NTNU – Trondheim
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Planning and Optimization of Smibelg Hydro Power Plant

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Hydropower Development
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Foreword

The thesis entitled “planning and optimization of Smibelg Hydropower plant” is submitted to the department of Hydraulic and Environmental Engineering, Norwegian University of Science and Technology (NTNU), Trondheim, Norway as an obligatory requirement for partial fulfilment of Masters of Science degree in Hydropower Development course 2012-2014.

This thesis mainly involves reconnaissance site investigation followed by alternative layout planning and optimization of the project scheme components using the theoretical knowledge acquired during the course of the masters programme. Simulation of energy production from the power plant has been done using nMag2004 model. Further discussions have been made on the economic viability of the project through economic and financial analysis. Finally Sensitivity analysis is used to foresee the probable outcome of changes on the course of project development and operation.

The working period for the thesis has begun from 10th January, 2014 to 9th June, 2014 under the supervision of Associate professor Brian Glover from Multi consult. This work is purely for educational purpose and does not mean to confront by way of any accusation to any individual, group or organization. The report presented is my own and all the significant sources and contributions made are duly acknowledged.

Acknowledgment

Apart from my work effort, I would like to express my deepest gratitude to my supervisor, Associate professor Brian Glover, for providing assistance, motivation and monitoring necessary for the completion of the paper.

Also special thanks shall goes to professor Annud kiligntivet and Professor Knut Alferdson for their immediate consultation when it comes to technical engineering guidance and data selection for the thesis. Also Mr. Netra prasad is acknowledged for his assistance in nMag2004 model implementation.

My deepest gratitude goes to the Norwegian government for providing me the chance of knowledge empowerment on my study here in Norway along with financial support. Also I would like to extend my gratitude to the administration and staffs of NTNU for their consistent service during my stay.

Further, I would like to extend my gratitude to my parents for their consistent blessing and encouragement. I would like to thank my fiancé for giving me continuous love, motivation and endless happiness. Finally I would like to thank all my friends and classmates for their support and encouragement along with all the fun that we have passed during our two year stay in NTNU.

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LIST OF ABBREVIATIONS AND ACHRONYMES

A	Catchment area
asl	Above sea level
B	Net benefit
B/C	Benefit – Cost Ratio
D	Pipe diameter
DI	Ductile iron
E	Energy production
F	Specific runoff
FIRR	Financial internal rate of return
g	Acceleration due to gravity
GWh	Giga watt hour
GWh/yr	Giga watt hours per year
Hg	Gross head
Hn	Net head
i	Discount rate
IRR	Internal rate of return
K	Capital cost
km	Kilometres
Km^2	Square Kilometres
kW	Kilowatt
l/s	Litre per second
m	Meter
m^3/s	Cubic meters per second
Mill	Million
MW	Megawatt
NOK	Norwegian Kroner
NPV	Net Present Value
npv	Net present value
NVE	National Directorate of Water and Environment
PE	Polyethylene
PW	Present worth
Δt	Time period
q	Flow rate per second
Q	Annual flow rate
s	Second
W	Watt
yr	Year

1 EXECUTIVE SUMMARY

1.1 Introduction

The Smibelg hydropower project was studied to a level required for concession permit by SkS Produksjon. The study has concluded that the project is economically attractive and it will benefit from regulation of exiting lakes. Upon this merit the project site is selected for thesis level investigation, planning, preliminary design and optimization of power plant.

It is presumed that the market will be partly domestic for consumption and for export. In addition it is presumed that there is a market for both firm and non-firm power at acceptable prices.

1.2 Power production and cost

The inflow data series are derived from vassvatnet gauging station for the period 1917-2013. However simulation has been undertaken for the recent 20years to uphold consistency of forecasted inflow data. Selections of reservoir characteristics are done based on the simulation result for different minimum and maximum reservoir levels. Based on the optimization analysis a maximum discharge of 5.26m^3/s is proposed providing installed capacity of 22MW, resulting in a plant factor of 0.73. Firm energy is defined as the energy supplied with 95% reliability.

The total cost for the power plant is estimated as 435.24 MNok. The cost of civil, electro mechanical and transmission is derived from NVE cost curve with a price base of 2010. Therefore cost variation due to under estimation of material price shall be expected.

Table 1 Cost Summary

Description	**Cost Mnok**
Dam including weirs	12.54
Intake	17.88
Water way	135.98
Power house	26.30
Access Road	27.69
Electro Mechanical	45.94
Transmission, switchyard and local supply	16.40
Engineering and administration	39.57
Contingencies	112.94
Total Project Cost	**435.24**

1.3 Base Case Economic Analysis

The economic energy cost i.e. unit generation cost till the nearest substation is calculated as 0.41Nok/KWh. This includes losses in the transmission system and grid rent costs. Comparing it to the sale price of 0.6Nok/KWh project is found to be attractive. It is calculated based on construction period of 3 years and 50years operation period, including annual operation and maintenance cost of 1%. The discount rate is set at 7%.

The main result of the base case economic analysis is shown in the table below;

Table 2 Base Case Economic Analysis summary

Unit cost	0.41	Nok/KWh	Levelized unit cost
NPV	84.38	MNok	Net present value
IRR	8.6%	%	Economic internal rate of return
B/c	1.20		Benefit cost ratio
Payback period	19.3	Years	Payback period

Sensitivity analysis response on discount rate, IRR, NPV, development rate and unit cost are evaluated. Basic elements of variation taken in to consideration are energy price, production, investment cost and discount rate. Direct linear correspondence is observed upon varying energy price and production i.e. an increase in production and energy price will lead increase in IRR, NPV, and development rate and vice versa. However indirect relation is observed upon varying investment cost and discount rate.

1.4 Environmental Impacts

There are no permanent settlements around the project site however on downstream section of the dam some scattered cabins have been observed. The cabins are located right below Lake Vassvatnet, the lake will help dampen any probable dam failure flood flows towards the cabins. Summary of analysis result using three step method of environmental impact assessment is shown in the following table;

Table 3 Summary Environmental Impact Assessment

Impact Area	Consequence
Geology and Landscape	Small negative
Biodiversity	small negative
Fish and fresh water biology	Small negative/Small positive
Cultural heritage	No impact
Recreation and outdoor activities	Small negative

Land use	No impact
Reindeer	small negative
Electrification	Large positive

1.5 Brief Description of Recommended Project

The smibelg hydropower project is located in the coastal area west of Mo I Rana, Nordland, Norway. The project forms by using water invasive approach of taking the regulated and unregulated catchment inflow to underground power house. There are a total of three unregulated catchments and a regulated catcment making the whole power generation system.

The power plant system normally gains much of its production capacity from the large head difference between the power house and catchment inflows at the top of the mountain. The system assumes to give priority for the unregulated section of the catchment followed by supplementing regulated inflow from the reservoir. It is planned as a semi reservoir scheme i.e. the gross head from the system is not computed as the difference between full supply level and turbine centre rather the reservoir is assumed to serve whenever the system demands power in excess of unregulated catchment inflow.

For energy simulation the gross head to the system is adopted from the lower intake point at Storåvaten to turbine centre. nMag2004 model has been used to simulate the production pattern and optimization of dam height. The silent features of the project design are summarized in the following Table 4 below;

1.5.1 Power plant System Setup

A total of 3 main intake weirs and main dam at storåga creating the reservoir have been proposed for the realization of the project. Selection of dam type for intake weirs have been undertaken based size, topography and degree of importance. A concrete gravity dam with overflow ogee spillway section along with the accompanying side intake structures has been proposed.

For the main dam a moraine core rock fill dam with concrete gravity dam section having an overflow spillway is proposed. The dam creates a reservoir with a gross volume of 13 Mm^3. The reservoir volume is created by combining the two natural lakes at Storåga and Smibelg through conductor tunnel. The conductor tunnel between the two natural lakes is proposed to have an area of 16 m^2 over 2444 m length.

Collection of water inflow starts at the reservoir, from reservoir a 16 m^2 tunnel having a length of 2530 m will take the inflow to a buried transfer pipe. The transfer pipe will serve as conduit between the two tunnels. In addition at the start of transfer pipe it adds inflow from the first supplying unregulated catchment from Vakker. The transfer pipe will end by adding additional unregulated inflow from Storåvaten, at the end of transfer pipe a 16 m^2 tunnel will deliver the water to the junction point of another supplying tunnel from Mannåga where the power intake will commence through a Ø1700mm diameter unlined penstock tunnel.

Finally the power house which is equipped with two generating turbine units totalling 22MW will produce the required energy production.

Table 4 Key Project Characteristics

Power and energy	Total rated output from two units	22	MW
	Mean annual energy generation	92	GWh/yr
	Firm annual energy	25	GWh/yr
	Deign discharge, total for two units	5.26	m3/s
	Maximum gross head	495	m
	Minimum gross head	490	m
	Type of transmission line	145	KV
	Length of transmission line	5.5	Km
Hydrological data	Catchment area	26	Km2
	Mean river flow from all	2.63	m3/s
	1000 year flood flow at dam site	17.31	m3/s
Reservoir	Full supply level (FSL)	502.5	masl
	Minimum operation level	498	masl
	Total volume at FSL	Appr. 18	Mm3
	Active Reservoir volume	13	Mm3
	Capacity factor	36.54	%
	Surface at FSL	1265	Km2
Main dam	Type of dam	Moraine core Rock fill	
	Dam crest Elevation	504.5	masl
	Max height of dam above foundation	6.5	m
	Crest length of dam	420	m
	Dam volume	49001	m3
weir at Vakker	Type of dam	Concrete Gravity Dam	
	Dam crest Elevation	502.5	masl
	Max height of dam above foundation	3.5	m
	Crest length of dam	20	m
	Dam volume	184	m3
weir at Storåvaten	Type of dam	Concrete Gravity Dam	

	Dam crest Elevation	501.5	masl
	Max height of dam above foundation	3.5	m
	Crest length of dam	25	m
	Dam volume	230	Mm3

weir at Mannåga	Type of dam	Concrete Gravity Dam	
	Dam crest Elevation	571.24	masl
	Max height of dam above foundation	2	m
	Crest length of dam	20	m
	Dam volume	42	m3
Main dam spillway	Type	Concrete Gravity Spillway	
	Elevation of crest	502.5	masl
	length of spillway crest	12	m
	Design flood magnitude over spillway	17.31	m3/s
	Reservoir elevation at FSL	503.26	masl
Head race tunnel	Type	Unlined tunnel	
	Shape Modified D shaped	16	m2
	Total tunnel length	7224	m
Transfer pipe	Type Buried	GRP	
	Total length	2350	m
	Pipe diameter	2000	mm
Penstock	Diameter of penstock	1700	mm
	length	650	m
Power House	Type of power house	underground	
	Power house cavern system lxwxh	30x10x16.8	m
	Elevation of machine hall floor	13.5	masl
	Cross section of access tunnel, Lxh	8x6	mxm
	Length of access tunnel	500	m
	Elevation of turbine center	5	masl
Tail race tunnel	Tunnel cross section	16	m2
	Tunnel length from turbine center	350	m
	Elevation of tail race outlet	0	masl
Turbine/generator	Type of Turbine 2units	pelton	
	Design discharge per unit	2.63	m3/s
	Total rated output from two units	22	Mw
	Synchronous speed	750	rpm
Transformer	Type and Number of transformers	3-Phase, 2 nos	
	Transformer cavern dimension lxwxh	8x10x8.5	

Structure of the Thesis Report

Volume I Reconnaissance Report

Volume I is the Reconnaissance Report, a stand-alone volume that details a complete picture of the project alternatives and the main results including the conclusion for the recommended project for detailed pre-feasibility study in Volume II.

Details including the studies and analysis with in the various fields [geology, hydrology, sediments, hydraulic analysis, economic analysis, etc.] are given in separate sections and annexes.

Volume II Main Report

Volume II is the main Report, a stand-alone volume that describes a complete detail picture of the recommended project and the main results of the analysis to a pre-feasibility level of study.

Details including the studies and analysis with in the various fields [geology, hydrology, sediments, hydraulic analysis, economic analysis, etc.] are given in separate sections and annexes.

Volume III Project Drawings

Volume III documents various project drawings in the form of drawing sheets for the recommended project.

Volume IV Various Analysis

Volume IV documents various project analysis results in the form of annex for each analysis section.

Volume I Reconnaissance Screening of Project Alternatives

1 INTRODUCTION

The first volume of this thesis report will detail the reconnaissance investigation for hydro power potential assessment of kystfelt, Sørfjordelva and Kjerringåga river basins located in Rødøy Municipality, Nordland Norway. The catchment includes all rivers discharging to Gjervalen and Aldersundet from the mountain top of Nubben, Fjellet and Strandtinden. The report will give details on methodology, assumptions and results undertaken during the reconnaissance report.

1.1 Previous Studies

SKS Produksjon undertook the project site identification and study for concession permit for ministry of water and energy for licencing in 2005 and has got permission for development in March 2012.

SKS concession plan is taken as a single alternative in the reconnaissance assessment during power potential investigation of the catchment and its feasibility is evaluated with the other ten identified interdependent potential development projects.

1.2 Scope of the present study

This thesis will envisage the identification and assessment of potential alternatives in the project site through a stepwise comprehensive planning and economic analysis. Special focus is directed to evaluate feasibility of potential schemes with respect to technical, economic, environmental and socio economic aspects. Hence, the report will state preliminary proposed plans for alternative development options, propose suitable engineering solutions, evaluate their economic merits and finally recommend a candidate project for refined study to volume II of this thesis report.

The study will analyse and document all important aspects for formal approval by Department of Hydraulic and Environmental Engineering, NTNU.

The main objectives of this screening report are:

- Provide comprehensive power potential assessment of the project catchment
- Identify suitable power projects that meet the planning criteria detailed below
- Assess the identified alternatives to the level required for reconnaissance study, the level of study is defined as that in Book no 5, planning and Implementation of hydro power projects, Hydro power development series (Raven, 1992)

- Perform preliminary economic assessment of the alternatives in order to compare the identified projects in terms of cost per KWh of generation. Cost base have been defined as per NVE cost curves , (NVE, 2014)
- Recommend the best alternative for prefeasibility study in volume II

1.3 Project location

The Smibelg hydropower project is located in the municipality of Rødøy, Nordland, Norway. The project site is located approximately 105 km west of Mo i Rana and 540 km north of Trondheim. The relative location of the catchment is $66^0 24'5''$:$13^0 10'55''$ latitude and longitude respectively and is shown in Figure 1 below;

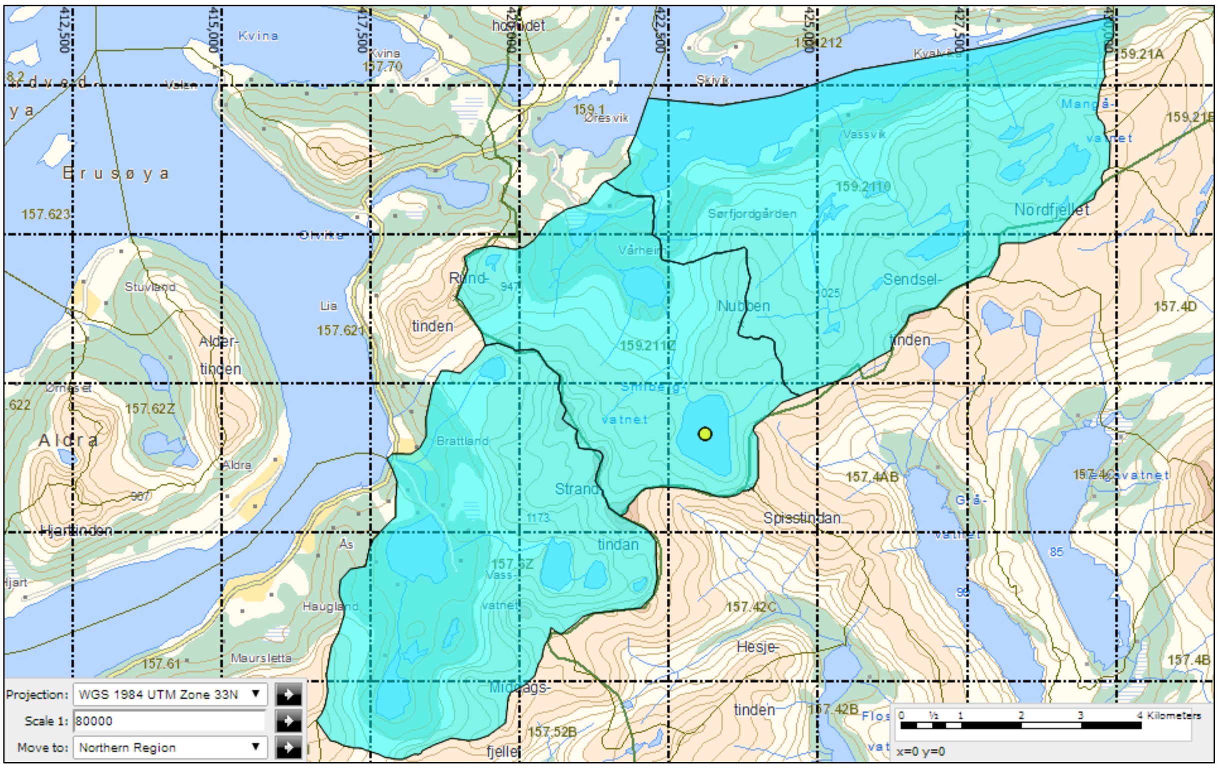

Figure 1 Project Catchment Location Map (NVEAtlas, 2014)

The project forms by using the water invasive approach of collecting water from effluent streams, lakes and the glacier deposit of the Nubben, Fjellet and Strandtinden mountain tops. The identified schemes will utilize the water from the existing mountainous rivers basins of kystfelt, Sørfjordelva and Kjerringåga, where the average annual precipitation rate is around 3000 mm/year.

1.3.1 Project Catchment Features

The project catchment has approximately an area of 65.36 km^2. The catchment has a length of approximately 6 km from the far end discharging point.

The catchment is characterized by four small river valleys directly discharging water forming their own drainage path down to the Norwegian Gjerval Sea. Steep mountain terrain is aligned on each side of the river valley making the catchment divide. The project will utilize the available flow by using a water collection system through tunnels and pipes to the desired intake location for optimum power production.

The elevation hypsography of the catchment varies from a minimum value of 0 to 1152masl and its distribution with in the catchment is shown below in Table 5. A small portion of the catchment (30%) is occupied with elevation less than 300masl; hence it will create a favourable ground for maximum power production by providing high head relative to power house location at 5masl.

Table 5 Elevation Hypsography of project Catchments Source: (Lavvann, 2014)

Kjerringåga	kystfelt	Sørfjordelva	
Elevation masl	Elevation masl	Elevation masl	% Comm. Area
0 - 148	0 - 413	0 -168	10 %
148 - 197	413 - 493	188 - 235	20 %
197 - 249	493 - 575	235 - 350	30 %
249 - 360	575 - 630	350 - 450	40 %
360 - 480	630 - 674	450 - 506	50 %
480 - 531	674 - 714	506 - 564	60 %
531 - 613	714 - 750	564 - 627	70 %
613 - 707	750 - 786	627 - 687	80 %
707 - 827	786 - 864	687 - 748	90 %
827 - 1160	964 - 1023	748 - 1152	100 %

1.3.2 Environment

The land use composition in the catchment comprises glacial mountain, marsh, forest and sea. Generally the project catchment is covered with glacier mountain tops and forest on down falling steep valleys, in addition to that it includes scattered farm lands and five to six households located downstream of the main river Vassvikelva. The land use distribution for the project catchment is shown below in Table 6.

There are no severe environmental disturbances however environmental as well social impacts of the alternative schemes are left for consideration to the next level of study.

However the need as well as extent of social and environmental investigation should at least cover the following core study points;

- Need for resettlement
- Minimum flow requirement
- Restricted regions
- Cultural and historical values
- Recreational value and fisheries

Table 6 land use pattern Source: (Lavvann, 2014)

Land use	Catchment		
	Sørfjordelva	kystfelt	Kjerringåga
Cultivated land	0.1 %	0.0 %	0.7 %
Marsh	0.6 %	0.0 %	0.7 %
Sea	8.9 %	5.0 %	8.4 %
Forest	16.5 %	1.4 %	28.5 %
Mountain	69.9 %	92.2 %	58.2 %
Urban	0.0 %	0.0 %	0.0 %

The summary for areal coverage with in the catchment was taken from the available 1: 50,000 scale NVE web based map output (NVE, 2014).

1.4 Planning Criteria

The planning criteria for this level of study are based on the overall power demand of Norway. The planning criteria taken in to the planning process lies in the identification of power plants which will support base load power demand to the existing stable nationwide grid. Under the firm power potential assessment the following list of economic criteria's are considered:

- Unit cost of generation should not exceed generation cost of 0.6 Nok/Kwh
- Assessment should avoid already developed projects
- Incorporation of protected regions with in the catchment shall be minimized
- Environmental impact of the new development shall be assessed
- Integration in to the existing Norwegian national grid should be documented

1.5 Power Market and Energy price

Power production has been increasing over the year, hence increased transmission capacity to fill the energy demand as a result a dynamic market has evolved where power can be bought and sold across regions and country easily.

In Norway the power market is deregulated in to a free market system which calls for variable power price that needs to be determined based on supply and demand just like other commodities. At this level of investigation a market selling price of 0.6 Nok/KWh is adopted.

1.6 Site visit and data collection

The thesis work was planned to incorporate two field visits to the site. However based on the fact that most of the catchment was covered with snow initial first visit was not possible. To supplement site visit exaggerated 3D-Model of project area was used as replacement to exactly locate and select locations of the major component structures.

1.6.1 Data

Topographic map

The Norwegian online web based platform covering the whole country is used from Norwegian mapping authority (StatnsKraftvek, 2014). A map scale of 1: 50,000 and below from Norgeskart and Gis link are used for topographic analysis of the catchment. Data gathered from the platforms for this level of study are geographical location, distance measurement and profiling of the selected section.

Runoff map

The Norwegian web based platforms NVE atlas and Lavvann for water resource development with varying scale are used to examine water resource potential of the project catchment. For this reconnaissance report they have been utilized to gather locations of existing plants, location gauging stations, identification of river basins, runoff maps etc.

Geological map

The Norwegian Web based platform from the Norwegian geological society (NGU, 2014) was used for examining the bed rock geology and soil cover of the project catchment. In addition sites of landslide, quick clay and stress map of the region was observed from the map.

2 REGIONAL GEOLOGY

Geological mapping and systematic investigation of the bed rock geology and soil cover of the project area is the key towards overall project cost and consequently to the feasibility of each alternative scheme. A preliminary geological investigation has been carried out for this level of study to foresee the existing geological units and soil cover of the project area and as such its influence in the hydro power development is stated.

2.1 Geological units

The Scandinavian Peninsula is characterised by the "Baltic Precambrian Shield" (Hveding, 1992). Norway bedrock is comprised of approximately 2/3 Precambrian and 1/3 Palaeozoic (often referred to as Caledonian) units. These units are more than 230 million years old and are the basis for the hard rock environment of Norway. The geological units within the region are composed mainly of calc-alkaline intermediate volcanic rocks and intruded by grano dioritic to granitic rocks (Skår, 2002).

The geological units within Norway, from a rock engineering point of view, are classified as being of high quality (Nilsen, 1993). Stability problems relating to weakness zones, faults, rock stresses, and unfavourable jointing are possible, and these need to be considered on a case by case basis at the specific project locations during the next phase of investigation.

2.1.1 Bed rock Geology

The general bed rock geology in the project catchment is mainly dominated with øyegneis, granite and foliated granite. The details of bed rock geology as observed from the (NGU, 2014) are shown in the Figure 2 below. Granite is a good rock from engineering point of view as such its intact rock quality may influence the tunnel, cavern and trench excavation in the proposed alternatives; therefore detailed geological observation is required in the next level of investigation.

2.1.2 Soil cover

There is no soil cover in the top mountain rather the topography of the area is exposed rock with undulating slopes and forest cover in the steep heel downfall as sited from aerial photo of the region. Generally variation in depth and type of soil will have prominent influence in the final cost of the project. The soil cover distribution with in the catchment is shown in the

Figure 3 below; the corresponding costing of the schemes in bare rock excavation is incorporated in section 0.

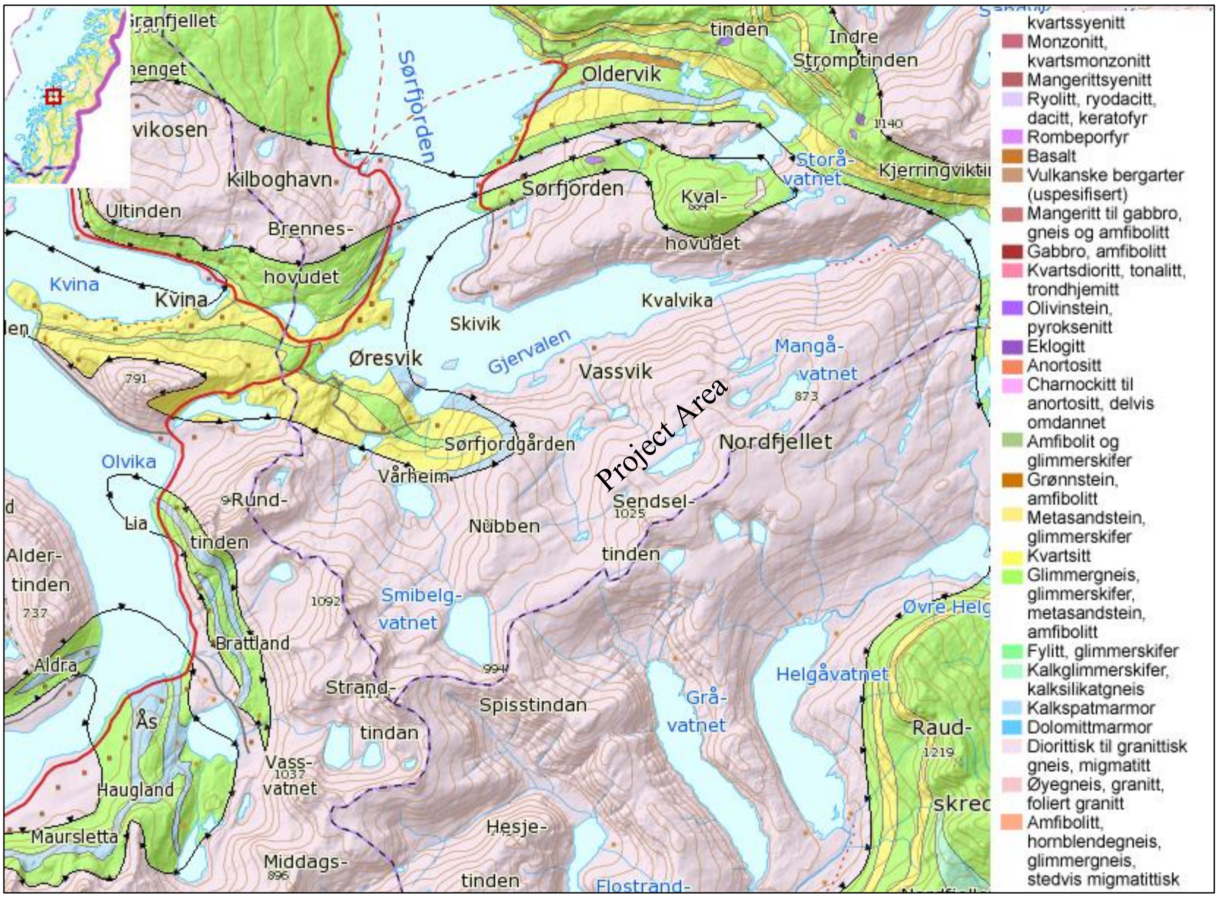

Figure 2 Bed rock geology of project Catchment, Nordland (NGU, 2014)

2.2 Seismic Hazard

The seismic effect in the design of the alternative schemes are left for the next prefeasibility study; however the seismic nature of the Rana region is known both from the fact that this was the location of the largest known earthquake in northern Scandinavia in recent times, M_s 5.6-6.5 earthquake of August 13, 1819 and relatively from its high and constant activity in 20th century (Erik C. Hicksa, 2000).

2.3 Limitations

The variation in the bed rock geology and rock quality at key project component locations in the surface will influence the feasibility of each alternative scheme identified in section 0 of this report; therefore a detailed geological investigation shall be conducted in order to evaluate the merits of the development options and endeavour possible rock quality issues.

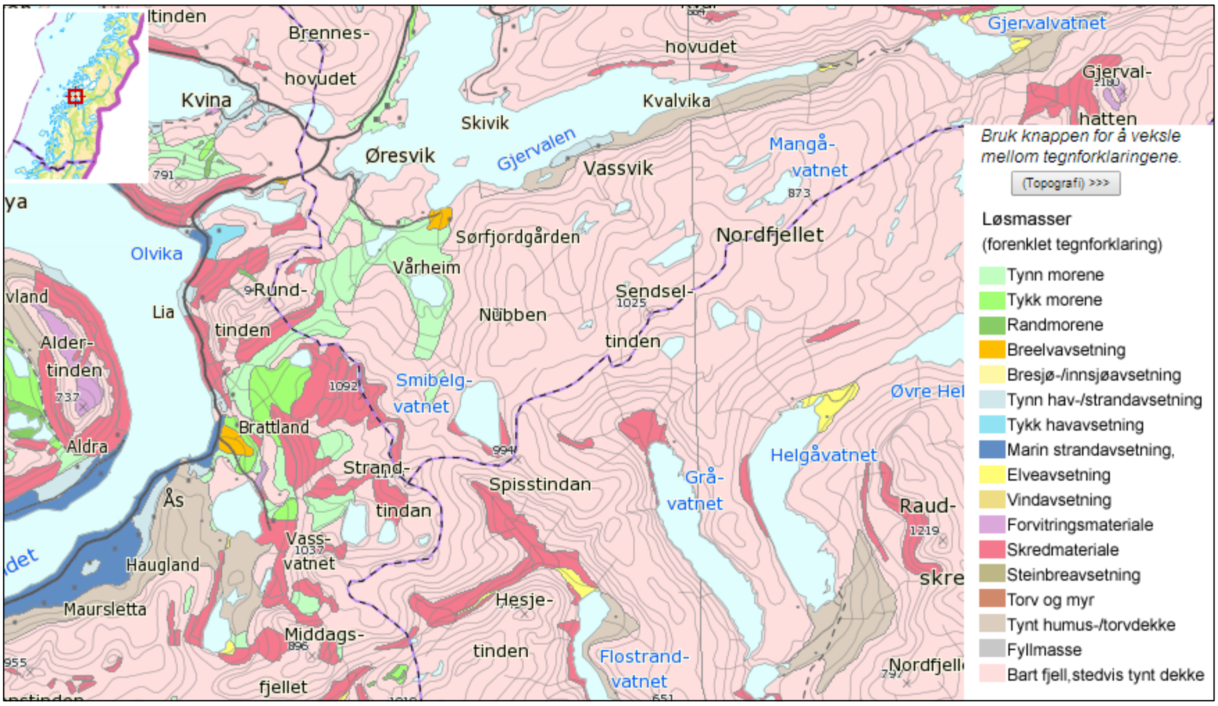

Figure 3 Soil cover of project Catchment (NGU, 2014)

3 HYDROLOGICAL ANALYSIS

3.1 Hydrological data and analysis

The inflow in to the system, from its contributing catchments and variation of the inflow over the year are the key to wards estimating overall potential output. “Water is the basic source (or “fuel”) for hydro power generation and knowledge about the availability and its distribution is vital for both planning and operation of a hydropower system” (Killingtvet, et al., 1995). The hydrological analysis has been undertaken and the results from the analysis are feed in to energy analysis described in section 1. The following step outlines the key steps undertaken for hydrological analysis.

3.1.1 Specific Runoff

It is deemed advantageous to use Specific runoff maps from NVE Lavvann (NVE, 2014) for reconnaissance investigation and have been used for this level of study. The online platform uses flows from 1961-2014 to determine the average specific runoff values for the project catchment in agreement with the GIS platform to include the variation in the topography of the region. Hence after planning suitable alternative layouts specific runoff at selected intake points have been recorded. Results of specific runoff are documented in Table 7.

3.1.2 Mean Flow

The average flow at predefined intake points have been calculated by multiplying the specific runoff with catchment area for each sub catchment. The sum of each sub catchment mean flow included in each scheme is taken as the total available main flow for each scheme identified below in section 4.

3.1.3 Design Flow

The design flow for this level of study is considered as two times the total average flow available in each scheme for dimensioning of project component structures. However detailed optimization analysis is required to determine the magnitude of the design flow and such analysis is mandatory in the prefeasibility level study.

3.1.4 Utilization Factor

Utilization factor indicates the percentage of the flow which a hydropower scheme is able to utilize for generation, flow duration curves are used as main tool in order to determine the utilization factor for the computed optimum design flow; basically two major factors influence the value for utilization factor:

- The proportion of time and the magnitude of events which exceed the maximum capacity of the hydropower scheme (Floods).
- The proportion of time and magnitude of events which are less than the minimum capacity of the hydropower scheme (Droughts, winter freezing of the river, environmental flows and minimum turbine flow).

As such to account for the above factors a generally accepted practical norm in the Norwegian hydropower Industry is used to determine the utilization factor. Utilization factor of 68.5% is adopted to modify the design flow stated in section 3.1.3 above. The results of these assumptions are used in section 1 to compute the required hydraulic and energy analysis for this level of study.

Table 7 Project Sub - Catchment at selected Intake points, NVE-Lavvann output.

Sno	Description	Elevation masl	Area Km2	Specific Runoff l/s/km2	Q_{av} m3/s
1	Nedre storåvatenet	380	3.7	126	0.466
2	Vakkersjordvatna	400	6.2	119.5	0.741
3	Mangåga	571	4.2	121	0.508
4	Smibelgvatnet	506	4.4	133.6	0.588
5	Storåga	497	4.2	152.4	0.640
6	Smibelg-1	499	0.6	153	0.092
7	Smibelg-2	506	0.7	152	0.106
8	Smibelg-3	498	0.1	119.6	0.012
9	Østre vakker	490	3.5	127.5	0.446
10	Østre storåvatnet	751	1.8	139.2	0.251
11	Svartvatnet	184	11.7	122.3	1.431
12	Vassvatnet	107	16.4	122.8	2.014
13	Heimstadelva	115	1.8	123.6	0.222
14	Dalåga	102	1.6	137.20	0.220

4 SCHEME IDENTIFICATION

The purpose of reconnaissance study was to identify as many schemes as possible satisfying the planning criteria stated above in section 1.4. This section of the report states the comprehensive rigorous assessment methodologies undertaken to identify potential schemes for the project catchment. The summary of the identified schemes is detailed in section 4.5.

4.1 Methodology

For this level of planning study, systematic identification of intake location, scheme alignment, storage possibilities, intra basin transfers, selection of required component structures etc. has been undertaken using comprehensive topographic and catchment analysis based on NVEs web based online platform. Details of the topographic and catchment identification are shown in separate section below.

Specific steps has been followed to maximize the key project qualities of a hydro power project, these are head and flow from the project catchment. The following preliminary steps have been followed to arrive at a suitable scheme:

- Catchment identification
- Major river identification
- Topographic analysis
- Scheme identification
- Selection of key project component location
- Review and enhancement

4.1.1 Catchment Identification

The extent of the project catchments was delineated by the online web based platform NVE atlas (NVE, 2014) and shown in Figure 1 above through the highlighted section. The catchment divide enables to identify the cross catchment possibilities of tapping water from one catchment to the other to maximize the flow for increased generation capacity.

4.1.2 Topographic Analysis

Detailed but preliminary topographic analysis has been undertaken to formulate the alternative schemes identified in the following section of the report focusing to maximize utilization of head and water available in the catchment. Long section of the river has been prepared for the four main rivers to foresee the extent of head concentration per meter length of the river using the GIS platform from Norgeskart (Norway, 2014) in addition to that relative cross-catchment possibilities are analysed and are detailed in annex A.

Intake locations are identified and catchment delineation followed by computation of average specific runoff were undertaken and summarized in Table 7 above. Using the advantage of existing natural topography combination of sub-catchments through intra basin transfer was used to come up with unique schemes described below in section 4.2.

4.2 Scheme Identification

The topographic analysis has been undertaken in two phases, these are:

- Identification of interdependent schemes to identify the effect of adding a sub-catchment at the expense of increased capacity and cost of the plant
- Rationalizing the identified interdependent schemes into independent schemes based on their economic merit and maximized power output.

Interdependent schemes were identified in the initial analysis to foresee the effect of adding a sub-catchment at the expense of the cost that the additional project structure might demand to add to the existing scheme. A total of eleven interdependent schemes are identified and summarized below in section 4.5.

Preliminary project costing and economic analysis described in section 6 has been conducted and resulted confirmation of feasibility for all schemes satisfying the planning criteria set above in section 1.4.

A total of five Independent schemes are selected upon feasibility of all alternative schemes towards maximized production output even if there were options with a smaller capacity that will give a smaller unit cost of development. The selected schemes are described as proposed alternatives in the following section and are documented independently along with cost estimate and economic analysis.

4.3 Layout of Proposed Alternatives

Alternative 1 describes Scheme 8 in scheme summary and it is the one proposed by SKS Produksjon for concession permit to NVE. The layout details are presented in map layout Drawing D1-A3. Alternative 2 to 5 are schemes proposed for this thesis work.

Alternative 2 describes Scheme 7 in scheme summary; the layout comprises a system of tunnels and pipes to tap all available flows with underground power house arrangement located under Loften Mountain north of river Vassvikelva.

Alternative 3 describes Scheme 6 in scheme summary; the layout comprises a system of pipes and tunnels collecting water from all sub-catchments for an increased potential output, though in this scheme there will be a greater construction difficulty due to steep gradient from selected intake points to penstock start location.

Alternative 4 describes scheme 10 the layout comprises a tunnel from Smibelg to Storåga and a penstock pipe taking the water from Storåga to Vassvatnet where the power house is located.

Alternative 5 describes scheme 11 where the water flowing from the alternative four power plant scheme is taken along with other sub catchments and drops to a power house at Ågneset.

The plan layout of each independent alternative scheme is documented along with cost estimate and economic analysis.

4.4 Scheme Components

The identified alternative schemes have been evaluated with respect to scheme components required to finalize a complete picture of each alternative. The following section describes the assumptions and procedure's undertaken for each scheme component under consideration.

4.4.1 Diversion and Intake Structures

A small concrete gravity dam has been proposed for all scheme alternatives. since the topography of the project catchment favours runoff the river schemes except at Lake Smibelgvatnet and Storåga which allows storage of water with significant amount of storage as compared to the surrounding small lakes.

Reference has been made to NVE cost curve design standards for small dams having the following construction features, construction of dams in sections of 6.1 m and foundation rock injection depth of 0.5 x H, where H is the water depth at the highest regulated water level HRWL.

Brook intake which includes intake pond, trash rack and a closing gate has been proposed to find the cheapest solution allowing optimum flow condition, whilst avoiding problems related with freezing of water and rock boulders entering into the intake.

4.4.2 Water ways

Most but not all of the identified schemes are fitted with tunnels and pipes to transport water from one sub catchment to the other. Here in this section of the report theoretical basis behind the selection, optimization and design of tunnels and pipes are described.

Tunnels

Tunnels are proposed from Storåga to Smibelg, Smibelg to Østre Vakker and from Manåga to Nedre Storåvatnet to transfer the water from each catchment based on the topography, bed rock geology, economics and probable construction difficulties.

The tunnels are aligned in such a way that they satisfy the minimum rock cover requirement, matches with the topography without losing head, technically easier for excavation and shortest possible path. Summary of proposed tunnels from all of the alternatives are documented below in Table 88.

Table 8 Summary of Proposed Tunnels

Description	Tunnel			Remark
	Length, m	A, m^2	Excavation Method	
Storåga to Smibelg	2444	16.00	Drill and blast	Free gravity flow
Smibelg to Østre Vakker	2530	16.00	Drill and blast	Free gravity flow
Manaåga to Storåvatnet	2100	16.00	Drill and blast	Free gravity flow
Penstock tunnel	565	varies but <10	Directional drill	pressurized flow
Tail race tunnel	300	16.00	Drill and blast	Free gravity flow
Access tunnel	600	30.00	Drill and blast	Transport and access

Design procedure

To assure the required stability requirement for tunnels summarized above the Norwegian rule of thumb principle is used to quantify the results. The minimum rock covers required against rock stress, squeezing and rock fall are calculated. Preliminary penstock tunnel diameter optimization has been undertaken using simplified formula shown below; (Gunnes, 2000).

$$A = 1.27 \ x \ Q^{0.82}$$

Where: A= penstock area in m^2 and Q = design discharge in m^3/s

However, among other factors the cross-sectional areas of proposed tunnels are determined by the minimum area required for drill and blast by Norwegian tunnel contractors.

Buried Pipes are normally preferred as compared to tunnels in cases where the topography allows for pipe alternative. Hence, DCI, PE and GRP pipes are compared in terms of the pressure and cost required per meter length of a pipe to be installed and all of identified project alternatives are fitted with buried GRP pipes. The summary of the installations for the realization of the schemes are shown in Table 9.

Table 9 Summary of Pipes to be installed

Description	pipe			Remark
	length m	Diameter mm	Type	
Nedre Vakker to nedre storåvatnet	465	Varies	GRP	Buried
Østre vakker to østre storåvatnet	3000	2800	GRP	Buried
Nedre storåvatnet to penstock	1200	Varies	GRP	Buried
Manåga to penstock	1700	1650	GRP	Buried
Surface Penstock				
Scheme 1,3,5	565	1850,2100,2100	GRP	Buried
Scheme 2 & 4	1432	1850,2100	GRP	Buried
Scheme 9	1050.00	1950	GRP	Buried
Scheme 10	1565	2000.00	GRP	Buried
Scheme 11	700.00	2750.00	GRP	Buried
underground penstock				
Scheme 6	565	2700	DCI	concrete Lined
Scheme 7	565	2700	DCI	concrete Lined
Scheme 8	600	2550	DCI	concrete Lined

4.4.3 Surge Chambers

Preliminary surge analysis of each independent scheme shows surge shaft is not required to alleviate the probable water hammer problem. For analysis the time required for the generator to reach from zero to full load normal speed (Ta) is recommended to be in the range of 5 to 8 sec hence 6 sec is adopted. Generally to have a stable governing system which can adjust the power demand with water requirement at the turbine, the dynamic properties of the conduit system should satisfy the following rules.

$$\frac{Ta}{Tw} > 6$$

Where: Ta = Time required for the generator to attain full load at normal speed

Tw = Penstock time constant, time that the penstock requires to reach from zero to maximum discharge under the influence of the available gross head.

$$T_w = \frac{Q}{gH} x \sum \frac{L}{A}$$

Where: Q = maximum design discharge H = Gross head

L = Length of tunnel plus penstock A = Cross sectional area

L/A = from the nearest water surface upstream to the nearest water surface downstream

The computed penstock time constant will satisfy the governing rules hence surge shaft is not required, however detailed analysis on pressure in front of the turbine and governor stability are required and posted for the next level.

4.4.4 Power station

The topography as well as capacity of the plant has a major influence for selection of power house type, hence for identified schemes of capacity less than 10 Mw a surface power house has been proposed.

For schemes greater than 10 Mw underground power house is proposed and is located in the Loften region having sufficient rock cover, good rock quality of granite and short access tunnel. The capacity of the underground excavation is fixed using the blasted volume required using the following formula obtained from NVE cost curve (SWECO Norge AS, 2012). However the arrangement and details of the power house outline are left for the next level of study.

$$V = 78\, x\, H^{0.5} x\, Q^{0.7}\, x\, n^{0.1}$$

Where: V = Blast Volume, m^3 H = Net head, m

Q = Total maximum water flow, m^3/s n = Number of units

4.4.5 Mechanical and Electro technical works

Turbines

Turbines are the main engines in any hydropower development and are used to convert potential energy of water in to rotational mechanical energy of turbine shaft which is coupled with the generator. Turbine type alternatives has been sought for the identified schemes taking the head and design flow as criteria from the following turbine selection design curve and two equal capacity Pelton turbine units are proposed except for Scheme 11 which is fitted with single Francis turbine at the expense of higher flow and low head.

At this level the possibility of using two turbines as compared to one is observed to fetch the extra advantage of using two units as compared to one unit. Hence, they will decrease the probability of power shutdown in case of sudden turbine breakdown and using two units of equal capacity will allow utilization of one spare part to maintain both units which will minimize the overall maintenance speed and cost; hence two units of equal capacity are provided for each scheme that has a capacity greater than 5 Mw and one unit for the rest.

Pelton turbines have a larger operational range and are able to be run with flows as low as 10 % of the maximum turbine discharge. This compares to Francis turbines which should not be run below approximately 40 % of the maximum turbine discharge. Minimum turbine flows are not incorporated into the hydrological analysis for this level and will have no effect on this study. This should be considered in further stages of investigation. The preliminary turbine centre level for surface as well as underground arrangements is set at 5 masl

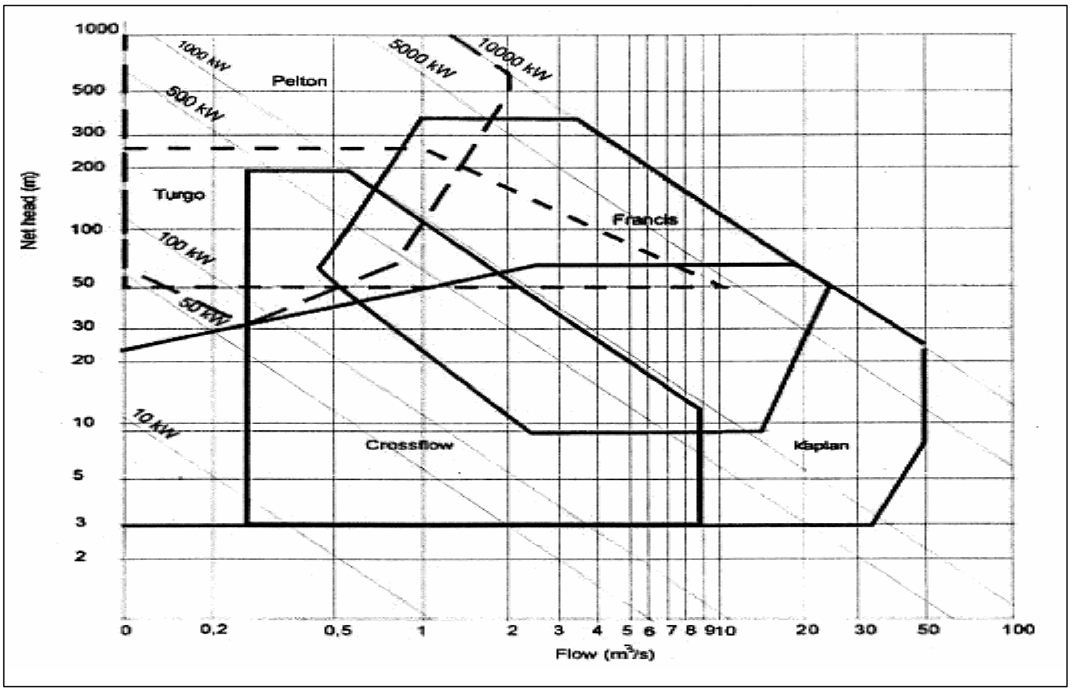

Figure 4 Guide Curve for Turbine Type Selection

Electro-mechanical components

Sizes of generator, transformer and other miscellaneous auxiliary equipment's are fitted as per NVE cost curve base. Design discharge and station installations were used to determine the magnitude of each installation.

4.4.6 Out fall

The out fall for releasing water back to Lake Gjerval is considered and the location of power house is set to ascertain the shortest possible distance and reduced cost.

The invert level out fall to the lake is set at 0 masl assuming no lake level fluctuation and backflow to the power plant.

4.4.7 Review and Enhancement

The full optimization is left for the next study; hence it will put a challenge on the screening assessment of this study to the extent of questioning feasibility of the recommended scheme. However the results are documented as reference for future assessment study.

4.5 Scheme Summary

This screening assessment has identified 11 schemes passing the planning criteria set above and are summarized with a key parameters in Table 10.The layouts of each scheme are fitted with the topographic map and are presented along with the cost estimation and economic analysis. Tabular summary of the independent schemes identified are presented in

Table 11 with the basic technical and economic parameters. There is no existing developed hydro power plant in the catchment considered and as such no detail is presented.

