurement starts. The following section provides details of the HVDC converter design.

#### 2.1 CONVERTER DESIGN OVERVIEW

##### 2.1.1 HVDC Network Topology

The HVDC power converter can be installed either as a dedicated link or as part of a multi-terminal direct current (MTDC) network. Network communication will be required to ensure that all of the converters on the network are operating in compatible modes, sharing information such as:

- Grounding polarity;
- DC voltage and current/power monitoring; and
- Converter operating or faulted status, including fault codes.

##### 2.1.2 HVDC Transmission Method

The HVDC converter being developed by PPS in this phase may be installed in an HVDC network that can transmit power through cables with positive, negative, or both polarities; the current may be returned using either the earth or a metallic connection.

A monopolar single-wire earth return configuration is shown on Figure 1.
The HVDC Converter consists of two 500-kW modules in parallel (see Figure 2), which are also capable of operating independently for optimum efficiency and reliability. Each 500-kW module converts 480 V input into 50 kV DC. The converter uses IGBT switching technology and features a high-efficiency, high-frequency (HF) voltage transformer.
2.2 **Power and Control Architecture**

The system will be designed using two separate sections because of size, weight, portability, and transport concerns. One section will be air-cooled and installed in a standard industrial enclosure and will meet the environmental specification. This is shown on Figure 3. Figure 4 shows the accompanying section, which will be an oil-cooled tank containing the step-up transformer and associated HV bridge. Figure 5 shows the overall control topology, which is simplified to illustrate the control signals that are sent to each bridge, and the voltage and current sensors, which provide feedback information for closed-loop control and fault detection.

![Diagram of HVDC Transformer Tank: Power Block Schematic](image)

*Figure 3: HVDC Transformer Tank: Power Block Schematic*
2.3 MECHANICAL DESIGN

Figure 6: LVAC Enclosure: Mechanical Layout

Figure 6 shows the power converter’s low-voltage alternating current (LVAC) enclosure with its doors open and the control compartment cover removed. This enclosure is designed for outdoor installations using a National Electrical Manufacturers Association (NEMA) 3R rated cabinet. It is anticipated that the unit will be installed inside a power plant or other enclosure with semi-controlled operating conditions. The LVAC enclosure is made from 14-gauge low-carbon steel and painted American National Standards Institute (ANSI) 61 gray to withstand the weather for a service life of up to 50 years. The cabinet design includes a structural frame and back panel to support the weight of components and to handle any excessive stress encountered during shipping. The layout of the components inside is optimized for even weight distribution and for establishment of the lowest possible center of gravity. It was also optimized for even air flow through the cabinet to maintain thermal stability. The cabinet is provided with a reinforced steel base that has 12 mounting holes. There are also 4 lifting eye-hooks at the top of the cabinet for loading and unloading during transportation. The lifting eye-hooks are removable to reduce the overall height of the cabinet and clear doorways. The enclosure exhaust plenum and wiring conduit are also removed during transportation. There are 12 bolt-down mounting holes in the base for the permanent installation of the enclosure onto a concrete foundation to meet requirements of seismic risk zone 4, as tested per CC-ES-AC 156.

Cabinet size: 66"W x 42"D x 66"H;

Cabinet weight: Approximately 2,200 pounds.
Figure 7 shows the HVDC Transformer tank assembly with the tank lid and attached transformer and power electronics components lifted for clear view. The tank assembly consists of HV IGBT switching stacks combined with a power transformer in the same oil-filled tank. The transformer tank is made of welded construction 12-gauge low-carbon-steel sheets and painted ANSI 81 gray. The tank lid has a supporting structure to mount power electronics components and the HVDC transformer onto it. The lid has hooks for lifting. The transformer tank has separate lifting hooks and eight mounting holes in the base to meet the requirements of seismic risk zone 4.

Tank size: 88"W x 39"D x 59.25"H;

Tank weight with oil: 4,200 pounds.

Transformer oil: Mineral Oil, Cross Trans 206.
Figure 8: LVAC Enclosure: Installation Drawing
(Bottom View)

Figure 9: HVDC Transformer Tank: Installation Drawing
(Bottom View)

1.4 THERMAL DESIGN

1.4.1 LVAC Enclosure
In the power converter’s LVAC enclosure, forced air cooling by blowers that are part of the AC/DC bridge modules and airflow patterns (see Figure 10) were used to determine optimal placement of power electronic components. The number of fans/blowers was minimized, due to the concern that fans are typically the most unreliable components in the system because of their rotating parts. Since each bridge module with blower was installed high or midway on the back panel, ducting of the bridge modules is relatively short. Hot air is exhausted directly out of the cabinet at the top toward the rear, and negative internal pressure is created, which in turn draws outside air through the front and side lower intake vents without use of additional intake fans.

It has been determined that four sets of intake louvers are needed for adequate airflow, two on the doors and two on side walls. Four air filters are to be installed inside the cabinet, one at each louver set, to ensure intake air quality.

![Figure 10: LVAC Enclosure: Airflow Pattern](image)

Overtemperature protection of the LVAC enclosure is provided by temperature sensors on critical components like the bridges and critical electronics. In the transformer tank, temperature sensors are placed on each HV stack board and the transformer itself. The controls will have a threshold setting to send an overtemp warning and then, when a higher threshold is reached, send an overtemp trip.

### 2.4.2 HVDC Transformer Tank

Two studies were done for the HVDC transformer oil tank. The first using 12-plate radiators, the second comparing the 12-plate radiator design with an 8-plate radiator design. Based on the studies and consultation with NWL Inc., the transformer tank manufacturer, PPS has concluded that a 10-plate radiator design will maintain the top oil temperature below 75 °C.

**Oil Temperature Goals:**

Maximum oil temperature of the top oil in the tank:
at 72.6 °C for 100% radiator efficiency,
at 73.7 °C for 68% radiator efficiency.

Maximum oil temperature in the entire system will be near the transformer core material:
at 107.5 °C for 100% radiator efficiency,
at 112.2 °C for 68% radiator efficiency.

<table>
<thead>
<tr>
<th>Factor</th>
<th>Units</th>
<th>Transformer Tank Radiator Configurations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Radiator Efficiency</td>
<td></td>
<td>100% 100% 68% 68%</td>
</tr>
<tr>
<td>Number of Plates</td>
<td></td>
<td>12 8 12 8</td>
</tr>
<tr>
<td>Model Heat Load</td>
<td>watt</td>
<td>1411 1411 1411 1411</td>
</tr>
<tr>
<td>Inlet Temperature</td>
<td>cb</td>
<td>50 50 58 58</td>
</tr>
<tr>
<td>Outlet Mass Flow</td>
<td>kg/sec</td>
<td>0.0 0.0 0.0 0.0</td>
</tr>
<tr>
<td>Outlet Average Velocity</td>
<td>ft/min</td>
<td>4.356 3.188 6.336 4.62</td>
</tr>
<tr>
<td>Radiator Design Loss @ 75 °C</td>
<td>watt</td>
<td>1820 1330 1820 1330</td>
</tr>
<tr>
<td>Thermal Conductivity of Core</td>
<td>W/M-K</td>
<td>9 9 9 9</td>
</tr>
<tr>
<td>Tank Converter Losses</td>
<td>watt</td>
<td>120 156 137 166</td>
</tr>
<tr>
<td>Net Radiator Heat Load</td>
<td>watt</td>
<td>1291 1255 1274 1245</td>
</tr>
<tr>
<td>Oil Temperature Rise</td>
<td>cb</td>
<td>1770.0% 2260.0% 1200.0% 1570.0%</td>
</tr>
<tr>
<td>Actual Radiator Loss</td>
<td>watt</td>
<td>1288.56 1202.32 1284.71 1228.29</td>
</tr>
<tr>
<td>Energy Balance Discrepancy</td>
<td></td>
<td>0.2% 3.7% 0.8% 1.2%</td>
</tr>
<tr>
<td>Outlet Oil Temperature</td>
<td>cb</td>
<td>87.7 72.6 70 73.7</td>
</tr>
<tr>
<td>Maximum Oil Temperature</td>
<td>cb</td>
<td>103.6 108.5 103 106.8</td>
</tr>
<tr>
<td>Maximum Solid Temperature</td>
<td>cb</td>
<td>107.5 112.2 103.7 107.5</td>
</tr>
<tr>
<td>Average Oil Temperature</td>
<td>cb</td>
<td>66.3 71.5 68.7 72.5</td>
</tr>
</tbody>
</table>

Table 19: Thermal Study of 8-Plate vs. 12-Plate Design

The temperature simulation images shown on Figure 11 through Figure 15 assume 68% efficiency and $K_{\text{core}} = 9 \text{ W/MK}$. 
Figure 11: HVDC Transformer Tank: Flow Streamlines
Figure 12: HVDC Transformer Tank: Velocity and Temp of Section through Inlet and Outlet
Figure 13: HVDC Transformer Tank: Velocity and Temp of Section through Co

Figure 14: HVDC Transformer Tank: Surface Temperatures
2.5 PACKAGING

The packaging design places heavy, dense components near the base of the cabinet to keep the center of gravity as low as possible. This will increase stability during shipping and installation and will result in a safer unit. Keeping the weight near the base also reduces the amount of load the walls must support, which can reduce structural cost and weight. The image below shows a top view of the VAC enclosure with the heaviest components shown. After the prototype unit is built and tested, the design and cost of goods of the cabinet can be reviewed for further optimization for manufacturing prior to the production run of the system.
Figure 16: LVAC Enclosure: Approximate Weight Distribution

2.6 Control Design
The HVDC section for the control system consists of the following:

- Stack board triggers originate on the control/peripheral board in the LVAC enclosure.
- Trigger expansion occurs inside the HVDC tank
  - Each trigger is duplicated 16 times (one for each HVDC stack board)
- Status is passed back to the control system via the tank status board
  - Each HVDC board reports status based on:
    - Four IGBT status signals
    - HVDC value within the specified tolerances.
    - IGBT heat sink temperature within the specified tolerances.
- Fiber-optic communication from control/peripheral to tank status
  - Used to set alarm thresholds for HV and temperature monitoring
  - Alarm thresholds are communicated to individual stack boards via the tank status board
- Debugging:
- Each stack board has debug reporting capability (not used for normal system operation)
- The tank status board can request debug info from the stack board
- The stack board can bypass 'normal' status chain and use a universal asynchronous receiver/transmitter (UART) instead when in debug mode.

![Control System: HVDC Trigger Board Diagram](image)

**Figure 18: Control System: HVDC Trigger Board Diagram**

- Optical triggering signals are received from the fiber-optic expansion board
- Using either two or four triggers
  - Legacy design required four triggers (due to Original Equipment Manufacturer trigger board requirements)
  - Existing design optimizes this down to two triggers (one for each "H Bridge Diagonal")
- Additional fiber-optic input for communication
  - Used to set "windows" for HV and temperature monitoring
  - Onboard micro monitors HV via 1000:1 test point and A/D converter
  - Onboard micro monitors one IGBT heat sink temperature via I²C interface
- Desaturation status for each IGBT
- Status output via fiber-optic (to tank status board)
  - Status is single-bit based on four desaturation statuses, HVDC value and IGBT temperature
- Status output can also be used to send debug data
  - Data path is changed to the microcontroller UART via a two-input MUX
  - 3 Byte Status
    - 4 bits for IGBT desaturation
    - 1 bit for HVDC status
    - 1 bit for IGBT temperature status
    - 10 bits HVDC
    - 8 bits temperature
- Fiber-optic expansion provides up to 16 optical inputs
- Provides up to 64 optical outputs
- Outputs are connected in groups of four
- Up to four output groups per input
- Can connect up to 16 outputs to each input
- Only required outputs need to be populated
- Input/output mapping achieved via ‘jumpers’ (0-Ω resistors)
- Design split into base board/plug-in boards
- Plug-in provides two inputs/eight outputs
- Each plug-in connects to all 16 receiver inputs
- Receiver inputs from plug-in are routed to base board
Figure 19: Control System: Fiber-optic Expansion Block Diagram

Figure 20: Control System: Tank Status Block Diagram

- **Upstream Data From:**
  - Peripheral Board to Tank Status Board
  - Tank Status Board to 16 HVDC Trigger Boards

- **Status Bit(s) From:**
  - 16 HVDC Boards to Tank Status Board
  - Tank Status Board to Peripheral Board
3.0 SYSTEM SIMULATION

3.1 INTRODUCTION

System simulations consisting of two HVDC converters were performed as shown in the topologies on Figure 22, Figure 39, Figure 56, and Figure 73. One HVDC converter (the upper unit in Figure 22) is connected to the grid in the first village. In the simulation, this converter operates in rectifier mode, drawing power from the AC grid and outputting power onto the HVDC intertie. The second converter (the lower unit in Figure 22) is simulated to operate as an inverter in either micro-grid or grid-tied mode, drawing power from the HVDC intertie and outputting it to the AC grid in the village either with or without an independent generator present.

Simulations were performed for both interleaved-bridges (original design) – i.e. the two bridges fire alternatingly, thereby doubling the effective switching frequency and improving THD – and single-bridge (updated/current design) units under similar conditions to compare both configurations and confirm the benefits of the single bridge design over the earlier interleaved bridge design. Based on the simulation results presented in this section, both configurations meet the required system specifications. While interleaved operation produces lower THD and smaller DC voltage ripple, the single bridge design was selected for this project because it is significantly less expensive.

In this simulation, it is assumed that the first village (rectifying converter) is always regulating the central DC voltage and the second village (inverting converter) is either following the user real and reactive power commands if it is in grid-tied mode (current source mode) or regulating the AC voltage if it is in microgrid mode (voltage source mode). The converter in the first village also performs power factor correction on its AC grid. The result of each simulated scenario is presented in two separate sets of plots. The first set includes high and low voltages over central DC buses; the second set illustrates the AC currents and voltages at each converter.
In addition, the total harmonic distortion (THD) results for both the single- and interleaved-bridge topologies are presented under the steady-state operation sections in all the operation modes. THD results are summarized in a table and individual phase THD plots are included below the tables.

### 3.2 Single-Bridge Unit

#### 3.2.1 Two-Terminal HVDC Intertie in Micro-Grid Mode (Receiving Village in Voltage Source Mode)

In this model, the rectifying converter is connected to the AC grid in the first village and acts as a source for the HVDC intertie bus, and the inverting converter is connected to the three-phase AC-load in the second village as shown on the Figure 22 schematic. The rectifying converter regulates the central DC bus voltage (low-voltage side) and the inverting converter controls the AC voltage in the second village to the nominal value. The grid phase in the source village are assumed to be balanced.

Based on the load connected to the inverter in the second village, the inverter will drain the central HVDC voltage at a certain rate and the rectifier in the first village will feed energy into the HVDC bus to maintain the nominal bus voltage. Note that because of the losses in the transmission circuit, the power input to the HVDC bus at the first village is slightly more than the power drawn from the HVDC bus at the second village.

The system behavior, under steady-state and extreme step-load cases (full load to no load, no load to full load), is presented on Figure 23 through Figure 29 and Figure 32 through Figure 38. THD results are shown in Table 20 and on Figure 30 and Figure 31.

![Figure 22: Schematic used for Simulation with Village #2 in Voltage Source Mode](image-url)
1.1.1.1 Steady-state

The following set of three figures shows the results of using the single-bridge model to simulate high and low voltages over central DC buses.

Figure 23 shows the simulated low-voltage central DC voltages compared between two villages at a 500 kW power transfer level. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. There is a difference of approximately 13 volts direct current (VDC) between the two. Y-axis units are volts and X-axis units are seconds.

![Figure 23: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 24 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage ($p_{VdcHV}$) is the requested voltage, and the voltage ($V_{dc\_HV}$) is the resulting voltage. There is an approximate difference of 500 VDC between the two. Y-axis units are volts and X-axis units are seconds.

![Figure 24: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 25 shows Village #1 grid real (blue) and reactive (red) power and Village #2 load power (green) and nominal power (pink). Note that there is minimal difference between $p_{Pwr}$ (requested power) and $loadPwr$ for Village #2. Y-axis units for Real$Pwr$, load$Pwr$, and $p_{Pwr}$ are watts. Y-axis units for Reactive$Pwr$ are volt-amperes reactive (VAR). X-axis units are seconds.

![Figure 25: Power Comparison between Villages](image)
Figure 25: DC Voltages and Powers Compared between Two Villages
Figure 26 shows the Village #1’s grid phase A, in which voltage and current are 180° out of phase because the unit draws power from the grid. The zero crossings of voltage and current overlap showing a power factor of 1. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 26: Village #1 Grid Phase A Voltage (Blue) and Current (Red)](image)

Figure 27 shows Village #2’s load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 27: Village #2 Load Phase A Voltage (Blue) and Current (Red)](image)

Figure 28 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

![Figure 28: Village #1 3-phase Grid Current](image)

Figure 29 shows all three phases of the load current for Village #2. Y-axis units are amps and X-axis units are seconds.

![Figure 29: Village #2 3-phase Load Current](image)
1.1.1.2 THD

The A, B, and C headings in Table 20 correspond to the A, B, and C designators on Figure 30 and Figure 31. These figures show a set of three THD phase plots (L to R, phases A, B, and C) for Village #1 and Village #2, respectively. The plotting results are summarized in the table.

<table>
<thead>
<tr>
<th>Phase</th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Village 1, THD %</td>
<td>1.35</td>
<td>1.34</td>
<td>1.33</td>
</tr>
<tr>
<td>Village 2, THD %</td>
<td>0.97</td>
<td>0.96</td>
<td>0.96</td>
</tr>
</tbody>
</table>

Table 20: THD Single Bridge Voltage Source Mode
Figure 30. Village #1 (Grid) Harmonic Analysis

Figure 31. Village #2 (Load) Harmonic Analysis
1.1.1.3 **Step-load: 100-0-100%**

The system operates under full-load condition before \( t=0.2 \)s and after \( t=0.4 \)s and under no-load condition in between \( t=0.2 \) and \( t=0.45 \)s.

No load condition is modeled by decreasing the load to take a negligible amount of power instead of removing the load completely. As shown on Figure 35 through Figure 38, the system regulates the AC voltage at nominal value during the no-load situation, too.

Figure 32 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. Y-axis units are volts and X-axis units are seconds.

![Figure 32: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 33 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (\( pVdcHV \)) is the requested voltage, and the voltage (\( Vdc_HV \)) is the resulting voltage. Y-axis units are volts and X-axis units are seconds.

![Figure 33: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 34 shows Village #1 grid real (blue) and reactive (red) power and Village #2 load power (green). Y-axis units for RealPwrV1 and loadPwrV2 are watts. Y-axis units for ReactivePwrV1 are VAR. X-axis units are seconds.
Figure 34: DC Voltages and Powers Compared between Two Villages

Figure 35 shows the Village #1’s grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

Figure 35: Village #1 Grid Phase A Voltage (Blue) and Current (Red)

Figure 36 shows Village #2’s load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

Figure 36: Village #2 Load Phase A Voltage (Blue) and Current (Red)

Figure 37 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

Figure 37: Village #1 3-phase Grid Current

Figure 38 shows all three phases of the load current for Village #2. Y-axis units are amps and X-axis units are seconds.
Figure 38: Village #2 3-phase Load Current
3.2.2 Two Terminal HVDC Intertie in Grid-Tied Mode (Receiving Village in Current Source Mode)

In this model, both the villages are generating electricity, and the HVDC intertie is transferring power from village 1 to village 2. The converter in village 1 is in rectifier mode, and regulates the central HVDC voltage, and the converter in village 2 is in grid-tied inverter mode, and follows a real and reactive user power command.

Based on the amount of the power requested from the second converter, this village will either drain (if power goes to the second converter following a positive power command) or feed (if power comes from the second converter following a negative power command) the central HVDC voltage. The converter at village 1 regulates the HVDC bus by adding or taking power from the HVDC bus as needed to regulate the HVDC voltage. Depending on conditions, this may result in power flow from village 2 to village 1.

Note that because of the losses in the transmission circuit, the first village power is slightly different from that of the second village.

The system behavior, under steady-state and extreme cases of step-power-command, is presented on Figure 40 through Figure 46 and Figure 49 through Figure 53. THD results are shown in Table 22 and on Figure 47 and Figure 48.
1.1.1.4 Steady State

Figure 40 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. There is a difference of approximately 13 VDC between the two. Y-axis units are volts and X-axis units are seconds.

Figure 40: Low-Voltage Central DC Voltages Compared between Two Villages

Figure 41 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (\(pVdcHV\)) is the requested voltage, and the voltage (\(Vdc_{HV}\)) is the resulting voltage. There is an approximate difference of 500 VDC between the two. Y-axis units are volts and X-axis units are seconds.

Figure 41: High-Voltage Central DC Voltage: Requested and Actual

Figure 42 shows Village #1 grid real (blue) and reactive (green) power, Village #2 real (red) and reactive (pink) and Village #2 real (black), reactive (blue x) power commands. Y-axis units for P1, P2, and Pcmd are watts. Y-axis units for Q1, Q2, and Qcmd are VAR. X-axis units are seconds.

Figure 42: DC Voltages and Powers Compared between Two Villages
Figure 43 shows the Village #1’s grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

**Figure 43: Village #1 Grid Phase A Voltage (Blue) and Current (Red)**

Figure 44 shows Village #2’s load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

**Figure 44: Village #2 Grid Phase A Voltage (Blue) and Current (Red)**

Figure 45 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

**Figure 45: Village #1 3-phase Grid Current**

Figure 46 shows all three phases of the grid current for Village #2. Y-axis units are amps and X-axis units are seconds.

**Figure 46: Village #2 3-phase Grid Current**
### 1.1.1.5 THD

The A, B, and C headings in Table 21 correspond to the A, B, and C designators on Figure 47 and Figure 48. These figures show a set of three THD phase plots (L to R, phases A, B, and C) for Village #1 and Village #2, respectively. The plotting results are summarized in the table.

<table>
<thead>
<tr>
<th>Phase</th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Village 1, THD %</td>
<td>1.35</td>
<td>1.33</td>
<td>1.34</td>
</tr>
<tr>
<td>Village 2, THD %</td>
<td>2.32</td>
<td>2.27</td>
<td>2.36</td>
</tr>
</tbody>
</table>

![Table 21: THD Single Bridge Current Source Mode](image)
Figure 47. Village #1 THD Test Plots

A:  
B:  
C:  

Figure 48. Village #2 THD Test Plots
1.1.1.6  Command: (Real Power 0%: 100%: 0%)

The system operates under 0 power before $t=0.2s$ and after $t=0.4s$, and under full-power condition, the first village feeds the second village with 100% of power in between $t=0.2$ and $t=0.4s$.

Figure 49 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. Y-axis units are volts and X-axis units are seconds.

![Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 50 shows high voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage ($pVdcHV$) is the requested voltage, and the voltage ($Vdc_HV$) is the resulting voltage. Y-axis units are volts and X-axis units are seconds.

![High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 51 shows Village #1 grid real (blue) and reactive (green) power, Village #2 real (red) and reactive (pink) and Village #2 real (black), reactive (blue x) power commands. Y-axis units for $P_1$, $P_2$, and $P_{cmd}$ are watts. Y-axis units for $Q_1$, $Q_2$, and $Q_{cmd}$ are VAR. X-axis units are seconds.
Figure 51: DC Voltages Compared between Two Villages
Figure 52 shows the Village #1's grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 52: Village #1 Grid Phase A Voltage (Blue) and Current (Red)](image)

Figure 53 shows Village #2's load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 53: Village #2 Grid Phase A Voltage (Blue) and Current (Red)](image)

Figure 54 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

![Figure 54: Village #1 3-phase Grid Current](image)

Figure 55 shows all three phases of the grid current for Village #2. Y-axis units are amps and X-axis units are seconds.

![Figure 55: Village #2 3-phase Grid Current](image)

### 3.3 Interleaved-Bridges Unit

The same simulation scenarios that were explained in Section 6.2 are performed in this section with parallel interleaved units.
3.3.1 Two-Terminal HVDC Intertie in Micro-Grid Mode (Receiving Village in Voltage Source Mode)

In this model, the HVDC converter in the first village works in rectifier mode, and acts as a source for the HVDC intertie bus. The HVDC converter in the second village works in microgrid inverter mode, generating the AC grid that serves the three-phase AC loads on the village distribution system. The rectifier unit regulates the central DC-bus voltage (low-voltage side), and the inverter unit controls the AC-load voltage to the nominal value.

Based on the load in the second village, the inverter will drain the central HVDC voltage at a certain rate and the converter in rectifier mode in the first village will fill the HVDC bus again. Note that because of the losses in the transmission circuit, the power input at the first village is slightly greater than the power output at the second village.

The system behavior under steady-state and extreme case of step-load (full load to no load, no load to full load), is presented on Figure 57 through Figure 63 and Figure 66 through Figure 72. THD results are shown in Table 22 and on Figure 64 and Figure 65.

Figure 56: Interleaved bridges, Village#2 in Voltage Source Mode
1.1.1.7 Steady State

Figure 57 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. There is a difference of approximately 13 VDC between the two. Y-axis units are volts and X-axis units are seconds.

![Figure 57: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 58 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (pVdcHV) is the requested voltage, and the voltage (Vdc_HV) is the resulting voltage. Y-axis units are volts and X-axis units are seconds.

![Figure 58: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 59 shows Village #1 grid real (blue) and reactive (red) power and Village #2 load power (green), nominal power (pink). Note that there is minimal difference between pPwr (requested power) and loadPwr for Village #2. Y-axis units for RealPwr[V1], loadPwr[V2], and pPwr are watts. Y-axis units for ReactivePwr[V1] are VAR. X-axis units are seconds.

![Figure 59: DC Voltages and Powers Compared between Two Villages](image)
Figure 60 shows the Village #1’s grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 60: Village #1 Grid Phase A Voltage (Blue) and Current (Red)](image)

Figure 61 shows Village #2’s load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 61: Village #2 Load Phase A Voltage (Blue) and Current (Red)](image)

Figure 62 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

![Figure 62: Village #1 3-phase Grid Current](image)

Figure 63 shows all three phases of the load current for Village #2. Y-axis units are amps and X-axis units are seconds.

![Figure 63: Village #2 3-phase Load Current](image)
1.1.1.8 THD

The A, B, and C headings in Table 22 correspond to the A, B, and C designators on Figure 64 and Figure 65. These figures show a set of three THD phase plots (L to R, phases A, B, and C) for Village #1 and Village #2, respectively. The plotting results are summarized in the table.

<table>
<thead>
<tr>
<th>Phase</th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Village 1, THD %</td>
<td>1.09</td>
<td>1.33</td>
<td>1.12</td>
</tr>
<tr>
<td>Village 2, THD %</td>
<td>0.81</td>
<td>0.81</td>
<td>0.82</td>
</tr>
</tbody>
</table>

Table 22: THD Interleaved Bridge Voltage Source Mode
Figure 64. Village #1 THD Test Plots

A: 

B: 

C: 

Figure 65. Village #2 THD Test Plots
1.1.1.9 Step Load: 0-100-0

The system operates under full-load condition before \( t = 0.2\)s and after \( t = 0.4\)s and under no-load condition in between \( t = 0.2 \) and \( t = 0.45\)s.

No-load condition is modeled by decreasing the load to take a negligible amount of power instead of removing the load completely. As shown on Figure 69, the system regulates the AC voltage at nominal value during the no-load situation as well.

Figure 66 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. Y-axis units are volts and X-axis units are seconds.

![Figure 66: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 67 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (pVdcHV) is the requested voltage, and the voltage (Vdc_HV) is the resulting voltage. Y-axis units are volts and X-axis units are seconds.

![Figure 67: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 68 shows Village #1 grid real (blue) and reactive (red) power and Village #2 load power (green). Y-axis units for RealPwrV1 and loadPwrV2 are watts. Y-axis units for ReactivePwrV1 are VAR. X-axis units are seconds.
Figure 68: DC Voltages and Powers Compared between Two Villages
Figure 69 shows the Village #1's grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 69: Village #1 Grid Phase A Voltage (Blue) and Current (Red)](image)

Figure 70 shows Village #2's load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Figure 70: Village #2 Load Phase A Voltage (Blue) and Current (Red)](image)

Figure 71 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

![Figure 71: Village #1 3-phase Grid Current](image)

Figure 72 shows all three phases of the load current for Village #2. Y-axis units are amps and X-axis units are seconds.

![Figure 72: Village #2 3-phase Load Current](image)
Two-Terminal HVDC Intertie in Grid-Tied Mode (Receiving Village in Current Source Mode)

In this model, both villages are connected to the grid. The first unit regulates the central voltage and the second unit follows a real and reactive user power command.

Based on the amount of the power request from the second unit, this village will either drain (if power goes to the second unit following a positive power command) or feed (if power comes from the second unit following a negative power command) the central voltage. The first village regulates the DC bus by either providing (positive power command in the second village) or absorbing (negative power command in the second village) the extra power in the system.

Note that because of the losses in the circuit components, the first village power differs slightly from that of the second village.

System behavior, under steady-state and extreme cases of step-power-command, is presented on Figure 74 through Figure 80 and Figure 83 through Figure 96. THD results are shown in Table 23 and on Figure 81 and Figure 82.

As can be seen in the figures and tables, the system meets all of the specification requirements in this mode of operation.

Figure 73: Interleaved bridges, Village#2 in Current Source Mode
1.1.1.10 Steady State

Figure 74 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. There is a difference of approximately 13 VDC between the two. Y-axis units are volts and X-axis units are seconds.

![Figure 74: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 75 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (pVdcHV) is the requested voltage, and the voltage (Vdc_HV) is the resulting voltage. There is an approximate difference of 500 VDC between the two. Y-axis units are volts and X-axis units are seconds.

![Figure 75: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 76 shows Village #1 grid real (blue) and reactive (green) power, Village #2 real (red) and reactive (pink) and Village #2 real (black), reactive (blue) x power commands. Y-axis units for P1, P2, and Pcmb are watts, Y-axis units for Q1, Q2, and Qcmd are VAR. X-axis units are seconds.

![Figure 76: DC Voltages and Powers Compared between Two Villages](image)
Figure 77 shows the Village #1’s grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

Figure 77: Village #1 Grid Phase A Voltage (Blue) and Current (Red)

Figure 78 shows Village #2’s load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

Figure 78: Village #2 Grid Phase A Voltage (Blue) and Current (Red)

Figure 79 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

Figure 79: Village #1 3-phase Grid Current

Figure 80 shows all three phases of the grid current for Village #2. Y-axis units are amps and X-axis units are seconds.

Figure 80: Village #2 3-phase Grid Current
### THD

The A, B, and C headings in Table 23 correspond to the A, B, and C designators on Figure 81 and Figure 82. These figures show a set of three THD phase plots (L to R, phases A, B, and C) for Village #1 and Village #2, respectively. The plotting results are summarized in the table.

<table>
<thead>
<tr>
<th>Phase</th>
<th>A</th>
<th>B</th>
<th>C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Village 1, THD %</td>
<td>1.23</td>
<td>0.99</td>
<td>1.26</td>
</tr>
<tr>
<td>Village 2, THD %</td>
<td>1.06</td>
<td>1.09</td>
<td>1.02</td>
</tr>
</tbody>
</table>

**Table 23: THD Interleaved-Bridge Current Source Mode**
Figure 81. Village #1 THD Test Plots

Figure 82. Village #2 THD Test Plots
1.1.1.12 **Real Power Command 0%: 100%: 0%**

The system operates under 0 power before t=0.2s and after t=0.4s, and under full-power condition, the first village feeds the second village with 100% of power in between t=0.2 and t=0.4s.

Figure 83 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. Y-axis units are volts and X-axis units are seconds.

![Figure 83: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 84 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (pV/dcHV) is the requested voltage, and the voltage (Vdc_HV) is the resulting voltage. Y-axis units are volts and X-axis units are seconds.

![Figure 84: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 85 shows Village #1 grid real (blue) and reactive (green) power, Village #2 real (red) and reactive (pink) and Village #2 real (black), reactive (blue x) power commands. Y-axis units for P1, P2, and Pcmd are watts. Y-axis units for Q1, Q2, and Qcmd are VAR. X-axis units are seconds.

![Figure 85: DC Voltages and Powers Compared between Two Villages](image)
Figure 86 shows the Village #1’s grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Graph 1: Village #1 Grid Phase A Voltage (Blue) and Current (Red)]

Figure 87 shows Village #2’s load phase A, in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

![Graph 2: Village #2 Grid Phase A Voltage (Blue) and Current (Red)]

Figure 88 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

![Graph 3: Village #1 3-phase Grid Current]

Figure 89 shows all three phases of the grid current for Village #2. Y-axis units are amps and X-axis units are seconds.

