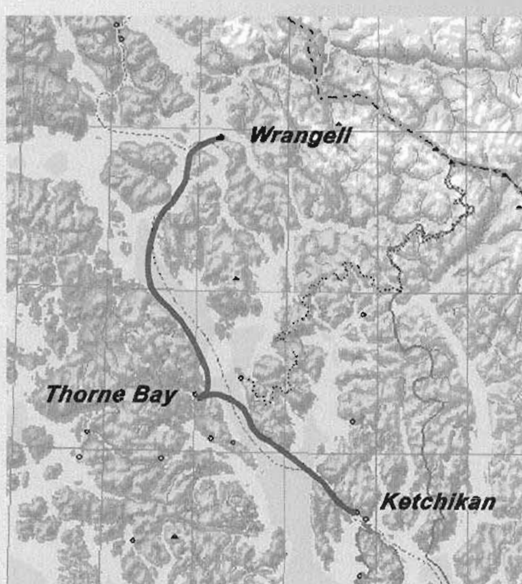
A Review of the Status of Development of HVDC Voltage Sourced Converters and Extruded Submarine Cable Technology for HVDC in Southeast Alaska



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Teshmont

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HVDC in Southeast Alaska

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EXECUTIVE SUMMARY

The development of high power insulated gate bipolar transistor (IGBT) switching devices has made it possible for a new generation of hvdc converter equipment to evolve, which is ideally suited for low and medium power applications such as the proposed interconnection of isolated communities in Southeast Alaska. This report provides a critical review of the state of development of the new technology. Information provided by three different suppliers was reviewed. These three suppliers have well-developed designs and prototype demonstration projects. One supplier has delivered several projects that have been in service for a number of years. Based on this response it is concluded that the converter technology and control and protection concepts have reached a sufficient level of technical maturity so that they can be applied in the electric power industry without undue risk.

Low cost extruded polymer cables for dc applications are also being developed by several European and Japanese manufacturers. The materials used in extruded cables have been shown to be practical in lab tests and cable designs have been factory tested. Extruded cables have been applied for dc in buried applications on land but not, as yet, for deep submarine cable applications. Given advances in cable manufacturing technology which allow very high quality control and material purity, the cable itself is regarded as practical and robust even though there is comparatively little long time experience in dc applications.

The successful long time application of any submarine cable depends on the ability to repair a damaged cable in a reliable and timely fashion. This requires that proven jointing technology be available to carry out any needed repairs. The development of field installable cable joints for both land and submarine cable applications has lagged behind the development of extruded cables. At the time writing of this report there are no field installed submarine cable joints in service in deep-sea applications anywhere in the world. Field installed land cable joints have been applied but there have been a number of failures. None of the vendors has given any information on the status of development of field installable extruded cable joints indicating instead that they would not offer a solution with field installed joints. Given these facts, it is considered that application of extruded polymer cables would involve a relatively high degree of risk. The cable itself would most likely give satisfactory service if it could be installed without damage. Any damage occurring after installation due to mechanical factors such as fishing, anchors, underwater landslide, etc. would likely mean that the entire cable length would have to be abandoned.

The use of mass impregnated non-draining (MIND) paper insulated cables and field installable submarine cable joints is fully proven in hvdc applications. Research on a cable that had been service in Sweden for more than 35 years indicated that there was virtually no deterioration in cable properties with age. MIND cables are between 20 and 30 % more costly than comparably rated extruded cables but the premium in cost can be justified on the basis that it completely eliminates the risk that the entire cable would need to be replaced in the event of damage to the cable.

A base dc transmission system was defined to serve as a basis of comparison with the proposed Lake Tyee to Swan Lake 115/69 kV ac intertie. The base dc system consisted of three 30 MW converter installations; one at Ketchikan, one at Thorne Bay and one Wrangell interconnected by submarine cables. This base system provides more functionality than the ac intertie as it also includes a connection to Prince of Wales Island.

A comparison of the base dc system to the Swan Lake-Lake Tyee ac line is given in Table E-1. indicates the following:

a) The dc system is lower in cost compared to the ac system while offering features not available in the ac option in that it provides an interconnection to Prince of Wales Island. The cost of a three terminal dc system with 30MW converters at each terminal and 30MW cables is estimated to be $64 million including a spare cable and major converter station spares. The dc system costs also include the cost of optical fibres in the power cables or in separate cables that would allow for better communications between communities as a side benefit to the power interconnection. By comparison the ac system has an estimated cost of $86 million.
b) The dc system also allows direct control of reactive power eliminating the need to design supply and install supplemental ac voltage control facilities such as SVC's.
c) With suitable spare equipment, the dc system will have similar reliability and availability to the ac alternative. Spare cables and spares of major equipment at the converter stations will eliminate long outages of the dc transmission system.
d) The dc system has the advantage of lower environmental impact since an all cable system can be implemented.

Table E-1
Comparison of Ac and Dc Transmission Options
Between Wrangell and Ketchikan

	Feature	Dc Option	Ac Option
1	Cost	$64 million	$ 86 million
2	Provides ac voltage control as well as power transfer	Yes (significant new capability to control voltage is added)	No (No new capability added)
3	Low Environmental Impact	Yes (all cable)	No (Includes overhead lines)
4	Provides Transmission path to Prince of Wales Island	Yes	No
5	Short Construction and Installation Time	Yes	Yes
6	Can incorporate optical fibre to provide improved communications between communities	Yes	Yes (does not directly link communities)
7	High Reliability and Availability	Yes (with major spares)	Yes (with major spares)
8	Can be expanded to include other communities	Yes	Not Easily
9	Easy Maintenance	Yes for equipment. Cables may be difficult.	Yes

1. INTRODUCTION

Alaska Power and Telephone (AP&T) are investigating the use of a multiterminal hvdc link based on voltage sourced converter (VSC) technology using IGBT (insulated gate bipolar transistor) switching elements and submarine cables. The system will allow the exchange of electric power in Southeast Alaska between the Petersburg/Wrangell area, the Ketchikan area and Thorne Bay on Prince of Wales Island. Conventional hvdc technology is not seen as being viable in this application due to cost and the relative inflexibility of changing or uprating the system.

Teshmont Consultants was requested by AP&T to review the status of hvdc VSC systems and prepare an assessment of the maturity of the technology, the suitability for this application and to compare the cost of a dc transmission system with the proposed ac transmission system between Tyee Lake and Swan Lake.

The world-wide installed base of VSC transmission systems for hvdc is relatively small with only one company (ABB) having completed commercial projects in operation. To assess the state of development, the methodology followed in this review was to request technical information on the status of development and pricing information from the major manufacturers and suppliers of this type of equipment.

A base dc system configuration with three dc terminals and two submarine cable sections was defined and a request for information [1] was sent to three manufacturers, ABB, Siemens and Toshiba. Separate discussions with Alstom indicate that, while they are actively developing a product, it is at least two years away from commercial realization. ABB, Siemens and Toshiba provided information in response to the request for information. Cost and technical information for submarine cables was also obtained independently from Nexans. The technical information received was considered sufficient to gauge the status of development of VSC converter equipment and extruded cables. However, no information was received from any of the cable manufacturers as to the status of development of field-installable submarine cable joints for extruded cables (repair joints). The information received in response to our request for information was supplemented using information that was separately supplied by ABB to AP&T.

This report summarizes the information received in response to these inquiries and gives an assessment of the state-of-the-art of:

- VSC dc converter technology using IGBT switching elements.
- robust control and protection algorithms for multiterminal operation.
- extruded cables and submarine cable joints for extruded cables.

The report also compares the performance, reliability, expandability and maintainability against a proposed 115/69 kV ac interconnection between Lake Tyee and Swan Lake.

2. ADVANTAGES OF USING VSC TECHNOLOGY

The advantages of VSC converters for hvdc transmission to connect small isolated power systems have been noted and described by other authors [2][3] and a detailed treatment is not given in this document. These advantages include:

- VSC converters are force commutated and thus can operate in ac systems with low short circuit levels down to zero
- Forced commutation capability allows the converter to energize a system which has lost all generation providing black start capability
- The converters can supply real power while at the same time controlling the flow of reactive power. The converters can absorb significant amounts of reactive power when not operating at maximum power transfer. This allows for very effective continuous ac voltage regulation at the converter terminals similar to a synchronous condenser or static var compensator.
- High speed pulse width modulation (PWM) combined with Selective Harmonic Elimination (SHEM) by firing angle control allows lower harmonic generation than conventional hvdc with a resulting saving in ac filter cost and also lower temporary overvoltage on load rejection
- Lower cost compared to conventional hvdc
- Lower ratings are economically feasible
- Power reversal does not require that the dc voltage be reversed. In addition the freewheeling diodes do not allow transient voltage reversal on the dc cables allowing a more economical cable design
- Cables allow the development of projects without overhead lines. This may simplify the environmental approval process.
- The technology does not require or allow dc current flow in the ground, making environmental approval process easier compared to a conventional dc system.
- Short delivery time from placing of an order to in service. Project times in the order of one year would be possible based on delivery of converter equipment only. The governing factor in the schedule of a particular project will usually depend on other factors such as the ability of the Owner to modify the substations where the dc converters will connect into the ac systems or the delivery and installation of land or submarine cables.

These can be compelling advantages and have resulted in the VSC converter technology being selected as the technology of choice on the Eagle Pass Back-to-Back Project (Texas) and the Direct Link hvdc transmission project (Australia). Many of these advantages would also apply to the proposed interconnections in Southeast Alaska. These advantages are balanced by the fact that VSC converters have higher overall converter losses compared with conventional hvdc transmission. The converter losses at full load can range between 1.4% to 2% per converter terminal depending on the design.