Table 10 summary of Schemes with key planning parameters

S.No.	Description	Intake level masl	Outlet level masl	Mean flow m^3/s	Tunnel length m	Pipe Transfer m	Penstock Length m
Scheme 1	Storåvatnet	382.00	10.00	1.21	x	1665.00	565.00
Scheme 2	Vakkersjordvatna	379.68	10.00	1.21	x	465.00	1432.00
Scheme 3	Storåvatnet	383.00	10.00	1.72	2100.00	1665.00	565.00
Scheme 4	Vakkersjordvatna	379.68	10.00	1.72	2100.00	465.00	1432.00
Scheme 5	Loftan	383.00	10.00	1.72		3365.00	565.00
Scheme 6	Loftan	383.00	10.00	2.30	7594.00	465.00	565.00
Scheme 7	Loftan	383.00	10.00	2.94	7074.00	465.00	565.00
Scheme 8	Loftan	484.25	10.00	2.64	7680.00	3450.00	1100.00
Scheme 9	Svartvatnet	187.00	10.00	1.43	x	x	1050.00
Scheme 10	Hundåga	498.00	110.00	1.44	2444.00	x	1565.00
Scheme 11	Brattland	102.00	10.00	3.25	2444.00	1175.00	700.00

Table 11 summary of Independent Scheme Alternatives

S.No.	Description	Intake level	Outlet level	Mean flow m3/s	Installed capacity	Turbine Type	Power House type
Scheme 6	Loftan	383	10	3.15338	20685.45	2 x pelton	Underground
Scheme 7	Loftan	383	10	3.15338	20671.25	2 x pelton	Underground
Scheme 8	Loftan	484.25	10	2.64309	22051.44	2 x pelton	Underground
Scheme 10	Hundåga	502	110	1.43808	9914.56	2 x pelton	surface PH
Scheme 11	Brattland	104	10	3.25392	5333.51	1 x Francis	surface PH

5 HYDRAULIC AND ENERGY ANALYSIS

5.1 Hydraulic calculations

To determine the available net head for generation probable hydraulic losses from the system layout has to be deducted from the gross head. Hydraulic losses with in hydropower development can be classified in to three:

- Major loss from tunnels and pipes
- Minor loss at contractions, joints, bends, entrances etc.
- Turbine and generator losses

For this level of study the minor losses are not calculated rather they are included in the general simple hand rule of 1 m/km as a total loss in the conduit system. The losses in the turbine and generator are accounted using efficiency value of 90 % for power calculation.

For transfer pipes and low pressure tunnels free flow with a velocity range of 0.7 to 1.5 m/s are considered in addition the manning roughness coefficient for pipes and tunnels are taken as 100 and 35 respectively. For penstock pipes flow velocity of 4 m/s and roughness value of 100 is considered in the analysis.

5.2 Energy computations

To determine energy potential of each identified scheme the following energy computation formula is used with some adjustment factors,

$$E = (\rho * g * n * q * H) * \Delta t * U$$

Where:

E = Energy potential, GWh

ρ = Density of water, Kg/m^3

g = Gravitational acceleration, m/s^2

q = Design flow, m^3/s

Δt = Time, hrs

U= utilization factor, 68.5%

The result of energy analysis has been feed in to economic analysis to compute the overall benefit from each individual scheme upon selling the energy produced. However storage possibilities for schemes that include Smibelg and Storåga will increase in secondary power and are considered as 10% of the total energy as added value in the economic analysis section of the report.

6 COST ESTIMATION

6.1 General Cost Estimation Basis

Cost base manual from NVE has been used to calculate the average foreseeable cost for contractors (Civil works) and supplier costs (mechanical and electro technical Equipment's) for capacity less than 10 Mw and greater than 10 Mw generating capacity (SWECO Norge AS, 2012).

The prices in the report are as of 1 January 2010. The prices and costs are recorded in Norwegian kroners. No taxes, import duties and interest during construction are included in the cost estimate. The following section describes the assumptions and steps taken to estimate the cost of each project component.

6.2 Estimate Civil works

This section provides a basis for calculating the average foreseeable contractors cost for civil work. Average foreseeable means there is a 50% risk of costs getting higher and a 50% risk they will be lower (SWECO Norge AS, 2012). With regard to uncertainty margins there is a 90% probability for real costs to be in the computed costs.

6.3 Estimate Mechanical and electro technical Equipment's

Generally the cost of the total mechanical and electro technical equipment's reaches up to 50% for hydro power developments. Estimation of the major component like turbine, generators, transformers, auxiliary system, pumps, control system and switching gear costs have been done and to account the unaccounted costs a 10% added cost of the calculated cost have been done to arrive at total cost.

6.3.1 Mechanical and Electro Technical Equipment's

The cost is derived from the cost curves based on the head and flow of each of the schemes.

The total cost for generators (both air cooled and water cooled), transformers, auxiliary system, switching gear and control system electro-technical equipment's are computed based on schemes generating capacity and are computed as a lump sum value from cost curves of both manuals.

7 ECONOMIC AND FINANCIAL ANALYSIS

7.1 Economic and financial analysis

To determine the viability of identified schemes a financial analysis is required. By evaluating the anticipated lifetime costs and benefits of schemes a degree of clarity can be provided on the overall return of the investment and the sequencing of cash flows. Commonly used discounting techniques are used to compute and compare the ranking of the identified schemes. The details of the discounting techniques are summarized below:

- Net present value(NPV):
  Calculates the net present value of the alternatives with preference being given to the alternative with the largest present worth

$$\mathrm{PW} = -\mathrm{K} + \mathrm{B}(\frac{\mathrm{P}}{\mathrm{W}}, \mathrm{i}\%, \mathrm{T})$$

- Benefit cost ratio(B/C)
  Calculates the net present value of the scheme benefits divided by net present value of the scheme costs.

$$\mathrm{B/C} = \mathrm{PW}_{\mathrm{b}} / \mathrm{PW}_{\mathrm{C}} = \frac{\sum_{t=1}^{40}\left(\frac{P}{F}, i\%, T\right)Bt}{\sum_{T=1}^{40}\left(\frac{P}{F}, i\%, T\right)Ct}$$

- Annual cost method
  Converting all costs and benefits into equal annual figures allows the profit or loss over the lifetime of a project be expressed on an annual basis. Here the levelized unit cost is used for comparisons of the alternatives.

$$\text{Levelised unit cost} = \frac{\text{total annual cost}}{\text{total annaul energy}}$$

- Internal rate of return (IRR)
  The internal rate of return is a measure of the return on the investment. The required IRR will vary between Clients based on the cost of financing that they can obtain and the IRR of alternative projects which they may have under consideration. The IRR of a scheme is calculated by setting the net present value equal to zero and determining the corresponding value of the IRR:

$$\mathrm{PW} = -\mathrm{K} + \mathrm{B}\left(\frac{\mathrm{P}}{\mathrm{W}}, \mathrm{i}\%, \mathrm{T}\right) = 0$$

- Development rate
  Development rate is a measure of the annual costs required during project lifetime at the expense of constant annual generation without outage of the power plant.

$$\text{Development rate} = \frac{\text{annual generation}}{\text{Annual cost}}$$

7.2 Comparison of the financial analysis methods

Each of the above techniques has advantages and disadvantages with regard to the presentation and understanding of the results of the study. The ranking of schemes varies between the NPV and the other four analysis methods, and as such the definition of the optimum project relates directly to the investment profile, alternative opportunities, and needs of the client. Summary of the financial analysis for independent schemes are shown in the table below,

Table 12 Financial analysis and ranking summary

Economic Analysis		Scheme 6	Scheme 7	Scheme 8	Scheme 10	Scheme 11
Total investment cost	M nok	285.6	283.7	302.0	141.9	117.7
Net present value	M nok	81.0	82.6	88.8	46.1	-9.5
Internal rate of return	%	0.092	0.092	0.092	0.095	0.063
Benefit cost ratio		1.28	1.29	1.29	1.42	0.92
Levelized Unit cost	Kr/Kwh	0.47	0.46	0.46	0.45	0.65
Development Rate, DR	Kr/kwh/year	2.3	2.3	2.3	2.3	1.5
Rank	unit cost	4	3	2	1	5
	DR	4	3	2	1	5
	b/c	4	3	2	1	5
	IRR	4	3	2	1	5
	NPV	3	2	1	4	5

It should be noted that there are many factors which may influence either the benefit or cost aspect of the financial analysis and as such the conclusion drawn above are based on the information that the author had during preparation.

7.3 Sensitivity analysis

Sensitivity analysis is used to cheek the robustness of project viability against varying circumstances that are bound to happen over the period of analysis. The results of analysis for scheme 10 are shown below in Figure 5 and Figure 6 representing the project response to NPV and unit cost.

Sensitivity analysis on NPV and unit cost against variation on investment cost, production, energy price and discount rate has been undertaken and viable response has been observed with 50% variation on either side of the base case scenario.

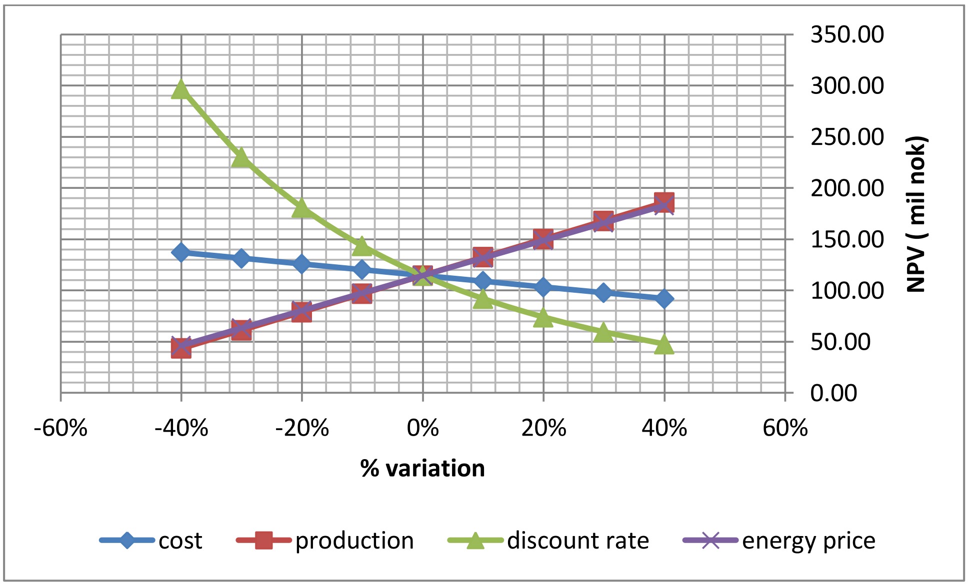

Figure 5 Sensitivity of NPV against variation, Scheme 10

Adopting a threshold value of 20 MNok for NPV, scheme 10 has been found viable to 44% variation on either side of the base case scenario. The scheme is economically attractive.

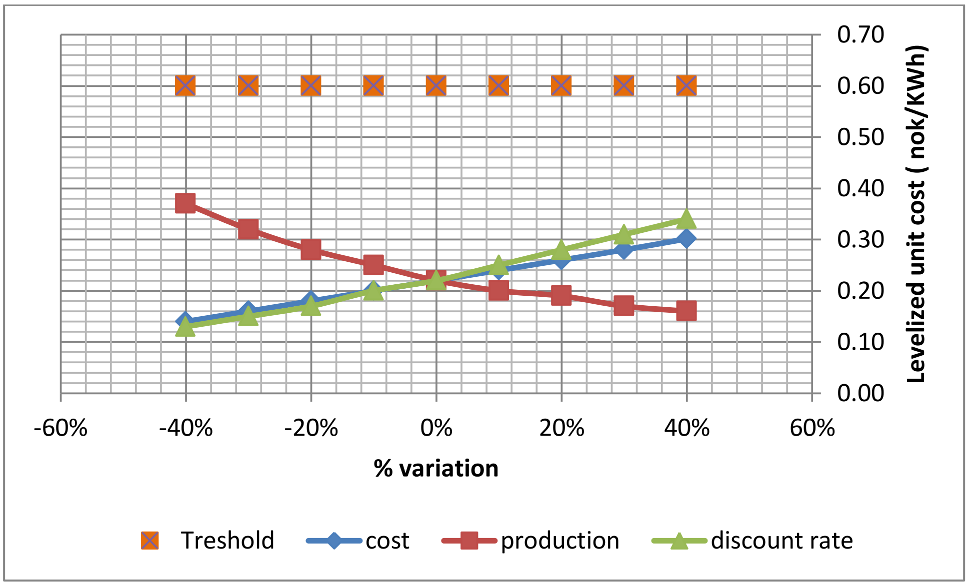

Figure 6 sensitivity of unit cost against variation Scheme 10

The result above shows the extent of project viability upon the imposed variations as compared to the threshold value of 0.6Nok/KWh. All results under 0.6Nok/KWh are found to be attractive for development.

8 CONCLUSION AND RECOMMENDATION

Conclusion

In this thesis reconnaissance report a total of eleven interdependent schemes has been identified and assessed to evaluate the viability of each scheme as per the planning criteria. The identified schemes have been rationalized to five independent schemes based on their characteristic merit. After identifying independent schemes preliminary component design followed by economic analysis has been undertaken.

The following conclusions are made based on the preliminary economic analysis on cost of construction and the following benefit from selling power.

- A number of project alternatives have been found feasible using a utilization factor of 68.5%
- Scheme 10 has the lowest unit cost (0.45 Nok/KWh), primary ranking criteria; however it has the lowest NPV and Installed capacity with a value of 46.1 MNok and 9.91 MW respectively. It also has a simple development setup.
- Scheme 8 follows with a unit cost of 0.46 Nok / KWh. It has the highest NPV and Installed capacity with a value of 88.8 MNok and 22.05 MW respectively
- Scheme 6 and 7 are mutually exclusive with scheme 8, hence development of scheme 8 will result rejection of scheme 6 and 7.

Normally the choice for decisions are left for client, however being a thesis report scheme 8 having a complex development setup with multiple engineering challenges is recommended for the prefeasibility level assessment.

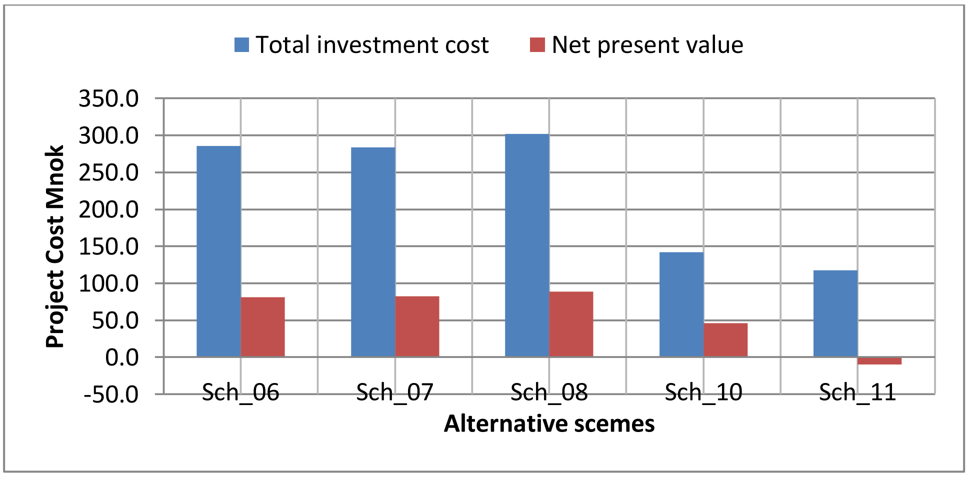

Figure 7 Comparative Displays of Investment Cost and NPV

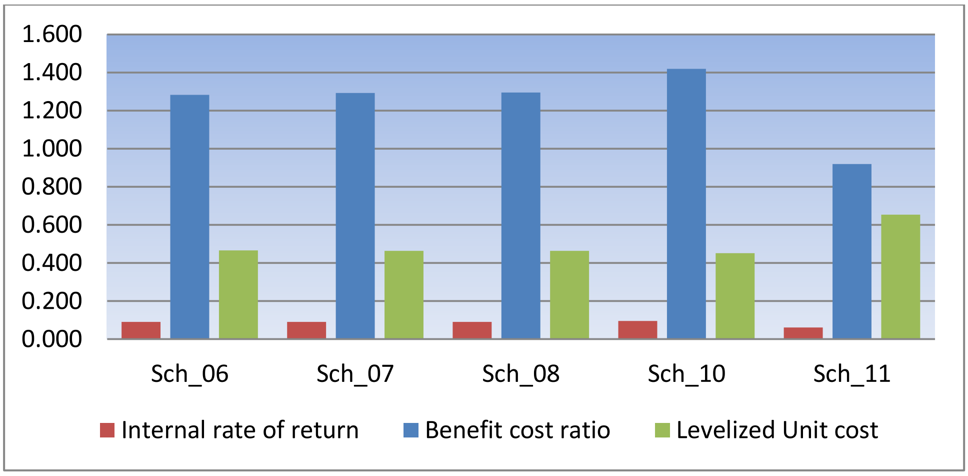

Figure 8 Comparative variations of Economic parameters for each alternative

Recommendation

There are a number of areas with major uncertainties regarding the assessment of the schemes as presented in this report; hence the following pointes should be noted in the next stages of investigation.

- Site specific Hydrological data; since the location of the nearby gauging station is at a lower elevation [200masl] than project catchment [400masl] variation in catchment response is expected. Setting a gauging station will avoid unnecessary uncertainties.
- Geological investigation; detailed geological investigation should be carried out to foresee the impact on the main structural locations
- Undertake detailed optimization of components structures and installations for the better realization of the project
- Prepare detailed cost estimate to the level required including the components that are left in this investigation
- Undertake environmental impact assessment for the recommended project by quantifying the extent of impact on affected areas
- Access road; during the reconnaissance only access road to reservoir dam site and power house is considered hence plan should be set out to cover all the main project components that might need access road
- Transmission; route as well as capacities of transmission lines required should be assessed to the required level
- Preliminary plan should be set out for construction and operation of the recommended project

Annex: Reconnaissance screening of project alternatives

Annex A project Catchment

Annex B project feature summary

Sno.	Project Description	Unit	Scheme 6	Scheme 7	Scheme 8	Scheme 10	Scheme 11
A	**Hydrological details**						
1	Catchment Area	Km2	24.1	24.1	19.5	10.0	25.6
2	Specific Runoff	l/s/km2	130.8	130.8	135.5	143.8	127.1
3	Mean Discharge	m3/s	3.2	3.2	2.6	1.4	3.3
4	Design Discharge	m3/s	6.0	6.0	5.0	2.7	6.2
5	Environmental flow	m3/s	0.2	0.2	0.1	0.1	0.2
B	**Intake pond**						
1	Highest regulated water level (HRWL)	masl	383.0	383.0	484.3	502.0	104.0
2	Lowest regulated water level (LRWL)	masl	381.0	381.0	482.3	498.0	102.0
C	**Headwork and Intake**						
1	Dam Length x Height @B	m x m	50 x 3	50 x 3	50 x 3		
2	Dam Length x Height @A	m x m	20 x 3	20 x 3	20 x 3		
3	Dam Length x Height @C	m x m	100 x 2	100 x 2	100 x 2		15 x 2
4	Dam Length x Height @E	m x m		70 x 6	70 x 6	70 x 6	70 x 6
5	Dam Length x Height @F	m x m			18x3,25 x 7,50x7		40 x 2
D	**Pipe/tunnel drill Diameter**						
1	Pipe Transfer A to B	m	465.0	465.0			
2	Pipe Transfer B to X	m		1200.0			
4	Pipe Transfer smibelg to østre storvatnet	m	1000.0	1000.0	3450.0		1175.0
5	Transfer Tunnel C to B	m		2100.0			
6	Transfer Tunnel C to X	m	1675.0				
7	Transfer Tunnel D to A	m	2530.0	2530.0	2400.0		
8	Transfer Tunnel E to D	m	2444.0	2444.0	2444.0	2444.0	
	Transfer Tunnel C to Y	m			1666.0		
9	Transfer Tunnel B to X	m	945.0		1170.0		
E	**pesntock**						
1	Diamter of penstock	mm				2000.0	2750.0
3	Unline tunnel	mm	2700.0	2700.0	2550.0		
F	**Power House**						
1	Power house type		Undergr PH	Undergr PH	Undergr PH	Surface PH	Surface PH
2	Power house elivation	masl	10.0	10.0	10.0	110.0	10.0
3	Outlet elevation	masl	5.0	5.0	5.0	102.0	5.0
G	**plant Capacity**						
1	Instatalled capacity	Kwh	20685.4	20671.2	22051.4	9914.6	5333.5
2	Gross Head	m	373.0	373.0	474.3	392.0	94.0
3	Head Loss	m	1.5	1.8	1.8	1.6	1.2
4	Net head	m	371.5	371.2	472.5	390.4	92.8
5	Energy Equivalent	KWh/m3	0.9	0.9	1.2	1.0	0.2
H	**Annual Energy production**						
1	Total energy production	Gwh	62.1	62.0	66.2	29.7	16.0
I	**Turbine Type**		2 x Pelton	2 x Pelton	2 x Pelton	2 x Pelton	Francis
J	**Access Road**	Km	7.0	7.0	7.0	5.0	3.0
K	**Economic Analysis**		Scheme 6	Scheme 7	Scheme 8	Scheme 10	Scheme 11
1	Total investment cost	M kr	285.5	283.7	302.0	141.9	117.7
2	Net present value	M kr	81.0	82.6	88.8	46.1	-9.5
3	Internal rate of return	%	0.092	0.092	0.092	0.095	0.063
4	Benefit cost ratio		1.28	1.29	1.29	1.42	0.92
5	Levelized Unit cost	Kr/Kwh	0.47	0.46	0.46	0.45	0.65
6	Development Rate,DR	Kr/kwh/year	2.3	2.3	2.3	2.3	1.5

Annex C project Energy Computations

Energy Calculation

Energy Calculations for reconnaissance level ranking of projects
Energy calculations based on specific runoff figures obtained from NVE
Head loss is assumed to be 1m per 1000m

Parameter	Unit	Scheme 6	Scheme 7	Scheme 8	Scheme 10	Scheme 11
Intake Head, H_i	m	383.00	383.00	484.25	502.00	104.00
Outlet Head, H_o	m	10.00	10.00	10.00	110.00	10.00
Gross Head, H_g	m	373.00	373.00	474.25	392.00	94.00
Specific Runoff, S	$l/s/km^2$	130.85	130.85	135.54	143.81	127.11
Area, A	km^2	24.10	24.10	19.50	10.00	25.60
Pipe length, $Pipe_L$	km	1.51	1.77	1.77	1.57	1.18
Efficiency, ŋ	%	90%	90%	90%	90%	90%
Utilization Factor, Cu	%	68.5 %	68.5 %	68.5 %	68.5 %	68.5 %
Average discharge, qav	m^3/s	3.15	3.15	2.64	1.44	3.25
Mean annual flow, Qan	$M\,m^3$	99.44	99.44	83.35	45.35	102.62
Head loss, Hl	m	1.51	1.77	1.77	1.57	1.18
Net head, Hn	m	371.49	371.24	472.48	390.44	92.83
Turbine capacity, Ptur	KW	20685.45	20671.25	22051.44	9914.56	5333.51
Available power, P	KW	10342.72	10335.62	11025.72	4957.28	2666.76
Energy Equivalent,EEKV	kWh/m^3	0.91	0.91	1.16	0.96	0.23
Energy production, E	GWh/year	62.06	62.02	66.16	29.75	16.00
Penstock Area, A	m2	5.75	5.75	4.97	3.02	5.90
Ø penstock	mm	2706.37	2706.37	2517.42	1961.46	2741.42
Ø pipe	mm	3726.59	3726.59	3411.77	2516.61	3785.54
Ø penstock standard	mm	2700.00	2700.00	2550.00	2000.00	2750.00
Ø pipe standard	mm	3750.00	2700.00	3450.00	2550.00	3800.00
Pipe area, A	m2	6.08	5.16	5.84	5.02	6.12
Penstock time constant, Tw	sec	0.30	0.33	0.16	0.39	0.86
Time for full load gener, Ta	sec	6.00	6.00	6.00	6.00	6.00
Ta/ Tw		19.77	18.13	37.89	15.36	6.97
Surge shaft		Not Required	Not Required	Not Required	Not Required	Not Required

1) Average Discharge

q_{avg}=A*S

2) Average Annual Discharge

Q_{an}=(qavg*Δt)/1000000

3) Pipe head loss

H_l = $Pipe_L$*1m/km

4) Net Head

H_n=H_g-H_l

5) Power Turbine

P_{tur} =9,81*ŋ*qavg*Hn*2

6) Power

P=9,81*ŋ*qavg*Hn

7) Energy Equivalent

EEKV = P/(qavg*3600)

8)Energy Production

E = P*Δt*Cu

8)optimum penstock area

A = 1.27 x Q^0.82

9) penstock time constant

Tw = Q/gH*(sum(L/A))

Annex D Scheme 6 plan, cost estimation and Economic analysis

Reconnaissance cost Estimate Model

Scheme 6

Item No.		Description	Unit	Quantity	Rate (NOK)		NVE Cost Curve
		Selected Scheme Components				Subtotals (NOK)	Cost base 2010
1		Civil works					
	1.1	Dam @A	m	20	39000	780000	FIG 2.2.2
	1.2	Dam @B	m	50	58000	2900000	FIG 2.2.2
	1.3	Dam @C	m	100	22500	2250000	FIG 2.2.2
	1.4	Dam @D	m	30	39000	1170000	FIG 2.2.2
	1.5	Dam @E	m	50	39000	1950000	FIG 2.2.3
	1.6	Intake					
		Brook Intake	LS	1	4000000	4000000	FIG.B.5.3
		lake Tap Intake	LS	3	1125000	3375000	FIG.B.5.3
	1.7	penstock					
		Unlined Tunnel	m	565	57000	32205000	FIG.B.8.1
	1.8	Tunnel Transfer	m	7594	8640	65612160	FIG 2.6.1
	1.9	Access Tunnel	m	500	20000	10000000	FIG.B.4.1
	2	pipe transfer	m	1465	1500	2197500	FIG 3.7.2
	2.1	under ground power station	m3	3607.4094	2250	8116671.182	FIG.B.10.2
	2.2	Access road	LS	7000	1500	10500000	Moderate to Difficult terrain
2		Mechanical Equipment					
	2.1	Turbines pelton 2 jets	KW	20685.449	597.0201626	12349630.03	FIG.B.10.2
	2.2	Trash racks		4	116000	464000	FIG 3.4.1
3		Electro technical equipment's					
	3.1	Generator	LS	1	15000000	15000000	
	3.2	Transformer	LS	1	3000000	3000000	
	3.3	Control system	LS	1	3600000	3600000	
	3.4	switch gear	LS	1	5040000	5040000	
	3.5	Auxiliary systems	LS	1	4200000	4200000	
	3.6	Pump	LS	1	238264.4442	238264.4442	FIG M.2.A
4		Over all project Development contingency					
	4.1	Physical contingency	LS	%	15% Of 1 & 10% of 2 and 3	26123812.68	
		Cost Estimate			Grand Total	215 072 038	

Economic Analysis- Scheme 6

Installed capacity	Mw	20.69	**Energy**	GWh	Tariff	**Price base**	2010			
Capital cost pp	M nok	297.65	Firm Energy	68.27	0.6	Fixed PP O&M	1%	Firm energy	68.27	
Capital cost T&D	M nok	2.98	Secondary Energy	0.00	0.25	Variable PP O&M	0%	Secon.egy		
Total capital cost	M nok	300.62	Total generation	68.27		T&D O&M	2%			
Construction period	yrs	4				Fuel cost nok/kwh	0	Capital cost	M nok	
Project life time	yrs	50	**Sensitivity**			Emission cost nok/kwh	0	Power plant	297.65	
Discount rate	%	7%	Investment	1		Carbon credit nok/kwh	0	T&D	2.98	
Transm and gen loss	%	15%	Firm Energy	1		**Investment**	Yr 1	Yr 2	Yr 3	Yr 4
						Investment profile pp	20%	25%	35%	20%
						Investment profile tran	0%	35%	35%	30%

Cash flows	Costs					Revenue					
year	capital cost power plant	Capital cost tran	Fixed pp O&M	Trans &dist O&M	Total cost	Firm energy	Total revenue	Incremental cash	Load as % of full load	Annual energy	Annual cost
1	59.53	0.00	0.00	0.06	59.59	0.00	0.00	-59.59	100%	0.00	
2	74.41	1.04	0.00	0.00	75.45	0.00	0.00	-75.45	100%	0.00	
3	104.18	1.04	0.00	0.00	105.22	0.00	0.00	-105.22	100%	0.00	
4	59.53	0.89	0.00	0.00	60.42	0.00	0.00	-60.42	200%	0.00	
5			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
6			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
7			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
8			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
9			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
10			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
11			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
28			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
29			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
30			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
31			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
32			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
33			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
34			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
35			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
36			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
37			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
38			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
39			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
40			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
41			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
42			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
43			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
44			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
45			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
46			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
47			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
48			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
49			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
50			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
51			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
52			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
53			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
54			2.98	0.06	3.04	34.82	34.82	31.78	100%	58.03	25.59
		PV COST	**285.54**	**PV of annual energy**	**610.95**		**NPV**	**81.03**	**UNIT COST**	**0.47**	
		PV Benfit	**366.57**	**Development Rate**	**2.27**		**IRR**	**9%**	**B/C**	**1.28**	

Annex E: Scheme 7 plan, cost estimation and Economic analysis

Scheme 7

Item No.		Description	Unit	Quantity	Rate (NOK)		NVE Cost Curve
		Selected Scheme Components				Subtotals (NOK)	Cost base 2010
1		Civil works					
	1.1	Dam @A	m	20	39000	780000	FIG 2.2.2
	1.2	Dam @B	m	50	58000	2900000	FIG 2.2.2
	1.3	Dam @C	m	100	22500	2250000	FIG 2.2.2
	1.4	Dam @D	m	30	39000	1170000	FIG 2.2.2
	1.5	Dam @E	m	50	39000	1950000	FIG 2.2.2
	1.6	Intake					
		Brooke Intake	LS	1	5000000	5000000	FIG.B.5.3
		lake Tap Intake	LS	5	800000	4000000	FIG.B.5.3
	1.7	penstock					
		Unlined Tunnel	m	565	57000	32205000	FIG 3.7.2
	1.7	Tunnel Transfer	m	7074	8640	61119360	FIG 2.6.1
	1.9	Access Tunnel	m	500	20000	10000000	FIG.B.4.1
	1.8	pipe pransfer	m	2665	1500	3997500	FIG 3.7.2
	1.9	under ground power station	m3	3607.4094	2250	8116671.182	FIG 2.4.1
	2	Access road	LS	7000	1500	10500000	Moderate to Difficult terrain
2		Mechanical Equipment					
	2.1	Turbines pelton 2 jets	KW	20671.25	597.0201626	12341152.94	FIG 3.2.1
	2.2	Trash racks		4	116000	464000	FIG 3.4.1
3		Electro technical equipment's					
	3.1	Generator	LS	1	15000000	15000000	FIG.E.1.1 b
	3.2	Transformer	LS	1	3000000	3000000	FIG.E.2.1.2 b
	3.3	Control system	LS	1	3600000	3600000	FIG.E.4.1 b
	3.4	switch gear	LS	1	5040000	5040000	FIG.E.3.3
	3.5	Auxiliary systems	LS	1	4200000	4200000	FIG.E.5.1 b
	3.6	Pump	IS	1	3409504.26	3409504.26	FIG M.2.A
4		Over all project Development contingency					
	4.1	Physical contingency	LS	%	15% Of 1 & 10% of 2 and 3	21598279.68	
		Cost Estimate			Grand Total	212 641 468	

Economic Analysis Scheme 7

Installed capacity	Mw	20.67	**Energy**	GWh	Tariff	**Price base**	2010			
Capital cost pp	M nok	295.70	Firm Energy	68.22	0.6	Fixed PP O&M	1%	Firm energy	68.22	
Capital cost T&D	M nok	2.96	Secondary Energy	0.00	0.25	Variable PP O&M	0%	Secon.egy		
Total capital cost	M nok	298.66	Total generation	68.22		T&D O&M	2%			
Construction period	yrs	4				Fuel cost nok/kwh	0	Capital cost	M nok	
Project life time	yrs	50	**Sensitivity**			Emission cost nok/kwh	0	Power plant	295.70	
Discount rate	%	7%	Investment	1		Carbon credit nok/kwh	0	T&D	2.96	
Transm and gen loss	%	15%	Firm Energy	1		**Investment**	Yr 1	Yr 2	Yr 3	Yr 4
						Investment profile pp	20%	25%	35%	20%
						Investment profile tran	0%	35%	35%	30%

Cash flows	Costs										
year	capital cost power plant	Capital cost tran	Fixed pp O&M	Trans &dist O&M	Total cost	Firm energy	Total revenue	Incremental cash	Load as % of full load	Annual energy	Annual cost
1	59.14	0.00	0.00	0.06	59.20	0.00	0.00	-59.20	100%	0.00	
2	73.93	1.03	0.00	0.00	74.96	0.00	0.00	-74.96	100%	0.00	
3	103.50	1.03	0.00	0.00	104.53	0.00	0.00	-104.53	100%	0.00	
4	59.14	0.89	0.00	0.00	60.03	0.00	0.00	-60.03	200%	0.00	
5			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
6			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
7			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
8			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
9			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
10			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
11			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
28			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
29			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
30			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
31			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
32			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
33			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
34			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
35			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
36			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
37			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
38			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
39			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
40			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
41			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
42			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
43			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
44			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
45			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
46			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
47			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
48			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
49			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
50			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
51			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
52			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
53			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
54			2.96	0.06	3.02	34.79	34.79	31.78	100%	57.99	25.42
		PV COST	**283.68**	**PV of annual energy**	**610.53**	**NPV**	**82.64**	**UNIT COST**	**0.46**		
		PV Benfit	**366.32**	**Development Rate**	**2.28**	**IRR**	**9%**	**B/C**	**1.29**		

Annex F: Scheme 8 plan, cost estimation and Economic analysis

Scheme 8

Item No.		Description	Unit	Quantity	Rate (NOK)		NVE Cost Curve
		Selected Scheme Components				Subtotals (NOK)	Cost base 2010
1		**Civil works**					
	1.1	Dam @A	m	20	39 000.00	780 000.00	FIG 2.2.2
	1.2	Dam @B	m	50	58 000.00	2 900 000.00	FIG 2.2.2
	1.3	Dam @C	m	100	22 500.00	2 250 000.00	FIG 2.2.2
	1.4	Dam @D	m	30	39 000.00	1 170 000.00	FIG 2.2.2
	1.5	Dam @E	m	50	39 000.00	1 950 000.00	FIG 2.2.2
	1.6	Intake					
		Brooke Intake	LS	2	5 000 000.00	10 000 000.00	FIG.B.5.3
		lake Tap Intake	LS	3	800 000.00	2 400 000.00	FIG.B.5.3
	1.7	penstock					
		Unlined Tunnel	m	700	57 000.00	39 900 000.00	FIG 3.7.2
	1.8	Transfer Tunnel	m	7680	8 730.00	67 046 400.00	FIG 2.6.1
	1.9	Access Tunnel	m	500	20 000.00	10 000 000.00	FIG.B.4.1
	2	pipe pransfer	m	3450	1 500.00	5 175 000.00	FIG 3.7.2
	2.1	under ground power station	m3	3595	2 250.00	8 088 391.35	FIG 2.4.1
	2.2	Access road	LS	7000	1 500.00	10 500 000.00	Moderate to Difficult terrain
2		**Mechanical Equipment**					
	2.1	Turbines pelton 2 jets	KW	22051.44	644.22	14 205 882.89	FIG 3.2.1
	2.2	Trash racks		4	116 000.00	464 000.00	FIG 3.4.1
3		**Electro technical equipment's**					
	3.1	Generator	LS	1	15 000 000.00	15 000 000.00	FIG.E.1.1 b
	3.2	Transformer	LS	1	3 000 000.00	3 000 000.00	FIG.E.2.1.2 b
	3.3	Control system	LS	1	3 600 000.00	3 600 000.00	FIG.E.4.1 b
	3.4	switch gear	LS	1	5 040 000.00	5 040 000.00	FIG.E.3.3
	3.5	Auxiliary systems	LS	1	4 200 000.00	4 200 000.00	FIG.E.5.1 b
	3.6	Pump	lS	1	3 409 504.26	3 409 504.26	FIG M.2.A
4		**Over all project Development contingency**					
	4.1	Physical contingency	LS	%	15% Of 1 & 10% of 2 and 3	28 874 956.99	
		Cost Estimate			Grand Total	239 954 135	

Economic Analysis Scheme 8

Installed capacity	Mw	22.05	**Energy**	GWh	Tariff	**Price base**	2010			
Capital cost pp	M nok	314.79	Firm Energy	72.78		Fixed PP O&M	1%	Firm energy	72.78	
Capital cost T&D	M nok	3.15	Secondary Energy	0.00	0.25	Variable PP O&M	0%	Secon.egy		
Total capital cost	M nok	317.93	Total generation	72.78		T&D O&M	2%			
Construction period	yrs	4				Fuel cost nok/kwh	0	Capital cost	M nok	
Project life time	yrs	50	**Sensitivity**			Emission cost nok/kwh	0	Power plant	314.79	
Discount rate	%	7%	Investment	1		Carbon credit nok/kwh	0	T&D	3.15	
Transm and gen loss	%	15%	Firm Energy	1		**Investment**	Yr 1	Yr 2	Yr 3	Yr 4
						Investment profile pp	20%	25%	35%	20%
						Investment profile tran	0%	35%	35%	30%

Cash flows	Costs										
year	capital cost power plant	Capital cost tran &	Fixed pp O&M	Trans &dist O&M	Total cost	Firm energy	Total revenue	Incremental cash	Load as % of full load	Annual energy	Annual cost
1	62.96	0.00	0.00	0.06	63.02	0.00	0.00	-63.02	100%	0.00	
2	78.70	1.10	0.00	0.00	79.80	0.00	0.00	-79.80	100%	0.00	
3	110.17	1.10	0.00	0.00	111.28	0.00	0.00	-111.28	100%	0.00	
4	62.96	0.94	0.00	0.00	63.90	0.00	0.00	-63.90	200%	0.00	
5			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
6			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
7			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
8			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
9			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
10			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
11			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
12			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
13			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
14			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
15			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
16			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
17			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
18			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
30			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
31			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
32			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
33			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
34			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
35			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
36			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
37			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
38			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
39			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
40			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
41			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
42			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
43			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
44			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
45			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
46			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
47			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
48			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
49			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
50			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
51			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
52			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
53			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
54			3.15	0.06	3.21	37.12	37.12	33.91	100%	61.86	27.06
		PV COST	**301.99**	**PV of annual energy**	**651.30**	**NPV**	**88.79**	**UNIT COST**	**0.46**		
		PV Benfit	**390.78**	**Development Rate**	**2.29**	**IRR**	**9%**	**B/C**	**1.29**		

Annex G: Scheme 10 plan, cost estimation and Economic analysis

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Scheme 10

Item No.		Description	Unit	Quantity	Rate (NOK)	Subtotals (NOK)	NVE Cost Curve
		Selected Scheme Components					Cost base 2010
1		**Civil works**					
	1.1	Dam @storåga	m	10	39 000.00	390 000.00	FIG 2.2.2
	1.2	Dam @D	m	30	39 000.00	1 170 000.00	FIG 2.2.2
	1.3	lake Tap Intake	LS	2	1 175 000.00	2 350 000.00	FIG 2.3.1
	1.4	penstock					
		Pipe cost GRP	m	1565	2 200.00	3 443 000.00	FIG 3.7.2
		Trench cost	m	1565	5 800.00	9 077 000.00	Table , 2.5 m at bottom
	1.5	power station	LS	1	4 800 000.00	4 800 000.00	FIG 2.4.1
	1.6	Access road	LS	5000	1 500.00	7 500 000.00	Moderate to Difficult terrain
2		**Mechanical Equipment**					
	2.1	Turbines pelton 2 unit	KW	9914.56	837.45	8 302 911.25	FIG 3.2.1
	2.2	Trash racks		1	100 000.00	100 000.00	FIG 3.4.1
3		**Electro technical equipment's**					
	3.1	Generator	LS	1	9 000 000.00	9 000 000.00	FIG 4.2.1 b
	3.2	Transformer	LS	1	2 000 000.00	2 000 000.00	FIG 4.3.1 b
	3.3	Control system	LS	1	2 200 000.00	2 200 000.00	FIG 4.4.1
	3.4	switch gear	LS	1	5 750 000.00	5 750 000.00	FIG 4.5.1
4		**Over all project Management**					
	4.1	Physical contingency	LS	%	15% Of 1 & 10% of 2 and 3	7 044 791.13	
		Cost Estimate			Grand Total	63 127 702.38	

Economic Analysis Scheme 10

Installed capacity	Mw	9.91	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	141.23	Firm Energy	32.72	0.6	Fixed PP O&M	1%	Firm energy	32.72
Capital cost T&D	M nok	1.41	Secondary Energy	0.00	0.25	Variable PP O&M	0%	Secon.egy	
Total capital cost	M nok	142.65	Total generation	32.72		T&D O&M	2%		
Construction period	yrs	3				Fuel cost nok/kwh	0	Capital cost	M nok
Project life time	yrs	50	**Sensitivity**			Emission cost nok/kwh	0	Power plant	141.23
Discount rate	%	7%	Investment	1		Carbon credit nok/kwh	0	T&D	1.41
Transm and gen loss	%	15%	Firm Energy	1		**Investment**	Yr 1	Yr 2	Yr 3
						Investment profile pp	40%	30%	30%
						Investment profile tran	30%	35%	35%

Cash fl	Costs										
year	capital cost power plant	Capital cost tran	Fixed pp O&M	Trans &dist O&M	Total cost	Firm energy	Total revenue	Incremen tal cash	Load as % of full load	Annual energy	Annual cost
1	56.49	0.42	0.00	0.00	56.92	0.00	0.00	-56.92	100%	0.00	
2	42.37	0.49	0.00	0.00	42.86	0.00	0.00	-42.86	100%	0.00	
3	42.37	0.49	0.00	0.00	42.86	0.00	0.00	-42.86	100%	0.00	
4			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
5			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
6			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
7			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
8			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
9			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
10			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
11			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
12			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
13			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
14			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
15			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
16			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
17			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
18			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
31			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
32			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
33			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
34			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
35			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
36			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
37			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
38			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
39			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
40			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
41			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
42			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
43			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
44			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
45			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
46			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
47			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
48			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
49			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
50			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
51			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
52			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
53			1.41	0.03	1.44	16.69	16.69	15.25	100%	27.81	12.14
		PV COST	**141.85**	**PV of annual energy**	**313.33**	**NPV**	**46.15**	**UNIT COST**	**0.45**		
		PV Benfit	**201.16**	**Development Rate**	**2.29**	**IRR**	**10%**	**B/C**	**1.42**		

Annex H: Scheme 11 plan, cost estimation and Economic analysis

Scheme 11

Scheme 11

Item No.		Description	Unit	Quantity	Rate (NOK)	Subtotals (NOK)	NVE Cost Curve
		Selected Scheme Components					Cost base 2010
1		**Civil works**					
	1.1	Dam @vassvatnet	m	60	39 000.00	2 340 000.00	FIG 2.2.2
	1.2	Brook intake	m	2	4 000 000.00	8 000 000.00	FIG.B.5.3
	1.3	lake Tap Intake	LS	1	1 175 000.00	1 175 000.00	FIG 2.3.1
	1.4	penstock					
		Pipe cost GRP	m	700	1 900.00	1 330 000.00	FIG 3.7.2
		Trench cost	m	700	5 800.00	4 060 000.00	Table , 2.5 m at bottom
	1.5	Pipe transfer	m	1175	1 500.00	1 762 500.00	
	1.6	power station	LS	1	6 000 000.00	6 000 000.00	FIG 2.4.1
	1.7	Access road	LS	3000	1 500.00	4 500 000.00	Moderate to Difficult terrain
2		**Mechanical Equipment**					
	2.1	Turbines Francis 2 unit	KW	5333.51	1 602.73	8 548 200.82	FIG 3.2.1
	2.2	Trash racks		1	100 000.00	100 000.00	FIG 3.4.1
3		**Electro technical equipment's**					
	3.1	Generator	LS	1	3 500 000.00	3 500 000.00	FIG 4.2.1 b
	3.2	Transformer	LS	1	750 000.00	750 000.00	FIG 4.3.1 b
	3.3	Control system	LS	1	1 950 000.00	1 950 000.00	FIG 4.4.1
	3.4	switch gear	LS	1	2 700 000.00	2 700 000.00	FIG 4.5.1
4		**Over all project Management**					
	4.1	Physical contingency	LS	%	15% Of 1 & 10% of 2 and 3	6 129 945.08	
		Cost Estimate			Grand Total	52 845 645.91	

Economic Analysis Economic Analysis Scheme 11

Installed capacity	Mw	5.33	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	112.97	Firm Energy	17.60	0.6	Fixed PP O&M	1%	Firm energy	17.60
Capital cost T&D	M nok	1.13	Secondary Energy	0.00	0.25	Variable PP O&M	0%	Secon.egy	
Total capital cost	M nok	114.10	Total generation	17.60		T&D O&M	2%		
Construction period	yrs	2				Fuel cost nok/kwh	0	Capital cost	M nok
Project life time	yrs	50	**Sensitivity**			Emission cost nok/kwh	0	Power plant	112.97
Discount rate	%	7%	Investment	1		Carbon credit nok/kwh	0	T&D	1.13
Transm and gen loss	%	15%	Firm Energy	1		**Investment**	Yr 1	Yr 2	
						Investment profile pp	60%	40%	
						Investment profile tran	50%	50%	

Cash flows	Costs										
year	capital cost power plant	Capital cost tran	Fixed pp O&M	Trans &dist O&M	Total cost	Firm energy	Total revenue	Incremental cash	Load as % of full load	Annual energy	Annual cost
1	67.78	0.56	0.00	0.00	68.35	0.00	0.00	-68.35	100%	0.00	
2	45.19	0.56	0.00	0.00	45.75	0.00	0.00	-45.75	100%	0.00	
3			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
4			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
5			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
6			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
7			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
8			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
9			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
10			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
11			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
12			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
13			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
14			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
15			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
16			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
17			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
18			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
34			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
35			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
36			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
37			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
38			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
39			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
40			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
41			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
42			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
43			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
44			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
45			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
46			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
47			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
48			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
49			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
50			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
51			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
52			1.13	0.02	1.15	8.98	8.98	7.82	100%	14.96	9.71
		PV COST	**117.73**	**PV of annual energy**	**180.35**	**NPV**	-9.52	**UNIT COS**	**0.65**		
		PV Benfit	**108.21**	**Development Rate**	**1.54**	**IRR**	6%	**B/C**	**0.92**		

Volume II Main Report

1 INTRODUCTION

Following the completion of reconnaissance study scheme 8 have been taken forward for prefeasibility study as being worthy for refined analysis.

This volume of thesis report will detail the prefeasibility assessment of the recommended alternative from volume I of the previous report. Hence this study is carried out with the main aim to establish the need and justification of the project; formulate tentative plan for development; determine the technical, economic and environmental practicability of the project and finally define the limits and make recommendation for full actions required.

The report will also set preliminary construction operation techniques and environmental impact assessment of the project. In addition to that this report will try to identify and solve the main challenges to be faced during construction as well as operation of Smibelg hydro power project. The report will finally concludes by making list of recommended actions required for the next feasibility level of study.

1.1 Scope of The study

This section of the report will envisage the economic assessment and optimization of the project component structures to assure a safe and reliable development solution. The following lists of design and optimization processes are covered as the main objective for this section of the report:

- Detailed hydrological analysis
- Detailed optimization analysis
- Design of major component structures
- Preliminary social and environmental impact assessment
- Investigate challenges of developing the project
- Make recommendation for feasibility study

1.2 Methodology

The preliminary methodologies adopted for volume I of the project are taken forward with more refined assessment in addition to that methods for hydrological analysis, design and dimensioning of component structures will be detailed in this section of the report.

1.3 Available Data

Most of the data sources are detailed in Volume I of this thesis report; however additional data are collected for hydrological analysis from NVE hydra II payment service. Summary of data used for this study are:

1.3.1 Data used for Volume I

Topographic map from Norgeskart, Geological information from ngu.no and hydrological data from nve.no are used during the reconnaissance assessment.

1.3.2 Sediment data

From the available geological and land use maps the catchment area of interest is covered with bare rock. There is no potential land slide and correspondingly erosion from the Smibelg catchment. Hence based on bedrock geology and mountainous topography with no soil cover it has been assumed that the amount of sediment is little to influence the construction and operation of the power plant.

1.3.3 Water quality and aquatic life

The information on water quality and aquatic life are important for evaluating the effect of the new power plant development on the environment. Disturbance in natural hydrological regime will always have impact on ecosystem; however most of the project components are located in the frozen ice for almost 65% of the year which makes its influence insignificant.

Minor disturbance on water quality shall be expected during construction period from explosive residues.

1.3.4 Seismicity

There is a strong seismic activity in the specific project catchment with magnitude ranging 3 to 5 in a Richter scale. Considering the time and resources available detailed seismic investigation studies are posted for feasibility study.

1.4 Power market

The electricity supply system in Norway consists of interconnected system ICS and small self-contained isolated systems running out of the grid. Currently there are five Elspot areas in Norway having unique electricity price based on region, where the price of electricity varies with supply and demand along with extent of precipitation, weather condition and power export capacity.

The current situation in Nordic power market is largely dependent on the following major factors:

- Existence of free market Nord pool
- A strong dependence on hydropower
- A higher level of consumption than production
- A strong public opinion against development of hydropower

Since liberalization of electricity in 1991 the country has become one of pioneer in free market energy distribution just like other commodities. A common energy market has been created with Sweden for multinational exchange of power which later created Nord pool spot price exchange for efficient power trading including Baltic and Nordic countries (Nord pool Spot, 2002).

The Nordic Power Exchange is divided into two entirely separate exchanges. One exchange “Elspot” deals with the physical spot market. The other “Eltermin” is a financial market which allows for hedging or speculation. Finally, “Over-the-counter” (OTC) markets are also provided by Nord Pool where both physical and financial contracts are traded. As of January 2002, the Elspot market is operated by Nord Pool Spot AS (Aarhus, 2004).