![Graph 4: Village #2 3-phase Grid Current]
1.1.1.13 Real Power Command 100%: -100%: 100%

Before t=0.2s and after t=0.4s, the second village takes 100% real power. Between t=0.2s and t=0.4s, the second village feeds the system with 100% real power. The first village balances the power flow under all these conditions.

Figure 90 shows the simulated low-voltage central DC voltages compared between two villages. The DC voltage levels for Village #1 are shown in blue and those for Village #2 in red. Y-axis units are volts and X-axis units are seconds.

![Figure 90: Low-Voltage Central DC Voltages Compared between Two Villages](image)

Figure 91 shows high-voltage central DC voltage (blue) and the nominal high voltage (red). The nominal high voltage (pVdcHV) is the requested voltage, and the voltage (Vdc_HV) is the resulting voltage. Y-axis units are volts and X-axis units are seconds.

![Figure 91: High-Voltage Central DC Voltage: Requested and Actual](image)

Figure 92 shows Village #1 grid real (blue) and reactive (green) power, Village #2 real (red) and reactive (pink) and Village #2 real (black), reactive (blue x) power commands. Y-axis units for P1, P2, and Pcmt are watts. Y-axis units for Q1, Q2, and Qcmd are VAR. X-axis units are seconds.

![Figure 92: DC Voltages and Powers between Two Villages](image)
Figure 93 shows the Village #1's grid phase A, in which voltage and current are 180° out of phase. Y-axis units are in volts and amps. X-axis units are seconds.

Figure 93: Village #1 Grid Phase A Voltage (Blue) and Current (Red)

Figure 94 shows Village #2's load phase A in which voltage and current are in phase. Y-axis units are in volts and amps. X-axis units are seconds.

Figure 94: Village #2 Grid Phase A Voltage (Blue) and Current (Red)

Figure 95 shows all three phases of the grid current for Village #1. Y-axis units are amps and X-axis units are seconds.

Figure 95: Village #1 3-phase Grid Current

Figure 96 shows all three phases of the grid current for Village #2. Y-axis units are amps and X-axis units are seconds.
3.4 Conclusion

During the early stages of this project, the system was designed to have interleaved pulse width modulation units due to high power and high voltage design risk. However, during the modeling and simulation phase, both interleaved and single-unit topologies were modeled.

Simulation showed that the system behavior with both topologies meets the specification requirements with a large margin. Although the THD and DC voltage ripples are smaller in the interleaved units compared with the single-unit topology, they are still acceptable. On this basis, the single unit was chosen for this project since it is significantly less expensive.

4.0 Reliability Analysis

Two mean time between failures (MTBF) analyses were performed on the power converter system to evaluate the expected system reliability. The first study determined that the expected system reliability was unacceptably low, and identified a series of design and component changes that would significantly improve the converter reliability. The second study calculated the MTBF of the prototype power converters to be 5.2 years with a design life of 51.3 years.

Near the end of the Phase II project, the IGBT switches in the high voltage tank were determined to not be suitable for this application. The MTBF and design life stated above reflect conversion to a new Powerex switching component that will address the overheating problem experienced with the IXYS IGBTs used in the prototype converters.

4.1 The Need for MTBF Studies and Its Relevance in Power Electronics

The mean time between failures (MTBF) is a statistical prediction of the elapsed time between failures of a system during operation. An MTBF study provides consumers with an estimated lifetime for the product they are interested in purchasing, within the environment they intend to use it. In utility scale power electronics, MTBF carries increased value as the estimated lifetime of grid-level systems catalyze many of the business and technical processes of the companies that utilize such systems. Providing accurate estimations of system life will be of great benefit to the manufacturer of those systems and those who intend to use them over their lifespan.

4.2 MTBF Measurement Standards and Methodology

The MTBF studies performed on the HVDC power converter by PPS’ MTBF consultant, Amoroso Reliability Associates, LLC (ARA), follow the Telcordia SR-332 standard. This standard allows the use of the parts-count method, a technique that allows for the development of an estimation of the
average life of a whole assembly. This exercise results in a calculated failure rate, denoted FR<sub>x</sub> (where x is a number). The MTBF is calculated from the failure rate as follows:

\[
MTBF = \frac{10000000\text{ hours}}{FR_1 \cdot FR_2 \cdot FR_3 \cdot \ldots \cdot FR_n}
\]

The failure rates of the individual components are determined either by referencing manufacturer data or by using the failure rates provided by the Military Handbook, Reliability Prediction of Electronic Equipment or MIL-HDBK-217. The individual failure rates are then summed to provide the net failure rate of the entire unit.

### Testing Conditions

The test results referenced in this report reflect the predicted life under what is known as Ground, Fixed, Controlled G<sub>B</sub> ρ<sub>C</sub>=1.0 conditions. Under these conditions, the parts are assumed to experience nearly no environmental stresses with optimum engineering operation and maintenance. The NEMA 3R standard that the HVDC power converter is designed to allows for more strenuous operating conditions. However, on the average, the unit will see conditions that are similar to those assumed in the Ground, Fixed, Controlled G<sub>B</sub> ρ<sub>C</sub>=1.0 standard.

### What is Failure?

In this study, failure of the entire power converter can be instigated by the failure of a single component, no matter the component or its function. Despite this, such a failure may not necessarily constitute the failure of the entire unit when operating in the field. As such, the MTBF may well reflect a truncated lifespan if interpreted without a comprehensive maintenance schedule. Such a schedule is contingent upon the completion of the second round of MTBF studies and will be presented later in this report.

#### 4.3 MTBF Goal for Alaska

As per the HVDC power converter specification (Section 4 of this report), the single unit will have an MTEF of 5 years, with a power electronics design life of 50 years.

#### 4.4 MTBF Study Results

##### 4.4.1 Initial Study Results

The first study undertaken by ARA was preliminary. As parts selection was not complete, the study analyzed only the main components, providing a general idea as to the performance of the entire system. This study produced a likelihood of 3.6 years between failures of Alaska systems. Examination of the data revealed that the high failure rate was not a systemic problem. Indeed, the Alaska unit’s poor performance was due to a small number of components, with a single item contributing significantly to the short lifespan. A tabulated list of the components and their estimated MTBF values are provided below:
<table>
<thead>
<tr>
<th>Description/Schematic ID</th>
<th>Part Number</th>
<th>Failure Rate/Unit</th>
<th>Qty.</th>
<th>Failure Rate</th>
<th>MTBF (Hrs.)</th>
<th>MTBF (Yrs.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alaska</td>
<td>N/A</td>
<td>31086.44</td>
<td>1</td>
<td>31086.44</td>
<td>32168.37</td>
<td>3.67</td>
</tr>
<tr>
<td>HVDC Transformer Board/HVDCB1-16</td>
<td>1750-0040</td>
<td>8328.02</td>
<td>16</td>
<td>133248.30</td>
<td>7504.79</td>
<td>0.86</td>
</tr>
<tr>
<td>Diode 4500 V 60A/NA</td>
<td>4801-0001</td>
<td>20.44</td>
<td>64</td>
<td>7847.53</td>
<td>127428.04</td>
<td>14.55</td>
</tr>
<tr>
<td>Strikerb 480 V Surge/VZ1-3</td>
<td>4302-0006</td>
<td>285.39</td>
<td>3</td>
<td>856.17</td>
<td>1187988.60</td>
<td>133.33</td>
</tr>
<tr>
<td>IGBT 4000 V 40A/NA</td>
<td>5105-0005</td>
<td>7.35</td>
<td>64</td>
<td>470.39</td>
<td>2125010.50</td>
<td>242.68</td>
</tr>
<tr>
<td>30651451/LVDC</td>
<td>5105-0006</td>
<td>311.55</td>
<td>1</td>
<td>311.55</td>
<td>3209744.15</td>
<td>368.41</td>
</tr>
<tr>
<td>30651447/LVAC1&amp;2</td>
<td>5105-0007</td>
<td>311.55</td>
<td>1</td>
<td>311.55</td>
<td>3209744.15</td>
<td>368.41</td>
</tr>
<tr>
<td>AC Precharge/CON1</td>
<td>4301-0036</td>
<td>248.70</td>
<td>1</td>
<td>248.70</td>
<td>4053620.48</td>
<td>462.73</td>
</tr>
<tr>
<td>Contactor, AC Normally Open/CON2</td>
<td>4301-0035</td>
<td>248.70</td>
<td>1</td>
<td>248.70</td>
<td>4053620.48</td>
<td>462.73</td>
</tr>
<tr>
<td>FUSE Disconnect 480 VAC 3/SW1</td>
<td>4301-0044</td>
<td>38.75</td>
<td>1</td>
<td>38.75</td>
<td>25806451.61</td>
<td>2945.94</td>
</tr>
<tr>
<td>3-Phase Output Filter Inductor/LAC1-2</td>
<td>1840-0013</td>
<td>17.36</td>
<td>2</td>
<td>34.72</td>
<td>28901329.01</td>
<td>3287.82</td>
</tr>
<tr>
<td>Fuse Holder 1 Pole Ultrasafe</td>
<td>4290-0001</td>
<td>2.4</td>
<td>13</td>
<td>31.2</td>
<td>32051282.05</td>
<td>3658.82</td>
</tr>
<tr>
<td>Resistor 25 Ohm 50W/R1-3</td>
<td>4718-0006</td>
<td>0.14</td>
<td>3</td>
<td>27.41</td>
<td>36481684.46</td>
<td>4164.58</td>
</tr>
<tr>
<td>Resonant Central Cap/CC1-2</td>
<td>1502-0013</td>
<td>0.63</td>
<td>28</td>
<td>17.68</td>
<td>56561764.2</td>
<td>6458.62</td>
</tr>
<tr>
<td>50 kV-800 V TX/TX</td>
<td>5600-0008</td>
<td>17.36</td>
<td>1</td>
<td>17.36</td>
<td>57602658.02</td>
<td>6575.65</td>
</tr>
<tr>
<td>HVDC Input Filter Cap 6uF/NA</td>
<td>1502-0012</td>
<td>0.63</td>
<td>16</td>
<td>10.10</td>
<td>98883087.35</td>
<td>11299.45</td>
</tr>
<tr>
<td>Inductor, 3-Phase Output/LAC3</td>
<td>1840-0012</td>
<td>6.40</td>
<td>1</td>
<td>6.40</td>
<td>158360064.0</td>
<td>17848.18</td>
</tr>
<tr>
<td>Fuse 44/100 A 1000VDC/FS6.1-62 &amp; FS4.1-4.2</td>
<td>4300-0028</td>
<td>1</td>
<td>4</td>
<td>4</td>
<td>250000000.0</td>
<td>28538.81</td>
</tr>
<tr>
<td>Fuse Fast Acting, 800A type</td>
<td>4300-0033</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>333333333.3</td>
<td>38051.75</td>
</tr>
<tr>
<td>Cap, 50uFL-L 3ph Delta/CAC1</td>
<td>1502-0008</td>
<td>2.62</td>
<td>1</td>
<td>2.62</td>
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<td>43618.80</td>
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<td>666666666.7</td>
<td>76103.50</td>
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| Table 24: Initial MTBF Results |
4.4.2 Problem Components

The high-voltage DC board failure rate was a conspicuously high 8328 failures per billion hours, producing an MTBF of 13.7 years each. As the aggregate MTBF of the entire unit is a weighted sum of its components, the 16 units combined produced an MTBF of 10.2 months. The low performance of these components dominated the MTBF estimate of the entire unit. Improving them would significantly improve the performance of the entire system.

4.4.3 Steps to Improve

The breakdown of the performance of individual components allowed PPS to create performance improvement goals for the least reliable components and allowed PPS to correct the MTBF values of various components so that the calculated reliability could be improved to meet the project specification. A 5-year MTBF target spreadsheet was created with new, higher-performance replacement parts and with adjusted failure rates for various other components. See Table 26 for the target spreadsheet. Note that the items in yellow are items that were changed from the first study. Key components that were revised are discussed below.

First, the Strikesorb 480-V surge arrester failure rate was reduced to 0. The surge arrester operates intermittently, under exigent conditions that diverge far from those considered in standard MTBF tests.

Next, the AC precharge fused disconnect and the AC contactor failure rates were adjusted to coincide with values obtained from ABB. These values reflect the expected MTBF under the operating conditions specified by PPS.

Next, the item highlighted in green in Table 26, a high-voltage IGBT module with integrated diode manufactured by Powerex (part number QID4515001), was added as a replacement for part numbers 5105-0005 and 4801-0001, the high-voltage board IGBT and Diode, respectively (highlighted in red). The use of integrated modules containing two IGBTs and two diodes in one package reduces the number of required components per high-voltage board from eight to two. Also, Powerex reports a failure rate of only 50 failures per billion hours of operation at the most, making this module a far better choice than the four IGBT modules and the four diodes.

The use of high-performing IGBT/diode modules in a future revision increased the MTBF of the high-voltage transformer boards significantly when compared to the original design. The failure rates of these boards were updated to reflect this improvement.

Finally, the failure rate of the entire Alaska system was updated. Given a quantity of two units per system, a total system MTBF of 26 years was calculated.

Note: The Alaska system failure rate refers ONLY to the power electronics.
<table>
<thead>
<tr>
<th>Description/Schematic ID</th>
<th>P/N</th>
<th>Failure Rate/Unit</th>
<th>Qty.</th>
<th>Failure Rate</th>
<th>MTBF (Hrs.)</th>
<th>MTBF (Yrs.)</th>
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<td>MTBF (Yrs.)</td>
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Table 25: 5-Year MTBF Goals
4.4.4 Second MTBF Study Results

After incorporating the failure rate corrections highlighted previously, the second study produced unremarkable results. Almost all power electronics component failure rates fell in line with expectations, eliminating a need for further iterations. The MTBF times, in years, for major components within the system can be found in Table 26.

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<th>P/N</th>
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<th>Target for 5-Year MTBF</th>
<th>Subsequent MTBF Study Result</th>
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### Alaska MTBF Comparison

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<th>Subsequent MTBF Study Result</th>
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### Alaska MTBF Comparison

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<th>Subsequent MTBF Study Result</th>
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**Table 26: Alaska MTBF Comparison**

*Note: The design of the power converter changed greatly between the first and second MTBF studies. So much so that direct comparison between the two final MTBF values has limited value. Instead, the control system and power electronic components should be looked at individually, along with the system level MTBF value of approximately 5.7 years, per unit, before corrections.*
<table>
<thead>
<tr>
<th>Description</th>
<th>Number</th>
<th>(hours)</th>
<th>(each)</th>
<th>(years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDCB1-16 Assembly</td>
<td>7005-1400</td>
<td>10</td>
<td>$1,100.00</td>
<td>26.27</td>
</tr>
<tr>
<td>V2.5 Control System</td>
<td>1750-0013</td>
<td>2</td>
<td>$1,350.00</td>
<td>82.39</td>
</tr>
<tr>
<td>MCR 3-way Isolating Amp/AIO1-2</td>
<td>1760-0012</td>
<td>1</td>
<td>$245.00</td>
<td>263.28</td>
</tr>
<tr>
<td>Voltage Transducer/VS1-VS8</td>
<td>4813-0011</td>
<td>1</td>
<td>$70.00</td>
<td>288.59</td>
</tr>
<tr>
<td>PCB6/Tank Status Board</td>
<td>1750-0046</td>
<td>3</td>
<td>$800.00</td>
<td>300.12</td>
</tr>
</tbody>
</table>

**Table 27: Outage Time and Replacement Cost**

The least reliable components tend to be within the control system. However, these components are easily accessible, thus are easy to replace. Last on both lists (lowest reliability) are semiconductor components within the transformer tank. When combined, these components form the HVDCB1-16 assemblies, with an MTBF of approximately 26 years. The lifespan of these assemblies is dominated by the failure rates of the current IXYS IGBTs and Powerex Diodes, part numbers 5105-0005 and 4801-0001, respectively. Redesigning the HVDC board by replacing both components with the Powerex IGBT/Diode component, part number QID4515001, will reduce failure rates such that the MTBF of the HVDC assemblies will increase (see Section 11).
4.4.5 Underperforming Components

Results from the second study showed that a few components failed to meet expectations. The impact of this underperformance varies depending on the specific function of the component and the extent to which the component failed to meet requirements. Therefore, each component needs to be assessed individually.

3-Phase Output Filter Inductor/LAC1-2 (1840-0013): An MTBF of 3,288 years was predicted in the first study and 2,330 years in the second, a difference of 958 years. Significant changes in the design life of the inductor are not expected, but the decrease in MTBF of the individual unit will decrease the MTBF of the whole to a small degree. No corrective action is needed.

50-kV–800-V High Frequency Transformer (5600-0008): An MTBF of 6,576 years was predicted in the first study and 4,659 years in the second, a difference of 1,916 years. As with the 3-phase output filter inductor, the significant changes in design life are expected only to affect the MTBF of the whole unit, not the transformer itself. No corrective action will be needed.

4.5 Prospective Changes and Upgrades

The second study results, combined with the manual adjustments to the MTBF values for individual components and the inclusion of the future transition to the Powerex module (see Section 7.3, Switch Failure Analysis), confirm the integrity of the Alaska design. With an MTBF of 6.2 years and a design life of 51.3 years, the proposed changes to the unit will allow it to meet and exceed requirements, providing a bidirectional inverter that will require minimal maintenance throughout its design life.

4.5.1 Powerex IGBT/Diode Module QID4515001

Since this study was conducted, PPS has discovered an issue with the performance of the current IGBT. PPS anticipates further investigation to decide which IGBT to move forward with.

Design objectives of a redesign phase of the Alaska project will focus upon replacing the current semiconductors with a Powerex IGBT/Diode module, part number QID4515001. Examined individually, the improved performance of the module will serve to increase the MTBF of the high-voltage DC boards an appreciable amount. PPS estimates this amount to be approximately 45.1 failures per billion hours per board. At the system level, a reduction of 7223 failures per billion hours (over 16 boards) or an increase in the MTBF of the unit by approximately 6 months is expected. The real value brought by this module comes from the simplification of the HVDC design (PCB and power electronics components), the reduction in size and complexity of the control and triggering circuitry and the increase in efficiency of the power train. Quantification of these benefits requires additional study, but the MTBF design life and efficiency of the unit is expected to increase further.

The cost of the replacement modules is significantly higher than the current Powerex units; however, with the reduction in parts count of the new control hardware and the HVDC assemblies, the final cost of the units is expected to be within the $250/kW ± 10% goal.

4.6 Outage Time and Replacement Costs

The projected outage time and replacement costs of the five least reliable parts are listed in Table 27.
<table>
<thead>
<tr>
<th></th>
<th>Number</th>
<th>(hours)</th>
<th>(each)</th>
<th>(years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDCB1-16 Assembly</td>
<td>7005-1400</td>
<td>10</td>
<td>$1,100.00</td>
<td>25.27</td>
</tr>
<tr>
<td>V2.5 Control System</td>
<td>1750-0013</td>
<td>2</td>
<td>$1,350.00</td>
<td>82.39</td>
</tr>
<tr>
<td>MCR 3-way Isolating Amp/AIO1-2</td>
<td>1760-0012</td>
<td>1</td>
<td>$245.00</td>
<td>263.28</td>
</tr>
<tr>
<td>Voltage Transducer/V51-V58</td>
<td>4813-0011</td>
<td>1</td>
<td>$70.00</td>
<td>299.59</td>
</tr>
<tr>
<td>PCB6/Tank Status Board</td>
<td>1750-0046</td>
<td>3</td>
<td>$600.00</td>
<td>300.12</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Number</th>
<th>(hours)</th>
<th>(each)</th>
<th>(years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Powerex IGBT/Diode 4500V/150A HVDCB1-16 HVDC PCB Assembly</td>
<td>QID4515001</td>
<td>10</td>
<td>$1755.00</td>
<td>79.02</td>
</tr>
<tr>
<td>V2.5 Control System</td>
<td>1750-0013</td>
<td>2</td>
<td>$1,350.00</td>
<td>82.39</td>
</tr>
<tr>
<td>MCR 3-Way Isolating Amp/AIO1-2</td>
<td>1760-0012</td>
<td>1</td>
<td>$245.00</td>
<td>263.28</td>
</tr>
<tr>
<td>Voltage Transducer/V51-V58</td>
<td>4813-0011</td>
<td>1</td>
<td>$70.00</td>
<td>299.59</td>
</tr>
<tr>
<td>PCB6/Tank Status Board</td>
<td>1750-0046</td>
<td>3</td>
<td>$600.00</td>
<td>300.12</td>
</tr>
</tbody>
</table>

**Table 27: Outage Time and Replacement Cost**

The least reliable components tend to be within the control system. However, these components are easily accessible, thus are easy to replace. Last on both lists (lowest reliability) are semiconductor components within the transformer tank. When combined, these components form the HVDCB1-16 assemblies, with an MTBF of approximately 26 years. The lifespan of these assemblies is dominated by the failure rates of the current IXYS IGBTs and Powerex Diodes, part numbers 5105-0005 and 4801-0001, respectively. Redesigning the HVDC board by replacing both components with the Powerex IGBT/Diode component, part number QID4515001, will reduce failure rates such that the MTBF of the HVDC assemblies will increase (see Section 11).
4.7 RELIABILITY STUDY CONCLUSIONS

The second study results, combined with the manual adjustments to the MTBF values for individual components and the inclusion of the future transition to the Powerex module, confirm the integrity of the Alaska design. With an MTBF of 6.2 years and, a design life of 51.3 years, the unit meets and exceeds requirements, providing a bidirectional inverter that will require minimal maintenance throughout its design life.

5.0 COST ANALYSIS

<table>
<thead>
<tr>
<th>Unit</th>
<th>BOM Summary</th>
<th>10 pcs.</th>
<th>100 pcs.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cabinet</td>
<td>Power Electronic</td>
<td>$33,325</td>
<td>$28,993</td>
</tr>
<tr>
<td></td>
<td>Controls &amp; Monitoring</td>
<td>$5,135</td>
<td>$4,366</td>
</tr>
<tr>
<td></td>
<td>Enclosure - BOS</td>
<td>$11,948</td>
<td>$8,959</td>
</tr>
<tr>
<td></td>
<td>Total Parts Cost 500 kW</td>
<td>$50,406</td>
<td>$42,317</td>
</tr>
<tr>
<td></td>
<td>Total Parts Cost 1 MW</td>
<td>$100,810</td>
<td>$84,634</td>
</tr>
<tr>
<td>Tank</td>
<td>Power Electronics</td>
<td>$32,032</td>
<td>$28,186</td>
</tr>
<tr>
<td></td>
<td>Controls &amp; Monitoring</td>
<td>$660</td>
<td>$804</td>
</tr>
<tr>
<td></td>
<td>Enclosure - BOS</td>
<td>$32,707</td>
<td>$22,896</td>
</tr>
<tr>
<td></td>
<td>Total Parts Cost 500 kW</td>
<td>$65,708</td>
<td>$51,888</td>
</tr>
<tr>
<td></td>
<td>Total Part Cost 1 MW</td>
<td>$131,414</td>
<td>$103,776</td>
</tr>
<tr>
<td></td>
<td>Total 1 MW Converter Cost</td>
<td>$232,224</td>
<td>$188,410</td>
</tr>
</tbody>
</table>

Table 28: Materials Cost based on Prototype Costs

Table 28 shows the direct costs of materials based on the BOM for prototypes built in Phase II. The materials cost for the converter in manufacturing quantities of 10 and 100 was quoted by the vendors that had been selected to provide the prototype parts. Costs are subject to change with future design revisions and vendor selection.

To estimate the labor component, some assumptions were made regarding loaded labor rates and assembly and test processes. It is estimated that a total of 252 hours for test and assembly labor will be required to build a 1-MW power converter system in small quantities of 1-3 per month. As volumes increase and the learning curve is reduced, it is further estimated that the hours would be reduced to 225. Assuming a production labor rate of $80 per hour, the labor component in small production quantities would be $20,160, becoming $18,000 as volumes increased and the learning curve is reduced.

The economics of remote Alaska power interties require that the HVDC converters meet a cost benchmark of $250 per kW in order for HVDC interties to be cost competitive with conventional AC interties. This price target is for a ‘commercial production’ unit. In this context, ‘commercial production’ means that substantial work has been done to take the prototype converter that has been developed and refine it into a commercial product that is efficient to manufacture and assemble, and that has successfully completed thorough testing and additional manufacturing engineering. This design refinement and additional testing has not yet been performed. PPS anticipates that some
manufacturing economies will be achieved even at relatively low production volumes of 10 units once PPS 'commercializes' the power converter design.

In summary, PPS believes that the target cost of $250/kW ±10% for the commercial system is reasonable in volumes of 10 and above. However, this target will not be achieved by building 1-2 more prototypes; it will take some effort to commercialize the product in order to reach this cost target.
SECTION 3: HVDC CONVERTER TESTING

6.0 SYSTEM VERIFICATION TEST PLAN

6.1 REFERENCED DOCUMENTS

Project References

[1] Exhibit B of EJCDC E-570 Standard Form of Agreement between Engineer and Consultant for Professional Services, the contract between Polarconsult and PPS


Installation and Standard Compliance Requirements


6.2 TEST SUMMARY

The test program identified three key phases of testing:

1) Component verification;

2) System bring-up; and

3) System verification testing, as per the “System Verification Test Plan” (this section).

Development will follow an informal test plan, such that tests may be selected to best address concerns and risks identified as development progresses. The System Verification Test Plan is designed to confirm the basic product specification as per the specification document [3], and is a project deliverable. This plan has been developed in order to confirm the following key specifications:

1) Dielectric Strength Test

2) Interface Test

   a. Local Human-Machine Interface (HMI)

   b. Remote User Interface via Web

3) Operational Test

   a. HVDC Rectifier Mode

   b. AC Grid-Tied Inverter Mode

   c. AC Microgrid Inverter Mode

4) Environmental Test
a. Acoustic Measurement

b. Temperature Rise Test

5) Efficiency Test

6) Protection Test
   a. Anti-islanding
   b. Inrush Current Measurement
   c. Software Security Protection
   d. Fault Simulation
6.3 Test Setup Schematics

Figure 97: Setup 1: Resistive Load Bring-up to 50 kV/50 kW.

Figure 98: Setup 2: Back-to-back Bi-directional Test, Grid-tied Mode, 500 kW.
Figure 99: Setup 3: Back-to-back Microgrid Test, 500 kW.
6.4 Test Equipment

6.4.1 Equipment List

<table>
<thead>
<tr>
<th>Item</th>
<th>Characteristics</th>
<th>Manufacturer</th>
<th>Model</th>
<th>Qty.</th>
<th>Schematic Identifier</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dielectric Tester</td>
<td>100 kV AC/100 mA</td>
<td>Hipotronics</td>
<td>100HVT</td>
<td>1</td>
<td>HVT</td>
</tr>
<tr>
<td>Test Bay PC</td>
<td>RS-232, 485, GPIB</td>
<td>Any</td>
<td>Any</td>
<td>2</td>
<td>PC</td>
</tr>
<tr>
<td>Oscilloscope</td>
<td>100 MHz or better</td>
<td>Agilent</td>
<td>6000 series</td>
<td>3</td>
<td>Scope 1-3</td>
</tr>
<tr>
<td>HV Voltage Probe</td>
<td>50 kV, 50 kHz BW</td>
<td>North Star</td>
<td>VD-60</td>
<td>4</td>
<td>HVP 1-4</td>
</tr>
<tr>
<td>Resonant Current Probe</td>
<td>50 kHz BW</td>
<td>Pearson</td>
<td>1330</td>
<td>2</td>
<td>A8-9</td>
</tr>
<tr>
<td>Differential Voltage Probe</td>
<td>±7 kV</td>
<td>Probe Master</td>
<td>4243A</td>
<td>2</td>
<td>DV 1-2</td>
</tr>
<tr>
<td>Power Meter</td>
<td>VT and CT scaling</td>
<td>Yokogawa</td>
<td>WT3000</td>
<td>2</td>
<td>PGA 1-2</td>
</tr>
<tr>
<td>DC Current Probe</td>
<td>DC-50 kHz BW</td>
<td>Danfysik</td>
<td>866R Ultrastab</td>
<td>4</td>
<td>A4-A7</td>
</tr>
<tr>
<td>AC Current Probe</td>
<td>1000 A /60 Hz / 600 V</td>
<td>AEMC</td>
<td>SR1000</td>
<td>3</td>
<td>A1-A3</td>
</tr>
<tr>
<td>Temperature Logger</td>
<td>8 Channels</td>
<td>Neoptix</td>
<td>OmniSense</td>
<td>1</td>
<td>Temp 1</td>
</tr>
<tr>
<td>Temperature Probe</td>
<td>50 kV Oil-compatible</td>
<td>Neoptix</td>
<td>T2</td>
<td>8</td>
<td>TS1-8</td>
</tr>
<tr>
<td>Logic Analyzer</td>
<td>With 2 Mictor header cables, for debugging only</td>
<td>Tektronix</td>
<td>TLA612/614</td>
<td>1</td>
<td>LA</td>
</tr>
</tbody>
</table>

Table 29: Test Equipment List

After the dielectric test, which has its own equipment needs, the following equipment shall be used to log the performance of the EUT. Logging shall be performed continuously on a dedicated test bay PC with a local area network connection to the equipment inside the test area.

1) Power analyzer (Yokogawa WT-3000) on each converter, monitoring:
   a. Input voltage, current, and power (fundamental)
   b. Input current harmonics, % THD (voltage and current)
   c. Output voltage, current, and power (DC)
   d. Output voltage ripple (up to 100th harmonic, approximately switching frequency)
   e. Efficiency (fundamental \( P_{out}/P_{in} \))

2) Neoptix 8Ch Omni-Sense temperature monitor
   a. Transformer core
b. Transformer primary winding  
c. Transformer secondary winding  
d. HVDC Stack IGBT  
e. HVDC Stack Diode  
f. Ambient oil temperature

3) Serial debug output data from both converters  
   a. Internal temperature, voltage, and desaturation status of all HV stacks  
   b. AC input current and voltages  
   c. LVAC and LVDC bus voltages  
   d. Central cap voltage swing  
   e. System temperatures

4) Agilent 6000 series scope monitoring on unit 1  
   a. DC output current and voltage using VD-60 HV divider and Danfysik Ultrastab 866R CT  
   b. 1/4, 1/2 and 3/4 stack increments (to confirm voltage sharing along the stack) using 3 VD-60 HV dividers

5) Agilent 6000 series scope monitoring on both converters  
   a. High-frequency (HF) resonant current and central cap voltage using a Probe Master 4243A (7-kV differential voltage probe) and a Pearson 1330.

6.4.2 Placement Notes

Table 31 provides placement notes for test probes.

<table>
<thead>
<tr>
<th>Probe SN#</th>
<th>Channel</th>
<th>Location</th>
<th>Placement</th>
</tr>
</thead>
<tbody>
<tr>
<td>443</td>
<td>0</td>
<td>Unit 1 Transformer Core, Top, Front</td>
<td>Inside corner of core</td>
</tr>
<tr>
<td>444</td>
<td>1</td>
<td>Unit 1 Transformer Primary, Top, Front,</td>
<td>Down primary spacer, adjacent to front wire</td>
</tr>
<tr>
<td>445</td>
<td>2</td>
<td>Unit 1 Stack 8 Transformer Secondary</td>
<td>Along ridge of secondary coil, terminating in</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>front secondary support brace</td>
</tr>
<tr>
<td>446</td>
<td>3</td>
<td>Unit 1 Stack 9 Diode</td>
<td>On heatsink, near base of fin</td>
</tr>
<tr>
<td>447</td>
<td>4</td>
<td>Unit 1 Stack 9 IGBT</td>
<td>Below heatsink base, adjacent to device</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>package</td>
</tr>
<tr>
<td>448</td>
<td>5</td>
<td>Unit 1 Oil, top, between stacks 9 and 16</td>
<td>At about 1/3 height of top capacitors</td>
</tr>
<tr>
<td>449</td>
<td>6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>450</td>
<td>7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 30: Thermal Probe Placement

<table>
<thead>
<tr>
<th>Cable</th>
<th>Position</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>NEG</td>
</tr>
<tr>
<td>2</td>
<td>¼ Voltage</td>
</tr>
<tr>
<td>3</td>
<td>½ Voltage</td>
</tr>
<tr>
<td>4</td>
<td>¾ Voltage</td>
</tr>
<tr>
<td>5</td>
<td>Full Voltage</td>
</tr>
<tr>
<td>6</td>
<td>NEG, power ground</td>
</tr>
</tbody>
</table>

Table 31: Voltage Reference Wires used for VD-60

6.5 DIELECTRIC TEST

The system consists of two chassis, each of which must be tested for leakage between each isolated barrier. The test specimen shall always be chassis grounded although, depending on the equipment used, the ground connection may either flow through an ammeter or be directly grounded. Each chassis itself should be isolated from the other so that all ground current flows through the dedicated ground connection and can be measured accurately. The system shall then be put in its final configuration as for the remainder of testing and then retested.

