Nw.04_Hol 1

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: Category 1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

Sub: Category 1-a) Energy Policies of Countries and States
Category 2-a) Technical innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Hol 1: Upgrading of Hol 1 Hydropower Plant

Name of Country (including State/Prefecture):

Norway, Buskerud County, Hol Municipality

Implementing Agency/Organization:

E-CO Energi AS

Implementing Period:

2006-2008 Initial studies, contracting and detailed engineering
2009 -2012 Implementation

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction (a, b)
(C) Needs for higher performance (a)

Keywords:

Equipment degradation
Replacing aged E&M equipment
Increasing production
Efficiency improvements

Abstract:

Hol 1 Hydropower Plant in Hallingdal in the southern part of Norway consists of two branches, with two vertical aggregates for each branch. Unit 1 and unit 2 (Votna branch) utilize the head from Varaldsetvatn (HRL 1005, LRL 997 (MASL)) to Storåne (598 MASL). Unit 3 and unit 4 (Urunda branch) utilize the head from Strandavatn (HRL 978, LRL 950) to Storåne. The four units have a common tailrace. The first two units were set in operation in 1949, and unit 3 and unit 4 in 1955 and 1956 respectively.

Total capacity before upgrading was 186 MW. Due to age and hence wear and tear, the owner E-CO Energi decided to implement a comprehensive upgrade of the generating equipment. The rehabilitation of the four units was triggered by a risk analysis that claimed risk of turbine runner breakdown in case of a long period with overspeed. New turbine runners would also increase the efficiency and production, which was wanted after the deregulation of the Norwegian power market early in the 1990'ies.

The four generators were refurbished with new stator windings and static magnetization in the 1970'ies. The turbines were upgraded with new labyrinth seals. The turbines were also rehabilitated in the 1990'ies, but the original turbine runners were in service until the upgrading 2009-2012.

New turbine runners increased both efficiency and design discharge, and the total capacity is now 34 MW higher than earlier. Increased production was anticipated to be 15 GWh/year. The estimation was based on increased efficiency for turbines and generators, together with a marginal decrease of head loss in the waterway. In addition, the high voltage buses from generator to transformer were replaced by buses with larger cross area, which also gave a little more production.

The production was calculated after upgrading, based on efficiency measurements of the turbines, calculated improvements of generator efficiency and reduced losses in the medium voltage constructions. These calculations show a total production increase for Hol 1 HPP of approximately 20 GWh, e.g. 5 GWh more than expected before upgrading.

The unit cost for the additional production (NOK/kWh) is high, but the investment is considered to be favourable for the future. Without upgrading, maintenance and rehabilitation costs would increase considerably within several years. This demonstrates the point that it is important to find the appropriate time for upgrading.

The upgrading was implemented in the period 2009-2012, and included works related to turbines, generators, control system and high voltage conductors from generators to transformers. No new or renewed licence was required, which is common practice for such projects in Norway.

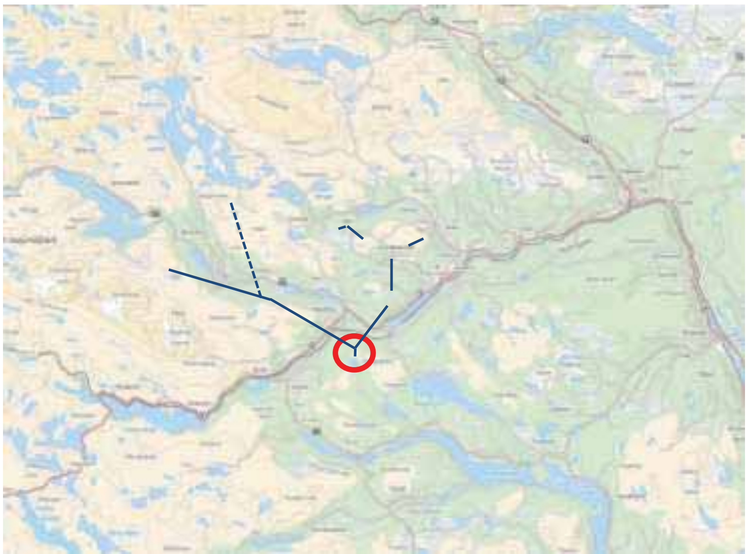
1. Outline of the Project (before Renewal/Upgrading)

Hol 1 HPP is located in the valley Hallingdal some 230 kilometers northwest of the Norwegian capital Oslo. The power was earlier dedicated for public use in the City of Oslo. Transmission lines from the Hallingdal region to Oslo were built for this purpose. After the liberalization of the power market in the 1990-ies, the power produced in the plant is sold in the power market.

The catchment area for Hol 1 HPP (Votna and Urunda rivers) is 721 km^2. Annual average precipitation is 1.0-1.3 m. Total reservoir capacity is 871.5 million m^3.

The construction works on Hol 1 Hydropower Plant started just before the second world war, and consists of two separate branches, Votna and Urunda. When finished there had been installed four units, two for each branch. Each unit had a vertical Francis turbine produced by Kværner Brug, Norway. The generators were delivered by Norsk Elektrisk Brown Boveri (NEBB), Norway. The first unit was brought into operation early in 1949 (Votna, unit 1), the second one (Votna, unit 2) later in the same year, and the two latest in 1955 (Urunda, unit 3) and 1956 (Urunda, unit 4).

The head for unit 1 and 2 is a little more than 400 m, and in 1949 this was the highest head in world for Francis turbines. These units had also the world's largest capacity by then, each of them 44 MW.



Location of Hol 1 power plant in Hallingdal. Urunda branch (left) and Votna branch (right)

Hol 1 Power Plant with penstocks, outdoor powerhouse and switchyard.

Hol I HPP was partly planned before World War II, and was the last large (even the largest) Norwegian hydropower plant with exterior penstock and surface power station. Later, Norwegian HPPs of this size and also a large number of smaller ones, were built with underground power station and pressure shaft.

Votna branch (Unit 1 and 2)

The Stolsvatn reservoir (HRWL 1091, LRWL 1078 (MASL)) is main reservoir for the “Votna branch.” From the reservoir the water is released to the natural river to Rødungen reservoir. Water from the smaller Bergsjø reservoir is also transferred to the Rødungen reservoir. From there the water is conducted in a tunnel to the intake reservoir Varaldsetvatn (HRWL 1005, LRWL 997).

Photo of dam Varaldset.

Total reservoir volume for the Votna branch is 252 mill. m^3. Due to a threshold in the reservoir Stolsvatn, an amount of the water can be led from Stolsvatn through a river. This river runs down to inlet Greinefoss on the Urunda branch, and is there led into the tunnel that supplies the “Urunda machines” (unit 3 and 4).

From the Varaldsetvatn reservoir the water is led through a 4.5 km headrace tunnel with cross section area 18 m^2 to a distribution basin. The Hol 1 power house is situated surface, and the water from Varaldsetvatn is led down to machine 1 and 2 in separate, exterior penstocks. Each penstock is approximately 840 m long, with diameter from 2 200 to 1 500 mm.

Urunda branch (unit 3 and 4)

Strandavatn reservoir (HRWL 978 LRWL 950) is the main reservoir for the Urunda branch. A 17 km headrace tunnel with cross section area 22 - 24 m^2 leads the water to a distribution basin. Three small rivers that cross the tunnel course are also led into the tunnel. Water is led down to machine 3 and 4 from the distribution basin in separate, exterior penstocks. Each penstock is approximately 770 m long, with diameter from 2 200 to 1 500 mm.

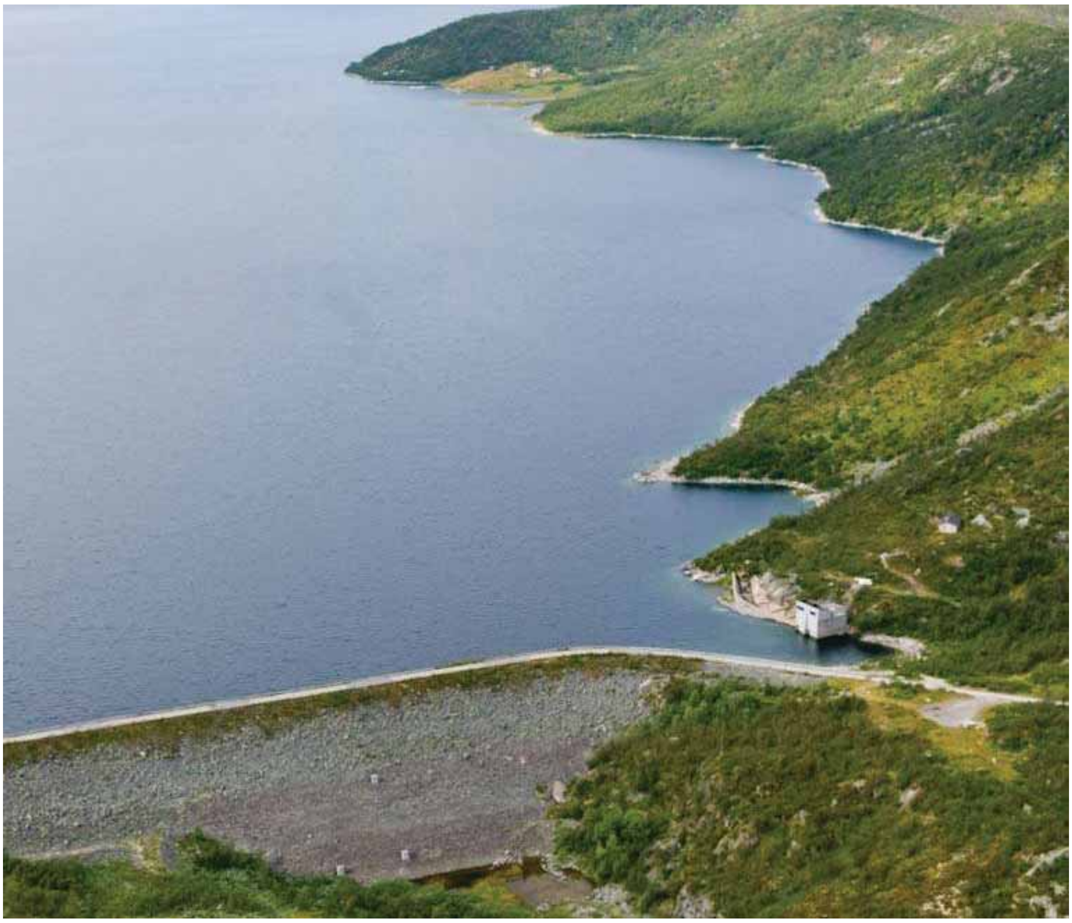


Photo dam Strandavatn.

Strandavatn reservoir is 554 mill. m^3. In addition, 66 mill. m^3 can be transferred from the bottom reservoir in Stolsvatn. This water is led into the headrace tunnel through intake Greinefoss.

Hol 1 HPP before upgrading

Data for Hol 1 HPP before upgading are shown in the table below.

Branch	**Reservoirs (mill. m^3)**	**Capacity (MW)**	**Production (GWh/year)**
Votna	251.7	88	348
Urunda	619.8	98	406
Sum	871.5	186	754

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

The main rationale for the realization of the project was that essential equipment became more and more inefficient caused by wear and tear. An upgrading was planned in order to increase efficiency and hence production. Trigger causes appear more thoroughly from Clause 2.3.

(i) Conditions, Performance and Risk Exposure and Others

(A) Degradation due to ageing and recurrence of malfunction (main trigger cause)

(a) Improvement of efficiency

The new and upgraded E&M equipment has higher efficiency than the old equipment. In addition,the total capacity has been increased, which gave increased production.

(b) Improvement of durability and safety

The E&M equipment in Hol 1 HPP was worn after near 60 years of operation. Further operation without upgrading would have been more and more unsafe and risky by time (increasing maintenance cost and time, collapse risk). The refurbished equipment will ensure durability and safety for decades.

(ii) Opportunities to Increase Value

(C) Needs for higher performance (secondary trigger cause)

(a) Efficiency improvements, expansion of power & energy, loss reduction

The upgrading of Hol I HPP was mainly triggered by degradation and risks. However, increasing production was an additional opportunity, which was met as a side effect when modernizing the equipment. The target can be expressed as increasing the production if possible, not only keeping up the existing.

(iii) Market Requirements

There were no particular market requirements. The upgrading of Hol 1 HPP started before the Norwegian- Electricity Certificate Market was carried into effect.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Planning and execution process:

2006	Initial studies
2007	Contracting
2008	Detailed engineering, order placement
2009	Mechanical work, Unit 1
2010	Mechanical work, Unit 4
2011	Mechanical work, Unit 2
2012	Mechanical work, Unit 3

2.3 Description of Work Undertaken (detail)

Category references

1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

These considerations are continuously ongoing in E-CO Energi (as in other Norwegian power companies), and was also the case for Hol I HPP. Comprehensive planning and economic and strategic considerations resulted in the decision to renew and upgrade the turbines and the generators. Included were parameters such as cost estimates, expected income and net present value (NPV). Failure probability was taken into account regarding life-cycle costs. The final scope was based on these considerations.

1-a) Energy Policies of Countries and States

Both present and preceding Norwegian governments have expressed that it is a prioritized target to increase renewable power production through refurbishment (upgrading and extension of existing hydropower plants). Such measures have often lesser environmental impacts than constructing power plants in unexploited areas.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

The old equipment was worn, with decreased efficiency. Other technical tasks were also taken into account in the planning. Even there were not developed particular new solutions for the project, it was important to ensure that state of art equipment was obtained. The selection was based on studies and up to date knowledge, including types and producers, cost, earlier experience, expert advice, etc.

Supplementary details for category references appear from the text below.

Scope of work

The upgrading in 2009-2012 included these measures:

<u>Unit no. 1 and 2:</u>

- Complete new generator
- New turbine, except spiral case and draft tube
- New inlet valve and governor
- New unit control system
- New high voltage conductors from generator to the transformer

<u>Unit no. 3 and 4:</u>

- New generator except rotor and thrust bearing bracket
- New turbine, except the spiral case and the draft tube
- New inlet valve and governor
- New unit control system
- New high voltage conductors from generator to the transformer

Original and upgraded units

Data for units before upgrading are shown in the table next.

Branch	Unit no.	Year	Rated turbine output	Rated generator output	Annual production	Rated head
Votna	1	1949	44 MW	50 MVA	348 GWh	385 m
	2	1949	44 MW	50 MVA		385 m
Urunda	3	1955	49 MW	55 MVA	406 GWh	350 m
	4	1956	49 MW	55 MVA		350 m
Sum			186 MW		754 GWh	

Data upgraded units (estimated before upgrading)

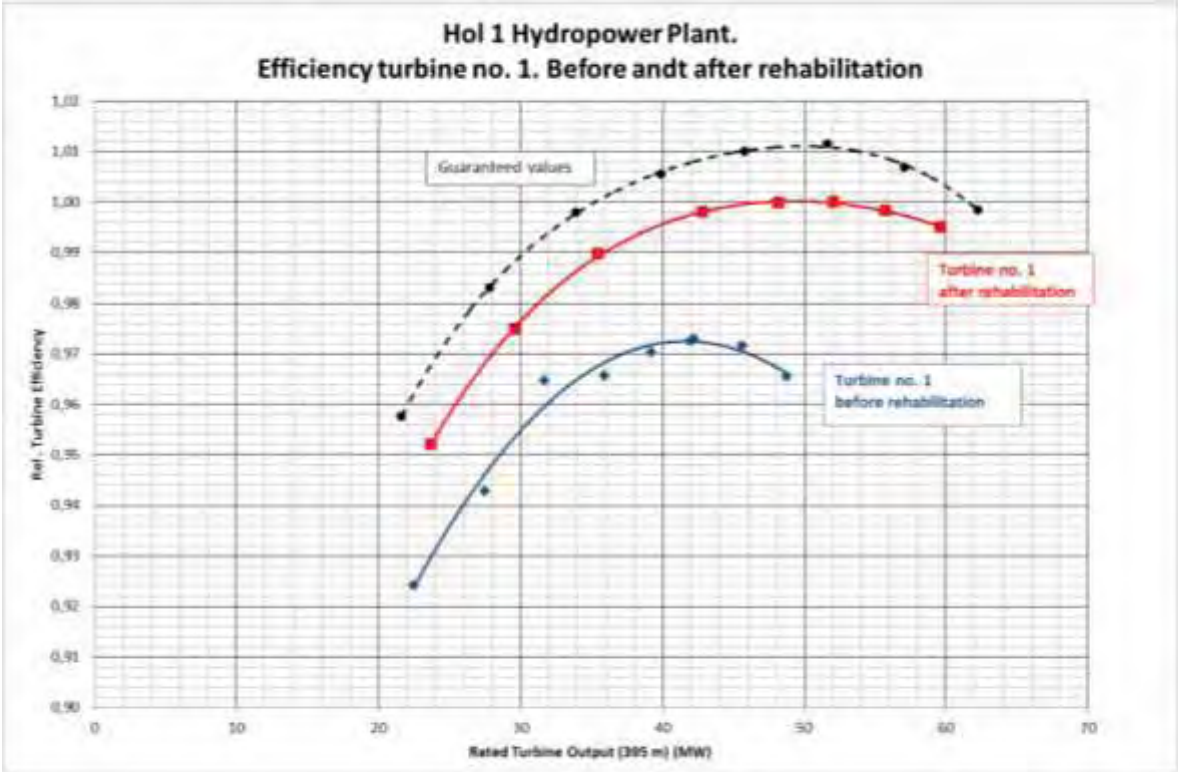
Branch	Unit no.	Rated turbine output	Rated generator output	Annual production	Rated head
Votna	1	57 MW	65 MVA	355 GWh	395 m
	2	57 MW	65 MVA		395 m
Urunda	3	53 MW	60 MVA	414 GWh	355 m
	4	53 MW	60 MVA		355 m
Sum		220 MW		769 GWh	

The 15 GWh increase in power production was due to an anticipated improvement of the turbine and generator efficiencies.