Hence in such a deregulated market system which includes power sources from hydro, nuclear, solar and winds it is easier to conclude that any additional development will face a power price competition with the existing power system which will challenge project feasibility for development.

1.4.1 Electricity price

The future price in electricity is generally difficult to predict hence trends in power sale from statistics are used to see the average price for household, commercials, grid rent and taxes to determine the net average power sale cost to end users.

As per statistics result obtained from statistic Norway the overall average price of electricity for households, including grid rent and taxes, amounted to 88.3 øre per kWh in 2013. This is 9 per cent higher compared to the year before. The grid rent and taxes came to 26.4 and 27.1 øre per kWh respectively.

Households tied to spot price contracts paid 34 øre per kWh on average, excluding grid rent and taxes, in 2013, while the price of variable price contracts amounted to 36.4 øre per kWh. New fixed-price contracts lasting one year or less and fixed-price contracts lasting one year or more totalled 35.1 and 35.9 øre per kWh respectively. Other fixed-price contracts amounted to 36.1 øre per kWh.

The average price of electricity in the service industry in 2013 was 33.6 øre per kWh, excluding taxes and grid rent. This is 18 per cent higher than the average price in 2012.In manufacturing excl. energy-intensive manufacturing the average price amounted to 32.4 øre per kWh. This is 17 per cent higher compared to 2012. For energy-intensive manufacturing, the average price of electricity was 28.9 øre per kWh in 2013, excluding taxes and grid rent. This is 9 per cent higher compared to 2012 (Statstics Norway, 2014).

Based on the fact that the end users are paying a higher cost per KWh in each year the price of selling electricity for this study is taken as 60 øre per KWh. However unit costs obtained at the end of the analysis results a lower unit cost of development than the assumed initial constant unit price.

1.4.2 Green Certificate Norway

Recently Norway has adopted green certificate scheme in order to increase utilization of renewable energy. In this scheme end users will be the source that will finance project investment cost through purchase of certificate. Being a new development three basic merits can be fetched from Smibelg hydropower plant. These are:

- Creates a direct link between electricity consumption and reduction of climate change
- It creates favourable condition for international renewable market
- It will give signal as to the price of renewable energy development in the region

Hence it is expected to benefit from green certificate scheme upon development. Hence in the final design the benefit from green certificate scheme shall be thoroughly analysed.

2 HYDROLOGY, FLOODS AND SEDIMENTS

2.1 Introduction

Hydrological inputs play a vital role in planning, execution and operation of any water resource projects. Hydrological studies are carried out at all stages of development to assess the quantity of available water and its distribution in time, estimate the design flood and diversion flood required for hydraulic design of spillways and assess impact of sedimentation on the live storage capacity of the reservoir.

The main objective of the hydrological study was to reassess climatological and hydrological characteristics of the region and produce set of hydrological design parameters for Smibelg hydro power project. The area covered by the hydrological study includes three river basins Sørfjordelva, Kystfelt and Kjerringåga.

Adopted conventions:

The following convention has been adopted for the present study:

- The hydrological year runs from 1st of September of the following calendar year
- The winter season is defined from November to April
- The summer season is defined from May to September

Scope of Hydrological Investigation

Primary emphasis has been given for current study on:

- Quality assessment and compilation of primary hydrologic data i.e. water level records and discharge measurements of the key river gauging station at Vassvatnet.
- Computation of hydrologic design variables
- Verification and validation of use for measurement data
- Assessment of design flood estimates
- Refinement of project site inflow series

2.2 Basin characteristics

Main rivers storåga, svartåga, tverråga vassvikelva and mannåg forms part of the river basin included for study and are located northwest of Mo I Rana. The whole part of the catchment lies within the Snowbelt accompanied by bare mountain tops and as such most of the discharge contribution comes from snowmelt.

2.2.1 The Catchment

The catchment area of Smibelg hydropower project up to the proposed intake site is 25.1 km^2. A plan layout of project site is shown in Figure 1. The project is highly mountainous terrain and is marked by a highly dissected topography having precipitous hills and steep mountainous sides. There are two major tributaries to the main river vassvikelva in the project catchment. In total four river basins are used to realize the complete picture of the project.

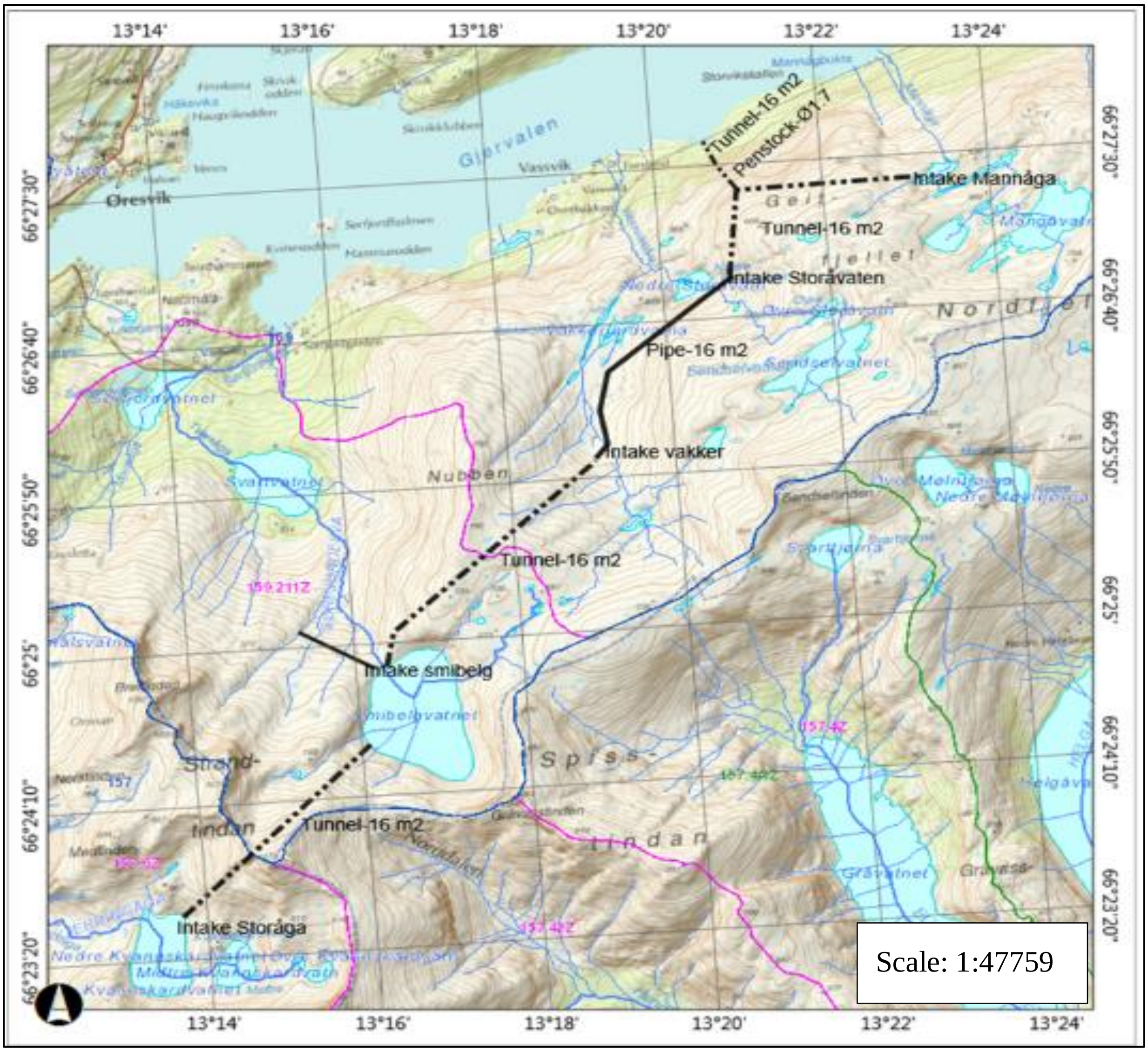

Figure 9 Project Layout plan Source: Gislink.no

2.2.2 Hypsometric details

The catchment area detail with elevation has been worked out for gauging site and the project catchment. The details of the catchment area Vs elevation is shown below,

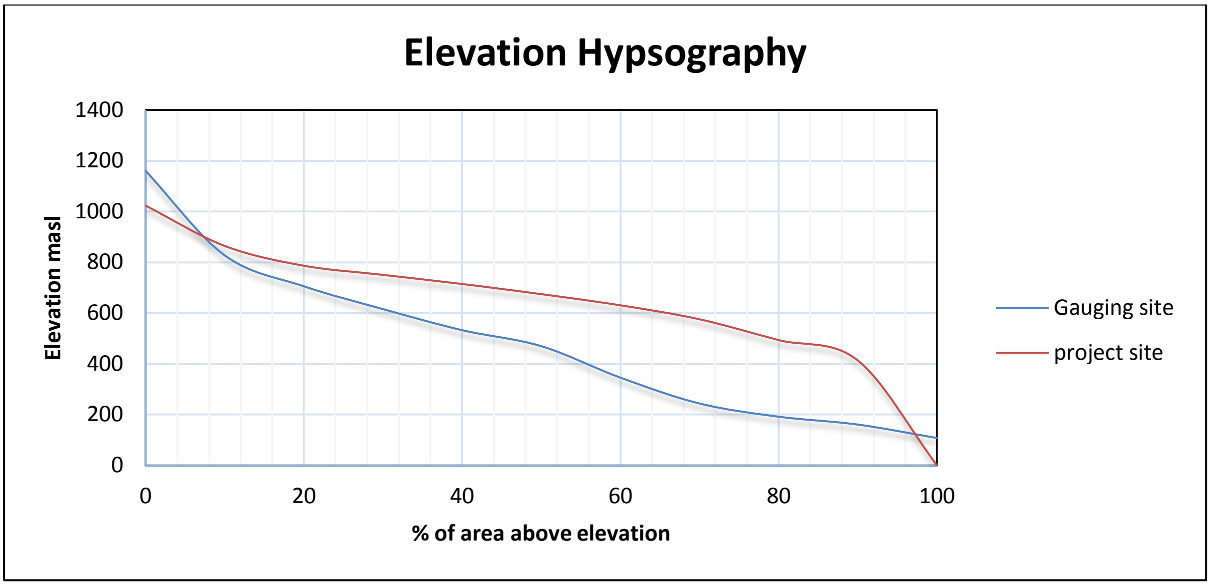

Figure 10 Hypsographic curve of Vassvatnet and Project site

It is easy to see that there is a variation in elevation distribution between the project site and gauging station. Hence inflow pattern at the project site will have a slower response time than the gauging site.

2.2.3 Climate

The region is characterized by costal climate where the variation in temperature is minimal as compared to inland regions. Coastal climate usually has evenly spread precipitation along the year, cool but not cold winters and partly warm summers.

The included statistics is from closest station located at lurøy municipality, 20 km from Smibelgvatnet. The variation in temperature as per (NRK, 2014) ranges -7.2 to 25^{0}C in January and May respectively. Monthly variation is shown in Table 13 below,

Table 13 Temperature and wind variation, Project Catchment Source

Months	Temperature				Wind	
	Average	Normal	Warmest	Coldest	Average	Strongest wind
Mar 2014	3.0°C		8.9°C Mar 28	-5.1°C Mar 20	8.0 m/s	21.6 m/s Mar 14
Feb 2014	3.7°C		8.3°C Feb 24	-4.5°C Feb 1	8.8 m/s	18.6 m/s Feb 2
Jan 2014	-0.6°C		8.4°C Jan 6	-7.2°C Jan 11	10.4 m/s	22.6 m/s Jan 28
Dec 2013	3.4°C		8.8°C Dec 11	-3.6°C Dec 8	8.7 m/s	24.8 m/s Dec 12
Nov 2013	4.1°C		9.6°C Nov 16	-2.5°C Nov 23	8.4 m/s	24.5 m/s Nov 17
Oct 2013	7.4°C		14.0°C Oct 3	0.6°C Oct 18	6.8 m/s	17.7 m/s Oct 19
Sep 2013	11.9°C		23.2°C Sep 9	5.8°C Sep 26	4.9 m/s	17.8 m/s Sep 16
Aug 2013	13.6°C		24.9°C Aug 4	9.0°C Aug 21	5.7 m/s	13.4 m/s Aug 28
Jul 2013	12.8°C		24.8°C Jul 1	7.5°C Jul 16	5.4 m/s	15.5 m/s Jul 7
Jun 2013	12.2°C		25.3°C Jun 1	7.6°C Jun 11	4.9 m/s	16.4 m/s Jun 3
May 2013	10.2°C		25.5°C May 30	0.3°C May 4	6.4 m/s	15.2 m/s May 3
Apr 2013	3.3°C		10.9°C Apr 29	-3.3°C Apr 5	6.2 m/s	15.3 m/s Apr 2

2.3 Water availability studies

2.3.1 Hydrological data

The hydrology department of the NVE is responsible for operation and measurement of river flow data in Norway. There are no gauging stations in Vassvikelva and hence selection of nearby gauging station has been undertaken. Existence of regulation, catchment size, terrain composition and specific runoff similarity of the gauging station has been evaluated between project catchment and nearby gauging stations. Station at Vassvatnet was found to be attractive as compared to other gauging stations.

Flow data from nearby gauging station at Vassvetnet from 01.09.1916 to 31.12.2013 and water level measurement at the project site from 01.01.2013 to 31.12.2014 are taken as a primary data for analysis.

2.3.2 Data quality verification

Mass curve representing the accumulated values of hydrological measurement data like discharge or rainfall against time is important tool in identifying any unexplained trends in the variable. In the present study, such mass curve has been prepared for Vassvatnet inflow measurement station. The result of the analysis confirms lack of inconsistency in the data series hence it is adopted for analysis.

Having cheeked the consistency of the gauging station the inflow series are scaled to the project site using scaling criteria.

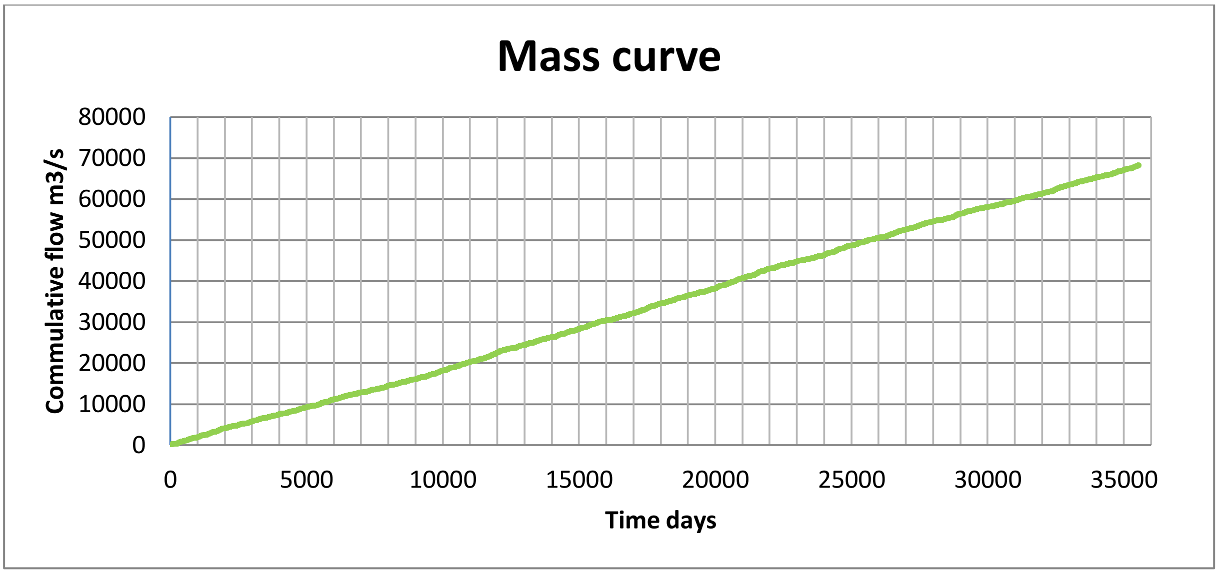

Figure 11 Mass curve for gauging station at Vassvatnet

2.3.3 Scaling of Inflow

Typically a scaling factor close to 1.0 is desired with regard to the comparison of a gauged catchment to an ungauged catchment. As this number becomes further from 1.0 the likelihood of the response to precipitation events between the gauged and ungauged catchments decreases.

Station Vassvatnet, which is located at coordinates ($66^0$43`49`` Latitude: $13^0$10`33`` Longitude) with no known regulation either from existing hydropower schemes or from other water abstractions is used. It is located immediately adjacent to the catchment of interest and has an area of 16.4 km^2. This compares to the project catchment of 22.8 km^2. The following points are made regarding its implementation within the analysis.

- The flow at the project site may have smaller peaks than experienced in the gauged catchment. This is due to:
  - Larger size of the project catchment and its capacity to buffer the flood flows
  - Almost all sub catchments making the project catchment are aligned horizontal
  - It has 90% elevation hypsography at a higher elevation than gauging site
- Data from Station vassvatnet for 97 yrs. period has been utilised in the analysis. This is a complete data series with no missing or erroneous values.

Average scaling factor of 0.225 was obtained between the gauging station and the sub catchments of the main project catchment. Hence, combing the total inflow from each sub catchment a scaling factor of 1.31 times the inflow at Vassvatnet will pass to the power plant. Gauging analysis results are enlisted in annex H-01.

2.3.4 Flow distribution

The flow values during the year vary markedly both in terms of average, maximum and minimum flows. It is noted that there will be exceptions to this data and the analysis undertaken only aims to provide an overview of the likely distribution of the flow pattern.

Sample analysis results showing distribution of average, median, minimum and percentage of flow under1.5, 1.75 and 2 m3/s over the year are shown in figure 12. Seeing the result it is easier to conclude that flow distribution over the year will have an immense impact on production pattern. However some percent of this unregulated variation over the year will be supplemented by regulation of inflow at Storåga- Smibelg reservoir.

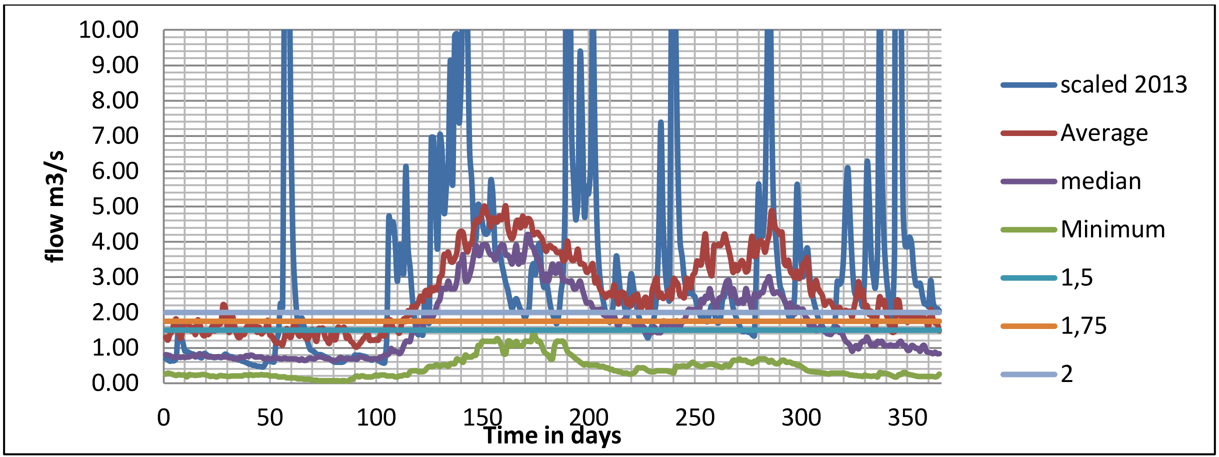

Figure 12 flow distribution in terms of Indicative parameters

An analysis of the flow pattern during the year has also been undertaken based on daily data. This is displayed in Figure 13. The analysis has been undertaken on 9 individual years, spaced 10 years apart, and is assumed to be representative of the flow patterns in the catchment. It can be seen that the flow throughout the year consists of spikes of high and low flows and there is no consistent pattern which suggest a period of extended low flow which could be used to undertake in-river constructions. It is noted that the period of low flows, February – March, coincide with winter and the worst conditions for construction during the year with regard to access and productivity.

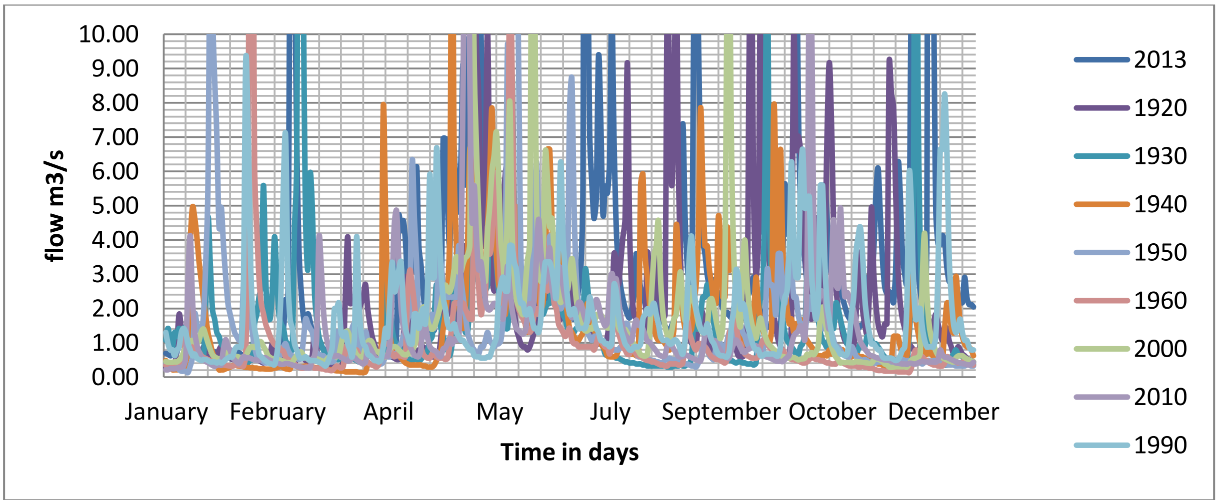

Figure 13 flow distribution over the year

2.3.5 Flow Duration Analysis

Having prepared the long-term daily average flow series for Smibelg hydro power plant the flow duration curve has been prepared after deducting the minimum environmental flow. The minimum environmental flow magnitude taken above is computed using 95% available flow for summer and winter independently.

The inflow contribution from the reservoir system is accounted after computing the probable reservoir outflow to the power plant using nMag2004 model detailed in reservoir operation planning. The probable outflow from the reservoir is computed by assuming a reservoir scheme from Smibelg-Storåga reservoir directly delivering to a single power plant. In the Figure 14 below final flow duration curve for the project is presented. The total inflow is taken as regulated outflow from the reservoir plus intra-basin inflows.

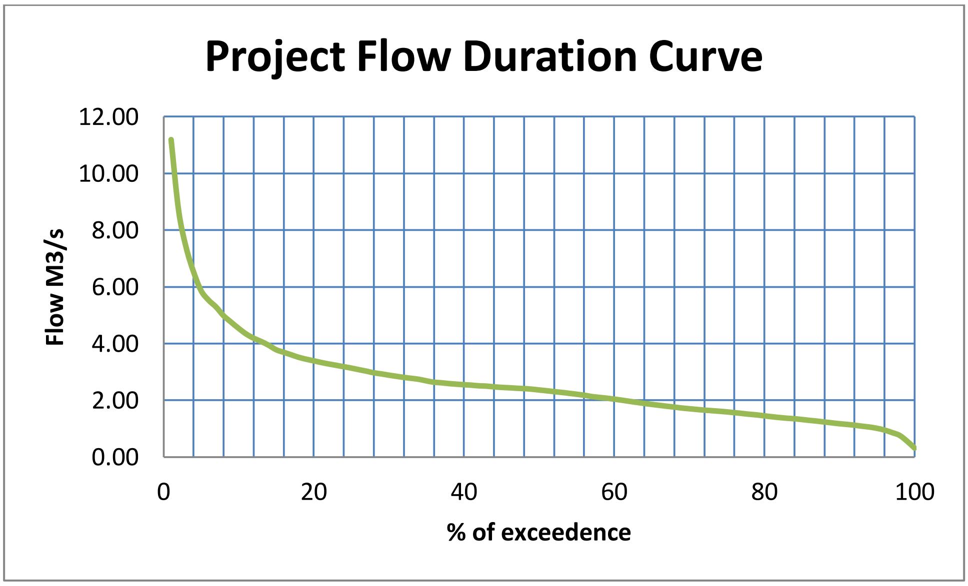

Figure 14 Flow duration curve project catchment FDC

From the FDC curve above, there is a high variability in the flow with a maximum and minimum flow magnitude of 15 and 0.3m^3/s respectively. The mean is computed as 2.63m^3/s. The production output is amplified from a high head and storage capacity from Smibelg-Storåga reservoir.

2.4 Flood Analysis

Estimation of design flood is a significant component of hydrological studies. Proper selection of design flood is important as an over-estimated value results cost increase while under-estimation will place a risk to the structure sustainability.

To determine the magnitude of this event a flood frequency analysis was undertaken on both the summer and winter annual maxima series. Prior to the frequency analysis being undertaken, the flood flows were not modified to accommodate instantaneous readings. The readings taken were daily readings, rather than instantaneous readings, and likely to underestimate the actual maximum flood. An EV1, or Gumbel probability distribution was found to be the best fit to the annual maximum series data.

Selection of floods in the current Norwegian Dam safety regulation, classification reflects the impact of possible failure on human life, property and environment.

Table 14 Dam failure Consequence Criteria

Class No.	Consequence	Consequence criteria
0	Minor	0 houses and minor consequence to the society
1	Small	0 houses, but other buildings and infrastructure affected
2	Medium	1-20 houses, or major infrastructure affected
3	High	21-150 houses, major damage to infrastructure
4	Very high	>150 houses

Table 15 Recommended design flood based on Dam Failure Consequence

Description	Design flood	Safety check flood
High	Q1000	PMF
Significant/medium	Q1000	PMF or 1.5x Q1000
Low	Q500	-

The results of flood frequency analysis are set out in the following table. Detail analysis result is documented at annex H-02.

Table 16 Design Flood computation

Description	Storåga	Øsre storåvatnet	Mannåga	Østre vakker
Consequence class	Class 2	Class 1	Class 1	Class 1
Design flood	Q1000	Q500	Q500	Q500
Dam safety cheek flood	1.5*Q1000	Q500	Q500	Q500
Mean m3/s	6.18	3.17	4.99	4.39
St. Deviation m3/s	2.26	1.16	1.82	1.61
N years	1000	500	500	500
Gumbel Coefficient K	4.94	4.39	4.39	4.39
Design flood m3/s	17.31	8.25	13.00	11.45

3 GEOLOGY, GROUND CONDITION AND CONSTRUCTION MATERIAL

3.1 Introduction

All analysis carried out for these sections of the report are based on desk study of available materials. In general this section of the report will address important geotechnical issues that should be checked out during field visit, testing and valuation of geological data. In addition proposed excavation techniques are stated. A critical analysis on sufficiency and quality shall be stressed during final design and development.

3.2 Field Investigation

Geological mapping of the area through a rigorous testing of the ground condition shall be undertaken. The test shall cover main ground conditions of the dam site, intake weirs, power house, tunnel and intakes at the planned locations. Tasks that are commonly used for undertaking geological investigation are:

- Aerial photo interpretation along with seismic investigation results
- Core drilling
- In-situ permeability tests
- Laboratory rock quality analysis on core samples

The geotechnical parameter test results should be evaluated to forecast the probable ground conditions. Conditions of major importance are stated below;

In regard to dam foundations, conditions of importance are the thickness and character of soil overburden, topography and character of bedrock, occurrence of potential leakage channels like high-permeability weakness zones and necessary excavation depth for the foundation. Another consideration is to define the effect of leakage zones, and conclude on potential remedial measures. In addition availability of construction materials shall be assessed.

For tunnels, considerations of importance are suitable location of tunnel portals, sufficient rock cover along the tunnel, tunnelling properties, stability conditions and permeability conditions. Tunnelling properties required are:

- Strength and strength anisotropy of the rock mass
- Content and form of abrasive materials

- Frequency orientation and characteristics of discontinuities
- Stress Evaluation

For power house, conditions of importance are sufficient rock cover, orientation of the cavern, size of the cavern, stability of the cavern, permeability of the cavern and cavern -tunnel system combination.

3.3 Construction Material

The granite muck material from excavation of tunnel is considered as a suitable ingredient for aggregate. Materials of sand and gravel should be prepared on site by Crushing of aggregates. Nearby sand and moraine sites should be assessed and transported to the project site.

Proposed main dam for this project comprises concrete as well as moraine core rock fill section at storåga. Aggregate results of approximately 2.5 Km tunnel on the head race section will suffice the volume of rock fill as well as the concrete section of the dam. Partly boulder requirement shall be replaced by cutting nearby quarry excavation.

3.4 Methods of Excavation

From the technical point of view of site geology, for granite it is possible to use traditional drill and blast or Full face tunnel boring Machine (TBM). However among other criteria's considering the length of tunnel as a comparison item, traditional drill and blast excavation methodology is proposed.

For shafts and inclined penstock tunnel the following list of alternative excavation mechanisms has been evaluated. Selection depends on factors like shape, length, contractor's preference etc. These are:

- Raise climber (ALIMAK)
- Reaming from a pilot hole(RBM)
- Shaft sinking by drill and blast

For this project reaming from a pilot hole by use of raise boring machine is proposed for all shafts.

Any rock fall in power station caverns and in transformer caverns is unacceptable, due to risk for personal injuries and for technical damage. Normally both the cavern roof and walls above the machine hall floor are supported by a combination of sprayed concrete and systematic rock bolting.

Excavation shall be done in stages and that rock support in the walls of previous stage has to be done before excavation of the stage below. This is important in view of access possibilities. Another aspect is that the amount of rock support installed has to be sufficient to take care of any potential change in stability condition encountered in the bench below. As a conclusion rock support quantities in the roof and walls of power station cavern should be conservative.

3.5 Limitations

Unfortunately for this project, there were no field visit in addition detailed geotechnical data for analysis were not available , as a result some items of reference that should be considered are not covered. Hence planning of the component structure is undertaken assuming a good quality rock all over the alignment of the main structures.

4 PROJECT DESCRIPTION

As discussed in previous sections, the project is being developed as a semi reservoir scheme having a reservoir with supplying intra-basin catchments. The system feeds water through a system of pipes and tunnels to underground power house. Installed capacity of the project is envisaged as 22 MW. The present chapter describes the layout optimization and design features of various civil engineering structures for realization of the project.

4.1 Scheme Optimization and Design

An initial optimisation was carried out to determine the arrangement and basic sizing of major scheme components prior to a detailed hydraulic and energy analysis. The stages in which the optimisation was undertaken are listed below, along with the key outputs from each stage. As each stage was completed the results of that stage were compared against the input parameters from the earlier optimisation stages and an iterative approach taken to ensure that the overall optimum scheme was determined from the process.

The following section outlines the key processes, assumptions and outcomes of each optimisation steps and following contemporary design.

4.2 Reservoir features

Preliminary analysis has been done in the first Volume of this report to foresee the benefits that can be gained by adding each Lake to the system independently and concluded to incorporate them in to the final design in order to maximize production.

The natural arrangement and location of the lakes with respect to power house dictates utilization of existing lakes Smibelg and Storåga as a combined or independent reservoir. Capacity inflow ratio for full diversion of average annual inflow to power plant were assessed independently and found to be 19% for both reservoirs. Combining them together a capacity inflow ratio of 43% was found for full utilization. In addition it was observed that both alternatives will require the same dam height at storåga. In the combined system of reservoir cost of dam at Smibelg is reduced. The following reservoir data has been gathered for combined system using 1:50,000 scale map and is shown in Figure 15.

To select the type of reservoir two alternative mechanisms have been proposed to select inflow transport mechanisms from Storåga [498 masl] to Smibelg [506 masl]. These are;

- Pump [storåga to smibelg]
- Conductor tunnel [storåga to smibelg] with two alternatives

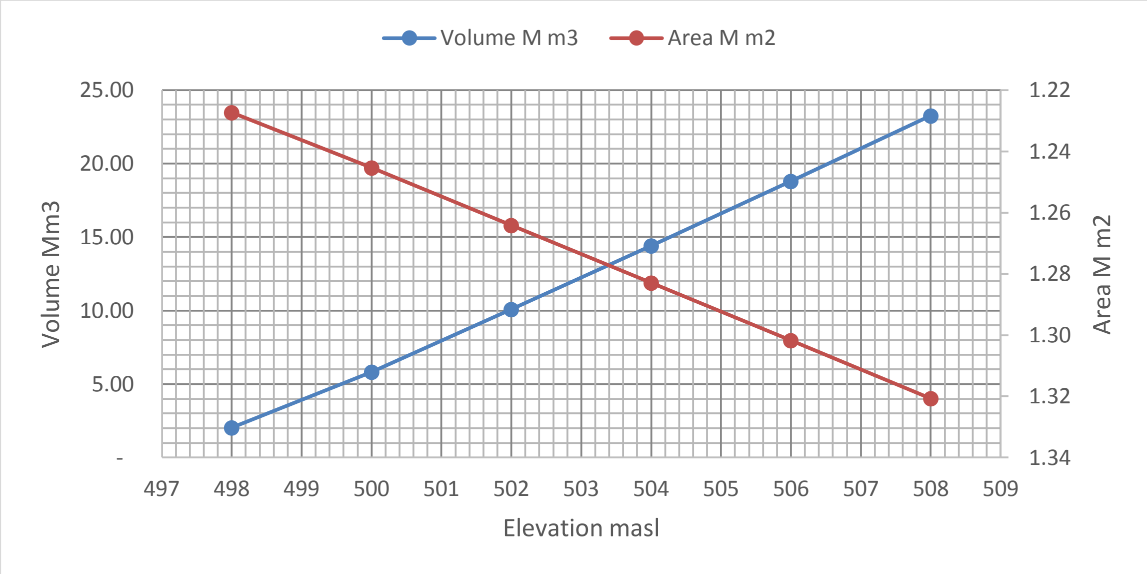

Figure 15 Reservoir Capacity, Area vs Elevation Relationships: Combined Reservoir

Pump

The natural arrangement of the two lakes dictates unnatural to directly tap water from a lower elevation to higher elevation. Hence pumping of water from storåga to Smibelg has been proposed as a single alternative solution to utilize the net annual inflow from storåga. Trial pump-tunnel alternative with different pumping head and dam height at storåga has been proposed to select the best alternative of pumping water from storåga.

After defining the alternatives hydraulic design followed by economic analysis on running cost of pump and tunnel has been undertaken. Alternative with a pump head of 4 m delivering inflow to nearby tunnel was selected. This will reduce the cost of underwater piercing and access problem at the inlet of the tunnel.

The real cost elements taken forward for comparison of pump and no pump alternative were access, underwater piercing, pump, dam at storåga and cost of dewatering Lake storåga. Comparing the result with no pump alternative, pump alternative was rejected.

Conductor Tunnel

For no pump alternative two ways of transporting the flow through tunnel as shown in Figure 16 has been proposed,

- Alt-01: Independent tunnel system having two reservoir

- Alt-02: Combined tunnel system having a single reservoir

The cost of tunnel, underwater piercing, dam and access were the dominant cost elements taken forward to compare the above mentioned alternatives while keeping other project cost elements constant. Cost comparison of alternatives resulted selection of combined reservoir system connected with a short conductor tunnel. For final plan a combined reservoir system serving as a single reservoir connected through tunnel has been proposed as the optimum solution.

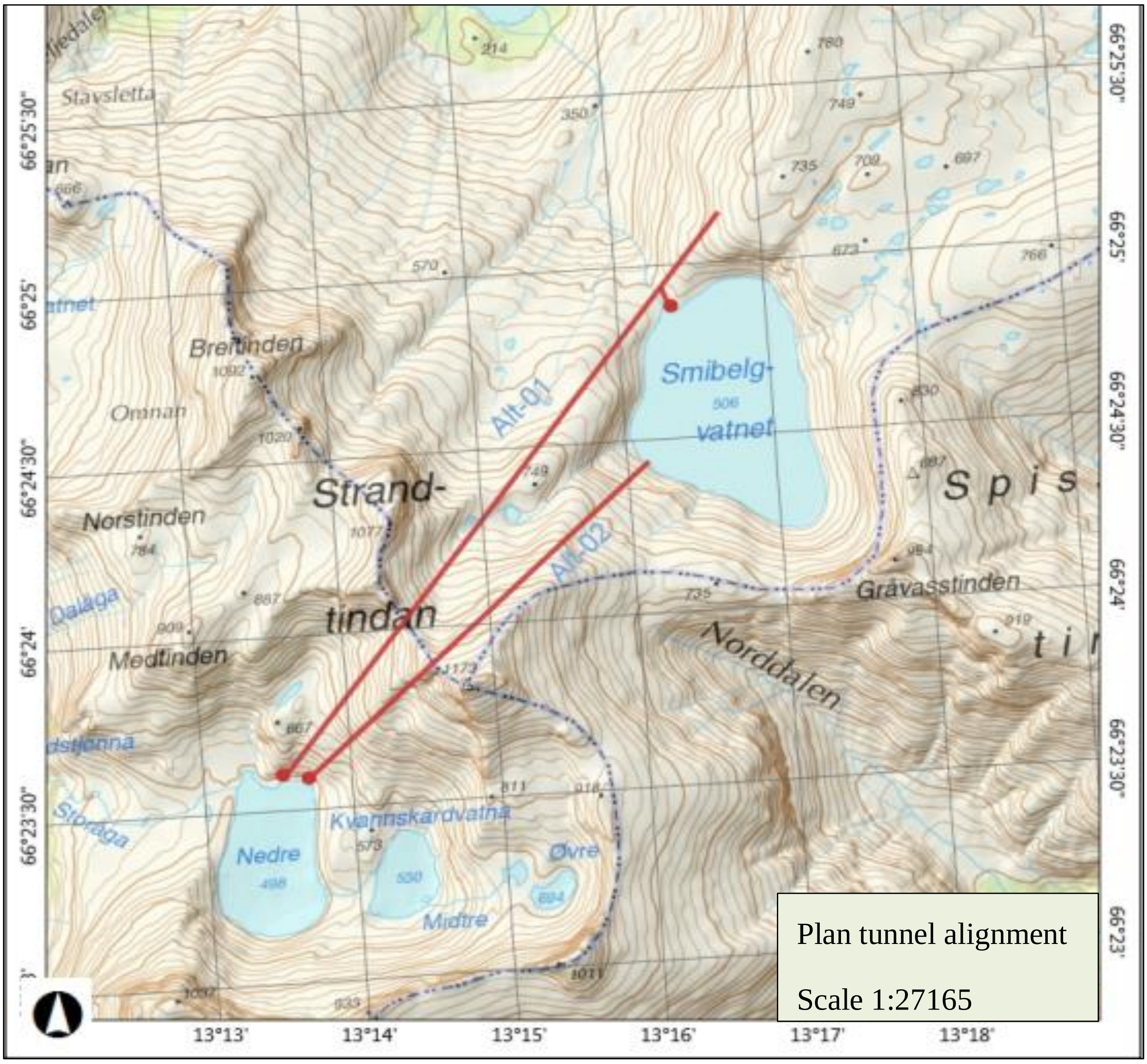

Figure 16 Alternative Tunnel Development plan Source: (Møre og Romsdal County counsil, 2000)

4.3 Temporary River Diversion Structure

The existing natural lake level of storåga is 498 masl. Proposed combined reservoir system will increase the natural lake level to 502.5 masl and conductor tunnel between the two lakes starts at invert level of 492 masl. Hence it is planned to dewater the natural lake level to 494 masl thereby creating favourable condition for the onset of tunnel construction from Storåga to Smibelg.

In order to dewater the lake level at storåga diversion tunnel through left side the river exit in the direction of the river flow has been proposed. However considering the final height of dam as well as the minimum water level rather simpler and cost saving solution using polymer or precast concrete walls at the entrance of tunnel excavation from storåga is proposed. The plan will require excavation of dam foundation at the exit of Lake to 494 masl i.e. 2m dam foundation plus additional 2m for dewatering of the lake. This will create a smaller protective wall height approximately 3 m at the entrance of tunnel excavation.

Dewatering of lake will create free surface for construction of accesses road till the entrance of conductor tunnel thereby reducing cost of adit tunnel and underwater piecing. The access road is proposed by cutting the existing natural topography from natural level of 500 masl to 492 over a length of 350m.

After finishing construction of conductor tunnel and tunnel from Smibelg to Vakker, tunnel system will be used to dewater the lake at smibelg and storåga. This will create suitable condition to start construction of main dam. Construction at river section shall be completed by implementing precast concrete walls to isolate a dry construction area i.e. construction shall follow by parts. Dam construction with blocks of 6.1 m should be used for concrete section of the dam.

Finally filing of the reservoir will take only a single season since the capacity of the reservoir is very small as compared to the net annual inflow to the reservoir. Plan for dewatering the lake is documented in annex D-01.

4.4 Diversion structures

Initial site identification followed by optimization has been undertaken to suit system layout. To reduce the number of optimization variables existing natural topography was used to select the most suited location of diversion and intake structures. The topography is used while maintaining the planning criteria to maximize power production from the system.

It is planned to locate diversion structures in the following geographical locations:

- Dam at Storåga $13^{0}12^{'}25^{''}$ Long: $66^{0}23^{'}37^{''}$ Lat
- Intake weir at Vakker $13^{0}19^{'}17^{''}$ Long: $66^{0}25^{'}52^{''}$ Lat

- Intake weir at Storåvatnet $13^0 20' 47''$ Long: $66^0 26' 44''$ Lat
- Intake weir at Mannåga $13^0 23' 29''$ Long: $66^0 27' 27''$ Lat

The diversion structure is set high enough, such that the pondage created is sufficient for the intake structure at the intake points of intra-basin transfers. Key project dimensions are:

Table 17 key project Parameters

Parameter	Smibelg-Storåga	Mannåga	Vakker	Storåvatn	Unit
Spillway crest elevation	502.5	571.76	503.5	502.5	masl
Minimum reservoir operation level	498	568.94	499	498	masl
Active volume	13	0.2	x	x	Mm3
Top Width	420	20	15	25	m
Dam/weir Height	6.5	2	3.5	3.5	m

Choice of main dam type at Storåga creating a combined reservoir has been undertaken based on availability of construction material, site topography, depth of overburden and bed rock geology of the dam site. However for intake weirs considering the height and volume of work required for construction, concrete gravity dams is taken as the only option.

4.4.1 Weir at Vakker, Storåvatn and Mannåga

As described above considering the volume work involved for construction of small weirs concrete gravity dams with ogee spillway crest is selected. The heights of weirs are fixed considering the required intake submergence. Side intake is proposed to divert the water to main transfer system.

Dam size and shape for intake weirs/small dams are determined as per NVE cost curve and has a d/s slope of 1:0.75.Their corresponding cost is computed as a lump sum value based on height of dams. Cross section and plan details of each weir are documented at annex D-02.

4.4.2 Dam Type Storåga

Project area encompasses a good rock quality around the dam site. The tunnels will also be excavated in rock type suitable for dam construction and concrete aggregate. While investigating the dam site Clayey, moraine or other type of natural materials suitable for use as low permeability material are not available along the vicinity of dam site hence earth dam is not considered as an option.

Three different rock fill dam types have been evaluated as choice of dam other than concrete gravity dam at Storåga:

- Concrete faced rock fill dam [CFRD]

  Offers advantages like low cement volume, rock fill from excavated tunnel etc. however it requires a spillway on the side or as a separate structure on the dam body. It also requires extensive amount of cement as compared to AMCRD.
- Roller compacted concrete dam [RCCD]

  Offers advantages like spillway on the body of the dam, not sensitive to weather condition during construction, smaller volume etc. however it requires extensive amount of cement and slag which are not available in the area.
- Asphaltic moraine core rock fill dam [AMCRD]

  Asphaltic concrete core dams has a core constructed with a special mix of binder in aggregate instead of cement and the core will be impervious and flexible which is of advantage with regard to settlement in the supporting rock fill.

Considering the extended U-shape topography Asphaltic moraine core rock fill dam with concrete gravity spillway at the river outlet is found to be least cost combination for the required diversion site. The selected layout of the dam comprises an ogee spill way at the centre of the river outlet and moraine core rock fill dam separated by a guide wall. Rock fill section of the dam has inclination of 1:1.5 both for u/s and d/s to resemble the NVE cost curve standard dam design. A net benefit of 6 MNok has been observed while comparing the cost of moraine core rock fill dam with concrete gravity dam.

4.4.3 Dam height optimization

Major factors affecting the magnitude of dam height are identified and used to determine the required dam height. The optimisation of diversion height was carried out considering the following factors:

- Inflow to the reservoir
- Outflow capacity from the reservoir using routing result from nMag2004
- Min reservoir water level, 498masl
- Reservoir elevation area volume relationship curve
- Intake submergence etc.

The inflow from 97 years data has been used to identify the wet, dry and average years, hence the annual sum of inflows in to the reservoir are used to develop a flow duration curve to identify periods occurring 5%, 50% and 95% of the time as dry, average and wet years respectively and are used for optimization analysis. Summary of annual inflow volume for each year are shown below in Table 18.

The year corresponding to each period is picked and used for developing a regulation curve using excel based programme to identify the relation between reservoir characteristics. The reservoir capacities required for each annual inflow is computed and are documented in Table 18. For final dam height optimization annual inflow corresponding to average year is used for analysis as a proposed solution.

Table 18 Data for wet, Dry and average years in terms of annual volume

		Smibelg	Storåga	Total		
% of time	Year	Annual volume Mm3	Annual volume Mm3	Annual volume Mm3	Dam height	CIR for 100% Reg.
50%	1917	17.458	19,012,838.40	36,471,168.00	4.5 m +Fb	43%
5%	1995	24,270,105.60	26,431,142.40	50,701,248.00	5 m + Fb	35%
95%	2010	12,740,544.00	13,874,976.00	26,615,520.00	4 m + Fb	28%

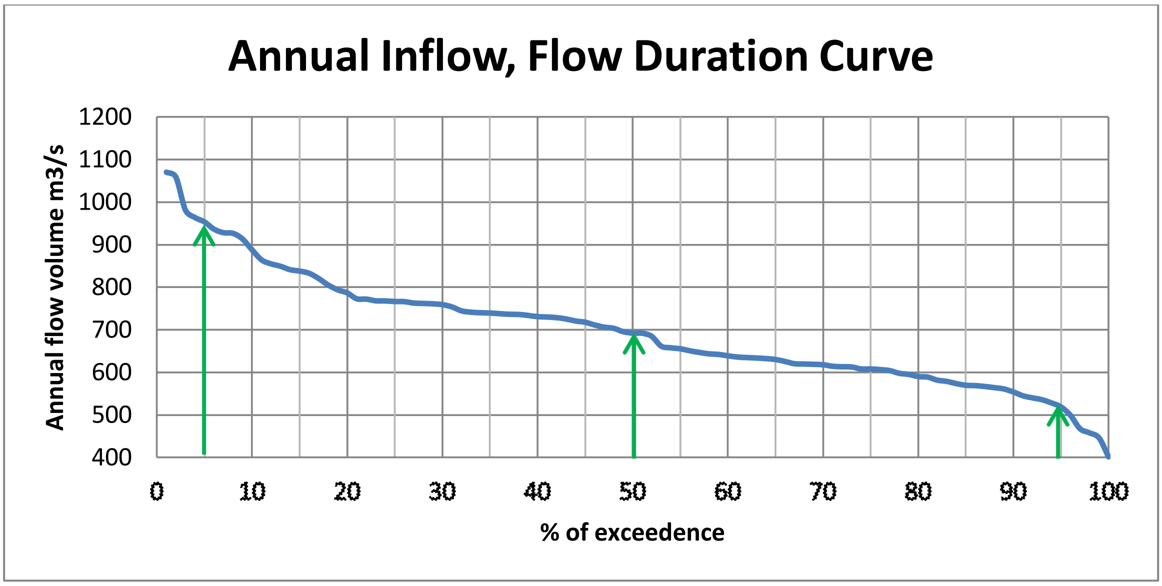

Figure 17 Yearly Annual flow Volume flow Duration Curve for 97yrs

The height of the dam is fixed using a multiple optimization analysis both from nMag2004 and economic marginal analysis. The optimum regulation limit has been fixed to 502.5 masl using nMag2004 model power simulation results as described in reservoir operation.