Each barrier is to be tested to a standard metric of \( V_{\text{test}} = 2V_{\text{nominal}} + 1000\text{V} \) for a period of 1 minute at full voltage. The voltage ramp shall be slow and not specifically defined other than to allow diagnosis of any changes in the current and to allow the best possible identification of the source of the change. To aid identification of failures, lighting and noise in the test area shall be kept to a minimum.

The voltage and current shall be recorded at the start and end of the 1 minute of fully applied voltage. The pass criterion is that not more than 50 mA (AC, root mean square [rms]) shall be observed during the test. Should this threshold be exceeded, attempts shall be made to improve the reading, and then retested. A decision shall be made by the team regarding safety and risk mitigation should the final assembly not pass.

The tests to be performed are:

1) Low-voltage cabinet on isolated pad
   480 V terminals to chassis, transformer primary and ground at 1.920 VAC

2) High-voltage tank on isolated pad
   HVDC port to chassis, transformer primary and ground at 42.5 kV AC

3) System as grounded in test configuration
   HVDC to 480-V terminals at 42 kV AC
6.6 **INTERFACE TEST**

6.6.1 **Local HMI Verification**

Using Setup 1, the following interfaces shall be evaluated for basic ability to control the EUT:

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Local HMI</td>
<td>• LCD Display</td>
</tr>
<tr>
<td></td>
<td>• Touchscreen pushbuttons</td>
</tr>
<tr>
<td></td>
<td>• Local/Remote control</td>
</tr>
<tr>
<td>Local PC (on front door below HMI)</td>
<td>• Ethernet via RJ45 Connector#1</td>
</tr>
</tbody>
</table>


6.6.2 Remote Interface Verification Test

This test shall be performed with the minimum functionality demonstrated of the items in Table 33.

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Remote Users via Web</td>
<td>• Ethernet via RJ45 Connector#2</td>
</tr>
<tr>
<td>External User Interface</td>
<td>• 2x Analog input, 0-10 VDC</td>
</tr>
<tr>
<td></td>
<td>• 2x Analog output, 0-10 VDC &amp; 4-20 mA</td>
</tr>
<tr>
<td></td>
<td>• 2x Digital input</td>
</tr>
<tr>
<td></td>
<td>• 2x Digital output</td>
</tr>
</tbody>
</table>

Table 33: Remote Interface Verification

The test shall be performed by having a video record of approximately 15 minutes while a test engineer demonstrates this functionality and other select functions included in the specification.

6.7 Operational Test

6.7.1 HVDC Rectifier Mode

Using Setup 2, running the units back-to-back with the first in Rectifier mode and the second in Grid-Tied mode, the parameters in Table 34 and Table 35 shall be measured and verified. Note that the current and power requirements are halved since the units are operating back-to-back rather than in parallel.

<table>
<thead>
<tr>
<th>DC Interconnection (HVDC)</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC Voltage</td>
<td>45</td>
<td>50</td>
<td>56</td>
<td>kV</td>
<td></td>
</tr>
<tr>
<td>DC Current</td>
<td>18.18</td>
<td>20</td>
<td>22.22</td>
<td>ADC</td>
<td>Rated power (1 MW)</td>
</tr>
<tr>
<td>DC Regulation Voltage</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>%</td>
<td></td>
</tr>
<tr>
<td>DC Voltage Ripple</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>%</td>
<td></td>
</tr>
<tr>
<td>DC Current Ripple</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>%</td>
<td>External inductance may be required to meet this spec</td>
</tr>
<tr>
<td>Overcurrent Protection Requirement</td>
<td>-</td>
<td>-</td>
<td>23</td>
<td>A</td>
<td>Software-based protection will limit DC fault energy[1]</td>
</tr>
<tr>
<td>Inrush Protection Current</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Software-based feature for black starting will limit DC inrush</td>
</tr>
<tr>
<td>Lightning Protection</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>External surge protection to be installed in switchyard by customer</td>
</tr>
<tr>
<td>Rated Voltage</td>
<td>-</td>
<td>-</td>
<td>60</td>
<td>kV</td>
<td>IEC 60099-4 is a minimum, but additional tests may be performed depending on construction (e.g., CIGRE 33/14-05, IEC TS 60071-5)</td>
</tr>
</tbody>
</table>
### Table 34: Rectifier Mode Performance Requirements

<table>
<thead>
<tr>
<th>Performance (Overall Specs)</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous Apparent DC power</td>
<td>-</td>
<td>1</td>
<td>-</td>
<td>MW</td>
<td>Rated ambient (60°C)</td>
</tr>
<tr>
<td>Allowable Overload</td>
<td>-</td>
<td>-</td>
<td>120</td>
<td>%</td>
<td>For 10 seconds</td>
</tr>
<tr>
<td>Converter Unit Startup Time</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>seconds</td>
<td></td>
</tr>
<tr>
<td>Converter Power Flow Direction Change Time</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>second</td>
<td>Power reversal from either AC supplied or DC supplied</td>
</tr>
<tr>
<td>Transient Response</td>
<td>-</td>
<td>-</td>
<td>300</td>
<td>μs</td>
<td>Response to 10%-90% power step</td>
</tr>
</tbody>
</table>

### Table 35: Overall Performance Requirements
6.7.2 AC Grid-Tied Inverter Mode

Using Setup 2, running the units back-to-back with the first in Rectifier mode and the second in AC Grid-Tied mode, the parameters in Table 36 and Table 37 shall be measured and verified. Note that the current and power requirements are halved since the units are operating back-to-back rather than in parallel.

<table>
<thead>
<tr>
<th>AC Interconnection - AC Grid Tied</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Phase Voltage</td>
<td>432</td>
<td>480</td>
<td>528</td>
<td>V&lt;sub&gt;ref&lt;/sub&gt;, L-L</td>
<td></td>
</tr>
<tr>
<td>AC Line Current</td>
<td>1127</td>
<td>1240</td>
<td>1378</td>
<td>A&lt;sub&gt;ref&lt;/sub&gt;, L-N</td>
<td>Max is derived from rated DC output power (1 MW) at min AC Voltage (432 V) with 97% Efficiency</td>
</tr>
<tr>
<td>AC Frequency</td>
<td>57</td>
<td>60</td>
<td>60.6</td>
<td>Hz</td>
<td></td>
</tr>
<tr>
<td>Grid-Tied Power Factor</td>
<td>±0.99</td>
<td>1</td>
<td>-</td>
<td>PF</td>
<td>When power &gt; 20% rated</td>
</tr>
<tr>
<td>Grid-Tied Total Harmonic Distortion</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>% (I&lt;sub&gt;ref&lt;/sub&gt;)</td>
<td>Percent fundamental</td>
</tr>
<tr>
<td>Allowable Voltage Imbalance</td>
<td>-</td>
<td>-</td>
<td>12</td>
<td>%</td>
<td>Voltage unbalance tested in IEEE 1547.1 abnormal voltage</td>
</tr>
<tr>
<td>Overcurrent Protection Requirement</td>
<td>-</td>
<td>-</td>
<td>800</td>
<td>A</td>
<td>Thermal-magnetic breaker with shunt trip installed for each 500 kW unit.</td>
</tr>
<tr>
<td>Inrush Protection</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Separate precharge circuit will limit DC bus charging from AC input</td>
</tr>
<tr>
<td>Surge Protection[1] (Line-Ground) Voltage</td>
<td>-</td>
<td>400</td>
<td>480</td>
<td>V&lt;sub&gt;ref&lt;/sub&gt;</td>
<td>Operating voltage</td>
</tr>
<tr>
<td></td>
<td>-</td>
<td>-</td>
<td>1800</td>
<td>VPR</td>
<td>VPR per UL1449 3rd Ed</td>
</tr>
<tr>
<td>Surge Protection (Line-Ground) Withstand Current</td>
<td>-</td>
<td>-</td>
<td>140</td>
<td>kA</td>
<td>8/20 ms surge pulse (NEMA LS-1)</td>
</tr>
<tr>
<td></td>
<td>-</td>
<td>-</td>
<td>7.5</td>
<td>kA</td>
<td>10/350 lightning pulse (IEC61643-1)</td>
</tr>
<tr>
<td>Surge Protection (Line-Line)</td>
<td>-</td>
<td>-</td>
<td>910</td>
<td>V</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>360</td>
<td>J</td>
<td></td>
</tr>
</tbody>
</table>

Table 36: AC Grid-Tied Inverter Mode Performance Requirements

<table>
<thead>
<tr>
<th>Performance (Overall Specs)</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous Apparent DC Power</td>
<td>-</td>
<td>1</td>
<td>-</td>
<td>MW</td>
<td>Rated ambient (50°C)</td>
</tr>
<tr>
<td>Allowable Overload</td>
<td>-</td>
<td>-</td>
<td>120</td>
<td>%</td>
<td>For 10 seconds</td>
</tr>
<tr>
<td>Converter Unit Start-up Time</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>seconds</td>
<td></td>
</tr>
<tr>
<td>Converter Power Flow Direction Change Time</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>second</td>
<td>Power reversal from either AC supplied or DC supplied</td>
</tr>
<tr>
<td>Transient Response</td>
<td>-</td>
<td>-</td>
<td>300</td>
<td>µs</td>
<td>Response to 10%-90% power step</td>
</tr>
</tbody>
</table>

Table 37: Overall Performance Requirements
### 6.7.3 AC Microgrid Inverter Mode

Using Setup 2, running the units back-to-back with the first in Rectifier mode and the second in AC Microgrid mode, the parameters in Table 38 and Table 39 shall be measured and verified. Note that the current and power requirements are halved since the units are operating back-to-back rather than in parallel.

<table>
<thead>
<tr>
<th>AC Interconnection - AC Microgrid</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Phase Voltage</td>
<td>432</td>
<td>480</td>
<td>628</td>
<td>V&lt;sub&gt;ma&lt;/sub&gt;, L-L</td>
<td>i.e., 10% Voltage regulation</td>
</tr>
<tr>
<td>AC Line Current</td>
<td>1061</td>
<td>1167</td>
<td>1296</td>
<td>A&lt;sub&gt;ma&lt;/sub&gt;, L-N</td>
<td>Max is derived from rated DC input power (1 MW) at min AC voltage (432 V) with 97% efficiency</td>
</tr>
<tr>
<td>AC Frequency</td>
<td>57</td>
<td>60</td>
<td>60.5</td>
<td>Hz</td>
<td></td>
</tr>
<tr>
<td>Allowable Power Factor</td>
<td>±0.85</td>
<td>1</td>
<td>-</td>
<td>PF</td>
<td></td>
</tr>
<tr>
<td>Allowable Total Harmonic Distortion</td>
<td>-</td>
<td>-</td>
<td>5</td>
<td>% (V&lt;sub&gt;ad&lt;/sub&gt;)</td>
<td>Percent fundamental, balanced load</td>
</tr>
<tr>
<td>Allowable Load Imbalance</td>
<td>-</td>
<td>-</td>
<td>12</td>
<td>%</td>
<td>Voltage unbalance tested in IEEE 1547.1 abnormal voltage</td>
</tr>
</tbody>
</table>

Table 38: AC Microgrid Inverter Mode Performance Requirements

<table>
<thead>
<tr>
<th>Performance (Overall Specs)</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous apparent DC power</td>
<td>-</td>
<td>1</td>
<td>-</td>
<td>MW</td>
<td>Rated ambient (50°C)</td>
</tr>
<tr>
<td>Allowable Overload</td>
<td>-</td>
<td>-</td>
<td>120</td>
<td>%</td>
<td>For 10 seconds</td>
</tr>
<tr>
<td>Converter Unit Startup Time</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>seconds</td>
<td></td>
</tr>
<tr>
<td>Converter Power Flow Direction Change Time</td>
<td>-</td>
<td>-</td>
<td>1</td>
<td>second</td>
<td>Power reversal from either AC supplied or DC supplied</td>
</tr>
<tr>
<td>Transient Response</td>
<td>-</td>
<td>-</td>
<td>300</td>
<td>μs</td>
<td>Response to 10%-60% power step</td>
</tr>
</tbody>
</table>

Table 39: Overall Performance Requirements

### 6.8 Environmental Tests

The units are designed to comply with the following environmental requirements. Only temperature rise and acoustic measurements shall be made at this stage in the project. External verification will be required at a later stage to demonstrate compliance with humidity, altitude, shock and vibration, and ambient storage. These tests may be verified using either construction review or test, as deemed appropriate.

<table>
<thead>
<tr>
<th>Environmental</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
<th>Conditions/Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ambient Temperature (operating)</td>
<td>-30</td>
<td>-</td>
<td>50</td>
<td>°C</td>
<td>Per component ratings</td>
</tr>
<tr>
<td>Ambient Temperature (storage)</td>
<td>-30</td>
<td>-</td>
<td>50</td>
<td>°C</td>
<td>Per component ratings</td>
</tr>
<tr>
<td>Humidity</td>
<td>5</td>
<td>-</td>
<td>95</td>
<td>% RH</td>
<td>Noncondensing</td>
</tr>
</tbody>
</table>
### Table 40: Environmental Test

<table>
<thead>
<tr>
<th>Environmental</th>
<th>Min</th>
<th>Nom</th>
<th>Max</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altitude</td>
<td>0</td>
<td>-</td>
<td>3300</td>
<td>ft (sea level)</td>
</tr>
<tr>
<td>Seismic</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Designed to comply with Zone 4 as tested per ICC-ES-AC 156</td>
</tr>
<tr>
<td>Shock and Vibration</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Designed to comply with IEC 60068-2-6 and IEC 60068-2-27</td>
</tr>
<tr>
<td>Expected Siting*</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>Inside power plant or prefab outhouse/enclosure</td>
</tr>
</tbody>
</table>

* No secondary oil containment required. Fire detection/protective for the oil-filled indoor transformer tank will be covered under the building maintenance and fire protection policies and procedures.

#### 6.8.1 Acoustic Test

An acoustic test shall be performed over all surfaces exposed after installation, at a 1-meter distance. The noise level shall be below 85 decibels, A-weighted (dBA).

#### 6.8.2 Temperature Rise Test

Using Setup 2 and setting both units close to their rated power capability, 500 kW, until thermal stability. Record temperature readings at 1-minute intervals and plot the chart.

Repeat the above test by setting the DC current flowing in the opposite direction.

#### 6.9 Efficiency Test

Using Setup 2, both input and output power shall be measured on each unit individually. Data shall be recorded from 10% to 100% at 10% interval of each unit’s rated power, 500 kW. Then a chart shall be plotted for each of the units.

Repeat the above test by setting the DC current flowing in the opposite direction.

#### 6.10 Protection Test

1.1.14 Anti-Islanding Test

The anti-islanding test shall be done as per UL-1741. Test Setup 2 can be used for this purpose. The test result shall comply with UL-1741 requirements.

1.1.15 Inrush Current Test

Using Setup 1, the voltage of the central capacitor bank shall be monitored and logged right after switching the unit on. Capacitor charging current shall be limited to the predefined value and the voltage shall increase gradually without tripping the circuit breaker or damaging any components and interconnection in the system.

1.1.16 Software Security Protection

Passwords for user, maintenance, and factory shall be verified.
### 1.1.1.7 Fault Simulation

Table 41 (pages 106 and 107) lists all specified faults and the planned test mode. In general, fault testing requires multiple setups and will be performed as soon as the relevant section of the operational test calls for the next test setup.

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Test Method</th>
<th>Test Setup</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC Operating Faults</td>
<td>Over/Undervoltage</td>
<td>Threshold adjustment based on measured line voltage, magnitude test only</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Over/Underfrequency</td>
<td>Threshold adjustment based on measured line frequency, magnitude test only</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Overcurrent</td>
<td>Threshold adjustment, requires microgrid operation</td>
<td></td>
</tr>
<tr>
<td></td>
<td>AC Overload</td>
<td>Threshold adjustment, requires some power</td>
<td>2</td>
</tr>
<tr>
<td>DC Operating Faults</td>
<td>Over/Undervoltage</td>
<td>Threshold adjustment</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Overcurrent</td>
<td>Threshold adjustment, requires some power</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>DC Overload</td>
<td>Threshold adjustment, requires some power</td>
<td>2</td>
</tr>
<tr>
<td>Line Faults (dead short)</td>
<td>DC + to – Bus Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>AC 1-ph Line to Line Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>AC Bolted Fault (all 3-ph faulted)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AC Ground Faults (dead short)</td>
<td>1 Line to Ground Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2 Lines to Ground Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>All 3 Phases to Ground Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Internal Operating Faults</td>
<td>High-Voltage Stage Trigger Failure</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>DC Bus Overvoltage</td>
<td>Threshold adjustment</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>DC Bus Overcurrent</td>
<td>Threshold adjustment, requires some power</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Overtemperature</td>
<td>Threshold adjustment</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Low Temperature</td>
<td>Threshold adjustment</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Sensor Loss (each sensor)</td>
<td>Removal of cable; do not test above 1 kV DC</td>
<td>1</td>
</tr>
<tr>
<td>Software Faults</td>
<td>Boot-up Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Calibration Load Fault</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Grid Synchronization Fault</td>
<td>Tested by reversing input phase order</td>
<td>1</td>
</tr>
<tr>
<td>Communication Faults</td>
<td>Analog Signal Loss</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Front Panel Interface</td>
<td>Removal of cable; do not test above 1 kV DC</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Communication Loss</td>
<td></td>
<td></td>
</tr>
<tr>
<td>User-Generated Faults</td>
<td>User Defined Trip</td>
<td>Not tested</td>
<td>n/a</td>
</tr>
<tr>
<td></td>
<td>External Trip</td>
<td>Test using digital input</td>
<td>n/a</td>
</tr>
<tr>
<td></td>
<td>Maximum Number of Retries</td>
<td>Not tested</td>
<td>n/a</td>
</tr>
</tbody>
</table>
Table 41: Fault Test Matrix

The table may be summarized as follows:

- **Voltage, frequency, and temperature trips**: While the unit is running open-circuited and at a low DC voltage, change the threshold so that running conditions exceed limit. The unit shall trip.

- **Current and power trips**: While the unit is running with a small load, change the threshold so that running conditions the exceed limit. The unit shall trip.

- **Short circuit and bolted faults**: Not tested. These should be tested at a facility designed to supply the rated fault current and in the next phase of the project. They are usually destructive tests.

- **Software and user fault tests**: Not tested. These are not deemed high-risk tests since the code and detection mechanisms have been proven on other PPS products with the same controls hardware and so have been omitted to give priority to demonstrating key project goals. The one exception is the external trip, since this would be relied upon in an E-Stop circuit.

### 7.0 TEST REPORT

The test report deliverable is presented here, to the extent that testing has been completed. The test program identified three key phases of testing:

1. Component verification;
2. System bring-up; and
3. System verification testing, as per deliverable 2.3 (6.0 System Verification Test Plan).

The third phase of testing has been performed to the extent possible. System testing may broadly be considered to be in the ‘system bring-up’ stage. Two critical issues were identified during testing in inverter (DC to AC power conversion) mode of the system resonant test in oil, which was the penultimate stage of system bring-up. Testing was subsequently halted in order to investigate these issues, and the findings are discussed in detail in the conclusion (Section 10.4). Briefly, problems were identified with the timing of the optical triggering system, and with the thermal performance of the IXYS IGBTs in the high voltage tank.

Because of these problems, the full test plan has not been completed, although the bring-up testing that was completed has effectively demonstrated key system functionality, achieving milestones in the rectification mode, where 50-kV operation was achieved and 50 kW drawn.

As discussed in greater detail in Section 10, PPS has identified corrective actions for both problems, and is currently (March 2012) in the process of implementing these actions. Once the fiber optic triggering and switching problems are corrected, PPS will complete the system bring-up tests, and the System Verification Test will be performed.
7.1 COMPONENT AND SUBSYSTEM TEST

The component tests were limited to the areas of highest technical risk. The following tests were performed and passed:

1) IGBT
   a. Voltage withstand
   b. Conduction loss/thermal test

2) Diode
   a. Voltage withstand
   b. Conduction loss/thermal test

3) HV Bridge resonance test
   a. Rectification mode
   b. Inversion mode

4) Transformer
   a. 20 kV AC Hi-pot (dry)

Both the IGBTs and the diodes on the HV stack board were tested as components. The tests are to be considered successful since both conduction losses and voltage hold-off were successfully demonstrated on both the IGBTs and the diodes. In hindsight, there were deficiencies in the plan for component testing, since the IGBT switching issue was not identified at this stage.

7.1.1 IGBT Test

1.1.1.18 IGBT Voltage Test

The purpose of this test was to confirm that the IGBTs used could withstand the nominal operating DC input voltage of 3.125 kV. The test was performed with a single HV stack board that had a high-voltage DC input and a resistive load, as per the test schematic (Figure 100). The DC input as measured was 3.312 kV (the green trace on Figure 101), 200 V higher than the typical stack voltage. The test was run for an hour into a 0.2-A (2%) load with no adverse effects or degradation observed. This can be seen in the purple trace.
1.1.1.19  IGBT Thermal Test

The design power and thermal simulations indicate that each of the IGBTs need to handle 5.5 A average current and dissipate at least 12.5 W below rated temperature at 120 °C. A similar test setup was used as per the Section 1.1.1.18 IGBT Voltage Test, but with an increased load. The IGBTs were not switched but left on to ensure that all losses were conductive. A DC current of 7 A was measured. Thermal readings were made and are shown on Figure 103 and Figure 104. 13 W of power loss were measured on each device. PPS concluded that the IGBT jacket temperature and heat sink temperature were below the rated design temperature, which is 120 °C at 7 A/13 W in air. Further, the air temperature should be higher than that recorded in oil.

The IGBT and high-voltage board passed the thermal test.
1.1.2 Diode Test

1.1.2.1 Diode Voltage Test

Unlike the IGBT DC to AC test, the diode test is an AC to DC rectifying test. Like the IGBT, the diode and high-voltage board also have to pass the voltage and thermal test to make sure the low-voltage AC resonant can be rectified to 50 kV DC. The test schematic is shown on Figure 105, using a high-voltage AC source and the same resistive load bank. The AC input was 60 Hz. The rectified output voltage was measured as 3,200 V, higher than the nominal operating voltage. The diode and HV stack board therefore passed thermal testing.
1.1.2.2 Diode Current Test

The design power and thermal simulations indicate that each of the diodes needs to handle 5.5 A average current and dissipate at least 18 W below rated temperature at 120 °C. A similar test setup was used as per the Section 1.1.2.1 Diode Voltage Test but with an increased load, shown on Figure 105.

The diodes were conducting for one-half cycle as per the real application. A DC current of 10 A was measured. Thermal readings were made and are shown on Figure 107 and Figure 108. 18-W power loss was measured on each device. The diode jacket temperature and heat sink temperature were at least 30 °C below the rated design temperature, which is 120 °C at 7 A/13 W in air. Further, the recorded air temperature should be higher than that recorded in oil.

The diode and HV stack board passed thermal testing.
Figure 106: Diode Thermal Test Schematic

Figure 107: Diode Jacket Temperature was measured as 88°C in Air

Figure 108: Diode Heatsink Temperature was measured as 52°C in Air
7.1.2 HV Bridge Resonance Test

A single HV bridge PCB was paired with an LV bridge and LV resonant capacitor and operated in both directions (see Figure 109). Transforming LV DC to HV DC is the key mechanism for the system to rectify HVDC (rectification mode) and transforming from HV DC to LV DC is that for AC generation (inverter mode). Both operations were tested, and passed.

![Image](image_url)

Figure 109: Central Resonant Link Test Setup, Showing (L to R) Resonant Capacitor, HV Stage, and Transformer.

1.1.2.3 Rectification Mode

The schematic is shown on Figure 110. The test was operated with the LVDC increased until the output was at 500 V in air. By switching the LV bridge, a single-phase AC square wave voltage was applied across the resonant circuit with 50% duty cycle. This pulse had sinusoidal current as determined by the leakage inductance of the transformer and the capacitor in the circuit. This pulse was transferred to the transformer secondary and stepped up by its turns ratio. It was then rectified and the DC output was loaded with a resistor. Soft switching and high-frequency resonance (22 kHz) were observed, and the test was therefore considered a success. The operation was monitored using an oscilloscope, from which a typical capture can be seen on Figure 111. The pink and purple curves represent the current for both primary and secondary side, respectively. The green curve is the output voltage, showing 500 VDC with low ripple.
1.1.2.4 Inversion Mode

This test was similar to that described in 1.1.2.3, Rectification Mode, with the source changed to the HV side and the load connected to the LV side. The HV side achieved 800 V in air, about \( \frac{1}{4} \) of normal operating voltage, which was sufficient to prove the resonant mechanism. The results are illustrated on Figure 113. The pink and purple curves represent the current for both primary and secondary side, respectively. The green curve is the output voltage, while the yellow signal is the trigger driver signal. The ratio of purple to pink traces shows the transformer action upon the current. The observation that the pink current is zero when the trigger is applied shows soft-switching, which is a necessary action for reduced switching losses.
Figure 114: Hi-pot Test Setup showing Transformer (Left) and Hi-pot Equipment (Right)

<table>
<thead>
<tr>
<th>Hi-pot (in air)</th>
<th>Hi-pot Voltage</th>
<th>Leakage Current</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer Secondary to High-Voltage Tank</td>
<td>20,000 V</td>
<td>1.8 mA @ 1 min</td>
<td>PASS</td>
</tr>
<tr>
<td>Transformer Primary to High-Voltage Tank</td>
<td>3,000 V</td>
<td>0.8 mA @ 1 min</td>
<td>PASS</td>
</tr>
<tr>
<td>Transformer Primary to Low-Voltage Cabinet</td>
<td>1,700 V</td>
<td>30 mA @ 1 min</td>
<td>PASS</td>
</tr>
</tbody>
</table>

Table 42: Transformer Hi-pot in Air Test Results

7.2 SYSTEM BRING-UP TESTING

The system bring-up tests consisted of the following tests:

1) Dry system tests
   a. Hi-pot (as a precaution)
   b. Rectification mode
   c. Inverter mode

2) System tests in oil
   a. Hi-pot (as a precaution)
b. Rectification mode

c. Inverter mode

d. Back-to-back operation

The system tests were successful until the inversion mode test in oil. Multiple issues were uncovered concerning the switch system, and testing was paused while the causes were investigated. PPS believes that the root causes have been positively identified and so feels confident in PPS’ proposal to correct the issues. The proposed solutions are discussed in the conclusion.

7.2.1 Dry System Resonant Test

Following validation of components and subsystems, the system was tested as a unit in air. This involved the LV enclosure being attached to the HV tank lid, which contains all of the electronics that are lowered into a tank of oil. The electronics being tested in air allow easier access to the HV circuitry for modification or probing as necessary. These tests did not use the final system software but a skeleton version designed to offer the basic power functionality while allowing parallel power and controls development.

1.1.2.5 Hi-Pot Test

The first test performed was to ensure that System #1 had maintained its dielectric strength in transit from the factory. This was confirmed using the setup shown on Figure 115, where a Hipotronics 880PL-10mA-A was used to confirm withstand at 55 kV. It measured 12 microamperes (µA), where the leakage current included both leakage to the LV side of the transformer and leakage through ground.

The test was also performed using an AC hi-pot tester to 33 kV AC. The setup is shown on Figure 115, with the test set a Hipotronics 100HVT, capable of 50 kV/50 mA. 33 mA leakage current was recorded. The LV bridges contributed at least 20 mA of this leakage current.

Both results were sufficiently low for testing to continue.
1.1.2.6 Rectification Mode

The setup is shown on Figure 116. Low-voltage DC was fed to the LV enclosure bridge directly and switched to produce LV resonant current. This was transformed to the HV resonant current and then rectified. A resistive load was then used. Based upon the successful test of a single board previously in generating 800 V out of the 3.125 kV rated voltage, this test was run until 8.315 kV was generated at the HVDC output.

The result is shown on Figure 117, where the four traces correspond to ¼ (pink), ½ (purple), ¾ (green), and unity (yellow) fractions of the total system HVDC voltage. Note that the high-voltage probe used (VD-60) has a ratio of 10,000:1; our oscilloscope (Agilent DSO6014A) has a maximum ratio of 1000:1, and so the reading “Avg (1):831.5V” displayed is actually is 8.315 kV.

It can also be seen from the picture that the voltage seems to be shared equally between the stages, with less than 0.4% deviation. This is important as otherwise some stages would be exposed to higher voltages than others, leading to premature aging through greater voltage stress or, in an extreme case, immediate failure.

Figure 118 shows the input voltage (130V) applied to the test power supply, and the test result (8315 V) is shown on Figure 117. Based on these values, the transformer ratio can be verified as 130 V input: 8315 V output or a ratio of approximately 1:62.5, which is exactly equal to the design value. This implies the capability of generating 50 kV with full input voltage of 800 V.
Figure 116: Dry System Rectification Mode Test Schematic and Setup Pictures
1.1.2.7 Inverter Mode
7.2.2 System Resonant Test in Oil

Having successfully completed in-air testing, the HVDC transformer tank lid was sent back to the manufacturer to be mated with the enclosing tank and filled with oil. A special process was used to remove any latent moisture from the system, and the oil was separately heated to boil off moisture. The tank was filled in a low-pressure, clean environment and sealed. It was then hi-pot tested at 55 kV DC and recorded leakage to ground less than 0.1 mA. This leakage rate is considered acceptable.

Following its return to PPS, the sealed tank was put through essentially the same tests as the dry preliminary tests except in oil. The full system voltage was able to be safely generated. Having proven its ability to generate this voltage open-circuited, a specially commissioned 50-kV, 50-kW resistive load was used to load the converter and prove that rectification mode was capable of sourcing some power. The full power test of 500 kW was not able to be performed until a second converter could be used to load the first and circulate power in a “back-to-back” topology (as illustrated on Figure 98 and Figure 99 of Section 6.3, Test Setup).
1.1.2.8 Rectification Mode

The general setup for Rectification Mode testing is shown on Figure 120 with both enclosure and tank depicted, as well as the high-frequency transmission between cabinets through the PVC conduit. Figure 121 shows the test equipment, namely the HV voltage dividers used to measure 1/4 increments of the applied system voltage and the 50 kV resistive load.

![Figure 120: System#1 HV Tank and LV Enclosure Undergoing System Test](image)

Figure 122 shows the 50-kV high-voltage DC generated and the well-balanced sharing for each of the switching stages. As in the case of other scope captures, the voltages displayed differ by a factor of 10, so that 50.29 kV is the voltage recorded. The voltage sharing between the stages differs by no more than 30 V from the nominal (0.06% variance from design), indicating excellent voltage sharing between the stages.
Figure 121: System #1 Showing HV Measurement Probes (Bottom) and Resistive Load (Top)
1.1.2.9 **Inverter Mode**

A second tank was manufactured and installed in the HV laboratory, as illustrated on Figure 98. A hipot test was performed at the tank manufacturer’s factory to confirm the general ability for the second unit to withstand 55 kV DC. The first unit was rectifying as previously tested, with the second unit acting as a load. The first unit was being powered as before by a low-power DC power supply, supplying up to 800 V and 10 A to the LV bus. The bridge of the second unit was loaded using a resistive load. The switching frequency of the second unit was reduced to decrease power throughput and the voltage of the rectifying unit was slowly raised from zero for precaution. Testing was successful, with operation achieved at this power level and 21 kV (Figure 123). The voltage was stepped in 500-V output increments, with power held stable for at least 10 minutes before increasing the voltage to allow for thermal readjustment.

![Figure 123: HV Test Control PC Showing 21.87kV Operation. HVDC Voltage (Left), LV Bus Current (Center), LV Resonant Current and Voltage (Right) and Temperature (Bottom Left)](image)

While operating in this manner at 30 kV, the HV stack in the inverting system failed; however, because of the precautions taken, the failure was not dramatic. The tank was opened and the failure investigated. The results of the investigation are described in the next section.

### 7.3 Switch Failure Analysis

The HVDC converter consists of the LV cabinet and the HV tank assembly. Functionally, the system consists of three bridges, two of which are in the LV enclosure and one in the HV tank, which act to convert the format of the electricity in the system. Each bridge consists of diodes, which generate DC from AC input (i.e., rectify) and switches, which generate AC output from DC input (i.e., invert).
During rectification mode, 3-phase 480 V is rectified and then switched into single-phase, high-frequency voltage by the LV enclosure. The HV tank is then responsible for transforming this voltage to 37-kV high-frequency AC, after which it is rectified using diodes. This mode was successful, and to the extent that it has been tested, it indicates successful design of the HV diodes, 3-phase diodes, and the low-voltage bridge in the LV enclosure that were used to generate the single-phase, high-frequency waveform that transmits power between the LV cabinet and the HV tank.