This report looks at the available VSC converter and submarine cable technology and gives an assessment of its suitability for use in Southeast Alaska. The criteria used in this assessment are:

- The technology should sufficiently mature to be applied without risk of poor performance and without being restricted to a single supplier.

- The cost of the hvdc system should be competitive with other alternatives such as ac lines.
- The reliability and dependability of the hvdc transmission system should be comparable to an equivalent ac connection.
- The hvdc system should have a well developed and robust control philosophy which can tolerate loss of communications and continue in operation
- It should be possible to operate and maintain the system to the extent possible using personnel already on staff without providing exceptionally difficult or extensive training. Ideally it should not be necessary to recruit or add or any new highly skilled staff.
- The system configuration should be readily expandable to allow flexibility in future system development.
- The proposed hvdc system should not present any environmentally unacceptable problems or risks

3. STATUS OF DEVELOPMENT OF VSC BASED HVDC TECHNOLOGY

In assessing the state of development of VSC based hvdc transmission the following factors were considered:

- Availability and rating of IGBT switching devices
- Status of development of converter valves
- Main circuit topologies which offer reliability and redundancy
- Status of development of control and protection concepts and implementation
- Development of extruded cables
- Development of field installable repair joints for extruded cables

3.1 Availability and Rating of IGBT Switching Devices

IGBT devices suitable for use in hvdc VSC converters are manufactured by Toshiba, Fuji and Eupec. The manufacturers of hvdc equipment would obtain devices from one of these device manufacturers and assemble them into a valve. Different designs are possible depending on the manufacturer's design philosophy. ABB incorporate the IGBT, free-wheeling diode and control unit all into a single press pack unit as shown in Figure 3.1-1. The entire unit would be replaced in the event of a failed component. Failed units would be returned to the manufacturer for fault analysis and repair.

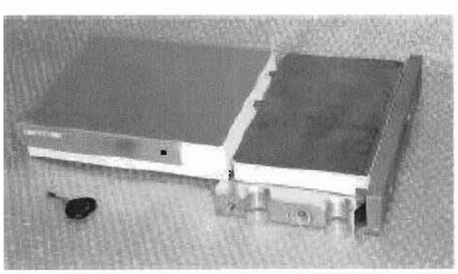


Figure 3.1-1
ABB Press Pack IGBT, Freewheeling Diode and Control Unit
Rating 2500V, 1300A, 1350Hz Switching Frequency

Siemens have a different design philosophy and prefer to separate the IGBT and free wheeling diodes and control units so that each can be replaced independently. Toshiba's design philosophy is similar to that of Siemens. Both philosophies result in viable designs.

Table 3-1 shows the device ratings proposed by the three suppliers who responded to the request for information.

Table 3-1
Proposed Switching Device Rating

Company	Device	Voltage (kV)	Current (A)
ABB	IGBT	2.5	500
Siemens	IGBT	4.5	>380
Toshiba	IEGT	4.5	1500

Toshiba have offered an IGBT with improved characteristics known as an IEGT (Injection Enhanced Gate Transistor). The IEGT is an IGBT with design improvements in the emitter area that has very low forward voltage drop (about equivalent to a thyristor or GTO) and hence lower operating losses. The blocking voltage performance is also increased. Toshiba chose a device rated 4.5 kV, 1500 A. Toshiba states that a STATCOM using IEGT devices has been in service since 2000.

IGBT's are considered to be fully proven power electronic devices due to their widespread successful use in the motor drives area. The extension of their use to hvdc converters primarily involves design considerations for series connection of devices to achieve the high voltages needed for hvdc transmission. The IGBT has very fast and consistent turn-on and turn-off characteristics compared with GTO's and GCT's. IGBT's also require less power to turn-on and turn-off and, because they are transistors, have continuous control characteristics rather than merely on/off control capability. These characteristics are ideal for series connection of devices since they minimize unequal voltage sharing between devices. Thus high voltage IGBT valves are relatively easy to implement. In addition the transistor characteristics provide inherent fault current limitation without any special protection action.

3.2 Status of Development VSC Converter Valves

Voltage source converter technology using IGBT's is well-established in industrial drive systems. IGBT based valves have also been used in STATCOM applications, back-to-back hvdc and long distance hvdc transmission up to 65 MW. The performance of the converter valves on these systems has been very good with no problems reported.

In 1997 ABB announced the introduction of IGBT based VSC to hvdc transmission under the trade name HVDC Light™. ABB's first in-service system was a demonstration project with a rating of 3 MW, ±10 kV between Hellsjön and Grängesberg in Sweden. Since that time commercial systems have been commissioned at Direct Link in Australia and Eagle Pass in Texas.

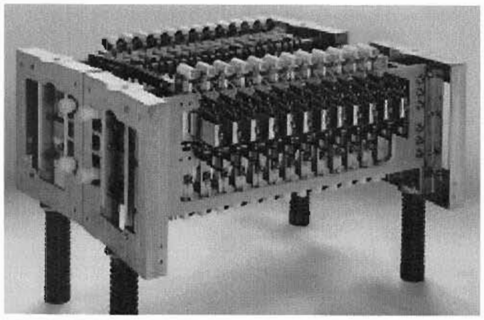


Figure 3.2-1
Siemens Floor-Standing VSC Valve Design

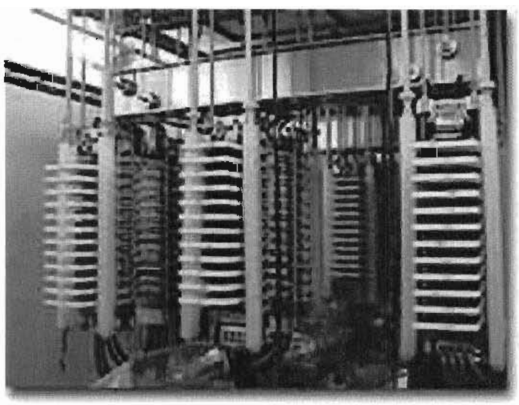


Figure 3.2-2
ABB VSC Converter Valve

ABB's experience list shows seven hvdc VSC converters installed or on order and about 1000 km of extruded polymer cable.

Siemens has developed and tested a prototype valve and is marketing its technology under the trade name HVDC Plus™. At this time Siemens does not have any hvdc VSC converters in commercial service.

Toshiba have completed development and testing of VSC valves and have supplied a prototype for a portion the Shin-Shinano hvdc station. These valves were based on the use of IGBT devices.

In summary, the three suppliers that responded to the request for information have fully developed VSC valve designs that have been proven in the factory. One supplier has supplied equipment for commercial installations. The successful application of the technology without any obvious problems indicates that the technology is already viable and will continue to improve as better devices become available.

3.3 Main Circuit Topologies

Three main circuit topologies were presented in the information received from the three vendors, a single converter "bipole" solution, a monopolar and two converter bipolar solution. These topologies are shown below in Figure 3.3-1 through Figure 3.3-3.

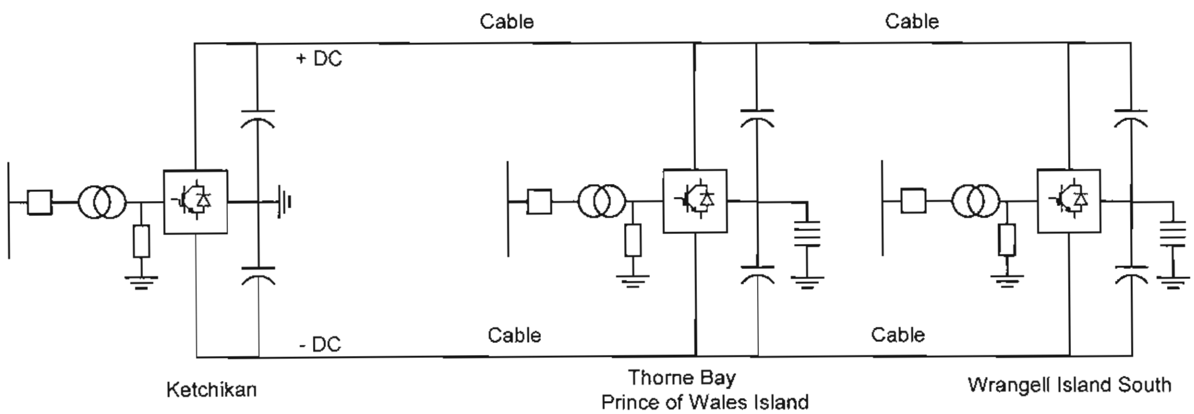


Figure 3.3-1
Single Converter Bipolar Multiterminal System
(ABB Power Systems)

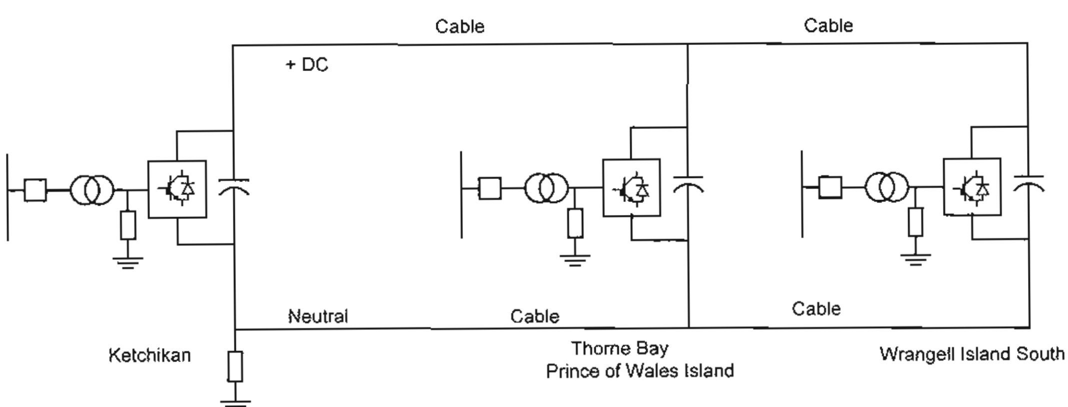


Figure 3.3-2
Single Converter Monopole Multiterminal System
(Siemens and Toshiba)