Marginal analysis on cost of constructing a dam and benefit from regulation resulted optimum dam height of 6.5m. During optimization process the following optimization parameters were considered discount rate 7%, analysis period 50yr, 0.6Nok/KWh power price and 0.1 annuity factor. Result of marginal analysis is shown below,

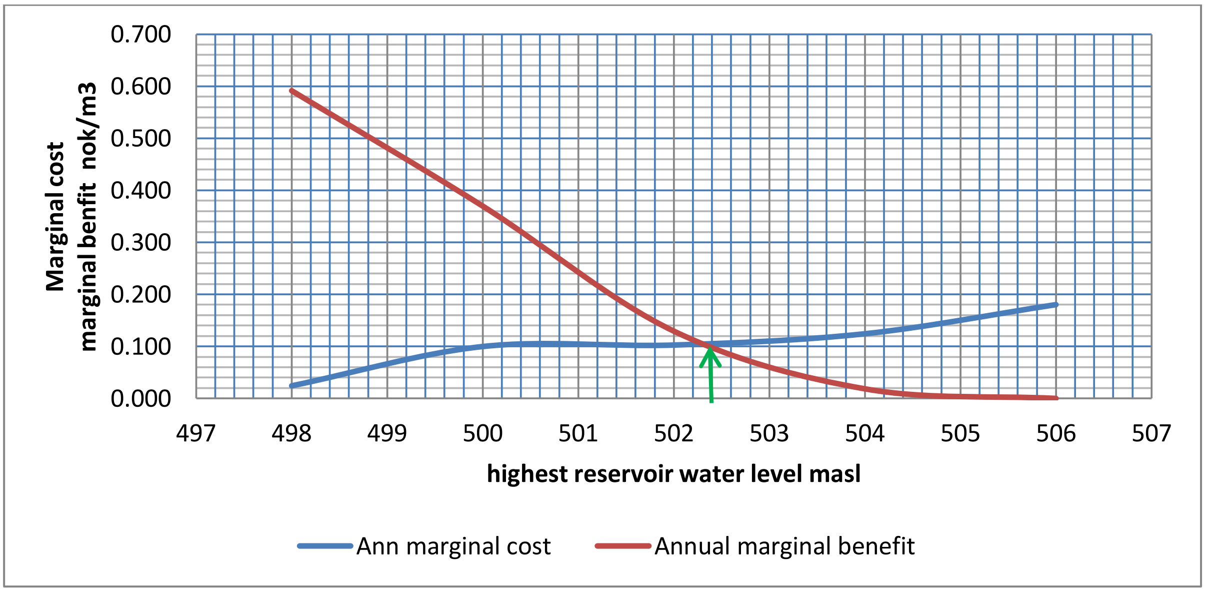

Figure 18 Dam Height Optimization: Marginal Analysis

The following features of the reservoir are selected.

- Highest reservoir water level, HRWL : 502.5 masl
- Lowest regulated water level, LRWL : 498 masl
- Live storage Volume, M m^3 : 13 Mm^3
- Average annual inflow volume, M m^3 : 36.47 Mm^3
- Capacity factor : 35.64%

Stability of the dam against overturning and sliding were evaluated and a factor safety factor of 2.16 and 0.49 were obtained for overturning and sliding respectively. Hence the concrete gravity section of the dam is stable. For rock fill section full dimensions are set as per NVE cost curve, hence rock fill section of the dam is stable. Results of stability analysis for concrete gravity section are documented in annex H-05.

Freeboard

Free board is the vertical distance between the top of the dam and still water level. The following criteria have been used for computation of freeboard for rock fill section of the dam;

- The free board is wind set-up plus one and half times wave height above normal pool elevation or above the maximum reservoir level corresponding to design flood, whichever gives the higher flood.
- Free board shall not be less than 1.0m above the maximum water level (MWL) corresponding to design flood.

Based on the above limiting criteria freeboard required for the dam is estimated as 0.71m using 1000yr return period flood. Hence for a design head over the spillway of 0.76m a minimum free board height of 2 and 1m for the rock fill and gravity dam section respectively are provided. The plan and section of the dam are documented in annex D - 03.

4.4.4 Spill way design

An ungated ogee spillway with crest elevation at 502.5 masl has been proposed to safely deliver excess water to d/s. For design of spill way, flood magnitude corresponding to 1000yr return period is used as design discharge and $1.5xQ_{1000}$ as a safety cheek flood as per Norwegian dam safety Regulations.

The following results are used as input data:

- Crest elevation : 502.5 masl
- River bed level : 498 masl
- Design flood Q_{1000} : 17.31 m^3/s
- Safety cheek flood : 25.97 m^3/s
- Spillway width : 12 m
- Downstream slope : 0.75:1
- Design head, Hd : 0.76 m

Ogee profile u/s Quadrant

The u/s profile is computed using a vertical u/s face and is shown by the following equation:

$$Y = 2.5(x + 0.205)^{1.85} + 0.096 - 0.389(x - 0.205)^{0.625}$$

Ogee profile D/s Quadrant

The d/s profile is computed using the general equation from U.S corps of engineers to determine the x and y coordinates and is shown in the equation stated below;

$$\mathrm{y} = 0.631\mathrm{x}^{1.85}$$

The main waterway comprises a centrally located spillway having a dimension of 12m (w) x 1m (H). Discharge capacity of spillway is confirmed using the above design cheek floods. Rating curve over the spillway is displayed in the figure below.

Design analysis for dimensioning of spillway is documented in annex H-04.

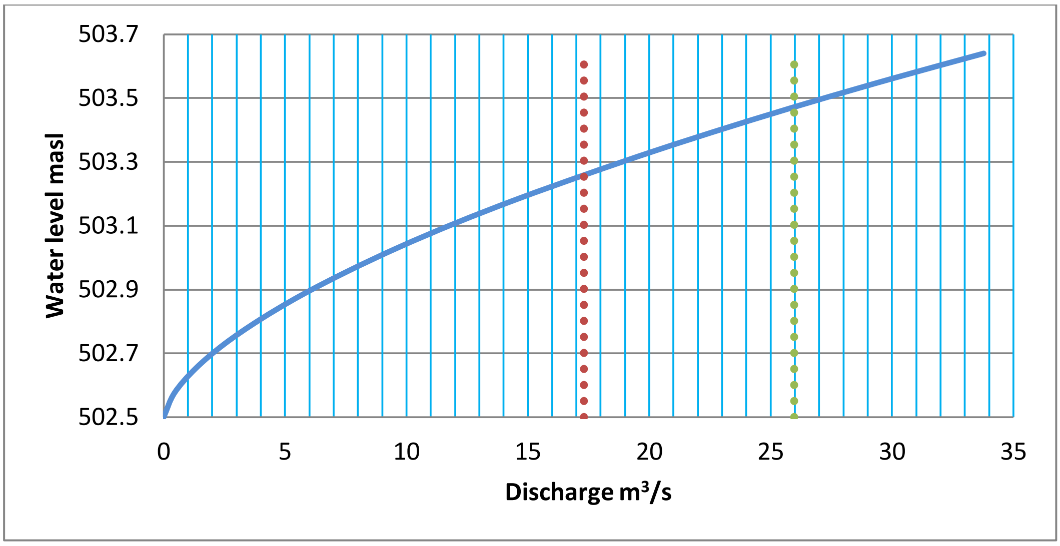

Figure 19 Rating Curve over the Spillway

Energy dissipation arrangement

A trajectory bucket type arrangement is envisaged as energy dissipater for ogee spillway section designed above; the riverbed in downstream of bucket comprises of sound rock and is capable of withstanding the impact of jet velocity. Thus provision of trajectory bucket is preferable.

The radius of the bucket required is computed using the following empirical formula (P. Novak, 2004),

$$R = 0.305 * 10^{\left(\frac{v+6.4Hd+4.88}{3.6Hd+19.52}\right)}$$

Problem related with cavitation is assessed and a bucket with a radius of 0.86m is provided. Plan and cross-section detail of spillway along with its energy dissipation structure is shown in annex D-03.

4.5 Intake Structure

Intake structure is provided at the left bank away from the body of the dam to ensure smooth entry of water from reservoirs as well as intra basin systems to water conveyance system. The geology of the respective intake site is assumed to be good rock for intake construction.

Intake structure includes an intake pond, Trash rack and a closing gate. The pond water levels on intra- basin catchments are designed by providing sufficient submergence to avoid problems that come with freezing of ice and debris floating on the water surface.

The basic criteria adopted for design of intake structures are:

- Submergence : adequate submergence below the minimum water level
- Flow velocity : to avoid vortices and clogging of water around the intake entrance velocity shall be in the range of 0.7 to 1.5 m/s

Hydraulic designs of intake comprises of fixing the size of inlet tunnels, fixing the invert level of the intake and size of trash rack bay and are detailed in the following section. Details of the key intake parameters are stated below,

Table 19 Key Intake parameters

Description	Location	Dimension L x H	Invert level	Rack inclination	velocity
Tunnel intake	Reservoir	4.25 x 4.25	492	15	1.04
Brook Intake	Vakker	3.5 x 2	499	15	1.36
Brook Intake	Storåvatn	3.5 x 2	498	15	0.96
Tunnel Intake	Mannåga	4.25 x 4.25	568	15	0.73

4.5.1 Intake Dimension

The intake structure at the Reservoir, Vakker, Storåvatn and Mannåga are designed using a design discharge of $2xQ_{mean}$. The sizing and hydraulic design of intakes is performed as per Norwegian regulation for design of intakes and dams.

4.5.2 Trash Rack

Trash racks are provided at the entrance of intake in order to prevent the entry of debris into the water conductor system so as to protect the turbines from objectionably large debris.

The basic criteria adopted for design of trash rack are:

- Flow at minimum depth of reservoir or pond which gives minimum depth of flow
- Net area of trash rack is assumed as 65% of the gross area
- Area of 33% of net area of trash racks assumed for extreme clogged condition

Summary details on location, alignment, design of intakes along with trash rack are documented on annex H-03.

4.6 Lake Tap Intake

Submerged tunnel piercing in to the lake Smibelg has been proposed to convert part of the dead storage volume of existing lakes in to live storage for reservoir regulation. The proposed system will provide a cheap source of stored water for winter power production even though drawing down the lake will cause some visual impact on the landscape (Dagfinn K. Lysne, 2003). Profile display of the planned layout is hsoen in annex D-05.

4.6.1 Layout and geological conditions at the Intake

Considerable planning and site investigation is required for selection and design of intake itself; hence for this level of study a compromise between function and optimality from hydraulic point of view has been used as criteria to plan the intake system.

Existing topography has been used to minimize the cost of submerged intake by selecting least cost alternative route for tunnel system running out of the reservoir. In addition to the effect of topography two geological considerations has been used determine choice of location and design concept. These are potential sites with faults, potential leakage paths shall be avoided and depth of overburden should be limited.

Analysis on topography and geology of piercing site while keeping the above basic rules resulted selection of open type piercing shown in Figure 20 i.e. initial filling of piercing section to form sufficient air pocket behind the plug prior to the final blast. Under open type piercing the following major dimensions has been considered for final design,

- Water depth to the plug and the gate, 9 m
- Tunnel cross-sectional area, 16 m^2
- Cross-section area and volume of the plug, 9 m^2
- Distance between the plug and the gate, 200 m
- Amount of sediments above and around the plug, Less than 1m
- Intake gate structure is a slide gate located 150m from the intake

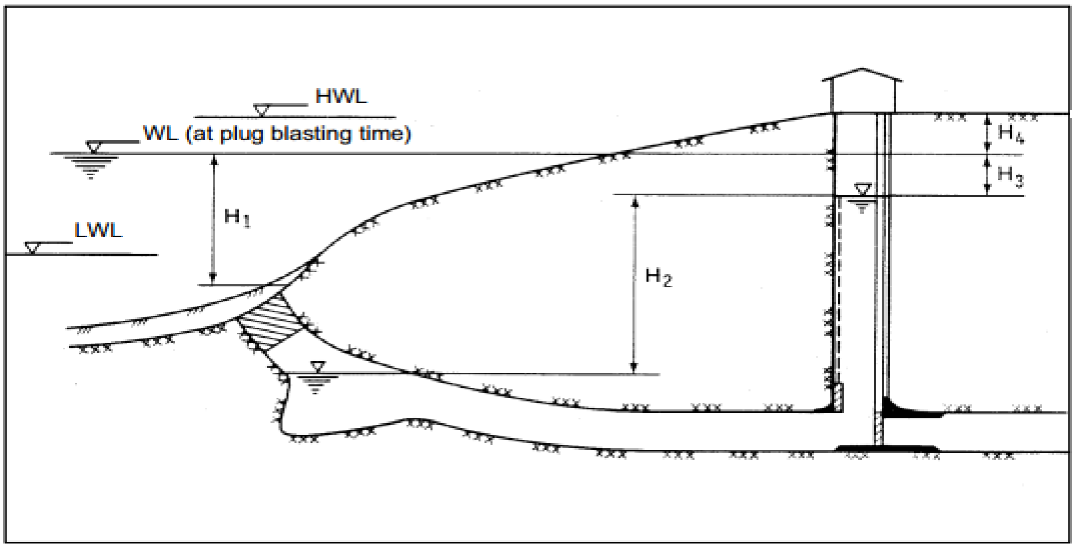

Figure 20 Open System Piercing, Geometric layout of intake Source: (Bruland, 2000)

4.6.2 Filling of water and air, and design of monitoring system

To prevent air evacuation through the plug air pressure shall be kept less than hydrostatic pressure against the tunnel plug. In other word:

$$H_2 < H_1 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots in\ the\ above\ figure!$$

Since the water level of the reservoir will be higher than the water level in the gate shaft surge shall be expected in the gate shaft, hence to avoid the damage to the gate house the following must be true:

$$H_4 > c.H_3 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots in\ the\ above\ figure!$$

Where c = constant (0.7 to 0.9) after (Bruland, 2000). The length is kept as 150 m from Lake.

Parameters computed for water filling are H_1 = 12, H_2 = 14, H_3 = 2 and H_4 = 36 m.

4.6.3 Tunnelling towards the Intake

Excavation of the last part of the tunnel towards the intake is regarded as sub-sea tunnelling and tunnelling with very low overburden. General principles to be followed are (Mathiesen, 2009):

- Systematic probe drilling in order to be well prepared for any adverse rock mass conditions or significant water leakage
- Probing all the way through to the reservoir at critical locations in order to verify the exact location of the tunnel in relation to the lakebed
- Careful blasting in shorter rounds as the face approaches the final rock plug
- System of probe drilling through the final face to gather data for the final blast design

4.6.4 Blast design, charging, and detonation system

The final rock plug is proposed to be circular with a diameter of 3.5 m and round length of 5 m resulting in a volume of 40 m^3. Allowing a factor of safety of 75% the capacity of the rock trap right below the tunnel plug is computed as 70 m^3. Details of blast design, charging and detonation system are posted for the next level of Investigation.

4.7 Water way

Waterways consisting of penstocks, pipes and tunnels are required to convey water to the power house. The size of the waterway is fixed by taking the minimum sum of the following two variables;

- Annual loss of revenue on account of power loss due to friction in the tunnel.
- Recurring annual expenditure on account of capital cost.

For tunnels the minimum cross sectional area required by contractors is taken as the final design cross section i.e. 16 m^2.

Table 20 Water way Description Detail

Chainage	Waterway type	Span x height mm x mm	Remark
CH- 0+000 to 2+444	Tunnel	4230x4230	Storåga to Smibelg
CH- 2+444 to 5+064	Tunnel	4230 x 4230	Start of tunnel to Vakker
CH- 5+064 to 7+214	Transfer pipe GRP	Ø 2000	Vakker to Storåvatn
CH- 7+214 to 8+064	Tunnel	4230 x 4230	Storåvatn to start of penstock
CH- 0+000 to 1+650	Tunnel	4230 x 4230	Mannåga to start of penstock
CH- 8+064 to 8+714	Penstock shaft	Ø 1700	Stone trap to power house

During the Optimization process inflow from the reservoir and intra basin transfer are considered in their respective reaches of waterway system. A total inflow comprising contributing sub-catchments and outflow from the reservoir are used for the analysis. For inflows coming from reservoir, through flow results from nMag2004 model are used as the outflow discharge. A summary of the optimization analysis for pipe and penstock are tabulated at annex H-06.

4.7.1 Head race Tunnel

The present section pertains to design of head race tunnel for each of the four water conductor systems in Smibelg HEP. The design includes fixing the optimum shape, size, rock support and construction methodology.

Layout

The tunnel system transfers water from the reservoir to transfer pipe at vakker and from Storåvatnet and Mannåga to start of penstock. D-shaped tunnel with 16 m^2 finished area has been proposed with a view to convey 5.26 m^3/s of design discharge from reservoir and intra-basin transfers to power house. Shape of the tunnel is proposed based on method of excavation, use, hydraulic efficiency and size of tunnel. Generally a circular section is hydraulically most efficient section in addition to that circular shape will carry the external load uniformly by compression as compared to other shapes, however considering construction flexibility and smaller losses in the tunnel system D-shaped tunnel is proposed.

Tunnel support system

Temporary as well as permanent support measures adopted for calculations are dependent on rock quality hence application shall follow the standard design norms. Hence in further study rock support design for 16 m^2 tunnel and rock type of granite and foliated granite should be prepared based on rock class along the stretch of the tunnel.

Head loss Estimation

The loss in HRT comprises major loss due to friction and minor loss at transition, gates and intake. Hence computation of the losses in the system is done using common equations as stated in reconnaissance assessment.

Result of the analysis using the fitted hydraulic channel gives a head loss magnitude of less than unity hence the inclination of the waterways selected in the conduit system is set nearly close to horizontal.

4.7.2 Tunnel Smibelg to Vakker

Two alternative tunnel alignments were proposed to convey outflow discharge from the reservoir to power plant as shown in the plan below in Figure 21. Optimization on major construction components that will differentiate the two alternatives alignments has been performed while keeping the rest cost elements constant. The cost of construction for tunnel, Lake Tap and access road along with other cost elements were considered. Results of the analysis are shown below;

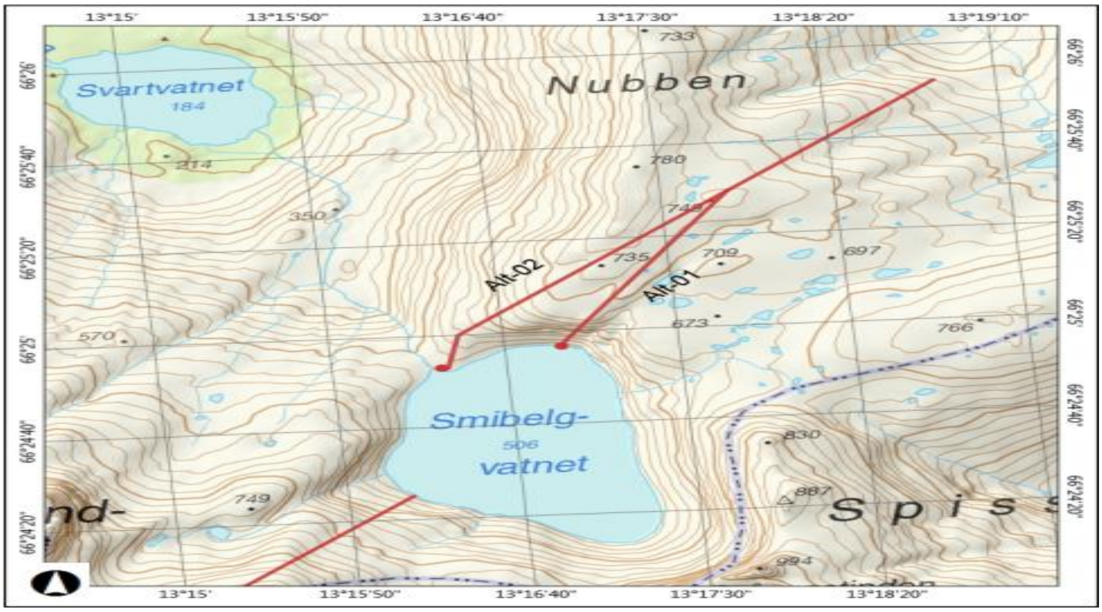

Figure 21 Tunnel plan from Smibelg to Vakker: Source (Møre og Romsdal County counsil, 2000)

Table 21 Cost comparison for Tunnel Alignment

Tunnel Alt-01	unit	Quantity	Rate	Cost Mnok
Tunnel Length 16m^2	m	2200	15000	33.00
Piercing section	m	40	150000	6.00
Gate shaft	m	197	36000	7.09
Gate cost	m	1	2500000	2.50
Access road	m	1400	2000	2.80
Road cut +transport	m^3	500	2250	1.13
			Total cost	**52.52**
Tunnel Alt-02	**unit**	**Quantity**	**Rate**	**Cost Mnok**
Tunnel length 16 m^2	m	2580	15000	38.70
Piercing section	m	40	150000	6.00
Gate shaft	m	36	36000	1.30
Gate cost	m	1	2500000	2.50
Access road	m	500	1500	0.75
			Total cost	**49.25**

From the above cost comparison, alternative two is selected with a least cost of construction.

4.7.3 Transfer Pipe

From the topographic analysis water way starting from Vakker to Storåvatn requires a pipe alternative to better utilize the available head. GRP pipe has been selected as a pipe material in the first section of this thesis report and is adopted in this section.

Plans showing the alignment and cross section of transfer pipe along with vertical profile are documented at annex D-04 & 06. In addition details of cut and fill section along the pipe route are prepared.

Economic Diameter

Optimization of the transfer pipe and penstock for varying design discharge values of (1, 1.25, 1.5 …x Q_{mean}) was undertaken while maintaining the philosophy stated above in section 0, Marginal analysis of 2xQ_{mean} is shown Figure 22.

The result of the study concluded a 2 m diameter GRP pipe will give smallest combination of economic loss and cost of construction. Hence it is adopted as a final installation pipe size diameter. Considering the tradition as well as duration of snow cover over the catchment transfer pipe from Vakker to Storåvatn is planned to be buried pipe.

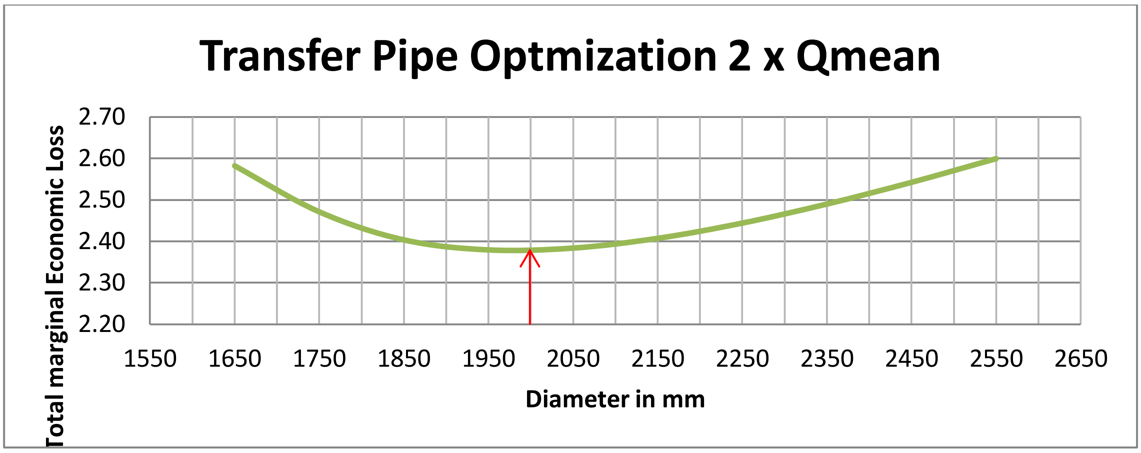

Figure 22 Pipe Optimization 2x Q mean

4.7.4 Tunnel Storåvatn & Mannåga to Stone trap

Tunnel starting from Stoåvatn and Mannåga to Stone trap follows the same design principle having the same cross section stated above. The bed rock geology of the excavation site is dominated with Granite and foliated granite. As the size of tunnel is quite small and good rock quality, it is proposed to carry out the excavation by drill and blast with a rail bound transport or small vehicle transport.

4.8 Rock trap and stone rack

The design philosophy of unlined headrace tunnel is to provide all potentially unstable areas with appropriate support measures. It is not possible to completely prevent occasional downfall of rock during operation of power plant under unlined tunnel. Under normal condition with water flowing at approximately 1 – 1.5 m/s rocks will remain in a stable position (Sverre Edvardsson, 2002). However during filling up of inspection there is a risk of rocks going down to power plant, hence to avoid that rock traps along with stone rack are provided.

The location of the Rock trap along with stone rack starts at the end of junction point between the incoming head race tunnels from Mannåga and Storåvaten at El. 490 masl. The penstock will start after the end of stone rack through contraction from 16 m^2 D shaped tunnel to Ø1.7 m circular pressure tunnel.

4.9 Surge Shaft

A quantitative Surge analysis has been undertaken to determine the necessity of surge shaft as project component structure. For suitable governance in the power generating units, analysis meeting the standard design procedure as stated in hydraulic design (Dagfinn K. Lysne, 2003) has been followed.

For smaller units of each 11MW capacity acceleration time [Ta] is adopted as 3 sec and Penstock time constant [Tw] is computed as 0.546 sec. Criteria for suitable governance system i.e. Ta/Tw>5 is evaluated as 5.48. A result of analysis shows surge chamber is not required.

4.10 Penstock Shaft

The rock composition along penstock from bed rock geological map of NGU shows homogeneous granite with thin foliation. Depth of overburden is kept in balance using method of equilibrium as per Norwegian rule of thumb. The pressure shaft ascends from east to west starting from Loftan to Storvika. A profile display of the penstock alignment is illustrated in Figure 23. Using Limit Equilibrum method (Nilsen, 1993) of determining minimum rock cover required for stable undergroung cavern, the minimem cavern distance from the tunnel shaft to the underlaying topogarphy were computed as 325m and correspondingly the inclination is set at $\alpha = 42.5^0$ with h = 301m in the following equation. L, h, α and H are shown below in Figure 23.

$H_{max} = 600$ m $\gamma_w = 10$ KN/m^3 $\gamma_r = 27$ KN/m^3 $\beta = 45^0$

$$\gamma_r * h * cos\alpha > H * \gamma_w \qquad ....1$$

$$\gamma_r * l * cos\beta > H * \gamma_w \qquad ....2$$

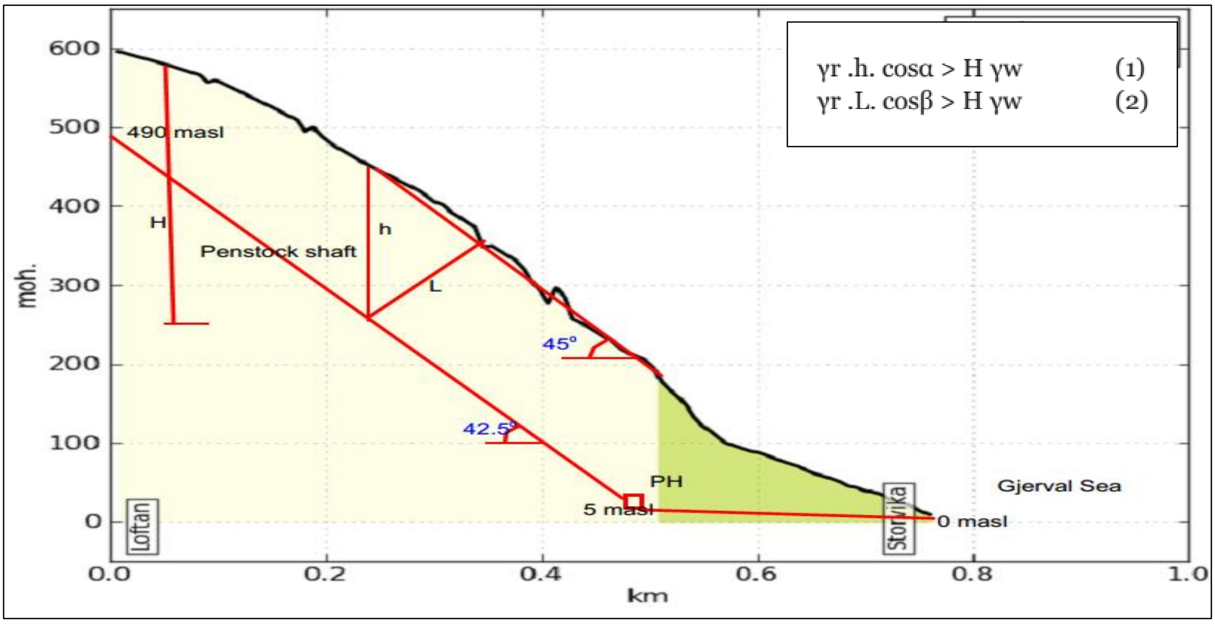

Figure 23 Limit Equilibrium method: Design for Minimum Rock Cover

Economic Diameter

Optimization of penstock diameter for varying design discharge values of (1, 1.25, 1.5…and $3xQ_{mean}$) was undertaken focusing to maintain the philosophy stated above in section 0, Diameter yielding minimum cost of pressure shaft i.e. 1.7m is adopted as economical diameter. Marginal analysis of $2xQ_{mean}$ is shown below in Figure 24.

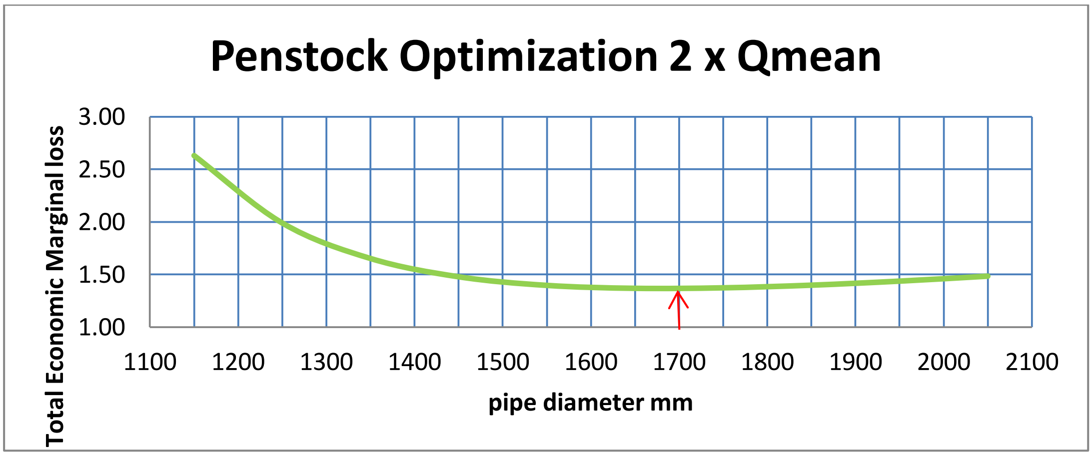

Figure 24 Penstock Optimization 2xQ mean

Layout and Configuration

After the stone trap, El 490 masl, 1.7m pressure shaft will descend down to power house [El. 5 masl] with inclination of 42.5^0. The length of penstock is fixed to 650 m, at the end it will bifurcate in two units of 1.2m diameter. After bifurcation, Butterfly valves (BFV) are provided in each of the pressure shaft and are housed in a cavern located downstream of the bifurcation.

It is envisaged to adopt unlined pressure shafts in the initial reach i.e. from stone trap to u/s of bifurcation for an inclined length of approximately 600m. In order to avoid unpredicted water leakage in to the power house cavern the final 50 m are proposed to be steel lined (Sverre Edvardsson, 2002). The BFV is located 5m upstream of power house cavern. Beyond this point, steel liner of suitable grade is proposed to be provided. After emanating from the BFV the pressure shaft drops horizontally by 485m to impact the two pelton turbine units .

4.11 Turbine capacity Optimization

Speed number and head available from project for each respective design discharge magnitude are used to identify suitable turbine type for the project. After deciding turbine type optimization analysis which will provide the optimum number and capacity of installation units was undertaken. Analysis for single, two units of equal capacity and 1/3& 2/3xQ_{mean} design discharge combinations were performed.

Modified MPC excel based model (Ånnund, 2014) were prepared to enhance the computation of energy production for different combinations of turbine installations in order to fix the size and number of turbine units. To arrive at solution varying design discharge magnitudes i.e. (1, 1.25, 1.5 …3xQ_{mean}) are cheeked. The combinations which will maximize energy production using the same inflow hydrograph are analysed. Installations containing two units of equal capacity are selected. For final installation two Pelton turbines each having identical capacity are provided. Summary result of the analysis are shown in Figure 25 below,

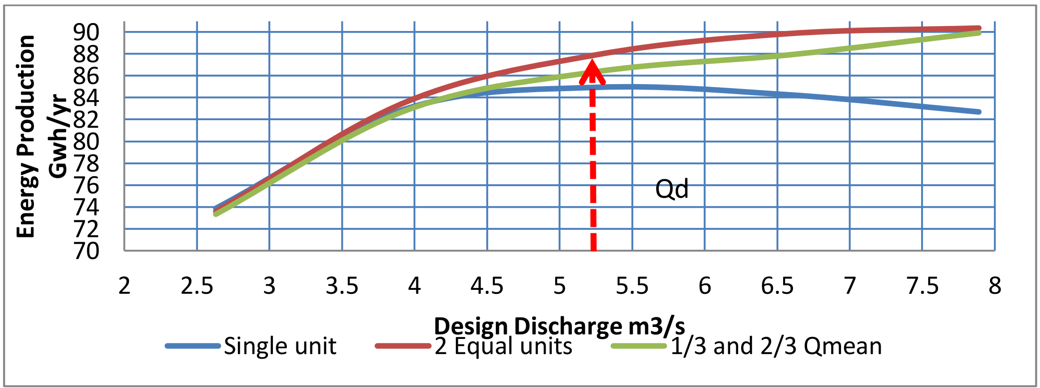

Figure 25 Turbine Optimization Result for Single unit, 2unit of Equal capacity and 1/3&2/3 Q_{mean}

4.12 Station Design Discharge Optimization

Optimum installations for tunnel, pipe, diversions, intakes, turbines etc are used to optimize the station installation. Analysis for varying design discharge magnitudes i.e. (1, 1.25, 1.5…and 3xQ_{mean}) was undertaken. The procedures followed are shown below;

- Optimum pipe size found from pipe optimization for each design discharge combination are used
- Optimum penstock size found from penstock optimization for each design discharge combination are used
- Cost of intake following each design discharge are computed
- Two units of equal capacity turbine units are selected
- Cost of related electro mechanical installations are derived as per NVE cost curve
- All costs are summed for each design discharge installation
- All benefits of the installation are calculated over the project life time i.e. 50 yrs. using 7% interest rate and 0.01 annuity factors.
- Finally the net annual benefit from installation is calculated and is shown below,

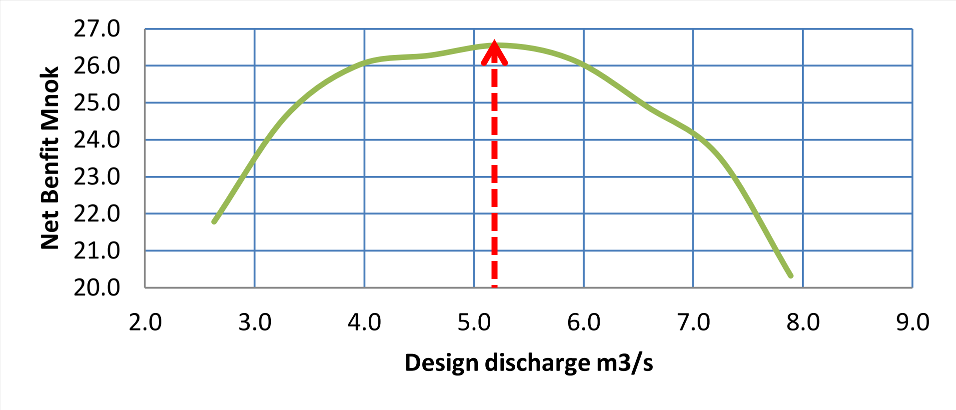

Figure 26 Net Benefit Method of Optimization Analysis Result

Marginal analysis and net benefit analysis on cost and benefit of installation resulted optimum design discharge of $2xQ_{mean}$ for the station installation. Summary of optimization procedure for varying discharge are tabulated at annex H-5.

4.13 Power house

Location

Analysing the general topography and geological quality of the catchment underground power house is proposed. A single economically viable site was found for power house complex on Loften Mountain, left of Gjerval Sea having sufficient rock cover and short access. The terrain on the site rises quickly from an elevation of 0 to 600 m at a slope of approximately 45^0. The bed rock geology of the cavern location is covered with good quality rock i.e. granite and foliated granite. Options related with fitting surface power house were rejected considering the steepness of the terrain, safety, construction difficulty and access. Plan on location as well as configuration of power house are documented at annex D-07.

Configuration and Orientation of Cavern System

In view of stability, accesses, location and cost of construction both perpendicular and inclined arrangement of pressure shaft in to the power house were considered. While keeping the power house cavern stable inclined pressure shaft with short access tunnel to power house is selected.

Based on geological map data from NGU and preliminary desk study on geotechnical parameters, the orientation of the long axis of the power house is arranged perpendicular to the pressure shaft entering to power house.

The approach to the power house cavern will be through a 455m long, 40 m^2 modified D-shaped access tunnel [AT]. The invert elevation of AT portal is at El. 50 masl and it meets erection bay at El. 12 masl. The slope of the AT is set at 1:12.

A branch adit of size 8x6m will descend down to penstock inlet and it will end at El. 5 masl. The length of the adit is approximately 185 m. another adit of the same shape will descend to tail race outlet.

A single cavern housing the two units with transformer located in extension of the same cavern is selected as compared to a separate independent transformer cavern. Factors considered during selection are:

- With a single cavern, a number of auxiliary electromechanical systems can be combined or provided with redundancy at a nominal extra cost.
- Control room can be placed in the same general location which will not only facilitate operations but also movement of the operating staff. A better coordination will also be achieved between the operations of the two schemes. Number of operation and maintenance staff can also be optimized thus reducing the operation costs.
- Facilities such as electrical and mechanical workshop, conference rooms and offices can be common, reducing both the space and the cost. The number of tools and tackles can certainly be optimized.
- Taking-off of power would be done from one “general” location.

The power house is designed to accommodate two turbines – generator sets. The main overall dimensions of the cavern is set to 30m L x 10m W x 16.8m Height. The turbine centre will be at El. 5 masl.

Turbine inlet valves are located at the exit of bifurcating horizontal pressure pipe on the upstream side of the dismantling joint. They are accessible by the main station crane via hatch opening in the floor above.

The vertical axis Pelton turbines are embedded in reinforced concrete and the generators are supported on an octagonal reinforced concrete plinth and enclosed in reinforced concrete air housing. The power house will accommodate all required rooms for safe operation of the power plant. Location of major components with in the power house:

- Main floor: El. 13.5 masl
- Generator floor: El. 10.0 masl
- Turbine floor: El. 6.50 masl

4.14 Tail Race Tunnel and Outfall

Tunnel corresponding to the minimum cross sectional area required by contractors is provided. The shape of the tunnel is planned to have a horse shoe shaped tunnel with span width and inclination of 4.23m and 1.67% respectively down to Lake Gjerval. The tunnel has a length of approximately 350 m. profile details of the tail race tunnel system is shown in annex D-07 along with penstock alignment.

4.15 Transmission lines

Study on the capacity as well as demand of new transmission line system is posted for further studies. However assuming the existing 400KV transmission line has the extra capacity to transport the added generation from Smibelg, route passing through the alignment of planned switching station till the existing transmission system is planned for costing of the transmission line.

5 RESERVOIR OPERATION AND POWER PRODUCTION

The objective of the reservoir operation studies was to evaluate reservoir regulation and its integration with intra-basin transfers for a number of alternative dam heights (full supply levels) and turbine discharge of the project and finally conclude Energy generation potential of the project. The following sub sections present a description of the applied methodology, data preparation and results obtained.

5.1 Methodology

5.1.1 General

The nMAG2004 simulation model is used to simulate the water balance and flow routing through a system of inter-connected water courses comprising river reaches, natural lakes, regulation reservoirs and hydroelectric plants.

The input matrix includes the following main parameters, to be selected by the user:

- Reservoir data, Volume area curve, evaporation etc.
- Turbine discharge m^3/s
- Nominal gross head m
- Head loss coefficient s^2/m^5
- Intra basin catchment inflow as annual mean flow Mm^3
- Control point
- Restriction data, compensation flow etc
- Operational strategy
    - Automatic reservoir balance
    - Reservoir regulation rule curve
    - Reservoir guide curve

The simulation model optimizes the energy output for a given reservoir alternative by an iterative process. The output from model can be determined by the user to present results of the simulation comprising statistics of:

- Inflow for each module m^3/s
- Outflow for each module m^3/s
- Spill and bypass m^3/s
- Reservoir levels and volume masl, Mm^3

- Power and energy output Mw, GWH
- Value of Energy, MU

All the results can be individually selected and stored in data files to facilitate post processing and analysis.

5.1.2 Reservoir Operation

For the present evaluation purpose the principal aim of the model is to maximize power and energy generation of Smibelg hydropower plant considering annual and seasonal hydrological variations contained in the inflow series, reservoir characteristics, operation rules and downstream water requirements.

The reservoir operation is simulated for daily time intervals applying:

- Daily inflow data m^3/s, with a scaling factor from Vassavetnet.
- Turbine flow 5.26 m^3/s
- Reservoir rule curve
- Minimum flow 0.1 m^3/s

From the three reservoir regulation rules mentioned above in the introduction typical Norwegian reservoir regulation curve for seasonal reservoirs have been adopted for analysis. Regulation curve adopted showing the variation of the reservoir over the year is shown in the following Figure 27.

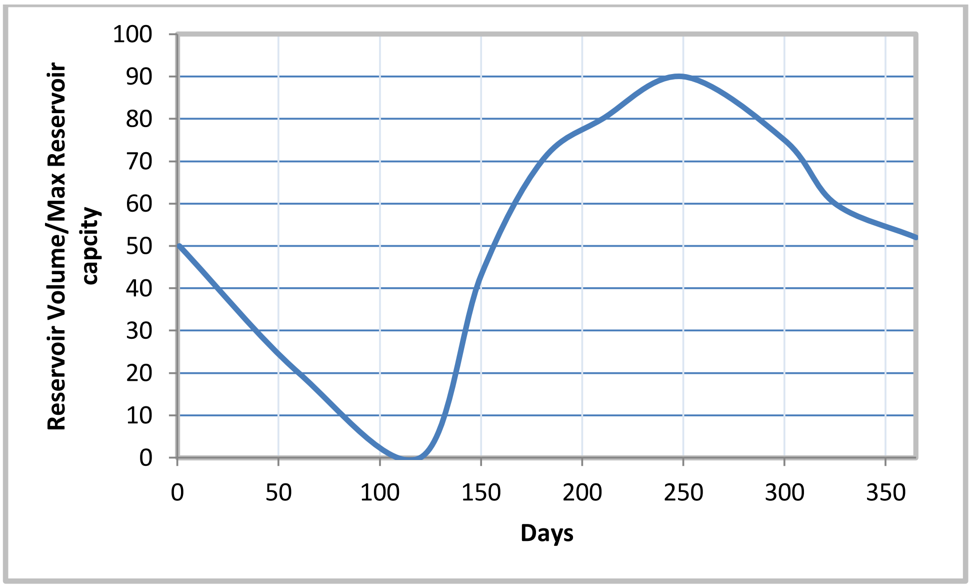

Figure 27 Reservoir Rule Curve: Source (Killingtivet, 2000)

5.1.3 Reservoir

The relation between reservoir level, volume and surface area is defined according to the reservoir topography using a map with a scale of 1:50,000 as given in ;

Table 22 below;

Table 22 Reservoir Elevation Area Capacity relationship

Elevation, masl	Volume, Mm^3	Area, m^2
498	2.05	1.23
500	5.81	1.25
502	10.08	1.26
504	14.41	1.28
506	18.8	1.3
508	23.24	1.32

5.1.4 Power plant

Daily values of the power output are calculated for each combination of head and flow with the following power formula:

$$\mathrm{p} = 9.81 * \eta t * \eta g * \mathrm{Q} * \mathrm{H}$$

Where: P = power production, Mw

$\eta t, \eta g$ = Turbine generator efficiency

Q = Design flow, m^3/s

$\mathrm{H} = \mathrm{Net\ head}$, m

5.2 Reservoir Operation simulation using nMag2004

Given the task of evaluating and comparing a number of various alternative combinations in terms of dam height and installed capacity repeated simulations have been undertaken. Power simulation has been undertaken for three full supply reservoir water levels under a constant minimum water level of 498 masl.

The turbine outflow discharge was varied from 1.75Qmean to 2.5Qmean to see the best way of using inflows from reservoir and intra basin systems. The net energy output per year were computed and used to compute the annual benefit in section 4.12.

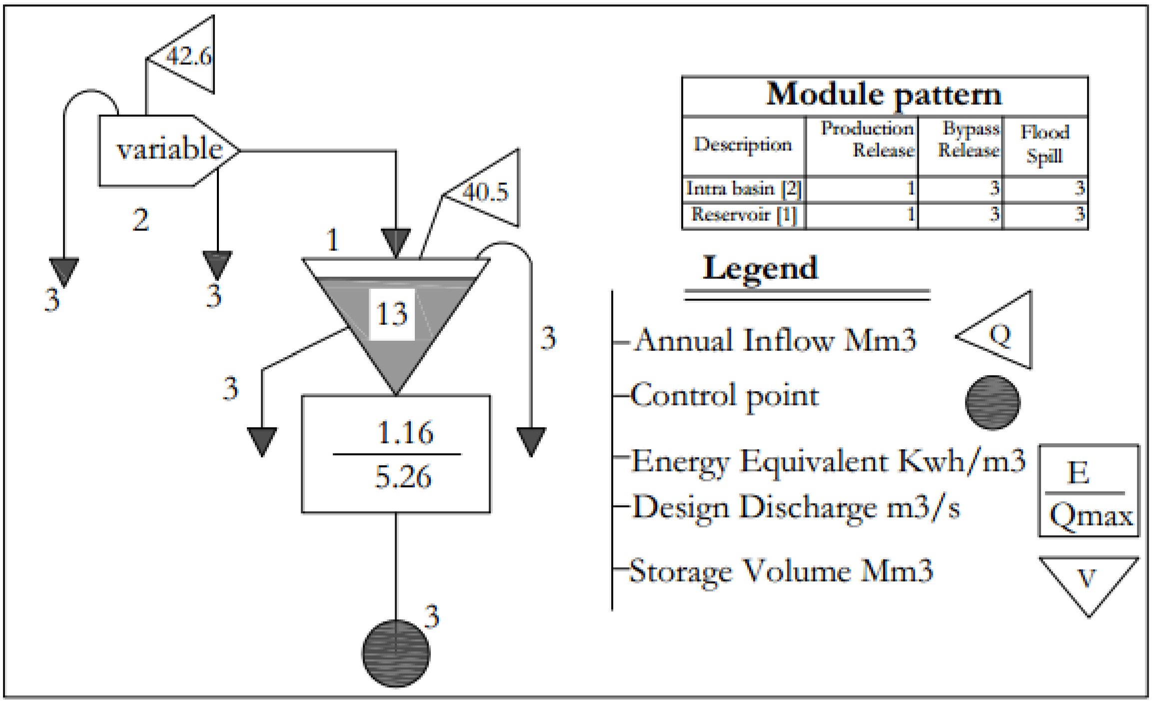

Figure 28 Layout of nMag2004 setup for the power plant system

Using the setup shown above result of optimization for dam height using marginal analysis was reviewed. Results of simulation were used to verify the probable energy production that can be attained at a certain level of regulation. Main simulation results are shown in the table below;

Table 23 Energy Potential Simulation 1993-2005, Smibelg Power plant

Turbine discharge m3/s				4.6025	5.26	6.575
HRWL	LRWL	Reservoir Volume Mm3	Firm Energy GWh/year	Average Energy GWh/year	Average Energy GWh/year	Average Energy GWh/year
502.0	498	10.81	25	91.07	92.70	93.91
502.5	498	13.00	25	97.07	98.67	99.87
504.0	498	14.41	25	92.12	93.55	94.21

5.3 Reservoir Operation Simulation using Excel based Model

Preliminary but simple linear excel based calculator sheet has been prepared to simulate the probable reservoir drawdown and corresponding release to the power plant using the inflow from contributing catchments. Simple water balance equation has been set to compute the storage variation with time giving initial priority to intra-basin transfers and second priority to release from the reservoir. In addition to that the calculator will also compute the corresponding water level at the start of each day using reservoir rating curve developed from 1:50,000 scale map.

Energy computation results from nNmag2004 have been confirmed using the model for total adjusted inflow considering the number as well as type of generating unit in a simpler Excel analysis.

Turbine discharge			4.6025	5.26	6.575
HRWL	LRWl	Reservoir Capacity Mm3	Average Energy GWh/year	Average Energy GWh/year	Average Energy GWh/year
502.0	498	10.81	91.89	94.98	99.8
502.5	498	13.00	96.39	99.21	101.2
504.0	498	14.41	98.82	100.52	102.77

Finally the regulation set is fixed with a combined reservoir volume of 13 Mm^3 and 502.5 masl as the HRWL. The design discharge is adopted as $5.26m^3/s$. energy production simulation from the system using the final reservoir volume and varying design discharge is used to optimize station installation as described in section 4.12.

5.4 Discussion and Results

The simulation result clearly illustrates the power plant has a smaller capacity to act as a firm energy production plant. The firm energy output of Smibelg hydropower is computed as 25 GWh/year with 92.5% demand coverage. It can be seen that months with potential deficit energy is during Feb to April and Aug to Sep.