Old runner taken out of turbine ....and a new runner on its way in.

Thermodynamic measurements

Thermodynamic measurements of the turbine runners have been measured a couple of times throughout the years, especially in connection with the rehabilitation in the 90'ies. Before starting the project in 2009 it was known that the turbines were due to some maintenance work, as the efficiency was expected to be reduced after near 20 years in service since the last rehabilitation. Before the rehabilitation of each turbine 2009-2012, thermodynamic measurements were executed. Results are plotted in the diagrams underneath. The measured efficiency for the new turbine runners are also plotted in the diagrams.


Hol 1 Hydropower Plant.
Efficiency turbine no. 1. Before andt after rehabilitation
Guaranteed values
Turbine no. 1
after rehabilitation
Turbine no. 1
before rehabilitation
Rel. Turbine Efficiency
Rated Turbine Output (395 m) (MW)
1,02
1,01
1,00
0,99
0,98
0,97
0,96
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0,93
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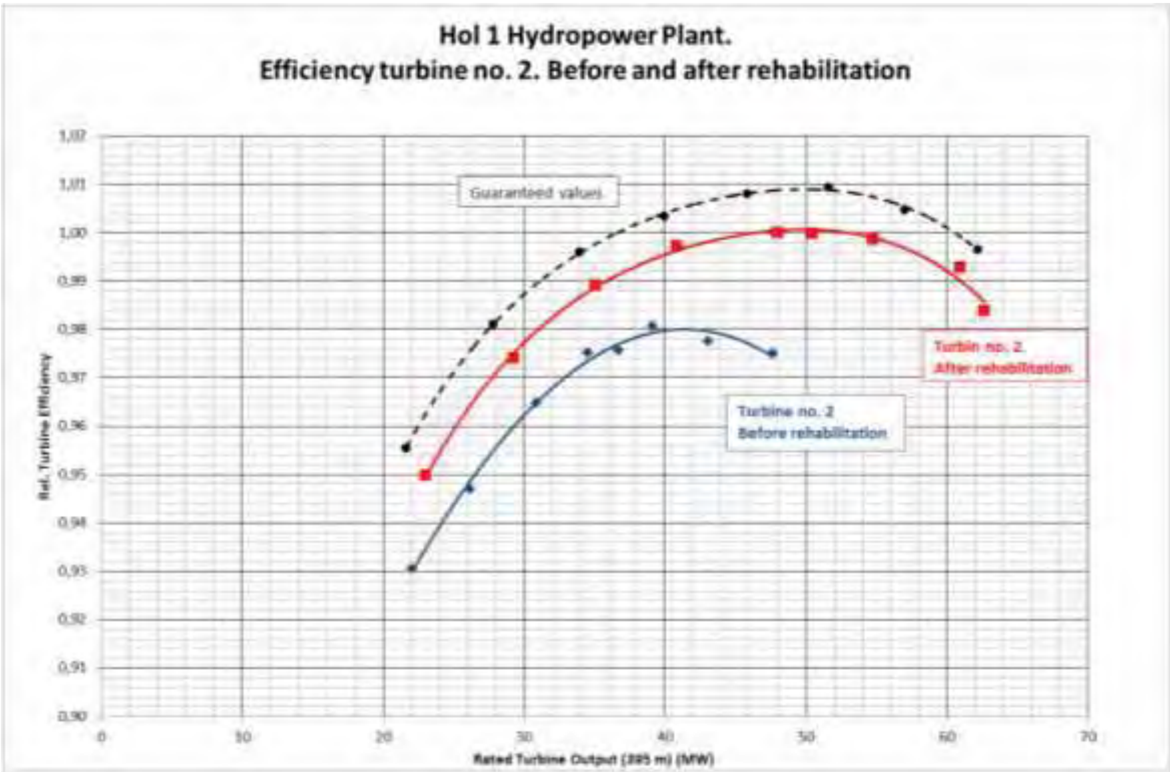
10
20
30
40
50
60
70


Hol 1 Hydropower Plant.
Efficiency turbine no. 2. Before and after rehabilitation
Guaranteed values
Turbin no. 2
After rehabilitation
Turbine no. 2
Before rehabilitation
Rel. Turbine Efficiency
Rated Turbine Output (395 m) (MW)
1,02
1,01
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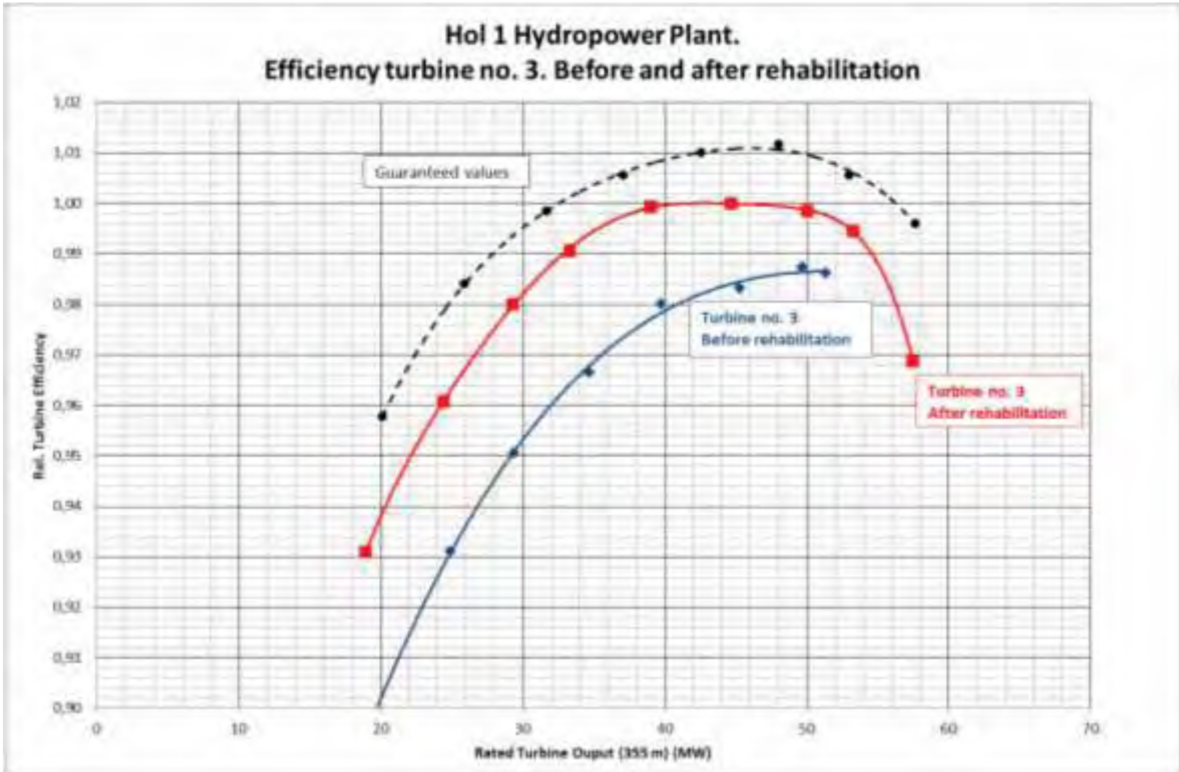
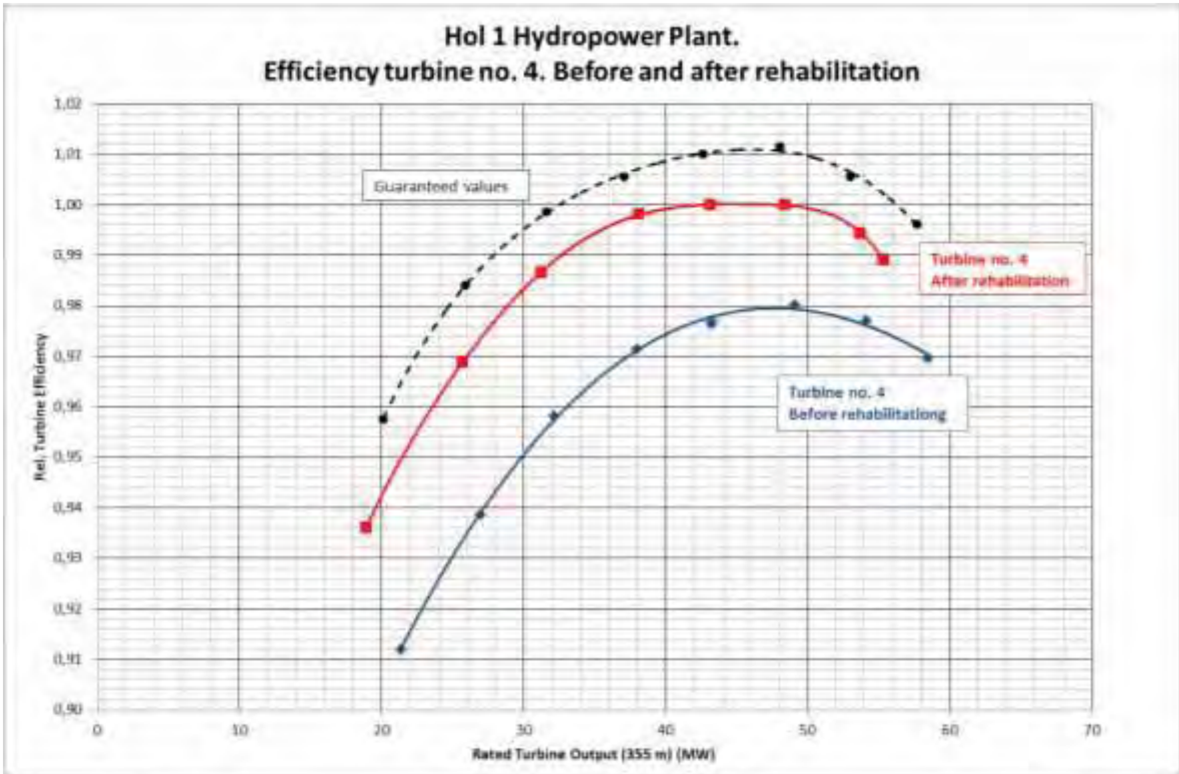




The results from the thermodynamic efficiency measurements performed after the upgrade demonstrates that the guarantee given by the vendor was not totally fulfilled. Even so, the project target is met to satisfaction.

Others

In addition to refurbishment and partly rebuilding of the turbines and generators, the existing gate valves were replaced with ball valves. Also the old regulators that worked on 30 bar oil pressure were replaced with new regulators that worked at 110 bar oil pressure.

Staying vane and spiral case, steel sheeting in the draft tube cone, safety valve and safety valve outlet was sandblasted and painting during the upgrade process. Due to a higher power output from each machine, the conductors from the generator to the transformers had to be replaced. The local unit control centers were replaced with new ones.

"Singing penstock"

After the upgrade of generator 1 and 2, an unexpected noise occurred, that spread in the open air penstock. Analysis showed that the noise occurred in the space between the guiding vanes and the inlet to the turbine runners. This is not an unknown phenomena, and the term "singing penstock" describes this. To get rid of this unwanted noise, the following efforts were carried out:

- Bracing regulating ring
- New lower labyrinth ring
- Cutting runner blade inlet
- New guide vane
- Bracing lower cover
- Isolating penstock
- Noise isolation in the powerhouse

The listed measures were carried out in order to change frequency pattern and resonance in the turbine. Cutting the runner blade in addition to guiding vanes gave measurable results. After some time, the lower part of the penstock was isolated, and this reduced the noise level even more.

There were discovered cracks in the transmission to the vanes in spring 2013. This was most likely because the natural frequency was too close to the nominal frequency during operation. The cracks on the runner wheels have been fixed up, and accordingly there has been cut approximately 50 mm of the inlet to each runner blade. This has changed the natural frequency of the running wheel.

Since the noise level still was in the higher end, the edge of the inlet for each runner blade was slightly changed. The 32 blades were adjusted with 3 different diameters, randomly distributed. The number of blades were unchanged, but the shape is slightly modified. These measures were anticipated to break down the precise frequency pattern when the runner blades pass the guiding vanes, and then hopefully reduce the noise level even more. The repairs and modifications were carried out for turbine 1 in 2013. The noise level was noticeably reduced, in particular in the powerhouse, but also in the nearby settlement. Similar action was performed for turbine 2 in 2014, and with same result as for turbine 1. It seems as if the noise level now is accepted, both by E-CO Energi and the local population.

The turbine efficiency was not particularly changed through cutting runner blades for turbine 1 and turbine 2. The peak efficiency was moved a little up in the efficiency curve, but the level of the total curve was no changed.

Results

Before and after the upgrading, the Votna units (unit 1 and 2) and the Urunda units (unit 3 and 4) have the following data:

Votna	Rated turbine output (MW at H_e)	Rated generator output (MVA)	Rated discharge (m^3/s at H_e)	Rated head (m)
Before	44	50	12,6	385
After	57	65	15,6	395

Unit 1 and 2

Urunda	Rated turbine output (MW at H_e)	Rated generator output (MVA)	Rated discharge (m^3/s at H_e)	Rated head (m)
Before	49	55	15,4	350
After	53	60	16,2	355

Unit 3 and 4

The estimated 15 GWh increase in power production was due to an anticipated improvement of the turbine and generator efficiencies before implementation. Measurements after upgrading verified the additional production to be 20 GWh/year, which is 5 GWh higher than calculated in beforehand. This gives results as shown in the table below.

Branch	**Capacity before (MW)**	**Capacity after (MW)**	**Production before (GWh/year)**	**Production after (GWh/year)**
Votna	88	114	348	358
Urunda	98	106	406	416
Sum	186	220	754	774

Total cost for upgrading of Hol 1 HPP was approximately 255 MNOK (33 MUSD with rate primo June 2015). This is a rather high cost per kWh, but the investment is favorable for the future. The upgrading had targets beyond increasing the production. Without upgrading, maintenance and rehabilitation costs would increase considerably within several years. The implemented upgrading ensures durability and safe hydropower production for decades, and is also a contribution to Norway's target for renewable energy.

3. Feature of the Project

3.1 Best Practice Components

By renewing old turbine runners with newer efficiency, and do some modifications on the generators, the production of renewable energy could be increased. The total design discharge for Hol I HPP was increased with 7.6 m^3/s. This increase had no environmental impacts, and was done within existing licence.

3.2 Reasons for Success

- Initial studies with detailed planning and production simulations for several alternatives
- Increased production by utilizing existing resources
- Skilled suppliers with significant experience
- No environmental impacts
- No landowner permissions needed
- Upgrade obtained within existing licence

4. Points of Application for Future Project

This project can be a benchmark for future similar projects with water surplus and a potential to improve efficiency.

5. Others (monitoring, ex-post evaluation, etc.)

Reference is made to Clause 2.3.