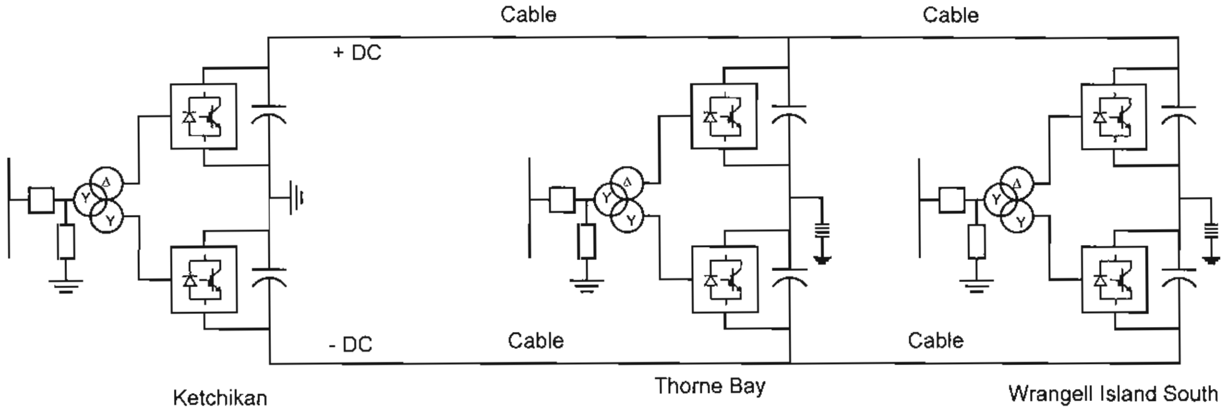


Figure 3.3-3
Two Converter Bipolar Configuration

From a practical point of view single converter bipole or the single converter monopole configurations are equivalent. The main difference is in the configuration of the cables. The single converter bipole requires two cables, one at each polarity, while the single converter monopole can be implemented with a single cable which includes a concentric neutral conductor (coax type cable). For a given converter voltage and power rating, the rated voltage of the two cables in the single converter bipole configuration would be half that of the single monopole.

Several variations are possible on the two converter bipole topology shown in Figure 3.3-3 as follows:

- Separate converter transformers could be provided for each converter to give better separation of equipment and better reliability.
- The converters could be configured in double monopole configuration

Cable configurations for the three topologies are shown in Figure 3.3-4.

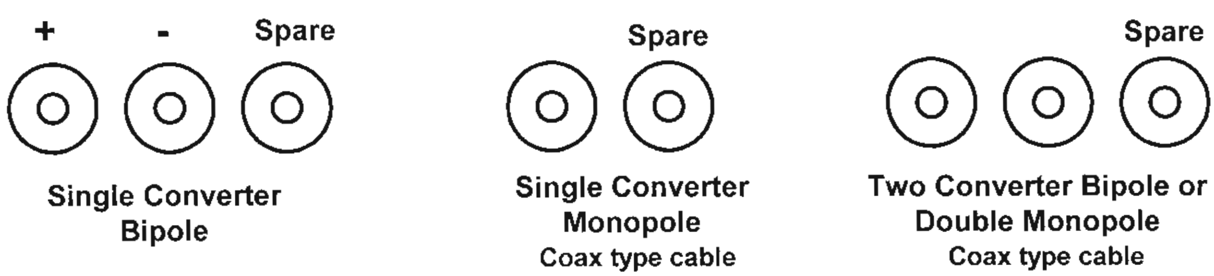
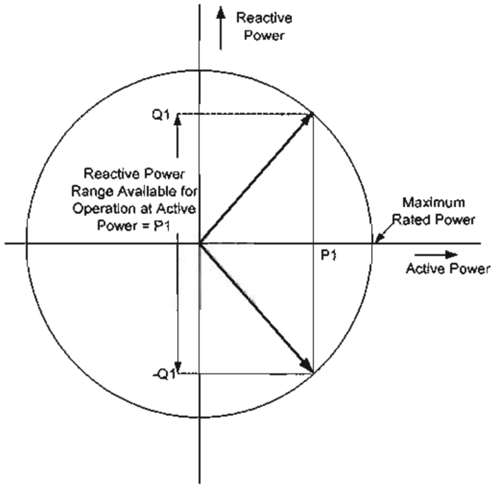


Figure 3.3-4
Cable Configurations Associated with Different Circuit Topologies

The single converter bipole configuration requires two cables plus a spare while the single converter monopole requires one coax type cable plus a spare. The two converter bipole or double monopole configurations require two coax type cables plus a spare. In each case, the spare cable could be omitted to reduce initial capital cost but would expose the Owner to the risk of a



long outage in case of cable failure. If purchased, the spare cable could be connected in parallel with one of the other cables to reduce operating losses. This would somewhat offset the capital cost of the spare cable.

3.3.1 DC Voltage and Current Selection

From a valve point of view it is desirable to utilize both the current and voltage capabilities of the switching devices to the maximum extent possible and thus minimize the total number of switching devices needed. However this generally does not result in optimal performance with respect to overall transmission system costs.

The selection of dc voltage is an economic optimization process taking into account converter equipment and cable costs as a function of voltage.
The optimization between equipment cost and value of losses can generally be carried out only by the hvdc equipment suppliers since only they have access to all the costs and economic factors.

In addition to transmitting active power VSC converters can absorb or generate reactive power up to the total MVA rating of the converter. This capability allows the converters to control the ac system voltage at the converter buses at the same time as it is transmitting power similar to a generator. Each converter can provide independent voltage support or voltage control to its respective ac system. The amount of reactive power that can be supplied or absorbed to control the ac system voltage is dependent on the active power delivered by the dc converter. If the converter is delivering rated power then there is little or no capability to provide any reactive power, while at lower transmitted power there would be significant reactive power capability as shown in Figure 3.3-4.

The dc voltage selected for the transmission system governs the number of series IGBT devices required in a valve. For a given dc voltage, all converters in the system even those with smaller rated power requirements will have the same number of series connected devices. Cost of the valve is strongly dependent on the number of series connected devices but less strongly dependent on the current rating of the IGBT and freewheeling diode. Thus, for a modest increase in cost the smallest converters can be upgraded to the same rating as the largest converters and would have a high inherent overcapacity. This overcapacity could be used to provide voltage control for the ac system or would provide reserve capacity for future load or generation additions.

From a practical point of view it may also be more economical to provide the same rating at all converters as the single valve design may result in lower initial cost, reduced requirement for spares and reduced training requirement for maintenance staff.

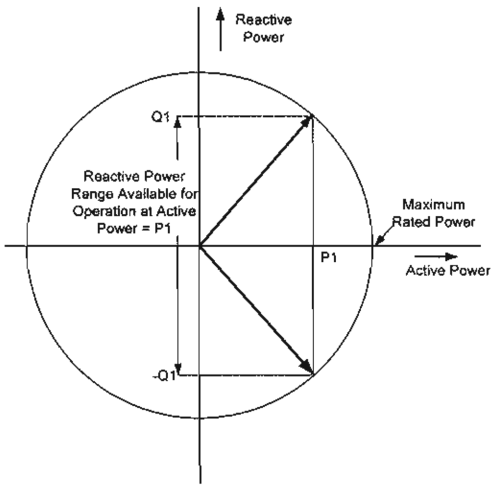


Figure 3.3-4
Active and Reactive Capability of a VSC converter

3.3.2 Reliability Considerations

One objective in the design of an hvdc system is to achieve high levels of availability and reliability. This is especially important where the dc system provides a large proportion of the power transfer capability in to or out of an isolated system. Careful attention must be given to related factors affecting the hvdc system performance including sub-system and system testing, protective relay coordination, proper setting of relays, spare parts, and redundancy of design.

The main criteria used to measure the reliability performance of the dc system are defined generally in accordance with CIGRE Study Committee 14 (DC Links) Working Group 04 definitions, as follows:

Forced energy unavailability (FEU):	A measure of the energy which could not have been transmitted due to forced outages
Scheduled energy unavailability (SEU):	A measure of the energy which could not have been transmitted due to scheduled outages
Forced outage rate (FOR):	Number of forced outage events during the year divided by the number of hours in the year

The selection of reliability performance indices usually involves a compromise between the required performance of the systems and cost.

Higher performance indices may be achievable but would increase the cost and complexity of the design. Based on analyses carried out for conventional hvdc installations, annual design target values of FEU, SEU and FOR that are considered to be achievable for an hvdc transmission system including the dc cable without a significant cost penalty while at the same time providing the load centers with good performance are as follows:

	Design Values Per Station Per Year	Design Values Total System Per Year
Forced Energy Unavailability (FEU)	0.25% or less	0.50% or less
Scheduled Energy Unavailability (SEU)	1.0% or less	1.0% or less
Forced Outage Rate (FOR)	3 outages or less	6 outages or less

The reliability performance of the hvdc system is dependent on the system topology and the amount of redundant and spare equipment included in the design. Topological configurations for VSC hvdc transmission systems include single converter bipolar, single converter monopole and double monopole.

In the single converter bipolar configuration the converter equipment can operate only in bipolar mode. This configuration has the disadvantage that a forced outage of the converter equipment stops power transmission at that station until the affected equipment can be returned to service. Similarly a failure in one of the dc cables connected to the station will interrupt operation until the cable problem is corrected.

From the point of view of reliability, the single converter monopole configuration and the single converter bipole configurations are identical. A converter equipment failure or cable failure will stop transmission on the affected portion of the system until the failed equipment can be repaired.