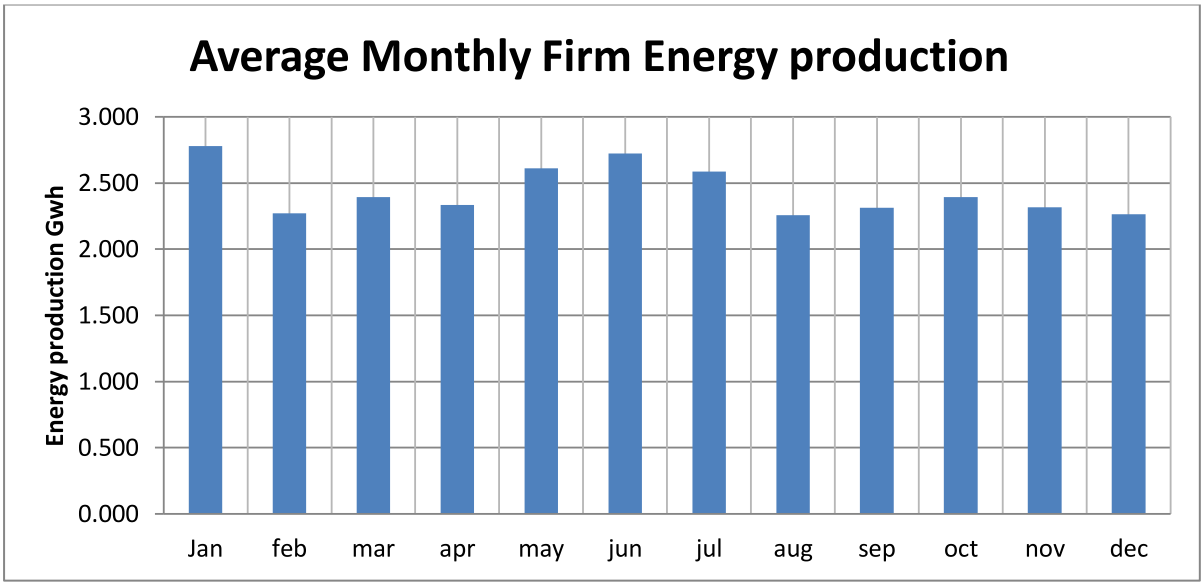

Figure 29 Average Monthly Firm Energy Output, Gwh

Results of reservoir volume and corresponding drawdown variation is shown in figure below,

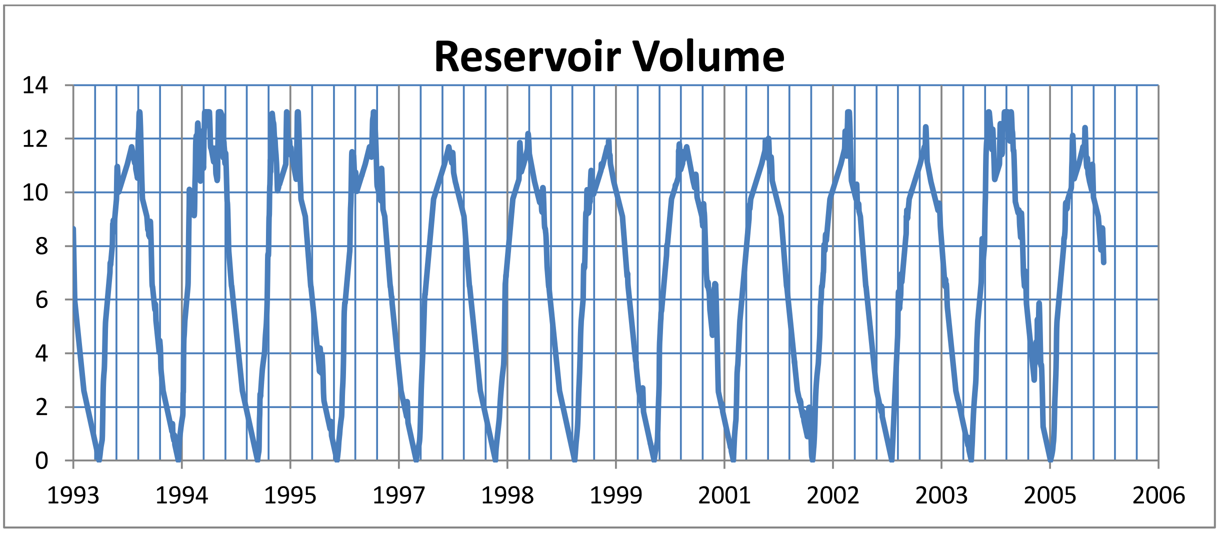

Figure 30 Reservoir Volume Mm3

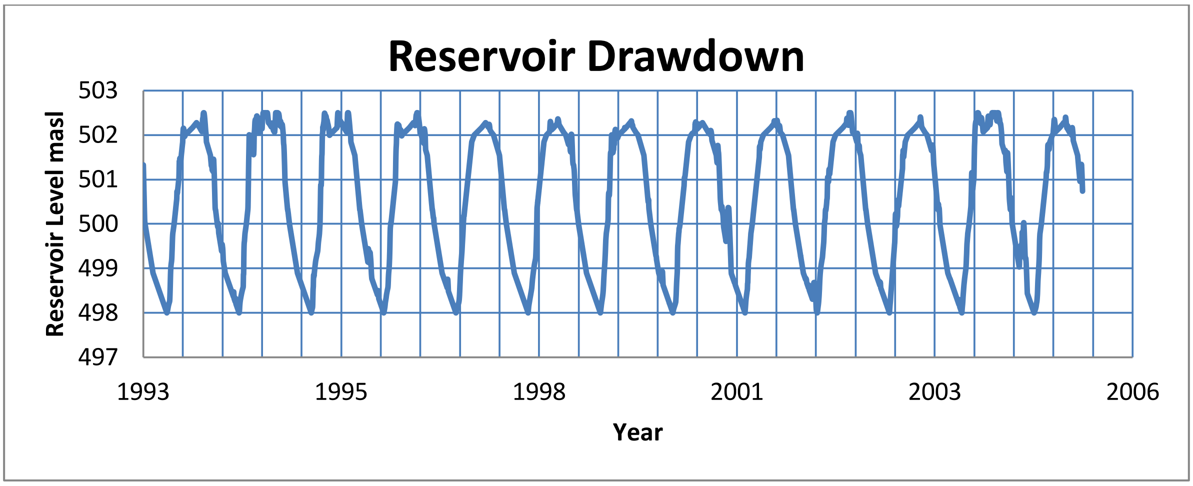

Figure 31 Reservoir Level masl

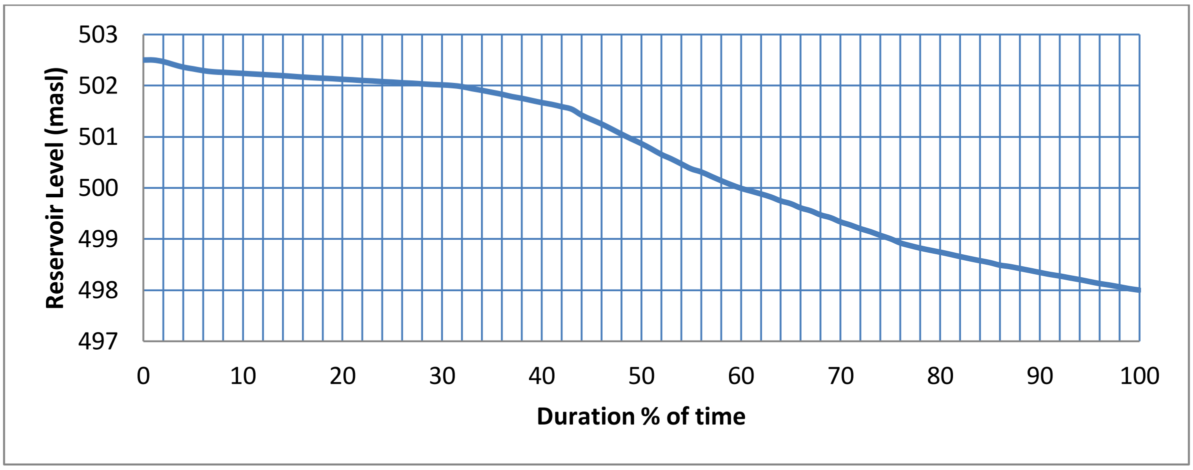

Figure 32 Reservoir Level Duration curve

From the reservoir level duration curve, it can be seen that the reservoir is small to generate a constant firm power over the whole period rather the reservoir is acting to redistribute the available water over the year to generate the required power.

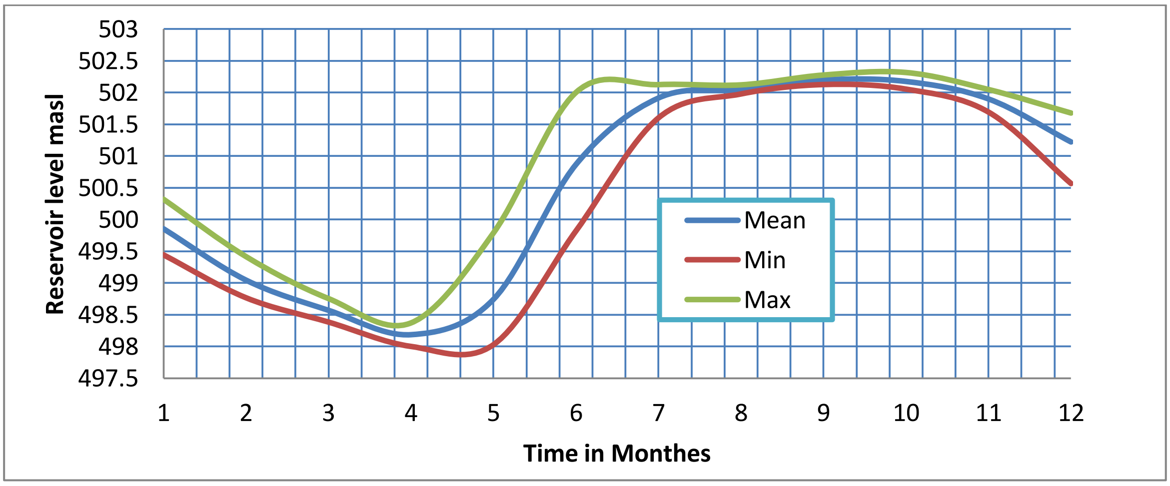

Figure 33 Monthly mean, max and min Reservoir level

Results of reservoir level variation plot shows there is a gradual drawdown of reservoir from November to April and gradual filing from Aug to November as specified by the reservoir operation strategy during simulation. The reservoir reaches full reservoir level only for small percent of the time within a year.

Simulation using automatic reservoir balancing was evaluated and a utilization factor much lower than the one achieved using reservoir guide curve was observed, hence in order to maximize production from the system Norwegian reservoir regulation pattern is adopted for operation.

Hence the following rule shall be adopted for operation of the power plant; release pattern from the reservoir shall follow when the power demand is in excess of inflow from supplying intra-basin catchments. Excess power production shall comply if and only if the reservoir is full.

6 SOCIAL AND ENVIRONMENTAL IMPACT ASSESSEMENT

6.1 General

The construction and operation of a dam and hydropower will result limited amount of impact both for u/s and d/s regions. Hence in Norway there are sequence of steps that has to be followed as per planning and building act to minimize the probable impact from altering the natural regime in the river and the corresponding consequential impact on socio-economic development of the region.

Impact assessment is a process which will ideally follow a sequence of steps starting from screening to final evaluation of impacts; hence the main steps that have to be followed are screening, scoping, full EIA and finally approval. The delimitation of impact zones encompassing the project area and the study area is explained below,

6.1.1 Direct Impact Zone (DIZ)

Inundation of the valley behind the dams, intake weirs and the associated works would create a direct impact zone with the following elements:

- A core area always under water;
- The drawdown zone, around the permanently flooded area in newly created ponds and main reservoir;
- A short altered river section between dam and tailrace outlet;
- The shore and periphery of the reservoir; and
- Sites of ancillary works, access roads and transmission lines.

6.1.2 Secondary Impact Zone

Secondary Impact Zone (SIZ) encompasses the areas adjacent to the DIZ/reservoir, along access routes and power transmission corridor, which will be effected by the project and people immediately downstream of the development. This zone includes communities which, although not physically displaced, come into direct contact with the development activities and staff. These communities may rely on resources within the DIZ.

6.1.3 Tertiary Impact Zone

Tertiary Impact Zone (TIZ), which encompasses possible issues up- stream and downstream due to the changes in river flow regime and dam wall barrier effects

6.2 Methods of Evaluating Environmental Impact assessment

Both the World Bank and Asian development bank has published a number of guidelines for evaluating EIA to compare the impact across various disciplines. Two useful and flexible methods are the RIAM-method developed by VKI of Denmark and the Three-step methodology, employed by NORPLAN of Norway.

From the above two methods three step method has been adopted to evaluate the probable environmental impact of Smibelg hydropower project. Steps to be followed are (NTNU/NORPLAN, 2010):

The first step in the three step methodology is to assign value or degree of vulnerability to the subject or item studied according to a set of valuation criteria and the vulnerability scale

The second step is assessing the degree of the project impacts in terms of magnitude and duration.

In the third step is to combine value with the degree of impact for an overall assessment .The no action alternative should be described to serve as a reference point for the analysis.

As a support to the overall impact assessment the following diagram is used as shown in Figure 34. Probable environmental impact on geology and landscape, biodiversity, fish, Cultural heritage, user interest and reindeer has been undertaken.

6.2.1 Geology and Landscape

The geological units making up the region is stated in reconnaissance section of this thesis report hence the area where the reservoir and new intake ponds that are going to be created as a result of regulation will have a little impact on existing bare rock geology since the area is covered with ice for almost the whole winter. In addition since the powerhouse is underground and waterway section of the project is tunnel plus buried pipe there will be no impact in the landscape.

The project area is not in the protected region and no land use is observed i.e. the area being exposed bare rock the minor impact will be from access road and transmission network Therefore it is concluded that the project will have a small negative impact on the geology and landscape of the region.

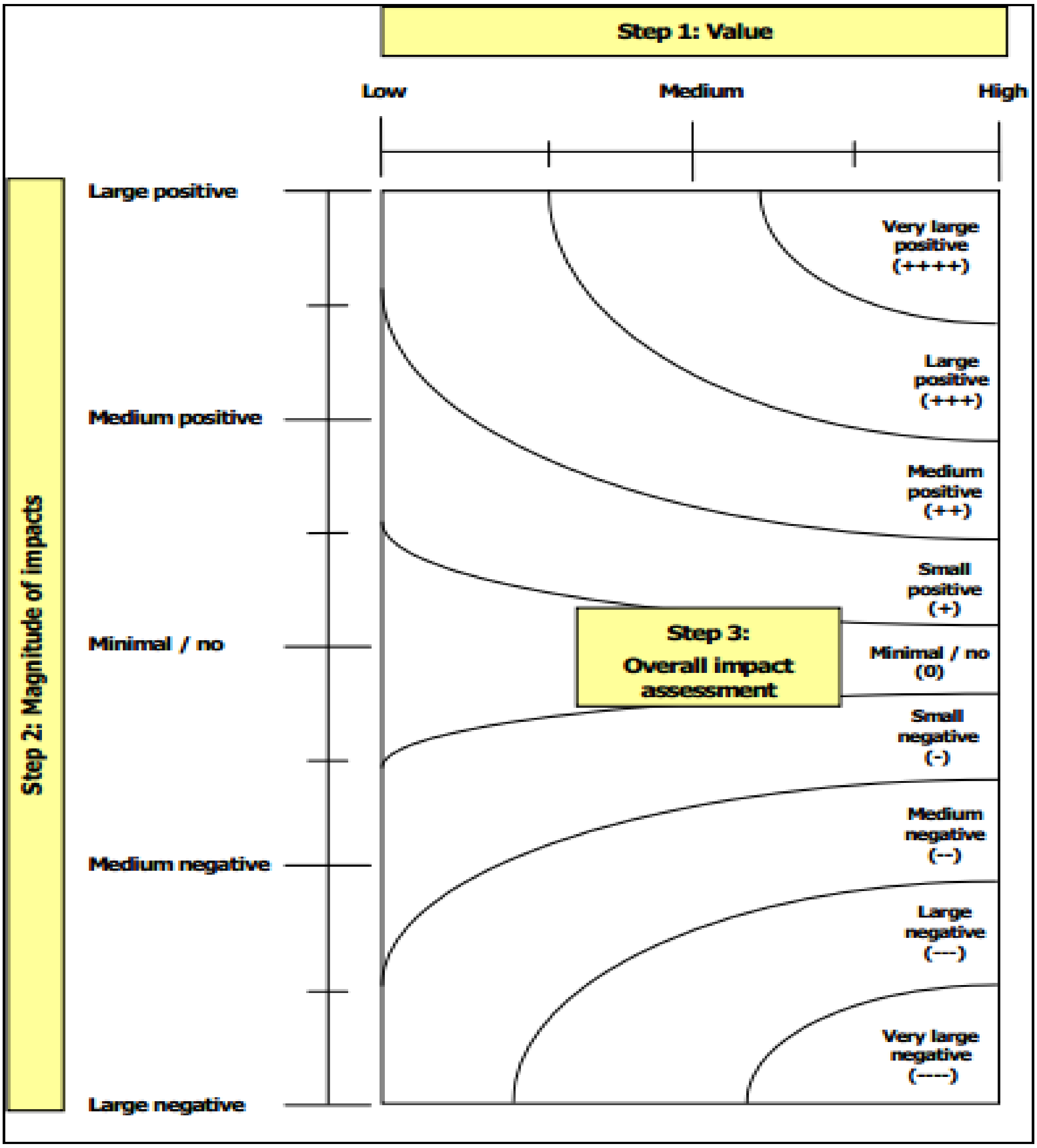

Figure 34 Three Step Impact Assessment Overall Impact Diagram Source: (NTNU/NORPLAN, 2010)

6.2.2 Biodiversity

Impact related to degree of variation of various life forms in the ecosystem as a result of project implementation can be roughly classified in three levels i.e. genetics, species and ecosystem. Directorate for natural management of Norway has set guidelines which will prove on how local authorities will carry out analysis of various elements of biodiversity (Norwegian Environmental Agency, 2007).

Hence using the regulation it is concluded that the project will have a small negative impact on the biotic life forms around the project area.

6.2.3 Fish and fresh water biology

Water flow and temperature are the most important factors that change after the regulation of the river. In many hydro power reservoir projects, water is stored in reservoirs to be used when power demands are high. Such storage will change the flow regime of the river (Allen, 2006). The temperature of the reservoir normally lowers in during summer and raised during winter hence it will have major impact in the protected lake Gjerval.

Also during construction ammonium from blasting work will be in the river system and finally in the lake with a high PH value to form ammonia, which is highly toxic to fish and benthic fauna. Assessment on value and vulnerability impact indicated that the development of the project will lead medium negative during construction period and small positive during operation period hence overall the project will have a small negative impact.

6.2.4 Cultural Heritage

There are no registered cultural heritage sites around the project area as per national database for nature management. Hence the project will have no influence on during both construction and operation of the power plant.

6.2.5 User interest

The project area where major areas of construction for diversion of water lies above 400masl hence the area is mostly covered with ice except during summer which it might be accessible for hiking. Therefore the project will create open access routes even for winter visit.

Flow reduction will have some aesthetic impact during summer however a minimum flow release of flow magnitude existing for 95% of the time is released from each sub catchment making the whole river basin system. Therefore the project is expected to have small negative impact.

6.2.6 Agriculture

There are some cultivated areas d/s of the mountain side right before reaching power house. The areas covered with agriculture will face negligible impact. Hence the project will have no impact with respect to agricultural development.

6.2.7 Reindeer

The project area is included in reindeer herding region, hence the project will have greater impact in herding during construction period. The waterway and reservoir system for development permits no disturbance except during construction. However during operation there will be a little less impact caused by the transmission routes. It is therefore expected to have a small negative impact for reindeer herding.

6.2.8 Electrification of the Region

The project will have a large positive impact in electrifying the region and beyond after joining the Nordpool energy market.

6.3 Resettlement

No permanent settlement is observed in the vicinity of the reservoir, however there are some cabins d/s of lake vassvatnet that are located 2Km downstream. Considering the size and height of the dam forming the reservoir no resettlement of people is required.

7 COST ESTIMATE

7.1 General

Detailed but preliminary cost Estimate has been prepared for the power plant. The price estimate for the component structures has been done as per NVE cost curve 2010. The cost estimate has been broken down in to the following main sections;

1. Access road
2. Dam and intake
3. Water way and Power house
4. Electro technical and Electro mechanical components
5. Power transmission, switching station and local supply
6. Engineering and administration

Table 24 Project Cost Summary

Description	Total Cost Mnok
Access Road	27.69
Dam	12.54
Intakes	17.88
Tunnels, shafts and access adits	122.46
Transfer Pipe	13.52
Power house	26.30
Electro Mechanical	45.94
Transmission, switchyard and local supply	16.40
Engineering and administration	39.57
Contingencies	112.94
Total Project cost	**435.24**

Ccost estimation for deferent combination of design discharge i.e. (1 to 3xQ_{mean}) has been undertaken. The cost analysis results are used to evaluate and optimize station installation in section 4.12. Summaries of the analysis are described in section 1.

7.2 Estimation Base

Cost base manual from NVE has been used to calculate the average foreseeable cost for contractors (Civil works) and supplier costs (mechanical and electro technical Equipment's) for capacity less than 10 Mw and greater than 10 Mw generating capacity (SWECO Norge AS, 2012).

7.3 Cost Estimate Civil

This section provides a basis for calculating the average foreseeable contractors cost for civil work. Average foreseeable means there is a 50% risk of costs getting higher and a 50% risk they will be lower (SWECO Norge AS, 2012). With regard to uncertainty margins there is a 90% probability for real costs to be in the computed costs.

The cost of construction for dam, intake, tunnels, pipes, roads etc. has been undertaken as per NVE cost curve standards as a lump sum value with their respective reading parameters.

To account the costs that are not foreseeable at this level cost contingencies have been added as 25% of civil cost. The costs of contractors are added as 20% of the civil cost. In addition to account cost variation related to lake dewatering at Storåga 2% of civil cost is considered.

7.4 Cost Estimate Electro mechanical

Generally the cost of the total mechanical and electro technical equipment’s reaches up to 50% for hydro power developments. Estimation of the major component like turbine, generators, transformers, auxiliary system, pumps, control system and switching gear costs have been done and to account the unaccounted costs a 15% added cost of the calculated cost have been done to arrive at total cost.

8 ECONOMIC AND FINANCIAL ANALYSIS

To determine viability of the project a financial analysis has been undertaken. Economic analysis parameters as described in the reconnaissance report assessment has been followed. Parameters used to evaluate the viability of the project are; Net present value, internal rate of return, Benefit cost ratio, Development cost, Payback period and Unit cost.

Base case scenarios used for economic analysis of the project are:

- Value of power : 0.6 Nok/KWh
- Time of analysis : 50 yr
- Discount rate : 7%
- Running cost : 1% of capital cost per year
- Construction period : 3 years

8.1 Economic Analysis

Economic analysis describing the costs and benefits of the project over the analysis period has been undertaken. Using the cost estimate result for each combination of design discharge i.e. (1 to 3xQ_{mean}) the capital cost required is taken forward for economic analysis. Economic analysis for single and 2 unit of generation has been undertaken. Results of the analysis are documented in annex H-07.

Economic analysis with Two Units of Generation

Economic analysis results with key project parameters are shown below in Table 25.

Table 25 Summary Economic Analysis Two units of Equal capacity

% Trial	Design Discharge M3/s	Installed capacity MW	Capital Cost Mnok	Energy GWh	NPV Mnok	IRR %	B/C	Development rate (Nok/KWh)/yr	Levelized unit cost Nok/KWh
100	2.63	10.84	397.113	78.46	56.449	8.15%	1.14	2.04	0.43
125	3.2875	13.36	406.767	84.08	79.151	8.56%	1.20	2.13	0.41
150	3.945	16.00	414.370	87.05	88.665	8.71%	1.22	2.17	0.40
175	4.6025	18.70	424.763	88.86	88.744	8.67%	1.21	2.16	0.40
200	5.26	22.00	435.236	89.91	84.378	8.55%	1.20	2.13	0.41
225	5.9175	24.00	443.173	90.1	77.588	8.41%	1.18	2.10	0.42
250	6.575	26.70	450.620	89.94	69.273	8.24%	1.15	2.06	0.42
275	7.2325	29.26	457.368	89.49	59.987	8.06%	1.13	2.02	0.43
300	7.89	32.00	468.924	88.92	45.237	7.79%	1.10	1.95	0.45

From the above tabular summary a design discharge combination of 200% is found to give a maximum net project net benefit as shown in section 4.12. Hence from the analysis result above design discharge of 5.26m3/s is adopted for final design for two units of generation.

Economic analysis one unit Generation

Table 26 Summary Economic analysis one unit of Generation

% Trial	Design Discharge M3/s	Installed capacity MW	Capital Cost Mnok	Energy GWh	NPV Mnok	IRR %	B/C	Development rate (Nok/KWh)/yr	Levelized unit cost Nok/KWh
100	2.63	10.84	386.480	78.28	67.008	8.39%	1.17	2.09	0.42
125	3.2875	13.36	396.620	83.37	89.228	8.80%	1.23	2.19	0.40
150	3.945	16.00	405.110	85.56	97.861	8.92%	1.24	2.21	0.39
175	4.6025	18.70	412.310	86.43	101.110	8.95%	1.25	2.22	0.39
200	5.26	22.00	420.030	86.63	99.477	8.89%	1.24	2.21	0.40
225	5.9175	24.00	425.820	86.14	94.819	8.78%	1.22	2.18	0.40
250	6.575	26.70	431.550	85.21	88.210	8.64%	1.21	2.15	0.41
275	7.2325	29.26	438.160	84.03	79.061	8.45%	1.18	2.11	0.41
300	7.89	32.00	448.040	82.7	65.975	8.19%	1.15	2.05	0.43

From the above tabular result optimum design discharge of 175% x Q_{mean} is found to be suitable for single unit installation. The design discharge corresponding to 175% x Q_{mean} is equal to 4.6m^3/s.

Discussion

Comparison between one unit and two units of installation has given a remarkably close result in terms of energy generation i.e. 86.43 and 89.91GWh respectively. The development cost required to produce the required energy for two units of generating units is smaller than that required for installation of a single unit, in other words cost required to generate each Kwh of energy for single unit of generation is higher than that of two units of generation.

In addition installing two generating units with the same capacity will give added advantage with operation and maintenance i.e. to use the same spare part to maintain both units, continuous power production in case of unit shut down, higher utilization factor, production at best efficiency and considerable fit for intra basin inflows to power units. Comparison summary using key economic parameters is shown in

Table 27 below;

Table 27 Summary one and two units of generation

	1 - unit	2 - unit
Installed capacity, Mw	18.70	22.00
Energy production, GWh	86.41	89.91
Capital cost, Mnok	412.31	435.24
NPV, MNok	101.11	84.38
IRR, %	8.95%	8.55%
Unit cost, Nok/KWh	0.39	0.41
B/C	1.25	1.20
Payback period, yrs	17.88	19.55
Development rate, (Nok/KWh/yr)	2.22	2.13

Hence considering the above mentioned merits and using development cost as a criterion of comparison two generating units has been adopted for final installation design. It is proposed to adopt $5.26m^3/s$ as a design discharge for smibelg power plant and $2.63m^3/s$ as design discharge for each unit.

8.2 Sensitivity Analysis

Sensitivity analysis has been undertaken to predict the outcome of variation in the basic economic parameters other than base case scenarios assumed for economic analysis. Hence in this section influence of variation in discount rate, energy price, capital cost and energy production are used to evaluate their impact on Internal rate of return, Net present value, Development rate, Benefit cost ratio and Unit cost.

Sensitivity analysis is normally undertaken for making final decision under the probable uncertainties that might happen during the project implementation and operation. Uncertainties that will be expected during implementation and operation of the project are:

- Increased unit cost of construction
- Project delay
- Extreme unforeseen civil work related problems
- Decrease in energy generation as a result of change in climate
- Stoppage in production as a result of damage in the power plant
- Lower electricity price and
- Fluctuation of power market due to variation in supply and demand

The following variation shown in Table 28 has been adopted to foresee project sensitivity against economic parameters;

Table 28 Summary of Imposed variation

Variation	50%	70%	90%	**100%**	110%	130%	150%
Investment Cost, MNok	217.62	304.668	391.716	**435.24**	478.764	565.812	652.86
Discount rate	0.035	0.049	0.063	**0.07**	0.077	0.091	0.105
Energy price, Nok/KWh	0.300	0.420	0.540	**0.600**	0.660	0.780	0.900
Production, GWh	44.955	62.937	80.919	**89.91**	98.901	116.883	134.865

The main merits of performing a sensitivity analysis are:

- It shows how significant a variation in a variable cause changes to the net output,
- It helps anticipating and preparing for ''what if'' questions in presenting a project and
- It can be used on any measure of project worth suspected to uncertainty. However as a main disadvantage it doesn't exactly measure the anticipated level of risk on variations.

Note: all sensitivity analysis stated below are based on varying a single variable while keeping the rest variables at the base case scenarios.

8.2.1 Project Sensitivity against NPV

From the analysis result shown below in Figure 35, it can be seen that variation in discount rate, energy price, production and investment cost has a very large impact on NPV of the project. Variation in energy price and production will have a direct influence on the viability of the project i.e. an increase in one of the variables will increase NPV and vice versa. In reverse indirect relation is observed while varying investment cost and discount rate.

Assuming a threshold value of 20 MNok, a decrease in 12% of the energy price or production from base case will result rejection of the project, while variation in investment cost requires an increase by 16% of the base case. In addition an increase in discount rate by 16% of the base case will result rejection of the project.

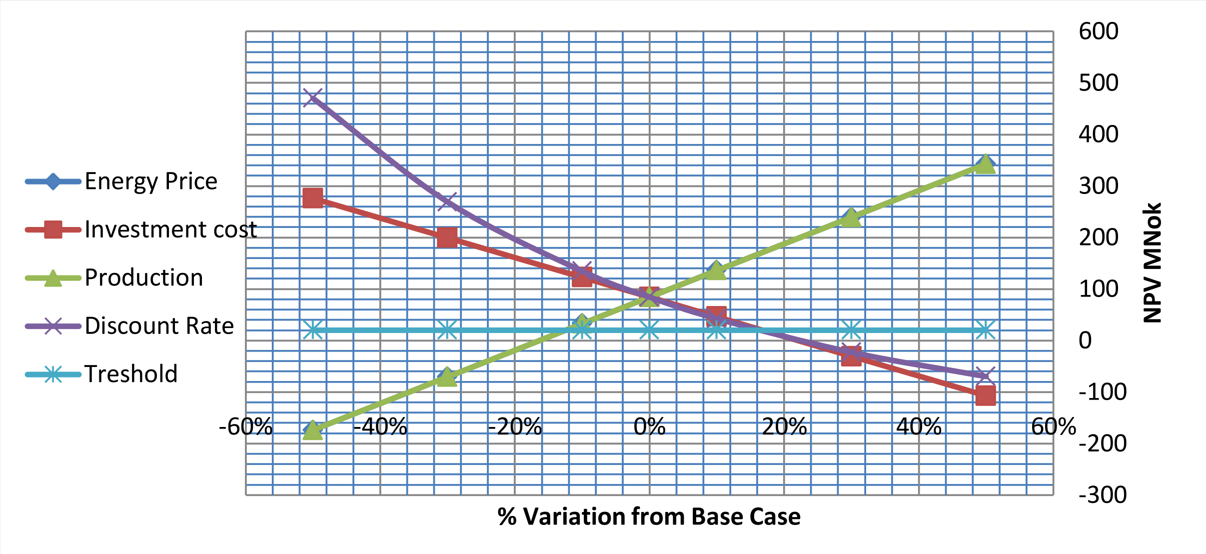

Figure 35 Sensitivity analysis: NPV against Variation

8.2.2 Project Sensitivity against IRR

From the analysis result shown below in Figure 36, it is observed that variation in discount rate will have no influence on IRR of the project. In addition it is also seen that variation on the rest of the variables will result considerable impact on IRR response.

Adopting a threshold value of 7% as a minimum return, the project is found to be feasible up on 20% increase in discount rate, 8% decrease in production and 16% decrease in energy price. The result of the analysis shows a smaller margin of flexibility for variation.

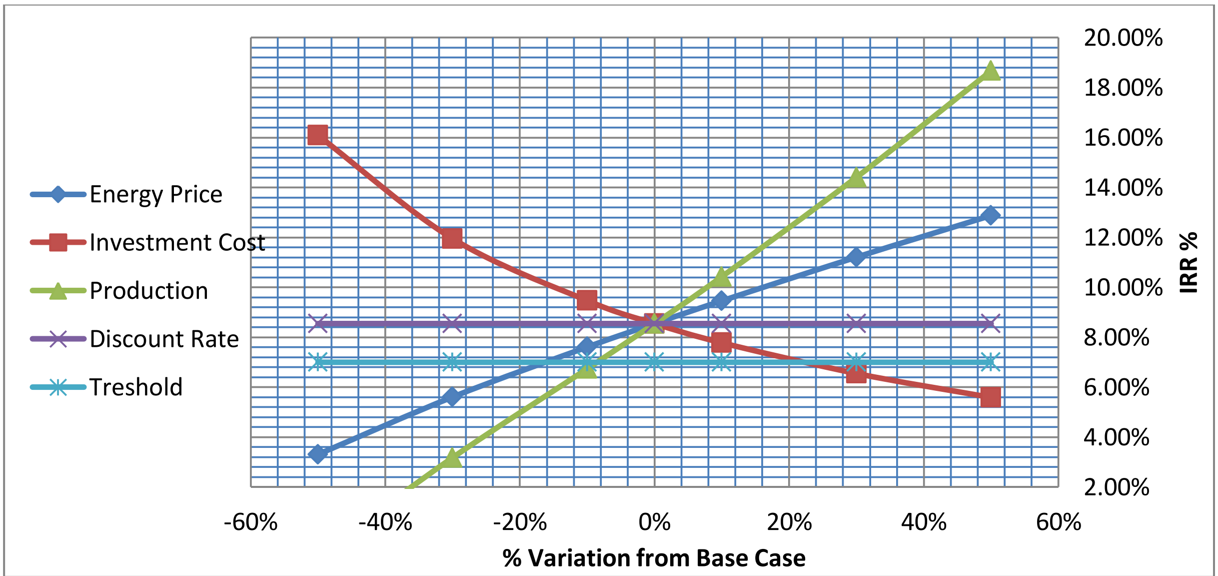

Figure 36 Sensitivity Analysis: IRR against Variation

8.2.3 Project Sensitivity against unit cost

Sensitivity analysis has been undertaken to foresee project response against unit cost of development. Assessment has been undertaken by varying a single element of variable while keeping others on base case scenarios. Analysis result is displayed in Figure 37.

From the analysis result, it can be seen that variations in energy price has no influence on unit cost of project. However variation in discount rate, investment cost and production has a strong influence on the unit cost of the project. The variations in any of the parameters are bound under the assumed threshold value of 0.6 Nok/KWh i.e. the project has a higher flexibility with regard to unit cost of development.

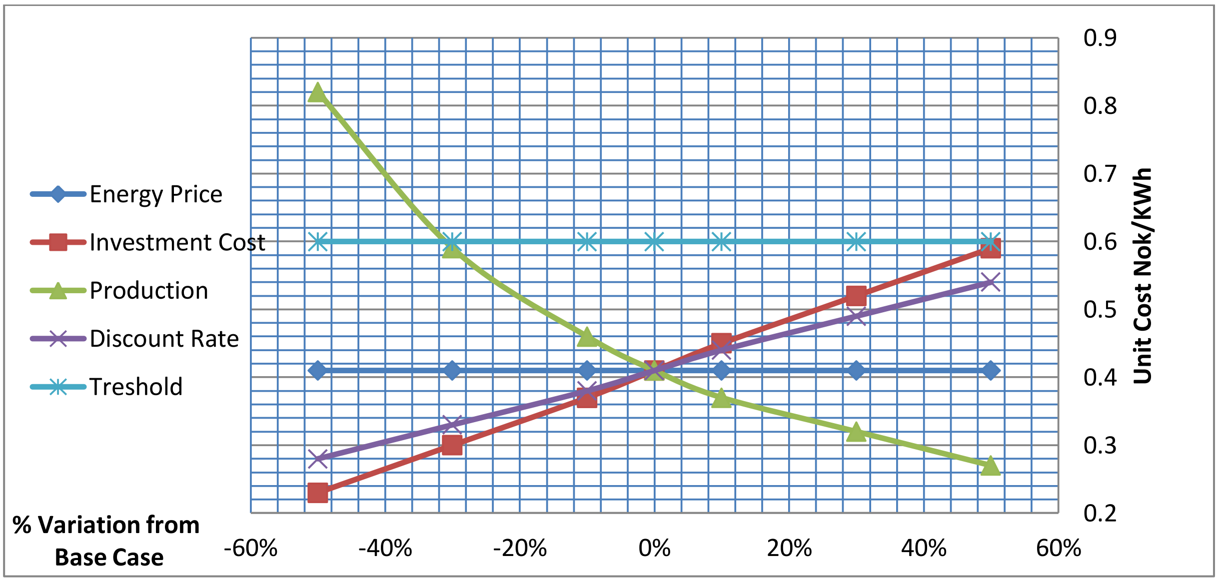

Figure 37 Sensitivity Analysis: Unit Cost against Variation

Project Sensitivity against B/C

From the analysis result shown in Figure 38 below, it can be seen that variation in any of the varying parameters will result quick response on B/C of the project. Assuming threshold value of 1.1 for B/C, it is found that the project will not satisfy viability requirement when energy price and production decreases by 8% and discount rate increases by 10%.

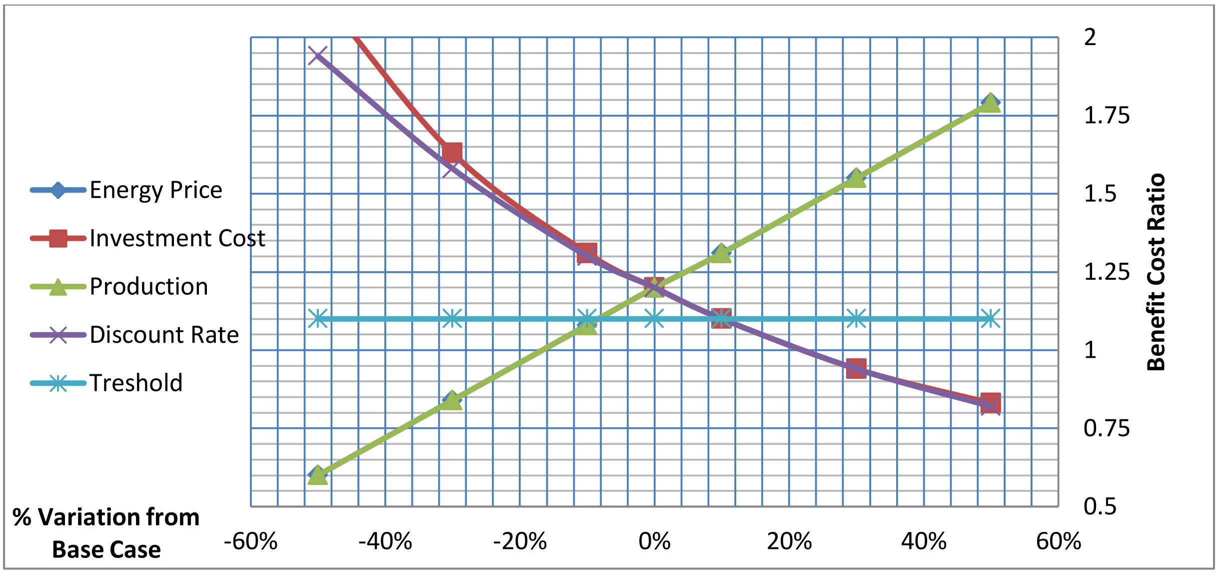

Figure 38 Sensitivity Analysis: Benefit cost ratio against Variation

8.2.4 Project Sensitivity against development rate

Sensitivity analysis on development rate of the project has been undertaken and is shown in Figure 39. From the analysis result it is concluded that variation in energy price doesn't affect the development rate of the project. However cost variation on discount rate, production and construction investment cost will have a strong influence on development rate of the project.

The development rate of the project is set to be under 5 Nok/KWh/yr and is shown as a threshold value in the graph below. For all scenarios undertaken for analysis the project is found to be under the presumed margin, hence it is easy to conclude that the project is viable for development.

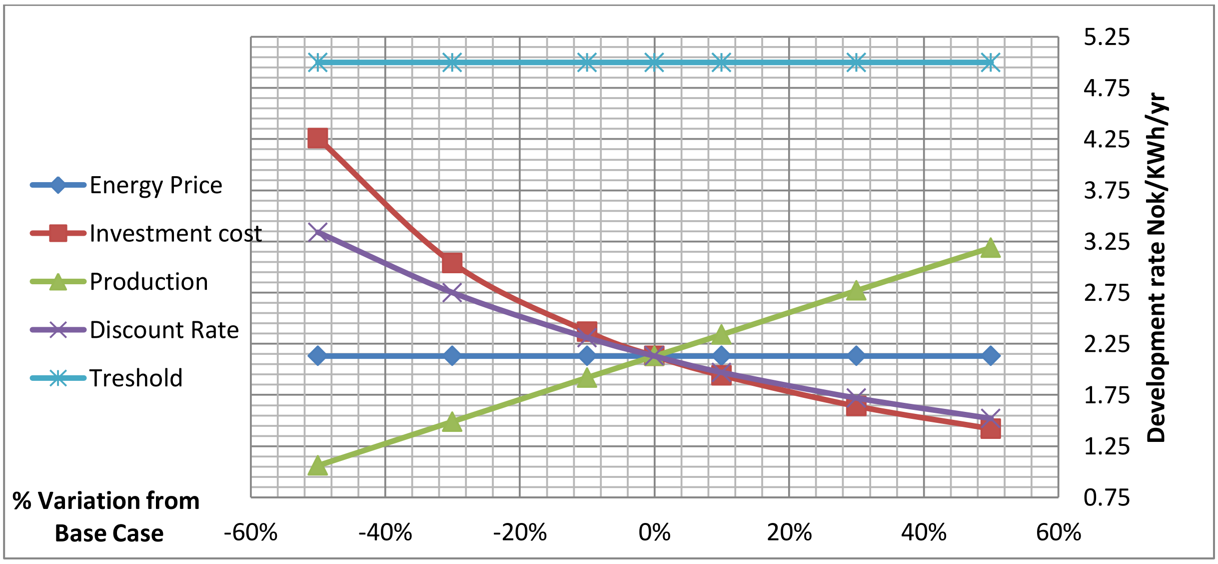

Figure 39 Sensitivity Analysis: Development Rate against Variation

Generally a lower development rate is achieved for the project. It is observed that an increase in discount rate and investment cost leads to a decrease in development rate which actually looks desirable but in reality the increase will question feasibility of the project. Hence a development cost of approximately 2-5 shall be selected.

Discussion and summary

In general the project is found to give a higher return on development. Under the imposed uncertainty margins the project has responded to be viable under the range of 20% increase on investment cost and discount rate. In addition a decrease in energy price and production will also have approximately 16% range to make the project viable.

Therefore during construction all elements which will affect viability of project shall be minimized. It is also preferable if the contract for construction is completed under a lower discount rate than assumed for loan. Special focus shall also goes to detailed optimized engineering solution for design and construction of the project.

Decision for development relays on investment potential and return requirement of the client however as a thesis report the project site is considered as promising for development.

9 CONCLUSION AND RECOMMENDATIONS

After reconnaissance screening of the project alternatives scheme 8 ranking on 2nd level has been selected for prefeasibility level study since both 1st and 2nd ranking project were attractive for development. A single scheme was forwarded for prefeasibility level planning and optimization in Volume II of this thesis report.

Reservoir optimization of the project site has resulted a combined reservoir system for Lake Storåga and Smibelg. A reservoir capacity of 13 Mm^3 was found under optimum dam height of 502.5 masl.

During the optimization progress Installation with two units of Equal capacity, single unit and (2/3 & 1/3) Q_{Design} was assessed under the same catchment hydrology. Installation containing two units of same capacity was selected as a final installation. A design discharge of 200%Q_{mean} was adopted as a final design discharge.

Optimization analysis of Smibelg has resulted station installation with a capacity of 22 MW. At the end of construction the plant will have annual generating capacity of 92 GWh with a firm power production capacity of 25 GWh.

A minimum environmental flow corresponding to a flow 95% probability of occurrence is provided for summer and winter independently. This minimum flow is expected to cop up with the flow requirement downstream of each river reach.

Based on preliminary Environmental impact assessment, the project will have a smaller negative influence on the project. No settlement of people is required and disturbance on the project site will be limited during construction period. Preliminary three year construction period is adopted. The project is considered to have a difficult access road with a steeply moving terrain. Challenges shall be expected on the construction of access road, main dam, conductor tunnel and underwater piercing at the exit of the reservoir.

Economic analysis of the project has resulted a net present value of 84.38 MNok, IRR of 8.55%, B/C of 1.2 and unit cost of development of 0.41 Nok/KWh. The project will have a payback period of less than 20 years. In addition a smaller development rate of 2.13 Nok/kwh/year was obtained. In general the project is attractive for development.