In inversion mode, the opposite action is used to produce 480V 3-phase. The high-voltage DC is switched to generate high-voltage and high-frequency single-phase AC, which is then transformed down, then transmitted to the LV enclosure where it is rectified by the low-voltage bridge, and then switched to become 480V 3-phase. During testing in inverter mode, two major issues were identified with the high-voltage DC switching mechanism. One relates to the power handling capability of the switches, the other to the control system that triggers the switches.

When operating, a switch will dissipate power and generate heat. Thermal analysis has shown that the HV switches generate more heat than anticipated. The root cause has clearly been identified as with the switch itself, known as an IGBT. Detailed loss calculations were made during the design phase, and subsequent analysis has shown them to be correct per the manufacturer’s data sheet. Unfortunately, the component is not meeting its manufacturer’s specification for losses under these operating conditions. After conversations with the component manufacturer have not resolved this issue, it has been determined that this component will not be appropriate for the converter in this application. PPS is currently modifying the system to use a different component, which is described in detail in the next section.

The HV bridge is comprised of 16 individual 3.125-kV bridges, which are mounted in series to act as a single 50-kV bridge for the application. While analyzing the power dissipation issue as part of the root cause of system failure, concerns were raised about the stack control mechanism as well. In particular, for bridges to operate as a single unit, triggering signals must be synchronized such that all switches turn on or off at the same time. It was observed that delays were present in the control system such that one switch would be triggered later than another. The control system generates a single logical signal, which is then sent via fiber optics to the HV tank and multiplexed so that copies of the signal are sent to each trigger. Because the variation is between stages, the problem is known to be originating at the earliest step in the signal routing and transmission to the trigger boards. It is therefore a hardware problem.

The same fiber network used for triggering the switches is also used by the trigger boards for communication. Communications reliability issues have been observed such that data is not always transmitted. This issue in itself is important but not critical. This second communication problem does help confirm that the triggering issue originates within the fiber transmission network. Investigation has shown significant optical losses in the fiber transmission system, and it is clear that the lens system used to focus the beams is not optimal. Replacing the existing lenses with suitable lenses will correct this problem.

### 7.3.1 IGBT Replacement Solution

The IXYS model 5105-0005 IGBTs used in the prototype converter construction were chosen for their compact package, ability to stand up to 4,000 V, and because their predicted losses under the converter operating conditions conformed to the converter’s efficiency and thermal design requirements. Unfortunately, empirical testing of the prototype converter has shown that this IGBT generates more heat when switching at the designed frequency of 8 kHz than the manufacturer’s data sheet indicated. Test results show that this IGBT goes into thermal runaway when switching 1A of current at 3,000 V and 1 kHz, in convection cooling condition in Luminol oil, as opposed to being able to switch more than 2 A current and remaining thermally steady, which would be necessary to operate the HVDC → LVDC conversion at full design frequency and power throughput.
After being discovered during testing of the prototype, this problem has been well reviewed and understood. A trade study has been done on the possible technical solutions, and the trade-offs are listed in Table 43.
<table>
<thead>
<tr>
<th>IGBT</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>6,500 V IGBT Module 200-400 A</td>
<td>Fewer stages&lt;br&gt;Robust electrically and thermally&lt;br&gt;Ease of use for HV tank mechanically</td>
<td>Long lead time (up to 52 weeks)&lt;br&gt;Prohibitively expensive. $150K-$225K IGBT cost.</td>
</tr>
<tr>
<td>4,500 V IGBT Module 150 A</td>
<td>Same number of stages&lt;br&gt;Robust electrically and thermally&lt;br&gt;Ease of use for HV tank mechanically</td>
<td>Long lead time (up to 16 weeks)&lt;br&gt;Additional cost&lt;br&gt;$46K IGBT cost</td>
</tr>
<tr>
<td>1,700 V 80 A single IGBT</td>
<td>1 for each transformer winding (40 Stages) Available off the shelf&lt;br&gt;Multiple sources of manufacturer&lt;br&gt;Low IGBT cost: $8K</td>
<td>Transformer secondary coils have to be changed&lt;br&gt;Complexity of triggering fiber optics</td>
</tr>
<tr>
<td></td>
<td>3 in series for each transformer winding (16 Stages) Available off the shelf&lt;br&gt;Multiple sources of manufacturer&lt;br&gt;Transformer and triggering mechanism can remain the same as current 4,000-V IGBT&lt;br&gt;Low IGBT cost: $7K</td>
<td>Voltage sharing balance during switching. Technical risk</td>
</tr>
</tbody>
</table>

Table 43: IGBT Trade Study Solution Matrix

Based on the trade study, the PPS engineering team recommends redesigning the HV stacks using a Powerex 4500 V 150A dual-package IGBT. PPS believes this device will lead to a better design than previously realized. Besides finally enabling the converter to meet the specification with minimum risk and cost, it will also considerably simplify the design of the HV stack PCB, increasing reliability and reducing repair cost and time (see Section 4.5, Prospective Changes and Upgrades, for a full analysis). It presents the best compromise of minimizing the redesign of the HV stacks while achieving specified performance with minimum additional risk and cost.

### 7.3.2 Fiber-Optic Replacement Solution

As of March 2012, PPS has already prototyped the identified solution to the fiber optic triggering problems identified during system testing. The new lenses have yielded significant improvement in the sensor feedback chain. PPS is proceeding to procure new lenses to replace the triggering systems on both 500 kW prototype power converters.
SECTION 4: CONCLUSION

8.0 SUMMARY OF PROGRESS

PPS has worked with Polarconsult and technology stakeholders in Alaska since 2007 to develop a low-cost, low-power bi-directional HVDC power converter to lower the costs of interconnecting Alaska’s remote villages and communities.

In this time, the HVDC converter technology has successfully moved through Phase I (development of a bench-top prototype of the core converter technology at a limited voltage and power capacity) and Phase II (specification, design, and testing of a 1-MW, 50-kV bi-directional converter capable of both grid-tied and microgrid operation).

Under Phase II of the HVDC development effort, PPS has successfully designed and built two 500 kW prototype HVDC power converters. In the course of testing, a prototype converter was successfully operated at limited power mode to confirm the control scheme. Power flow in rectification (AC to HVDC) mode was tested first at reduced voltage in air and then at full voltage in oil. Rectification mode operation passed system bring-up tests, confirming the control scheme and proving rectifier operation.

Power flow in inverter (HVDC to AC) mode was tested in oil at limited power, and successfully demonstrated operation of the system in inverter operation. This testing successfully demonstrated basic voltage insulation compliance with the system operating at the full 50 kV. Higher-level power testing in inverter mode revealed two serious problems with components within the prototype systems that prevented full power testing in inverter mode. Upon through investigation of these issues, PPS has pinpointed the problem components, and has developed corrective actions to both problems.

**Fiber Optic Triggering System in High Voltage Tank**

A fiber optic network is used to trigger the IGBT switches inside the high voltage tank. Testing revealed problems with the triggering timing and reliability of this fiber system. Investigation revealed that the lenses used in the fiber optic system have unacceptable signal losses, causing the timing and reliability issues. PPS has identified and tested different lenses, and is proceeding to replace the lenses in both prototype converters to solve this problem.

**IGBT Switches in High Voltage Tank**

The IGBT switches in the high voltage tank were found to go into thermal runaway when the prototype converter is operated in inverter mode. Investigation has determined that these switches do not perform in accordance with the manufacturer’s specifications. Consultations with the manufacturer has not produced an acceptable remedy, and PPS has concluded that these IGBTs cannot be used for this application. PPS has identified alternate IGBTs that meet the technical and economic criteria of this project, and is proceeding to upgrade the converters with these switches. Because the switches operate at a different voltage than the original switches and have a different form factor, redesign of the high voltage stage boards is necessary.
At this time, the Phase II specification, design, construction, and test plan deliverables have been completed. Prototype testing is not completed, and is currently on hold pending completion of the corrective actions for the two problems identified in testing.

PPS continues to work on the hardware modifications needed to correct these two problems. Due to the long lead time for the new IGBT switches, the converter modifications and testing is not expected to be completed until late 2012. PPS will issue a supplemental report detailing the results of final Phase II testing when testing is completed.

50-kV operation has been achieved and power flow in the rectification mode (LVAC to HVDC) demonstrated up to the capability of the laboratory. Low-power inversion has also been performed, confirming the basic voltage and current control concept. The current state of the technology is summarized on Figure 124.

![Simplified Schematic Illustrating Technical Progress](image)

**Figure 124: Simplified Schematic Illustrating Technical Progress**

PPS continues to work on the hardware modifications needed to correct these two problems. Due to the long lead time for the new IGBT switches, the converter modifications and testing is not expected to be completed until late 2012. PPS will issue a supplemental report detailing the results of final Phase II testing when testing is completed. This supplemental report and the fully operational converters will be PPS’ final deliverable under Phase II.
APPENDIX G

HVDC SYSTEM PROTECTION, CONTROLS, AND COMMUNICATIONS
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G.1 INTRODUCTION

This appendix discusses electrical protection, controls, and communications requirements needed to operate the high-voltage direct current (HVDC) systems discussed in this report. There are certain minimum protection, control, and communication provisions required of any HVDC system.

In its simplest form, the protection, controls, and communications provisions may be manually operated. This approach is simpler to manage and less costly to install and maintain than fully automated systems, but is generally limited to point-to-point interties.

The protection, controls, and communications needs of more complex multiterminal HVDC (MTDC) systems requires the use of automated controls for operation. The requirement for automated capabilities are more costly and complicated to operate.

G.1.1 Point-to-Point Systems

Many rural HVDC interties may benefit from a point-to-point HVDC system. Low-power (<1 MW) point-to-point monopolar HVDC systems can automatically regulate power flow over the HVDC system by monitoring the HVDC voltage. No communications between the converters are needed to achieve this basic power transfer function. Existing commercial telecommunications networks in the communities can be used to provide some degree of monitoring and control function.

G.1.2 Multiterminal HVDC (MTDC) Systems

MTDC networks by definition have more than two HVDC converter stations connected to a given HVDC line. Each of the converter stations is capable of adding or subtracting power from the HVDC line.

MTDC networks are projected to be the lowest cost intertie solution for many of the rural energy networks under consideration. These regions include interconnection of several southeast communities, the adjacent communities in the Yukon-Kuskokwim Delta, and others in the Bristol Bay area. Accordingly, the technical feasibility of MTDC networks is of particular interest for Alaska's utility industry.

G.2 PROTECTIVE HARDWARE

Recommendations prepared by the Manitoba HVDC Research Centre (MHRC) discuss the general DC-side HVDC converter station hardware necessary for basic operation and protection of the HVDC system. This information is presented in Attachment G-1 to this appendix and is titled “Technical Note on HVDC Station Hardware.”

Protective AC-side hardware will include fuses or breakers, disconnects, and controls as needed to integrate with the local generating plant. Project-specific design is necessary as these interfaces can range from basic and manually operated to highly integrated and automated, depending on the needs of the particular application. The power converters developed by PPS support standard communication protocols to allow integration with overall control systems.

G.3 COMMUNICATIONS

Communications are used for monitoring of converter station status, economic dispatch of distributed generation assets, fault detection on the HVDC network, and related utility functions. Systems often include dedicated voice and data circuits to facilitate communications between different parts of the utility transmission network.
G.3.1 Fault Detection

Without differential current monitoring between the HVDC converter stations, if the total current into the HVDC system (fault current + load current) is less than the rated system current (20 amperes for a 1-MW intertie), the rectifying converter will not be able to distinguish the fault load from a normal load and will continue to input power into the HVDC line to maintain the HVDC voltage. If the fault current is high enough to exceed the capacity of the rectifying converter, then the converter will trip and announce a fault.

The result is that a low impedance fault can generally be detected by the anomalously high power draw, whereas a high impedance fault can remain undetected indefinitely with this scheme. Timely detection and correction is therefore desirable where practical.

AC systems experience similar problems detecting high impedance faults, so this type of risk is not without precedent on utility systems. The remoteness and lack of people in the vicinity of these transmission lines is a factor that should be considered when utilities evaluate this risk. A project-specific analysis should be conducted for every intertie to evaluate the cost of fault detection capabilities against the risks associated with undetected faults.

Detection of persistent high impedance faults requires, at a minimum, slow-speed communication between the converter stations and differential current monitoring. If the fault impedance is so high that the fault current is below the error of the differential current detection method (as could be the case for a downed conductor lying on ice, for example), the fault may remain unnoticed even with this detection regime in place. The only practical way to identify such faults is by physical inspection of the intertie line. Fault detection is discussed in the MHRC Technical Note on HVDC Station Hardware Recommendations included as Attachment G-1 to this appendix.

G.3.2 Infrastructure

All remote Alaska communities have access to basic telephone service and broadband internet service. At a minimum, these services are provided through geosynchronous satellite platforms. Depending on the project location, communities may be served by existing microwave relay systems, copper wire networks, fiber-optic networks, or a combination of these.

The slowest communication option available statewide is geosynchronous satellite-based communications with an inherent latency of at least 250 milliseconds for one-way communications. This latency arises from the travel time for a signal to reach the orbiting satellite and return to earth. Signal processing at the Earth stations or aboard the satellite add to this latency.

This communications method would be sufficient for a basic differential current monitoring protocol and for certain supervisory control and data acquisition (SCADA) functions for an HVDC intertie.

Options for integrated dedicated communications circuits are discussed in “Technical Note on Carrier Communications,” prepared by MHRC, included as Attachment G-3 to this appendix.

The cost-effectiveness of such options will depend on the type of HVDC intertie, and on the specific configuration of the HVDC line. Table G-1 summarizes the three basic HVDC intertie configurations and potentially suitable communications technologies for each.

<table>
<thead>
<tr>
<th>Intertie Type</th>
<th>Communications Option</th>
</tr>
</thead>
</table>

Table G-1 Communications Options with HVDC Interties
G.4 OVERHEAD INTERTIE COMMUNICATION OPTIONS

G.4.1 Optical Ground Wire

Optical ground wire (OPGW) is a type of electrical conductor that has aluminum conductor strands surrounding a stainless-steel tube at the conductor's core. Optical fibers are routed through the stainless-steel tube. OPGW is commonly used as an overhead grounding wire on AC transmission towers for lightning protection.

Depending on the application, OPGW may be suitable for use as the current-carrying conductor on an HVDC transmission line. One potentially significant drawback would be the increased complexity of repairing conductor breaks due to the stainless-steel tube and optical fibers. The need for specially trained personnel and equipment to repair this type of conductor could significantly delay the repair of a conductor break, reducing the reliability of the transmission line.

The MHRC Technical Note included as Attachment G-3 to this appendix discusses OPGW applications in more detail.

G.4.2 Power Line Carrier

Power line carrier (PLC) is a means of using a current-carrying conductor in an intertie circuit to carry a data signal as well. A coil is used to magnetically induce a data waveform onto the conductor, and a second coil is used to receive the waveform. PLC systems have been implemented on HVDC circuits and are discussed in the MHRC Technical Note in Attachment G-3.

G.4.3 Wrapped Fiber-Optic Cable

Optical fiber packages are available that can be wrapped over a messenger wire, such as the power conductor. There are two potential drawbacks with this option. The first is that the optical fiber cable would increase the wind exposure and icing surface of the conductor, increasing environmental loadings on the overhead system. The second is that the presence of the optical fiber cable would complicate the repair of broken conductors.

G.4.4 Separate Telecom Underbuild

Depending on the type of overhead line construction used for the HVDC intertie line, a conventional telecommunications underbuild may be appropriate. This could use fiber or copper depending on the specific circumstances.

G.5 UNDERGROUND CABLE INTERTIE OPTIONS
The most straightforward means of adding communications to an underground cable HVDC intertie is to include a separate fiber-optic or copper cable. Fiber optics would be preferred if a single-wire earth return (SWER) circuit is used, as it would not pick up the return current. Conventional design and construction practices are suitable for installation of co-located underground communication and power cables.

G.6 SUBMARINE CABLE INTERTIE OPTIONS

There are three general options for bundling telecommunications with submarine power cables. All three utilize fiber optics, and are accepted practice for submarine power and/or telecommunication cables. These methods are:

- Replacing one or more of the armor wires on the submarine cable with a hollow stainless-steel tube and routing optical fibers through the tube(s).
- Utilizing a hollow copper tube as the current-carrying conductor and routing optical fibers within the copper tube. This is a common cable construction on transoceanic fiber-optic cables.
- Inserting a stainless-steel tube between two layers of the submarine cable, typically between the lead sheath (if so equipped) and the polyethylene outer cable jacket. Optical fibers are routed through this tube.

G.7 BROADBAND INTEGRATION

There is an opportunity to integrate broadband communications with certain HVDC intertie projects. Where feasible, combining power and telecommunications connectivity into a single project can significantly increase the benefits of an intertie project and deliver both capabilities at a lower cost than possible through individual projects.

This opportunity is particularly promising for underground and submarine cable applications. In many applications, the incremental cost of including a fiber optic bundle with either power cable is expected to be modest compared to the resulting benefits. Attachment D-1 discusses this opportunity in the context of submarine cables.
APPENDIX G ATTACHMENTS

Attachment G-1:
MHRC Task 3, HVDC Station Hardware Recommendations
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Technical Note

Alaska HVDC: HVDC Station Hardware Recommendations

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File # 20-250-00033
Rev. 2
Date: Feb 8, 2012

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Alaska HVDC : Station Hardware Recommendations

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Alaska HVDC: Station Hardware Recommendations

February 3, 2012

Polarconsult Alaska, Inc.
Attn: Joel Groves
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Anchorage, AK 99503
USA
Email: joel@polarconsult.net

RE: Alaska HVDC Station Hardware Recommendations

Dear Mr. Groves,

The Manitoba HVDC Research Centre (MHRC), a division of Manitoba Hydro International Ltd., is pleased to provide you with technical comments regarding the Alaska HVDC Multi-Terminal VSC.

As per the Deliverables outlined in Task 3, MHRC is to provide recommendations on Loading HVDC Hardware.

If you have any questions, please contact Randy Wachal or Les Recksiedler for further discussion.

Sincerely,

[Signature]

Randy Wachal, P.Eng.
Manitoba HVDC Research Centre

cc: Les Recksiedler
Statement of Work

Task 3 Task Description as taken from the scope of work proposal, is presented below, followed by the Task 3 report.

Task 3: Recommendations on Locating HVDC Hardware

In this task, Manitoba HVDC Research Centre will provide recommendations for the source and supply of hardware that is suitable for one MW, 50 kV power transmission. Hardware of interest may include arrestors, bushings, cables, switches, insulators, and similar items. Technical adequacy, cost, and functionality in arctic conditions are all key factors in component selection. Our extensive experience in HVDC transmission in northern climates will be very helpful in this matter.

Where commercial products are not identified, Polarconsult and the Manitoba HVDC Research Center together with vendors will form a plan to develop the required component(s). The HVDC Research Centre believes that all the hardware should be available as there exists a number of back to back HVDC schemes in operation utilizing 50 kV DC. The larger concern may be costs and functionality at -50 °C. Some testing may be required to prove equipment viability for cold climate operation.

Deliverable: Bill of Material with supply sources for necessary HVDC hardware.
Alaska HVDC - Station Hardware Recommendations

Task 3 - DC Switchyard Apparatus

The following Single Line Diagram (SLD) of a Multi Terminal Singlewire earth return (SWER) system has been developed. This figure was initially presented in our Task 2 report.

Fig 1: VSC Multi-terminal Single Line Diagram.

50 kV DC equipment is generally available and has been implemented in the neutral return / electrode circuits on traditional high power dc projects since the 1960s, and in back-to-back dc projects. There is no dc apparatus that would be required for the 50 kV SWER system that is currently unavailable from a commercial vendor. Several possible station layouts are proposed. The list of DC equipment has been reviewed with possible vendors and estimates

Station Layout:

A proposed station SLD has been developed for this application based on our understanding of the Princeton Power Systems (PPS) converter design. PPS converters are 500 kVA in size. It is possible to parallel units to deliver higher levels of power. Each 500 kVA converter block requires a separate 25 kV circuit breaker and 25 kV/440V transformers on the ac side. It is important to provide isolation and grounding capability for each converter on the dc side as well, in order to deal with multi terminal connection points on dc side. A configuration of 3 disconnect switches is proposed as shown in Figure 1. The function of the switches as described as follows. There are separate line 1 and line 2 disconnects connecting the converter station to either line 1, line 2 or both. Also there is a bypass disconnect, which with line 1 and line 2 disconnects open, provide for bypass of this DC station completely to allow for station maintenance. Whether or not the switches are manually operated (using a defined safety switching procedure) or controlled automatically as motor operated disconnects (MOD) by a PLC based controller is a question of cost and operational convenience.

Each PPS converter block requires protection and voltage/current measurements for control and protection purposes. There are a number of options regarding the number and location of DC current transducers and voltage dividers presented as follows:

Option 1: Shown in Figure 2. The least-cost option is to use one set of measurements current devices, voltage devices and arrestors for the entire station. This concept reduces the number of devices required but increases the impact and complexity of the protection action. Both converter
Alaska HVDC: Station Hardware Recommendations

blocks (the entire station) would be tripped if either converter block indicated either a dc differential or a dc overcurrent condition.

![Diagram](image)

**Figure 2. Single point measurements**

**Option 2: Shown in Figure 3.** One high voltage divider and individual current measurements for each converter block. In this configuration both high and low-side current measurements are provided for each converter block. A single common high voltage measurement and high side arrester is used. Total current on the transmission line and in the electrode is calculated by adding measurements from each converter block. Each converter block has its own dc differential and overcurrent measurements. The non-faulty converter block can continue operation while the faulty block is removed from service. This feature is enhanced if motorized disconnect switches are utilized instead of manually operated switches.
Option 3: Shown in Figure 4. One high voltage divider and individual current measurements for each converter block. In this configuration both high and low side current measurements are provided for each converter block. Additional low side electrode current measurements and transmission line total current measurements are included. Total current on the transmission and in the electrode is measured directly. Each converter block has its own dc differential and overcurrent measurements. The non-faulty converter block can continue operation while the fault block is taken out of service, especially if MOD switches are utilized instead of manually operated switches, similar to option 2. The additional measurement locations add the possibility of back-up protections and an addition high-side protection zone. A single high-side arrester should provide adequate surge protection.
Alaska HVDC: Station Hardware Recommendations

DC Equipment:

Specialty DC equipment is presented as follows:

- 50 kV Dc Arrester
- 66 kV suitable for 50 kV DC operation, Motor operated disconnect (MOD) and/or integrated ground disconnect
- 50 kV DC Voltage measurements
- 50 kV DC current measurement
- 50 kV DC wall bushing
- 50 kV DC breakers are not available and not required. The PPS 50 kV converter valve design has been reviewed and determined to have inherent ability to control dc current to zero. This results in the elimination of a requirement for an external dc breaker.

1 50 kV DC Arrester: A high voltage DC arrester would typically be located at the connection between the PPS converter high voltage connection and the transmission line. This arrester would protect the converter from damage due to a lightning or surge event on the transmission line. DC arrestors are readily available from many vendors: GE, ABB, Alstom Grid, Hubbell Siemens, etc.

Alaska HVDC: Station Hardware Recommendations

Budgetary quotations were not sought but a 50 kV arrester is estimated at $10-15k USD.

2. 50 kV motor operated disconnect (MOD) and/or integrated ground disconnect. A suitable rated 66 kV class single pole ac switch would be suitable and readily available from multiple vendors. As a manually operated alternative, a 66 kV cut-out switch with or without a fuse could be used.

Budgetary quotation were not sought but a 66 kV MOD with ground switch is estimated at 6-10K$ USD, without including installation costs. A manually operated 66kV cut-out switch, operated by maintenance staff using a hotstick, is estimated at $1k USD.

3. 50 kV DC Voltage measurements: 50 kV voltage dividers measurement devices are readily available. Quotations from Ross Engineering (attached catalogue) and Schniewindt were requested. One vendor's costs were considerably higher and not listed.

Estimated cost $7K -10K USD.

4. 50 kV DC current measurement: In traditional HVDC systems 50 kV DCCT have been manufactured and delivered but at much higher current than required for the SWER system proposed. Two vendors (Alstom/Nxtrphase and Schniewindt) provided suitable solutions. Estimated cost is $25-32k USD. The Schniewindt system is a combination voltage and current system, insulated to the high voltage level. The Alstom system can be delivered at the high voltage or can also be used at ground potential circling the converter bushing or dc wall bushing. (Alstom brochure attached) which may provide a less expensive alternative. Electrode current measurements on the neutral conductor (l_dc1 on Figure 3) at the 10-100 amps range are inexpensive and estimated at $500 per location.

Estimated cost is $25-32k USD. (Location l_dch in Figure 2).

5. 50 kV Wall Bushing: At first glance this device appears not necessary. The question is whether the converter is indoor or outdoor system. If the system is indoors (because of the -20 C valve rating) then DC wall bushings will be required. The HV converter system is oil filled, and may require additional fire safety and oil containment, especially if an indoor design is utilized but oil containment may also be required outdoors. There are multiple vendors but the wall bushing is a specialty device. Type testing should not be necessary provided that long/short sheds are specified with a 35 mm /kV creepage distance. It is recommended that the bushing go through the roof of the building to avoid the problem of half wetting the bushing during rain and causing a flashover. The building shields half of outside portion of the wall bushing during a rain storm. A silicone rubber shed wall bushing can be installed in the side of the building but may be more costly.

The estimate for a 50 kV DC 100 Amp wall bushing is $15-20k USD.
Alaska HVDC: Station Hardware Recommendations

Task 6 High Impedance Transmission Line Faults:

A high impedance dc line fault can occur when the fault mechanism does not produce a low or zero dc voltage. Such a fault can occur for events like a tree branch contact with the transmission line or a fault generated from forest fire smoke. Sometimes a high impedance fault will convert to a low impedance fault naturally, but a long time high impedance ground fault is a possibility.

For transmission line high impedance ground faults, the only practical method is a slow speed (300 msec to seconds) line differential protection but that requires communication between the stations. With interstation communications available, the incremental cost of providing this protection is very minimal. The required dc current measurements at the high voltage location are already in place. Without interstation communications this is a fault type that you have to be prepared to accept the risk.

Prepared by:
Les Recksiedler
Randy Wachal
Dec 16, 2011
Sample DC CT VT specification

Schniewindt Combined Voltage and Current Transformer (Sensor)

- Rated Voltage: 50 kV DC
- Maximum continuous Voltage: 62.5 kV DC
- Rated Current: 20 Amps
- Peak Current: 100 Amps
- Creepage distance: 1750 mm
- Strike distance: 600 mm
- Temperature range: -50°C → +40°C
- SIL: 130 kV
- BIL: 150 kV
- Color of composite insulator: grey

1 COMPLETE SET (POLE) is made of:
- Quantity, 2 measuring units (sensors)
- Quantity, 2 set of Optical Powered Data Link (OPDL) (2 Local Control Units and 2x6-Channel Analog Output Modules)
Attachment G-2:
MHRC Task 2, Multi-Terminal HVDC Technical Review
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Technical Note

Alaska HVDC: Multi-Terminal HVDC Technical Review

Polarconsult Alaska, Inc.
Attention:
Joel Groves

Manitoba HVDC Research Centre, a division of
Manitoba Hydro International Ltd.
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Winnipeg, MB R3P 1A3
CANADA

File # 475.00
Rev: 1
Data: Sept 15, 2011

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Alaska HVDC : Multi-Terminal HVDC:

June 14, 2011

Polarconsult Alaska, Inc.
Attn: Joel Groves
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RE: Alaska HVDC Multi-Terminal VSC Technical Discussion

Dear Mr. Groves,

The Manitoba HVDC Research Centre (MHRC), a division of Manitoba Hydro International Ltd., is pleased to provide you with technical comments regarding the Alaska HVDC Multi-Terminal voltage source converter (VSC).

As per the Deliverables outlined in Task 2 section 5.2 of the proposal submitted to Polarconsult on August 2010, MHRC is to provide a high-level technical review of the feasibility of a multi-terminal VSC grid.

If you have any questions, please contact Randy Wachal or Les Recksiedler for further discussion.

Sincerely,

Randy Wachal, P.Eng.
Manitoba HVDC Research Centre

cc: Les Recksiedler
Alaska HVDC: Multi-Terminal HVDC

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1. Statement of Work

The Task 2 Deliverable requirement for this project is listed below:

Provide an opinion on the current state of multi-terminal direct current (MTDC) transmission networks, control protocols, and supervisory control and data acquisition (SCADA) communications requirements. The suggested deliverable for this task would be a letter report detailing the current status of MTDC research, technology, algorithms, and more, with regard to:

- Theoretical/conceptual feasibility (are there any basic theoretical limitations or fundamental outstanding concerns to MTDC networks?)
- Commercial readiness of MTDC technologies
- Suggested actions necessary to achieve commercial readiness

MHRC has recently completed a study on multi-terminal HVDC technologies applied to onshore renewables in the United Kingdom Grid, and we are developing a MTDC models for use with our Power Systems Computer Aided Design (PSCAD) study product for another client.

MTDC works in theory but has been applied in limited commercial applications. The development of a HVDC breaker is likely critical factor in the successful operation of a MTDC system in order to remove faulted elements and provide continuity of supply to the remaining system.

If an HVDC breaker is to be used, the circuit must create a current zero for the breaker to be able to open, and this will require tuning for the intended application. The International Electrotechnical Commission (IEC) and Internationale des Grands Reseaux Electriques (CIGRE) are developing standard voltages for MTDC, which shows that the industry considers these developments to be important.

2. Executive Summary Multi-Terminal VSC HVDC for Alaska

This document is a high-level technical review for a proposed distribution level multi-terminal voltage source converter (VSC) grid system for possible application in rural Alaska. There are no fundamental technologies or conceptual issues that would prevent the installation of the 50-kilovolt (kV) class direct current (DC) distribution systems, including multi-terminal type systems. The PPS full bridge design is advantageous because it can act as a DC breaker and be used to eliminate DC fault current without the requirement of de-energizing the entire converter using an AC side breaker.

This discussion paper looks at a multi-terminal 50-kV distribution system that could be implemented in Alaska.
2.1. Multi-Terminal: Voltage Source Converters (VSC) DC Distribution System Requirements

The following items are required for Multi-Terminal Voltage Source Converters DC Distribution system:

1. All connected converter to common DC voltage ratings (50 kV seems reasonable). There is no similar DC distribution system anywhere else in the world. In some respects, this is the initial standard for this class of equipment. Together, IEC and CIGRE have started work on standardization of VSC voltage levels at much higher power transfer levels (a minimum of 200 megawatts [MW]).

2. The ability to connect, disconnect, and allow the flow of power independently of any other converters connected to the grid is necessary. Each converter can be configured to be a rectifier or an inverter, as described below:

   a. At least one converter must be able to transfer power from the AC system into the DC transmission line. Generally, this converter is referenced as the rectifier. The connected AC system for the rectifier has the capability to supply the watts (and volt amperes reactive [VARs]) required by all the loads and power losses of the DC transmission connected to the system. (VARs can be produced to support and/or control the alternating current [AC] voltage; no VARs are transferred via the DC link.) The rectifier converter typically controls the DC voltage of the system.

   Additional rectifier terminals can be added to the network and be controlled by adjusting the volts direct current (VDC) reference with a droop characteristic for each rectifier. Ref [1]

   b. The inverter(s) (DC link terminals that transfer power from DC side to AC system) must be able to connect and operate in parallel with existing load side generators (e.g., diesel, wind, small hydro) or operate with no local generation.

   The VSC Inverter must be able to either set the frequency and AC voltage magnitude for the other connected systems, or work together with existing diesel generators (with voltage [VAR] and frequency [power] droop settings).

3. The ability to detect and isolate faults on DC transmission line is needed. Different approaches affect the system cost, reliability, and availability, as discussed below:

   a. DC breakers: The development of DC breakers would provide for a high reliability but also high cost. DC breakers at 50 kV and 100 DC amp range are not in the marketplace although technology makes this development technically feasible.

   The PPS-H bridge configuration should be able to function as a DC breaker and allow a converter to be isolated. A cost effective alternative is to install either manually or motor-operated DC disconnects. A motor-operated 50-kV disconnect with a minimum current interlock is an available solution. A simulation of fault responses is required to confirm the ratings.

   b. Application of line protection fuses: Application of 50 kV DC fuses for protection from DC line faults is technically feasible, depending on the DC fault current
levels. This potentially is the main DC line fault protection mechanism although simulations showing converter response to DC faults for fuse coordination and rating are required. This is the lowest cost option but may require manual intervention to restart the DC transmission system. Any current-based protection may not be able to distinguish for high-impedance faults. (For a high-impedance fault, the fault current can be at the same level as the load current. A current differential system can be developed based on DC current measurements at each converter, but this protection is relatively slow [500 milliseconds (ms) to 1 second] and requires communication between the two converters.