A double monopole configuration provides redundancy of both cables and converters. A fault in the converter equipment or cables in one pole will not affect the other pole. The unaffected monopole can continue to operate and transmit power during the forced outage of the other monopole. If the second monopole has sufficient capacity it can rapidly pick up power to compensate for loss of the first monopole. The disadvantage of this system topology is higher cost than a single monopole system.

The effect of the forced outages of other equipment must also be considered in the design of the transmission system. The effect of failures, other than catastrophic failures, in most equipment such valves, valve cooling, controls and filter banks can be minimized by the use of redundant equipment and the purchase and stocking of appropriate component spares. However, major failures of certain equipment such as converter transformers, series reactors or dc cables can lead to extended outages potentially lasting up to a year. Although low in probability, such an extended outage could have serious consequences to the load centers. To minimize the effects of the failure of this type of equipment, spare equipment should be purchased and kept on site. This would include major equipment such as one spare converter transformer and one spare series reactor at each converter station in addition to spare parts for the converter valves, control equipment and ac side equipment.

Unless the Owner can accept the risk of a long outage, a spare submarine cable should also be installed between each converter station. The repair of a failure in a cable can take a significant time and is dependent on factors such as weather and the availability of a repair ship.

The presence of an installed spare submarine cable provides the opportunity to reduce losses by operating the spare cable in parallel with one of the main cables to reduce losses in the initial years. The spare cable can also provide additional capacity as the system grows but if the spare is not replaced would mean curtailment of dc transmission in the event of cable failure.

Forced outages for converter equipment are generally limited in duration when sufficient spare parts are available. If major spares such as, series reactors, dc capacitors, converter transformers, valve components, and control and protection equipment are available on-site or in Alaska, it should be possible to place the facility back into service within a few hours or days. This would not significantly impact the reliability indices. The Owner would need to be able to cover the loss of transmission capacity with other generation until repairs are complete.

The facility could be badly damaged or destroyed by catastrophic events such as fire, equipment arcing, weather events (flooding, tsunami) and geological events (landslide, earthquake). The design criteria and philosophy followed should ensure that the damage caused by these potentially catastrophic events will not completely disable the transmission system.

3.3.3 Flexibility for Future Expansion

The manufacturers appear to have concentrated their development efforts in the converter power ratings from about 100 MW and up rather than the lower ratings targeted on this project. Thus it is easily possible to realise the smaller 30 MW and lower converter ratings needed on this project.

As noted in Section 3.3.1 above, it is relatively economical to select the current rating of the IGBT or IEGT devices larger than required for the smaller Thorne Bay converter in the base system. The voltage rating is determined by the power rating of the largest converters. All the converters in the base three terminal system can be selected to have the same current rating. At small load centers such as Thorne Bay there will be significant overcapacity initially.

This inherent overcapacity does provide the potential for future upgrading of the system without having to upgrade the converters. In future it may be desirable to upgrade the system voltage from 34.5 kV to 69 kV. This could be accomplished by adding a 34.5/69 kV transformer bank or optionally by replacing the converter transformer with another transformer with increased rating and higher ac side voltage rating. It should not be necessary to change the converters, as they would have adequate rating up to 30 MW. The planning for the ultimate rating upgrade should be included at the initial design stage to provide for overall minimum cost.

At the larger converters, uprating can take the form of new converters in parallel with the original converters. It would be necessary to ensure that the cable ratings are adequate for the increased power flows. This can be addressed at time of uprating by installing new cables or by installing some cable over capacity at the initial stage. For the purpose of the cost estimate, costs were obtained for both 30 MW cables and 50 MW cables to check the price sensitivity of installing additional cable capacity at the initial stage.

DC transmission systems composed of dc converters are easily expandable because of the inherent flexibility and robust nature of the control philosophy as discussed in Section 3.4.

Extension of the system by the addition of new cables from an end point converter or a middle converter within a network is easily possible provided adequate cable capacity exists on the other branches of the network.

3.4 Status of Development of Control and Protection Concepts

All three of the suppliers provided information of the status of two terminal and multiterminal control and protection concepts for VSC hvdc systems. The responses show that control system development is well advanced, inherently stable and will be able to operate even if communication to the central control location is out of service.

3.4.1 Control Concepts for Two terminal and Multiterminal Operation

Steady-State Operating Characteristics

The basic control concept for VSC dc systems is based on using a voltage margin method of control (analogous in concept to the current margin method of control used on conventional hvdc systems). A detailed description of voltage margin concept is given in reference [6]. Figure 3.4-1 from [6] reproduced below shows the typical steady state operating characteristics for a two terminal VSC dc link. Each converter has two basic controllers; a dc voltage controller and a dc current controller. Only one of these two controllers can be active at any given time. By suitably arranging the set points of the converters at the two ends of a transmission system it is possible to ensure that one converter controls the dc voltage and one converter controls the dc current.

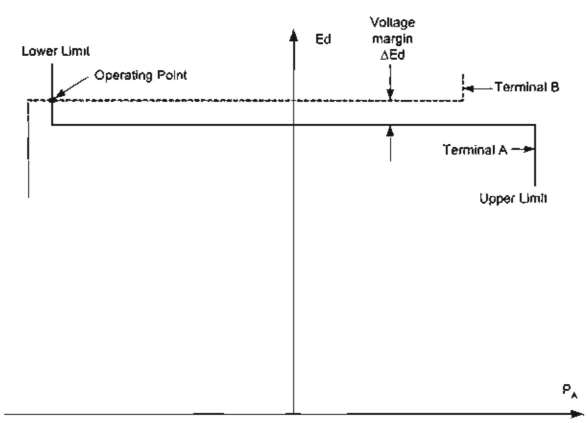


Figure 3.4-1
Operating Point for a Two Terminal HVDC System Using the Voltage Margin Approach

In a two terminal hvdc system one of the terminals will act as the voltage setting terminal and the other terminal will adjust the power flow. There is normally no need for fast communication between the converter stations because the voltage setting can be fixed at one terminal and the power flow can be adjusted at the other terminal. Loss of either converter results in interruption of power transfer.

This control strategy is easily extendable for multi-terminal operation with one terminal designated as voltage setting terminal and all the other terminals controlling current. Usually the converter located in the system with the largest amount of generation would be selected to be the voltage setting converter. The voltage setting converter acts does not have a defined power setting. Instead its power flow is determined by the demands of all of the remaining converters and it would automatically adapt its power flow in response to changes at the other terminals. Its operation can be considered to be analogous to a "slack" generator in an ac system. If the ac system associated with the voltage setting terminal can tolerate the range of power changes that can occur at the other terminals then the terminals could theoretically be operated completely autonomously without need to coordinate setpoints of the terminals. In practice however the capacity of the ac system associated with the voltage setting terminal would have limitations and some coordination would be required.

The current setpoints of the current controlling converters can be set directly by the operators or calculated automatically by a higher level controller which will adjust the current setpoint to maintain a given power order or to maintain ac system frequency at the nominal value. Figure 3.4-2 below reproduced from [6] shows the characteristics for a three terminal system.

If a terminal that is in current control is tripped, it results in loss of that terminal only with the other two terminals continuing to operate. The loss of a voltage setting terminal results in one of the two power flow setting terminals becoming a voltage setting terminal and operation continuing as shown in reference [6] and reproduced below as Figures 3.4-2 and 3.4-3.

The process of control mode changeover if one terminal is tripped is inherently very robust provided the voltage and current limit setpoints of each converter are carefully chosen to coincide with the inherent limitations of the ac systems in which the converter is located. Control mode changes and reallocation of power flows occur automatically without any need to rapidly exchange information between the terminals or between the terminals and the central control location.

Overall control

The overall system can be operated either from the individual converter locations or from a central control location.

The central control location can be located at one of the converter stations or at a remote location. Operation from a central control location makes it makes it easy to coordinate operation of all converter stations. The central control location can control all functions such as start-stop, issuing operator power transfer settings, voltage and current settings and limits and coordination of settings when reversing power in a station.

However, as noted above, central operation is not essential. It would likely be implemented as the most convenient method of controlling the transmission system even though fully satisfactory control can be achieved by local operators who are in telephone contact with each other. Local operator control would be the fallback control method in the event that communications between terminals are not possible.