6. Further Information

6.1 References

IEA expert meeting, Gol, Norway, June 2013. Presentation of Hol 1 Upgrading by Eirik Bøkko, E-CO Energi AS

6.2 Inquiries

Company name: E-CO Energi AS
URL: www.e-co.no

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: Category 1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

Sub: Category 1-a) Energy policy of Countries and States
Category 1-c) Integrated management of water resources and river systems
Category 1-f) Environmental conservation and improvement

Project Name:

Hunsfos East Hydropower Plant

Name of Country (including State/Prefecture):

Norway, Vest-Agder County, Vennesla municipality in southern Norway

Implementing Agency/Organization:

Agder Energi Hydro Production

Implementing Period:

2001 Start of planning for a new power plant
2005 Startup of site work
2008 The new power plant Hunsfos East was ready for normal operation

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction (a, b)
(B) Environmental deterioration (b)
(C) Needs for higher performance (a)

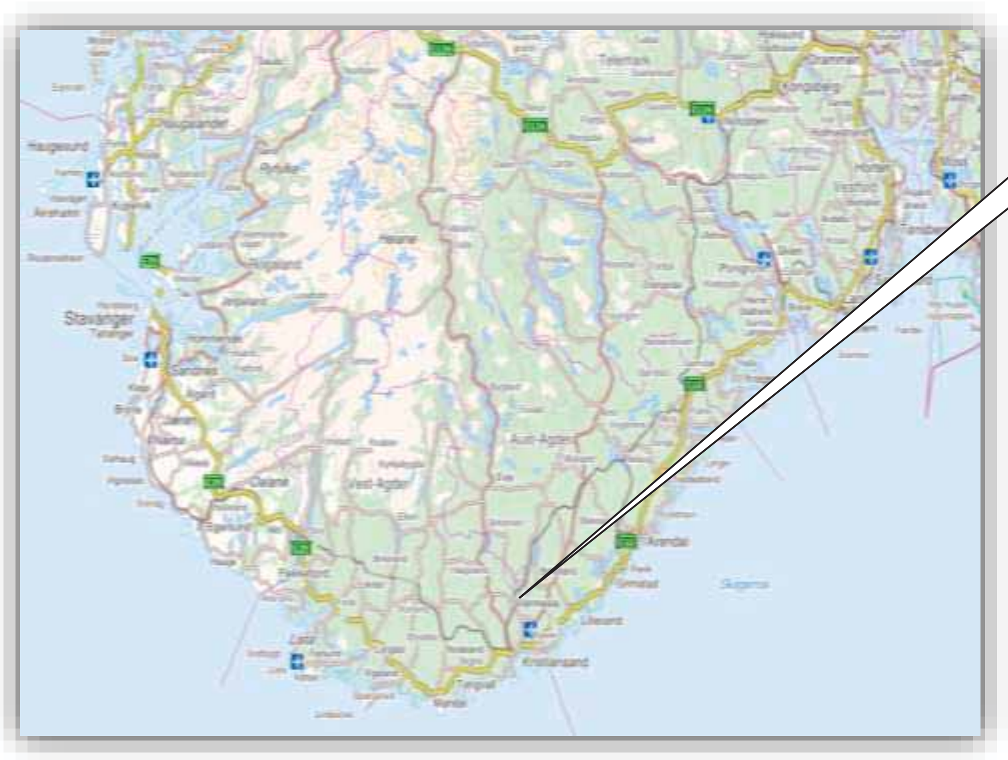
Keywords:

Run-off-River (RoR) hydropower plant
Increased capacity
New renewable energy production
A new power plant in parallel with an existing one

Abstract:

The waterfall Hunsfos in the Otra river course has been exploited for hydro energy generation since early in the twentieth century. Hunsfos is located at the village of Vennesla some 20 kilometers north of the city of Kristiansand on the south coast of Norway.

There is a small island in the middle of the river at Hunsfos. A paper industry facility was located on this island. Before construction of Hunsfos East there was a power plant in the western stream (Hunsfos West HPP) with capacity 15.5 MW (3 MW + 12.5 MW).



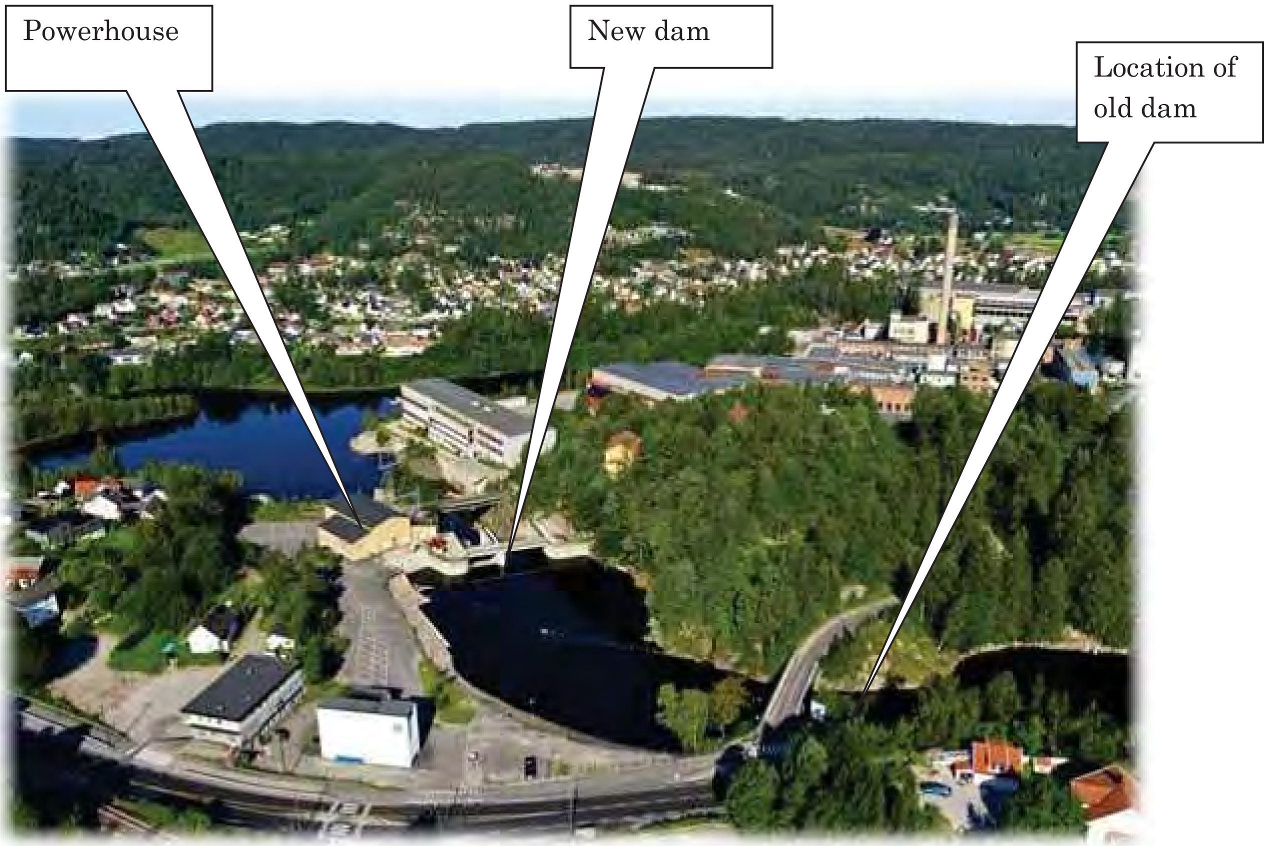
Location of Hunsfos in river Otra

The old small unit (3 MW) from 1926 in Hunsfos West HPP was worn and there was a need for a total overhaul if continued operation. When building Hunsfos East HPP the old unit was removed. The new Hunsfos East HPP was designed to include also the lost capacity when removing the old unit (and in fact more than so).

Hydropower production is now located in both river streams, eastern (new) and western (old). Both power plants are run-off river plants with no reservoir, only a common, small intake pond. Hunsfos East is located in a river course, and building the new power plant and the dam was quite a challenge.

The new Hunsfos East hydro power plant is an extension of capacity and production at Hunsfos. The target was to utilize more of the water resources in energy production. Hunsfos West is still in operation, but one of the original two units (3 MW) is removed. In addition Hunsfos East HPP also contributed to an improvement of the cascade hydropower system in the river Otra.

Due to the situation in the Norwegian power marked during the nineties, extension (renewal and upgrading of hydropower plants) of hydropower production was seldom regarded profitable again before the beginning of the 21st century.



Hunsfos East

The planning of Hunsfos East started in 2001. Construction works started in 2005, and was completed in 2008. By building a second power plant at Hunsfos, most of the water in the river is now utilized for power production. Mean total production is now approximately 145 GWh/year, while the increase caused by the construction of Hunsfos East is some 65 GWh. The cost when completed in 2008 was approximately 250 MNOK (35 MUSD with rate ultimo May 2015).

1. Outline of the Project (before Renewal/Upgrading)

Before the project Hunsfos East was implemented there was a substantial amount of water in the river Otra at Hunsfos that was not exploited for power production.

The power was earlier used in industrial enterprises close to the power plant. The industry was mainly based on the vast local forest resources, with production of pulp and paper. In addition to hydropower production, some water was used directly for grinding lumber. This use of water was ended in the eighties. This gave later Agder Energi the opportunity to build a second power plant in the eastern river stream, utilizing the water that earlier was used for grinding lumber.

The power production was located on the western side of the river in connection to the earlier pulp and paper production. The hydropower plant, Hunsfos West, was built by the owners of the paper plant in the early sixties to ensure enough energy to the paper production. The power company Agder Energi bought the power plant in the early eighties, with the opportunity to expand the power production as the owner of the paper plant had plans for shutting down grinding of lumber.

Before building Hunsfos East, the eastern river path was only used for "draining" excess water when the water flow in the river exceeded the capacity of Hunsfos West power plant. The excess water was led from the intake pond through a dam with hatches. The old dam in the eastern stream has now been replaced by a new dam which was built in connection with the new power station.

Hunsfos West power plant had two units, one 3 MW unit from 1926 and one 12.5 MW unit from 1964. The oldest unit was considered to be completely worn out. Renovation of this unit was concluded to be unrealistic due to high cost and low production. The location was not suitable for installation of a larger turbine and generator.

The total discharge in Hunsfos West HPP was approximately 130 m^3/sec, which is lower than the mean water flow in the river (some 150 m^3/s). Hunsfos could then also be regarded as a bottleneck in the cascade system, and at least after increasing the discharge in power plants both upstream and downstream. It was therefore decided to build a new power plant on the east side of the river, as an addition to the plant on the west side, but keeping only the large unit there.

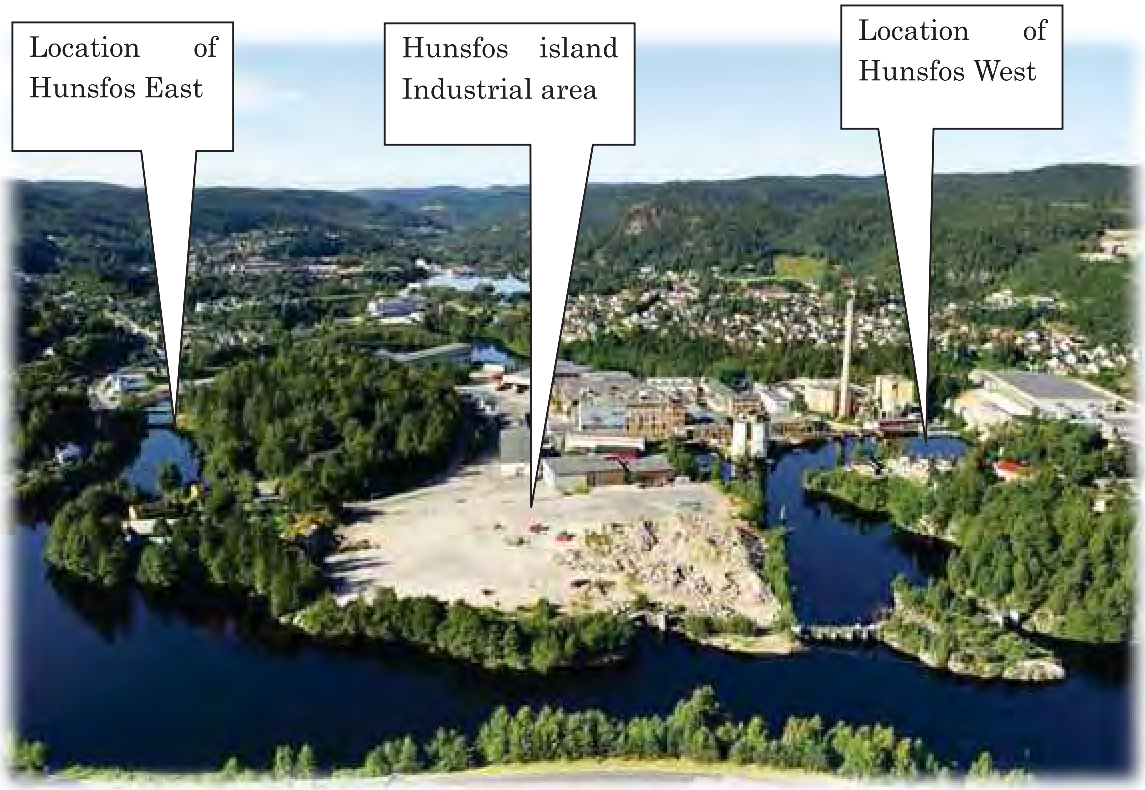
Unit	Capacity (MW)	Design discharge (m^3/s)	Production (GWh/year)	Year
Unit 1	3.0			1926
Unit 2	12.5			1964
Sum		130	80	

Hunsfos West before Hunsfos East

There are reservoirs higher up in the river basin. Together there are 16 hydropower plants in the basin (main river and tributaries), included also rather small HPPs. Some of them are of same type as Hunsfos HPPs (RoR), and with a rather large range regarding age and conditions for operation. It is a need for modernization of some of the plants. In addition, an extension (increased capacity, increased head or other measures) is often beneficial.

Iveland HPP, which is also presented as a case in Annex XI, is also located in the river Otra, upstream Hunsfos. There are two power plants between Iveland and Hunsfos; Nomeland and Steinsfoss HPPs. Design discharges are 180 m^3/sec and 245 m^3/sec respectively. Current discharge in Iveland HPP is 116 m^3/sec. An increase to 215 m^3/sec is ongoing.

These three power plants are also owned by Agder Energi.



Location of both hydropower plants at Hunsfos

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

The main rationale for realization of the project was that the capacity of the old plant (Hunsfos West) was not sufficient to utilize the water flow in the river as much as economic beneficial.

(i) Conditions, Performance and Risk Exposure and Others

(A) Degradation due to ageing and recurrence of malfunction

(a) Improvement of efficiency

Malfunction has here also the meaning of insufficient utilization of water resources. The utilization could be improved by increasing design discharge and installed capacity. The total capacity was increased with 12.5 MW, which gave an additional mean production of 65 GWh.

(b) Improvement of durability and safety

The new power plant in addition to the remaining unit in Hunsfos West HPP ensures trustable and safe production for decades.

(B) Environmental deterioration

(b) Improvement of river development

Near hundred years of industrial activities in the area had caused contamination. However, the water quality had improved during the last decades, so the construction of Hunsfos East HPP did not directly affect water quality or the environment, but will contribute in conserving the improved conditions.

(ii) Opportunities to Increase Value

(A) Needs for higher performance

(a) Efficiency improvements. Additional power and energy. Loss reduction

There was a potential for higher performance. The construction of Hunsfos East power plant gave larger capacity at Hunsfos (Hunsfos West and Hunsfos East), then leading to reduced flow losses and increased production.

(iii) Market Requirements

There were no particular market requirements. Hunsfos East HPP was built before the Norwegian-Swedish Electricity Certificate Market was carried into effect.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Planning and execution process:

2001	Start up of planning
December 2004	Licence to build the new plant was granted
February 2005	Startup of work on site
November 2007	Hunsfos East was ready for testing
December 2007	Guide vanes collapsed during testing
October 2008	Reparation of guide vanes was completed, and the plant was put into normal operation

Agder Energi was awarded licence in December 2004 to build the new plant Hunsfos East. The investment decision was made by the Board the same month. At that time the civil contractor was ready to start.

2.3 Description of Work Undertaken (detail)

Category references

1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

These considerations are continually ongoing in Agder Energi (as in other Norwegian power companies), and was also the case for Hunsfos. Comprehensive planning and economic and strategic considerations resulted in the decision to construct a new power station in the east stream of Otra river at Hunsfos. Included in the considerations and calculations were parameters such as cost estimates, expected production income and net present value (NPV). Failure probability was taken into account regarding life-cycle costs. The final scope was based on these considerations.

1-a) Energy policy of Countries and States

Norwegian governments have for many years expressed that it is a prioritized target to increase renewable power production during refurbishment (upgrading and extension of existing hydropower plants). Such measures have often lesser environmental impacts than constructing power plants in unexploited areas.

1-c) Integrate management of water resources and river system

There are five Run-off-River hydropower plants in a cascade in the river. It was therefore a goal to optimize the capacity of the plants in order to minimize the water loss in the power plant, i.e. increase the production.

1-f) Environmental conservation and improvement

Due to almost 100 years of industrial activities, mainly forest industry, some area of the land at east bank had become contaminated. Several thousand m^3 soil had to be removed and handled as dangerous waste by approved companies, before the construction works could be started.