4. Note that automatic “control” restarts after line faults are not possible if fuses are used.

5. It is necessary to isolate faulty DC converters from the system without de-energizing every converter connected to the system. This requirement requires some discussion and understanding. If the grid is designed as a radial feeder, then any upstream transmission line fault will impact all downstream converters. It is possible to develop a configuration of the low-cost disconnect switches to allow for an automatic or manual bypass of converter station, in case of station fault or maintenance.

Figure 1: Possible System Configuration

5. The location of the DC Bus fault is an issue that is system configuration dependent meaning whether the system is radial or mesh. Locating and Isolating DC Faults in Multi-Terminal DC Systems, an Institute of Electrical and Electronics Engineers (IEEE) publication [2], evaluates the direction of current and changes in current direction as a method to identify the faulty line sections in VSC multi-terminal systems. The faulty line section between terminals should be identifiable by the isolation of the line section as described in Section 3 of this report. The location of HVDC DC fault is precisely located using a Global Positioning System (GPS) based line fault locator (LFL) system. This LFL system has been implemented on many HVDC systems with overhead lines and successfully pinpoints line fault location to within 500 meters (m). Present research (2010) indicates that this technique can be applied to multi-terminal systems and DC lines.
consisting of both overhead and cable line sections. The cost of these detection systems (estimated at $250,000 per line section) may be cost prohibitive for the distribution system.

6. Auxiliary power requirements should be defined. This is particularly important for the remote converter. What is the rating and type of energy required to blackstart the PPS converter? Typically, it would be expected to have a DC battery system and an AC charger to power the controls. The PPS high-voltage valves are immersed in oil within the transformer. Is any oil flow or transformer cooling (or heating) required to start the valves? A similar question should be asked for any auxiliary power requirements for the low-voltage power electronics.

7. Investigate future system operation where optimization of power flow and a schedule of power transfer may be beneficial to grid operation. This would involve an overall SCADA control/dispatch system and require communications with each converter station and perhaps each diesel generator.

Based on discussions with the operational engineer, it is understood that a much more simplistic system is desired at this stage. Essentially, the inverter station should act identical to a generator, and the rectifier bus is chosen with enough capacity to supply any real-time load requested by all connected rectifiers.

Action Items are identified in Section 2.2 below.

2.2. Future Action Items

Future action items are as follows:

1. Determine via simulation the response characteristics of the PPS converter to a DC transmission line fault. Key questions include:

   Can the PPS converter act like a DC breaker, or is it necessary to clear the DC fault by opening the AC breakers?

   What is the DC fault current level with the PPS design?

   Would DC fuses as per item 2 be sufficient or would they work at all?

   PPS has confirmed that the converter would operate like a DC breaker, eliminating DC current within the time required for two firing pulses (well within a cycle of the fundamental frequency). PPS also confirmed the presence of DC side capacitors that will supply an initial level of DC fault current. A large VSC HVDC transmission system at much higher voltages requires special fast action to protect the insulated gate bipolar transistor (IGBT) and integrated diode within its current limits. This current limitation does not appear to be the case for the PPS converter.

2. Determine whether fuses located on the DC line could isolate a DC line fault based on current. Key questions include: What is the impact of fuse characteristic with respect to fault clearing time? What is the limit of any fault impedance for detection? (simulation) Determine if the PPS converter can function as a DC breaker, and ensure that a DC current zero is achieved with control action.
PPS [3] states there is 6 pF capacitance in each of the 16 series connected high-voltage sections. During a DC line fault event, a DC current will be driven from this capacitance, which should be larger than the expected maximum load current. PPS confirms that within two firing pulses for the high-voltage H bridges, the converter can effectively reduce the DC current to zero and thereby the converter can function as a DC breaker. DC line fault detection and isolation can be achieved by two different mechanisms:

a. **Installation of DC fuses.** The converter firing controls can be adjusted to allow enough current to interrupt/operate the fuse based on threshold of DC current that is distinguishable and higher than any expected or normal load current. The normal load current for a 1-MW power transfer at 50 kV is 20 amps. PPS simulation results indicated that a fault with no control action is approximately 320 amps. For example, a fuse selected at 100 amps (5X rated) could be coordinated to work by increasing the time delay for the firing controls long enough to allow the fuse sufficient time and fault energy to operate. The disadvantage of this approach is that fuses require manual replacement.

b. **50-kV motor-operated disconnectors (MODs) could be used as isolation switches.** Detection of the DC line fault by either DC overcurrent measurement or DC voltage (dv/dt) can be used to activate the fast converter protection. Once DC current measurement is confirmed at zero amps, the MOD can be opened, thereby isolating the converter or the line section. Automatic sequences can be developed; therefore, the entire multi-terminal network need not be impacted by a DC line fault in one line section.

3. **Investigate different configurations and sequence controls to allow for isolation/bypass in order to start up and shut down individual converters connected to the grid, with minimum disturbance to the other converters.**

4. **Determine auxiliary power type and rating for the local converter and for any black start converter station(s).**

5. **Investigate possible DC line fault location techniques.** While location of the DC fault is imperative on a large high-power grid, it may not be as important for this application, at least at the initial stages.

6. **Investigate SCADA grid control opportunities.** A SCADA system has the potential to maximize the benefits of the multi-terminal VSC system by optimizing system operation.

### 2.3. DC Grid Operation

The DC grid system has both similarities and unique differences in operation when compared to traditional AC distribution systems. Similar to an AC system, interconnected stations must be rated for the same terminal voltage levels, except in this case the DC voltage rating is the common parameter.

System operations are somewhat different. In a passive AC distribution system, when load is connected or the AC interconnected lines are closed, the line current and phase angle between the current and voltage is determined by the passive configuration of the AC system.
Alaska HVDC: Multi-Terminal HVDC

impedances. Voltage levels and power angles are adjusted generally by the addition of passive only components, for example, loads or perhaps power factor correction capacitors banks.

Power (real and reactive) will flow from the generators toward the load(s), provided that there is sufficient generation capability online to meet the load requirements. The excitation system of the generators maintain frequency and voltage levels at the terminals of the generator to predetermined or set points limits, thereby matching the power requirements with generator real power output to system real power load demand in a continuous real-time manner.

In the DC distribution system envisioned for Alaska, the VSC inverter terminal is simply seen as another generator configured in parallel with the existing generator. Like a generator, the VSC terminal should be able to start against a no voltage (dead) network and also be able synchronize to an existing voltage waveform, if such a waveform exists. Load balancing between the VSC and generator would be accomplished with voltage reference and frequency reference droop settings. It should be possible to (with either point-to-point systems or a multi-terminal VSC system) perform the following steps:

1. Start the VSC in parallel to the existing generator
2. Stop the generator and supply load only from the VSC
3. Start the generator with the existing VSC
4. Stop the VSC with and leave the generator online to handle the load

In a VSC DC grid application, the power electronic converters are different from a classical AC system operation in that several different control tasks or duties may be assigned to a specific converter. The overall task possibilities of interconnected converters are dependent on what the other connected converters are tasked with. This may be analogous to the manner in which generation is dispatched and controlled by the isolated AC system, with the distinction that the VSC terminals could act either as generators (sources of power) or as loads (absorbers of power). The DC distribution offers increased flexibility but perhaps at a price of increased operating and protection complexity.

3. Valves Multi-terminal HVDC

The DC voltage design levels must be same (50 kV +/- 10 percent) for each converter. Each converter should be able to locally protect itself without communications from the other station.

4. Description of VSC System Control and Operation

Each VSC converter can operate in several different control modes, and, generally, two separate functions can be controlled at each terminal or converter. The terminal is defined either as a rectifier (real power in DC link) or as a inverter (real power is output from the DC link).

1. Control Input Power P (iq ref control): Set Power order In (rectifier or inverter)
2. Control Input Power $Q$ (id ref control): Set a MVar order or Control VAC magnitude (rectifier or inverter)

3. Control VDC (set VDC value): By controlling the DC voltage, the converter is effectively operating like an AC generator. As the DC voltage decreases, this indicates to increase real power input to increase the DC voltage. At least one converter in the grid must be in VDC control mode. Application of DC voltage droop at each rectifier terminal would allow multiple rectifiers to operate in the multi-terminal system.

4. Control VAC and system frequency (Islanded Mode) DC terminal behave like an isolated generator. Note that with the addition of AC voltage droop, similar to a diesel automatic voltage reference (AVR) control, and frequency droop, the VSC terminal should be able to operate in parallel with an existing generator.

4.1 General VSC Concepts

This concept can be visualized using the phasor diagrams in Figure 2. In this figure, if the converter voltage $U_C$ lags the grid voltage $U_F$, active power will flow from the AC system to the DC bus (rectifier mode), and vice versa. In addition, the converter absorbs reactive power if $U_C < U_F$, and vice versa.

![Figure 2: Phasor diagrams demonstrating (a) active power control, and (b) reactive power control, in VSC-HVDC](image)

The phase angle $\delta$ and the magnitude $U_C$ can be controlled either directly or by using a vector control strategy. In vector control, the converter current phasor is controlled to satisfy the phasor diagrams in 2, in order to achieve the desired active and reactive power flow. Vector control also allows for decoupled $P$ and $Q$ control.

4.2 VSC Control Mode

As stated in the section above, VSC offers several control mode options to each VSC terminal. These options are split in three categories: (1) controls for active power ($\delta$ angle), (2) reactive power (VAC magnitude), and (3) Islanded modes. The possibility of controlling $P$ and $Q$ independently is enabled by using the decoupling technique. The Park transform used in the decoupling process is aligned in phase with the voltage such that controlling the active power is associated with the $d$ axis.
Alaska HVDC: Multi-Terminal HVDC

component, and controlling the reactive power is associated with the q axis. The resonant converter
configuration may or may not use this control D-q strategy.

Under the islanded control mode, a voltage wave is generated according to a given AC voltage
order. The active and reactive power consumption is dictated by the load connected to the terminal.

Table 1 summarizes the control modes.

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<th>Control mode</th>
<th>Controlled variable</th>
</tr>
</thead>
<tbody>
<tr>
<td>P, VDC</td>
<td>δ, VDC</td>
</tr>
<tr>
<td>Q, VAC</td>
<td>VAC magnitude</td>
</tr>
<tr>
<td>Islanded mode</td>
<td></td>
</tr>
</tbody>
</table>

Table 1: VSC Control Modes

4.2.1 Reactive Power: Q-axis Control

Figure 3 shows the q-axis control. The Q-component current reference $i_{ref}$ is controlled by either the
reactive power regulator or the AC voltage regulator loops. The selection is made by means of a
"two-input selector" component.

![Diagram of Reactive Power Control](image)

Figure 3 Q-axis Control: Reactive Power Control or AC Voltage Control

4.2.2 Real Power: D-axis Control and DC Voltage Droop Control

Figure 4 shows the D-axis control for a typical high power VSC controller. The D-component current
reference $i_{ref}$ is controlled by either the active power regulator or the DC voltage regulator loops.
The selection is made by means of a "two input selector" component.
In the active power control loop, the rate of the power order \( (P_{\text{ref}}) \) change is limited to a prespecified slope. Similarly, the DC voltage order applies a ramp to any changes in the DC voltage order.

As part of the VDC control mode, a voltage droop factor can be integrated into the control loop(s). For the series resonant converter, which has a low DC voltage and a high DC voltage bus, the voltage droop would be applied to the high bus. It should be possible to operate both a classic converter and a series resonant converter in the same multi-terminal VSC system. Flexibility and/or the ability to reconfigure the control system, particularly in the implementation of droop controls, would be an advantage when integrating different converter types in the same system at a future date.

When operating under the VDC control mode, the droop will determine the power sharing and the voltage levels of the terminals. This option together with the VDC limiting option creates a V-I characteristic as shown in the figure below:

![Voltage Droop Characteristic](image)

Figure 5 Voltage Droop Characteristic: Positive current corresponds \( I_{dc} \) flowing from the AC system into the DC system.

The DC voltage reference can be limited or drooped can be implemented within the D-axis control. Alternatively, the droop function can be developed in the higher-level system (SCADA) controller.
4.2.3 Series Resonant Converter

Figure 6 is an illustration of a DC-DC series resonant converter. This use of IGBT elements allows this converter to have bi-directional power flow. The converter can be operated as rectifier or inverter. This type of converter has two DC bus voltages (low and high). The low-voltage DC bus is converted to high-frequency AC (approx. 8 kilohertz [kHz]). There is a special high-frequency transformer between the two converters. The high-frequency AC is converted to the high DC voltage using series H bridge converters. In Figure 6, two high-side series converters are shown. The PPS design has 16 H bridge converters in series. Upon a DC line fault, any capacitance connected to the DC bus will discharge through the fault. By rapid detection and blocking the pulses on the high side converters, it is possible to prevent any additional DC current from being transmitted by the converters through the DC line fault. This fast-acting protection functions like a DC breaker in this configuration.

![Series Resonant Converter Diagram]

Figure 6: Series Resonant Converter

4.2.4 Islanded Control (With and Without Parallel Generators)

Using the islanded control mode, a voltage wave is generated according to a given AC voltage order (the VSC converter sets the AC system voltage magnitude [Vref] and frequency [Fref]). The active and reactive power levels delivered by the VSC are dictated by the load(s) connected to the terminal, which vary in real time as the system load adjusts. For the VSC converter to operate in parallel with a generator, synchronization with the existing generator is required, if that generation is in service. The AVR (Vref setting) needs to be drooped appropriately between the VSC terminal and any existing generator to allow sharing of voltage control (VARs). The governor settings (Fref) also need to be drooped (or otherwise adjusted) between the VSC terminal and any other generation to share load (power) duty between them. Figure 7 shows the PSCAD implementation of the Islanded control without droop inputs indicated.
Alaska HVDC: Multi-Terminal HVDC

Figure 7: Islanded Control

To optimize fuel or other resource usage [5], a higher level control system (i.e., SCADA), either an automatic or manual dispatch, may be required. This system controller would set the power references based on the different generation types available. For example, if the VSC terminal has sufficient rating and capacity to supply the entire load, then after synchronization and parallel of the VSC and diesel generator, the diesel unit may be turned off. If the load exceeds the VSC capacity, then a diesel generator or the other generation alternatives may be started (synchronized) with the VSC.

4.2.5 Additional Control Features Included in a Typical VSC Control

The following features may be included in the higher level of VSC controls:

- **Converter current limiting.** A maximum current limit input in per unit was included in the model. The method implemented in the PSCAD model effectively limits the current in the dq components, thus effectively limiting the AC current. It does so by converting the initial dq current reference idref and iqref into polar coordinates, then applying the limit to the magnitude of the vector and finally converting the current reference back into dq Cartesian coordinates. This means that the angle of the current order is preserved after its magnitude has been limited. Figure 8 shows the implementation of the current limiting action in PSCAD.

Figure 8: Converter Current Limiter in PSCAD
5. References


3. E-mail from Frank Hoffman (PPS) Dated April 1, 2011 (included in Appendix).


6. **Appendix A: Email Correspondence re: PPS Dymola Simulations**

**From:** Frank Hoffmann  
**Sent:** Friday, April 01, 2011 5:09 PM  
**To:** Paul Heavener; Zahra Mohajerani  
**Cc:** Erik Limpaecher; Mahesh Gandhi  
**Subject:** RE: PPS Dymola Simulations

Hello Randy –

Let me try to answer the questions first:

1) You are correct. The control system can stop switching the H-bridges of the HV chopper within two pulses upon detection of a fault. In that case, the stacked DC caps (16 of them in series, 6 uF each) are the only energy storage connected to the DC link. They would discharge into the shorted DC link.

2) I'm not sure if I get this one. Do you mean that only the current sensor measuring the DC current fails? In that case, the DC voltage inside the converter will drop below a (settable) threshold and the unit will stop operating. If the whole control system fails then there's nothing firing the IGBTs and the is no DC voltage ...

About the files:

You should have found a folder of "mat" files – one for each simulation we've done. These files can either be opened in Dymola as described in Zahra's tutorial, or they can be opened with Matlab (they contain a struct with all vector descriptions and data). For browsing the data files, opening them in Dymola is the preferred way as it allows you to then select the vectors you're interested in Dymola. Just in case, I'm attaching a tutorial Zahra has written about how to look at the data in Matlab.

We have not performed a simulation with two units, one as source and one as sink, yet.

Please let us know if this helps?

Regards,

Frank
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Attachment G-3:
MHRC Task 5, Carrier Communications
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Technical Note

Alaska HVDC: Task 5 Carrier Communications

Polarconsult Alaska, Inc.
Attention:
Joel Groves

Manitoba HVDC Research Centre, a division of
Manitoba Hydro International Ltd.
211 Commerce Drive
Winnipeg, MB R3P 1A3
CANADA

Prepared By: Murray Matiowsky, Manitoba Hydro Telecom
Reviewed by: R. Wachal, Manitoba HVDC Research Centre

File # 20-250-00033
Rev: 1
Date: Sept 16, 2011
Alaska HVDC: Task 5 Carrier Communications – Technical Note

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September 16, 2011
Alaska HVDC : Task 5 Carrier Communications – Technical Note

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Alaska HVDC: Task 5 Carrier Communications – Technical Note

September 14, 2011

Polarconsult Alaska, Inc.
Attn: Joel Groves
1503 West 33rd Ave., Suite 310
Anchorage, AK 99503
USA
Email: joel@polarconsult.net

RE: Alaska HVDC Task 5 Carrier Communications – Technical Note

Dear Mr. Groves,

The Manitoba HVDC Research Centre ("MHRC"), a division of Manitoba Hydro International Ltd., is pleased to provide you with technical comments regarding Task 5: Carrier Communications as part of the Alaska HVDC project.

As per the Deliverables outlined in Task 5 of the proposal submitted to Polarconsult in August 2010, MHRC is to locate experts from Manitoba Hydro’s Communications Department in order to provide meaningful discussions on implementing carrier-type communications systems on DC conductors, and determine if existing designs can be adapted to a communications system over long-distance 50 kV HVDC circuits with sufficient bandwidth and reliability to service the SCADA systems for point-to-point and/or MTDC networks.

If you have any questions, please contact Randy Wachal for further discussion.

Sincerely,

Randy Wachal, P.Eng.
Manitoba HVDC Research Centre

cc: Les Recksiedler, Manitoba HVDC Research Centre
Alaska HVDC : Task 5 Carrier Communications – Technical Note

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1. Background Task 5

As per the Deliverables outlined in Task 5 of the proposal submitted to Polarconsult in August 2010, MHRC is to locate experts from Manitoba Hydro’s Communications Department to provide meaningful discussions on implementing carrier-type communications systems on DC conductors, and determine if existing designs can be adapted to a communications system over long-distance 50 kV HVDC circuits with sufficient bandwidth and reliability to service the SCADA systems for point-to-point and/or MTDC networks. The following technical review was prepared by Murray Matiowsky, Manitoba Hydro Telecom, a Division of MHI.

2. Task 5: HVDC Communication Systems

There are presently a number of HVDC projects which use power line carrier (PLC) communications. A notable system is the HVDC link between Mozambique and South Africa which is over 1000 km operating at +/- 533 kV. Clearly PLC systems can be used on HVDC transmission lines.

MHRC has the following list of questions related to this task:

1. Would it work to have PLC communications on a 50 kV DC circuit 50-75 km?
   a. Is such a system commercially available (possible vendors)?
2. Performance / Bandwidth and expected reliability
3. Cost
4. Other communication options
   a. Fibre
   b. Microwave
   c. Other alternatives
   d. Performance and cost of other options
      i. Perhaps fibre or something else would be an option if it brought communication ancillary services with it.

2.1 Communication System Requirements for Power Systems

In a traditional AC power transmission line application, a high performance and high reliability communications system is required to interconnect the generation and load ends to operate protection schemes as well as for metering and control. This same telecom system is typically used for administrative voice and data communications as well. The high performance requirement is primarily required for the protection scheme with a latency of no greater than 12 milliseconds end to end. This is necessary to ensure that dangerous over current conditions do not exceed one 60 Hz cycle. Meeting this stringent requirement ensures that equipment and field workers in the vicinity of the equipment are protected from damage and injury. High
**Alaska HVDC: Task 5 Carrier Communications – Technical Note**

Voltage DC transmission lines have the same requirement in order to protect the equipment up and downstream from the HVDC transmission line.

Three proven technologies have been used to implement a communications system capable of meeting performance requirements, as follows: Power Line Carrier, Microwave Radio and Fiber Optic Cable.

### 2.2 Power Line Carrier Systems

Power line carrier systems use existing conductors to transmit and receive radio signals in the range of 50 to 500 kHz. Continuous tones are transmitted for failure detection. Such systems are extremely cost effective and meet power system performance requirements but have the least capacity with 2 voice grade channels per radio. There are three key elements in a power line carrier: the main coil (wave trap), a tuning device (radio), and lightning arrestor. The wave trap is used to block the high frequency carrier signal while allowing the 60 Hz to pass. The cost for an end to end solution is in the range of $200,000 - $400,000 depending on the distance and characteristics of the transmission line.

Possible PLC suppliers: ABB

### 2.3 Microwave Systems

Microwave radio communications have traditionally been used by most utilities around the world over the past 40 years. A well designed microwave radio will meet all protection, metering and control requirements as well as providing a modest amount of voice and data communications sufficient for most utility operational requirements. Repeaters are required every 40 miles. Such systems have a tendency to suffer from fading in the spring and fall, resulting in what is known as crosstalk errors, but are reliable otherwise. To maintain performance and reliability microwave systems require regular and costly maintenance of radio towers and antennae as well as their feed lines and radios although digital radios require less maintenance and tend to have self-diagnoses that warn operators of problems. In remote areas helicopter access may be the only viable way to access repeater sites. Repeaters sites in remote areas will also require a power source which can be achieved with a distribution line where available or continuous operation of a diesel generator. In the case of a diesel generator, fuel will need to be delivered regularly to ensure an adequate supply. Guyed repeater towers will be needed to gain the height needed to reach the next radio site and will require annual excavation to ensure the anchors have not corroded. Modern technologies can deliver data rates of about 150 Mbps. The initial capital expenditure for a microwave radio system can be very high because of the need to install towers, back-up power systems and buildings in addition to radio equipment and antennae. The total cost per radio site will be in the range of $1,000,000 to $1,500,000 depending upon the span to be covered and terrain conditions.

Microwave suppliers: Alcatel, NEC, Harris
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2.4 Fibre Optic Systems

Many utilities have been transitioning their backbone communications systems from microwave to fiber optic cable systems. Once installed such systems require little maintenance and have life cycles that exceed 50 years. There are three methods of implementing fiber optic communications in the case of a transmission line, as follows:

1. Optical Ground Wire (OPGW),
2. Buried
3. All Dielectric Self-Supporting (ADSS).

Buried cable is constructed with protective layers (3 polyethylene and 2 corrugated steel jackets) that can be buried directly using a plow, a trench or directional drill. For added protection and reliability such cables can be blown into a high density polyethylene duct using compressed air to lubricate the cable as it is inserted into the duct. The cost for a buried fiber installation will vary between $30 and $90 per meter depending on terrain, installation methods, cable characteristics and the number of splice cases required. A single cable reel can hold up to 8 kilometers of 46 strand double armor triple jacket cable; hence the need for splice vaults and cases a minimum of every 8 km. Additional splice cases may be required where additional drops are deemed necessary.

OPGW cable consists of a hollow stainless steel core surrounded by aluminum conductive strands and has the outward appearance of an ACSR cable. Forty eight optical fibers are typically inserted in the hollow core, which is deemed to be more than sufficient to meet all present and future requirements for the life of the cable plant. The lifespans of a fiber optic cable is considered to be greater than 50 years for depreciation purposes; however, the actual life will likely be 70 - 80 years. With the development of new technologies this life span could be extended further. Installation costs for OPGW are lower relative to buried fiber ranging between $30 and $60 per meter.

Also fewer repeaters are required as compared to a microwave radio installation. Depending on the fiber characteristics and the desired bandwidth, repeaters can be placed every 150 – 200 kilometers. The capacity available in a fiber optic cable implementation is substantially more than is required for power system operations and therefore additional services can be delivered to those communities situated along the transmission line. This has proven to be a significant advantage for isolated communities where satellite communications is the only option as well as an additional source of revenue for the asset owner.

OPGW conductor could be utilized as the main current carrying conductor (up to a limit 100 amps DC) and include the optical communication for the Alaskan SWER concept. For a 50 km system installed costs are estimated at $1.5M to $3M. Special attention is required to isolate the 50kV outer conductor from the inner fiber optic cables. High quality ancillary communication services, (such as high quality Internet, television, etc.) would also be available at the remote communities interconnected by the SWER.

Special fiber splicing arrangements of the inner core fiber cable would have to be designed to accommodate the 50 kV DC voltage level on the outer conductor. If this approach was used the installation of the main SWER conductor could be deducted from the cost of the integrated
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Conductor. One commercially available product available in the marketplace is an external wrapped spiral fiber that has been utilized at voltages up to 133 kV AC. Reference: www.attcale.com/products/fiber_optic_cable/skywrap/

Fiber optical cable suppliers:
- www.attcale.com
- www.coming.com
- www.drakausa.com
- www.sfpcd.com/english
Our comprehensive COSI range (Compact Optical Sensor Intelligence) includes innovative digital instrument transformers for AC and DC applications. The COSI-NXCT F3 optical current sensor is the most flexible, portable optical current transformer sensor available and the easiest to install.

Three product types are available, Type A, Type B, and Closed Loop, each optimized for different applications and specifications.

Each F3 has a wrap-around sensing head around high-voltage bushings, generator buses, and other conductors in ways not possible with conventional Current Transformers.

The sensing loop is an all-dielectric cable, which connects to the standard Alstom Grid electronics, giving the user the same high performance capability and output options as the high-voltage optical CT. It is an ideal solution for installations in difficult spaces, on a temporary or permanent basis.

Type A F3 Current Transformer
The type A F3 CT is a fiber optic current sensor consisting of an electronic module, a fibreglass sensor box, and a flexible PVC conduit wrap-around sensing cable.

The sensing fiber resides in the PVC conduit, which attaches directly to the sensor box.

Standard telecommunications optical fiber cabling and wire cabling connect the electronics module to the sensor box. Because the sensor box has a wire connection to the electronics, it should not be installed in a high-voltage environment.

However, it may be installed in a low-voltage environment, allowing the sensing cable to be wrapped around a high-voltage bushing.

Customer Benefits
- Flexible Form Factor
- Easy installation and configuration
- Improved measurement performances
- On-site calibration tool
- World-wide standard for interconnection
Flexible Form Factor

The type A F3 CT has metering grade accuracy to 0.15%, and it can measure both AC and DC currents with this accuracy from 1 A to 160 kA, depending on the number of sensing cable wraps used to measure the current.

The cable length between the electronics module and the sensor box can be up to one kilometer. The sensing cable has a standard length of 20 m, but other lengths may be specified at the time of order.

The output of the type A F3 CT can be an analog voltage (11.3 V full scale) a current (1 A or 5 A formats), or digital (IEC 61850).

- Applications include GIS metering and protection, wrap around bushing for metering or protection, DC valve hall measurements for metering and protection, and very large aperture applications.

Type B F3 Current Transformer

The type B F3 CT is a fiber optic current sensor consisting of an electronics module, a fiberglass sensor box, and a flexible PVC conduit wrap-around sensing cable. The sensing fiber resides in the PVC conduit, which attaches directly to the sensor box. Standard telecommunications optical fiber cabling connects the electronics module to the sensor box.

In the type B sensor, no wire connection is required at the sensor box, allowing it to be installed in a high-voltage environment.

The type B F3 CT is a protection grade sensor with accuracy to 1%. It measures AC currents over a bandwidth of 10 Hz to 3 kHz and can cover a range from 1 A to 160 kA, depending on the number of sensing cable wraps used to measure the current.
The cable length between the electronics module and the sensor box can be up to 10 km. The sensing cable has a standard length of 20 m, but other lengths may be specified at the time of order. The output of the type B F3 CT can be an analog voltage (11.3 V full scale), a current (1 A or 5 A formats), or digital (IEC61850).

Applications include GIS protection, wrap-around bushing for protection, temporary field service measurements, and underground cable monitoring.

The underground cable monitoring application uses sensors at both ends of the underground line to measure the differential current. When the underground cable is in good condition, there is little to no difference between the two measured currents. But, when the cable between the two sensors has failed, there is a substantial differential current.

Because the type B F3 CT sensor box can be placed up to 10 km away from its associated electronics, this line differential current protection scheme can be implemented at remote sites where there is no substations or power available (such as an overhead to underground line transition).

Closed Loop F3 CT

The Closed Loop F3 CT is a fiber optic current sensor consisting of an electronics module, a fiberglass sensor box, and a flexible PVC conduit wrap-around sensing cable.

The sensing fiber resides in the PVC conduit which attaches directly to the sensor box. Standard telecommunications optical fiber cabling and wire cabling connect the electronics module to the sensor box. Because the sensor box has a wire connection to the electronics, the sensor box should not be installed in a high-voltage environment. However, it may be installed in a low-voltage environment allowing the sensing cable to be wrapped around a high voltage bushing.

The Closed Loop F3 CT uses a current feedback to null the impact of the sensed current on the sensing cable. As a result, the Closed Loop F3 CT achieves accuracies better than 0.1%. Both AC and DC currents are measured from 1 A up to >500 kA. Because of the need to close the loop with current, the distance between the electronics module and the sensor box is limited to 100 m. The sensing cable has a standard length of 20 m, but other lengths may be specified at the time of order. The output of the Closed Loop F3 CT can be an analog voltage (11.3 V full scale), a 1 A current, or digital (IEC61850).

Applications include high accuracy metering, field calibration, and ultra-high current sensing. For industrial processing applications above 25 kA, including aluminum smelting, the Closed Loop F3 is sold through our OEM partner, Dynamp LLC.

Dynamp 125 kA 0.1% class DC CT for aluminum smelting
## FLEXIBLE OPTICAL CURRENT TRANSFORMER

### COSI-NXCT F3

**Current Transformer Specifications**

- Single phase, three phase, and six phase system configurations available.
- Sensor enclosure: fiberglass box.
  - Type A and Type B: Dimensions: 14 x 12 x 5.74 inches
  - Weight: 20 lbs
  - IP65
  - Closed Loop F3: Dimensions: 16 x 14 x 5.74 inches
  - Weight: 45 lbs
  - IP66
- 20-meter length wrap around sensing fiber standard, other lengths available on request.
- Programmable output scaling
- Output format options: analog voltage (IEC 60044-8 200 mV and 4 V format), current (1 A or 5 A metering format), digital (IEC 61850)

<table>
<thead>
<tr>
<th>F3 P/N</th>
<th>Type A</th>
<th>Type B</th>
<th>Closed Loop</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class 1</td>
<td></td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Class 10</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class 2s</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class 3</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class 4</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AC</td>
<td>(up to 50 kHz)</td>
<td>(up to 10 kHz)</td>
<td>(up to 20 kHz)</td>
</tr>
<tr>
<td>DC</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AC/DC</td>
<td></td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Sensor box HV isolated</td>
<td>x</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max distance between electronics and sensor</td>
<td>1 km</td>
<td>10 km (to power)</td>
<td>100 m</td>
</tr>
<tr>
<td>Fiber cable required</td>
<td>x</td>
<td>x</td>
<td></td>
</tr>
<tr>
<td>Copper cables required</td>
<td>x</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Rated Current Range vs. Number of Fiber Wraps**

<table>
<thead>
<tr>
<th>No of Fiber Wraps</th>
<th>Minimum Rated Current*</th>
<th>Max Rated Current*</th>
</tr>
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<tbody>
<tr>
<td>1</td>
<td>2000 A</td>
<td>80 kA</td>
</tr>
<tr>
<td>2</td>
<td>1000 A</td>
<td>40 kA</td>
</tr>
<tr>
<td>5</td>
<td>400 A</td>
<td>16 kA</td>
</tr>
<tr>
<td>10</td>
<td>200 A</td>
<td>8 kA</td>
</tr>
<tr>
<td>20</td>
<td>100 A</td>
<td>4 kA</td>
</tr>
</tbody>
</table>

* Percent accuracy class from 1% to 2% of rated current.
TRANQUELL® SURGE ARRESTERS

Special Applications of TRANQUELL Metal Oxide Technology

In some power system installations, special TRANQUELL arresters are required to address the particular needs of the application. These requirements include high energy capability, low protective levels, or unusual voltage stresses such as harmonic or dc voltages. GE has applied the unique capabilities of metal oxide disks in many situations including series capacitors, HVDC converter stations, and transmission lines.

HVDC Terminals

HVDC back-to-back, separated, and multiterminal converter stations provide a unique opportunity for the application of TRANQUELL surge arresters. Stable protective characteristics and multiple column arrester designs simplify the insulation coordination process on both the AC and DC systems.