Sensitivity analysis on NPV, IRR, unit cost, development rate and benefit cost ratio against variation in energy price, production, investment cost and discount rate has resulted a +/-20% variation margin for project viability. Hence the project is considered viable for development

Recommendation

There are a number of areas with major uncertainties regarding the assessment of the schemes as presented in this report; hence the following pointes should be noted in the next stages:

- Site specific Hydrological data; since the location of the nearby gauging station is at a lower elevation [200masl] than project catchment [400masl] variation in catchment response is expected. Setting a gauging station will avoid unnecessary uncertainties.
- Geological investigation; detailed geological investigation should be carried out to foresee the impact on the main structural locations
- Prepare detailed cost estimate to the level required including the components that are left in this investigation
- Undertake environmental impact assessment for the recommended project by quantifying the extent of impact on affected areas
- Access road; during the reconnaissance only access road to reservoir dam site and power house is considered hence plan should be set out to cover all the main project components that might need access road
- Transmission; route as well as capacities of transmission lines required should be assessed to the required level
- Preliminary plan should be set out for construction and operation of the recommended project

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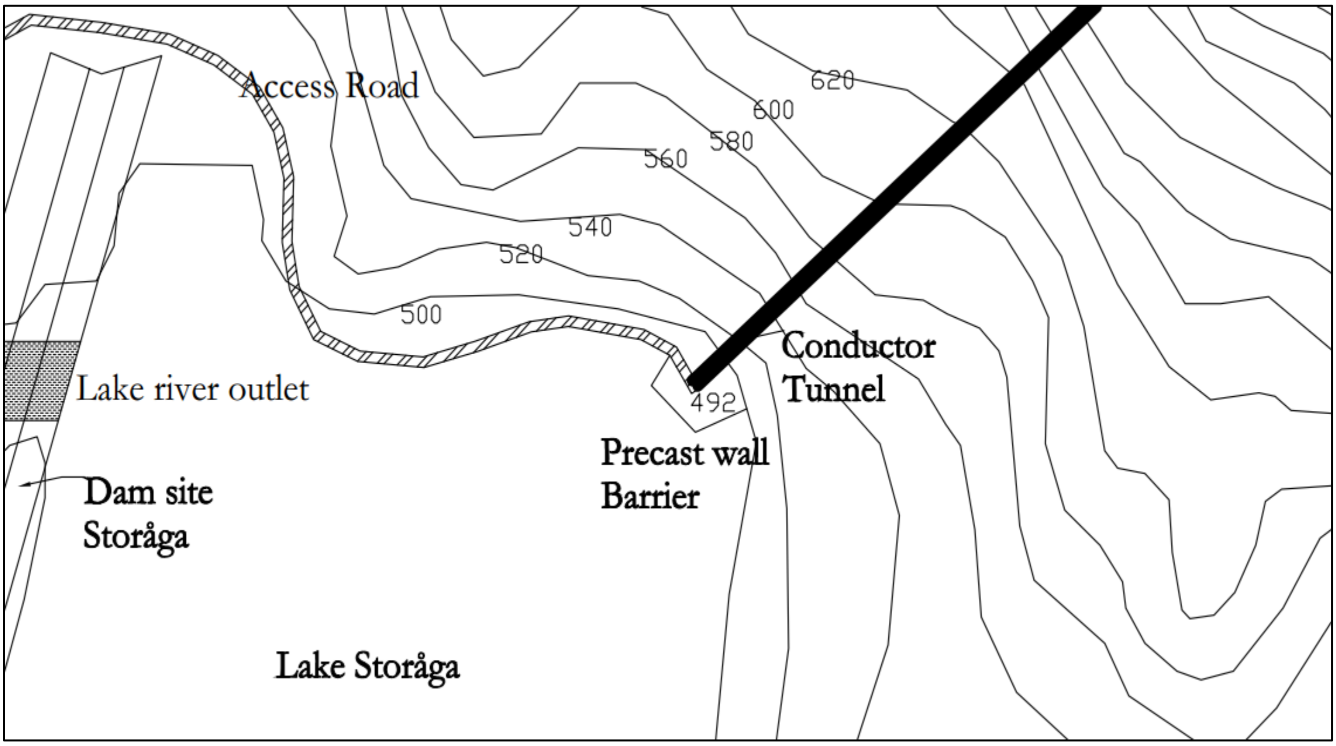
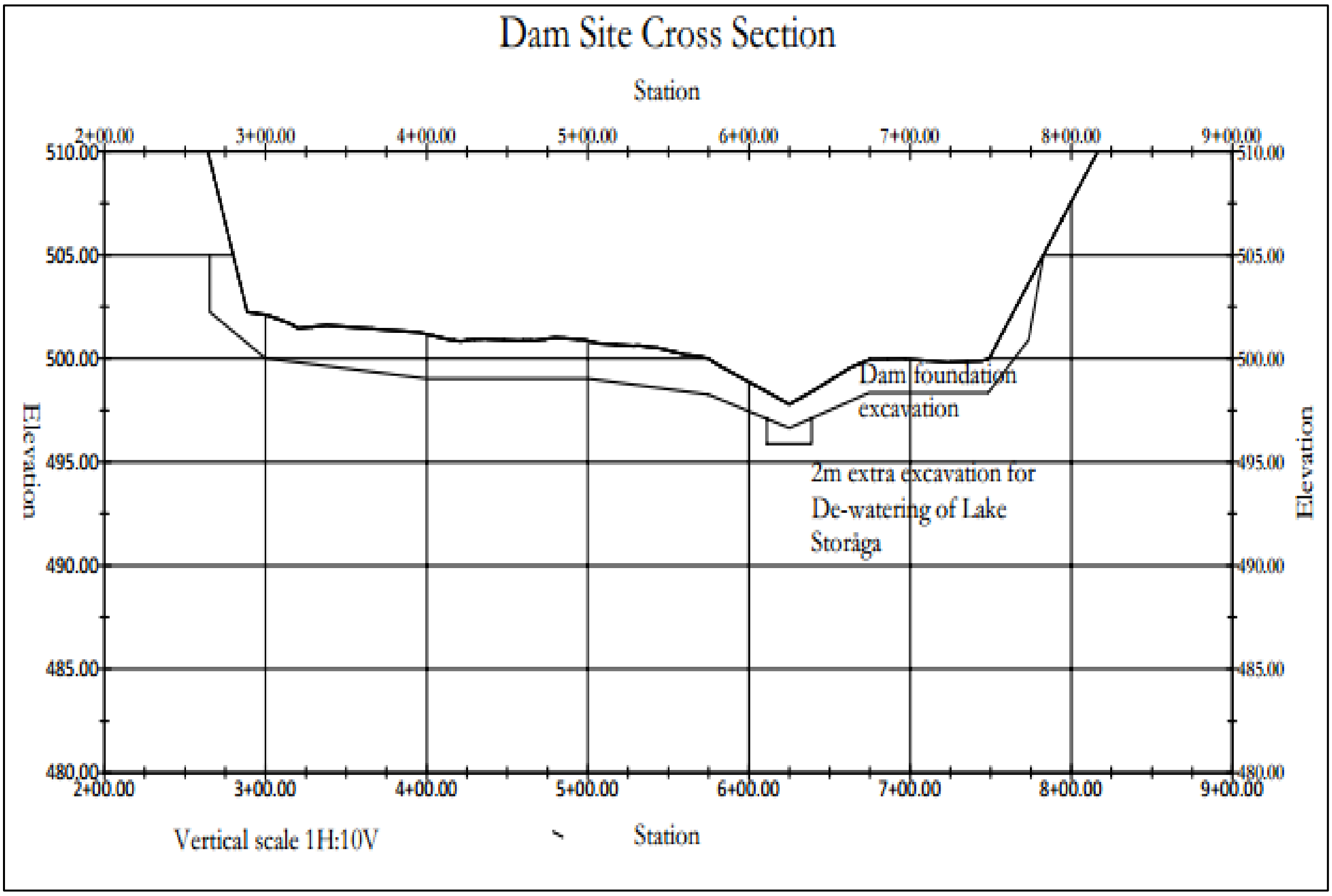
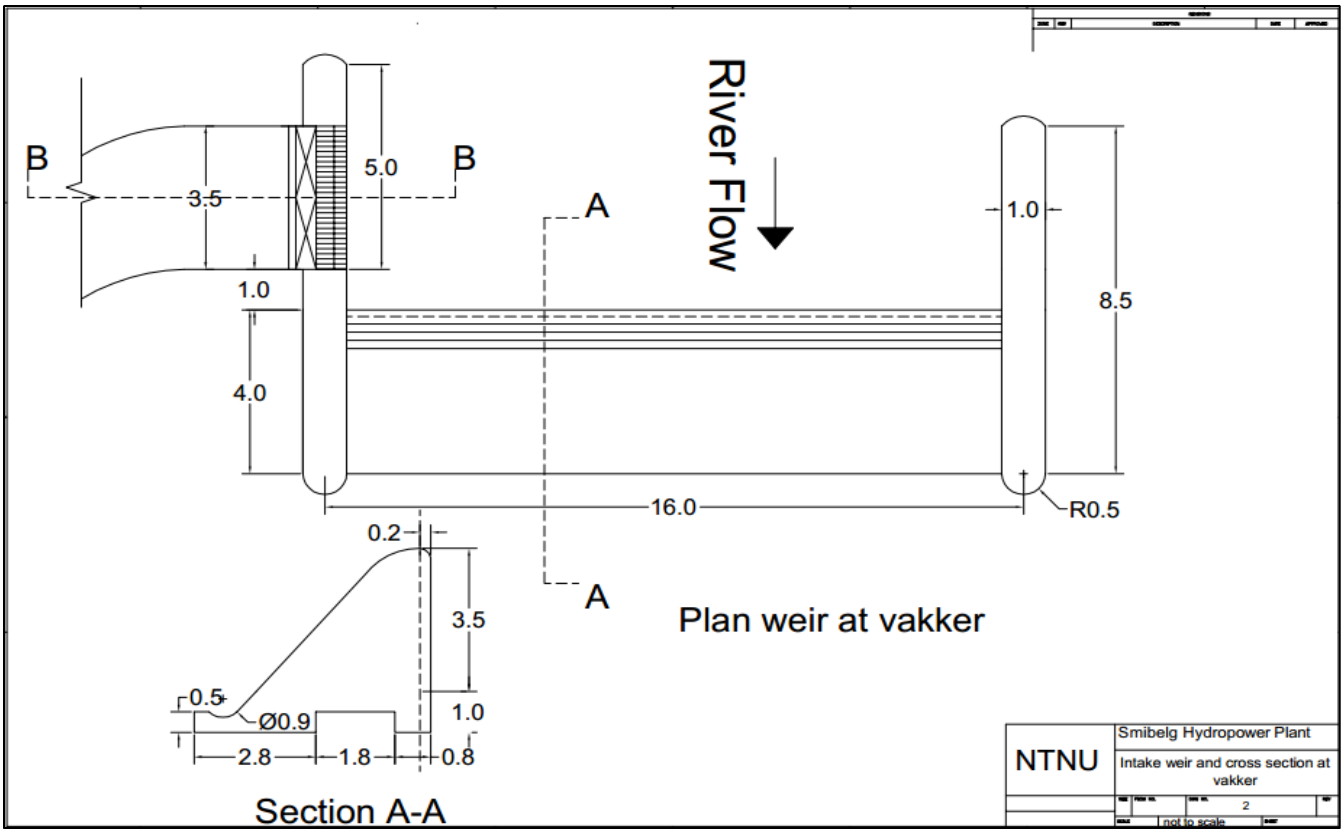
Volume III Project Drawings

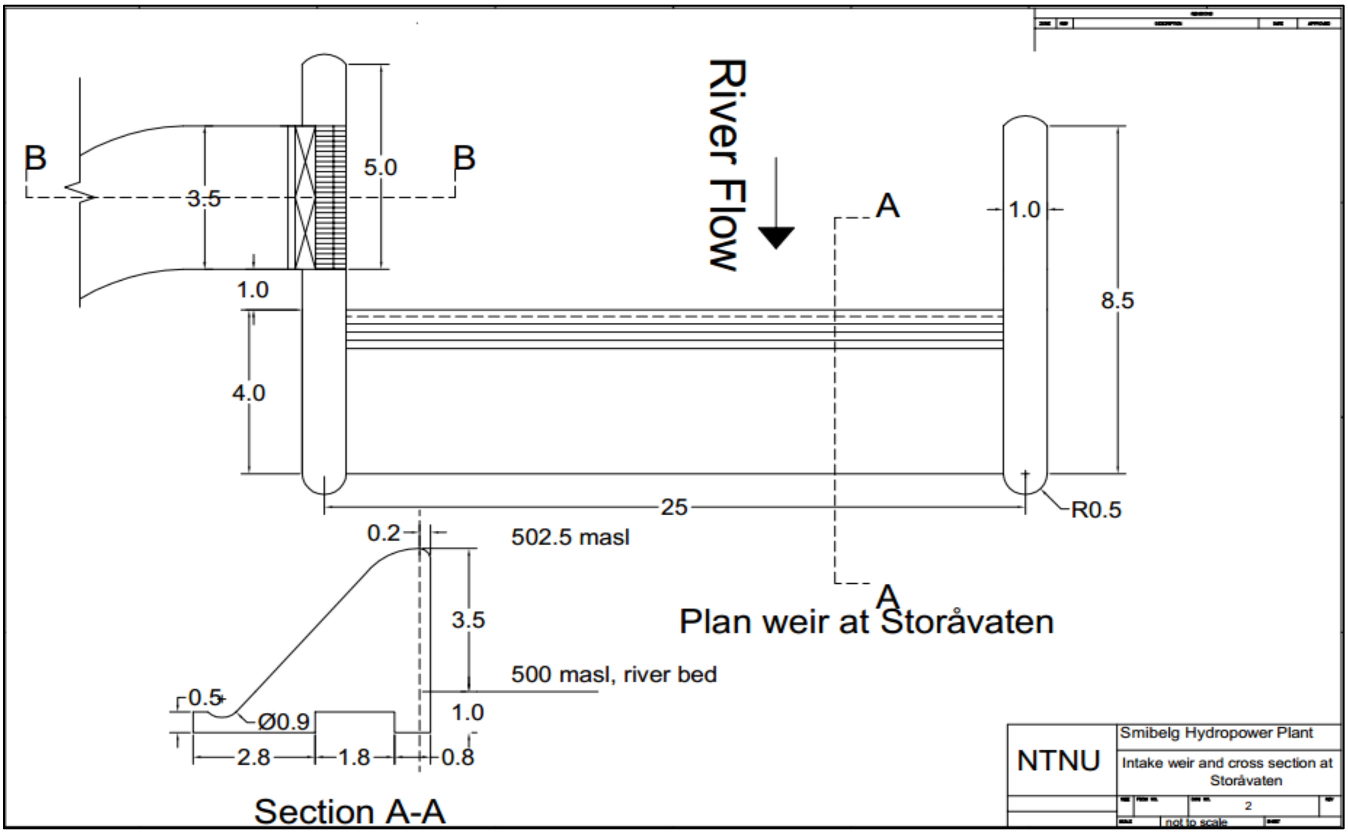
Annex D-01: Plan layout for dewatering of Lake Storåga

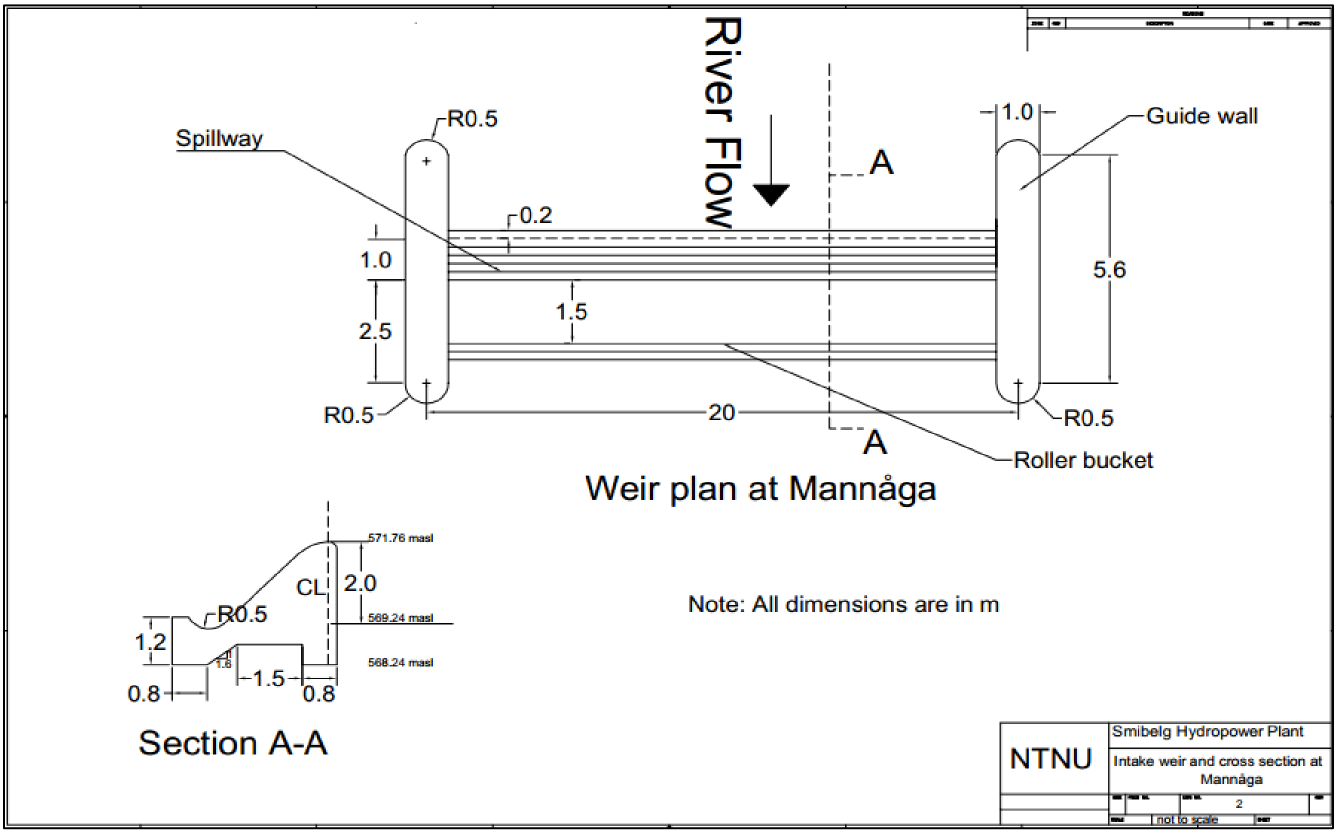




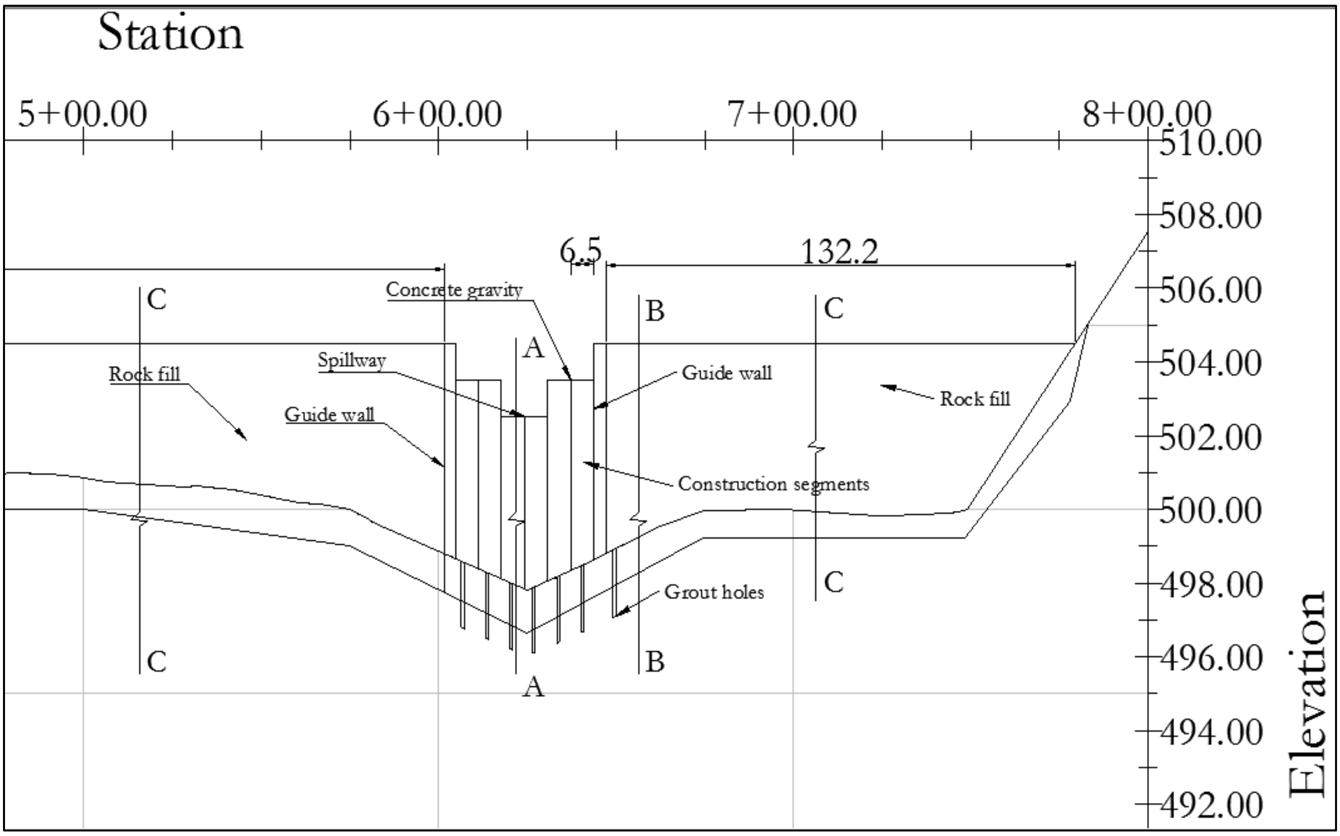
Annex D-02 plan and cross section detail, weir @ vakker, Storåvaten & mannåga



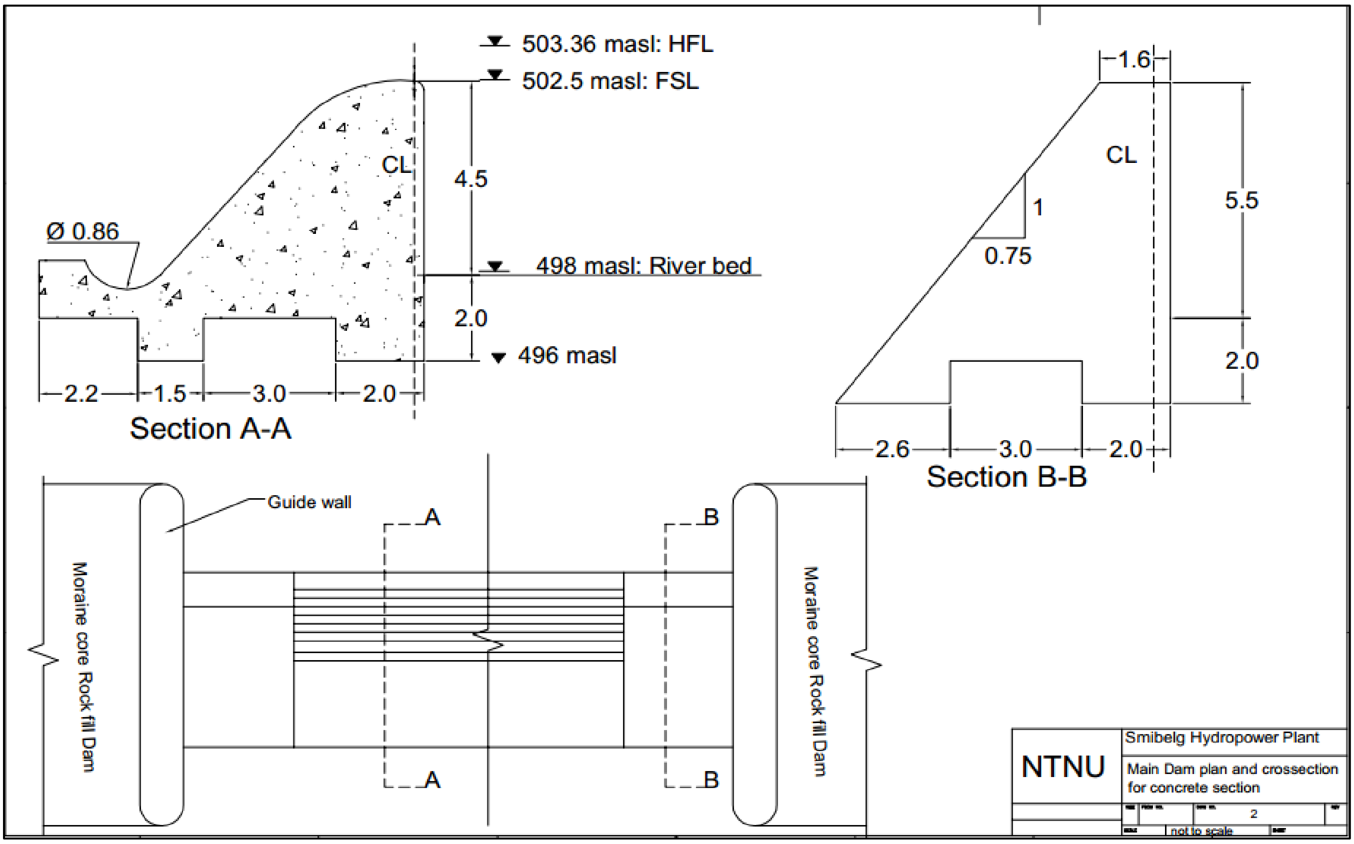


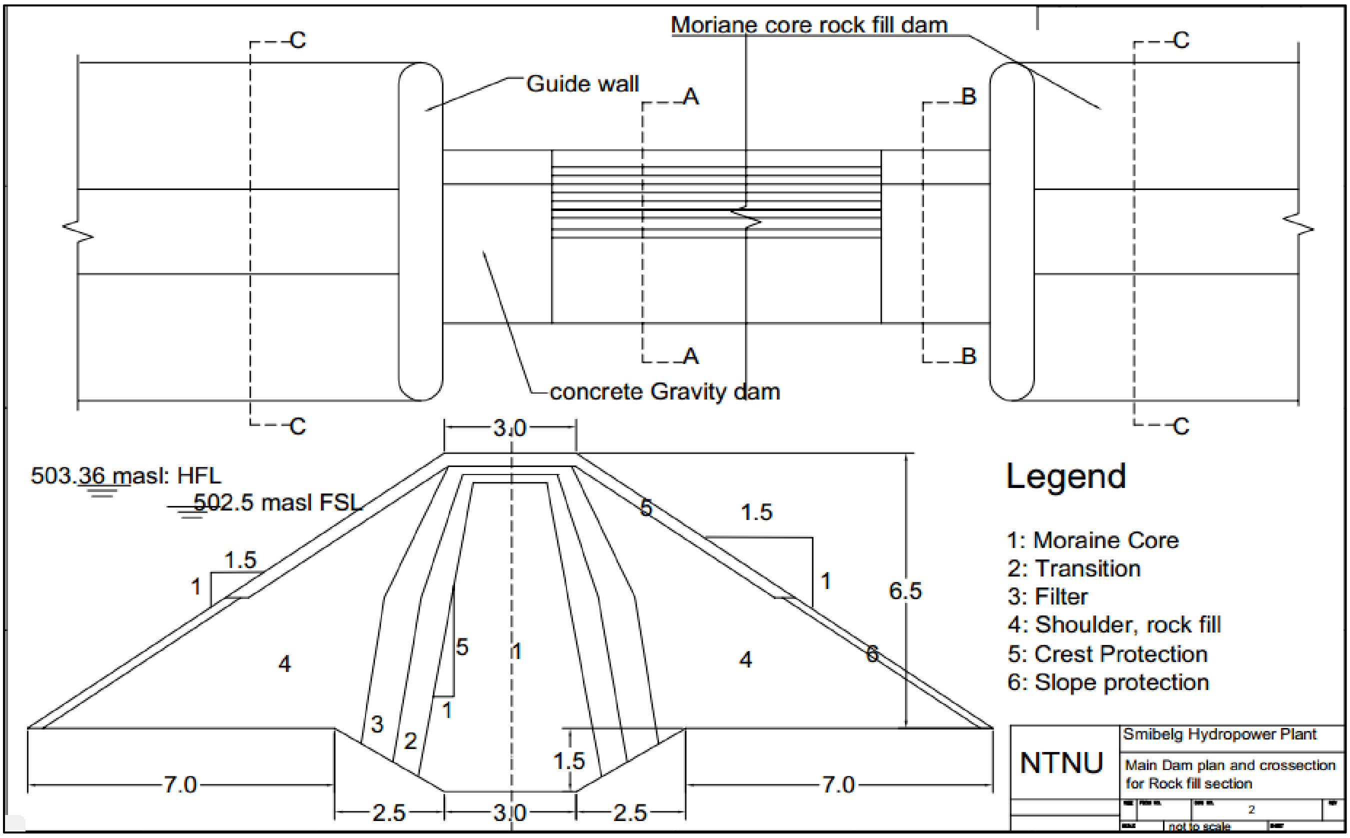

River Flow
Spillway
R0.5
0.2
1.0
2.5
1.5
R0.5
20
A
A
1.0
Guide wall
5.6
R0.5
Roller bucket
Weir plan at Mannåga
571.76 masl
CL
2.0
569.24 masl
R0.5
1.2
0.8
1.5
0.8
568.24 masl
Section A-A
Note: All dimensions are in m
NTNU
Smibelg Hydropower Plant
Intake weir and cross section at Mannåga
2
not to scale

Annex D-03 plan and cross section detail for dam @ Storåga



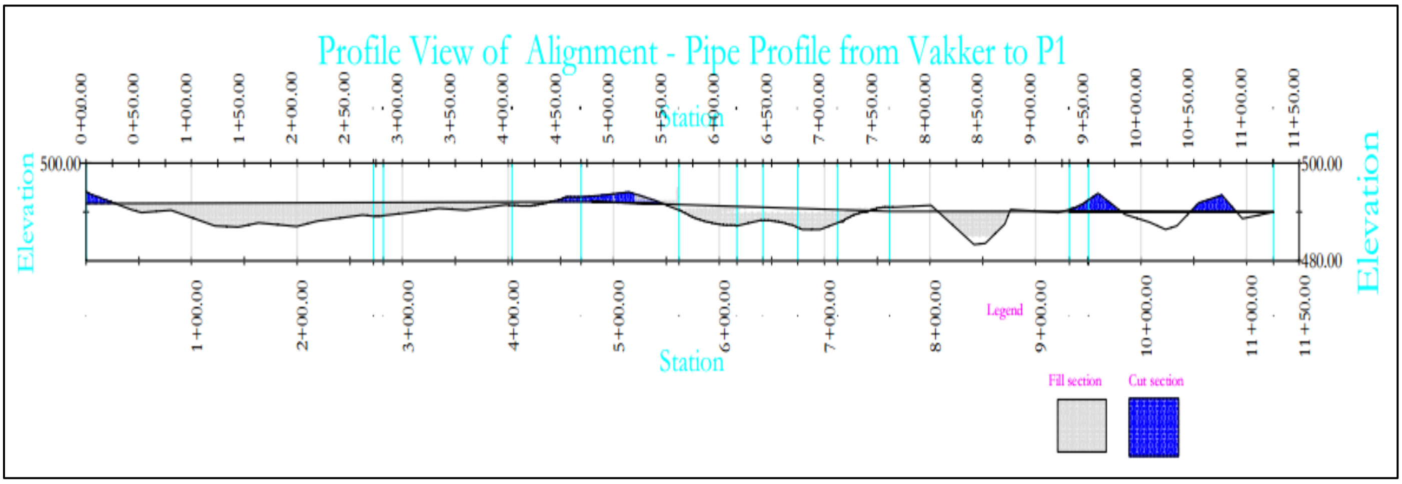
Dam site cross section Source: Auto cad Civil 3D

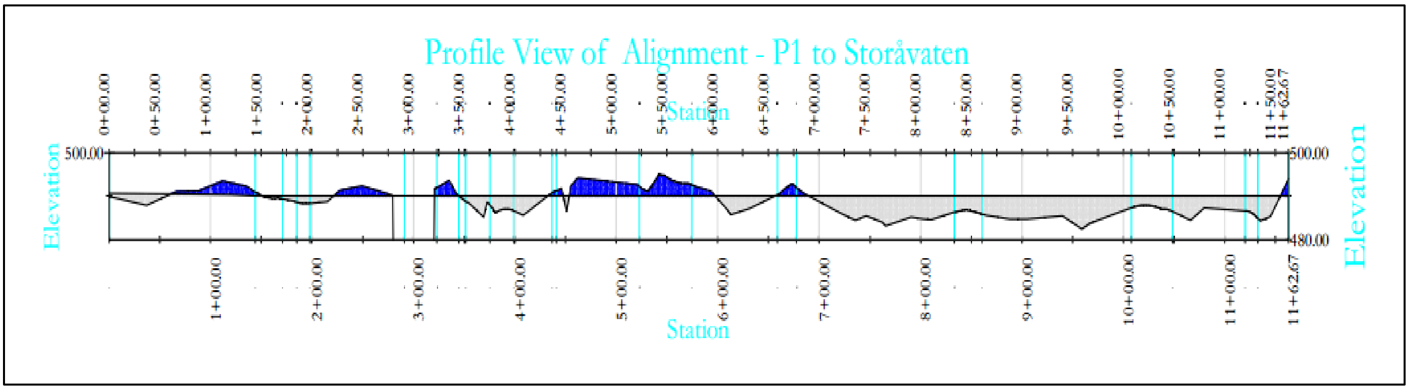




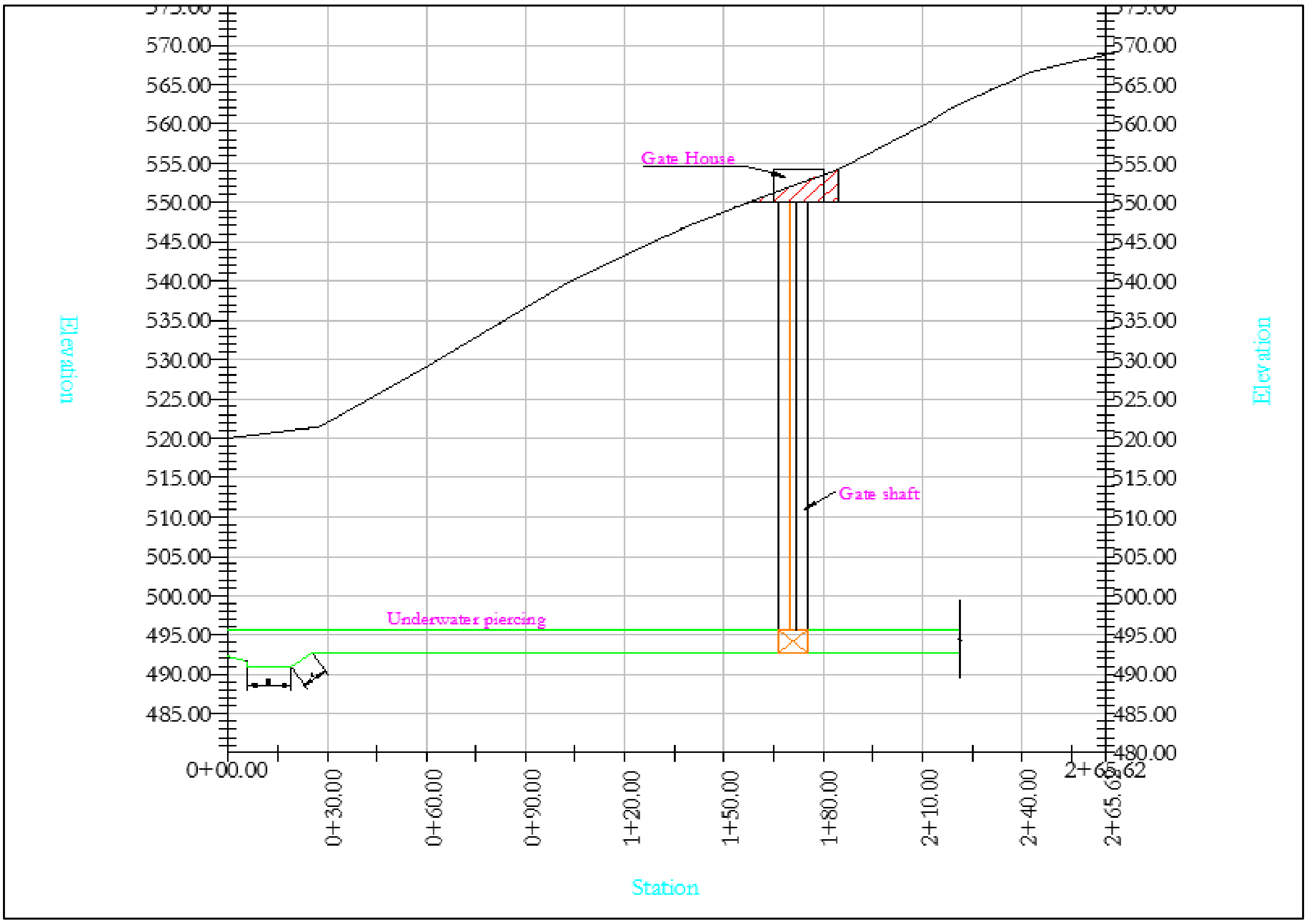
All dimensions are in m.

Annex D-04 Profile transfer pipe layout

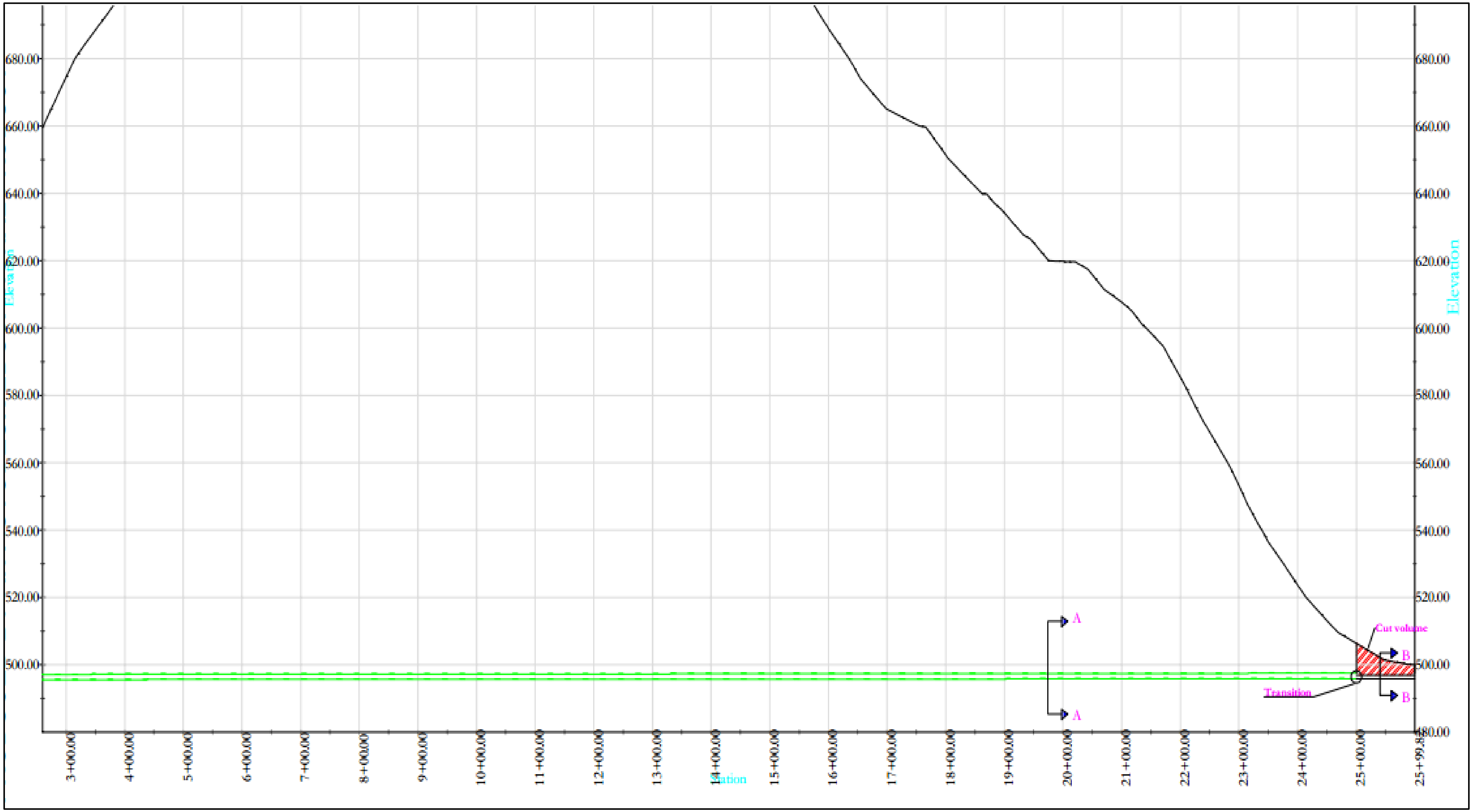




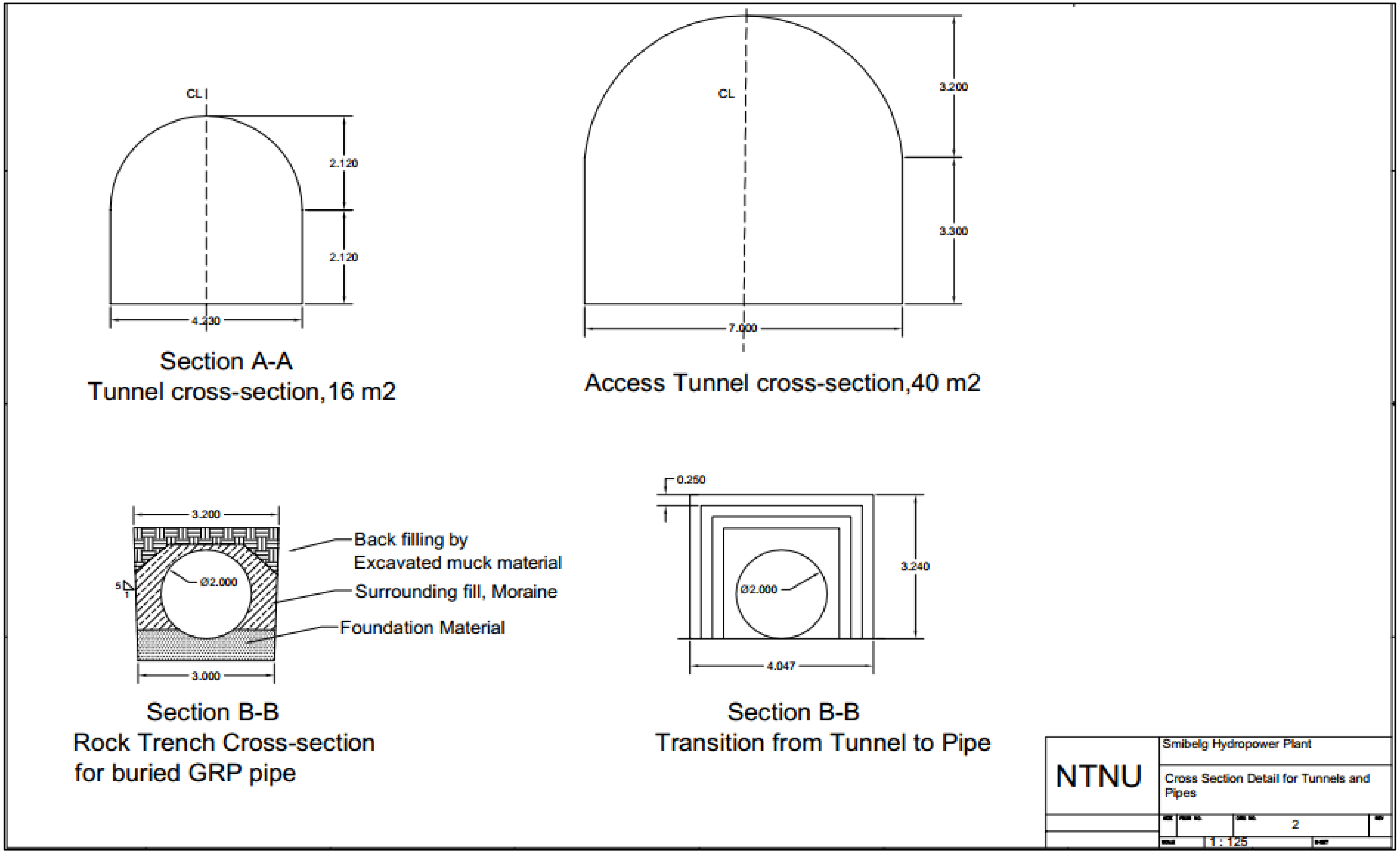
Annex D-05 Profile HRT- underwater piercing system layout



Annex D-06 Cross - profile Head Race Tunnel

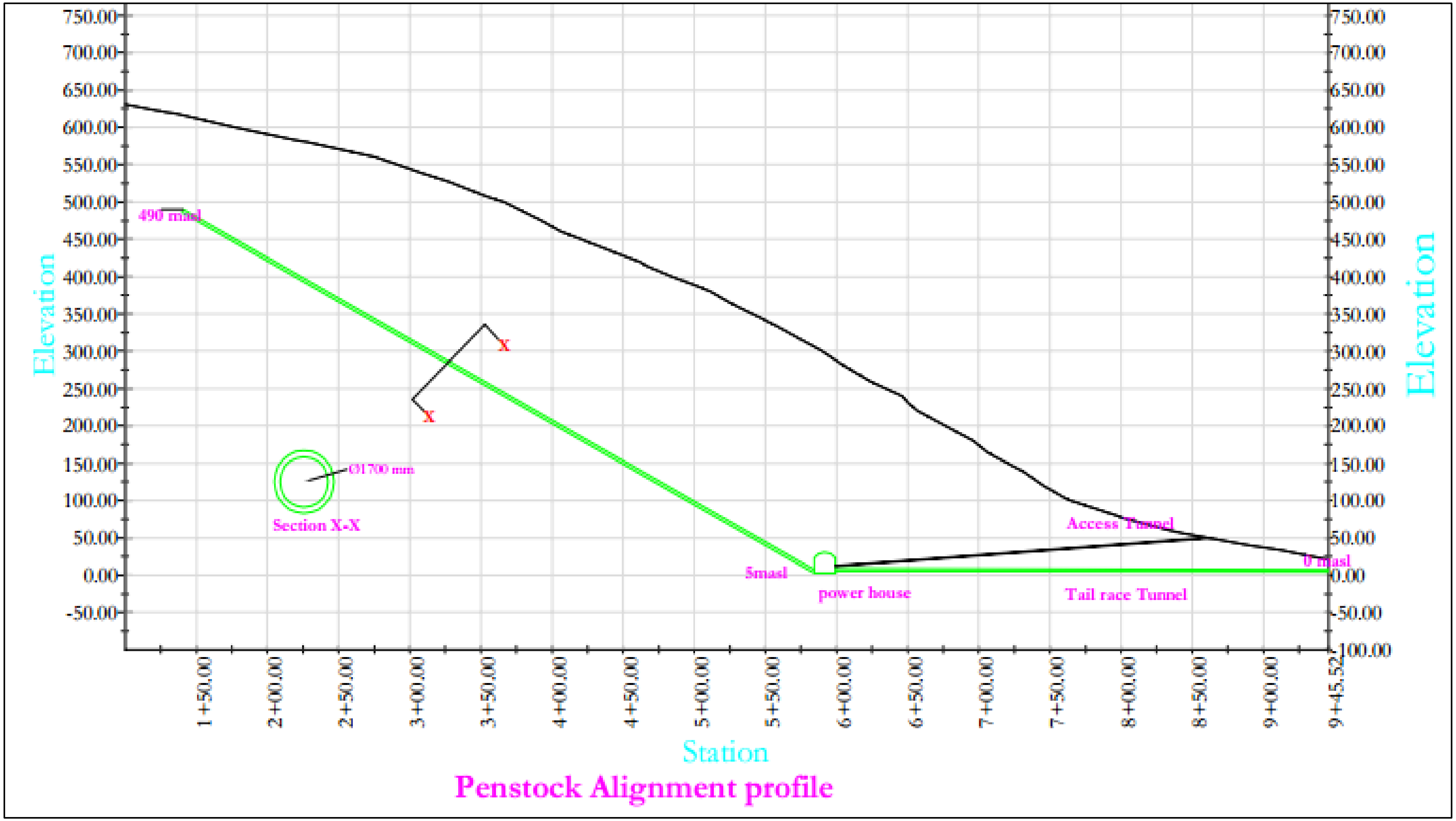


Annex D-06 Cross - Section Detail for HRT Tunnel, Access tunnel and Pipe

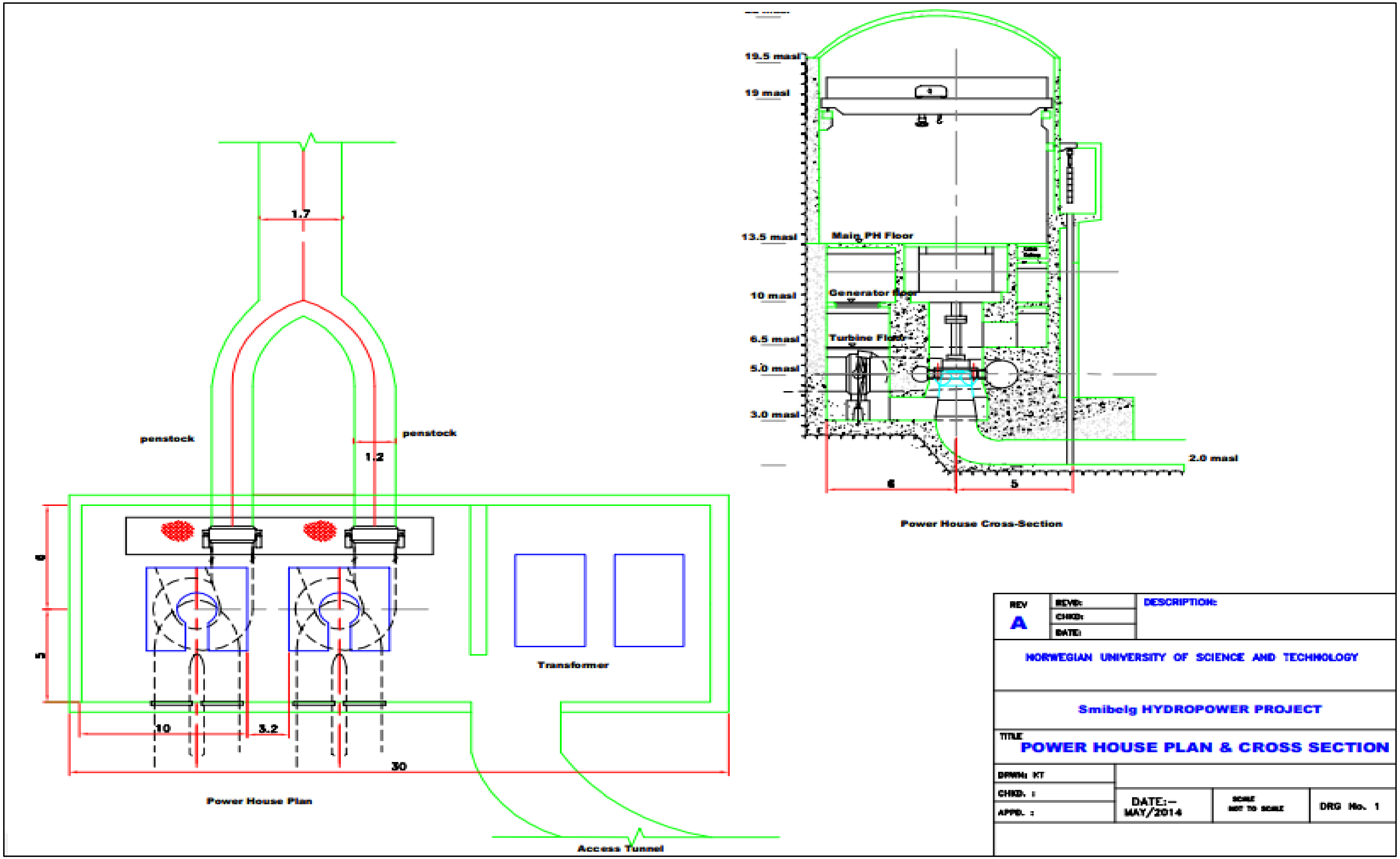


Profile detail underwater piercing, all dimensions are in meter, Source: Auto cad-Civil 3D Vertical exaggeration = 2.5

Annex D-07 power house profile and Cross section detail



Profile detail penstock and tail race tunnel, Vertical exaggeration = 0.5, Source: Auto cad civil 3D