Otra River was for many years a heavy polluted river due to industrial pollution. Some 30 years ago a project for cleaning the river from industrial pollution was initiated. The water quality has been better and in recent years the river has become one of Norway's best rivers for fishing, especially regarding salmon. Due to a waterfall approximately 3 km downstream the power plant the salmon is not able to reach the outlet from the power plant. Therefore the plant does not affect the fish migration in the river.

Supplementary details for category references appear from the text below.

Hunsfos East HPP

Category	Specifications
Maximum output	15 MW
Hydraulic head	14 m
Turbine type	Kaplan with 4 m runner diameter
Water flow capacity	120 m^3/sec
"Tunnel" length	100 m
"Tunnel" type	Reinforced concrete
"Tunnel" cross section area	80 m^2
Dam height	13 m
Dam length	40 m
Dam type	Reinforced concrete

Specifications of Hunsfos East Hydropower Plant

Construction period

Rock excavation started in February 2005. In brief, the first year (2005) was mainly dedicated to rock excavation and starting concrete works in the powerhouse. Dam construction started in spring 2006, and all concrete works were more or less completed late 2006. The rock excavation and preparing the site for building powerhouse and dam was done in 2005.

Installation of technical equipment, such as turbine, generator, switchgear and control system was also started in 2006. The plant was ready for testing in November 2007, on schedule. During testing a major failure occurred. The guide vanes to the turbine runner collapsed, caused by a design failure. The failure was due to a minor calculation error by the turbine contractor. The incident caused damage not only to the guide vans but also to the generator shaft. The error caused a ten month delay in the project, and the plant was not completed for normal operation before October 2008. Hunsfos East HPP has been operated without problems since the start up in 2008.

The main challenge during construction was to control the water flow. During the most critical periods of construction the total water flow in the river Otra had to be led through the river's western stream. This was necessary to allow the construction of the intake dam to Hunsfos East directly in the riverbed. The construction works were well planned, but heavy rain in some periods made problems when the water flow in the river Otra exceeded the capacity of the power plant in the western stream.

Operation and production

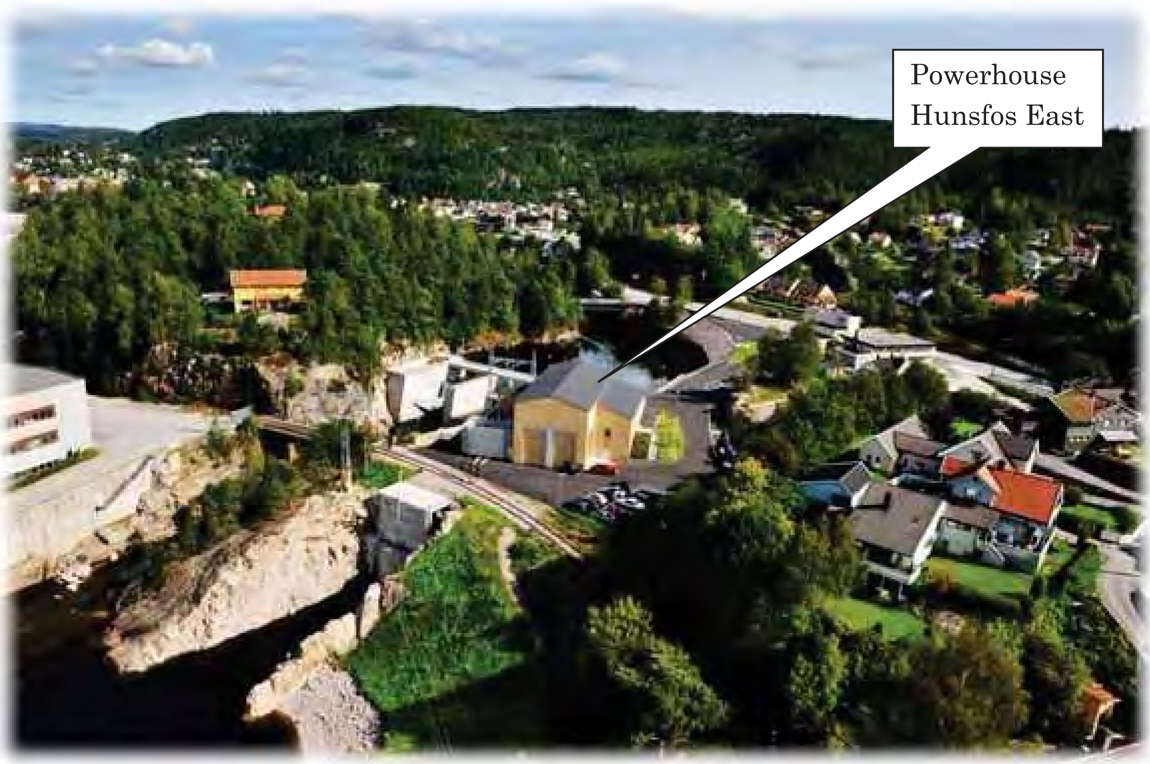
The design discharge in Hunsfos West is now 110 m^3/s, and for Hunsfos East the discharge is 120 m^3/s. This will say 230 m^3/s together, which is an increase of approximately 100 m^3/s. Hunsfos East will be the main power plant. Hunsfos West will be in operation when the flow is larger than the maximum discharge in Hunsfos East.

The mean annual production for Hunsfos East and Hunsfos West will be approximately 145 GWh. This is an increase of 65 GWh compared with the earlier situation. Predictable and cost effective power production with minimal environmental foot prints is secured for the next 50 – 100 years.

Building of a power plant in the eastern stream of the river Otra at Hunsfos enables Agder Energi to fully exploit the water flow in the river. In earlier days the pulp and paper industry made use of the water for mechanical grinding of lumber to the paper production. As the use of water for this purpose stopped, the power company became interested in utilizing the water for hydro electric production. The mean water flow at Hunsfos is approximately 150 m^3/s. The capacity at Hunsfos West HPP was about 130 m^3/s. By building a new plant, Hunsfos is not a bottleneck in the hydropower system in river Otra.

Category	Before	After	Hunsfos East, net
Capacity, MW	15.5	27.5	12.0
Design discharge, m^3/s	130	230	100
Production, GWh/year	80	145	65

Before and after construction of Hunsfos East Hydropower Plant



Hunsfos East Power Plant

3. Feature of the Project

3.1 Best Practice Components

Since the dam had to be built in a dry riverbed, the control of water flow and water quality in the river during the construction process was important for the implementation.

Agder Energi has similar projects in the portfolio, and hence the information gained from this project, especially regarding the river bed and controlling the water flow during construction, will be useful information to other projects.

3.2 Reasons for Success

Control of the water flow during construction was a key factor for success, both regarding influence on the building process as well as environmental impacts.

The river is a major river for salmon fishing, which required good water quality at the same time as the most intense building process took place directly in the river bed. Sedimentation ponds had to be built in the river downstream the construction area to ensure that the water quality in the river was good and had no negative effect on the fish.

4. Points of Application for Future Project

References are made to clauses 3.1 and 3.2.

5. Others (monitoring, ex-post evaluation, etc.)

References are made to Clause 2.3.

6. Further Information

6.1 Reference

None

6.2 Inquiries

Company name: Agder Energi Hydro Production AS
URL: www.ae.no

Nw.06_Iveland #2

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-b) Investment incentives (Feed-in-Tariff (FIT), Renewable Portfolio Standard (RPS), subsidies, financial assistance, tax deductions, etc, where it is located

Sub: 1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

1-a) Energy policy of Countries & States

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Iveland 2 Hydropower Plant

Name of Country (including State/Prefecture):

Norway, Aust-Agder County, Iveland Municipality in southern Norway

Implementing Agency/Organization:

Agder Energi Hydro Production

Implementing Period:

Planning	2005-2012
Construction	2013-2016

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction (a, b)

(C) Needs for higher performance (a, b)

Keywords:

Run-off-River (RoR) hydropower plant

New hydropower plant in parallel with an old one

Reducing water loss

New renewable energy production

Abstract:

Iveland (1) Hydropower Plant was built in the period 1949-1955, with a quite small design discharge referred to later premises. Iveland 1 HPP has then for many years been regarded as a bottleneck for hydropower production in the river Otra. Increased capacity at Iveland HPP has been considerd since the 1980s. During the nineties the marked for electric energy became somewhat unpredictable and investment in a new plant at Iveland to increase production was put on hold.

In 2005 Agder Energi started planning to increase production at Iveland again. The main trigger for the project was to increase renewable hydropower production. By building a new, second hydropower plant at Iveland most of the water in the river Otra passing Iveland will be used for hydropower production. When the new Iveland 2 HPP has been commissioned in 2016 the total peak load capacity at Iveland will be doubled, and the total annual power production will increase with approximately 45%.

The introduction of the Norwegian-Swedish Electricity Certificate Market has been an important incentive for the project. The project is also positive regarding the 2020 goal for reduction of greenhouse gases emission.

The new hydropower plant Iveland 2 will be built in parallel with the old hydropower plant Iveland 1, using the same dam, the same intake reservoir (pond), but the there will be two separate intakes two separate tunnel systems. Iveland 1 HPP will be in operation during the construction period as well as after construction of Iveland 2 HPP.

The construction works are on schedule, and the new power station will be in operation in 2016. Current cost estimate is 700-750 MNOK (90-100 MUSD).

Old (blue) and new (red) power stations and waterways

A strong incentive to upgrade the plant with a new plant Iveland 2 in parallel is the fact that the design discharge in Iveland 1 is lower than the mean flow in the river.

In addition, Iveland 1 HPP will need technical upgrade within a few years due to aging of components. Iveland 2 HPP will enable Agder Energi to reduce production loss during maintenance shutdown of Iveland 1 HPP.

The project demonstrates that extension in combination with an upgrade can be a good solution. Parallel tunnels and powerhouses reduce the risks and enable production to continue during the construction period. In addition, the extension and upgrade ensure durability and safe production for decades.

1. Outline of the Project (before Renewal/Upgrading)

Iveland 1 hydropower plant was commissioned in the period 1949-1955 (with 3 units successively) and was not utilizing the full potential for hydropower production in the river. The purpose was to cover the local and partly regional demand at that time.

Category	Specifications
Maximum output	45 MW
Hydraulic head	50 m
Turbine type	Francis (3 x 15 MW)
Water flow capacity	116 m^3/sec
Tunnel length	2.6 km
Tunnel cross section area	50 m^2
Reservoir capacity	2.8 million m^3
Dam type	Reinforced concrete

Features for Iveland 1 Hydropower plant

Iveland 1 hydropower plant consists of a small intake reservoir, one dam (reinforced concrete), a 2.6 km long and narrow tunnel and 3 units (more or less similar) with a total capacity of 45 MW. The power station is located surface. The head is 50m between the intake in the small lake Gåsenflofjorden (a widening of the river) to outlet in Nomelandsfjorden, also a widening of the river. Nomelandsfjorden is intake pond for the next downstream power plant, Nomeland HPP. The current mean annual production in Iveland 1 HPP is approximately 350 GWh.

The design discharge for Iveland 1 HPP is 116 m^3/sec, while the mean flow at Iveland is 130 m^3/s. Hence, the design discharge is lower than the mean flow. Since there is only a small reservoir capacity (and even there are reservoirs higher up in the river basin) there is a large loss of water. Then there is a potential for higher production by increasing the capacity.

There are reservoirs higher up in the river basin. Together there are 16 hydropower plants in the basin (main river and tributaries), included rather small ones. Some of them are of same type as Iveland HPP (RoR), and there is a rather large range regarding age and conditions for operation. It is a need for modernization and upgrading of some of the plants. In addition, an extension (increased capacity, increased head or other measures) is often beneficial.

The implementation of Iveland 2 HPP will increase the production, and is an example of extension by extended capacity. In addition, the units in Iveland 1 HPP will be upgraded within a few years, with new improved runners with better efficiency, which also will contribute to increased production.

Photo of the existing power station

2. Description of the Renewal and Upgrading Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

The main rationale for realization of the project is that the capacity in the old plant was not sufficient to exploit the water flow in the river as good as desirable. A larger capacity will increase production. The trigger causes appear more detailed from Clause 2.3.

(i) Conditions, Performance and Risk Exposure and Others

(A) Degradation due to ageing and recurrence of malfunction

(a) Improvement of efficiency

Malfunction has here also the meaning of insufficient utilization of water resources. The utilization can be improved by higher design discharge and installed capacity. The total capacity will be increased with 45 MW, which will give an additional mean annual production of 150 GWh. The total implementation includes upgrading of low efficiency units in Iveland 1 HPP.

(b) Improvement of durability and safety

The additional turbine (Iveland 2) will reduce maintenance and downtime in the combined scheme Iveland 1 and Iveland 2, and will still more increase durability and safety for decades (the three turbines in Iveland 1 will be ugraded).

(ii) Opportunities to Increase Value

(C) Needs for higher performance

(a) Efficiency improvements, addition power & energy, loss reduction

New equipment (new power plant) gave higher efficiency per m^3 of water. However, the existing power plant was built under other premises than what is relevant today. The total design discharge and installed capacity were therefore relatively low, with a rather high loss of water and production. It was then beneficial to increase the total capacity to reduce water loss, and hence increase total production.

(b) Role change of hydropower generation, addition of new functions

The introduction of the Norwegian-Swedish Electricity Certificate Market in 2012 was an investment incentive for the new power station Iveland 2. The final planning and realization of the project started before 2012, but there were strong and highly trustable indications that a certificate market was in the pipeline. Power plants (renewal and upgrading included) for which construction started after 7th of September 2009 are qualified for the certificate market. Construction works for Iveland 2 started in 2013.

(iii) Market Requirements

An investment incentive for new renewable energy production was in place by the establishment of the Norwegian-Swedish Electricity Certificate Market in 2012.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

2005	Start of project planning
2007	Application for licence to build the new plant (to Norwegian Water Resources and Energy Directorate (NVE)
2009	NVE's recommendation to Ministry of Petroleum and Energy (OED)
2011	Licence granted by OED
May 2013	Investment decision was made by the company board
June 2013	Mobilization and start up of construction works
Q1 2016	Water filling and testing
April 2016	Scheduled commission of Iveland 2 HPP

2.3 Description of Work Undertaken (detail)

Category references

1-b) Investment incentives (Feed-in-Tariff (FIT), Renewable Portfolio Standard (RPS), subsidies, financial assistance, tax deductions, etc, where it is located

A strong incentive for development of new renewable energy production, including hydropower, is the introduction of Norwegian-Swedish Electricity Market from 2012. The income from new power plants will come from ordinary power sale and from sale in the electricity certificate market. The extra power production caused by Iveland 2 hydropower plant will qualify for such certificates.

1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

Iveland 2 HPP is a refurbishment and extension project, and is a part of a long-term strategy for optimal development of Agder Energi's hydropower portfolio within profitable limits. These considerations are continually ongoing in Agder Energi (as in other Norwegian power companies), and was also the case for Iveland 2 HPP. Comprehensive planning and economic and strategic considerations resulted in the decision to renew and upgrade the turbines and the generators. Included were parameters such as cost estimates, expected income and net present value (NPV). Failure probability was taken into account regarding life-cycle costs. The final scope was based on these considerations.

1-a) Energy policy of Countries and States

The Norwegian governments have for many years expressed that it is a prioritized target to increase renewable power production during refurbishment (upgrading and extension of existing hydropower plants. Such measures have often lesser environmental impacts than constructing power plants in unexploited areas.

2-a) Technological innovation and deployment expansion of electro-mechanical (E/M) equipment

Technical innovation & deployment expansion of electro-mechanical (E/M) equipment are, to some degree, in question during upgrading of existing Francis turbines in Iveland, but probably not beyond existing know how on turbine design.

Supplementary details for category references appear from the next.

Selection of sceme

Design study for the new power plant Iveland 2 was carried by the company's engineering and operation staff with assistance from the engineering consultant SWECO, Norway. The background for the study was the current low design discharge and also the age of the existing units. These circumstances were combined during the study. Different alternatives were considered, and can be summarized in two main alternatives.