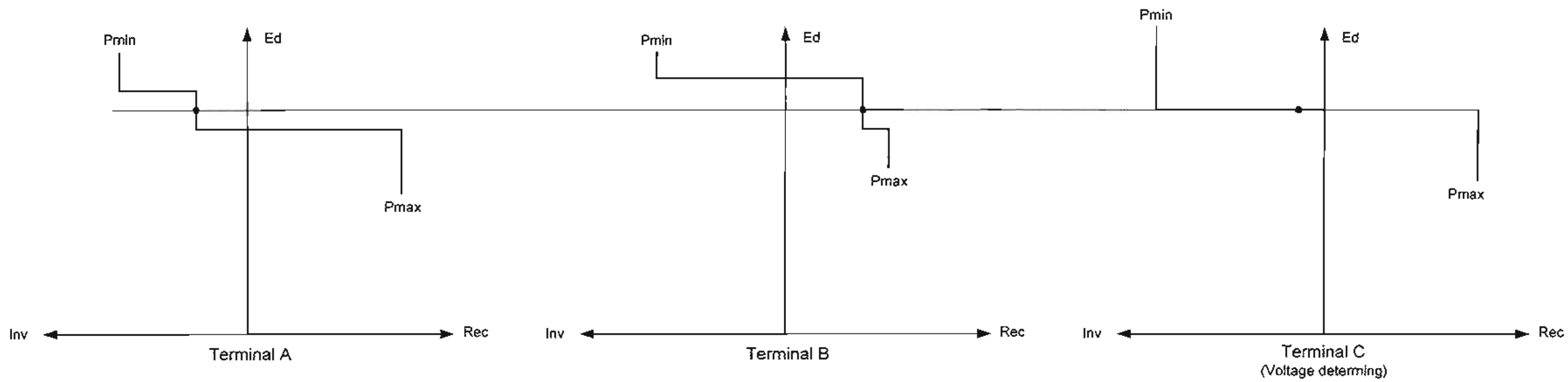


Figure 3.4-2
Operating Points of Three Terminal System

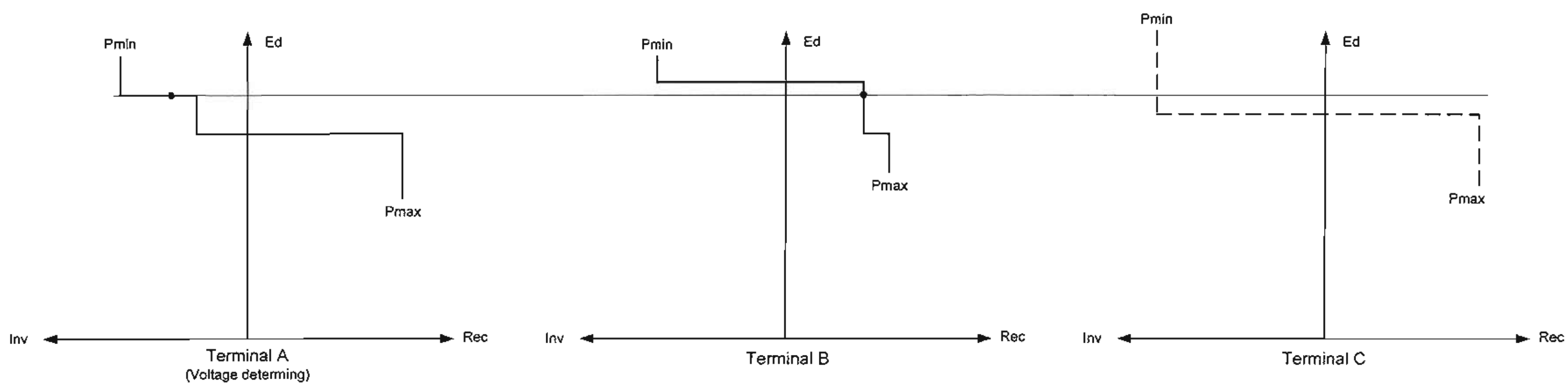


Figure 3.4-3
Operating Points of Three Terminal System Following Trip of Terminal C

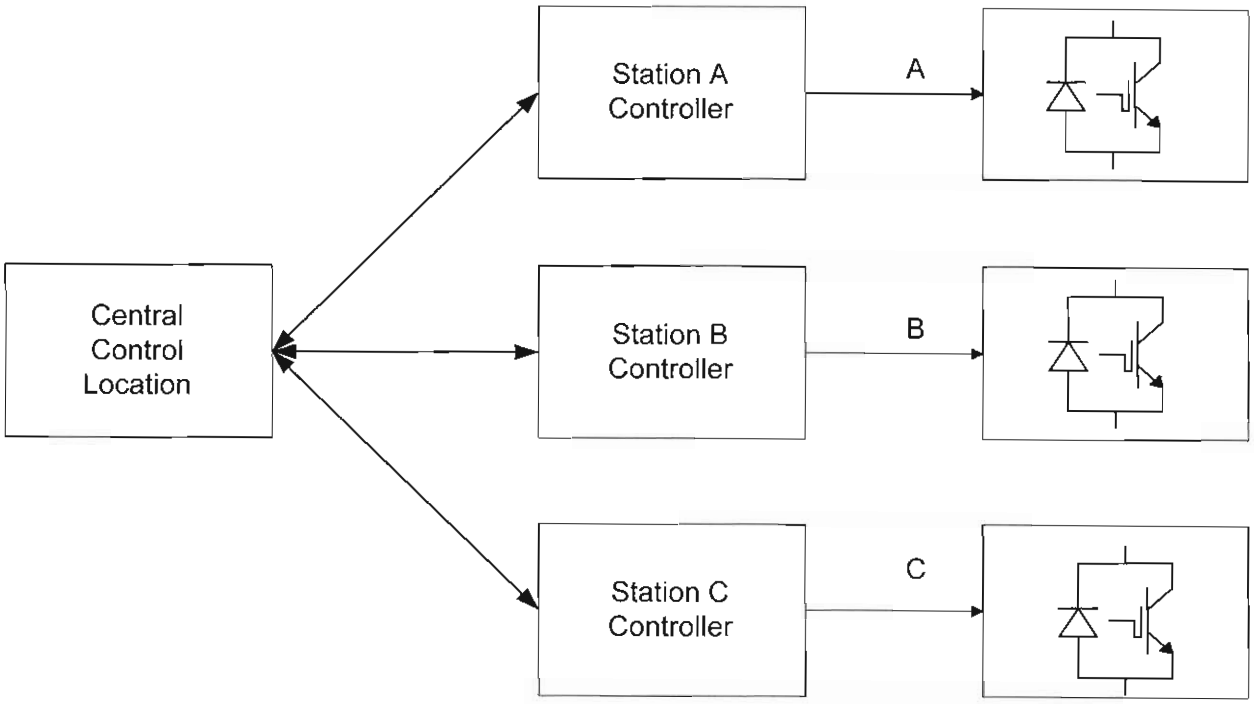


Figure 3.4-4
Simplified Block Diagram of Overall Controls

Simplified block diagrams of the overall controls for a three terminal system and the station controller are included in Figures 3.4-4 and 3.4-5.

All three suppliers indicated that control systems have been developed and tested. Performance test results have been presented from tests done on actual systems as well as laboratory tests. These tests confirm that control systems can be designed that are robust and inherently stable and can function or continue to operate if fast communications to the central control location is lost or absent. The control methodologies developed are suitable for use on two terminal as well as multi-terminal dc transmission systems.

Protection

VSC converter valves are susceptible to damage by overcurrents exceeding design limits. Protection action relies on the fast acting VSC firing controls to limit overcurrents, failing which the faulty converter must be tripped and removed from service. Other protections required for the converters are ac and dc side overvoltage protection and protection from ground faults. Fully redundant protection systems are generally provided for the converters. Protection is also required for main circuit equipment other than converter valves and auxiliary equipment

For VSC converters connected to ac systems with low short circuit ratio, detection and clearing of converter faults or other faults may be very slow resulting in the system voltage collapsing before the ac circuit breakers have cleared the fault. Additional CT's, sensitive differential protection and very high speed circuit interrupting devices have been proposed by the suppliers to avoid ac system voltage collapse and to allow auto-reclosing.

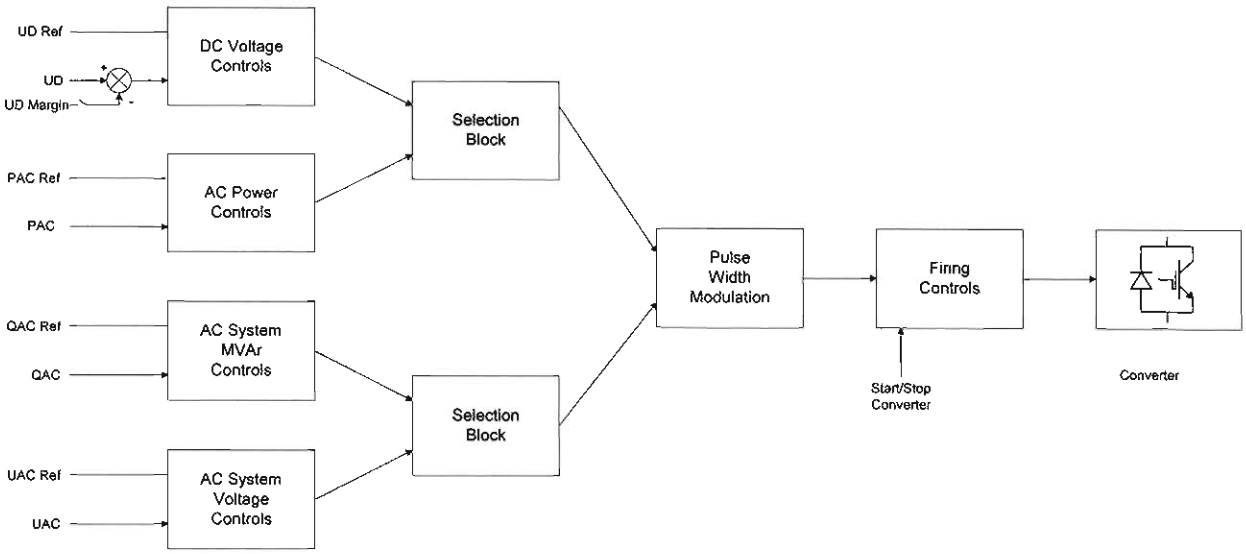


Figure 3.4-5
Simplified Block Diagram of Station Controls

3.4.2 Communications Requirements

Communication requirements for a VSC dc transmission system are generally much less demanding than for conventional hvdc. The voltage margin method is an inherently robust control philosophy which is very tolerant of setpoint changes at individual converters and, with carefully chosen limits and setpoints will also tolerate loss of converters without need for fast coordination of power orders and settings. High speed communications are normally not required unless there is some reason to want to automatically change control settings for system control or protection purposes.

The most convenient control strategy would be to control all converters from a central location and to implement functions that would automatically coordinate power transfer between converters and adjust setpoints in response to changes in load demands. However, manual operation from individual terminals would also be possible with only voice communication (telephone) between terminals.

Failure of communications while in service would not directly affect the hvdc system. The converters would continue to operate and function at the last ordered setting values. Each VSC station would be fully self-protected by local protection systems and would not rely on communications for protection of equipment. A fault in one station in a three terminal system, while the communication has failed, would result in the faulty station being removed from service and the other two continuing to operate.