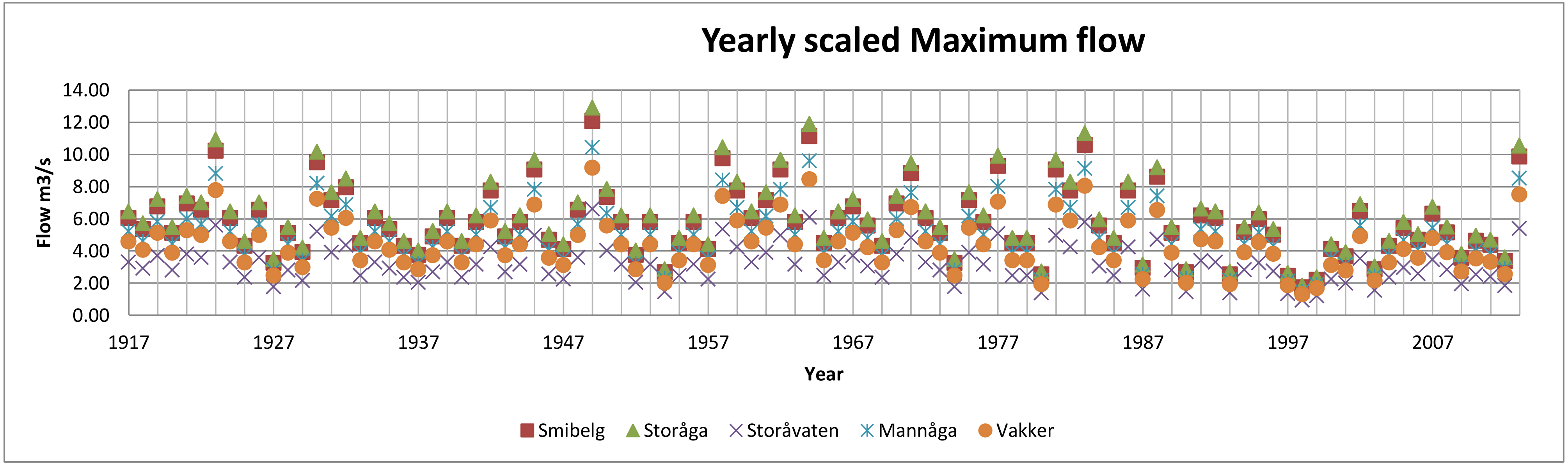
19.5 masl
19 masl
13.5 masl
Main PH Floor
10 masl
Generator floor
6.5 masl
Turbine Floor
5.0 masl
3.0 masl
2.0 masl
6
5
Power House Cross-Section
1.7
penstock
penstock
1.2
6
5
10
3.2
30
Transformer
Power House Plan
Access Tunnel
REV
A
RECVD:
CHKD:
DATE:
DESCRIPTION:
NORWEGIAN UNIVERSITY OF SCIENCE AND TECHNOLOGY
Smibelg HYDROPOWER PROJECT
TITLE
POWER HOUSE PLAN & CROSS SECTION
DRWN: KT
CHKD. :
APPD. :
DATE:– MAY/2014
SCALE NOT TO SCALE
DRG No. 1

Volume IV Project Analysis and Calculations

Annex H-01 Gauge Analysis:

		Station	Sub-catchments						
parameter	Units	vassvatnet	Storåga	smibelg	øvere Vakker	nedre storåvatnet	østre storåvatnet	Mannåga	TR smibelg
Catchment area	km2	16.4	4.2	4.4	3.5	3.7	2.4	4.2	1.4
specific runoff	l/s/km2	122.8	152.4	133.6	127.5	126	134.1	121	145
Annual average precipitation	mm	2620	2865	3010	3041	3011	3026	3029	2921
Min elevation	masl	107	497	504	485	376	500	571	498
Max elevation	masl	1160	1160	1152	1023	1020	1020	947	1085
Terrain type									
Dyrket Mark	%	0.6	0	0	0	0	0	0	0
Myr	%	0.2	0	0	0	0	0	0	0
Sjø	%	10.9	12.3	21.2	2.2	10.5	13.9	12.7	0.3
Skog	%	29.4	0	0	97.7	0	0	0	0
Snaufjell	%	56.9	87.7	78.8	0	89.4	86	87.2	99.7
Sub -Total	%	98	100	100	99.9	99.9	99.9	99.9	100
Other	%	2	0	0	0.1	0.1	0.1	0.1	0
Total	%	100	100	100	100	100	100	100	100
Scaling factor			0.318	0.292	0.222	0.231	0.160	0.252	0.101

Annex H-02 flood frequency analysis



Description	Smibelg	Storåga	Øsre storåvatnet	mannåga	østre vakker
Consequence class	Class 1	Class 2	Class 1	Class 1	Class 1
Design flood	Q500	Q1000	Q500	Q500	Q500
Safety cheek flood	Q500	1.5*Q1000	Q500	Q500	Q500
Mean m3/s	5.78	6.18	3.17	4.99	4.39
St. Deviation m3/s	2.11	2.26	1.16	1.82	1.61
N years	500	1000	500	500	500
Gumbels coefficient K_T	4.39	4.94	4.39	4.39	4.39
Design flood m3/s	15.06	17.31	8.25	13.00	11.45

$$Q\ mean = \frac{\sum Qmax}{n}$$

$$Q_T = Qmean + K_T x S$$

$$K_T = -\frac{\sqrt{6}}{\pi}\left(0.5772 + \ln\left(\ln\left(\frac{T}{T-1}\right)\right)\right)$$

n = 97 years

T = 1000 year for Storåga and 500 for the rest

Annex H-03 Intake and trash rack Design

Intake Structure Design					
Intake	unit	Smibelg	Vakker	Storåvatn	Mannåga
Area of conduit	m2	16	3.14	3.14	16
Inclination of intake with the horizontal		0	0	0	0
Coefficient of expansion/Contraction		2.00	0.60	0.60	1.26
Area of intake required	m2	16.00	6.23	6.23	16.00
Height of intake	m	4.5	2	2	4.5
Width of intake	m	4.5	3.5	3.5	4.5
LRWL	masl	498.00	500.00	499.00	570.00
Design Flow	m3/s	5.26	5.26	5.26	5.26
Maximum velocity clogged condition	m/s	1.53	3.93	3.93	1.53
Maximum velocity without clogging	m/s	0.51	1.30	1.30	0.51
Acceleration due to Gravity	m/s2	9.81	9.81	9.81	9.81
Froud Number		0.08	0.20	0.20	0.08
Minimum Submergence	c/c	6.06	1.00	1.00	1.76
Inlet Invert	masl	491.94	499.00	498.00	568.24
Inlet crown	masl	494.19	500.00	499.00	570.49
Bottom Clearance	masl		0.50	0.50	0.00
HRWL	masl	502.5	503.50	502.50	571.76
Dam height required	m	4.50	3.50	3.50	1.76
Proposed dam height	m	6.5	3.5	3.5	2

Trash Rack Design					
Trash rack	unit	Smibelg-storåga	Vakker	Storåvaten	Mannåga
Mean annual discharge	m3/s	1.32	0.73	0.3	0.47
% of flow		200%	200%	200%	200%
Q design	m3/s	2.64	1.46	0.60	0.94
Velocity of water at the intake	m/s	4.14	4.14	4.14	9.32
Intake opening required	m2	0.64	0.35	0.14	0.10
height	m	2	2	2	3
Width 1 panel	m	2.00	2	2	3
Inclination		15.00	15.00	15.00	15.00
Area provided	m2	4.14	4.14	4.14	9.32
Trash Rack Details					
width of steel bar	mm	5	5	5	5
width of opening	mm	75	75	75	75
Number of openings	no	479	479	479	1077
Area covered with steel bars	m2	1.45	1.45	1.45	3.26
Net available flow area	m2	2.69	2.69	2.69	6.06

Annex H-04 Spillway shape calculations

Design Parameters	unit	Storåga	Mannåga	Vakker	Storåvaten
Design flood	m3/s	17.31	13	11.45	8.25
Crest length	m	420	20	15	25
Spillway length	m	12	20	15	25
Design head	m	0.76	0.45	0.5	0.29
Effective length	m	11.848	19.91	14.9	24.942
Computed discharge	m3/s	17.35	13.28	11.64	8.61
Dam height [p]	m	4.50	2.00	3.50	3.50
Cd cheek (P/Hd>4)		5.92	4.44	7.00	12.07
D/s profile [y]	x^1.85	0.631	0.986	0.901	1.432
Max horizontal distance	m	1.08	0.64	0.71	0.41
Max vertical distance	m	0.732	0.433	0.481	0.279
U/s profile					
R1	m	0.38	0.225	0.25	0.145
R2	m	0.152	0.09	0.1	0.058
b	m	0.214	0.127	0.141	0.082
a	m	0.133	0.079	0.088	0.051
Discharge per unit length	m2/s	1.461	0.653	0.768	0.331
Velocity at the dam Toe		2.68	2.74	3.23	4.79
Radius of bucket		1.103	0.957	1.034	1.108

Annex -05 Dam stability anaysis calcualation

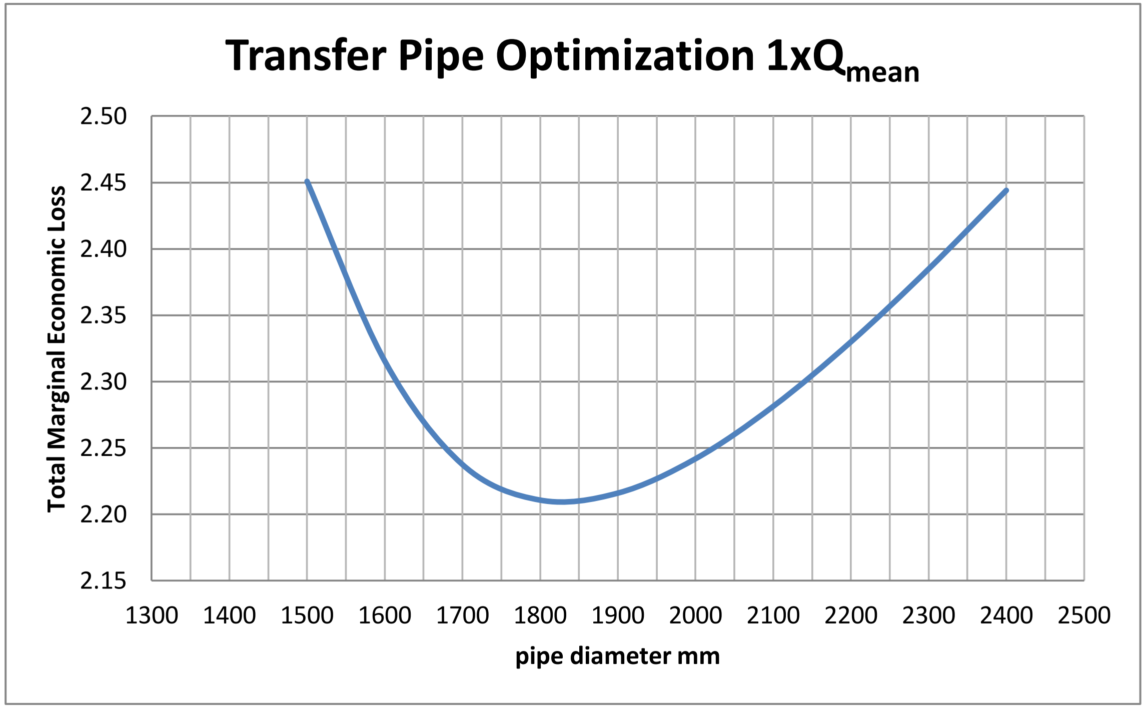
Dam stability calculations	Quantity KN	moment arm m	Moment KNm	Remark
Horizontal force due to U/s water	101.25	1.5	151.875	Overturning moment
Uplift force	135	4	540	Overturning moment
Horizontal ice force U/s water	0.3125	4.25	1.328125	Overturning moment
vertical force due to self-weight				
W1	220	5.2	1144	Stabilizing Moment
W2	121	2.93	354.93	Stabilizing Moment

Sum of horizontal forces	101.5625	KN
Sum of vertical forces	206	KN
Sum of overturning moment	693.20	KNm
Sum of stabilizing moment	1498.93	KNm

Safety factor against sliding	0.49	Less than 0.75 Safe!
Safety factor against overturning	2.16	Greater than 1.5 Safe!

Annex H-06
Transfer Pipe Optimization 1xQ_{mean}

Diameter	1400	1500	1600	1700	1800	1900	2000	2100	2200	2300	2400
Total Pipe cost	19.07	20.80	22.63	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84
Marginal pipe Cost	0.00	1.73	1.83	1.90	1.97	2.04	2.12	2.19	2.26	2.33	2.40
Economic Loss	2.52	1.80	1.32	0.98	0.74	0.57	0.45	0.35	0.28	0.23	0.18
Marginal Economic loss		0.72	0.49	0.34	0.24	0.17	0.13	0.09	0.07	0.05	0.04
Pipe Diameter Increase		1450.00	1550.00	1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00
Total Economic Loss		2.45	2.32	2.24	2.21	2.22	2.24	2.28	2.33	2.38	2.44

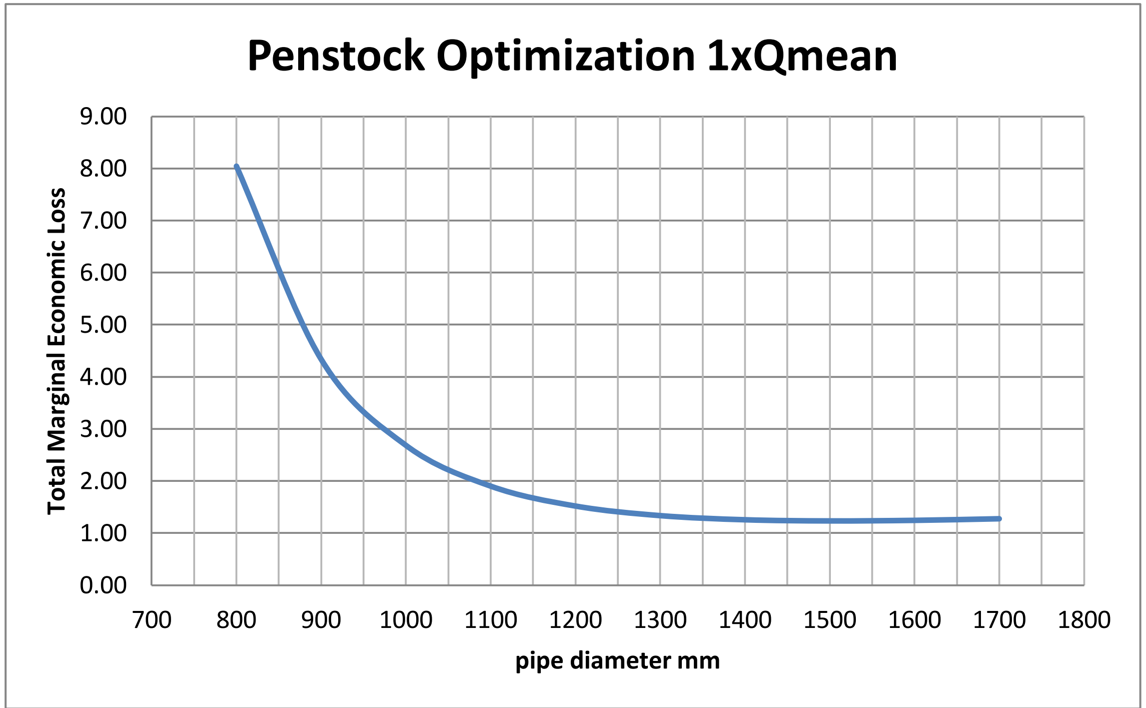


<u>Analaysis Input data</u>:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1800**	**mm**

Penstock tunnel Optimization 1xQ$_{mean}$

Total Tunnel cost	9.77	10.36	11.01	11.73	12.51	13.36	14.29	15.27	16.33	17.45	18.64
Marginal Tunnel Cost		0.58	0.65	0.72	0.79	0.85	0.92	0.99	1.05	1.12	1.19
Economic Loss	16.21	8.75	5.07	3.10	1.99	1.32	0.91	0.64	0.46	0.34	0.26
Marginal Economic Loss		7.46	3.68	1.96	1.11	0.67	0.41	0.27	0.18	0.12	0.09
Pipe Diameter		800	900	1000	1100	1200	1300	1400	1500	1600	1700
Total Marginal Economic Loss		8.04	4.33	2.68	1.90	1.52	1.33	1.26	1.23	1.24	1.27

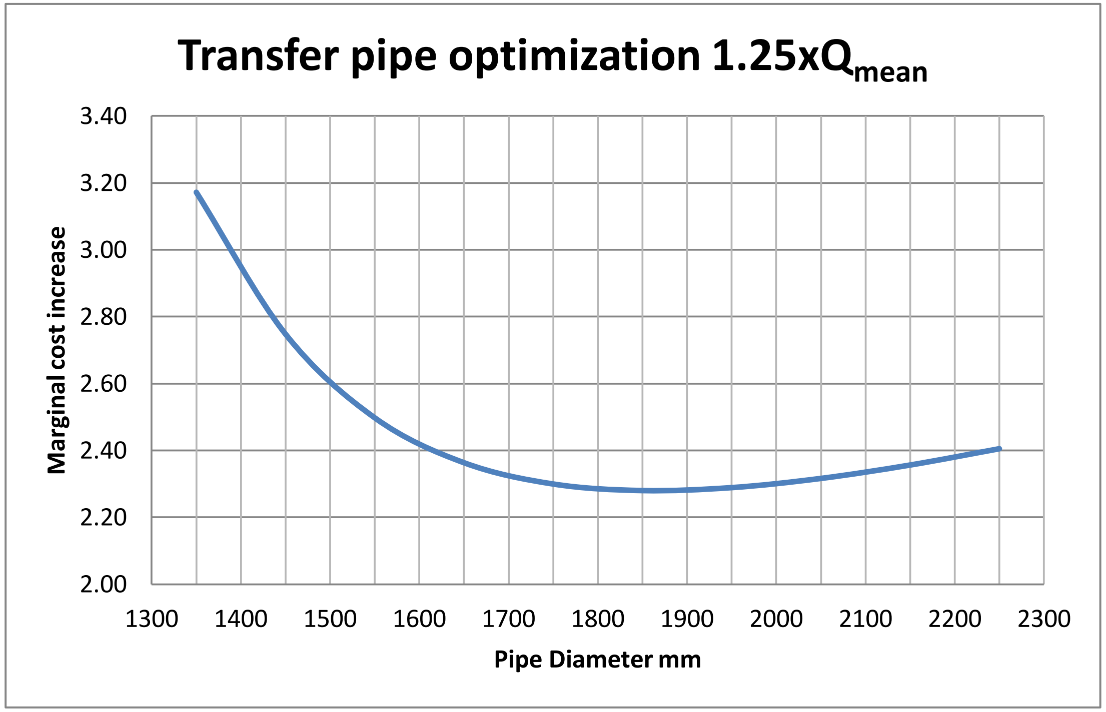


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1500**	**mm**

Transfer Pipe Optimization $1.25xQ_{mean}$

Diameter	1300	1400	1500	1600	1700	1800	1900	2000	2100	2200	2300
Total Pipe cost	17.38	19.04	20.80	22.63	24.53	26.51	28.55	30.67	32.85	35.11	37.44
Marginal pipe Cost	0.00	1.66	1.76	1.83	1.90	1.97	2.04	2.12	2.19	2.26	2.33
Economic Loss	4.97	3.46	2.47	1.81	1.35	1.02	0.78	0.61	0.48	0.38	0.31
Marginal Economic loss		1.51	0.99	0.67	0.46	0.33	0.24	0.17	0.13	0.10	0.07
Pipe Diameter increse		1350.00	1450.00	1550.00	1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00
Total Economic Loss		3.17	2.75	2.50	2.36	2.30	2.28	2.29	2.32	2.36	2.41

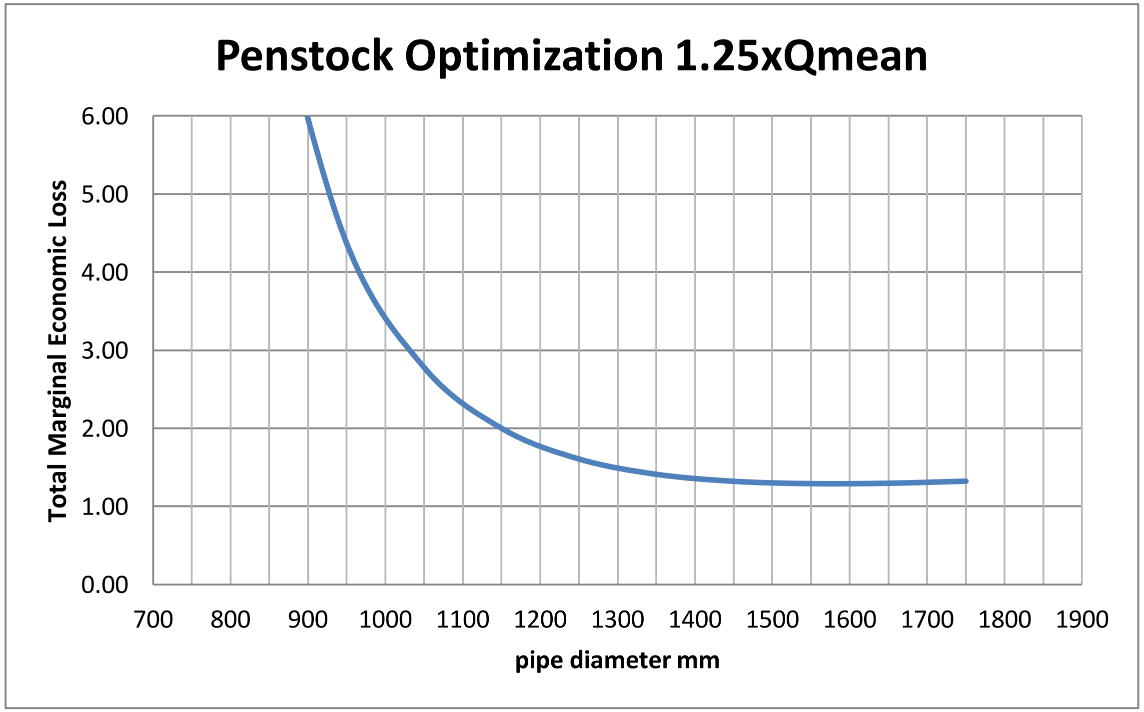


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1850**	**mm**

Penstock tunnel Optimization 1.25xQ_{mean}

Total Tunnel cost	10.06	10.67	11.36	12.11	12.93	13.82	14.77	15.79	16.88	18.04	19.26
Marginal Tunnel Cost		0.62	0.68	0.75	0.82	0.89	0.95	1.02	1.09	1.16	1.22
Economic Loss	16.28	9.11	5.43	3.40	2.22	1.50	1.05	0.75	0.55	0.41	0.31
Marginal Economic Loss		7.17	3.68	2.03	1.18	0.72	0.46	0.30	0.20	0.14	0.10
Pipe Diameter		850	950	1050	1150	1250	1350	1450	1550	1650	1750
Total Marginal Economic Loss		7.78	4.37	2.78	2.00	1.61	1.41	1.32	1.29	1.30	1.32

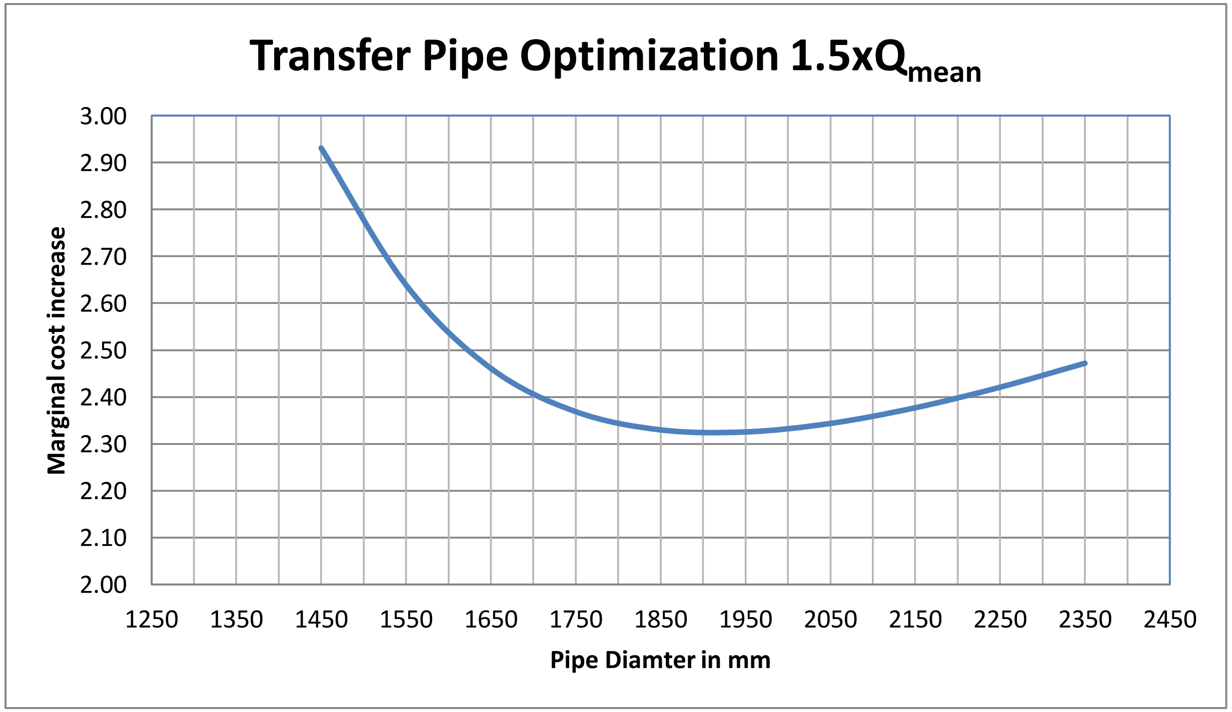


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	3.29	m^3/s
Opt. Pipe Diameter	**1600**	**mm**

Transfer Pipe Optimization $1.5xQ_{mean}$

Diameter	1400	1500	1600	1700	1800	1900	2000	2100	2200	2300	2400
Total Pipe cost	19.07	20.80	22.63	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84
Marginal pipe Cost	0.00	1.73	1.83	1.90	1.97	2.04	2.12	2.19	2.26	2.33	2.40
Economic Loss	4.20	3.00	2.19	1.63	1.23	0.95	0.74	0.58	0.47	0.38	0.31
Marginal Economic loss		1.20	0.81	0.56	0.40	0.29	0.21	0.16	0.12	0.09	0.07
Pipe Diameter increase		1450.00	1550.00	1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00
Total Economic Loss		2.93	2.64	2.46	2.37	2.33	2.33	2.34	2.38	2.42	2.47

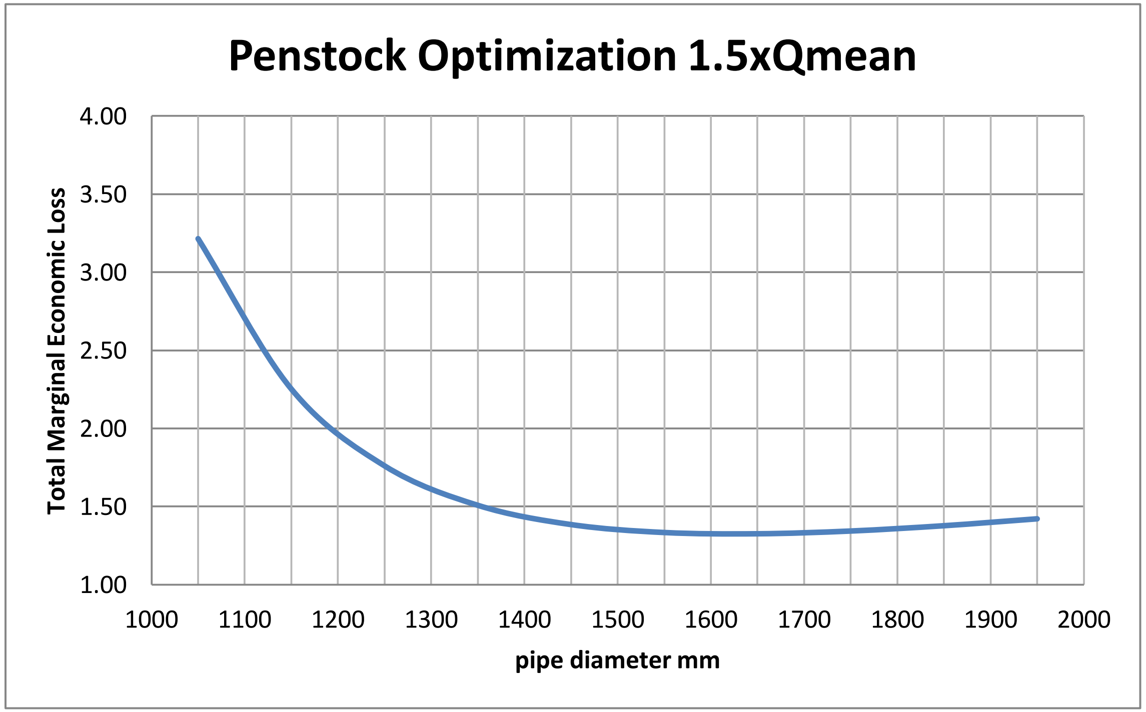


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1900**	**mm**

Penstock tunnel Optimization 1.5xQ_{mean}

Total Tunnel cost	11.36	12.11	12.93	13.82	14.77	15.79	16.88	18.04	19.26	20.55	21.91
Marginal Tunnel Cost		0.75	0.82	0.89	0.95	1.02	1.09	1.16	1.22	1.29	1.36
Economic Loss	6.59	4.13	2.70	1.82	1.27	0.91	0.66	0.49	0.37	0.29	0.22
Marginal Economic Loss		2.46	1.43	0.87	0.55	0.36	0.24	0.17	0.12	0.09	0.06
Pipe Diameter		1050	1150	1250	1350	1450	1550	1650	1750	1850	1950
Total Marginal Economic Loss		3.21	2.25	1.76	1.51	1.38	1.33	1.32	1.34	1.38	1.42

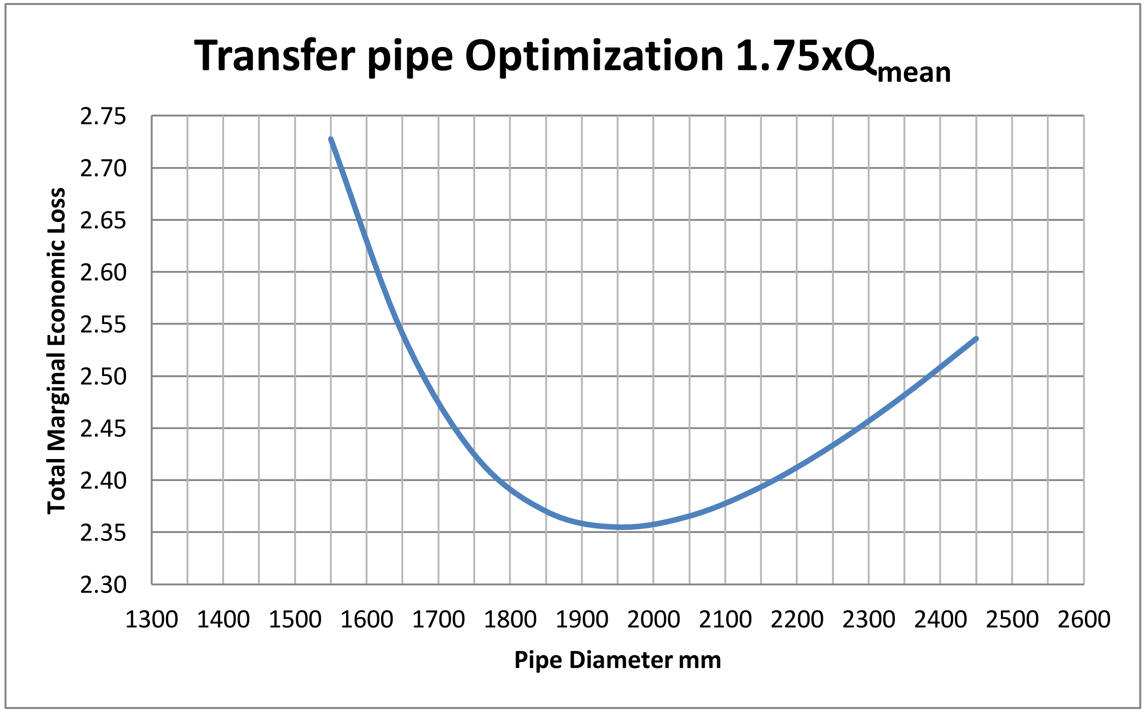


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	3.95	m^3/s
Opt. Pipe Diameter	**1650**	**mm**

Transfer Pipe Optimization 1.75xQ_{mean}

Diameter	1500	1600	1700	1800	1900	2000	2100	2200	2300	2400	2500
Total Pipe cost	20.83	22.63	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84	42.32
Marginal pipe Cost	0.00	1.80	1.90	1.97	2.04	2.12	2.19	2.26	2.33	2.40	2.47
Economic Loss	3.42	2.50	1.86	1.41	1.08	0.84	0.67	0.53	0.43	0.35	0.29
Marginal Economic loss	0.00	0.92	0.64	0.45	0.33	0.24	0.18	0.13	0.10	0.08	0.06
Pipe Diameter increase	0.00	1550.00	1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00	2450.00
Total Economic Loss	0.00	2.73	2.54	2.42	2.37	2.35	2.37	2.39	2.43	2.48	2.54

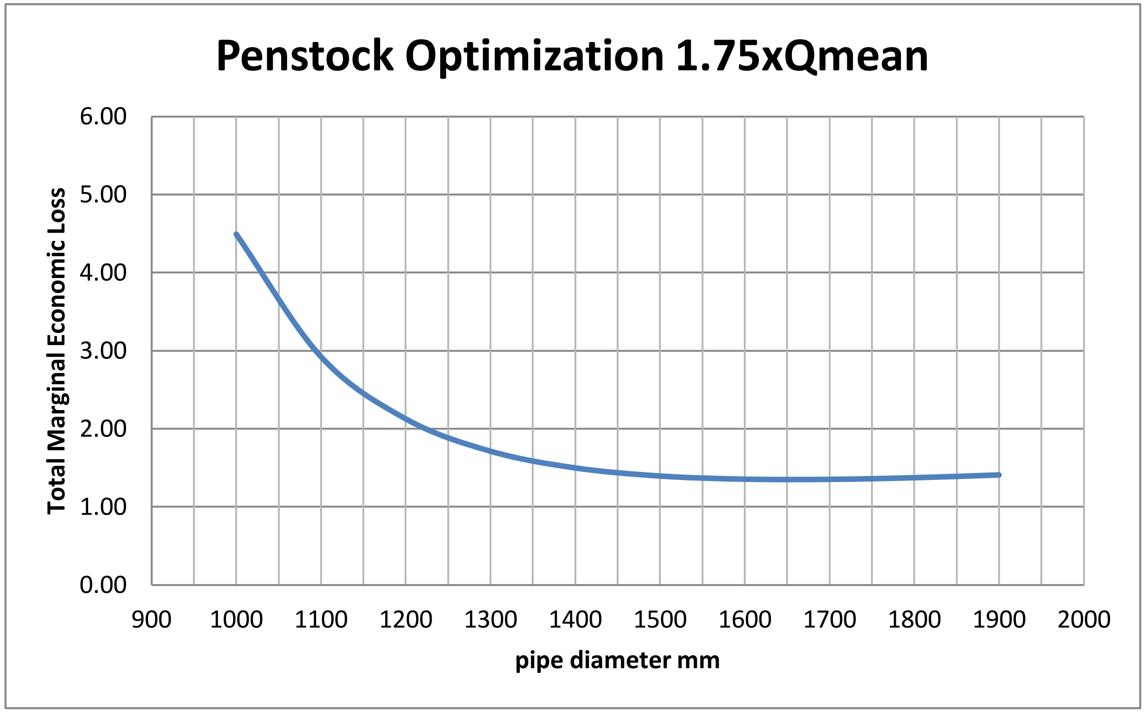


<u>Analaysis Input data:</u>

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1950**	**mm**

Penstock tunnel Optimization 1.75xQ_{mean}

Total Tunnel cost	11.01	11.73	12.51	13.36	14.29	15.27	16.33	17.45	18.64	19.90	21.22
Marginal Tunnel Cost		0.72	0.79	0.85	0.92	0.99	1.05	1.12	1.19	1.26	1.32
Economic Loss	9.71	5.93	3.80	2.52	1.73	1.22	0.88	0.65	0.49	0.37	0.29
Marginal Economic Loss		3.77	2.14	1.27	0.79	0.51	0.34	0.23	0.16	0.12	0.08
Pipe Diameter		1000	1100	1200	1300	1400	1500	1600	1700	1800	1900
Total Marginal Economic Loss		4.49	2.92	2.13	1.71	1.50	1.39	1.35	1.35	1.37	1.41

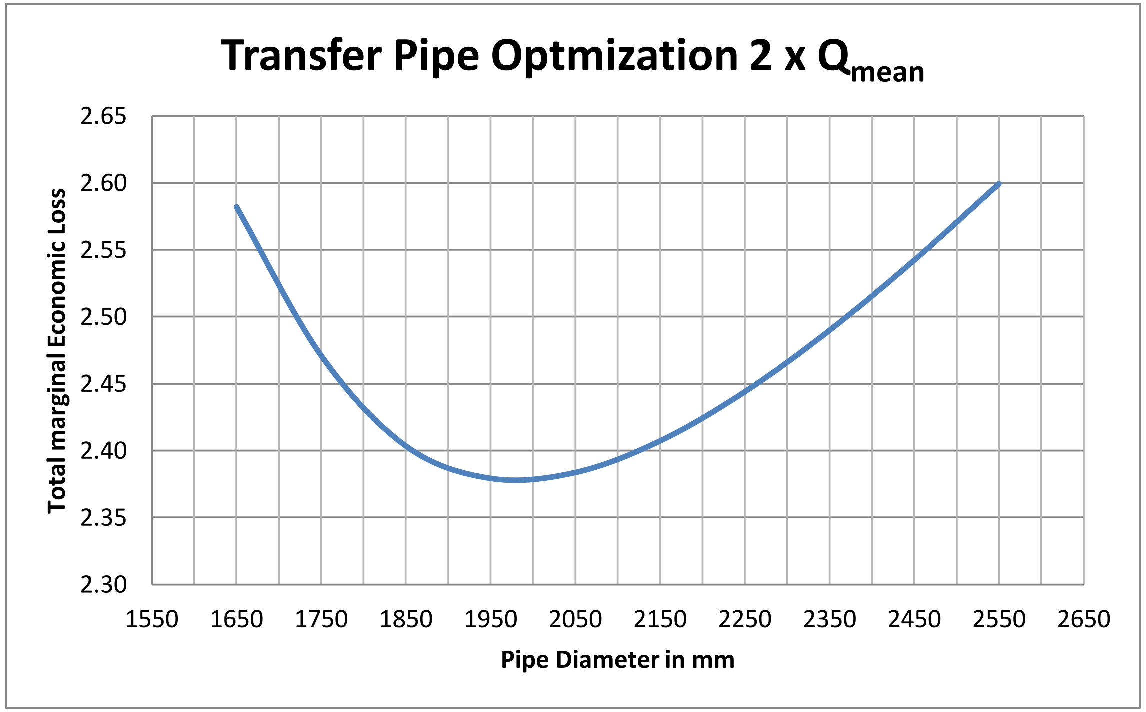


Analaysis Input data:

Description	**Quantity**	**Unit**
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	4.6	m^3/s
Opt. Pipe Diameter	**1650**	**mm**

Transfer Pipe Optimization 2xQ_{mean}

Diameter	1600	1700	1800	1900	2000	2100	2200	2300	2400	2500	2600
Total Pipe cost	22.66	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84	42.32	44.86
Marginal pipe Cost	0.00	1.88	1.97	2.04	2.12	2.19	2.26	2.33	2.40	2.47	2.54
Economic Loss	2.75	2.05	1.55	1.19	0.93	0.73	0.58	0.47	0.38	0.31	0.26
Marginal Economic loss		0.70	0.50	0.36	0.26	0.20	0.15	0.11	0.09	0.07	0.05
Pipe Diameter increase		1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00	2450.00	2550.00
Total Economic Loss		2.58	2.47	2.40	2.38	2.38	2.41	2.44	2.49	2.54	2.60

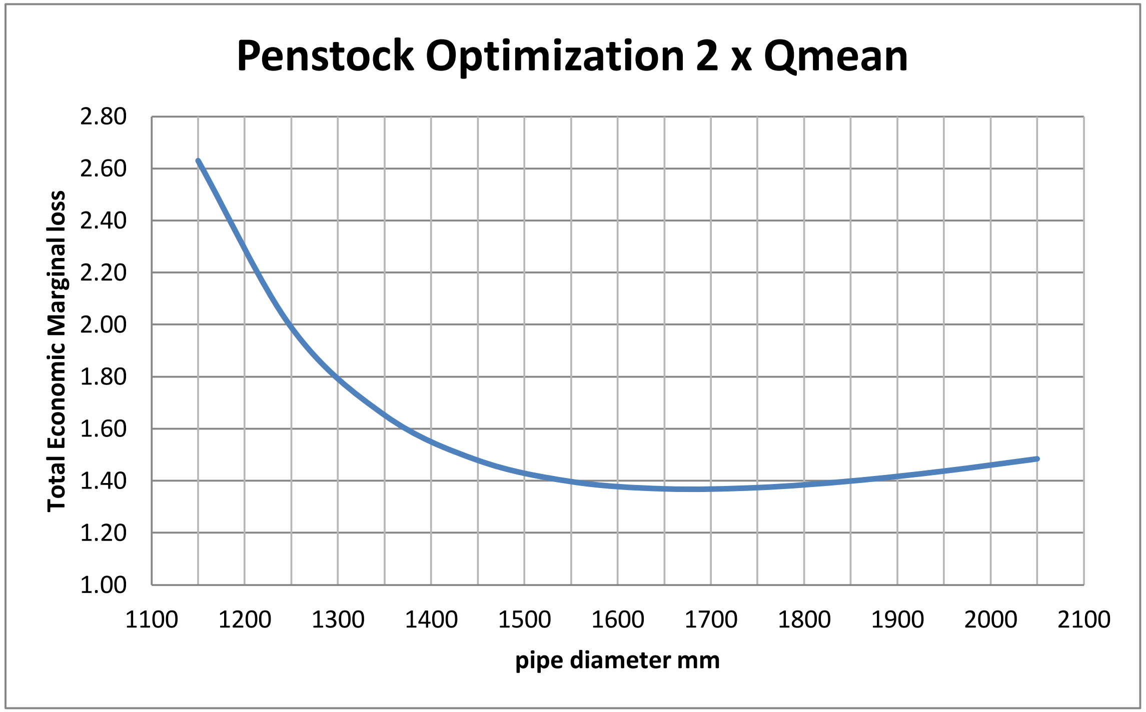


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1950**	**mm**

Penstock tunnel Optimization 2xQ_{mean}

Total Tunnel cost	12.11	12.93	13.82	14.77	15.79	16.88	18.04	19.26	20.55	21.91	23.33
Marginal Tunnel Cost		0.82	0.89	0.95	1.02	1.09	1.16	1.22	1.29	1.36	1.42
Economic Loss	5.21	3.40	2.30	1.60	1.14	0.83	0.62	0.47	0.36	0.28	0.22
Marginal Economic Loss		1.81	1.10	0.70	0.46	0.31	0.21	0.15	0.11	0.08	0.06
Pipe Diameter		1150	1250	1350	1450	1550	1650	1750	1850	1950	2050
Total Marginal Economic Loss		2.63	1.99	1.65	1.48	1.40	1.37	1.37	1.40	1.44	1.48

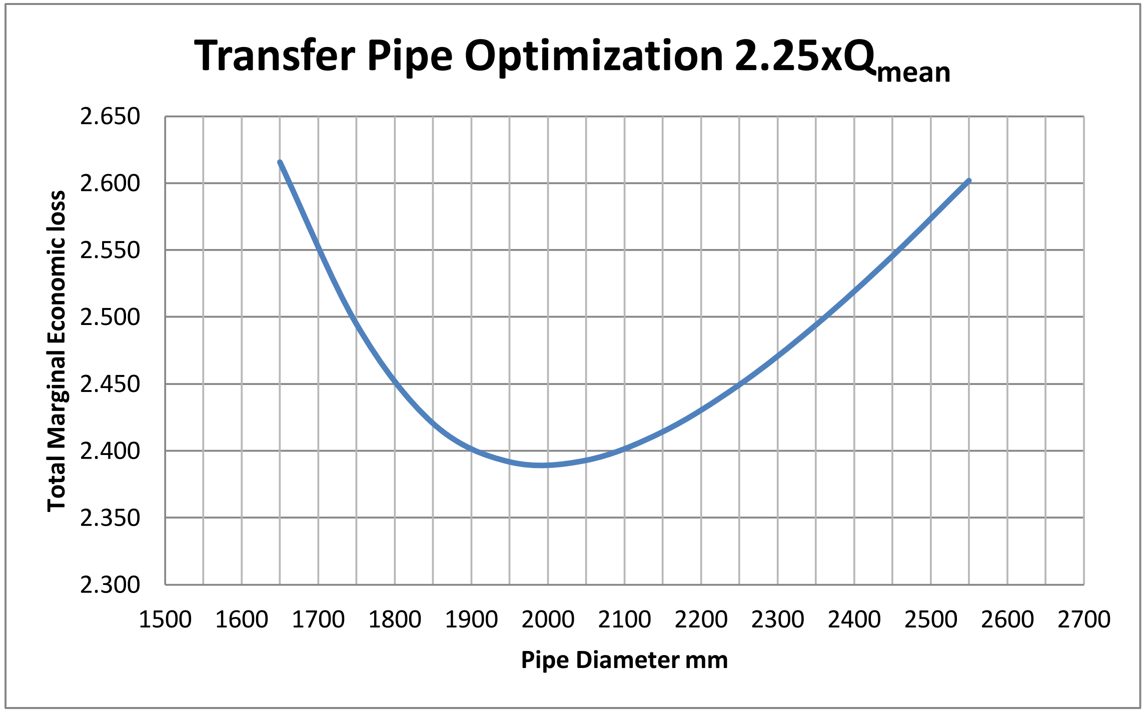


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	5.26	m^3/s
Opt. Pipe Diameter	**1700**	**mm**

Transfer Pipe Optimization 2.25xQ_{mean}

Diameter	1600	1700	1800	1900	2000	2100	2200	2300	2400	2500	2600
Total Pipe cost	22.66	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84	42.32	44.86
Marginal pipe Cost	0.00	1.88	1.97	2.04	2.12	2.19	2.26	2.33	2.40	2.47	2.54
Economic Loss	2.88	2.15	1.62	1.25	0.97	0.77	0.61	0.49	0.40	0.33	0.27
Marginal Economic loss		0.74	0.52	0.38	0.28	0.21	0.16	0.12	0.09	0.07	0.06
Pipe Diameter increase		1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00	2450.00	2550.00
Total Economic Loss		2.62	2.49	2.42	2.39	2.39	2.41	2.45	2.49	2.55	2.60

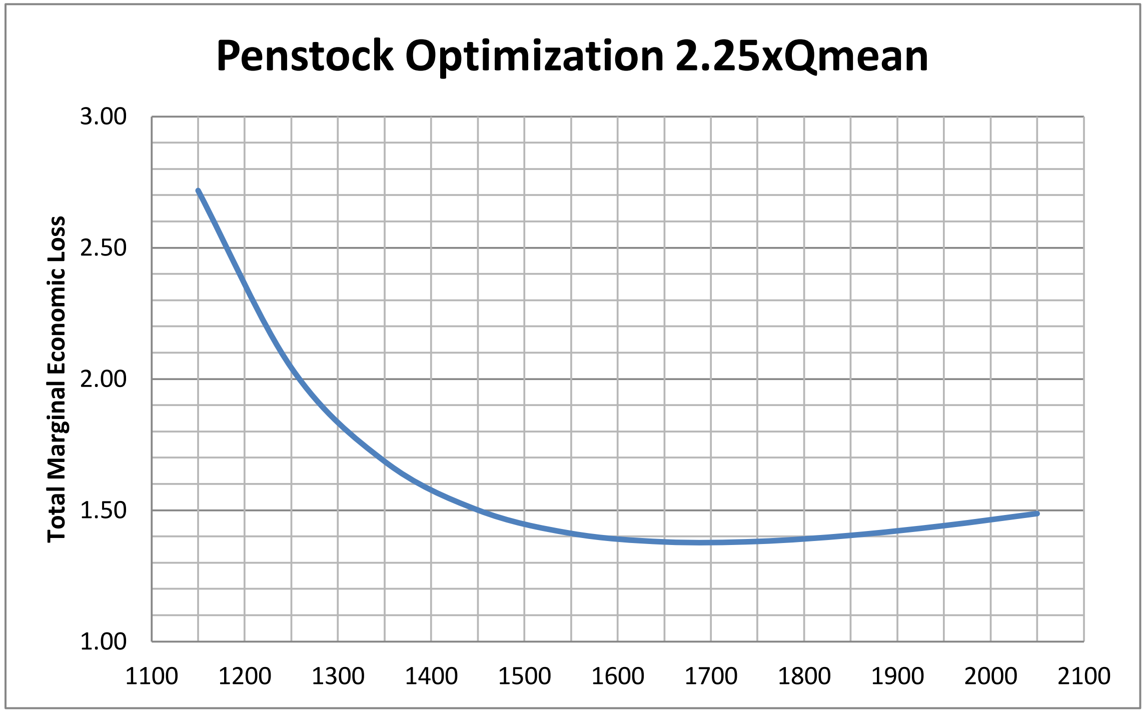


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**1800**	**mm**

Penstock Tunnel Optimization 2.25xQ_{mean}

Total Tunnel cost	12.11	12.93	13.82	14.77	15.79	16.88	18.04	19.26	20.55	21.91	23.33
Marginal Tunnel Cost		0.82	0.89	0.95	1.02	1.09	1.16	1.22	1.29	1.36	1.42
Economic Loss	5.46	3.56	2.41	1.67	1.20	0.87	0.65	0.49	0.38	0.29	0.23
Marginal Economic Loss		1.90	1.16	0.73	0.48	0.32	0.22	0.16	0.11	0.08	0.06
Pipe Diameter		1150	1250	1350	1450	1550	1650	1750	1850	1950	2050
Total Marginal Economic Loss		2.72	2.04	1.69	1.50	1.41	1.38	1.38	1.40	1.44	1.49