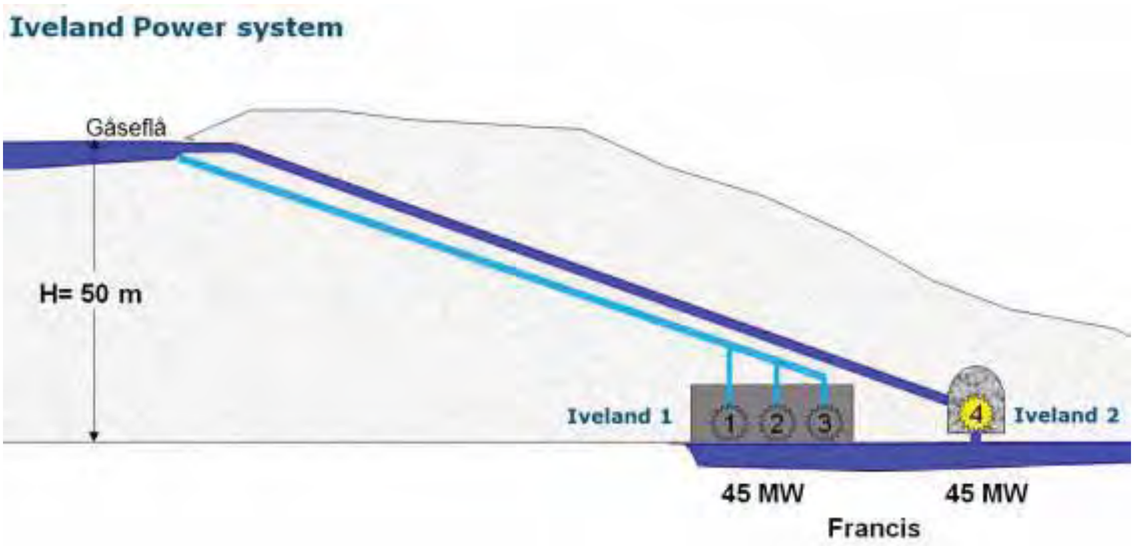
1. Upgrading with new turbine runners. The increased mean annual production was estimated to 20 GWh, with cost estimate approximately 19.5 mill. NOK (2.5 mill. USD). Then the specific cost is 1.0 NOK/kWh (13 USc). This would given good economy per kWh, but there was obviously a potential for a higher total income.
2. Increasing the capacity to 90 MW, it will say to double the capacity. The increased mean annual production was estimated to 150 GWh, with cost estimate approximately 750 mill. NOK (100 mill. USD). Then the specific cost is 5 NOK/kWh (65 USc). The cost per kWh is higher than for alternative 1, but total income is higher (for instance with reference to Net Present Value, NPV). The extension is favorable in a long term perspective.

The cost estimate for alternative 1 refers to the level by then, and with the current rate NOK/USD. For alternative 2 the cost estimate is updated to current price level, and with reviewed and revised technical solutions.

The final solution was then to increase the capacity with one new unit, and also to upgrade the three existing units. A new intake, new waterway and a new underground power station were necessary.

Construction of a new, second power plant in addition to the old Iveland 1 hydropower plant makes it possible to utilize the water flow in the river better than now. Iveland 1 HPP is also a bottleneck in the cascade of hydropower plants in the river Otra since other power plants in the river have a higher design discharge.

There will be two parallel tunnels in the new system. The power stations can be operated independently, thus providing the possibility and flexibility to perform planned maintenance with a minimum loss of water. The new underground power station will be located close to the existing surface power station.



Sketch of the Iveland HPP system

The licence application for Iveland 2 HPP was prepared and submitted to the Norwegian Water Resources and Energy Directorate (NVE). NVE recommended licence to be granted, and licence was granted by Ministry of Petroleum and Energy (OED) in 2011.

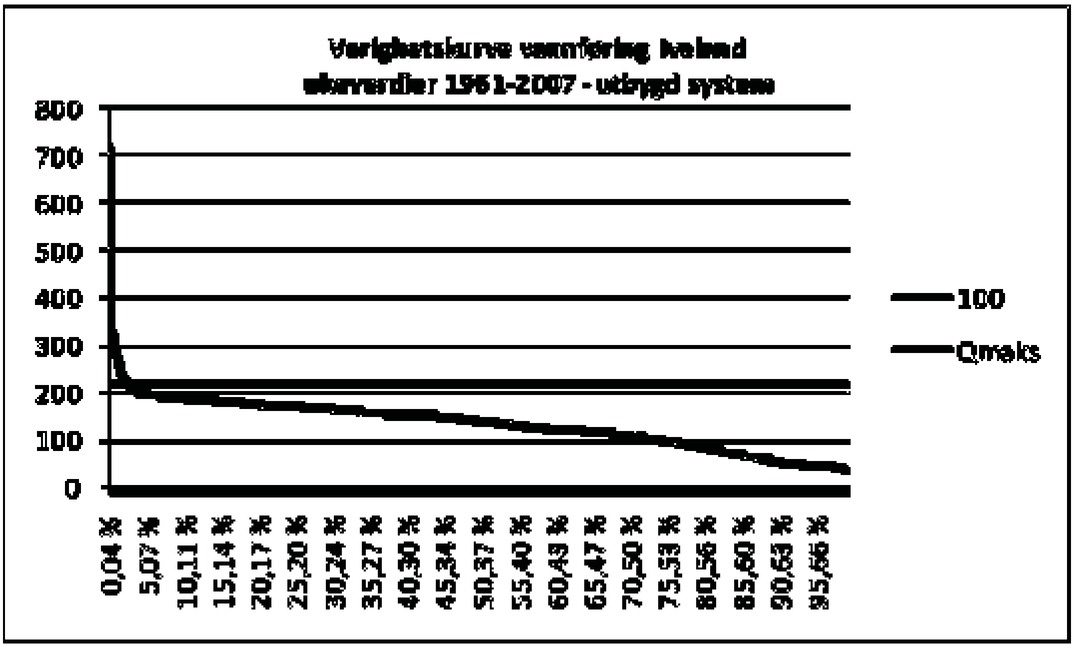
Economic results and investment plans for the project were considered and elaborated on basis on licence requirements, tenders, estimated production and other conditions. This was decisive documentation for the Board's decision (May 2013).

Project plan

A thorough study of the projects impact on the environment was carried out by Agder Energi's own environmental department and external resources. A part of this study was considerations of need for and proposing environmental flow release.

A hydrological and operational study has been carried out. This shows how a new power plant will affect the total hydropower production in the river Otra. Further, the study gave a basis for the optimization of the new power plant, and hence new total capacity and production for the two power plants.

The figure below shows the duration curve for water flow in river Otra at Iveland. The total capacity of Iveland 1 and Iveland 2 is 216 m^3/sec, which will be sufficient to exploit near 100% of the runoff.



Red curve: water flow in the river in m³/sec, duration (in % of the year)
Blue line: total capacity (design discharge) for Iveland 1 and Iveland 2 in m³/s
Current capacity for Iveland 1 is 116 m³/s

The duration curve is a simple method to illustrate the selected design discharge. The curve is very steep for water flows larger than about 200-220 m³/s, indicating that the optimal design discharge likely is in this range. The curve also shows that water flows between current and new design discharge occur in 70% of the time.

The duration curve gives a rough indication of optimal design discharge, but production is also calculated by use of a more sophisticated simulation model. The simulation model includes the entire hydropower system in Otra basin.

Construction period

Tender documents were prepared on basis of results from studies mentioned above and the licence requirements. Geological studies for the tunnel and power station areas were carried out. Results are important for planning, tender documents, tenders and execution.

The next step was preparation of detailed plans for implementation of the project. The construction works started in June 2013. The construction period will be about 2.5 years, followed by a testing and commissioning period.

In brief, the first year of construction was used for tunnel and power station excavation. Installation of draft tube and spiral casing was carried out late summer 2014. The concrete works in the power station followed. The installation of turbine, generator and other mechanical and electrical equipment will be finalized. Testing period and water filling in winter 2015/2016 will complete the implementation. It is scheduled that commercial production will start in April 2016.

Illustration of the old (left) and the new power plant (right) with respective waterways

Construction works are on schedule. Agder Energi's cooperation with consultant, civil contactor and main supplier is well organized and tasks are properly executed.

Summary

Category	Specifications
Maximum output	45 MW
Hydraulic head	50 m
Turbine type	Francis
Water flow capacity	100 m^3/sec
Tunnel length	2 km
Tunnel cross section area	85 m^2

Features for Iveland 2 Hydropower Plant

Reservoir and dam are same as earlier.

Category	Before	After	Iveland 2, net
Capacity, MW	45	90	45
Design discharge, m^3/s	116	216	100
Production, GWh/year	350	500	150

Iveland HPPs, before and after construction of Iveland 2 HPP

Total budget is 750 MNOK (100 MUSD), and estimates so far show that total cost will end up with 700-750 MNOK.

3. Feature of the Project

3.1 Best Practice Components

Comprehensive planning and optimization have been the case throughout the entire process.

3.2 Reason for Success

The factor for the success of this project so far (planning and scheduled construction works) was the thorough design study that was done during the concept study that enabled us to optimize the plant, including:

- Environment
- Health and safety during implementation and operation
- Operation of Iveland 2 HPP in the total hydropower system
- More efficient maintenance for Iveland 1 and Iveland 2
- Cost optimization
- Plan for effective implementation

The main factors for success for the rest of the project time will be, in brief:

- Health and safety, no injuries
- No negative impacts on the environment
- Construction period on schedule
- Construction costs within the budget
- Power production as planned
- Iveland 2 together with Iveland 1 will improve the power plant system in the Otra river basin

4. Points of Application for Future Project

During planning of this project many issues regarding health and safety, environment and operational optimization have been revealed and solved. This experience can and will be important knowledge for future projects.

5. Others (monitoring, ex-post evaluation, etc.)

References are made to Clause 2.3.

6. Further Information

6.1 Reference

None

6.2 Inquiries

Company name: Agder Energi Hydro Production AS

URL: www.ae.no

Nw.07_Rånåsfoss #3

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 2-a) Technological innovation & deployment expansion of E/M equipment.

Sub: 1-b) Investment incentives: Feed-in-Tariff (FIT), Renewable Portfolio Standard (RPS), subsidies, financial assistance, tax deductions, etc, where it is located.

1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

1-f) Environmental conservation and improvement

Project Name:

Upgrading of Rånåsfoss Hydropower plant

Name of Country (including State/Prefecture):

Norway, Akershus County, Sørum Municipality

Implementing Agency/Organization:

Akershus Energi AS

Implementing Period:

2010 - 2016

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction (a,b,d)

(C) Needs for higher performance (a,b)

Keywords:

Equipment degradation

Replacing aged E&M equipment, new design

Increasing production

Abstract:

Rånåsfoss I power plant was commissioned in 1922. After nearly 90 years of operation, the operators experienced increased frequency and extents of maintenance works on critical components.

Late 2007, Akershus Energi AS initiated a feasibility study to identify and evaluate alternatives for renewal and upgrading. Hydraulic design and model testing of recommended solution from the feasibility study were performed from 2009. Based on the results from the model test, technical specifications for new power units and civil works were prepared.

After investment decision in June 2010, project implementation started in October with building of a new power house. Upgrading of the first of six identical units started in April 2011, and the new unit is in regular operation since June 2013. Last unit will be finalized in 2016.

The units are upgraded in sequence, with increasing extent of parallel works as experience from the first units are gained. Old units are in regular operation until upgrading commences, to limit energy production loss. With parallel operation of old units and upgrading works, close cooperation between contractors, project management and operators is required.

1. Outline of the Project (before Renewal/Upgrading)

Location

River Glomma is Norway's longest river with a length of more than 600 kilometers running through four counties to sea level in the Oslo Fjord by Fredrikstad. The river was heavily used for timber floating until 1985, and has been vital for timber related industry.

Glomma is used for hydro power production through roughly 40 hydro power plants, providing approximately 10 TWh, or nearly 8 % of Norwegian annual hydropower production.

Rånåsfoss waterfall in river Glomma has been utilized for hydro energy generation since 1922, when the first power plant was commissioned. Located in Sørum Municipality, approximately 40 kilometers north-east of Norwegian capital Oslo, the power plant was built to supply the capital and surroundings with electricity.

Figure 1 Location of Rånåsfoss (source: Kartverket)

History

Rånåsfoss I (RI) hydropower plant was built from 1918 to 1922 by Akershus County. This project included building of a dam with three main gates in addition to the power station itself. The power plant's net head is 12.5 meters.

Six double Francis units are installed in the power station. Two runners are connected to the generator through a horizontal shaft. Each unit has a discharge flow of approximately 90 m^3/s and 9 MW output. Three turbines were delivered by KMW in Sweden, and the other three by Voith.

The power plant buildings are monumental, and considered worthy of preservation. Between 3500 and 7500 pupils from Akershus County visit Rånåsfoss power plant every year. Figure 2 below shows a cross section of the power plant.

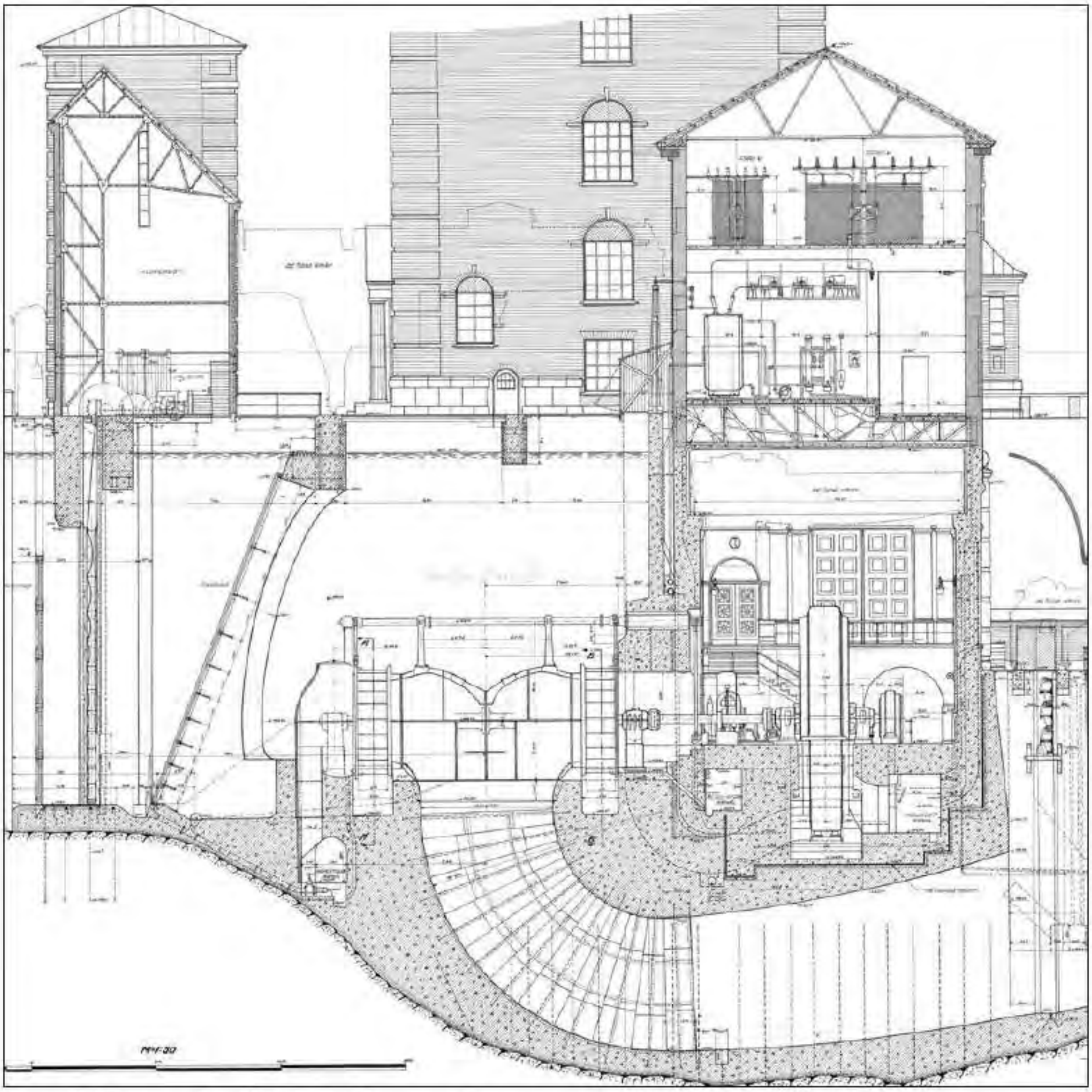


Figure 2 Cross section of Rånåsfoss I power station

From 1980 to 1983, Rånåsfoss II (RII) was built on the west bank of the river, in parallel with RI. One Kaplan unit was installed, with discharge flow 400 m^3/s and 45 MW output.

Both RI and RII are owned and operated by Akershus Energi AS (AE). Area plan for Rånåsfoss power plant is shown in Figure 3.