During periods when there are no communications, a local operator having voice communication with other station operators can make changes to power settings in the station to which communications are interrupted.

3.5 Maintenance Requirements

Equipment within the VSC converter stations will consist of:

- HV equipment consisting of power transformers, IGBT valves, reactors, capacitors, arresters, circuit breakers and disconnects and grounding switches.
- Control equipment using electronics and computer based controls.
- Communications equipment.

The maintenance requirements for the HV equipment are similar to those in ac substations. The IGBT valves are one item not found in ac substations. Special test apparatus for checking the IGBT valves and associated electronics would be required and would be acquired from the valve manufacturer. Staff normally working on HV equipment and having some familiarity with electronics should be capable of maintaining the IGBT valves with only minimal training.

Another item not commonly found in ac substations is harmonic filters. Maintenance requirements are similar to shunt capacitors and should not present any difficulty to utility staff.

The control and protection equipment and communications equipment can be maintained by staff who are familiar with SCADA type and telephone equipment. Some training will be required particularly in the software area to familiarise maintenance staff with the equipment including special test equipment specifically delivered. Maintenance support can usually be arranged with the supplier and fault trouble shooting and diagnosis would be possible from a remote location provided a telephone link is available. It is unlikely that a significant change in software would be needed after commissioning in any case. Minor adjustments and setting changes would be within the capability of electronic maintenance staff. There is no significant increase in complexity over equipment already serviced by AP &T staff.

4. STATUS OF DEVELOPMENT OF EXTRUDED CABLES

Extruded cables have been used worldwide for over 20 years for ac applications with installed cables operating with voltages up to 500 kV ac. The initial applications of extruded ac cables ran into a high rate of failure associated predominately with joints for the cable joints. These initial problems have been largely overcome. In North America extruded cables are applied at voltages up to 230 kV.

The use of extruded cable for dc voltages was not successful until the mid 1990's due mainly to problems related to the build-up of space charge within the insulating material. The space charge build-up leads to high localized stresses and eventual breakdown of the insulation and cable failure. This situation was has been overcome by advances in purity of cable insulation materials, improved manufacturing extrusion and curing methods and by the addition of organic fillers into the material which prevents the accumulation of space charge within the insulating material.

4.1 Status of Development of Extruded Cables

ABB's first VSC-based hvdc transmission system, which used HVDC Light™ extruded cable technology, was installed in 1997. In the ABB application, the extruded cables are operated in bipolar mode with one positive polarity cable and one negative polarity cable, and are installed close together in bipolar pairs with anti-parallel currents. ABB has developed designs for land cable, submarine cable and deep sea cable. ABB has installed or has had orders for over 1000 km of HVDC Light cable. Figure 4-1 shows picture of a deep sea double-armoured cable. A single armoured cable is shown together with a cable installation ship in Figure 4-2.

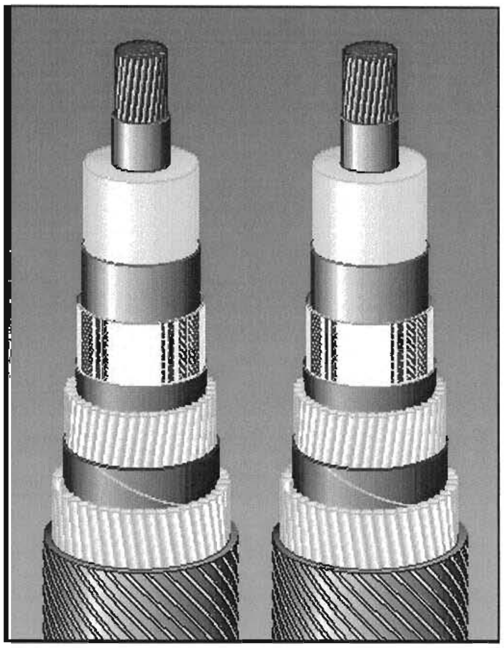


Figure 4-1
Deep Sea Extruded Submarine Cable
(ABB Cables)

Toshiba has produced a ±250 kV DC filler-added XLPE cable and factory joint and has verified both the electric performance and long-term stability and ageing performance. According to reports published in 1998, the test results indicate that the characteristics of the cable and factory joint are suitable for practical use [4].

Toshiba did not provide an experience list for dc submarine cable projects using extruded cable

The RFI specified that submarine cables could be located in waters as deep as 650 m. This is very deep and to Teshmont's knowledge there are no extruded DC cables installed at this depth in service anywhere in the world.

4.2 Submarine Cable Factory Joints for Extruded Cables

In the 1998 published reports submitted by Toshiba [4], the electric performance and a long-term stability of a ±250 kV DC filler-added factory joint has been verified. The test results indicate that both the cable and factory joint had suitable electrical, mechanical and ageing properties for practical use.

Toshiba did not submit a list of practical experience with extruded cable joints.

ABB has installed or has orders for over 1000 km of HVDC extruded cable, for systems ranging from 7 MW to 330 MW. ABB did not provide an experience list for extruded dc submarine cables and cable joints.

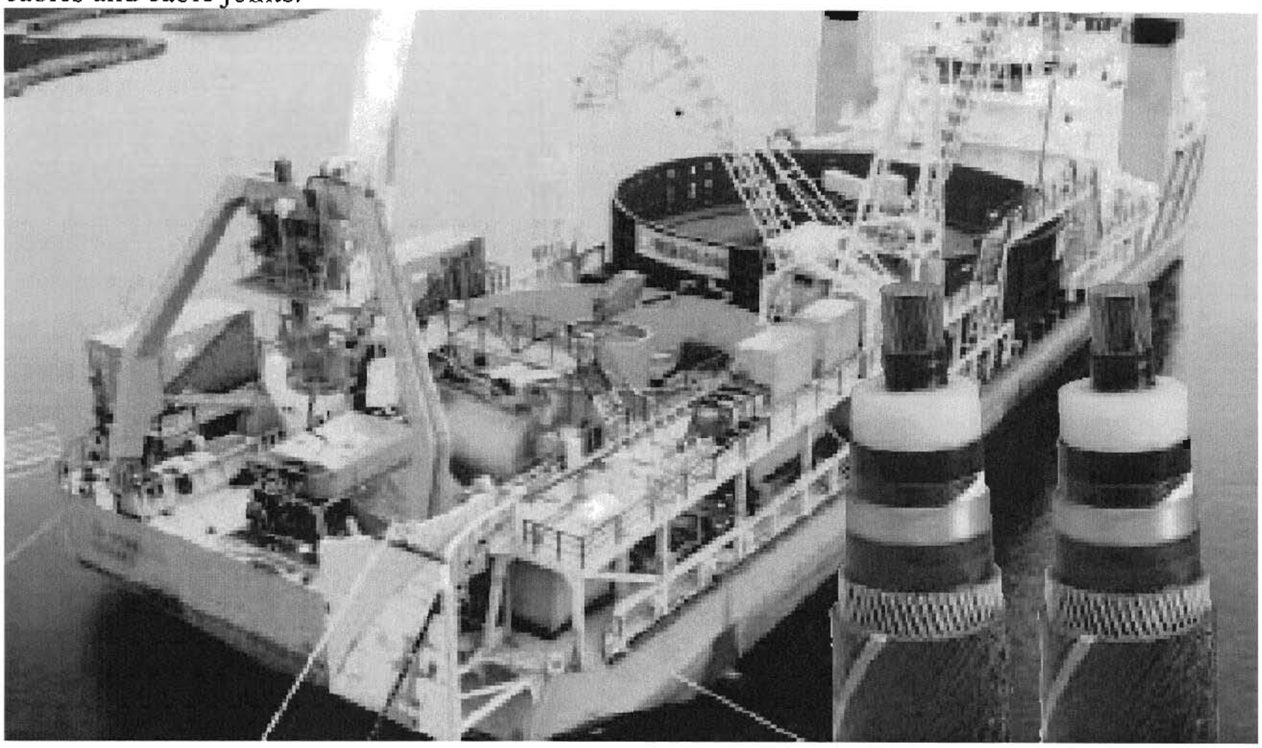


Figure 4-2
Cable installation Ship
(Insert Single-Armoured Submarine Cables - ABB Power Systems)

4.3 Field Installable Submarine Cable Joints for Extruded Cables

None of the vendors provided any information on the status of development of field installable extruded cable joints. Toshiba stated that their proposed solution did not include field installed joints.

ABB did not state whether or not field installable submarine cable joints have been used in any of their projects.

It is known that field installed land cable joints were used on both the Gotland and Directlink Projects. On the Gotland Project there have been no reported problems with field installed joints. On Direct link there were a number of failures. ABB advise that these failures were due mostly to the tolerance issues between some of the joint kits and the cables. The Directlink cable was a little larger diameter than the Gotland cable making the cable joint kits of the size selected a bit difficult to install. This led to manhandling of some of the joints during installation and it was these joints which experienced failures. Joints that were not forced during installation did not experience any problems. The joint kits have subsequently been redesigned to make them less susceptible to improper installation. There have not been any reported failures of the redesigned joints. This indicates that field jointing may be practical for extruded dc cables on land.

Installation of a field installable joint in a submarine cable is likely to be more difficult than for a land cable due to a number of factors including the fact that the joint will need to be made in non-ideal conditions on a ship or barge possibly during poor weather conditions. This would increase the possibility of an unsatisfactory joint due to ship movement during the jointing or curing processes or contamination due to salt spray. The submarine cable joints will also be subjected to more severe mechanical stresses during laying than a land cable.

At the time of this report we are not aware of any projects in which field installable submarine cable joints are used in deep water to the depths required in this application. Nor are we aware of any field trials in deep water.