In many cases, equipment insulation can be reduced resulting in a reduction in size and cost of the terminal. TRANQUELL AC and DC surge arresters can be applied to systems where a wide variety of steady-state voltage waveshapes are encountered. For example, bridge arresters are exposed to DC voltages with periodic polarity reversals while AC filter reactor arresters are exposed to power frequency and harmonic voltages. GE has supplied the arresters for many HVDC converter stations worldwide.
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APPENDIX H

CANDIDATE HVDC SYSTEM DEMONSTRATION PROJECTS
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H.1 INTRODUCTION

This report includes the evaluation of potential projects for demonstration of the high-voltage direct current (HVDC) technology in Phase III. This effort consisted of the following major activities:

- Defining the primary objectives of a demonstration project;
- Defining the key criteria for candidate projects;
- Identifying potential intertie projects;
- Contacting local stakeholders to gather information about those projects; and
- Evaluating the projects for suitability as a demonstration of this HVDC technology.

This appendix summarizes and presents the findings from these activities. A specific site has not been selected for a demonstration project at this time. Polarconsult will continue to work with the various project stakeholders to identify a specific demonstration project in the future.

H.2 DEMONSTRATION PROJECT OBJECTIVES

Polarconsult worked with the Stakeholder’s Advisory Group (SAG), individual stakeholders, Polarconsult subcontractors, and other interested entities over the course of Phase II to refine the objectives of the Phase III demonstration project for the proposed HVDC system.

Defining these objectives was a major topic of discussion at the 2nd SAG Meeting, held in Anchorage on January 14, 2011. A series of conference calls were held with members of the SAG in January and February 2011 to refine the objectives of the demonstration project and the candidate sites identified by Polarconsult.

These efforts established the following as key objectives of the demonstration project:

- Facilitate expeditious advancement of the proposed HVDC system. A demonstration project that cannot be implemented for years due to prohibitive cost, regulatory impediments, or similar factors could unduly delay commercial acceptance of the system and widespread deployment in Alaska.
- Demonstrate to stakeholders (Alaska utilities, policy makers, regulators, etc.) that the HVDC converter is functional, robust, and practical under the logistical, electrical, and environmental operating conditions typical of rural Alaska applications.
- Demonstrate that innovative aspects of the transmission line construction, such as use of single-wire earth return (SWER) circuits in permafrost regions, new overhead line designs or materials, and similar system elements are reliable, cost-effective, and appropriate for rural Alaska intertie applications.

One of the key insights provided by the SAG was that the commercialization plan for the proposed system, including the demonstration phase, should be designed in a measured manner that incrementally demonstrates and proves up the various technical aspects of the system. It was suggested that a single overly ambitious demonstration project that features several innovative technologies increases the risk that any one noncritical technical failure may become interpreted as a failure of the overall system.

The goal of Phase III will include full testing of the converter system, including the manufacturer and third-party functional, compliance, and performance testing needed to move the converter technology
from advanced prototypes to a commercial product. Phase III will also include a full scale field
demonstration of the HVDC technology on a utility system in Alaska. The specific project details are
dependant on the candidate location selected for the intertie. Phase III is intended to be the final proof-of-
concept project, to be followed by commercial deployment of the system.

H.3 CRITERIA FOR DEMONSTRATION PROJECT SITES

Phase III demonstrations will present a fully functional real-world HVDC transmission line using the
converter technology developed in this project. Available inventories of Alaska intertie candidates are
presented in *Distributing Alaska's Power* (WH Pacific, 2008) and *Rural Alaska Electric Utility Interties
Survey* (Neubauer, 1997).

Polarconsult conducted an extensive review of potential candidate demonstration projects, starting from
these resources and other current information. The resulting list of potential demonstration projects is
not comprehensive, as there are numerous opportunities for rural Alaska power interties, but it does
provide a representative selection of geographic and technical criteria for demonstration sites. Three
types of demonstration projects were considered, listed below. Key factors about the suitability of these
types of projects are summarized in Table H-1.

1. **New Rural Alaska HVDC Intertie.** This option would be a fully functional HVDC intertie
demonstration. It would consist of building a new intertie between two Alaska villages, or
possibly between a larger grid and a village.

2. **New AC Distribution Line Extension Operated as HVDC for Trial Period.** This option would be
a new alternating current (AC) distribution line extension from an existing system to a new area. The
line extension would be operated as an HVDC line for the demonstration period, and then
converted to AC after the demonstration project concluded.

3. **Existing AC Distribution Line Extension, Converted to HVDC for Demonstration Then
Switched Back to AC.** This option would convert an existing AC distribution line to HVDC for the
demonstration project. The line would be converted back to AC after the demonstration project
concluded.
<table>
<thead>
<tr>
<th>Projects</th>
<th>Permanent HVDC Intertie Between Two Alaska Villages <em>(Operate as HVDC)</em></th>
<th>AC Distribution System Extension <em>(Operate as HVDC, then convert to AC)</em></th>
<th>Existing AC Distribution Line <em>(Convert to HVDC, then revert to AC)</em></th>
</tr>
</thead>
<tbody>
<tr>
<td>Function</td>
<td>Intertie limited to power transmission (no services along intertie route)</td>
<td>Minimize intertie length (to maintain affordable budget and help avoid funding delays)</td>
<td></td>
</tr>
<tr>
<td>Power Capacity</td>
<td>Peak load limited to 500 kW (to utilize existing prototype converters)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost &amp; Length</td>
<td>Intertie length of 10+ miles to achieve cost savings over an AC intertie</td>
<td>Minimize intertie length (to maintain affordable budget and help avoid funding delays)</td>
<td></td>
</tr>
<tr>
<td>Schedule</td>
<td>3 to 5+ years</td>
<td>1-3+ years</td>
<td>+/- 1 year</td>
</tr>
<tr>
<td></td>
<td>Requires (design, permitting, right-of-way, funding, etc.)</td>
<td>(May require right-of-way acquisition, design, permitting, funding, etc.)</td>
<td></td>
</tr>
<tr>
<td>Benefits</td>
<td>1. HVDC demonstration.</td>
<td>1. HVDC demonstration.</td>
<td>1. HVDC demonstration only. Hosting utility incurs costs and customers incur service interruptions.</td>
</tr>
<tr>
<td></td>
<td>2. New intertie lowers utility costs to both communities.</td>
<td>2. Utility/public receive an AC line extension.</td>
<td></td>
</tr>
<tr>
<td>Organizational Complexity</td>
<td>Two utilities involved, may require RCA involvement and regulatory oversight.</td>
<td>Single utility involvement (to reduce interconnection or regulatory issues).</td>
<td>Single utility involvement (to reduce interconnection or regulatory issues).</td>
</tr>
<tr>
<td>Technical</td>
<td>Intertie connections at 480-V bus of existing power plants.</td>
<td>Intertie connections at distribution voltage. Step up/down transformers required.</td>
<td>Intertie connections at distribution voltage. Step up/down transformers required.</td>
</tr>
</tbody>
</table>

kW: kilowatt  
RCA: Regulatory Commission of Alaska  
V: volt
H.4 POTENTIAL DEMONSTRATION PROJECTS

H.4.1 Summary of Projects Considered

The interties projects reviewed by Polarconsult are listed by category in Table H-2 and shown on Figure H-1. More detailed information and preliminary maps of potential intertie routes are provided on the following pages.

<table>
<thead>
<tr>
<th>Table H-2 Potential HVDC Demonstration Projects</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>AC Line Extension</td>
</tr>
<tr>
<td>Existing AC Line Demonstration</td>
</tr>
</tbody>
</table>

Acronyms and Abbreviations:

NEC Nushagak Electric Cooperative, Inc. CEA Chugach Electric Association, Inc.
NSB North Slope Borough HEA Homer Electric Association, Inc.
NJUS Nome Joint Utility Service CVEA Copper Valley Electric Association, Inc.
IPEC Inside Passage Electric Cooperative, Inc. KEA Kodiak Electric Association, Inc.
SEAPA Southeast Alaska Power Agency OED City of Ouzinkie Electric Department
GEC Gustavus Electric Company MEA Matanuska Electric Association, Inc.
AVEC Alaska Village Electric Cooperative, Inc. GVEA Golden Valley Electric Association, Inc.
Figure H-1  Location Map for Potential Demonstration Project Sites
H.4.2 HVDC Demonstration Projects on Existing AC Distribution Lines

This section provides overviews of potential HVDC demonstration projects that would be implemented on existing AC distribution lines. The AC line would be converted to HVDC service for the demonstration project, and after the HVDC demonstration is completed, the line would be reverted to AC service. The candidate interties are organized geographically, moving from northwest to southeast.

H.4.2.1 Dillingham to Aleknagik AC Line Conversion (Demonstration Only)

This is an existing, approximately 25-mile-long, three-phase AC intertie that provides electric service to Aleknagik from Nushagak Electric Cooperative’s diesel generators in Dillingham (Figure H-2). The line is understood to be of standard Rural Utilities Service (RUS) construction, insulated to 34.5 kilovolts (kV) but operated as a 7.2/12.4-kV intertie. This existing line would be converted to HVDC operation for a demonstration period, and then reverted to normal AC operation after the demonstration is completed.

The load in Aleknagik is not known. If it exceeds 500 kilovolt-amperes (kVA), then either additional intertie capacity or diesel generators in Aleknagik would be required.

The existing insulators on the intertie should be sufficient for service at 50 kV DC. Because the line is insulated at 34.5 kV (approximately equal to 60 kV DC), there may be issues with buildup of contamination under a static DC electric field leading to arcing over the insulators. If this became an issue, the insulators would need to be cleaned. Analysis is warranted to see if the HVDC intertie voltage should be reduced to avoid this problem. Voltage reduction would also decrease the power throughput capability of the HVDC converters.

H.4.2.2 Eureka AC Line Conversion (Demonstration Only)

This is an existing, approximately 50-mile-long, single-phase, 14.4-kV distribution line owned and operated by Copper Valley Electric Association, Inc. (CVEA) serving the communities and residents west of Glennallen, Alaska (Figure H-3). The demonstration project would consist of converting a segment of this line to HVDC operation for the demonstration period, then converting it back to AC operation.

The geotechnical conditions along this line are believed to be favorable for testing a SWER configuration in permafrost soils although an appropriate line segment would need to be identified for SWER operation.

The peak load on the HVDC segment of the line would depend on where the demonstration would take place along the line. A peak load of 167 kVA or less would be preferred to allow use of the 500-kVA prototype converters.

Preliminary discussions were held with CVEA in February 2011 regarding this demonstration project. A specific site was not identified, but CVEA was generally supportive of hosting the HVDC demonstration project, provided that it did not damage utility assets or negatively impact customers and was revenue-neutral to the utility (Botulinski, private conversation, 2011).

H.4.2.3 Hope Substation to Hope AC Line Conversion (Demonstration Only)

This is an existing, approximately 20-mile-long, single phase, 14.4-kV distribution line owned and operated by Chugach Electric Association, Inc. (CEA) serving the community of Hope on Turnagain Arm near Anchorage (Figure H-4). Hope has a peak load of approximately 300 kilowatts (kW). CEA is planning a multipart upgrade of this line to address reliability issues. The first part of this upgrade project would rebuild and relocate approximately 4 miles of the intertie starting at the Hope Substation near the Hope
Junction on the Seward Highway. CEA estimates that this project would be ready for construction in 2013 (Jenkins, private conversation, 2011). The demonstration project would coordinate with the line upgrade.

The demonstration project would require transformers on either end of the demonstration segment to convert between 14.4 kV and the 480-V AC interface of the power converters. In addition, because the 14.4-kV line is single phase, the converter capacity would be reduced by approximately 1/3 to 167 kVA. This could be addressed either with increased converter capacity or occasional operation of the existing diesel generator in Hope to meet peak loads.

CEA is supportive of hosting the HVDC demonstration project, provided that it did not damage utility assets or negatively impact customers and was revenue-neutral to the utility. While this intertie appears technically feasible, less complicated HVDC demonstration projects likely exist within the state.

**H.4.2.4 Homer – Seldovia AC Line Conversion (Demonstration Only)**

This is an existing distribution line owned and operated by Homer Electric Association, Inc. (HEA), serving the communities on the south side of Katchemak Bay from Halibut Cove to Seldovia. The line is three-phase, 24.9-kV AC starting in Homer. It crosses Katchemak Bay with a 4.5-mile-long cable installed in 2001, and then continues as an overhead line to the south bay communities (Figure H-5). The overhead line is a combination of conventional RUS construction and tree cable. Load on this distribution circuit is approximately 1,100 kVA (McDonough, private conversation, 2011).

The concept for this demonstration project would be to operate the existing submarine cable as an HVDC cable for the demonstration project. There are two challenges with this concept:

1. The peak load on the circuit is approximately twice the capacity of the prototype converters. This will require load sharing between HEA through the HVDC link and diesels on the south side of the cable. This is not a technical challenge; however, it will result in significant costs that the demonstration project budget would need to absorb. 500 kW of continuous diesel generation for a 6-month demonstration period would cost approximately $700,000. A better alternative at this price may be to build two more 500 kW converter modules, increasing the HVDC intertie capacity to 1,000 kW.

2. The existing submarine cable is only rated for 24.9 kV AC. This is approximately equal to 43 kV DC, less than the nominal HVDC system voltage of 50 kV. Two possible remedies exist for this. If HEA can be assured that the cable will operate at 50 kV DC without ill effect, then the demonstration project could proceed. Given that cables are typically subjected to DC voltages on the order of 50 to 100 kV during acceptance tests, it seems likely that this would be possible. The nature of these assurances has not been defined. The second remedy is to decrease the operating voltage of the HVDC intertie. PPS has indicated that the converter software can be programmed to reduce the DC voltage; however, this will decrease the power rating of the converters. Lowering the voltage from 50 to 40 kV would lower the power rating of a converter module from approximately 500 to 400 kVA.

HEA is supportive of hosting the HVDC demonstration project, provided that it did not damage utility assets or negatively impact customers and was revenue-neutral to the utility. While this intertie appears technically feasible, less complicated HVDC demonstration projects likely exist within the state.

**H.4.3 HVDC Demonstration Projects on New AC Distribution Line Extensions**

This section provides overviews of potential HVDC demonstration projects that would be implemented on purpose-built AC distribution line extensions. After the HVDC demonstration is completed, the line would be converted to AC service and would be a lasting benefit to the utility and newly served customers. The candidate interties are organized geographically, moving northwest to southeast.
H.4.3.1  GVEA Phillips Road Line Extension

This project would be an approximately 1.75-mile single-phase overhead distribution extension to serve several residences at the end of Phillips Road in Delta Junction, within the Golden Valley Electric Association, Inc. (GVEA) service area (Figure H-6). The line extension would be built as a standard AC distribution line, operated as an HVDC intertie for demonstration purposes, and then turned over to GVEA for subsequent operation as an AC distribution line.

GVEA and the residences at the end of the line would both likely contribute funds or in-kind services to the line extension. Total contribution is estimated at $50,000, and the line build, excluding any costs associated with the HVDC demonstration, is budgeted at $140,000. A right-of-way would need to be obtained for the project, which would take an estimated 6 to 12 months.

The project is located in close proximity to the Trans-Alaska Pipeline System, and as such would likely not be suitable for demonstration of SWER operation. The peak load of the residences at the end of the line is likely less than the approximately 167-kVA capacity of the 500-kW prototype converters in single-phase operation.

GVEA is very supportive of hosting the HVDC demonstration project, provided that it did not damage utility assets or negatively impact customers and was revenue-neutral to the utility, beyond the in-kind construction contributions that GVEA offered for the line extension (Wright, private conversation, 2011).

H.4.3.2  GVEA Cummings Road Line Extension

This project would be an approximately 4- to 6-mile single-phase overhead distribution extension to serve several residences at the end of Cummings Road in Deltana, within the GVEA service area (Figure H-7). The line extension would be built as a standard AC distribution line, operated as an HVDC intertie for demonstration purposes, and then turned over to GVEA for subsequent operation as an AC distribution line.

GVEA and the residences at the end of the line would both likely contribute funds or in-kind services to the line extension. Total contribution is estimated at $60,000, and the line build, excluding any costs associated with the HVDC demonstration, is budgeted at $560,000. A right-of-way would need to be obtained for the project, which would take an estimated 6 to 12 months.

The peak load of the residences at the end of the line is likely less than the approximately 167-kVA capacity of the 500-kW prototype converters in single-phase operation.

GVEA is very supportive of hosting the HVDC demonstration project, provided that it did not damage utility assets or negatively impact customers and was revenue-neutral to the utility, beyond the in-kind construction contributions that GVEA offered for the line extension (Wright, 2011).

H.4.3.3  MEA to Independence Mine Line Extension

This project would be an approximately 5.5-mile underground AC distribution line from the end of Matanuska Electric Association, Inc. (MEA)’s existing Hatcher Pass distribution line up to the Independence Mine State Historical Park (State Park) (Figure H-8). The line would be built as an AC distribution feeder, operated as an HVDC line for the demonstration project, and then reverted to AC operation.
Easements for the first approximately 2 miles of the line extension are pending from the Alaska Department of Natural Resources (ADNR) and Matanuska-Susitna Borough (MSB) for a proposed hydroelectric project located along the route. New easements would be required for the remaining approximately 3.5 miles to the State Park. The intertie would eliminate the need for diesel generation at the State Park during the summer months. The hydroelectric project developer and ADNR Division of Parks and Recreation both may support this project with matching funds.

When contacted regarding this project, the State Park was supportive (Biessel, private conversation, 2011). Three private entities located near the park expressed no interest in connecting to the line. When contacted regarding this project, MEA expressed concerns about its staff availability to support this project (Kuhn, private conversation, 2011).

**H.4.4 HVDC Intertie Projects**

This section provides overviews of potential HVDC interties between rural Alaska communities. The interties are organized geographically, starting in the northwest and moving to the southeast.

**H.4.4.1 Barrow to Atqasuk HVDC Intertie**

This 75-mile-long overland intertie would connect Atqasuk, which uses high-cost diesel for electricity, to Barrow, which generates electricity from low-cost natural gas (Figure H‐9). This project could include conversion of Atqasuk to electric heating to achieve greater benefits. The North Slope Borough is currently studying this intertie. If the HVDC technology is commercially available in a timely manner, it could be used on this intertie. If it is not, the intertie would be built as a three-phase AC line.

**H.4.4.2 Nome to Teller and Brevig Mission HVDC Intertie**

This approximately 75-mile-long overland intertie would connect Teller and Brevig Mission—which both generate electricity with diesel fuel—to Nome, which generates electricity from diesel and some wind (Figure H‐10). The Alaska Village Electric Cooperative, Inc. (AVEC) recently built an intertie between Teller and Brevig Mission. If the Pilgrim Hot Springs geothermal resource is developed and is large enough to supply Nome as well as Teller and Brevig Mission, it could significantly reduce electric costs in these villages.

**H.4.4.3 Pilgrim Hot Springs to Nome HVDC Intertie**

The geothermal resource at Pilgrim Hot Springs could provide electricity for Nome. One of the challenges with this renewable energy concept is the cost of the approximately 60-mile transmission line between Pilgrim Hot Springs and Nome (Figure H‐10). Using this HVDC technology could reduce the costs of this intertie, improving project economics. One potential hurdle for this demonstration project candidate is that the Pilgrim Hot Springs resource has been tentatively estimated at 5 megawatts (MW). This is larger than the capacity of the prototype converters, and approximately ten 500-kW converters would be needed at each end of the intertie. PPS has indicated that paralleling this many converters together is technically feasible but this function has not been verified at this time. ACEP is assessing the geothermal resource at Pilgrim Hot Springs, which will help determine how much power can be derived from the resource (Mager, private conversation, 2011).

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42 The developer of this hydroelectric project is an affiliated interest of Polarconsult Alaska, Inc.
**H.4.4.4  St. Michaels – Stebbins HVDC Intertie**

This approximately 10-mile-long overland intertie would connect St. Michaels and Stebbins, two villages served by the AVEC, allowing AVEC to economize by consolidating bulk fuel and generation assets and operations at one village (Figure H-11). There is good marine access to both villages. The relatively short distance of this intertie reduces the savings of an HVDC intertie compared with an AC intertie.

**H.4.4.5  St. Mary’s to Mountain Village HVDC Intertie**

This approximately 26-mile-long overland intertie would connect St. Mary’s and Mountain Village on the Yukon River, allowing AVEC to economize by consolidating bulk fuel and generation assets and operations at one village (Figure H-12). There is good access to both villages, and an existing road between them would facilitate construction of the overhead intertie.

**H.4.4.6  Dillingham to Manokotak HVDC Intertie**

This approximately 20-mile-long intertie would connect Manokotak to Dillingham (Figure H-2). This intertie would allow the Dillingham and Manokotak electric utilities to consolidate operations, lowering costs in Manokotak, and improving the economies of scale for both utilities. In addition, Dillingham is currently studying two hydroelectric resources, Lake Grant and Lake Elva, which would provide stable, low-cost electricity. If these projects are built, rates in Manokotak would be significantly reduced with this intertie. An intertie between Manokotak and Dillingham has been studied in the past (Polarconsult, 1986) but has not been constructed. The proposed HVDC technology could reduce costs for the intertie, improving project economics.

**H.4.4.7  New Stuyahok – Ekwok HVDC Intertie**

This approximately 8-mile overland intertie would connect these two AVEC villages, allowing AVEC to economize by consolidating bulk fuel and generation assets and operations at one village (Figure H-13). The relatively short distance of this intertie reduces the savings of an HVDC intertie compared with a conventional AC intertie.

**H.4.4.8  Kodiak – Ouzinkie HVDC Intertie**

This approximately 8-mile-long submarine cable intertie would connect Ouzinkie with the Kodiak Electric Association, Inc. (KEA) grid (Figure H-14). Ouzinkie generates electricity with a combination of hydro and diesel. KEA generates electricity from a combination of hydro, wind, and diesel. Due to the different generation sources and economy of scale on the KEA system, KEA’s electric rates are significantly lower than Ouzinkie’s. The intertie would benefit KEA by increasing load and would benefit Ouzinkie by reducing rates. KEA and Ouzinkie have already studied an overland intertie with a short AC cable crossing of Narrow Strait (Dryden & Larue, 2011). The estimated costs of the short cable crossing are a significant portion of the total project cost, in part due to the mobilization costs of specialized equipment for cable installation. It may be more cost-effective to install a submarine HVDC cable for the entire route.

This intertie appears to be a suitable candidate for an HVDC demonstration project. The economic benefits to Ouzinkie appear to be significant (Totemoff, private conversation, 2011). A submarine HVDC cable using the technology developed in this project appears to be a less expensive option than the overhead/cable crossing option. Ouzinkie’s peak load is approximately 400 kW, within the capacity of the prototype converters. Further conversations with the project stakeholders are warranted.
H.4.4.9  Green’s Creek to Hoonah HVDC Intertie

This 26-mile-long submarine intertie would connect Hoonah to Alaska Electric Light and Power Company (AEL&P)’s Juneau power grid, providing lower-cost power to Hoonah (Figure H-15). The intertie is a good length for HVDC and would provide a clear benefit to Hoonah. The intertie has been under consideration for several years, and significant engineering studies have already been completed. The intertie is uneconomic using AC transmission or existing HVDC technology. The proposed HVDC technology could reduce costs for the intertie, improving project economics.

H.4.4.10  Petersburg to Kake HVDC Intertie

This approximately 60-mile-long submarine and overland intertie would connect Kake with the Petersburg-Ketchikan grid (Figure H-16). The intertie would allow Kake to convert from high-cost diesel electricity to low-cost hydro electricity, and would be part of the proposed southeast intertie grid. Using HVDC could reduce costs by allowing longer spans, buried cable, or increased use of submarine cable. While a 1-MW monopolar HVDC intertie would be sufficient to serve Kake, future extension of the southeast intertie to Sitka or development of nearby hydropower resources could increase the load on this intertie to tens of megawatts.

H.4.4.11  Gustavus to Glacier Bay National Park Intertie (HVDC Demonstration Only)

With the completion of the 800-kW Falls Creek Hydroelectric Project in 2009, Gustavus now has excess hydropower. The headquarters of Glacier Bay National Park, located approximately 5 to 10 miles from Gustavus, continues to rely on diesel generation for electricity (Figure H-15). Connecting the park headquarters with Gustavus would allow the Park to reduce fuel consumption and operating costs and would allow Gustavus to increase its rate base and power sales, lowering overall rates. A buried HVDC cable would be preferable to overhead AC lines in the park, where aesthetics are a major factor. Due to the relatively short length, an HVDC intertie may not be cost-effective compared to an AC intertie.
H.4.5  Project Maps

Figure H-2  Vicinity Map for Demonstration Projects near Dillingham
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Figure H-9  Vicinity Map for Barrow – Atqasuk HVDC Intertie

POSSIBLE TRANSMISSION ROUTE (FOLLOWS EXISTING WINTER TRAILS)

BARROW

ATQASUK

MILES

0  10  20
Figure H-10  Vicinity Map for Demonstration Projects near Nome
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Figure H-15  Vicinity Map for Gustavus and Hoonah HVDC Interties

Figure H-16  Vicinity Map for Kake – Petersburg HVDC Intertie
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APPENDIX I

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I.1 INTRODUCTION

This appendix provides the following detailed information regarding the Stakeholders Advisory Group (SAG) formed for Phase II of the High-Voltage Direct Current (HVDC) Development Program:

- List of SAG members;
- Summary of SAG role and policies;
- Summary of key informal correspondence between SAG members and Polarconsult over the course of the project;
- Handouts and transcripts from the three SAG meetings; and
- Handouts from other meetings and outreach activities conducted over the course of the project.

Meeting transcripts are available separately.
I.2 LIST OF SAG MEMBERS

Table I-1 List of SAG Members

<table>
<thead>
<tr>
<th>Company</th>
<th>First Name</th>
<th>Last Name</th>
<th>Position</th>
</tr>
</thead>
<tbody>
<tr>
<td>Denali Commission</td>
<td>Denali</td>
<td>Daniels</td>
<td>SAG Chair</td>
</tr>
<tr>
<td>Alaska Center for Energy and Power (ACEP)</td>
<td>Gwen</td>
<td>Holdmann</td>
<td>ACEP Director</td>
</tr>
<tr>
<td>Alaska Center for Energy and Power (ACEP)</td>
<td>Jason</td>
<td>Meyer</td>
<td>ACEP Project Manager</td>
</tr>
<tr>
<td>Alaska Center for Energy and Power (ACEP)</td>
<td>Brent</td>
<td>Sheets</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Polarconsult Alaska, Inc.</td>
<td>Joel</td>
<td>Groves</td>
<td>Project Manager</td>
</tr>
<tr>
<td>Polarconsult Alaska, Inc.</td>
<td>Earle</td>
<td>Ausman</td>
<td>President</td>
</tr>
<tr>
<td>Polarconsult Alaska, Inc.</td>
<td>David</td>
<td>Ausman</td>
<td>Vice President</td>
</tr>
<tr>
<td>Princeton Power Systems, Inc. (PPS)</td>
<td>Darren</td>
<td>Hammell</td>
<td>Executive Vice President</td>
</tr>
<tr>
<td>Alaska Department of Labor (AKDOL)</td>
<td>Daniel</td>
<td>Greiner</td>
<td>Alt. SAG Member</td>
</tr>
<tr>
<td>Alaska Department of Labor (AKDOL)</td>
<td>Alvin</td>
<td>Nagel</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Alaska Division of Community and Regional Affairs (DCRA)</td>
<td>Percy</td>
<td>Frisby</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Alaska Energy Authority (AEA)</td>
<td>David</td>
<td>Lockhard</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Alaska Power &amp; Telephone Company (APT)</td>
<td>Bob</td>
<td>Grimm</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Alaska Power Association (APA)</td>
<td>Marilyn</td>
<td>Leland</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Alaska Village Electric Cooperative, Inc. (AVEC)</td>
<td>Meera</td>
<td>Kohler</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Alaska Village Electric Cooperative, Inc. (AVEC)</td>
<td>Brent</td>
<td>Petrie</td>
<td>Alt. SAG Member</td>
</tr>
<tr>
<td>Bering Straits Native Corporation (BSNC)</td>
<td>Jerald</td>
<td>Brown</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Bethel Electric Utility (BEC)</td>
<td>Bob</td>
<td>Charles</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Copper Valley Electric Association (CVEA)</td>
<td>Robert</td>
<td>Wilkinson</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Dillingham</td>
<td>Nels</td>
<td>Andersen</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Golden Valley Electric Association, Inc. (GVEA)</td>
<td>Brian</td>
<td>Newton</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Homer Electric Association, Inc. (HEA)</td>
<td>Brad</td>
<td>Janorschke</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Inside Passage Electric Cooperative (IPEC)</td>
<td>Jodi</td>
<td>Mitchell</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Institute of Northern Engineering (INE, UAF)</td>
<td>Ron</td>
<td>Johnson</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Kodiak Electric Association, Inc. (KEA)</td>
<td>Darron</td>
<td>Scott</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Kotzebue Electric Association, Inc. (KoEA)</td>
<td>Brad</td>
<td>Reeve</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Matanuska Electric Association (MEA)</td>
<td>Joe</td>
<td>Griffith</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Matanuska Electric Association (MEA)</td>
<td>Trivia</td>
<td>Singaraju</td>
<td>Alt. SAG Member</td>
</tr>
<tr>
<td>Naknek Electric Association, Inc. (NEA)</td>
<td>Donna</td>
<td>Vukich</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Nat’l. Rural Electric Cooperative Association (NRECA)</td>
<td>Tom</td>
<td>Lovas</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Nome Chamber of Commerce (NCC)</td>
<td>Mitch</td>
<td>Erickson</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Nome Joint Utilities (NJUS)</td>
<td>John</td>
<td>Handeland</td>
<td>SAG Member</td>
</tr>
<tr>
<td>North Slope Borough (NSB)</td>
<td>Kent</td>
<td>Grinage</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Northwest Arctic Borough (NWAB)</td>
<td>Ingemar</td>
<td>Mathiasson</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Nushagak Electric Association</td>
<td>Mike</td>
<td>Favors</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Nuvista Light and Power, Inc. (NLP)</td>
<td>Bob</td>
<td>Charles</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Southeast Conference (SEC)</td>
<td>Robert</td>
<td>Venables</td>
<td>Alt. SAG Member</td>
</tr>
<tr>
<td>Southeast Conference (SEC)</td>
<td>Shelly</td>
<td>Wright</td>
<td>SAG Member</td>
</tr>
<tr>
<td>Southwest Alaska Municipal Conference (SWAMC)</td>
<td>Andy</td>
<td>Varner</td>
<td>SAG Member</td>
</tr>
<tr>
<td>U.S. Department of Agriculture (USDA) Rural Utilities Service (RUS)</td>
<td>Eric</td>
<td>Marchegiani</td>
<td>SAG Member</td>
</tr>
<tr>
<td>University of Alaska Fairbanks (UAF)</td>
<td>Richard</td>
<td>Wies</td>
<td>SAG Member</td>
</tr>
</tbody>
</table>
I.3 SUMMARY OF SAG ROLE AND POLICIES

I.3.1 Policies and Procedures

The SAG is an advisory body comprised of representatives of Alaska’s rural electric utility industry and related professionals. The purpose of the SAG is to provide comments, feedback, review, and recommendations to the HVDC Development Program, awarded by the Denali Commission (Commission), managed by the Alaska Center for Energy and Power (ACEP), and contracted to Polarconsult Alaska, Inc. (Polarconsult).

I.3.1.1 Formation

To maintain independence of the SAG, ACEP identified members for participation, with consideration of recommendations from Polarconsult and the Denali Commission. A final candidate list was sent out for comment to Polarconsult and forwarded for approval to the Denali Commission.

I.3.1.2 Scheduled Meetings

Per the scope of work under UAF – Polarconsult Contract #10-0055, the SAG formally convened three times over the course of the HVDC Project. Per the scope of work and budget, the cost of convening these meetings was the responsibility of Polarconsult. Funding for member travel and participation costs was not provided. The meetings were convened in a manner conducive to remote participation of members. The meeting dates were April 28, 2010; December 1, 2010; and July 15, 2011.

The agenda for these meetings was set by ACEP, with input from Polarconsult and the Denali Commission and final approval by the Denali Commission.

I.3.1.3 Organization

The SAG shall consist of the Chair (the Denali Commission) and members. To maintain equality on the SAG, individual organizations may hold only one member position. Up to 30 SAG members will be allowed, the final number determined based on the level of interest. If at any time over the course of the project one of the members resigns or is no longer active, ACEP will invite another individual to fill this position, with the approval of the Denali Commission. Members may designate proxies from within their organization to attend meetings.