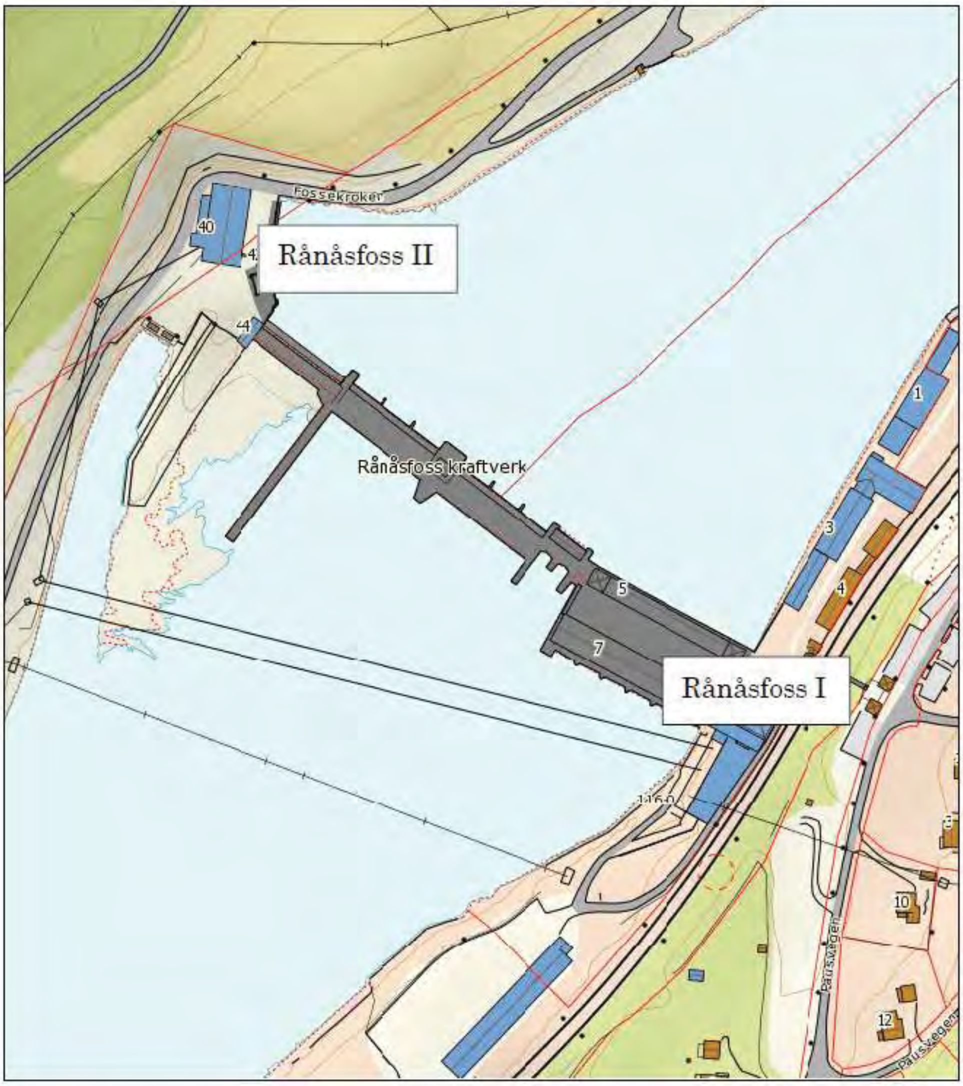


Figure 3 Area plan Rånåsfoss (source: Kartverket)

Hydrology

RI and RII are run of river hydropower plants. Average flow in Glomma is 680 m^3/s, and current maximum total discharge capacity is 940 m^3/s. However, the river flow varies throughout the year, as showed in Figure 4 below. With average river flow, Rånåsfoss power plants experience water loss 2-3 months per year. Additionally, recent years show increasing river flow and thus increasing water losses.

Production

Mean annual production in R1 (before upgrading) is 220 GWh.

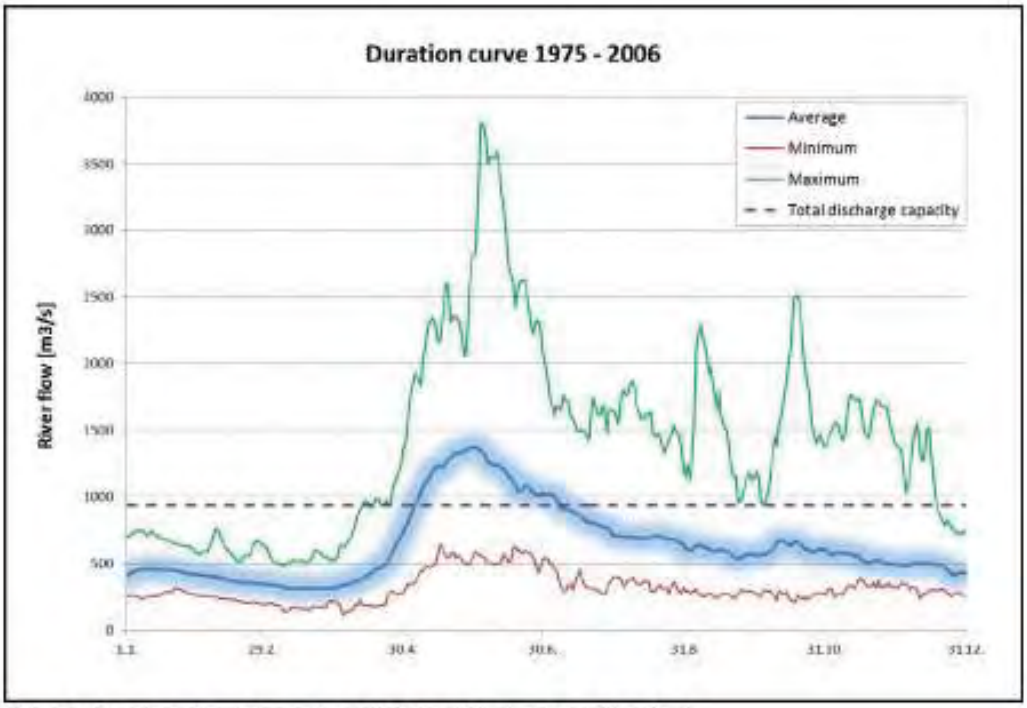


Figure 4 Duration curve, Glomma at Rånåsfoss. Total capacity at RI and RII.

Figure 5 Rånåsfoss I / III during spring flood 2013

Main refurbishments at RI before 2007

During the initial commissioning of RI problems with runners on three units were discovered, and they were replaced shortly after. Stiffeners between the runner blades were later installed.

For the other three units the shafts were the main problem. These units have no intermediate bearing on the 12 meters long shaft, as shown in Figure 2. All shafts are replaced at least once. The shaft stress resulted in returning cracks in the runners and yearly welding reparation works.

By the end of the 1970s the turbine governors were rebuilt from mechanic/hydraulic to electric/hydraulic. In the 1990s the governors were digitalized, and all turbines and generators were refurbished.

Apart from main refurbishments described above, the units in RI had original equipment. Operator AE experienced increased frequency and extents of maintenance works on critical components. The risk of a major failure within the next 10 to 15 years was considered high.

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

The main rationale for the realization of the project was equipment which became more and more inefficient caused by wear and tear. An upgrading was planned in order to increase efficiency and hence increased production. Trigger causes appear more thoroughly from Clause 2.3.

(i) Conditions, Performance and Risk Exposure and Others

(A) Degradation due to ageing and recurrence of malfunction

(a) Improvement of efficiency

The upgraded E&M equipment has higher efficiency than the old equipment. In addition, the total capacity has been increased, which gives increased production.

(b) Improvement of durability and safety

The old E&M equipment in Rånåsfoss was worn after more than 40 years of operation. Further operation without upgrading would have been more and more unsafe and risky by time (increasing maintenance cost and time, major failure risk). The new equipment will ensure durability and safety for decades.

(d) Easy equipment with less labor

The maintenance for the replaced plant was already time and resource consuming, and hence pro rata expensive. The new power plant Rånåsfoss III, with new and modern equipment, simplifies maintenance works. Use of time, use of resources and hence costs are reduced considerably.

(ii) Opportunities to Increase Value

(C) Needs for higher performance

(a) Efficiency improvements, addition power & energy, loss reduction

New equipment (new power plant) gave higher efficiency per m^3 of water. The total design discharge and installed capacity (Rånåsfoss I and II) were low. It was then beneficial to increase the total capacity to reduce water loss, and hence increase total production.

(b) Role change of hydropower generation. Addition of new functions

The introduction of the Norwegian-Swedish Electricity Certificate Market in 2012 was not critical for the investment decision, but will provide extra value of the new production.

(iii) Market Requirements

The Norwegian-Swedish Electricity Certificate Market will be a valuable plus to the income.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

2007-2008	Feasibility study (AE/Sweco/Voith)
2009-2010	Detailed design, hydraulic analysis, model testing (Voith)
2009	Architect design competition for new machine hall
Jun 2010	Investment decision
2010-2011	Building of new power house (Contractor: Kruse-Smith)
2011-2016	Replacement of 6 hydropower units - civil and el/mech works (AF (Contractor), Voith (Supplier))
February 2016	Commissioning unit 6

2.3 Description of Work Undertaken

Category references

2-a) Technological Innovation & Deployment Expansion of Electro-Mechanical (E/M) Equipment

It was important to ensure that optimal equipment and materials were obtained. The selections were based on studies and up to date knowledge (state of the art), including types and producers, cost, earlier experience, expert advice, etc.

1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

These considerations are continually ongoing in Akershus Energy AS (as in other Norwegian power companies), and was also the case for Rånåsfoss I/III. Comprehensive planning and economic and strategic considerations resulted in the decision to substitute the old Rånåsfoss I HPP with a new Rånåsfoss III HPP. Several alternatives were identified. Included were parameters such as cost estimates, expected production and income and cost/benefit analyses. Failure probability was also taken into account.

1-b) Investment incentives (Feed-in-Tariff (FIT), Renewable Portfolio Standard (RPS), subsidies, financial assistance, tax deductions, etc, where it is located.

The common Norwegian-Swedish Electricity Certificate Market (incentive for development of new renewable power) is important for the project's economy, but was decisive for the Board's decision to realize the project.

1-f) Environmental Conservation and Improvement

The existing buildings have a high cultural value, and it will be a challange to consolidate these values when planning and building the new power station

Supplementary details for category references appear from next.

Feasibility study

In 2007 a feasibility study was initiated by AE. The purpose was to identify alternatives for renewal and upgrading of RI power station. The study was performed by consultant Sweco and supplier Voith Hydro, in close cooperation with AE.

Due to the monumental character of the buildings, AE emphasized that the buildings should be preserved as far as possible. The study early realized that building a coffer dam was not realistic due to cost and production loss, so existing intake gates and outlet stop logs defined project civil boundaries.

Several alternatives were identified in the feasibility study, and evaluated based on cost/benefit calculations. Base case was renewal of existing units, with replacement of components on a like-for-like basis. New turbine concepts considered included bulb, Kaplan, S-type and propeller turbines.

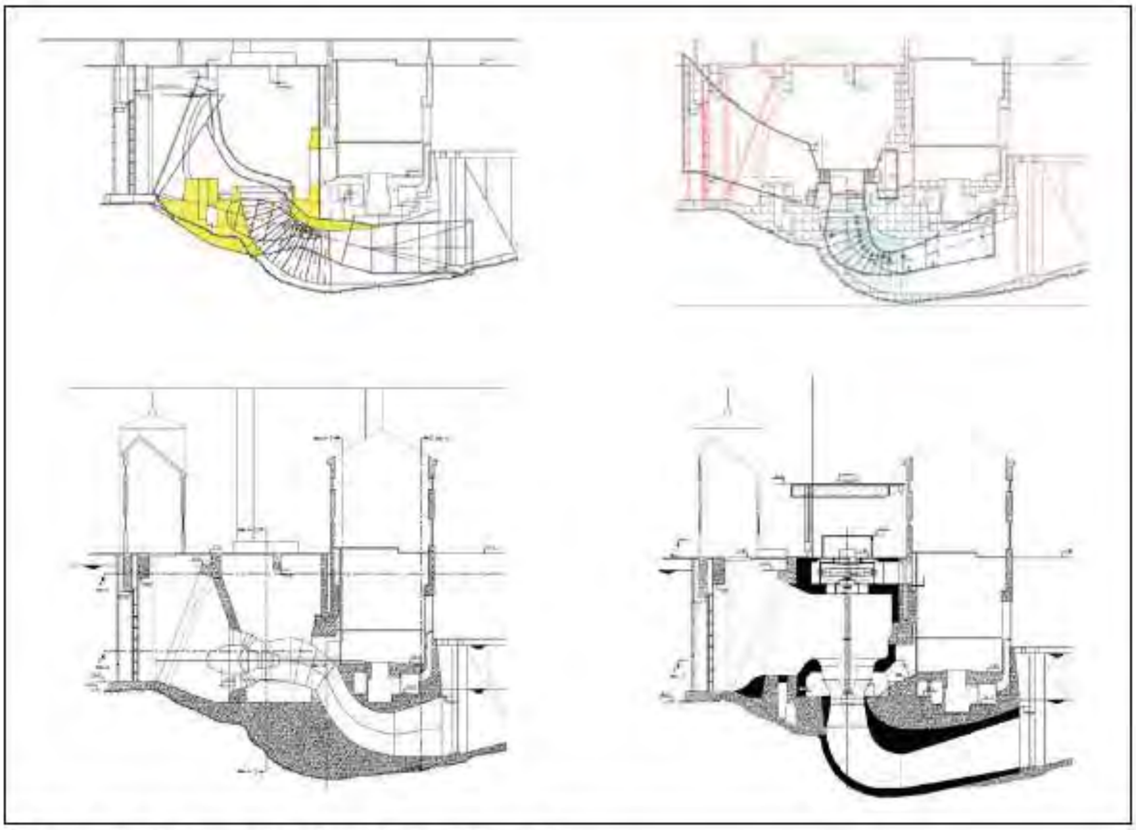


Figure 6 Turbine concepts evaluated in feasibility study

The vertical propeller turbine in an open inlet cone, shown at bottom right in Figure 6, was recommended as best solution. Main reasons for this conclusion were increased power production combined with limited civil works. In addition, it was possible to upgrade units in parallel with operation on neighboring old units.

The feasibility study recognized that to increase power production, increased flow was more essential than higher turbine efficiency. Runner diameter was set as large as possible within civil boundaries, runner hub as narrow as possible and spiral casing was replaced by an inlet cone. As there is a fully regulated Kaplan unit in parallel at RII, the new units could be operated at an "on-or-off" regime.

The new, vertical units were placed in the original intake chambers, making it possible to operate old units in parallel with upgrading of new units. Hence, production losses during project execution were minimized. Increased annual power production was calculated to 40 GWh.

The old, monumental machine hall was basically kept untouched, with original generators. Draft tube and intake were modified to improve hydraulics.

Detailed design

In 2009, AE arranged an open bidding on detail design and model testing of recommended solution from the feasibility study. Voith Hydro was engaged to do detailed hydraulic design of the new turbines, including intake and draft tube. CFD (Computations Fluid Dynamics) calculations were heavily used during the iterative design phase. A fully homologous model test was performed in Voith's laboratory in York, USA.

Turbine power and efficiency proved during model testing exceeded the estimates from the feasibility study. Turbine power output increased nearly 14 % due to higher flow and efficiency. Increased annual production was calculated to be 60 GWh, compared to 40 GWh estimated in feasibility study.

The generators were placed below maximum head water level, giving strict requirements to the shaft sealing. Control equipment was mainly located in the old building.

Based on the results from the model test, technical specifications for new power units and civil works were prepared.

Late 2009, AE initiated an architectural design competition for a new machine hall. The winning design was a modern looking machine hall, made mainly by glass and steel.

Introduction of Norwegian-Swedish Electricity Certificate Market

A common Norwegian-Swedish market for electricity certificates was launched in January 2012 as an incentive for new renewable energy production. Power plants (renewal and upgrading included) for which construction started after 7th of September 2009 are qualified for the certificate market. Construction works for Rånåsfoss III started in October 2010. The establishment of the market was not critical to the project, but will provide extra value of the new annual 60 GWh produced.

Project management

AE is not manned for managing projects of this scale internally. External personnel are hired both in project management and as technical advisors, working in close cooperation with AE. Operators from AE have been involved through all phases of this project, to secure focus on operation and maintenance of the power plant. Health and safety have highest focus and priority during project implementation.

This project contains many interfaces. During building of new power units, the interface between civil works and electro/mechanical installations is expected. Coordination of activities is challenging, as they touch the interface between operation of old units and upgrading works on neighboring units. Involvement of operators in all site coordination is critical.

Nearly all new control and automation equipment are located in the old buildings. Hence, piping and cabling routes for this equipment are between new and old buildings, and in between the old installations. As some units are still in operation when new units are built, cabling routes and location of new equipment must be adjusted to installations and cables for the old units still in operation. Cabling and piping routes was not planned at necessary detail level prior to start upgrading, and this has cost AE both time and money.