Given these facts, the application of field installed submarine cable joints on extruded polymer cables cannot be considered to be a proven and mature technology. Given the obviously lower cost of the extruded cable designs, the Owner would need to make an assessment as to whether the cost saving is worth the risk.

4.4 Mass Impregnated Paper Insulated Cables and Joints

Mass impregnated cables have been applied in dc applications for over 35 years. Both the cable and joints have been proven to water depths of over 600 m. A mass impregnated paper insulation, lead sheath design would be preferred because it has been proven (by Pirelli) to 1000 m depth. The technology is considered to be proven and reliable.

Neither Toshiba nor Nexans provided any data regarding their experience with mass impregnated cables but ABB provided a list of hvdc cable projects, which includes approximately 2350 km of hvdc mass impregnated cable.

A CIGRE paper [5] concluded that there were no measurable changes or deterioration in the electrical properties of the Gotland mass impregnated cable in Sweden which was in service for 32 years before it was replaced due to increased rating requirement.

The use of mass impregnated cable, although somewhat more expensive than extruded cable designs, would significantly reduce the risk of extended outages due to cable failures since both the cables and field installable joints been proven by field experience.

4.5 Cable Repair Considerations

Underwater cables are subject to potential mechanical damage from external sources, such as ship anchors, fishing activities and underwater landslides. External and mechanical protection needs to be considered during the design stage to limit the exposure of the cable to external damage to a reasonable level. No cable can be fully protected from all types of possible external impact. To ensure availability of the cable, a cable repair plan must be established at the time of cable installation. Storage facilities would need to be provided to store suitable quantities of spare cable to be used in making repairs.

When cable damage is detected, the cable fault location and cause of failure would need to be investigated using fault location devices. Ideally the fault locating equipment should be available in Alaska to avoid having to find and import the equipment when a failure occurs.

Repair of cables is a specialized task requiring both skilled personnel and special vessels and equipment. Given that cable failures from internal causes are relatively rare, it is not likely that it would be economical to maintain a fully stocked repair vessel or barge ready to go at all times. The repair time of the cable will therefore depend on the availability of special cable vessels and could be further delayed by bad weather in some seasons of the year. The outage time of the cable could vary from about 6 months to as long as one year.

The cost of repair would include cost to charter the vessel, cost of labour for skilled personnel and standby charges in case of bad weather.

In addition there will be a cost associated with the outage due to the inability to transmit electrical power. The extended loss of transmission capacity may be very costly especially if it involves running diesel generation. The total cost of the outage could exceed the cost of a spare cable.

Installed spare cables are the best solution to minimize the risk of extended outages associated with cable failure.

5. COST ESTIMATES

A base hvdc system was defined to provide a basis for comparison to the proposed Lake Tyee-Swan Lake ac transmission. The dc system provides additional flexibility compared with the Lake Tyee-Swan Lake ac connection in that it also includes a dc converter at Thorne Bay on Prince of Wales Island making it possible to develop small hydro sites on Prince of Wales Island. The base configuration of the proposed hvdc VSC system is shown in Figure 5-1.

The prices supplied by the bidders were not directly used in the cost estimates for a number of reasons:

- they are considered to be confidential
- some suppliers did not quote on all of the items
- some suppliers did not offer specific required items such as cable embedment or land cable trenching.
- the prices offered by some suppliers may have been out of line with those offered by other suppliers thus indicating fundamental differences in interpretation of the requirements.
- Different equipment types may have been offered that could not be directly compared such as coaxial type cable and single core cable.

Engineering judgement was applied to arrive at an amalgamated price using information supplied by all of the suppliers. The estimated cost therefore does not necessarily represent either the lowest price submitted nor the highest price submitted.

5.1 DC System Costs

Table 5-1 summarizes the cost of the base dc system consisting of three 30 MW dc converters using 30 MW mass impregnated cables and alternately 50 MW cables. Table 5-2 summarizes the costs of the base dc system consisting of three 30 MW converters but with 30 MW or 50 MW extruded cables. The alternate 50 MW cable rating gives a substantial margin in capacity and will allow for future expansion at a later date without adding any cable capacity on routes that already have a cable installed.

Table 5-1
Estimated DC System Cost Using Mass Impregnated Cables

Item	30 MW Cable Rating	50 MW Cable Rating
Converter rating	3 x 30 MW	3 x 50 MW
Converter cost	$27,000,000	$27,000,000
Cost for Major Converter Spares	$1,500,000	$1,500,000
Cable cost including installation	$20,200,000	$26,600,000
Allowance for land trenching and near shore embedment	$4,000,000	$4,000,000
Spare cable cost including installation	$9,300,000	$12,200,000
Additional cost for fiber optics	$2,200,000	$2,200,000
Total system cost without spare cable	$54,900,000	$61,300,000
Total system cost with spare cable	$64,200,000	$73,500,000

— 9,000,000
64,500,000

Table 5-2
Estimated DC System Cost Using Extruded Cables

Item	30 MW Cable Rating	50 MW Cable Rating
Converter rating	3 x 30 MW	3 x 50 MW
Converter cost	$27,000,000	$27,000,000
Cost for Major Converter Spares	$1,500,000	$1,500,000
Cable cost including installation	$18,500,000	$22,100,000
Allowance for land trenching and near shore embedment	$4,000,000	$4,000,000
Spare cable cost including installation	$7,900,000	$10,200,000
Additional cost for fiber optics	$2,200,000	$2,200,000
Total system cost without spare cable	$53,200,000	$56,800,000
Total system cost with spare cable	$61,100,000	$67,000,000

The estimated prices exclude taxes and duties but do include the following:

a) manufacture, test, supply, installation commissioning and warranty of all dc converter equipment including spares.
b) manufacture, test, supply, installation commissioning and warranty of the dc submarine cables including spares
c) ac breakers and disconnects for connecting the dc converters to the ac system
d) fibre optic communications equipment between the converter stations consisting of either a separate cable or fibres included in the submarine power cable.
e) converter buildings or factory manufactured converter enclosures.
f) foundations for all supplied equipment
g) near shore cable embedding and land cable trenching and burial.

It was assumed that the converter stations could be located within 0.5 kilometre of the coast and that dc overhead lines will be avoided by installation of land cable. Overhead dc lines are undesirable because of possible problems with insulator contamination and flashover due to salt spray from the ocean. All dc equipment at the converter stations would be located indoors.

Figure 5-2 shows the assumed routing of the submarine cables. The assumed sea cable route is approximately 190 km in length with a maximum cable depth of approximately 650 meters. The cables would be laid directly on the sea bottom and would not be buried in deep water where they are beyond the reach of anchors or bottom dragging fishing activities.

The cables will be trenched near the shore and on land to the converter stations. For the inter-tidal zone it was assumed that one eight inch PE pipe per cable would be pre-installed from extreme high water to three meters below mean low water level. This is particularly advantageous in Alaska, where tidal ranges are relatively high, because it reduces the time the expensive cable laying vessel needs for cable installation at the shores. After the cables are pulled into the pipes they would be filled with low thermal resistivity grout. This approach also provides good mechanical protection in a zone exposed to storms, foreshore sediment transport and changes in the beach morphology and is intended to protect the cables from boat/barge grounding and damage due to driftwood pounding at low tide during storms.

It was assumed that cable landings would be selected where there is very limited threat from anchors and fishing activity. In this case, further cable burial underwater would not be needed. Considering the overall economics of the project, it was assumed that trenching underwater in rock would not be affordable and alternate cable landings would be selected instead. It was assumed that the total distance of water jetting to reach a 30 meter depth would be 1 km and that this would include a mixture of sand and hard clay seabed.

The quantity of water jetting depends on the steepness of the off-shores slopes and the resulting estimates could vary significantly. It would therefore be advantageous to select landing sites where the cable descent was relatively fast, but not so fast that cables would be placed at risk due to rugged slopes, free-spanning and potential slope instability.

Trenching of cables on land was assumed to be partially in granular material and partially in rock and included imported backfill material for a total distance of 0.5 km. Costs for cable trenching and embedding are very sensitive to the conditions actually encountered and thus could vary significantly from the assumed total.