ACEP encourages organizations and individuals not selected for the SAG to participate informally in this project. Public comment is always welcome and an e-mail list and forum will be made available on the ACEP project website.

I.3.1.4 Communication

At certain project milestones, or upon recommendation from ACEP, Polarconsult shall solicit comments, review, and recommendations to the HVDC program. All formal communication between Polarconsult and the SAG shall be through the Chair, with inclusion of ACEP. Polarconsult is free to contact the whole SAG formally or contact individual SAG members informally, as the need arises. All informal communication will not represent the advice or recommendations of the SAG. In the interests of promoting maximum feedback from the industry, confidential communications will be accepted where there is a demonstrated need to maintain confidentiality.

Table I-2 provides a summary of correspondence with SAG members related to this project.
<table>
<thead>
<tr>
<th>Date</th>
<th>SAG Member</th>
<th>Participants</th>
<th>Subject</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan.–Feb. 2010</td>
<td>MEA</td>
<td>Trivi Singaraju (MEA) Gary Kuhn (MEA) Joel Groves (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>Jan.–Feb. 2010</td>
<td>CVEA</td>
<td>Chris Botulinski (CVEA) Earle Ausman (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>Jan.–March 2010</td>
<td>At Large Citizen</td>
<td>Nels Anderson Earle Ausman (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>Jan.–March 2010</td>
<td>HEA</td>
<td>Brad Zubeck (HEA) Kathy McDonough (HEA) Joel Groves (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>May–June 2010</td>
<td>NWAB</td>
<td>Ingemar Mathiasson (NWAB) Earle Ausman (Polarconsult)</td>
<td>International examples of electric codes</td>
<td>Mr. Mathiasson used his contacts in Sweden to request examples of international electric codes with regard to SWER circuits, HVDC, and related rural electric issues.</td>
</tr>
<tr>
<td>July–October 2010</td>
<td>AVEC</td>
<td>Brent Petrie (AVEC) Bill Thomson (AVEC) Mark Tietzel (AVEC) Joel Groves (Polarconsult) Earle Ausman (Polarconsult)</td>
<td>HVDC Converter Specification</td>
<td>Discussions and comments from AVEC on draft specification for HVDC power converter.</td>
</tr>
<tr>
<td>August 2010</td>
<td>AVEC</td>
<td>Mark Teitzel (AVEC) Joel Groves (Polarconsult)</td>
<td>Conceptual Design of Overhead Line</td>
<td>Request for examples of environmental loadings used on previous AVEC interties, performance of these projects.</td>
</tr>
<tr>
<td>September 2010</td>
<td>IPEC</td>
<td>Peter Bibb (IPEC) Joel Groves (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>October–November 2010</td>
<td>GVEA</td>
<td>Mike Wright (GVEA) Searl Burnett (GVEA) Earle Ausman (Polarconsult)</td>
<td>Conceptual Design of Overhead Line</td>
<td>Site visit to review design, performance, and failure modes of guyed Y and X towers on transmission lines between Fairbanks and Healy.</td>
</tr>
<tr>
<td>November 2010</td>
<td>AVEC</td>
<td>Brent Petrie (AVEC) Joel Groves (Polarconsult) Earle Ausman (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>January 2011</td>
<td>APT</td>
<td>Bob Grimm (APT) Earle Ausman (Polarconsult) Joel Groves (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>Date</td>
<td>SAG Member</td>
<td>Participants</td>
<td>Subject</td>
<td>Summary</td>
</tr>
<tr>
<td>----------------------</td>
<td>------------</td>
<td>---------------------------------------------------</td>
<td>----------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>January 2011</td>
<td>NWAB</td>
<td>Ingemar Mathiasson (NWAB) Brent Petrie (AVEC)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>January 2011</td>
<td>RUS</td>
<td>Eric Marchegiani (RUS) Joel Groves (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>January 2011</td>
<td>Multiple</td>
<td>Multiple SAG Members</td>
<td>Demonstration Project Sites</td>
<td>Teleconference with SAG members on HVDC demonstration project sites.</td>
</tr>
<tr>
<td>January–March 2011</td>
<td>GVEA</td>
<td>Mike Wright (GVEA) Joel Groves (Polarconsult)</td>
<td>Demonstration Project Sites</td>
<td>Discussing potential HVDC demonstration project sites.</td>
</tr>
<tr>
<td>March 2011</td>
<td>AVEC</td>
<td>Bill Thomson (AVEC) Joel Groves (Polarconsult)</td>
<td>HVDC Controls and integration</td>
<td>Discussions among Polarconsult, Manitoba, and AVEC on system controls and integration needs.</td>
</tr>
<tr>
<td>May–June 2011</td>
<td>CVEA</td>
<td>Chris Botulinski (CVEA) Earle Ausman (Polarconsult)</td>
<td>HVDC Test Site</td>
<td>Discussions looking for a test site for HVDC pole and foundations.</td>
</tr>
<tr>
<td>June–July 2011</td>
<td>GVEA</td>
<td>Mike Wright (GVEA) Joel Groves (Polarconsult)</td>
<td>HVDC Test Site</td>
<td>Discussions looking for a test site for HVDC pole and foundations.</td>
</tr>
<tr>
<td>July 2011</td>
<td>AKDOL</td>
<td>Al Nagel (AKDOL) Dave Greiner (AKDOL) Randy Wachal (MHRC) Joel Groves (Polarconsult)</td>
<td>SWER circuit safety.</td>
<td>Discussions with Alaska Department of Labor regarding HVDC SWER circuits and soliciting comments on the SWER analysis prepared by Manitoba.</td>
</tr>
<tr>
<td>November 2011</td>
<td>AVEC</td>
<td>Pam Lyons (AVEC) Joel Groves (Polarconsult)</td>
<td>Converter Shipping Cost</td>
<td>AVEC assistance on obtaining shipping costs to move prototype converters to Alaska.</td>
</tr>
<tr>
<td>December 2011</td>
<td>AKDOL</td>
<td>Al Nagel (AKDOL), Dave Greiner (AKDOL), Jason Meyer (ACEP), Joel Groves (Polarconsult)</td>
<td>SWER circuit safety.</td>
<td>Discussions with Alaska Department of Labor regarding HVDC SWER circuits and NESC code.</td>
</tr>
</tbody>
</table>

### I.3.1.5 Termination

The SAG shall be formally terminated upon the end of the project issued from the Denali Commission.
I.4 STAKEHOLDER ADVISORY GROUP (SAG) MEETING PRESENTATION MATERIALS

I.4.1 Sag Meeting #1 – Fairbanks, Alaska (April 27, 2010)
HVDC Phase II - Prototyping and Testing
High Voltage Direct Current

Stakeholder Advisory Group
Meeting #1 – April 27th, 2010

AGENDA

Location: Conference Room 1, Marriott Springhill Suites, Fairbanks AK
Phone: 1-866-931-7845, PIN #553414
Time: 3:30pm – 5pm

The objective of today’s meeting is to introduce the HVDC project to the SAG, establish the role of the SAG in the HVDC project process, establish policies and procedures of the SAG, and to introduce several initial items for comment and feedback from the SAG.

3:30pm  Introductions
3:40pm  SAG Role, Policies, and Procedures
3:50pm  HVDC Phase I Project Overview
4:05pm:  HVDC Phase 2 Project Framework
4:20pm  BREAK
4:30pm  Overview of initial items for comment and feedback
  1) Phase II Transmission System Sizing
  2) Alaska State Electrical Code: HVDC research and information needs
  3) Criteria for Phase III Project Location(s)
4:40pm  Findings of Transmission System Sizing Analysis
4:50pm  Closing Q&A with the SAG
  1) Call for information and experiences on Alaska transmission
  2) Instructions for feedback and comments
HVDC Transmission for Rural Alaska

STAKEHOLDERS’ ADVISORY GROUP
FIRST MEETING
April 27, 2010
FAIRBANKS, ALASKA

Joel D. Groves, P.E.
polarconsult alaska, inc.
ENGINEERS - SURVEYORS - ENERGY CONSULTANTS
1503 W. 33rd Avenue, Suite 310
Anchorage, Alaska
(907) 258-2420
www.polarconsult.net
joel@polarconsult.net
MEETING GOALS

1. HVDC PROJECT OVERVIEW
2. ROLE OF THE SAG
3. SAG INPUT TOPICS

HVDC OVERVIEW – THE GOAL

➢ REDUCE REMOTE AK ENERGY COSTS

➢ Provide a lower cost, technically superior remote Alaska power intertie option
➢ Enable villages to form micro grids and
➢ reach out to local energy resources
HVDC – THE TECHNOLOGY

➢ HVDC is used world wide for large-scale power transmission and linking large grids

➢ Asynchronous intertie
➢ Long-distance cables possible
➢ Long interties are more efficient & less costly

HVDC PROJECT OVERVIEW

➢ Develop HVDC system for use in Alaska
  ➢ 1 MW HVDC Converter
  ➢ Conceptual intertie designs optimized for HVDC and remote Alaska conditions
  ➢ Gain industry support so Alaska benefits from the technology and investment
  ➢ Clear regulatory impediments
HVDC PROJECT ORGANIZATION

- **PHASE I** – Prove Converter Technology
  *Successfully completed in 2008-09*

- **PHASE II** – Build and Test Prototypes
  *Underway, complete in 2011*

- **PHASE III** – HVDC Demonstration Project
  *Fully functional HVDC intertie in Alaska*
  *Location and schedule TBD*

---

PHASE I FINDINGS

- 12 kVDC to 250 kW 3Ø 480 VAC bench top converter was successfully built and tested to prove the technology
- Met cost and performance benchmarks
- 56% capital cost savings over AC line costs
- 28% life-cycle savings over AC line costs
PHASE I FINDINGS

250kW DC to AC Converter table top Assembly

Input HVDC Rectifier and DC Filter Capacitor

PHASE I FINDINGS

High Voltage Board Stack

Oil Proof Fiber Optic Transceiver

Fiber Optic Mother Board & Trigger Cards
PHASE II OVERVIEW

- Design/build/test full-scale prototype converter
- Develop & test conceptual designs for transmission lines
- Test DC SWER performance in AK soils
- Update system economics with Phase II data
- Advance industry support for the system
- Identify project for Phase III – HVDC demo

PHASE II OVERVIEW – HVDC CONVERTERS

- Develop functional and technical specifications
- Design, model converter
- Build, test converter
PHASE II OVERVIEW – TRANSMISSION DESIGN

Conceptual Design
  Basis Document(s)
  Performance Specification
  Commercial Availability

  no
  yes
  Design, Fabricate, Test
  Cost & Availability
  Optimization Possible?

PHASE II OVERVIEW – SWER TESTING

➤ Install ground return circuit in permafrost soils
➤ Operate and monitor performance
➤ Data collection objectives
  ➤ Test grounding site reconnaissance methods
  ➤ Refine grounding system design criteria
  ➤ Construction methods
  ➤ Voltage rise and step potential data
  ➤ Resistivity data
2. PURPOSE OF THE SAG

- HELP THE HVDC SYSTEM BECOME A USEFUL TECHNOLOGY FOR ALASKA

- System Review
  - Design basis and functional aspects
  - Political aspects

- Understand and Support Code Revisions
  - Define code revisions
  - Define actions necessary to build support
SAG INPUT PROCESS

1. PCA and ACEP will issue documents for SAG input
2. SAG members comment
3. PCA and ACEP will incorporate comments

SAG ISSUES

1. System Sizing (1 MW, 2 MW, 5 MW, 10 MW)
2. System Design Parameters
   - Functionality
   - Environmental Loadings
3. Code Changes & Strategy
4. Vision / Applications / Priorities
   - Phase III Project
   - State-wide deployment
SAG 1 ➔ SYSTEM SIZING

- Review PCE Database for Peak Loads
  - Past 3 years of Monthly Peak Data
  - 176 communities / utilities
- Evaluate Peak Load vs. Intertie Capacity

1 MW HVDC CONVERTER ADEQUACY TO MEET REMOTE UTILITY POWER NEEDS

- 2 MW Bipolar HVDC Intertie - Adequate for 82% of Utilities
- 1 MW Monopolar HVDC Intertie - Adequate for 76% of Utilities
- 500 kW Intertie - Adequate for 60% of Utilities
### SAG 2 ➔ TYPICAL DESIGN PARAMETERS

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Design Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>NESC Design Class</td>
<td>Class B</td>
</tr>
<tr>
<td>Radial Ice</td>
<td>1-inch</td>
</tr>
<tr>
<td>Wind</td>
<td>120 mph at 70 feet height</td>
</tr>
<tr>
<td>Ground Clearance</td>
<td>NESC for 69 kV AC, roads in rural districts</td>
</tr>
<tr>
<td>Soils</td>
<td>Silt rich, water saturated, marginal permafrost</td>
</tr>
<tr>
<td>Peak Electrical Throughput</td>
<td>1 MW (1 MVA)</td>
</tr>
<tr>
<td>Operating Voltage</td>
<td>50 kV DC</td>
</tr>
</tbody>
</table>

---

### SAG 2 ➔ DESIGN PARAMETERS

- Modular design – easy to repair/maintain
- Redundant – continue operating with failure
- Small + light – air cargo to bush
- Fully automatic – self diagnosing
- Input / output power
  - Unbalanced phases, low power factor, etc.
SAG 3 → CODE MODIFICATIONS

- Allow SWER in remote areas
- Allow shallower cable burial in remote areas
- Other?
- Develop a plan to achieve these goals
  - Research or testing?
  - Board or Council Support?
  - Political leadership?

SAG 4 → PHASE III PROJECT CRITERIA

- Demonstrated need/benefit for intertie
- ~ 25 mile intertie
- No loads / potential loads along route
- Road access desirable
- Permafrost country (overhead line)
- Submarine cable portion
SAG 4 → PHASE III CANDIDATES

- St. Mary’s – Mountain Village (25-mi)
  Consolidate duplicate bulk fuel and generation
- Barrow – Atqusuk (75 mi)
  Bring Barrow’s low-cost electricity to Atqusuk
- Southeast (where?)
  Bring low-cost hydro to nearby villages
- Southwest (where?)
  Wind, geothermal, or hydro to nearby villages

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St. Mary’s – Mountain Village

Mountain Village
St. Mary’s
Pilot Station
Marshall
25 Miles

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What can HVDC do for Rural Alaska? - - Galena Nuclear Plant

KOYUKUK
NULATO
GALENA
25 MILES
RUBY
KALTAG
TO UNALAKEET

SAG 4 → STATE-WIDE VISION

- Coordinate state-wide energy plan and policy
- Coordinate with regional grid concepts
  Bethel region, Naknek/Bristol Bay, Southeast Intertie…
- Coordinate with major projects
  Donlin, Pebble, Pilgrim Hot Springs, Gas line, Railbelt expansion…
I.4.2    SAG Meeting #2 – Anchorage, Alaska (January 14, 2011)
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HVDC Transmission for Rural Alaska

STAKEHOLDERS’ ADVISORY GROUP
SECOND MEETING
January 14, 2011
ANCHORAGE, ALASKA

Joel D. Groves, P.E.
polarconsult alaska, inc.

MEETING GOALS

1. PROJECT STATUS UPDATE
2. DISCUSS PHASE III GOALS, SITES
3. FORM SAG WORK GROUPS
4. PROJECT Q & A
5. NEXT MEETING
Project Status – Highlights

- Manitoba International, LTD under contract as specialist HVDC consultant
- Operates Nelson River Bipoles, 2 HVDC circuits (3,400 MW) in arctic climate.
- Operates HVDC Research Centre, Expertise in HVDC operations, hardware, R&D and testing capabilities
- Tasked with technical review, MTDC network assessment, special hardware, cold climate experience, communications, fault detection, and regulatory assistance.
High Voltage Assembly

Weight & Dims
62"H x 36"D x 127"L
4,900 lbs (wet)
2,100 lbs (dry)

Emergency Transport
CASA 212-200

Cooling
Coolant is Luminol TR/TRi
Pour Point -60°C
Flash Point 170°C
Natural Oil Convection

Project Status – Intertie Control

- Phase III Demo Controls
  - Phase III demo will be point-to-point
  - HVDC power regulation by DC line voltage
  - Communications desirable for control and fault detection
  - Communications necessary for load shed

- HVDC Vision for Alaska = MTDC Networks
  - More work is needed to define control schema
  - Manitoba tasked with developing a roadmap
Project Status – Overhead System

- Validated conceptual design
- Foundation design in progress
- Waiting for pricing and product development options from vendors

Project Status – OH Example
GVEA Northern Intertie

- Commissioned 1968
- Guyed lattice, 138 kV
- 1,000’ – 1,200’ spans
- Permafrost soils
- Some frost jacking issues
### Project Status – Submarine Cable Work Plan

- Conceptual materials and design of cable done
- Soliciting budgetary pricing from manufacturers to design and manufacture cable in commercial quantities
- No testing needed in Phase II

### Project Status – Buried Cable Work Plan

- Unarmored submarine cable is suitable
- Existing 1/0 35kV AC cable is suitable
- Frost cracking is key issue in arctic soils
  - No proven solution from utility/oil industry experience. GCI doing some interesting work with telecom cables – same problem
  - Evaluating test options and developing test plan
Project Status – Construction and O&M Methods

- Identified existing rigs/equip that can be adapted to construct overhead system
- Working on O&M methods

Project Status – Economics

- Collecting cost data
- Economic analysis will start in Q2 2011
Phase III Demonstration Project - PROJECT OBJECTIVES

- Prove up HVDC Hardware
- Prove up innovative technologies
  - Overhead, overland cable, etc.
- Prove functionality of SWER

Phase III Demonstration Project - PROJECT CRITERIA

- Transmission only
- Lengths > 10 miles
- Load < 1 MW
- Benefit
- Readiness
- Constructability
SAG Working Groups

- #1 Code Approval of SWER
- #2 Funding Strategy
Working Group on Code Issues 1/3
April Recap

- Maintain Focus on Rapid HVDC Deployment
  - Avoid buried cable if technically challenging
  - Use two-wire monopole if regulatory concerns persist
  - Prove up basic HVDC system without full cost savings
  - Advance cost-saving aspects of technology for use on follow-on projects

Working Group on Code Issues 2/3
April Recap

- Project Waiver is fast - weeks
- AK Code Amendment by regulation – 1 year
  - Demonstrate public safety – Manitoba, others
  - Industry support – SAG, others
  - Example language from int'l jurisdictions – PCA, others
Working Group on Code Issues 3/3 Tasks

- Case for Public Safety
- Examples from int’l jurisdictions
- Manitoba opinion
- Industry Support
- Amendment Language
- Studies / Research

QUESTIONS AND COMMENTS
I.4.3 SAG Meeting #3 – Anchorage, Alaska (October 25, 2011)
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HVDC Transmission for Rural Alaska

STAKEHOLDERS' ADVISORY GROUP
THIRD MEETING
October 25, 2011
ANCHORAGE, ALASKA

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PHASE II PROJECT TEAM

- Denali Commission (Funding Agency)
- ACEP (Grant Management, Economic Analysis, Independent Assessment / Reporting)
- Polarconsult (Project Management, Strategic Vision, Concept Design, Reporting)
- Princeton Power Systems (Converter Development)
- UAF/Dr. Wies (Alaska Integration / Practicality / Converter / System Review)
- AVEC (Alaska Integration / Practicality)
- SAG (Practicality / Industry Acceptance)
- Manitoba HVDC Research Centre (HVDC Expert – Integration, Technical Issues)
- Line Design Engineering (Structural and Code Expert)
- Golder Associates (Geotechnical Expert)
- Almita (Foundation Supplier)
- Arctic Foundations (Foundation Supplier)
- Zarling Aero Consulting (Thermal Soils Analysis)
- STG (Rural Intertie Contractor – logistics, cost)
- Alaska Foundation Technology (Foundation Contractor – logistics, cost)
- GeoTek Alaska (geotech, contractor – logistics, equipment)
- Cabletricity (Submarine Cable / HVDC Expert)
- Okonite (Cable Supplier)
PROJECT STATUS UPDATE

- Converters built, testing underway
- Overhead conceptual design complete, field tests starting in Fairbanks Nov. 7
- Submarine cable concept designs complete
- Overland cable testing next week
- Economic analysis underway
- Final report to ACEP for review Nov. 21

PROJECT STATUS UPDATE

Overhead System

- Conceptual design is very flexible, robust, adaptable
- Foundations are key - systems are being installed and validated in Fairbanks
- Long-term performance monitoring will be performed by ACEP
PROJECT STATUS UPDATE
Submarine System

- Existing cables work
  - Okonite URO-J 1/0 Cu Cable...
- Economics in Progress
  - Guidelines on need for armor
  - Laying equipment and costs
- Tel/co Integration
  - No technical hurdles
  - Looking for interested vendors

PROJECT STATUS UPDATE
Field Tests

- Fairbanks Test Site
- Erect guyed fiberglass pole
  - Test installation methods
  - Test pole base foundation
  - Test four guy foundations
  - Setup for multi-season monitoring by ACEP
- Materials and Contractors queuing for Nov. 7
Phase II Final Report

- Executive Summary – 2 or 3 pages
- Main Body of Report – ~ 30 pages
  - What was done
  - Current status of technology / system
  - Next steps for deployment

- Appendices
  - Project Record
  - Technical Data
  - References
  - Examples
Phase II Final Report

❖ SAG – Main Narrative
  ➢ Main Narrative – overview of SAG’s role, members
  ➢ Appendix - Transcripts, Correspondence, etc.

❖ Code Issues
  ➢ Main Narrative – Summary of Findings
  ➢ Appendix - Discussions with Dept of Labor, MHRC White Paper

Phase II Final Report

❖ Demonstration Site Selection
  ➢ Main Narrative - List of Goals, Criteria, Sites, Future Actions
  ➢ Appendix - detailed info on candidate sites
Phase II Final Report

- System Integration
  - Main Narrative – How it all fits together. Interface with village micro grids, diesels, etc.
  - Appendix – Technical reports from sub-consultants (MHRC, etc) on MTDC networks, SCADA integration, communication options, etc.

Final Report

- Converter Development
  - Main Narrative – Headline functionality, footprint, cost, test results, etc.
  - Appendix - detailed info on development, specifications, testing, etc (PPS Report)
Phase II Final Report

- Overhead Transmission System
- Submarine Cable System
- Buried Overland Cable System
  - Main Narrative – Conceptual design methodology, conceptual designs, applications
  - Appendix - detailed info on design, loadings, etc. Technical reports from sub-consultants

Phase II Final Report

- Construction & Maintenance Methods
  - Main Narrative – design objective, results
  - Appendix – detailed technical data and subconsultant reports. Findings from Fairbanks Test Site.
Phase II Final Report

- **Economic Analysis**
  - Main Narrative – cost estimates for representative systems – similar to Ph 1 Report
  - Appendix – Detailed support for cost data, life cycle analysis, comparative costs.

**Example**

- **Overhead System**
OVERHEAD SYSTEM Conceptual Design Methodology

- Gather load data from utilities
- Design target is ‘worst case common’ condition
- Deal with unique loadings by reducing spans, doubling components, etc.
- Maintain robust, adaptive design
  - Deal with varying geotechnical conditions
  - Deal with variety of installation / repair conditions

OVERHEAD SYSTEM Conceptual Design

- 60-foot fiberglass pole, 14” dia x 0.3” wall. 4 guys per pole
- Post top insulator for monopolar
- Cross arm and suspension insulators for bipolar (shorter spans)
- All three for AC lines. (neutral lower on pole)
- Suite of standard foundation options for pole base and guys
  - Thermosiphon (1-1/2” x 25’ pipe, CO₂ working fluid)
  - Screw Anchor (multiple suppliers exist)
  - Micropile (2” – 3” pipe, 25-50’ long (as required)
- 19#10 Alumoweld at 30-40% initial tension
POLE SPLICE

1. Pole section will be stocked in 10' and 8' lengths.
2. Locate screws on non-ream faces.
3. Pole cap and plug must be stocked independently.

THERMOSIPHON

SPECIAL INSTRUCTIONS:
Weld the top 5" cap onto the unit after the valve has been installed and pressure tested. Then, drill 5 each 1/4" drainage holes equally spaced around the pipe at the lower end of the B trap. Prior to painting, grind all girth welds smooth to the diameter of the pipe.

NOTES:
1. All pressure retaining welds are full penetration groove welds. Welding procedure specifications are qualified in accordance with ASME Section IX. Welding is performed by welders qualified per ASME Section IX.
2. The brace vane to steel connection is silver brazed per API standard procedure.
3. Gear upper half of anchor with R. B. Miller P-974 friction bond cap over 3 mils bimetal, impregnated aluminum applied per API C2.2. Insert the 3 mils of bimetal impregnated aluminum applied per API C2.2 into the section shaft and add additional 2 feet. Brush blast mill finish of bearing zone of anchor.
5. Materials are API standard for the intended service.
6. Build 9 units as shown herein.
薄有机层，没有绝缘层和热堆单位导热系数为1.0 BTU/hr-ft-F

冬春 季末 冬初 冬末

厚有机层，四英寸厚绝缘层和热堆单位导热系数为1.0 BTU/hr-ft-F

冬春 季末 冬初 冬末
THERMOSIPHON

Thermal Analysis of Thermal Pin Piles

Thin organic layer, four-inch thick insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F

Spring  End of Summer  Early Winter  Mid Winter

Thick organic layer, no insulation and thermal pile unit conductance is 1.0 BTU/hr-ft-F

Spring  End of Summer  Early Winter  Mid Winter
PROJECT STATUS UPDATE
Overhead System Load Cases

- NESC 250B, 4 psf wind, no ice
- NESC 250C, 120 mph wind, no ice
- NESC 250D, 80 mph wind, ¼” ice
- 1” ice, no wind

- Max final tension (42.1%) and sag (25.5’) with 1” ice
- Max transverse load on guys with 120 mph wind (27.8% of NESC limit, 3/8” EHS guy wire)
- 24’ ground clearance goal met with 50’ pole/insulator.
- Standard construction OK for 10-degree angles

PROJECT STATUS UPDATE
Overhead System Foundations

- Pole base – compression (and some moment)
  - 5,000# short-term load
  - 10,000# long-term load
- Guys – tension loads
  - 5,000# short-term load
  - 10,000# short-term load
- Guys must resist creep and frost jacking
SAG Discussion

Future of Project and Technology

- Recap
  - Extensive review of possible demonstration sites
  - Applied for Phase III Funding (EETF)
Future of Project and Technology

❖ Lessons Learned
  ➢ Focus on successful converter demonstration
  ➢ Shouldn’t wait for a rural intertie (~5 years?)
  ➢ Railbelt feeder line ‘demo conversions’ don’t demonstrate much, not very cost effective.
    (thanks to utilities for helping!)
  ➢ Focus on useful demo of converter with rapid deployment schedule

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engineers  planners  energy consultants
Current Working Plan

- Part 1
  - More testing in Princeton, final commercialization work
- Part 2
  - Alaska demonstration installation
  - Working on a site
- Part 3
  - Work with utilities to find HVDC projects
  - Forge partnership with utilities/communities for full demo

polarconsult alaska, inc. engineers planners energy consultants

QUESTIONS AND COMMENTS

[Map of Alaska]
Who is Princeton Power?

Princeton Power Systems designs and builds high-performance power electronic converters for military and commercial distributed generation applications, and designs and installs complete photovoltaic systems.

Our Distributed Generation Systems, including solar systems, include energy storage, critical load control, backup power, and other advanced features.

Competitive advantages come from patented technologies, and system engineering expertise.

CLEAN POWER, MADE SIMPLE.

3490 US Route 1
Princeton, NJ 08540
www.princetonpower.com
sales@princetonpower.com
p. 609.955.5390 x 103

Copyright 2011 Princeton Power Systems, Inc.
Company Timeline

- **2001**: Princeton University spin-out
- **2002 – 2007**: R&D programs with NASA, DOE, ONR, Navsea, Army, NJ BPU, private clients
- **2008**: Hybrid (wind, solar, battery) systems installed in Bermuda, Virginia, California, New Jersey
- **2009**: GTIB 480-100 UL 1741 listing, “Green Product of the Year” Award, $3.3M NJ-sponsored investment in manufacturing plant begins
- **2010**: Military VSD deployments on the Gerald Ford Aircraft Carrier
- **2011**: ~3MW GTIB’s deployed, new production facility opened with 12 MW capacity, Demand Response Inverter final pre-production testing
<table>
<thead>
<tr>
<th>Project Description</th>
<th>Technical Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Princeton Power Systems Facility, Princeton, NJ</td>
<td>200 kWe / 164 kWe lithium-ion</td>
</tr>
<tr>
<td>Multi-functional demonstration, grid-tied and backup</td>
<td></td>
</tr>
<tr>
<td>‘Earth Day’ PHEV Charging Station, grid-tied storage, 100 kWe / 26 kWe lithium-ion</td>
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</tr>
<tr>
<td>U.S. Army Forward Operating Base</td>
<td>100 kWe Solar Configuration, 100 kWe deep-cycle lead-acid</td>
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<tr>
<td>Field-deployed microgrid</td>
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<tr>
<td>Alcatraz Island, National Park Service (Q3 2011)</td>
<td></td>
</tr>
<tr>
<td>Bermuda Electric Light Company (BELCO)</td>
<td>‘Remote Controller’ for microgrid operation</td>
</tr>
<tr>
<td>Wind, solar battery system deployed in Bermuda, lead-acid</td>
<td></td>
</tr>
</tbody>
</table>
HVDC Power Converter Background

- The HVDC power converter changes low-voltage alternating current (LVAC) power to high-voltage direct current (HVDC) to allow efficient power transmission between communities, and usable power within the community.
- The HVDC Power Converter plays a key role in reducing transmission costs and increasing grid reliability for remote and isolated electrical systems.
- The HVDC power converter has been a ‘missing link’ in realizing the HVDC Transmission concept.
- PPS’ HVDC converter, partially funded through PolarConsult, is a 500 kW power converter, capable of parallel operation to 10 MW or more, and bi-directional power conversion between three-phase 480 VAC and 50 kVDC.
Power Converter Components

High-Voltage Enclosure (800 VAC ↔ 50 kVDC) Includes transformer in oil

Low-Voltage Enclosure (480 VAC ↔ 6-8 kHz 800 VAC)
Phased Development Summary

- In Phase I, a design was completed and a bench-scale concept and feasibility unit was constructed, and concept validation testing performed (December 2007 – February 2009)

- In this Phase II, 2 500kW prototype units are being built and tested
  - Contractual PoP: May 2010 – October 2011
  - PPS will work through December 2011 to complete Testing

- A Phase II technology demonstration is scheduled for November 14th 2011, at Princeton Power Systems High Voltage Testing Facility in Princeton, NJ.
Phase II Status Summary

- Previously Completed Milestones

- Schedule for Completion of Phase II

May 2010 — Dec 2011

Nov 2011
Technology Demonstration
# Phase II Task Status

<table>
<thead>
<tr>
<th>Task</th>
<th>Percent Complete</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.1 Develop Converter Voltage Standards</td>
<td>100%</td>
</tr>
<tr>
<td>2.1.1 Review Voltage Stds with PCA and AVEC</td>
<td>100%</td>
</tr>
<tr>
<td>2.1.2 Review Safety Packaging &amp; Perf. Req. with PCA &amp; AVEC</td>
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</tr>
<tr>
<td>2.1.3 Review Power Line Comm. System</td>
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<tr>
<td>2.1.4 Develop System Spec for 1MW and Sign off w/PCA</td>
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<tr>
<td>2.2 Converter Design and Construction</td>
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<tr>
<td>2.2.1 Modify PE and Circuit Topology (Procurement Spec)</td>
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<tr>
<td>2.2.2 Perform Computer Modeling</td>
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<tr>
<td>2.2.3 Reliability / failure analysis of HVDC Converter Design</td>
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</tr>
<tr>
<td>2.2.4 Modify Control Software</td>
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</tr>
<tr>
<td>2.2.5 Evaluate and Mod design to diagnose faults/failures</td>
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</tr>
<tr>
<td>2.2.6 Develop Thermal Management System</td>
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<tr>
<td>2.2.7 Generate Mech Design (HVDC System)</td>
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<tr>
<td>2.2.8 Generate 3D Model and Detailed Metalwork Fabrication</td>
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<tr>
<td>2.2.9 Identify / Develop Vendor / Procurement</td>
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<tr>
<td>2.2.10 Assemble (1) 1MW Unit</td>
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<td>2.3 Converter Test Plan</td>
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<td>2.3.1 Develop Converter Test Plan</td>
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<tr>
<td>2.3.2 Review and Appr of Test Plan by ACEP</td>
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<tr>
<td>2.3.3 Test Plan Revisions</td>
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<td>2.4 Converter Testing and Reporting</td>
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<td>2.4.1 Dielectric Test</td>
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<td>2.4.2 Various failure mode response testing</td>
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<td>2.4.3 Operational / Functional Testing</td>
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<td>2.4.4 Efficiency Testing</td>
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<td>2.4.5 Temperature Rise Testing</td>
<td>20%</td>
</tr>
<tr>
<td>2.4.6 Test Report</td>
<td>0%</td>
</tr>
</tbody>
</table>
Completed Milestones