Project execution

AE made their investment decision to upgrade RI to Rånåsfoss III (RIII) in June 2010. From October 2010 to April 2011 the new machine hall was built in connection to the old buildings. New ventilation system was installed, with heat recovery from the new generators' cooling water for heating of buildings.

Figure 7 Interior and exterior of new machine hall, RIII.

After stop of the old unit, all turbine parts are disassembled and removed. Concrete and rock, mainly from draft tube area, is demolished together with old draft tube steel liner. See pictures below.

Figure 8 Disassembly of old double Francis units

Figure 9 Demolition of concrete and rock in intake chamber and draft tube

Cross section of new unit layout is shown in Figure 10 below. Draft tube design is changed, based on hydraulic analysis. The draft tube outlet is concreted; cone and bend are steel lined. Both draft tube and inlet cone are delivered in parts and assembled on site.

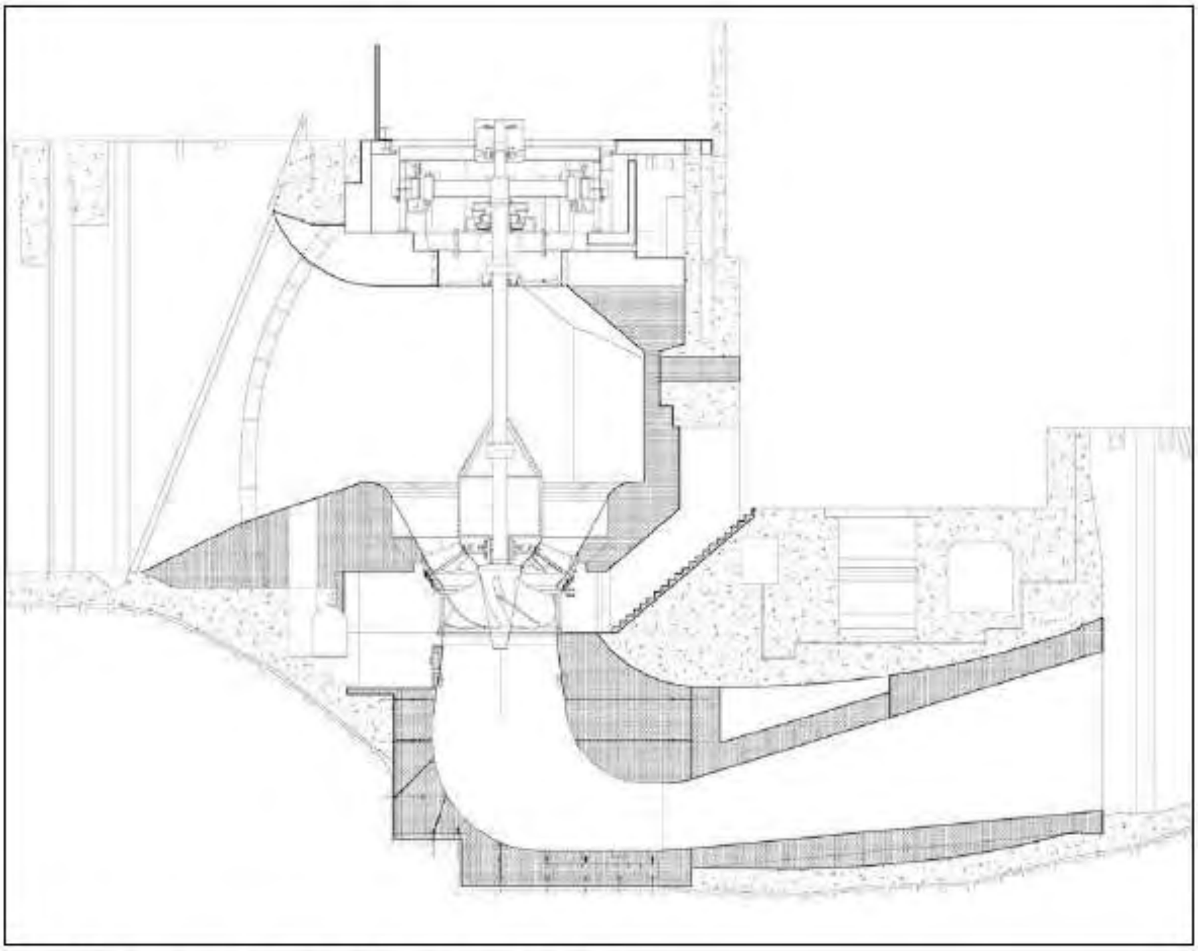


Figure 10 Cross section of new unit layout (Sweco drawing)

Figure 11 Assembly of draft tube steel liner (left and center) and inlet cone (right)

After embedding of draft tube and inlet cone, the civil works commence up to generator level. Bolts are drilled to the intake chamber's original walls, and the whole generator floor of 1300 tons is hanging from these bolts.

Figure 12 Drilling of bolts and preparations for concreting of generator floor

As civil works are finished, embedded parts are sandblasted and painted before main erection of new units. Turbine parts are transported to site and lowered directly to the pit for assembly.

Due to large dimensions, the generator must be assembled on site. A new assembly hall with strict requirements to temperature variations is built for this purpose. After assembly stator and rotor are transported to power house and lowered into the generator pit.

Figure 13 Turbine erection. Runner with fixed blades.

Figure 14 Installation of stator and rotor

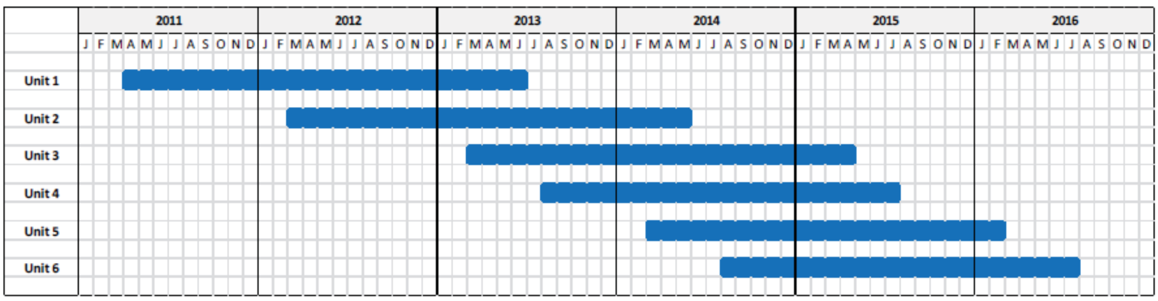
Figure 15 Unit 1 in regular operation from June 2013

Progress

Upgrading of each unit takes nearly 2 years, from stop of old unit to finished trial run for new unit. The six units are upgraded in sequence in order to minimize the production losses. Old units are in normal operation in parallel with upgrading of neighboring units.

Six more or less identical units are to be upgraded. Find project execution time schedule, as per December 2013, in Table 1 below. The time schedule reflects AE's expectation that based on experience from the first units, upgrading of the last units can be done with more parallel works without affecting progress or quality

Table 1 Project execution time schedule, from stop of old unit until end trial run



Capacity and production

Data for Rånåsfoss I/III are shown in Table 2 below

Table 2

Power plant	Capacity (MW)	Production
Rånåsfoss I	54 (6 x 9)	220
Rånåsfoss III	81 (6 x 13.5)	280
Increase	27	60

Cost estimate is 800 MNOK (100-105 MUSD with rate primo June 2015).

3. Feature of the Project

3.1 Best Practice Components

By replacing old units in RI with new units and new design in RIII, predictable and cost efficient power production will be secured for a long time. Need for maintenance and reparation works will be reduced. Increased annual power production is estimated to 60 GWh, qualifying for electricity ("green") certificates. This is obtained within existing licence, and without environmental impacts.

3.2 Reasons for Success

- Initial phases, before investment decision:
  - Feasibility study: Several alternatives identified and evaluated based on cost/benefit.
  - Detail design: Hydraulic analysis and model testing, technical specification for power units and civil works prepared based on model testing.
- Project management: Operators from AE involved in all phases and site coordination.
- High focus on Health and Safety in planning and execution.

4. Points of Application for Future Project

This project can be benchmark for future similar projects with old and outdated equipment, and water surplus.

5. Others (monitoring, ex-post evaluation, etc.)

Technical solutions and execution evaluated during and after upgrading of each new unit, internally and with suppliers/contractors. Annual energy production increase will be monitored and analyzed.

6. Further Information

6.1 Reference

(None)

6.2 Inquiries

Company name : Akershus Energi
URL: www.akershusenergi.no

Akershus Energi www.akershusenergi.no

Nw.08_Kongsvinger

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

Sub: 1-a) Energy Policies of Countries & States

Project Name:

Kongsvinger Hydropower Plant – Unit No. 2

Name of Country (including State/Prefecture):

Norway, Kongsvinger Municipality in Hedmark County in South East Norway

Implementing Agency/Organization:

Eidsiva Vannkraft (Eidsiva Hydropower)
Eidsiva Vannkraft is a subsidiary company of Eidsiva Energi (Eidsiva Energy)

Implementing Period:

Before 2008:	Planning and evaluation; Feasibility Study
March 2008:	Board decision
August 2008-April 2011:	Construction period

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction (a, b)
(C) Needs for higher performance (a)

Keywords:

Run-off- River (RoR) hydropower plant
Increased capacity
New renewable energy production
Increased flexibility

Abstract:

Kongsvinger Hydropower Plant is located in the river Glomma, a few kilometers downstream the town Kongsvinger. Glomma is the largest river in Norway with length approximately 620 kilometers. Water resources in Glomma have been exploited for hydropower production for more than 100 years.

Kongsvinger HPP is a run-off-river (RoR) hydropower plant, constructed with only one unit when it was commissioned in 1975. All maintenance works which required stop of the unit resulted in production losses and then also economic losses.

Location of Kongsvinger HPP

The aggregate was in bad condition after more than 30 years in operation. A comprehensive rehabilitation was necessary for further secure production. This would require until one year out of operation if the generator had to be dismantled. One year stop could give a production loss of 130 GWh (mean annual production). An installation of a new aggregate would give flexible time for maintenance in 6 months per year without production losses.

The water flow in the river Glomma at Kongsvinger hydropower plant is higher than the capacity of Unit No. 1 for six months a year. It was computed that two units with a total capacity of 500 m^3/s would increase the power production with 70 GWh/year to 200 GWh/year. In addition, a larger period without production was then avoided. By installing a second unit in Kongsvinger HPP, a larger amount of the water in the river is now utilized for power production.

In the case with installing a new aggregate, an easier maintenance was needed for Unit No. 1 in the short term. This could be done in winter time without production losses. A more comprehensive measure could eventually be carried out later when the new unit had been installed.

All maintenance works which require stop of the unit will also result in stressful situations for the operators. With two units in the power plant it will give free time for maintenance five months every winter, when the water flow in the river is low. The works can then go on without production losses. Hence, maintenance works can be carried out without loss of production.

No licence related to water legislation was required for the extension of Kongsvinger HPP. An essential reason for this was that the environmental consequences were considered to be small.

The Norwegian-Swedish Certificate Electricity Market, which is a market-based support system for renewable electricity production, started up January 1 in 2012. Unit No. 2 was set in operation in 2011, and will then not be rewarded certificates in this market.

The project demonstrates that extension in combination with an upgrade can be a good solution. Two units instead of one reduced risks and enabled power production to continue during the construction period, and ensure durability and safe production for decades. The construction works and the installation of the new unit while the existing unit was in operation was a great challenge, but was implemented successfully.

Kongsvinger HydropowerPlant

1. Outline of the Project (before Renewal/Upgrading)

Kongsvinger hydropower plant is located in river Glomma, and was commissioned in 1975. The power plant is located in the concentrated fall Svartfoss about 7 kilometers downstream the town of Kongsvinger in Hedmark County. The gross head is now 10.25 meter, after increasing the maximum water level in 1988.

Glomma is the largest and longest river in Norway with length approximately 620 km. The river runs from elevation about 700 m.a.s.l in the lake Aursunden to sea level. Water resources in Glomma have been exploited for hydropower production since 1895, and a large number of power plants have been built since then. There are power plants at approximately 15 locations. All of them are of the run-off-river type, and utilizing mainly concentrated falls. Many of the power plants are modernized and also extended.

When we came to the 1960ties and 1970ties, most of the concentrated falls in river Glomma had been developed for hydropower. Lowest utilized head was about 10 meters for a few of them. However, the majority had heads of 20 meters and higher. Turbine types were Francis and Kaplan.

There were by then still some heads which could be beneficial to utilize. The bulp turbine had been developed in Germany and Swiss during the twenties and thirties in the previous century, but had only to a small degree been installed in Norwegian hydropower plants. With the purpose to utilize more of low heads in Glomma and other large rivers, the bulb turbine was found to be economic beneficial in some locations.

The bulb turbine is a variation of the propeller-type turbine (similar to the Kaplan turbine). In the bulb turbine arrangement the generator is encapsulated and sealed with a streamlined watertight steel housing mounted in the center of the water passageway. The generator is driven by a variable-pitch propeller located on the downstream of the bulb. Unlike the Kaplan turbine, water enters and exits this unit with very little change in direction. The wheel is not unlike a propeller, with 3 to 8 blades, which all can be rotated for any case of load. This gives the bulb turbine a better efficiency for loads which differs from the optimum than what is the case for a low head Francis turbine or a Kaplan turbine.

The compact nature of the design allows for more flexibility in powerhouse design. Bulb turbines can, however, be somewhat more difficult to access for service, and they require special air condition and cooling within the bulb.

A number of power plants with the bulb turbine were built in Norway, in particular in the seventies and beginning of the eighties. Four of them, including Kongsvinger HPP, are located in the river Glomma. The lowest head is about 5 meters, while the three others utilize heads of 9-10 meters.

Kongsvinger power station in the river Glomma

Category	Specification
Catchment area	Appr. 19,000 km^2
Mean annual inflow	Appr. 9,500 mill. m^3
Mean inflow	300 m^3/s
Gross head	10.25 m
Capacity	21 MW
Turbine type	Bulb (one)
Design discharge	250 m^3/s
Mean annual production	130 GWh
Dam type	Concrete, with flood gates
Nos of gates	4
Commissioning	1975

Features for Kongsvinger HPP before Unit No. 2

The design discharge was a little more than 80% of mean inflow. This is low, and utilization of the potential was approximately 60%.

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

The main rationale for realization of the project was that the capacity of the existing power plant was not sufficient to utilize the water flow in the river as much as economic beneficial. The trigger causes appear more detailed from clause 2.3.

(i) Conditions, Performance and Risk Exposure and Others

(A) Degradation due to ageing and recurrence of malfunction

(a) Improvement of efficiency

The old unit in Kongsvinger HPP was worn, and efficiency had been reduced since 1975. A thorough maintenance was necessary, but would be time consuming, with a long stop of operation, and hence production loss. Upgrading was triggered both by low efficiency and collapse risk.

Malfunction has here also the meaning of insufficient utilization of water resources. The utilization could be improved by increasing design discharge and installed capacity. The total capacity was increased with 22 MW, which gave an additional mean annual production of 70 GWh. The total implementation included upgrading of the existing worn unit. The new unit gave also more flexibility to carry out the required upgrading of Unit No. 1.

(b) Improvement of durability and safety

The new turbine in combination with the upgraded old turbine will reduce maintenance time and downtime in Kongsvinger HPP and will still more increase durability and safety for decades.

(ii) Opportunities to Increase Value

(C) Needs for higher performance

(a) Addition of units, Expansion of power and energy

Higher capacity was considered technical feasible, and would give additional power output to acceptable costs. The installation of Unit No. 2 gave larger capacity at Kongsvinger HPP, then leading to reduced flow losses and hence increased production and income.

(iii) Market Requirements

There were no particular external investment incentives beyond general incomes. The plant was commissioned in 2011, and is then not a subject for certificates in the Norwegian-Swedish Electricity Certificate Market, which is running from January 2012. The basis for decision was the production, costs and general market prognosis without taken electrical certificates into account. In addition, durability and safety were essential incentives.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Before 2008:	Planning and evaluation; Feasibility Study
March 2008:	Board decision to realize the project
August 2008:	Startup of site work
January 2011:	Testing
April 2011:	The new unit in operation
June 2011:	The power station area rounded off and cleared

2.3 Description of Work Undertaken (detail)

Category references

1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

Installation of Unit No. 2 in Kongsvinger HPP is a refurbishment and extension project, and is a part of a long-term strategy for optimal development of Eidsiva Vannkraft's hydropower portfolio. These considerations are continually ongoing in Eidsiva Vannkraft (as in other Norwegian power companies), and was also the case for Kongsvinger HPP. Comprehensive planning and economic and strategic considerations resulted in the decision to install Unit No. 2. Included were parameters such as cost estimates, expected income and net present value (NPV). Failure probability for Unit No. 1 was taken into account regarding life-cycle costs. The final scope was based on these considerations.