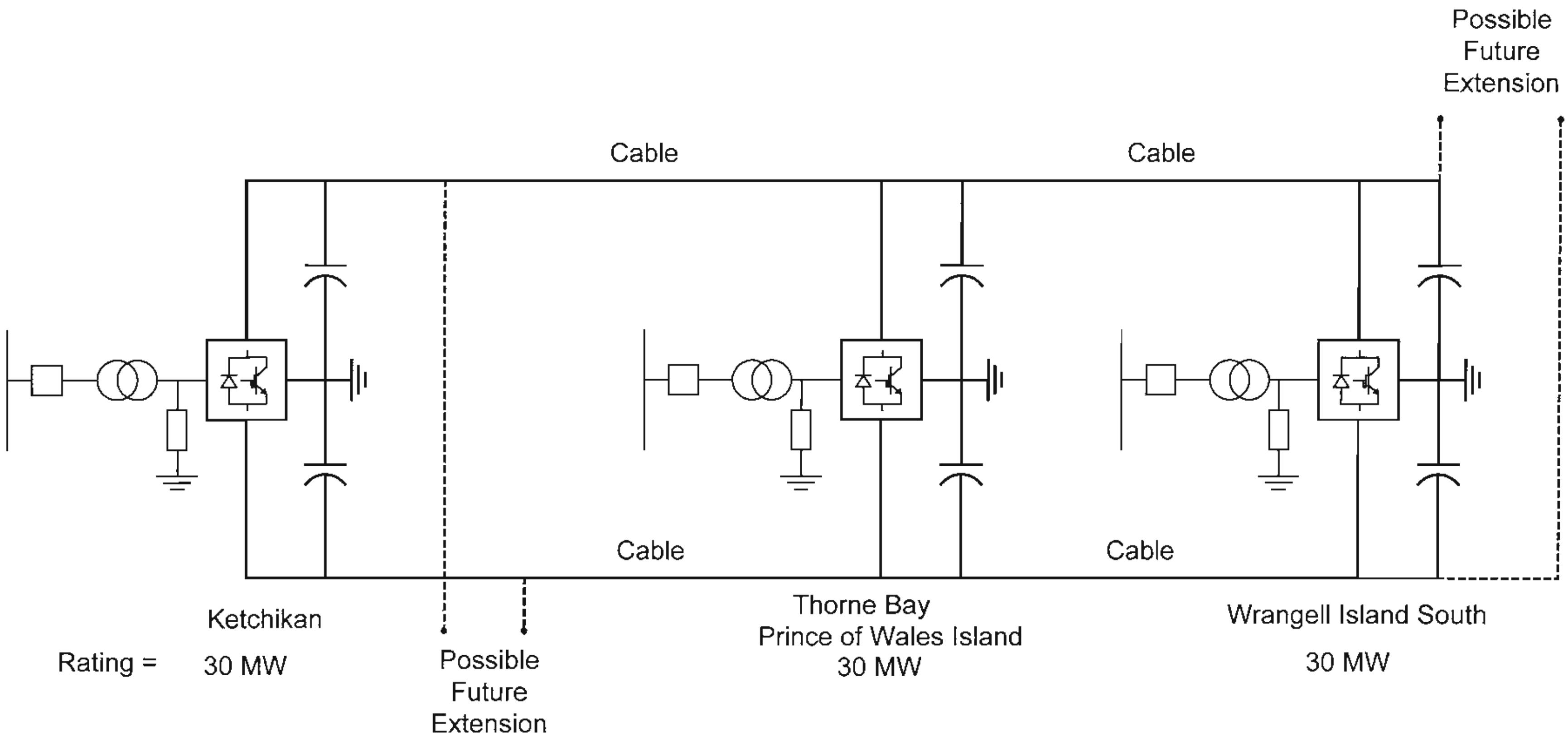


Figure 5-1
Simplified Single Line Diagram of Base DC System

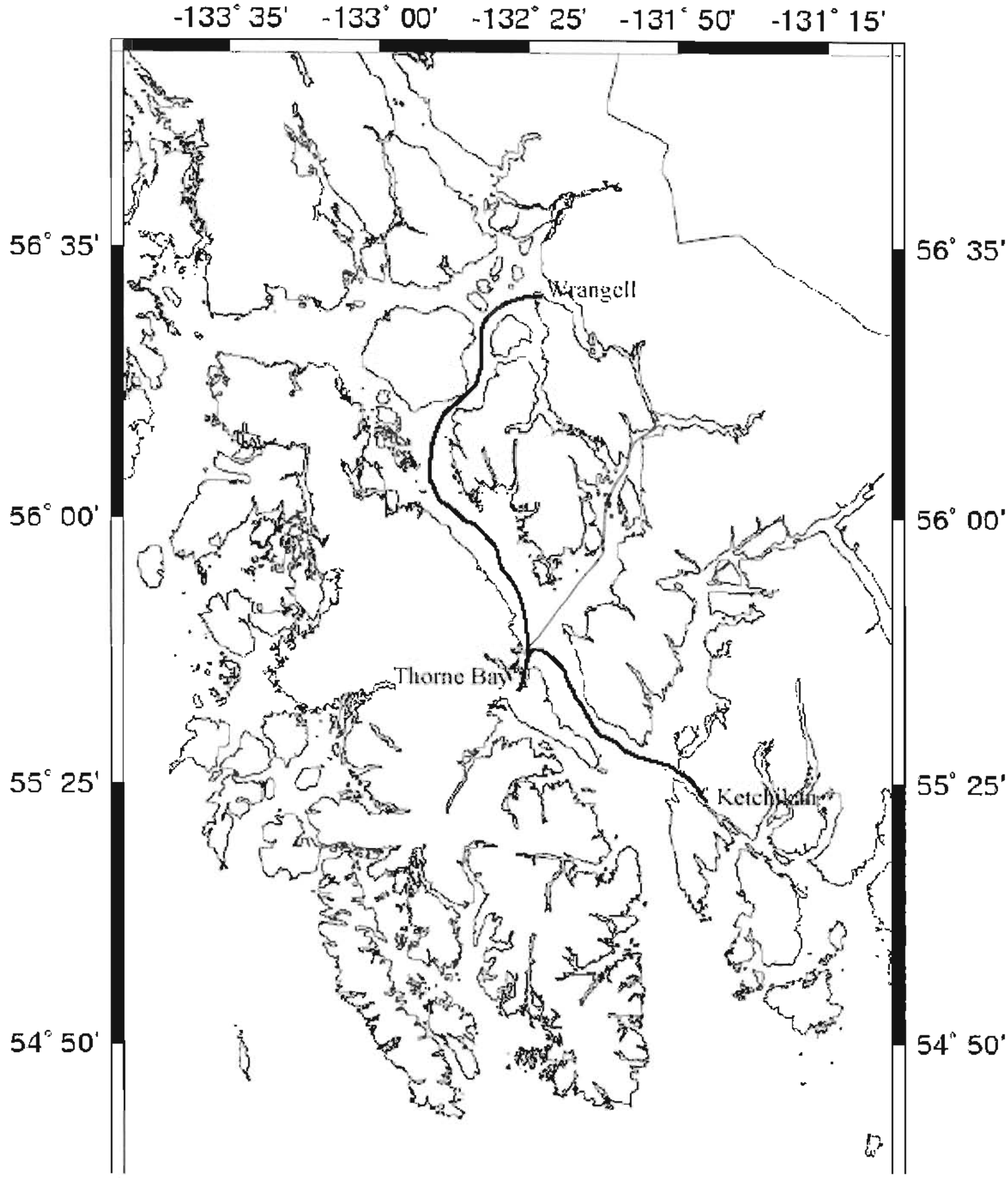


Figure 5-2
Assumed Cable Route

6. LAKE TYEE – SWAN LAKE AC SYSTEM

6.1 Description

The proposed Swan Lake - Lake Tyee ac intertie is intended to provide a source of power for the City of Ketchikan's immediate and long range energy needs as well as provide power to a greater number of small communities. The intertie would allow surplus power in the Lake Tyee area to be transmitted to Ketchikan. The proposed intertie would consist of a single circuit ac line running from Lake Tyee to Swan Lake. The line would be designed for ultimate operation at 138 kV.

6.2 Cost of AC System

The cost of the ac intertie has been estimated by others on a number of occasions. As these estimates were quite comprehensive, the cost was not re-estimated. The costs presented below were obtained from the Document of Interdisciplinary Review dated 19th January 2001.

Table 6.2-1
Part of the Swan Lake - Lake Tyee Intertie FEIS request for Supplement Document of Interdisciplinary Review, 19 January 2001

		Prices in 1997 USD		Prices in 2001 USD	
Item	**# units**	**Unit Cost**	**Total Cost**	**Unit Cost**	**Total Cost**
Construction	1	$2,764,400	$2,764,400	$3,065,814	$3,065,814
Contingency	1	$5,293,200	$5,293,200	$5,870,339	$5,870,339
Engineering	1	$5,500,000	$5,500,000	$6,099,687	$6,099,687
AC Transmission Lines	58	$966,176	$56,038,200	$1,071,522	$62,148,269
Owner's Cost	1	$3,325,200	$3,325,200	$3,687,760	$3,687,760
Forestry / Licensing	1	$2,000,000	$2,000,000	$2,218,068	$2,218,068
FOW (Stumpage cost)	1	$48,000	$48,000	$53,234	$53,234
Switchyard	3	$750,000	$2,250,000	$831,776	$2,495,327
Subtotal			$77,219,000		$85,638,496
Total Estimated Cost			***$77,219,000***		***$85,638,496***

8. REFERENCES

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2. HVDC Light - DC Transmission Based on Voltage Sourced Converters, ABB Review 1/98.

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5. G.Hjalmasson et. al., After Service Analysis of the 32 Year-Old HVDC Cable Gotland 1, CIGRE 21-02, September 1992

6. T.Nakajima, S.Irokawa, A Control System for HVDC Transmission by Voltage Sourced Converters, IEEE Summer Power Meeting, 1999

7. SUMMARY AND CONCLUSIONS

The development of high power insulated gate bipolar transistor (IGBT) switching devices has made it possible for a new generation of hvdc converter equipment to evolve, which is ideally suited for low and medium power applications such as the proposed interconnection of isolated communities in Southeast Alaska. Three different suppliers are capable of supplying converter equipment using this technology with one supplier having already supplied equipment for commercial installations. The successful application of VSC hvdc converters without any obvious problems indicates that the technology is already viable and will continue to improve as better devices become available. Control system development is well advanced, inherently stable and will be able to operate even if communication to the central control location is out of service.

Based on an analysis of the supplier information it is concluded that VSC converter technology and control and protection concepts have reached a sufficient level of technical maturity so that they can be applied in the electric power industry without undue risk. At the present state of development VSC hvdc systems are ideally suited for the lower range of power ratings being considered for Southeast Alaska.

The application of field installed submarine cable joints on extruded polymer cables cannot be considered to be a proven and mature technology. Given the obviously lower cost of the extruded cable designs, the Owner would need to make an assessment as to whether the cost saving is worth the risk.

The use of mass impregnated cable, although somewhat more expensive than extruded cable designs, would significantly reduce the risk of extended outages due to cable failures since both the cables and field installable joints been proven by field experience.

The estimated cost of a three terminal 30 MW base VSC hvdc system using mass impregnated cables is approximately $64 million. This compares to the estimated $86 million cost of the proposed ac system between Swan Lake and Lake Tyee.