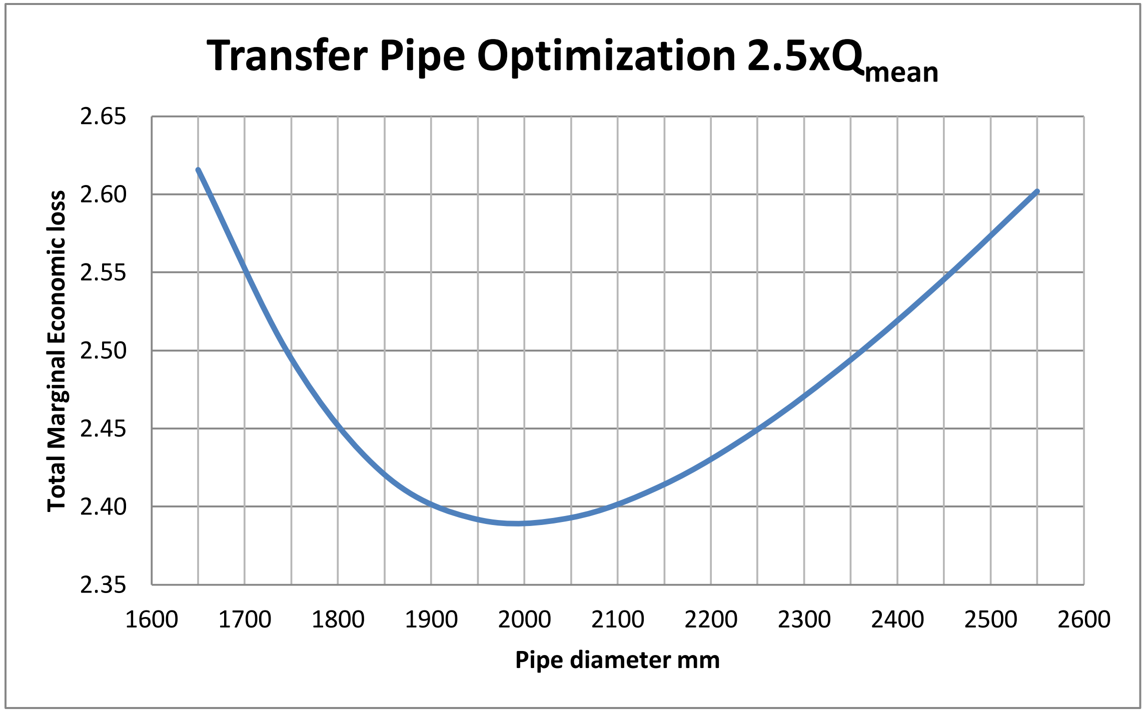


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	5.92	m^3/s
Opt. Pipe Diameter	**1700**	**mm**

Transfer Pipe Optimization 2.5xQ_{mean}

Diameter	1600	1700	1800	1900	2000	2100	2200	2300	2400	2500	2600
Total Pipe cost	22.66	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84	42.32	44.86
Marginal pipe Cost	0.00	1.88	1.97	2.04	2.12	2.19	2.26	2.33	2.40	2.47	2.54
Economic Loss	2.88	2.15	1.62	1.25	0.97	0.77	0.61	0.49	0.40	0.33	0.27
Marginal Economic loss		0.74	0.52	0.38	0.28	0.21	0.16	0.12	0.09	0.07	0.06
Pipe Diameter increase		1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00	2450.00	2550.00
Total Economic Loss		2.62	2.49	2.42	2.39	2.39	2.41	2.45	2.49	2.55	2.60

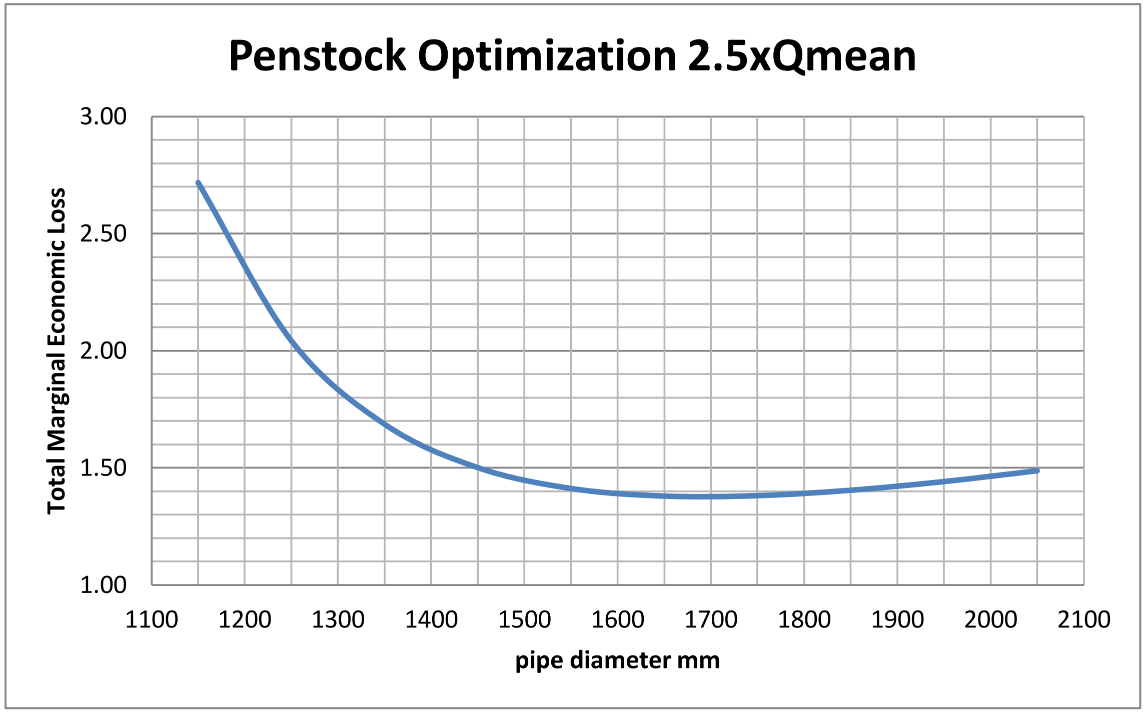


Analaysis Input data:

Description	**Quantity**	**Unit**
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**2000**	**mm**

Penstock Tunnel Optimization 2.5xQ_{mean}

Total Tunnel cost	12.11	12.93	13.82	14.77	15.79	16.88	18.04	19.26	20.55	21.91	23.33
Marginal Tunnel Cost		0.82	0.89	0.95	1.02	1.09	1.16	1.22	1.29	1.36	1.42
Economic Loss	5.46	3.56	2.41	1.67	1.20	0.87	0.65	0.49	0.38	0.29	0.23
Marginal Economic Loss		1.90	1.16	0.73	0.48	0.32	0.22	0.16	0.11	0.08	0.06
Pipe Diameter		1150	1250	1350	1450	1550	1650	1750	1850	1950	2050
Total Marginal Economic Loss		2.72	2.04	1.69	1.50	1.41	1.38	1.38	1.40	1.44	1.49

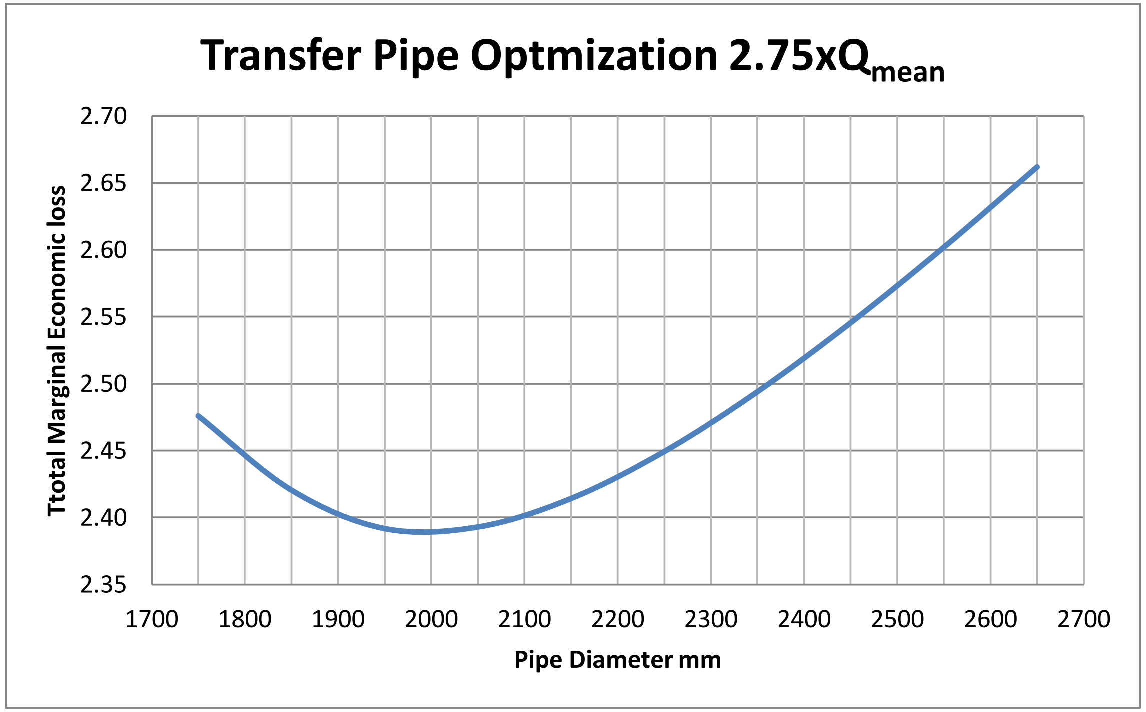


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	6.58	m^3/s
Opt. Pipe Diameter	**1700**	**mm**

Transfer Pipe Optimization 2.75xQ_{mean}

Diameter	1700	1800	1900	2000	2100	2200	2300	2400	2500	2600	2700
Total Pipe cost	24.55	26.51	28.55	30.67	32.85	35.11	37.44	39.84	42.32	44.86	47.48
Marginal pipe Cost	0.00	1.95	2.04	2.12	2.19	2.26	2.33	2.40	2.47	2.54	2.62
Economic Loss	2.15	1.62	1.25	0.97	0.77	0.61	0.49	0.40	0.33	0.27	0.23
Marginal Economic loss		0.52	0.38	0.28	0.21	0.16	0.12	0.09	0.07	0.06	0.05
Pipe Diameter increase		1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00	2450.00	2550.00	2650.00
Total Economic Loss		2.48	2.42	2.39	2.39	2.41	2.45	2.49	2.55	2.60	2.66

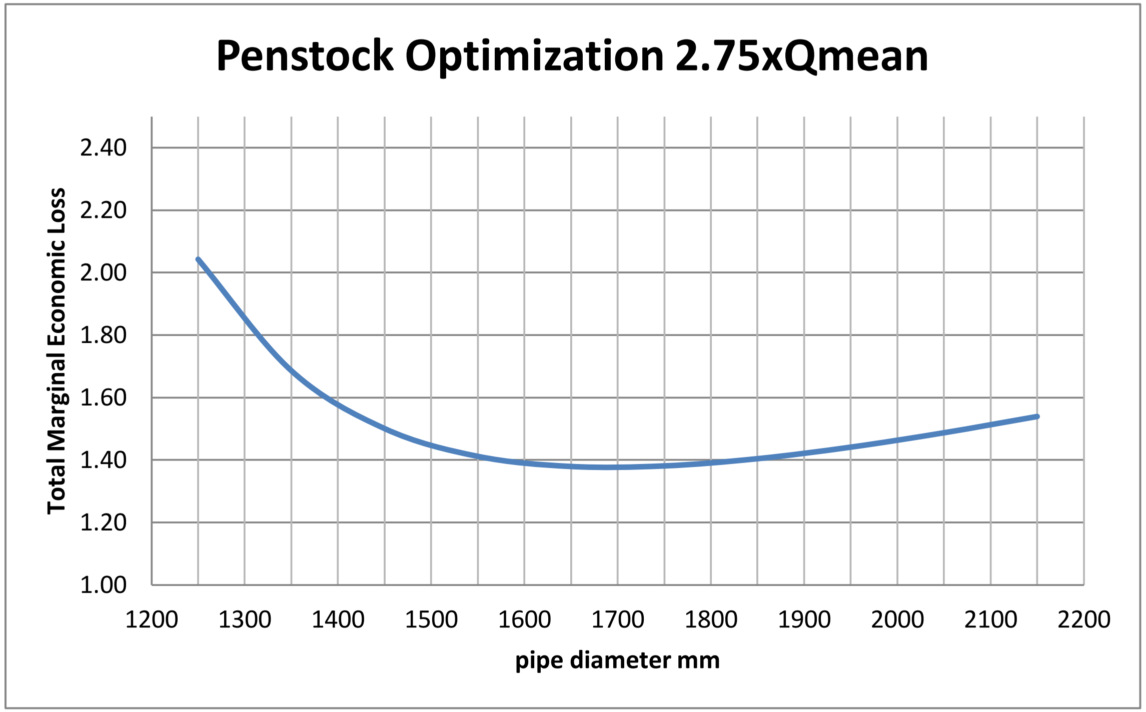


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**2000**	**mm**

Penstock Tunnel Optimization 2.75xQ_{mean}

Total Tunnel cost	12.93	13.82	14.77	15.79	16.88	18.04	19.26	20.55	21.91	23.33	24.82
Marginal Tunnel Cost		0.89	0.95	1.02	1.09	1.16	1.22	1.29	1.36	1.42	1.49
Economic Loss	3.56	2.41	1.67	1.20	0.87	0.65	0.49	0.38	0.29	0.23	0.19
Marginal Economic Loss		1.16	0.73	0.48	0.32	0.22	0.16	0.11	0.08	0.06	0.05
Pipe Diameter		1250	1350	1450	1550	1650	1750	1850	1950	2050	2150
Total Marginal Economic Loss		2.04	1.69	1.50	1.41	1.38	1.38	1.40	1.44	1.49	1.54

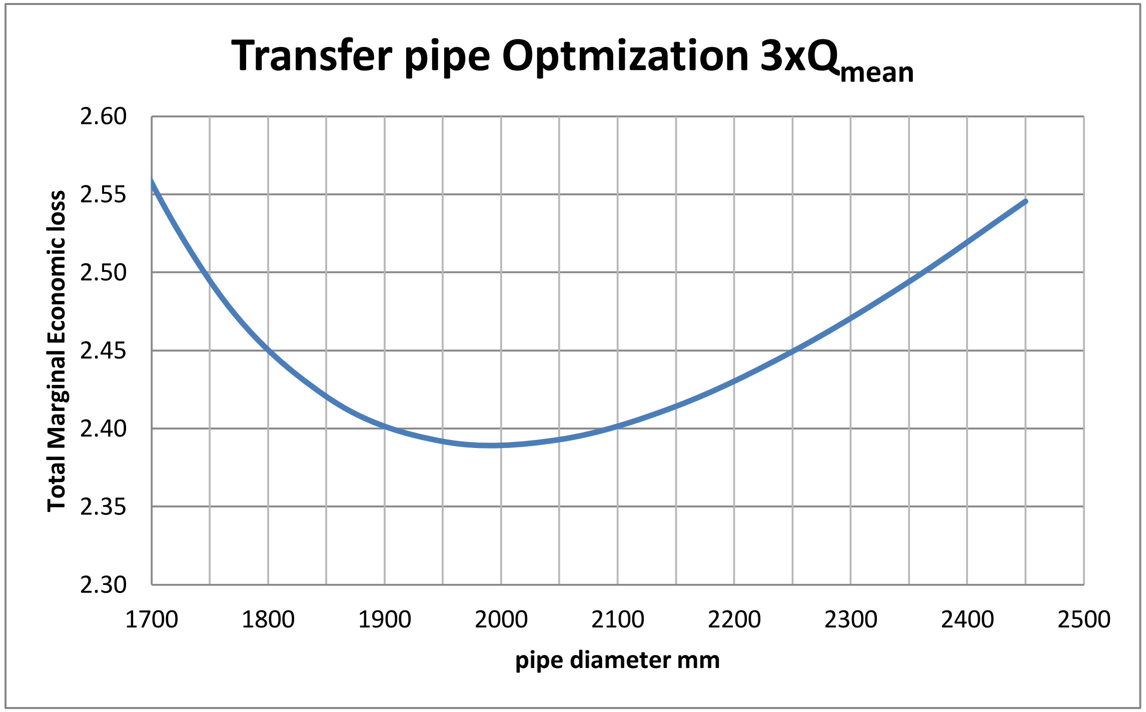


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	7.23	m^3/s
Opt. Pipe Diameter	**1700**	**mm**

Transfer Pipe Optimization 3xQ_{mean}

Diameter	1500	1600	1700	1800	1900	2000	2100	2200	2300	2400	2500
Total Pipe cost	20.83	22.63	24.53	26.51	28.55	30.67	32.85	35.11	37.44	39.84	42.32
Marginal pipe Cost	0.00	1.80	1.90	1.97	2.04	2.12	2.19	2.26	2.33	2.40	2.47
Economic Loss	3.95	2.88	2.15	1.62	1.25	0.97	0.77	0.61	0.49	0.40	0.33
Marginal Economic loss		1.07	0.74	0.52	0.38	0.28	0.21	0.16	0.12	0.09	0.07
Pipe Diameter increase		1550.00	1650.00	1750.00	1850.00	1950.00	2050.00	2150.00	2250.00	2350.00	2450.00
Total Economic Loss		2.87	2.64	2.49	2.42	2.39	2.39	2.41	2.45	2.49	2.55

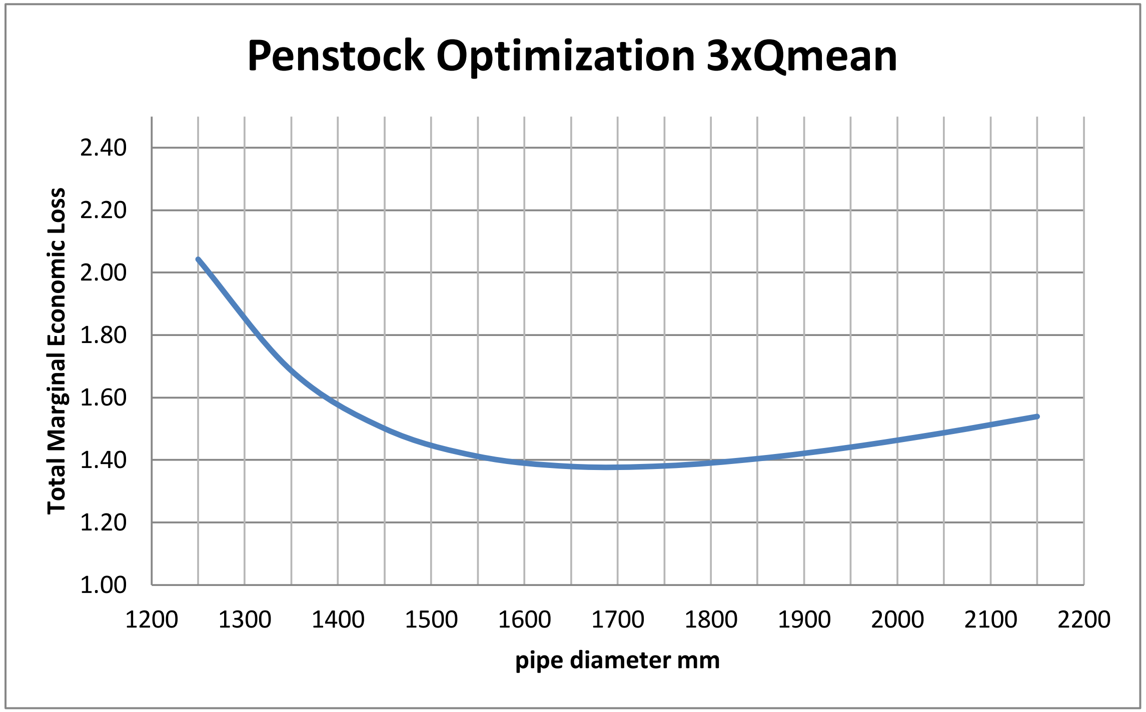


Analaysis Input data:

Description	Quantity	Unit
Length of pipe	2150	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	2.63	m^3/s
Opt. Pipe Diameter	**2000**	**mm**

Penstock Tunnel Optimization 3xQ_{mean}

Total Tunnel cost	12.93	13.82	14.77	15.79	16.88	18.04	19.26	20.55	21.91	23.33	24.82
Marginal Tunnel Cost		0.89	0.95	1.02	1.09	1.16	1.22	1.29	1.36	1.42	1.49
Economic Loss	3.56	2.41	1.67	1.20	0.87	0.65	0.49	0.38	0.29	0.23	0.19
Marginal Economic Loss		1.16	0.73	0.48	0.32	0.22	0.16	0.11	0.08	0.06	0.05
Pipe Diameter		1250	1350	1450	1550	1650	1750	1850	1950	2050	2150
Total Marginal Economic Loss		2.04	1.69	1.50	1.41	1.38	1.38	1.40	1.44	1.49	1.54



Analaysis Input data:

Description	Quantity	Unit
Length of pipe	650	m
Analysis period	50	yr
Discount rate	7	%
Maximum discharge	7.89	m^3/s
Opt. Pipe Diameter	**1700**	**mm**

Annex H-07 Cost Estimate and Economic analysis
Two Units of Equal Capacity

Cost Estimate $1xQ_{mean}$ for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill Dam 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete Dam 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	2.63	3.44	3.44
	2.2	Intake at Vakker 6m2	m2	4	2.63	2.06	2.06
	2.3	Intake at storåvatnet 6m2	m2	4	2.63	2.06	2.06
	2.4	Intake at Mannåga 16	m2	16	2.63	3.44	3.44
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	1800	2350.00	4863.76	11.43
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
4		**Power house**					
	4.1	Power House	m3	2.63	3622.74	2250.00	8.15
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Subtotal Civil Works**					210.14
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.20
	6.2	Contractors cost @20% of Civil works				20%	42.03
	6.3	Contingencies @25% of civil cost				25%	52.53
		Total cost of Civil Works					**308.90**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 11Mw	Ls	2.63	10842.00	870.37	9.44
	7.2	Lifting Equipment	ton	1	5.00	394961.50	0.39
	7.3	Generator n=750 Rpm	Pcs	2	5.50	5.98	11.96
	7.4	Transfermor	Pcs	2	5.50	1.10	2.20
		Subtotal Elctro Mechanical Works					**45.31**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	6.80
		Total cost Elctro Mechanical Works					**52.11**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	36.10
		Total Project Cost					**397.11**

Cost Estimate 1.25xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	3.2875	3.46	3.46
	2.2	Intake at Vakker 6m2	m2	4.5	3.2875	2.15	2.15
	2.3	Intake at storåvatnet 6m2	m2	4.5	3.2875	2.15	2.15
	2.4	Intake at Mannåga 16	m2	16	3.2875	3.46	3.46
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	1850	2350.00	5080.92	11.94
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.55	600.00	6515.86	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.55	50.00	63810.05	3.19
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	3.2875	4235.21	2250.00	9.53
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Subtotal Civil Works**					212.67
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.25
	6.2	Contractors cost @20% of Civil works				20%	42.53
	6.3	Contingencies @25% of civil cost				25%	53.17
		Total cost of Civil Works					**312.62**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 13.55Mw	Ls	3.2875	13552.72	790.56	10.71
	7.2	Lifting Equipment	ton	1	5.00	394961.50	0.39
	7.3	Generator n=750 Rpm	Pcs	2	6.75	6.77	13.55
	7.4	Transfermor	Pcs	2	6.75	1.30	2.60
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	6.75	2.41	4.82
	7.7	Auxilary systems	Pcs	2	13.55	3.55	7.09
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Subtotal Elctro Mechanical Works					**49.71**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	7.46
		Total cost Elctro Mechanical Works					**57.16**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	36.98
		Total Project Cost					**406.77**

Cost Estimate 1.5xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	3.945	3.49	3.49
	2.2	Intake at Vakker 6m2	m2	5	3.945	2.23	2.23
	2.3	Intake at storåvatnet 6m2	m2	5	3.945	2.23	2.23
	2.4	Intake at Mannåga 16	m2	16	3.945	3.49	3.49
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	1800	2350.00	4863.76	11.43
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.6	600.00	6515.89	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.6	50.00	73751.24	3.69
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	3.945	4811.73	2250.00	10.83
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					214.18
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.28
	6.2	Contractors cost @20% of Civil works				20%	42.84
	6.3	Contingencies @25% of civil cost				25%	53.54
		Total cost of Civil Works					**314.84**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 16Mw	Ls	3.945	16263.26	730.82	11.89
	7.2	Lifting Equipment	ton	1	5.00	394961.50	0.39
	7.3	Generator n=750 Rpm	Pcs	2	8.00	7.51	15.02
	7.4	Transfermor	Pcs	2	8.00	1.49	2.99
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	8.00	2.58	5.16
	7.7	Auxilary systems	Pcs	2	16.20	3.91	7.81
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**53.79**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	8.07
		Total cost Elctro Mechanical Works					**61.86**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	37.67
		Total Project Cost					**414.37**

Cost Estimate 1.75xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	4.6025	3.52	3.52
	2.2	Intake at Vakker 6m2	m2	5.5	4.6025	2.31	2.31
	2.3	Intake at storåvatnet 6m2	m2	5.5	4.6025	2.31	2.31
	2.4	Intake at Mannåga 16	m2	16	4.6025	3.52	3.52
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	1900	2350.00	5301.58	12.46
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.65	600.00	6515.92	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.65	50.00	85417.34	4.27
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	4.6025	5359.99	2250.00	12.06
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					217.24
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.34
	6.2	Contractors cost @20% of Civil works				20%	43.45
	6.3	Contingencies @25% of civil cost				25%	54.31
		Total cost of Civil Works					**319.35**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 19Mw	Ls	4.6025	18973.81	683.84	12.98
	7.2	Lifting Equipment	ton	1	10.00	430096.00	0.43
	7.3	Generator n=750 Rpm	Pcs	2	9.50	8.33	16.67
	7.4	Transfermor	Pcs	2	9.50	1.72	3.44
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	9.50	2.76	5.52
	7.7	Auxilary systems	Pcs	2	19.00	4.26	8.51
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**58.09**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	8.71
		Total cost Elctro Mechanical Works					**66.80**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	38.61
		Total Project Cost					**424.76**

Cost Estimate $2xQ_{mean}$ for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	5.26	3.54	3.54
	2.2	Intake at Vakker 6m2	m2	6	5.26	2.40	2.40
	2.3	Intake at storåvatnet 6m2	m2	6	5.26	2.40	2.40
	2.4	Intake at Mannåga 16	m2	16	5.26	3.54	3.54
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	2000	2350.00	5753.40	13.52
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.7	600.00	6515.95	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.7	50.00	99107.62	4.96
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	5.26	5885.16	2250.00	13.24
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					220.39
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.41
	6.2	Contractors cost @20% of Civil works				20%	44.08
	6.3	Contingencies @25% of civil cost				25%	55.10
		Total cost of Civil Works					**323.98**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 22Mw	Ls	5.26	22000.00	645.60	14.20
	7.2	Lifting Equipment	ton	1	10.00	430096.00	0.43
	7.3	Generator n=750 Rpm	Pcs	2	11.00	9.11	18.22
	7.4	Transfermor	Pcs	2	11.00	1.94	3.88
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	11.00	2.93	5.86
	7.7	Auxilary systems	Pcs	2	22.00	4.61	9.21
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**62.34**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	9.35
		Total cost Elctro Mechanical Works					**71.69**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	39.57
		Total Project Cost					**435.24**

Cost Estimate 2.25xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	5.9175	3.57	3.57
	2.2	Intake at Vakker 6m2	m2	8	5.9175	2.65	2.65
	2.3	Intake at storåvatnet 6m2	m2	8	5.9175	2.65	2.65
	2.4	Intake at Mannåga 16	m2	16	5.9175	3.57	3.57
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	2000	2350.00	5753.40	13.52
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.75	600.00	6515.98	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.75	50.00	115173.31	5.76
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	5.9175	6390.95	2250.00	14.38
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					222.90
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.46
	6.2	Contractors cost @20% of Civil works				20%	44.58
	6.3	Contingencies @25% of civil cost				25%	55.73
		Total cost of Civil Works					**327.67**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 24.4Mw	Ls	5.9175	24394.89	613.64	14.97
	7.2	Lifting Equipment	ton	1	10.00	430096.00	0.43
	7.3	Generator n=750 Rpm	Pcs	2	12.20	9.70	19.40
	7.4	Transfermor	Pcs	2	12.20	2.11	4.22
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	12.20	3.05	6.10
	7.7	Auxilary systems	Pcs	2	24.40	4.87	9.74
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**65.41**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	9.81
		Total cost Elctro Mechanical Works					**75.22**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	40.29
		Total Project Cost					**443.17**

Cost Estimate 2.5xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	6.575	3.60	3.60
	2.2	Intake at Vakker 6m2	m2	9	6.575	2.80	2.80
	2.3	Intake at storåvatnet 6m2	m2	9	6.575	2.80	2.80
	2.4	Intake at Mannåga 16	m2	16	6.575	3.60	3.60
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	2050	2350.00	5984.56	14.06
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.75	600.00	6515.98	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.75	50.00	115173.31	5.76
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	6.575	6880.11	2250.00	15.48
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					224.89
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.50
	6.2	Contractors cost @20% of Civil works				20%	44.98
	6.3	Contingencies @25% of civil cost				25%	56.22
		Total cost of Civil Works					**330.58**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 27Mw	Ls	6.575	27105.44	586.40	15.89
	7.2	Lifting Equipment	ton	1	15.00	465230.50	0.47
	7.3	Generator n=750 Rpm	Pcs	2	13.50	10.32	20.63
	7.4	Transfermor	Pcs	2	13.50	2.29	4.58
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	13.50	3.18	6.35
	7.7	Auxilary systems	Pcs	2	27.00	5.14	10.29
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**68.76**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	10.31
		Total cost Elctro Mechanical Works					**79.07**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	40.97
		Total Project Cost					**450.62**

Cost Estimate 2.75xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	7.2325	3.63	3.63
	2.2	Intake at Vakker 6m2	m2	10	7.2325	2.94	2.94
	2.3	Intake at storåvatnet 6m2	m2	10	7.2325	2.94	2.94
	2.4	Intake at Mannåga 16	m2	16	7.2325	3.63	3.63
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	2050	2350.00	5984.56	14.06
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.75	600.00	6515.98	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.75	50.00	115173.31	5.76
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	7.2325	7354.79	2250.00	16.55
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					226.29
	6	**Unforeseen civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.53
	6.2	Contractors cost @20% of Civil works				20%	45.26
	6.3	Contingencies @25% of civil cost				25%	56.57
		Total cost of Civil Works					**332.65**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 30Mw	Ls	7.2325	29815.00	562.80	16.78
	7.2	Lifting Equipment	ton	1	15.00	465230.50	0.47
	7.3	Generator n=750 Rpm	Pcs	2	15.00	11.00	22.00
	7.4	Transfermor	Pcs	2	15.00	2.50	5.00
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	15.00	3.31	6.62
	7.7	Auxilary systems	Pcs	2	30.00	5.45	10.89
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**72.29**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	10.84
		Total cost Elctro Mechanical Works					**83.14**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	41.58
		Total Project Cost					**457.37**

Cost Estimate 3xQ_{mean} for two units Of Equal capacity

Item		Description	Unit	Quantity	Description	Rate	Cost(Mnok)
		Civil Works					
1		**Diversion**					
	1.1	Dam at Storåga rock fill 4m	m	1	380.00	21000.00	7.98
	1.2	Dam at Storåga concrete 4.5m	m	1	40.00	69000.00	2.76
	1.3	Weir at Vakker 3.5m	m	1	15.00	48000.00	0.72
	1.4	Weir at Storåvatn 3.5m	m	1	25.00	24000.00	0.60
	1.5	Weir at Mannåga 2m	m	1	20.00	24000.00	0.48
2		**Intake**					
	2.1	Intake at Smibelg 16m2	m2	16	7.89	3.65	3.65
	2.2	Intake at Vakker 6m2	m2	12	7.89	3.20	3.20
	2.3	Intake at storåvatnet 6m2	m2	12	7.89	3.20	3.20
	2.4	Intake at Mannåga 16	m2	16	7.89	3.65	3.65
	2.5	Uderwater piercing	m2	1	40	150000.00	6.00
3		**Water way**					
	3.1	Tunnel Storåga-Smibelg 16m2	m2	16	2444.00	14871.62	36.35
	3.2	Tunnel Smibelg- Vakker 16m2	m2	16	2580.00	14871.62	38.37
	3.3	Pipe Vakker- Storåvatn PN 10	m	2050	2350.00	5984.56	14.06
	3.4	Tunnel Storåvatn-Penstock 16m2	m2	16	650.00	14871.62	9.67
	3.5	Tunnel Mannåga- Penstock 16m2	m2	16	1550.00	14871.62	23.05
	3.6	Tail race tunnel 16m2	m2	16	327.00	14871.62	4.86
	4.5	Pressure shaft unlined (penstock)	m	1.75	600.00	6515.98	3.91
	4.6	pressure shaft steel lined (penstock)	m	1.75	50.00	115173.31	5.76
	4.7	Gate shaft at intake	m	1	36.00	36000.00	1.30
4		**Power house**					
	4.1	Power House	m3	7.89	7816.68	2250.00	17.59
	4.2	Emergency bypass 16m2	m2	16	50.00	14871.62	0.74
	4.3	Construction adit to bypass 16m2	m2	16	75.00	14871.62	1.12
	4.4	access tunnel 30m2	m2	30	500.00	19796.90	9.90
	4.5	Cable shaft	m	1	200.00	6515.56	1.30
5		**Access Road**					
	5.1	Existing road Rehablitation	m	1	850.00	150.00	0.13
	5.2	Vassvatnet to Storåga	m	1	2230.00	1500.00	3.35
	5.3	Sørfjorelva to Forslund	m	1	4330.00	1500.00	6.50
	5.4	Forslund to akker	m	1	3600.00	1500.00	5.40
	5.5	Sørfjordgården to Smibelg	m	1	4995.00	1500.00	7.49
	5.6	Forslund to Mannåga	m	1	3220.00	1500.00	4.83
6		**Sutotal Civil Works**					227.90
	6	**Unforeseen Civil Works**					
	6.1	Diversion works @2% of Civil works				2.0%	4.56
	6.2	Contractors cost @20% of Civil works				20%	45.58
	6.3	Contingencies @25% of civil cost				25%	56.98
		Total cost of Civil Works					**335.02**
7		**Electro Mechanical Components**					
	7.1	Turbines 2 pelton units , 35.5Mw	Ls	7.89	35526.53	542.08	19.26
	7.2	Lifting Equipment	ton	1	15.00	465230.50	0.47
	7.3	Generator n=750 Rpm	Pcs	2	17.75	12.18	24.36
	7.4	Transfermor	Pcs	2	17.75	2.87	5.74
	7.5	Switching station Double bus bar 132 KV	Pcs	2	Outdoor	5040.00	5.04
	7.6	Control System	Pcs	2	17.75	3.54	7.08
	7.7	Auxilary systems	Pcs	2	35.50	5.96	11.93
	7.8	Power Line	Pcs	1	5500.00	1.00	5.50
		Sutotal Elctro Mechanical Works					**79.37**
8		**Unforeseen Electro Mechanical Works**					
	8.1	Contingencies @15% of Electro Mechanical cost				15%	11.91
		Total cost Elctro Mechanical Works					**91.28**
9		**Engineering and Adminstration**					
	9.1	Engineering and Adminstration 10% of Civil and E&M				10%	42.63
		Total Project Cost					**468.92**

Economic analysis Two Units of Equal Capacity

Economic Analysis 1x Q mean for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	10.84	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	397.11	Firm Energy	78.46	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	397.11	Secondary Energy	0.00	0.25	Firm energy Gwh	78.46		
Construction period	yrs	3	Total generation	78.46		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	397.113		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream				Revenue Stream					
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	119.13	0.00	119.13	0.00	0.00	0.00	-119.13			
2	198.56	0.00	198.56	0.00	0.00	0.00	-198.56			
3	79.42	0.00	79.42	0.00	0.00	0.00	-79.42			
4		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
5		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
6		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
7		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
8		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
9		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
10		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
11		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
12		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
13		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
14		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
15		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
16		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
17		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
18		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
19		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
20		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
21		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
22		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
23		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
24		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
25		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
26		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
43		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
44		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
45		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
46		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
47		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
48		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
49		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
50		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
51		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
52		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
53		3.97	3.97	40.01	0.00	40.01	36.04	100%	66.69	32.75
		PV COST	**394.34**	**PV of annual energy**	**920.39**	**NPV**	**56.45**	**UNIT COST**	**0.43**	
		PV Benfit	**450.79**	**Development Rate**	**2.04**	**IRR**	**8.15%**	**B/C**	**1.14**	

Economic Analysis 1.25x Q mean for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	13.36	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	406.77	Firm Energy	84.08	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	406.77	Secondary Energy	0.00	0.25	Firm energy Gwh	84.08		
Construction period	yrs	3	Total generation	84.08		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	406.767		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream				Revenue Stream					
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	122.03	0.00	122.03	0.00	0.00	0.00	-122.03			
2	203.38	0.00	203.38	0.00	0.00	0.00	-203.38			
3	81.35	0.00	81.35	0.00	0.00	0.00	-81.35			
4		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
5		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
6		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
7		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
8		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
9		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
10		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
11		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
12		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
13		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
14		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
15		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
16		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
17		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
18		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
19		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
20		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
21		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
22		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
23		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
24		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
25		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
26		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
43		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
44		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
45		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
46		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
47		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
48		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
49		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
50		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
51		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
52		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
53		4.07	4.07	42.88	0.00	42.88	38.81	100%	71.47	33.54
		PV COST	**403.92**	**PV of annual energy**	**986.31**	**NPV**	**79.15**	**UNIT COST**	**0.41**	
		PV Benfi	**483.07**	**Development Rate**	**2.13**	**IRR**	**9%**	**B/C**	**1.20**	

Economic Analysis 1.5x Q $_{mean}$ for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	16.00	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	414.37	Firm Energy	87.05	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	414.37	Secondary Energy	0.00	0.25	Firm energy Gwh	87.05		
Construction period	yrs	3	Total generation	87.05		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	414.370		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream				Revenue Stream					
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	124.31	0.00	124.31	0.00	0.00	0.00	-124.31			
2	207.19	0.00	207.19	0.00	0.00	0.00	-207.19			
3	82.87	0.00	82.87	0.00	0.00	0.00	-82.87			
4		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
5		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
6		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
7		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
8		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
9		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
10		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
11		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
12		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
13		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
14		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
15		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
16		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
17		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
18		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
19		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
20		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
21		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
22		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
23		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
24		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
25		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
26		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
43		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
44		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
45		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
46		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
47		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
48		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
49		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
50		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
51		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
52		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
53		4.14	4.14	44.40	0.00	44.40	40.25	100%	73.99	34.17
		PV COST	**411.47**	**PV of annual energy**	**1,021.15**	**NPV**	**88.67**	**UNIT COST**	**0.40**	
		PV Benfit	**500.14**	**Development Rate**	**2.17**	**IRR**	**9%**	**B/C**	**1.22**	

Economic Analysis 1.75x Q $_{mean}$ for two units of Equal Capacity

Economic Analysis

Installed capacity	Mw	18.70	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	424.76	Firm Energy	88.86	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	424.76	Secondary Energy	0.00	0.25	Firm energy Gwh	88.86		
Construction period	yrs	3	Total generation	88.86		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	424.763		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream			Revenue Stream						
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	127.43	0.00	127.43	0.00	0.00	0.00	-127.43			
2	212.38	0.00	212.38	0.00	0.00	0.00	-212.38			
3	84.95	0.00	84.95	0.00	0.00	0.00	-84.95			
4		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
5		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
6		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
7		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
8		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
9		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
10		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
11		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
12		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
13		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
14		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
15		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
16		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
17		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
18		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
19		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
20		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
21		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
22		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
23		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
24		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
25		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
26		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
43		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
44		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
45		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
46		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
47		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
48		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
49		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
50		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
51		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
52		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03
53		4.25	4.25	45.32	0.00	45.32	41.07	100%	75.53	35.03

PV COST	**421.79**	**PV of annual energy**	**1,042.38**	**NPV**	**88.74**	**UNIT COST**	**0.40**
PV Benfi	**510.54**	**Development Rate**	**2.16**	**IRR**	**9%**	**B/C**	**1.21**

Economic Analysis 2x Q mean for two units for Equal Capacity

Economic Analysis										
Installed capacity		Mw	21.36	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp		M nok	435.24	Firm Energy	89.91	0.6	Fixed PP O&M	1%		
Total capital cost		M nok	435.24	Secondary Energy	0.00	0.25	Firm energy Gwh	89.91		
Construction period		yrs	3	Total generation	89.91		Secon.egy Gwh	0.00		
Project life time		yrs	50	**Sensitivity**			Capital cost pp Mnok	435.236		
Discount rate		%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss		%	15%	Investment	1		Investment profile	30%	50%	20%
	Cost stream				Revenue Stream					
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	130.57	0.00	130.57	0.00	0.00	0.00	-130.57			
2	217.62	0.00	217.62	0.00	0.00	0.00	-217.62			
3	87.05	0.00	87.05	0.00	0.00	0.00	-87.05			
4		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
5		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
6		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
7		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
8		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
9		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
10		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
11		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
12		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
13		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
14		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
15		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
16		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
17		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
18		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
19		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
41		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
42		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
43		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
44		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
45		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
46		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
47		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
48		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
49		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
50		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
51		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
52		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
53		4.35	4.35	45.85	0.00	45.85	41.50	100%	76.42	35.89
		PV COST	**432.19**	**PV of annual energy**	**1,054.70**	**NPV**	**84.38**	**UNIT COST**	**0.41**	
		PV Benfit	**516.57**	**Development Rate**	**2.13**	**IRR**	**8.55%**	**B/C**	**1.20**	

Economic Analysis 2.25x Q $_{mean}$ for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	24.00	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	443.17	Firm Energy	90.10	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	443.17	Secondary Energy	0.00	0.25	Firm energy Gwh	90.10		
Construction period	yrs	3	Total generation	90.10		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	443.173		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream			Revenue Stream						
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	132.95	0.00	132.95	0.00	0.00	0.00	-132.95			
2	221.59	0.00	221.59	0.00	0.00	0.00	-221.59			
3	88.63	0.00	88.63	0.00	0.00	0.00	-88.63			
4		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
5		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
6		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
7		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
8		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
9		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
10		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
11		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
12		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
13		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
14		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
15		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
16		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
17		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
18		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
19		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
20		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
21		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
22		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
23		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
24		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
25		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
26		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
43		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
44		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
45		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
46		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
47		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
48		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
49		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
50		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
51		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
52		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
53		4.43	4.43	45.95	0.00	45.95	41.52	100%	76.59	36.54
		PV COST	**440.07**	**PV of annual energy**	**1,056.93**	**NPV**	**77.59**	**UNIT COST**	**0.42**	
		PV Benfi	**517.66**	**Development Rate**	**2.10**	**IRR**	**8%**	**B/C**	**1.18**	

Economic Analysis 2.5x Q mean for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	26.70	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	450.62	Firm Energy	89.94	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	450.62	Secondary Energy	0.00	0.25	Firm energy Gwh	89.94		
Construction period	yrs	3	Total generation	89.94		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	450.620		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream			Revenue Stream						
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	135.19	0.00	135.19	0.00	0.00	0.00	-135.19			
2	225.31	0.00	225.31	0.00	0.00	0.00	-225.31			
3	90.12	0.00	90.12	0.00	0.00	0.00	-90.12			
4		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
5		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
6		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
7		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
8		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
9		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
10		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
11		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
12		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
13		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
14		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
15		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
16		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
17		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
18		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
19		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
20		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
21		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
22		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
23		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
24		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
25		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
26		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
43		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
44		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
45		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
46		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
47		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
48		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
49		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
50		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
51		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
52		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
53		4.51	4.51	45.87	0.00	45.87	41.36	100%	76.45	37.16
		PV COST	**447.47**	**PV of annual energy**	**1,055.05**	**NPV**	**69.27**	**UNIT COST**	**0.42**	
		PV Benfit	**516.74**	**Development Rate**	**2.06**	**IRR**	**8%**	**B/C**	**1.15**	

Economic Analysis 2.75x Q $_{mean}$ for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	29.26	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	457.37	Firm Energy	89.49	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	457.37	Secondary Energy	0.00	0.25	Firm energy Gwh	89.49		
Construction period	yrs	3	Total generation	89.49		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	457.368		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream				Revenue Stream					
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	137.21	0.00	137.21	0.00	0.00	0.00	-137.21			
2	228.68	0.00	228.68	0.00	0.00	0.00	-228.68			
3	91.47	0.00	91.47	0.00	0.00	0.00	-91.47			
4		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
5		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
6		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
7		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
8		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
9		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
10		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
11		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
12		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
13		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
14		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
15		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
16		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
17		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
18		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
19		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
20		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
21		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
22		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
23		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
24		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
25		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
26		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
43		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
44		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
45		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
46		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
47		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
48		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
49		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
50		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
51		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
52		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
53		4.57	4.57	45.64	0.00	45.64	41.07	100%	76.07	37.71
		PV COST	**454.17**	**PV of annual energy**	**1,049.77**	**NPV**	**59.99**	**UNIT COST**	**0.43**	
		PV Benfit	**514.16**	**Development Rate**	**2.02**	**IRR**	**8%**	**B/C**	**1.13**	

Economic Analysis 3x Q $_{mean}$ for two units for Equal Capacity

Economic Analysis

Installed capacity	Mw	32.00	**Energy**	GWh	Tariff	**Price base**	2010		
Capital cost pp	M nok	468.92	Firm Energy	88.92	0.6	Fixed PP O&M	1%		
Total capital cost	M nok	468.92	Secondary Energy	0.00	0.25	Firm energy Gwh	88.92		
Construction period	yrs	3	Total generation	88.92		Secon.egy Gwh	0.00		
Project life time	yrs	50	**Sensitivity**			Capital cost pp Mnok	468.924		
Discount rate	%	7%	Firm energy	1		**Investment**	Yr 1	Yr 2	Yr 3
Transm and gen loss	%	15%	Investment	1		Investment profile	30%	50%	20%

	Cost stream			Revenue Stream						
year	**capital cost power plant**	**Fixed pp O&M**	**Total cost**	**Firm energy**	**Sec energy**	**Total reven**	**Incremental cash flow**	**Load as % of full load**	**Annual energy**	**Annual cost**
1	140.68	0.00	140.68	0.00	0.00	0.00	-140.68			
2	234.46	0.00	234.46	0.00	0.00	0.00	-234.46			
3	93.78	0.00	93.78	0.00	0.00	0.00	-93.78			
4		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
5		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
6		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
7		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
8		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
9		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
10		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
11		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
12		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
13		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
14		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
15		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
16		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
17		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
18		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
19		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
20		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
21		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
22		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
23		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
24		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
25		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
26		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
43		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
44		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
45		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
46		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
47		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
48		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
49		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
50		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
51		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
52		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
53		4.69	4.69	45.35	0.00	45.35	40.66	100%	75.58	38.67
		PV COST	**465.65**	**PV of annual energy**	**1,043.09**	**NPV**	**45.24**	**UNIT COST**	**0.45**	
		PV Benfit	**510.88**	**Development Rate**	**1.95**	**IRR**	**8%**	**B/C**	**1.10**	

Annex H-08 Cost Estimate and Economic Analysis
Single unit Installation Summary

	Energy price			0.6				
	Capital recovery factor			0.082				
	Design discharge m3/s	Project cost	Annualized cost	Cost Increment	Annual Energy	Annual revenue	Incremental benefit	Net Benefit
	M3/s	MNok	MNok	MNok	GWh	MNok	MNok	MNok
$1xQ_{mean}$	2.63	386.48	31.692		78.28	46.968		15.28
$1.25xQ_{mean}$	3.2875	396.62	32.523	0.831	83.37	50.022	3.054	17.50
$1.5xQ_{mean}$	3.945	405.11	33.219	0.696	85.56	51.336	1.314	18.12
$2xQ_{mean}$	4.6025	412.31	33.809	0.591	86.43	51.858	0.522	18.05
$2.25xQ_{mean}$	5.26	420.03	34.443	0.633	86.63	51.978	0.12	17.54
$2xQ_{mean}$	5.9175	425.82	34.918	0.475	86.14	51.684	-0.294	16.77
$2.25xQ_{mean}$	6.575	431.55	35.387	0.470	85.21	51.126	-0.558	15.74
$2.5xQ_{mean}$	7.2325	438.16	35.929	0.542	84.03	50.418	-0.708	14.49
$3xQ_{mean}$	7.89	448.04	36.739	0.810	82.7	49.62	-0.798	12.88