- Air Testing Completed on Transformer assembly #1.
  - Issues with design exposed during Hi-Pot test.
  - Changes implemented, 20kV Hi-Pot test passed.
- Transformer #1 immersed in oil
- Hi-Pot 70kV Test Passed
- Implemented design changes to Transformer #2.
- Transformer #2 20kV Hi-Pot Test Passed.
- LV Enclosure #1 assembly complete
- Functional testing completed
- LV Enclosure #2 assembly complete
Transformer and HV Stacks

Completed:
- Assembly of Module #1 completed.
- Hi-Pot tested in air to 15kV.
- Operational Testing to 9kV.
HV Transformer #1

Transformer #1 immersed in oil tank for in-oil testing
Controls Sub-Assembly Testing

Component Tests Completed
- Tank Status Board
- Fiber Optic assembly
- FPGA Configuration
- Individual Circuit tests
- Sensor inputs
- Status output
- UART input/output
Controls Sub-Assembly Testing

Component Tests Completed

• Peripheral board
  – Trigger Tests
  – Sensor Tests
  – Fiber Optic Tests
• Simulated system test of the Tank Status board
• DSP software coding and modification
  – Software start up
    • Initialization
    • Calibration
• Basic peripheral control and monitoring
Current Status

500kW Module 1
HVDC Transformer and LVAC Enclosure
Installed in PPS HV Test Lab for HV Bring Up

500kW Module 2
Transformer Tank
awaiting in air testing completion
Transformer HV Assy
ready for In Air testing 10-28

LVAC Unit completed at PPS HV Lab

March 2012 Final Report
Schedule for Completion of Remaining Phase II Tasks as of 10/25/2011

<table>
<thead>
<tr>
<th>Task Name</th>
<th>Duration</th>
<th>Start</th>
<th>Finish</th>
<th>Predecessors</th>
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<tbody>
<tr>
<td>2 System #1 Hi-Pot Testing</td>
<td>1 day</td>
<td>Mon 8/1/11</td>
<td>Mon 8/5/11</td>
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<tr>
<td>3 System #2 Bring Up in Air</td>
<td>35 days</td>
<td>Tue 8/8/11</td>
<td>Mon 9/12/11</td>
<td>2</td>
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<tr>
<td>4 Re-installed RMAs 90 deg</td>
<td>1 day</td>
<td>Tue 8/8/11</td>
<td>Mon 9/12/11</td>
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<tr>
<td>5 Repair 2 Trigger Bids</td>
<td>3 days</td>
<td>Wed 8/16/11</td>
<td>Fri 8/19/11</td>
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<tr>
<td>6 Re-work Transformer more Kapton</td>
<td>1 day</td>
<td>Thu 8/18/11</td>
<td>Thu 8/25/11</td>
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<tr>
<td>7 HI Pot Transformer</td>
<td>1 day</td>
<td>Fri 8/19/11</td>
<td>Fri 8/26/11</td>
<td></td>
</tr>
<tr>
<td>8 Integrate IGBT Temp Sensors</td>
<td>1 day</td>
<td>Wed 9/1/11</td>
<td>Wed 9/8/11</td>
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<tr>
<td>9 Power Supply Switcher Bld</td>
<td>22 days</td>
<td>Wed 9/1/11</td>
<td>Thu 9/28/11</td>
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<tr>
<td>10 AC to DC Tool</td>
<td>2 days</td>
<td>Mon 9/5/11</td>
<td>Mon 9/9/11</td>
<td>11, 12</td>
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<tr>
<td>11 DC to AC Switching Test</td>
<td>4 days</td>
<td>Wed 9/7/11</td>
<td>Thu 9/22/11</td>
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<td>12 Final Verification</td>
<td>3 days</td>
<td>Tue 9/13/11</td>
<td>Thu 9/15/11</td>
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<tr>
<td>13 Task #1 Transformer Insert to NML for Oil Processing</td>
<td>5 days</td>
<td>Tue 10/1/11</td>
<td>Mon 10/17/11</td>
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<td>14 System #1 LV Controls Bring up</td>
<td>29 days</td>
<td>Wed 10/5/11</td>
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<td>15 Control Bld DSP Code</td>
<td>20 days</td>
<td>Wed 10/5/11</td>
<td>Tue 11/1/11</td>
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<td>18 System #2 Kit for IRML</td>
<td>45 days</td>
<td>Mon 10/22/11</td>
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<tr>
<td>21 System #1 HV Testing at 3175</td>
<td>13 days</td>
<td>Tue 10/18/11</td>
<td>Thu 11/1/11</td>
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<td>24 System #1 HV Testing</td>
<td>1 day</td>
<td>Thu 10/19/11</td>
<td>Thu 10/26/11</td>
<td>13 11</td>
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<td>25 System #1 HV Bring Up</td>
<td>12 days</td>
<td>Wed 10/19/11</td>
<td>Thu 11/5/11</td>
<td>24</td>
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<tr>
<td>26 System #2 Bring Up in Air</td>
<td>9 days</td>
<td>Fri 10/28/11</td>
<td>Wed 11/2/11</td>
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</tr>
<tr>
<td>27 Tank Insert #2 Returned to PPS for Dry Testing</td>
<td>1 day</td>
<td>Fri 10/28/11</td>
<td>Fri 10/28/11</td>
<td>22</td>
</tr>
<tr>
<td>28 System #2 Hi-Pot Testing</td>
<td>3 days</td>
<td>Mon 11/3/11</td>
<td>Wed 11/9/11</td>
<td>27</td>
</tr>
<tr>
<td>29 System #2 Bring Up in Air</td>
<td>5 days</td>
<td>Thu 11/9/11</td>
<td>Wed 11/16/11</td>
<td>28</td>
</tr>
<tr>
<td>31 System #2 LV Controls Bring Up</td>
<td>4 days</td>
<td>Thu 11/9/11</td>
<td>Thu 11/16/11</td>
<td>32</td>
</tr>
<tr>
<td>32 Bring Up and Verify</td>
<td>3 days</td>
<td>Wed 11/9/11</td>
<td>Fri 11/14/11</td>
<td>15, 27</td>
</tr>
<tr>
<td>33 System #2 HV Testing at 3175</td>
<td>9 days</td>
<td>Mon 11/17/11</td>
<td>Thu 11/24/11</td>
<td></td>
</tr>
<tr>
<td>34 Tank #2 Transformer Insert to NML for Processing in Oil</td>
<td>3 days</td>
<td>Mon 11/17/11</td>
<td>Wed 11/24/11</td>
<td>30</td>
</tr>
<tr>
<td>35 Tank #2 Returned to PPS Processed</td>
<td>1 day</td>
<td>Thu 11/17/11</td>
<td>Thu 11/24/11</td>
<td>34</td>
</tr>
<tr>
<td>36 System #2 HV Bring Up</td>
<td>5 days</td>
<td>Fri 11/18/11</td>
<td>Thu 11/25/11</td>
<td>36</td>
</tr>
<tr>
<td>37 System HV Testing</td>
<td>24 days</td>
<td>Mon 11/14/11</td>
<td>Thu 12/15/11</td>
<td></td>
</tr>
<tr>
<td>38 HV System Testing</td>
<td>20 days</td>
<td>Fri 11/18/11</td>
<td>Thu 12/15/11</td>
<td>26, 36</td>
</tr>
</tbody>
</table>

APPENDIX C - FIG 270

March 2012 Final Report
Phase II Remaining Tasks

- LV Enclosure #1 with Transformer #1 Operational Testing to 50kV underway
- Transformer #2 assembly ready for Air Testing. 10-28
- LV Enclosure #2 Operational Testing underway
- Transformer #2 immersed in oil 11-7
- LV Enclosure #2 with Transformer #2 Operational Testing to 50kV 11-17
- Dual-module System Testing 11-17 to 12-15
“Module 1” HV Testing

Module Integration (Underway)

- Visual inspection
- Tank: Electrical / Mechanical
- LV Enclosure: Electrical / Mechanical
- Hi-Pot
- Across transformer, 71 kV
- DC to ground
- AC to ground
- LV Enclosure (DC and AC) to ground
“Module 1” HV Testing

- Controls Operational Testing (Underway)

- Control power
- Communication interfaces
- Sensor input
- System I/O
- User I/O
- Triggering check
  - Check trigger lines for basic operation
  - Characterize propagation delay and skew between electrical and optical transmission lines, and correct if necessary.
  - Switch power using a test pattern and LVLE (Low voltage, Limited Energy) power source to confirm correct ability to switch at frequency, with dead time etc.
1MW Dual-module System Testing

- Functional tests
  - Rated voltage test- 50kV DC using earth return
    - 3 phase 480 VAC to 50 kVDC
    - 50 kVDC to 3 phase 480 VAC
  - Power sharing between parallel systems
- Efficiency test @ several power levels
- Temperature rise test @ rated current and low voltage
Air Testing Configuration

Polarconsult Alaska, Inc.

PHASE II – PROTOTYPING AND TESTING

MARCH 2012  PAGE I-97
Phase II Converter Materials Costs

<table>
<thead>
<tr>
<th>BOM Summary</th>
<th>10pcs.</th>
<th>100pcs.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power Electronics</td>
<td>$116K</td>
<td>$100K</td>
</tr>
<tr>
<td>Controls &amp; Monitoring</td>
<td>$32K</td>
<td>$26K</td>
</tr>
<tr>
<td>Mechanical- BOS</td>
<td>$69K</td>
<td>$56K</td>
</tr>
<tr>
<td>Total Parts Cost 1MW</td>
<td>$217K</td>
<td>$182K</td>
</tr>
</tbody>
</table>

We have a $250/kW cost target for a ‘commercial production’ unit in low-medium volumes.

‘Commercial Production’ means that substantial work has been done to take the functional Phase II prototype and perform thorough testing and manufacturing engineering to reduce costs. This will require additional work for testing and design refinement/cost reduction.

This additional work accounts for achieving $250/kW based on the actual numbers from Phase II.
## Phase II Converter Efficiency

### Total Full-Power Loss Calculation

<table>
<thead>
<tr>
<th>Component</th>
<th>RMS</th>
<th>Linear</th>
<th>Fixed</th>
<th>sum</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parasitic</td>
<td>500</td>
<td>500</td>
<td>500</td>
<td>1500</td>
<td>0.300%</td>
</tr>
<tr>
<td>HVDC Bridge</td>
<td>979</td>
<td>2774</td>
<td>3</td>
<td>3756</td>
<td>0.751%</td>
</tr>
<tr>
<td>HF Transformer</td>
<td>716</td>
<td>0</td>
<td>1300</td>
<td>2016</td>
<td>0.403%</td>
</tr>
<tr>
<td>HF Capacitors</td>
<td>226</td>
<td>0</td>
<td>0</td>
<td>226</td>
<td>0.455%</td>
</tr>
<tr>
<td>HV Stack 50kV Balancing</td>
<td>0</td>
<td>0</td>
<td>781</td>
<td>781</td>
<td>0.158%</td>
</tr>
<tr>
<td>HV Stack 24V Balancing</td>
<td>0</td>
<td>0</td>
<td>150</td>
<td>150</td>
<td>0.030%</td>
</tr>
<tr>
<td>LVDC Bridge</td>
<td>1349</td>
<td>0</td>
<td>0</td>
<td>1349</td>
<td>0.270%</td>
</tr>
<tr>
<td>LVAC Bridge</td>
<td>7224</td>
<td>2382</td>
<td>0</td>
<td>9606</td>
<td>1.921%</td>
</tr>
<tr>
<td>AC Filter Inductor (L1)</td>
<td>755</td>
<td>113</td>
<td>0</td>
<td>868</td>
<td>0.174%</td>
</tr>
<tr>
<td>AC Filter Capacitor (Cac)</td>
<td>150</td>
<td>0</td>
<td>0</td>
<td>150</td>
<td>0.030%</td>
</tr>
<tr>
<td>Grid Inductor (L2)</td>
<td>748</td>
<td>0</td>
<td>0</td>
<td>748</td>
<td>0.150%</td>
</tr>
<tr>
<td>Control System</td>
<td>100</td>
<td>50</td>
<td>0</td>
<td>150</td>
<td>0.030%</td>
</tr>
<tr>
<td>Cooling System</td>
<td>826</td>
<td>0</td>
<td>0</td>
<td>826</td>
<td>0.165%</td>
</tr>
<tr>
<td>Wiring &amp; Bus Bar</td>
<td>100</td>
<td>400</td>
<td>0</td>
<td>500</td>
<td>0.100%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>12747</strong></td>
<td><strong>6982</strong></td>
<td><strong>2897</strong></td>
<td><strong>22627</strong></td>
<td><strong>4.525%</strong></td>
</tr>
</tbody>
</table>

### Converter Efficiency w/aux losses

<table>
<thead>
<tr>
<th>Power %</th>
<th>RMS loss</th>
<th>Linear Loss</th>
<th>Fixed Loss</th>
<th>Total Loss</th>
<th>Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>1%</td>
<td>1.3</td>
<td>69.8</td>
<td>2897.4</td>
<td>2968.5</td>
<td>40.6%</td>
</tr>
<tr>
<td>3%</td>
<td>11.5</td>
<td>209.5</td>
<td>2897.4</td>
<td>3118.3</td>
<td>79.2%</td>
</tr>
<tr>
<td>10%</td>
<td>127.5</td>
<td>698.2</td>
<td>2897.4</td>
<td>3723.1</td>
<td>92.6%</td>
</tr>
<tr>
<td>20%</td>
<td>509.9</td>
<td>1396.4</td>
<td>2897.4</td>
<td>4803.7</td>
<td>95.2%</td>
</tr>
<tr>
<td>30%</td>
<td>1147.3</td>
<td>2094.6</td>
<td>2897.4</td>
<td>6139.3</td>
<td>95.9%</td>
</tr>
<tr>
<td>40%</td>
<td>2039.6</td>
<td>2792.8</td>
<td>2897.4</td>
<td>7729.8</td>
<td>96.1%</td>
</tr>
<tr>
<td>50%</td>
<td>3186.9</td>
<td>3491.0</td>
<td>2897.4</td>
<td>9575.3</td>
<td>96.2%</td>
</tr>
<tr>
<td>60%</td>
<td>4589.1</td>
<td>4189.2</td>
<td>2897.4</td>
<td>11675.7</td>
<td>98.1%</td>
</tr>
<tr>
<td>75%</td>
<td>7170.4</td>
<td>5236.5</td>
<td>2897.4</td>
<td>15304.3</td>
<td>99.9%</td>
</tr>
<tr>
<td>80%</td>
<td>8188.3</td>
<td>6586.6</td>
<td>2897.4</td>
<td>16841.3</td>
<td>99.8%</td>
</tr>
<tr>
<td>90%</td>
<td>90325.4</td>
<td>6283.8</td>
<td>2897.4</td>
<td>19506.5</td>
<td>95.7%</td>
</tr>
<tr>
<td>March 2012 Final Report</td>
<td>1000</td>
<td>6982.0</td>
<td>2897.4</td>
<td>22628.8</td>
<td>95.5%</td>
</tr>
</tbody>
</table>
Beyond Phase II

- The Phase II project includes the following: Dielectric test, Basic failure mode response testing, Basic Operational / Functional testing, Efficiency testing at various power levels, and temperature rise testing at rated current and low voltage.

- We anticipate that the following testing will be required to prepare the 500kW HVDC units for deployment in a commercial setting:
  - Detailed Failure Mode Response Testing.
  - Thorough Operational and Functional Testing.
  - Confidence Testing including load and endurance tests.
  - Design review and modifications based on test results.
Beyond Phase II

- Documentation including Operations Manual.
- Training for Utility Team, Installation and Commissioning.
- On-site support for Installation and Commissioning.
- Site development
  - General Electrical Design
  - Protective Relay Design
  - System Dielectric Coordination
  - Communications System Design
  - Structure / Container Design
- PPS recommends having spare modules and components that may be required throughout this phase.
- It is anticipated that this phase would require 8-10 Months and cost between $600k and $800k
1.5 HANDOUTS FROM OTHER MEETINGS CONDUCTED DURING THE PROJECT
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1.5.1 Southeast Conference Mid-Session Summit – Juneau, Alaska (March 2, 2010)
High Voltage Direct Current Transmission Project

Project Status Update to Southeast Conference

March 2nd, 2010

Joel Groves – Project Manager
Polarconsult Alaska, Inc.
907-258-2420
joel@polarconsult.net
Project Background

PURPOSE

➢ Develop HVDC Transmission for Remote Alaskan Electrical Interties
  ➢ Reduce Transmission Capital Costs
  ➢ Enable More Interties
  ➢ Enable More Local Energy Developments

TASKS & SCHEDULE

➢ Phase I (Proof of Concept) Completed Summer 2009
➢ Phase II (Prototyping and Testing) Spring 2010 – Fall 2011
➢ Phase III (Demonstration Project) TBD
Phase II Overview

- Funded by Denali Commission
- Managed by UAF/ACEP
- Major Tasks
  - Design, Build, Test Prototype Converter
  - Design & Test Overhead Transmission System
  - Design & Test Overland/Submarine Cable Systems
  - Design & Test Key Construction Methods
  - Develop Cost Estimates and Economic Analysis
Stakeholder Involvement

- ACEP will be forming a Stakeholder Advisory Group for Phase II
  - Provide Input
  - Review Major Deliverables
- SAG will meet at Rural Energy Conference in Fairbanks – Late April
  - Informal SAG meeting after today’s Legislative Panel
  - Contact me for more information
    - joel@polarconsult.net
    - 907-258-2420
I.5.2 Emerging Energy Technology Forum – Juneau, Alaska (February 14, 2011)
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High Voltage Direct Current Transmission
For Remote Alaska Inter ties (Phase II/III)

Polarconsult Alaska, Inc.
Joel D. Groves, P.E.
Project Manager
joel@polarconsult.net
HVDC Project Summary

- Phase I – Technical and Economic Feasibility Study
  - 2008-2009
- **PHASE II – Converter Design & Testing, System Integration & Transmission Conceptual Designs**
  - 2010-2011
- Phase III - 1st Commercial Demonstration in Alaska
  - 2012-2014
- Commercial Use on Alaska Projects
  - 2014 and beyond

Phase II Project Summary

- Goal: Lower Cost of Remote Alaska Interties
- Lead: Polarconsult Alaska, Inc. (Anchorage)
  - Management, Conceptual Transmission Designs
  - Princeton Power Systems, Inc. (New Jersey)
    - Converter Development and Testing
  - Manitoba HVDC Research Centre (Winnipeg)
    - HVDC Systems Integration
Technology Overview

- High Power HVDC Systems are common
  - New Jersey – Long Island - China
  - Texas - Scandinavia (starting 1950s)
  - Pacific Intertie - Tasmania
- Utility Grade Low Power HVDC Systems have not been commercialized (Smallest ~10 MW)
- HVDC is a good option for Alaska, but smaller capacity needed to be economical
- Low Power HVDC System (1 MW, 50 kV)

System Highlights

- 1 MW power throughput
- Redundant design – two parallel 500 kW systems
- 480V 3 phase AC
- 50 kV HVDC (+ or – relative to ground)
- Bidirectional Power Flow
- 2-wire Monopolar, 1 wire Monopolar SWER, and/or Bipolar operation
- Overhead, Underground, or Submarine Transmission
Alaska Applications

- Interties are a proven means to lower village energy costs
- AC interties cost $300-400k / mile
- HVDC interties projected at $100-200k / mile
- HVDC Benefits
  - Submarine Cables
  - Overland Cables
  - Build Economy of Scale
  - Develop More Local Energy Resources
  - Consolidate Operations
  - Common Cable with Telecoms

**LOWER ENERGY COSTS**
Tasks & Timeline (Phase II)

- Stakeholder Involvement
  - Railbelt Utilities
  - Rural Utilities
  - Regulatory & Governmental
  - Industry Professionals

- Converters: Design, Build, Test 1st Article Converter
  - Build & Test Q2&3 2011

- Transmission: Conceptual Designs, Identify Suppliers
  - Key Field Tests Q2&3 2011

- Economics & Planning
  - Final Report October 2011

Project Status - Converters
Low Voltage Cabinet

Weight & Dims:
63"H x 42"D x 74"L
2,300 lbs

Emergency Transport:
CASA-212-200

Cooling
Forced Air

High Voltage Tank

Weight & Dims:
62"H x 36"D x 127"L
4,900 lbs (wet)
2,100 lbs (dry)

Emergency Transport
CASA 212-200

Cooling
Coolant is Luminol TR/TRi
Pour Point -60C
Flash Point 170C
Natural Oil Convection
Transmission Highlights - Overhead

- 1 or 2 wires vs. 3 or 4 for AC
- Less load on poles
- No/less wire spacing needed
- Less hardware and wire
- Longer spans, fewer poles, lower cost
- Design for remote logistics
  - Small Equipment
  - Air Transport for Emergency
  - Simple, robust designs

Overhead Transmission Example

- GVEA's Northern Intertie #1
- Commissioned 1968
- 138 kV guyed lattice
- Permafrost soils
- Some frost jacking
Other Activities

- Overland Cable Systems
  - AC cables are suitable for DC use
  - Evaluating solutions to ground cracking
- Submarine Cable Systems
  - Identified Conceptual Cable Design
  - Talking to Vendors on Availability, Cost
- System Integration
- SWER approval

Questions

Economic Value Hubs and Existing and Proposed Transmission Lines

FROM DISTRIBUTING ALASKA’S POWER
NANA PACIFIC/WI PACIFIC/NANA COLT
DECEMBER 2008
I.5.3 Brown-Bag Work Session – Anchorage, Alaska (August 29, 2011)
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HVDC System for Rural Alaska Applications
Project Overview and Status Update

Joel Groves, PE
Polarconsult Alaska, Inc.
August 29, 2011

Meeting Outline

HVDC PROJECT OVERVIEW
Project Goals
Program Organization

UPDATE ON CURRENT WORK STATUS
POLICY IMPLICATIONS
UPCOMING MEETINGS AND EVENTS
Q & A
HVDC Project Overview

The Problem

- Energy Crisis in Rural Alaska
  - ~80,000 people in 185 villages and ~170 micro grids
  - Generally rely on diesel gen sets
  - Electric rates from 35 – 150 cents/kWh
  - PCE helps residential rates, ~$30M/year subsidy
  - No subsidy to businesses

- Affordable Interties are a solution

HVDC Project Overview

The Goal

- REDUCE ENERGY COSTS IN ALASKA VILLAGES

  - Provide a lower cost, technically superior power intertie option
  - Enable villages to form micro grids and
  - Reach out to local energy resources
HVDC Project Overview

The Solution

- Interconnect Villages to Build Loads
  - Eliminate bulk fuel storage
  - Eliminate power plants
  - Boost plant efficiencies and operations
  - Build loads that can justify tapping local energy resources
- Remote Alaska Interities are Prohibitively Expensive
  - AC tie lines are $300,000+ per mile
- HVDC Offers a Less Expensive Alternative

---

HVDC Project Overview

The Solution

- HVDC instead of AC
- Use Single Wire Earth Return (SWER) Circuits
- One wire aloft instead of 3 or 4
  - Simpler structures
  - Reduced environmental loads
  - Tall poles, long spans
  - Indicated cost of ~$150,000 per mile
- Asynchronous Interities
- Long-Distance Buried or Submarine Cables
HVDC Project Overview

The Solution

- HVDC converters are more expensive
- HVDC intertie per mile is less expensive
- Breakeven point is ~7 miles

HVDC Project Overview

Program Goals

- Develop HVDC System for Use in Alaska
  - One MW HVDC converter
  - Conceptual intertie designs optimized for HVDC and Alaska conditions
- Gain industry support so Alaskans benefit from the technology and investment
- Clear regulatory impediments
- Prove the technology in the field
HVDC Project Overview

PROGRAM OVERVIEW

- **Internal Review** (Polarconsult, 2005-07)
- **Phase 1 – Proof of Concept** $700,000 DC funds, AVEC Completed 2008 – 09
- **Phase II – Prototyping & Testing** $2.2M DC funds, ACEP Underway 2010-11
- **Phase III – Demonstration Project** Site and Budget TBD 2012-2014 *(limited demo proposed under EETF)*
- **Commercial Deployment**
  2014 and after

---

HVDC Project Overview

PHASE I FINDINGS

- 12 kVDC to 250 kW 3ph 480 VAC bench top converter was designed, built, and tested to prove the technology
- Met Cost and Performance Benchmarks
- 56% capital cost savings over AC line costs
- 28% life-cycle savings over AC line costs
HVDC Project Overview

**PROGRAM OVERVIEW**

- **Converter Input Power (kW)**
  - 96.00%
  - 96.25%
  - 96.50%
  - 96.75%
  - 97.00%
  - 97.25%
  - 97.50%
  - 97.75%
  - 98.00%

**Converter Efficiency**

**Phase II Overview**

- Design/Build/Test Full Scale Converter
- Two 500 kW modules 50 kVDC ↔ 480 VAC
- Princeton Power Systems, Inc.
- Develop and Test Conceptual Intertie Designs
- Update System Economics with Phase II Data
- Advance Industry Support for HVDC
  - Stakeholder’s Advisory Group (AK utilities, local governments, regulatory personnel)
HVDC Project Overview

Phase II Project Team

- Denali Commission (Funding Agency)
- ACEP (Grant Management, Economic Analysis, Strategy)
- Polarconsult (Project Management, Strategic Vision, Design)
- Princeton Power Systems (Converter Development)
- UAF/Dr. Wies (Alaska Integration / Practicality)
- AVEC (Alaska Integration / Practicality)
- SAG (Practicality / Industry Acceptance)
- Manitoba HVDC Research Centre (HVDC Expert)
- Line Design Engineering (Structural and Code Expert)
- Golder Associates (Geotechnical Expert)
- Almita, Inc. (Foundation Supplier)
- Arctic Foundations, Inc. (Foundation Supplier)
- Zarling Aera Consulting (Thermal Soils Analysis)
- STG, Inc. (Rural Intertie Contractor)
- Cabletricity, Inc. (Submarine Cable / HVDC Expert)

HVDC Project Overview

SAG Members

- Denali Commission
- Alaska Center for Energy & Power
- Polarconsult Alaska, Inc.
- Alaska Village Electric Cooperative
- Alaska Energy Authority
- North Slope Borough
- Naknek Electric Association
- Nome Joint Utilities
- Nome Chamber of Commerce
- Bering Straits Native Corporation
- Alaska Department of Labor
- IPEC
- AP&T
- CVEA
- MEA
- USDA-RUS
- GVEA
- Nuvista Light & Power
HVDC Project Overview

SAG Members

- Denali Commission
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- Polarconsult Alaska, Inc.
- Alaska Village Electric Cooperative
- Alaska Energy Authority
- North Slope Borough
- Naknek Electric Association
- Nome Joint Utilities
- Nome Chamber of Commerce
- Bering Straits Native Corporation
- Alaska Department of Labor
- IPEC
- AP&T
- CVEA
- MEA
- USDA-RUS
- GVEA
- Nuvista Light & Power

HVDC Project Overview

1 MW Converter (20 x 13)
HVDC Project Overview
Overhead Transmission

- 70' 14" dia. X .3" wall fiberglass pole
- 4 guys per structure
- 1,000' ruling span
- Typical six foundations per mile
- 4-season constructability

HVDC Project Overview
Overhead Transmission

- Variety of Load Cases
- NESC 250C w/ 120 mph Wind is Limiting
- 10,000 lb load at pole base
- 10,000 lb load on guy
- 'Cafeteria Plan' design approach
- Range of foundations for soil conditions
- Flexible equipment for installation
HVDC Project Overview
Cable Transmission

- 500 kW is 10 amperes at 50 kV
- Okonite URO-J cable is adequate
- Opportunity to bundle with broad-band telco

Project Work Status
Code Issues

- AK DOL and MHRC dialog to resolve general concerns on earth return grounding
- Projects will be issued NESC waivers for ground-return operation
Project Work Status

Construction / Maintenance Equipment

- OH system construction is flexible
  - Winter or Summer construction is possible
  - Overland or helo construction is possible
  - Methods are project and contractor-specific
- Maintenance/Repair
  - FG poles have existing climbing solutions
  - Room exists for innovation

Project Work Status

Controls / Integration

- MHRC and AVEC input to converter interface needs
- MHRC White Paper on MTDC Networks w/ PPS Valve
- PPS Converter is uniquely well-suited to MTDC operations
  - Valve can be self regulating
  - Valve can act as HVDC breaker
  - Converters can operate autonomously in two-terminal system
- Master SCADA needed for MTDC networks
- Reliable Communication Link is Desirable
**HVDC Project Overview**

*Phase II Closeout*

- Completion December 30, 2011
- Converters Operational and Tested
- Foundations Test Site in Fairbanks
- Final Report
  - Technology Reports
  - Economics
  - Logistics Narrative

**Policy Implications**

*Current Chatter on State Energy Policy*

- State Subsidy of Cook Inlet Gas Exploration State Subsidy of $7B Natural Gas Line from NS → ANC?
- State Subsidy of Susitna Hydro ~$3B?
- Gas network into bush communities (propane/NG)?
- Large-Scale HVDC backbone NS → ANC → SW Mines
  - (HVDC Light or HVDC Conventional)
- HVDC branches to hubs and villages (<10 MW)
  - This Technology
Policy Implications
GCI’s Terra Project

- What if Fiber Cables had included HVDC Conductor?
- $40M additional cost (very rough!)
- 12 - 500kW HVDC converters
- 8 villages served (1,000 pop)
- Hypothetical $0.20/kWh rate
- Saves SOA $532,300/yr in PCE
- Saves villages $1.9M/yr
- $400,000 year for system O&M
- Simple payback 16 years
**HVDC Opportunities**

*Intertie Projects in Development*

- Barrow-Atqasuk
  - Permitting – birds are major issue
- Petersburg-Kake-Takatz-Sitka
  - EIS underway – 25 MW intertie
- St. Mary’s-Mountain Village
  - Permitting
- Gustavus-Glacier Bay National Park HQ
  - EIS done, 4 years away
- Kodiak-Ouzinkie
  - Feasibility stage
HVDC Opportunities
Intertie Projects in Development

- Barrow-Atqasuk
  - Permitting – birds and overhead lines are major issue
- Petersburg-Kake-Takatz-Sitka
  - EIS underway ~ 25 MW intertie, long submarine segments
- St. Mary’s-Mountain Village
  - Permitting
- Gustavus-Glacier Bay National Park HQ
  - EIS done, 4 years away aesthetics are critical issue
- Kodiak-Ouzinkie
  - Feasibility stage, submarine crossing

Upcoming Events

- Oct. 25.  SAG Meeting #3. Phase II Findings
- Sept. 28-30  Rural Energy Conference
- Nov. 14.  Denali Commission/SAG to PPS
I.5.4  HVDC Converter Demonstration – Lawrenceville, New Jersey (November 14, 2011)
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REDUCE ENERGY COSTS IN RURAL ALASKA

Energy Crisis in Rural Alaska

- ~80,000 people in 185 villages and ~170 micro grids
- Generally rely on diesel gen sets
- Diesel from $4 to 8+ per gallon
- Electric rates from 35 – 150 cents/kWh
- State subsidizes residential rates, ~$30M/year subsidy
- No subsidy for businesses
HVDC Project Overview
How Does HVDC Get There?

- Reduce intertie costs to Interconnect Villages
  - AC interties are costing $200,000 – $400,000 per mile
  - HVDC interties can cost $100,000 – 200,000 per mile

- Interconnect Villages to Build Economy of Scale
  - Consolidate bulk fuel storage
  - Eliminate power plants
  - Boost plant efficiencies and operations
  - Build loads that can justify tapping local energy resources

Where might the Economies of Scale Begin?

- 2007 - 2009 Peak Power Demand (kW)
- 2007 Energy Price (cents / kWh)
- 2008 Energy Price (cents / kWh)
- 2009 Energy Price (cents / kWh)

Yearly variation of the peak power demand and energy price for various communities.
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1.6 ADDITIONAL MEETINGS
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The following additional meetings were held during the course of this project regarding a HVDC transmission system in rural Alaska.

- Southeast Conference Mid-Session Summit – Juneau, Alaska (March 2, 2010)
- Emerging Energy Technology Forum – Juneau, Alaska (February 14, 2011)
- Brown-Bag Work Session – Anchorage, Alaska (August 29, 2011)
APPENDIX J

BIBLIOGRAPHY


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