1-a) Energy policies of Countries & States

The extension is an important environmental effort, and in accordance with the Parliament's and the Government's stated superior goal to increase the production of renewable energy through a better utilization of the potential in existing power plants. Such measures have often lesser environmental impacts than constructing power plants in unexploited areas.

Category 2 Key Points were not evident or dominant regarding this project, and are therefore not particularly mentioned. Technical innovation & deployment of electro-mechanical (E/M) equipment were, to some degree, in question during upgrading of Unit No. 1 as well as installation of Unit No. 2, but not beyond existing know how on turbine design. The absolute conspicuous moments are the planning, total solution and the implementation.

Supplementary details for category references appear from the next.

Background

Eidsiva Energi with the subsidiary company Eidsiva Vannkraft, owns and operates a large number of hydropower plants. Mean annual hydropower production is 3.5 TWh. The ownership is public; 26 local municipalities and 2 county municipalities.

It is a pronounced policy in Eidsiva Vannkraft to increase the hydropower production (renewable energy). Some of the power plants have reached an age when renewal and upgrading is relevant. Considering this is a continuous process, and in some cases this also leads to extension of the existing plant. This was the case for Kongsvinger hydropower plant.

Due to the situation in the Norwegian power marked during the nineties, extension of hydropower plants was in general not regarded profitable again before the beginning of the 21st century. Then the planning of a new unit in Kongsvinger HPP started.

Planning

The aggregate (Unit No. 1) was in bad condition after more than 30 years in more or less continuous operation. It was calculated that one year was required for a rehabilitation to satisfaction, and hence a considerable loss of production and income.

The capacity was (too) small, partly due to the developer's limited financial means in the seventies. It was therefore recommended to install an additional unit, with same size as the first one. All together, this was a better solution than a upgrading of Unit 1 only. The investment decision was made by the Board on March 26th in 2008. Site works started first of August in 2008.

With only one unit in a run-off-river hydropower plant it is highly restricted time for maintenance without production losses. Maintenance normally requires stop of the unit, and may result in lower maintenance activities than required. This will lead to higher risk for damages of the equipment. It was considered that two units would be important for flexible maintenance and reduced production losses.

Implementation

When Kongsvinger power plant was built in 1975, it was prepared a space for one extra unit. Upstream, in the dam, the open space was closed by blocks. The rock was not drilled and blasted, and there was not built a barrier against the tail water. Building of barriers was done in autumn 2008. On the opposite side of the existing powerhouse, the fish ladder was used as a barrier. The fish ladder was anchored with steel wires which were fastened in 8 meter deep drilled holes in the rock.

In 2009 the drilling and blasting of 5 000 m^3 rock was going on. Against the existing powerhouse and the dam pillar the rock was split by wire sawing. This work had to be done when the existing aggregate was in operation. The blasting resulted in some vibrations in the existing powerhouse, and some actions had to be done to reduce the vibrations in the control center. The total consumption of concrete was about 9 000 m^3.

Drilling and blasting

The erection of the new unit was carried out during the year 2010. The turbine is of the Bulb turbine type, with 5.5 m runner diameter. The stator diameter is 5.9 m.

Final erection and testing were implemented during January to April in 2011.

Upper left: Draft tube construction
Upper right: Assembly of turbine runner
Lower: Assembly of stator

Kongsvinger HPP. Longitudinal section

A challenge during construction was coordination of a large number of contractors and suppliers. In the most intensive period, there were 7 contractors and suppliers operating at the same time.

Salient features

Salient features for Kongsvinger HPP after Unit No. 2 are shown in the table below.

Category	Specifications Unit 1	Specifications Unit 2	Summary
Gross head	10.25 m	10.25 m	
Installed capacity	21 MW	22 MW	43 MW
Turbine type	Bulb turbine	Bulb turbine	
Rpm		93.75 rpm	
Design discharge	250 m^3/s	250 m^3/s	500 m^3/s
Generator capacity		25.8 MVA	
Annual production	130 GWh		200 GWh
Commissioning	1975	2011	

The production for Unit No. 1 is before installation of Unit No. 2. Unit No. 2 has 1% higher efficiency than Unit No. 1. The new unit will therefore be preferred for operation when the inflow is lower than the design discharge for each turbine.

After Unit No. 2, the relation between design discharge and mean inflow is 1.7 (doubled). The utilization of the potential is now approximately 90%, increasing from 60%.

The new unit was put in operation on April 15th in 2011, on contractual date. The total cost was NOK 356.5 MNOK (approximately 46-47 MUSD with rate May 2015). This was 3.8% below budget.

3. Feature of the Project

3.1 Best Practice Components

Planning and implementation were carried out properly.

Eidsiva Vannkraft AS has now started works for installation of an additional unit in Braskereidfoss HPP. This power plant is also located in the river Glomma, approximately 70 kilometers upstream Kongsvinger HPP. Braskereidfoss HPP is of same type as Kongsvinger HPP, a run-off- river HPP with a bulb turbine. Braskereidfoss HPP was commissioned in 1978, with one unit.

The design discharge is 270 m^3/s, and the capacity is 22 MW. The situation is similar to that of Kongsvinger HPP. The design discharge is relatively low, and an additional unit will reduce water losses and increase production. In addition, there will be more flexibility for maintenance works.

Hence the experience gained from Unit No. 2 in Kongsvinger HPP, especially regarding the river bed and controlling the water flow during construction, will be useful information when planning and installing a new unit in Braskereidfoss HPP. The construction works started in July2013. The implementation is scheduled to be finalized in December 2015.

3.2 Reasons for Success

1. Civil construction works and installation of a new unit (turbine, generator) while operating the existing unit for full production
2. Similar to any project, implementation on time and budget was important and an obvious indicator for success
3. Successful coordination of a number of contractors and suppliers

4. Points of Application for Future Project

The project gave useful experience for planning and implementation of an additional unit in Braskereidfoss HPP.

5. Others (monitoring, ex-post evaluation, etc.)

Reference is made to Clause 2.3.

6. Further Information

6.1 References

None

6.2 Inquiries

Company name : Eidsiva Vannkraft (Eidsiva Energi)
URL: https://www.eidsivaenergi.no/

Nw.09_Rendalen

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

Sub: 1-a) Energy Policies of Countries & States

Project Name:

Rendalen Hydropower Plant – Unit No. 2

Name of Country (including State/Prefecture):

Norway, Rendalen Municipality in Hedmark County in East Norway

Implementing Agency/Organization:

Opplandskraft DA (Power Production)

Implementing Period:

Before September 2009:	Planning and evaluation, Feasibility Study
September 2009:	Board decision
September 2009-March 2013	Construction and testing
March 2013:	Unit No. 2 in commercial operation

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction (a, b, d)
(C) Needs for higher performance (a)
(B) Environmental deterioration (b)
(D) Needs for safety improvement (a) (i.e. flexibility)

Keywords:

Run-of- River (RoR) Hydropower Plant – with a minor day/night regulation
Old power station – increasing time for maintenance
Production lost during maintenance periods
Two alternating units give increased flexibility for maintenance

Abstract:

Rendalen Hydro Power Plant utilizes the head between intake in the river Glomma and outlet in the river Rena in the neighbor valley Rendalen. This gives a gross head of approximately 210 meters. The river Rena is a tributary to the main river Glomma, with confluence close to the village Rena some 80 kilometers downstream the outlet from the power station.

In brief, the power plant consists of a dam at Høyegga in the river Glomma, a long headrace tunnel, underground power station and tailrace tunnel to the river Rena. The license was given in August 1966.

Rendalen Hydro Power Plant was commissioned as a Run-of-River Hydropower Plant with one unit in 1971. The capacity was 92 MW, with one Francis turbine. Mean annual production was 675 GWh.

Regular maintenance has been performed since commissioning, but equipment was nevertheless worn and in need for a major revision. All equipment maintenance which required stop of the unit resulted in production losses and hence also economic losses. Besides this, annual stop for emptying the sand trap had historically caused a stop of production for 2 – 3 weeks.

Rendalen power plant has normally water for continuous production. Time for maintenance, inspection and removal of sediments from the sediment chamber resulted in lost production. Growing age of all components implied increasing time for proper maintenance.

Normally the power plant is shut down for maintenance 1–3 weeks annually. This is considered too little for reliable production. One major shut-down due to turbine failure has occurred since the power plant was commissioned in 1971.

Critical components were in such a condition that comprehensive maintenance works were necessary to maintain operation to satisfaction. Need for a major stop was approaching. Without more extensive measures than regular maintenance, it was foreseen longer and longer periods for maintenance to ensure defensible profitable and technical operation in the future.

After evaluation of the situation, it was concluded that it would be beneficial to install a duplicating unit with same capacity as the existing one. By doing so, it would not be necessary to stop operation for maintenance and revisions. One of the units can be maintained while the other one is in operation.

The new unit would not increase the total design discharge, which was restricted to licensed 55 m^3/s. For environmental reasons, an increase was not considered to be acceptable. The operation philosophy is then to operate one unit, and hence it is sufficient time for maintenance of the other unit. This opens for a more flexible operation of the power plant, without losing production related to maintenance works. Increased mean production was calculated to be approximately 50 GWh per year.

The planning ended up with installation of a new unit in a separate power station, about 200 meters from the old one.

The plan was then presented to the Board, and the investment decision was made in September 2009. Site work started immediately after. The new power station was in operation in March 2013.

No license related to water legislation was required for the new unit in Rendalen HPP. An essential reason for this was that the environmental consequences were considered to be small. The new arrangement was evaluated to have no or minor negative impacts on the water flow in the river Glomma or the river Rena. The licensing authority Norwegian Water Resources and Energy Directorate (NVE) therefore concluded that a public inquiry was not necessary.

The implementation was finalized on time and budget, and is characterized as an example of good practice as to technical solution as well as implementation.

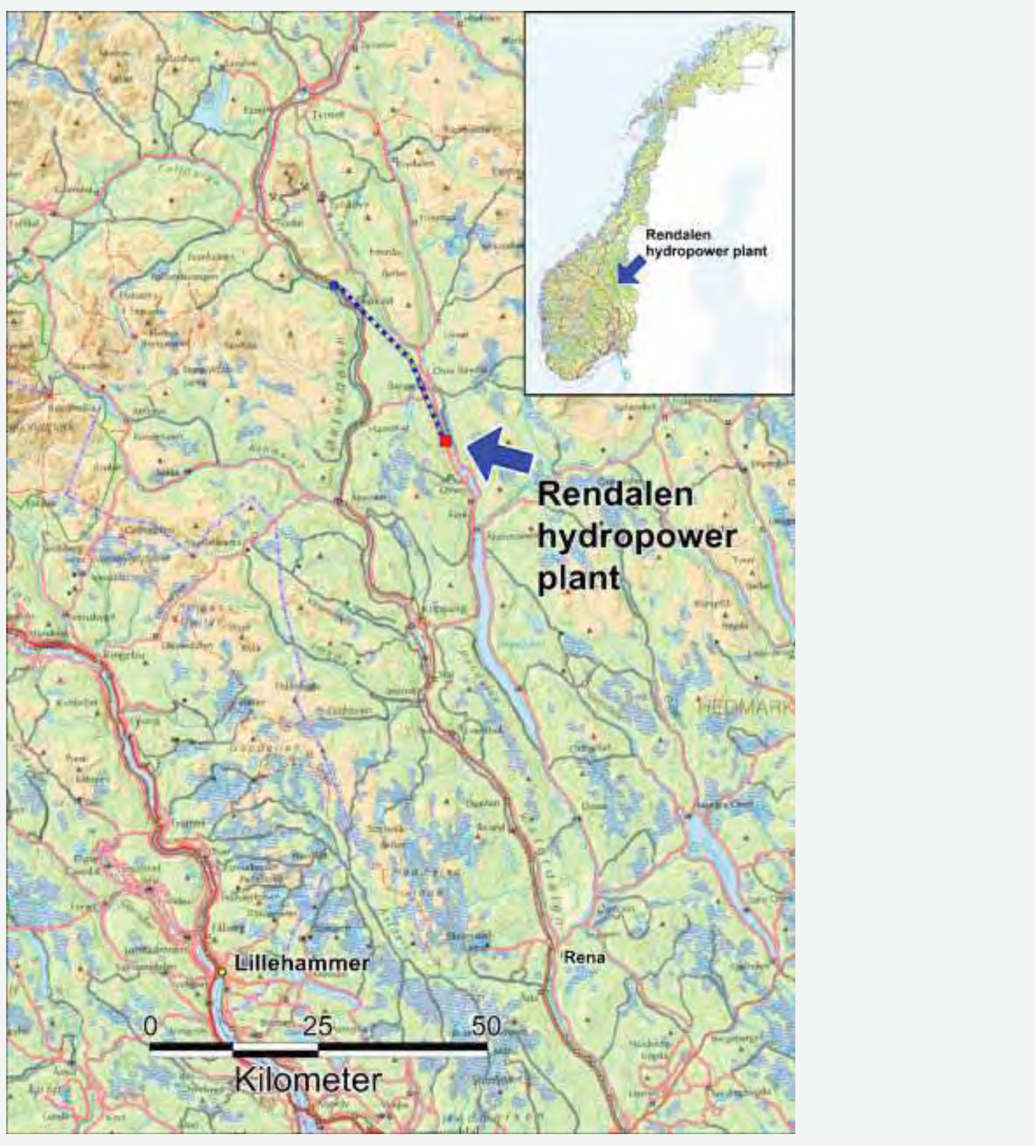


Figure 1Location of Rendalen Hydropower Plant

1. Outline of the Project (before Renewal/Upgrading)

The water from the river Glomma is diverted through a 29 km long head race tunnel from Høyegga near Alvdal to the river Rena at Hornset in Rendalen, and utilized in a hydro power plant. The power production started in 1971. The total catchment area for the diversion is approximately 6,600 km^2. Some 5,000 km^2 is unregulated.

Within the limits of the license, approximately 40% of total inflow is diverted to Rendalen. In addition approximately 10% of the inflow is required in order to meet the minimum water requirement in the river Glomma downstream the diversion dam. Diversion of water is shut down in case of local flood incidents in Rendalen valley.

The license for diverting water was limited to 55 m^3/s with minimum 10 m^3/s passing the dam as environmental release. An application for diverting 60 m^3/s has been submitted and is at present being appraised by the licensing authorities.

The dam at Høyegga is 175 meter long with maximum height 10 meters. The dam has four gates; one tilting gate, two sector gates and one slide gate. A 50 m long fish trap is constructed close to the dam.

Rendalen Hydro Power Plant utilizes the head of 210 meters in the waterway system. The head race tunnel with cross section 38/42 m^2 was excavated from 6 adits, and partly through extreme difficult geological conditions. The tunnel ends up in a sedimentation chamber, and then the water flows through a steel lined pressure shaft down to the power station and the turbine. The length of the pressure shaft is 215 meters.

The tailrace tunnel is 800 meter long, with cross section 24 m^2, and is entirely concrete lined. A tunnel with length 340 meters gives access to the power station.

Rendalen I power station is located in one cavern. The turbine is of the Francis type. The transformer is located in the same cavern as the generator. As transformers are considered a major hazard risk, new underground power stations are normally built with a separate cavern for transformers.

Data for Rendalen HPP

Mean annual production in Rendalen power plant before Renewal/Upgrading was 675 GWh. The diverted water is utilized in two power plants – Rendalen HPP and Løpet HPP before it returns to Glomma at Rena village. It is not allowed to establish reservoirs in the river Rena.

The power plant is connected to the 300 KV main grid.

Data are shown in Table 1 below.

Category	Specification
Catchment area	Appr. 6,600 km^2
Mean annual inflow	Appr. 2,940 mill. m^3
Gross head	210 m
Mean inflow	93 m^3/s
Design discharge	55 m^3/s
Capacity	92 MW
Turbine type	Francis (one)
Generator	110 MVA
Mean annual production	675 GWh
Dam type	Concrete, with flood gates
Nos of gates	4
Commissioning	1971

Table 1 Data before implementation of Unit No. 2

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

Trigger Causes

The main rationale for realization of the project was the low flexibility for maintenance works, which caused lost production. Trigger causes can be listed as follows:

(i) Conditions, Performance and Risk Exposure and Others

(A)-(a, b, d) Degradation due to ageing and recurrence of malfunction

- A thorough maintenance of Unit No. 1 was necessary, but would be time consuming, with a long stop of operation, and hence production loss. Even such a maintenance work had been carried out, the problem would occur again within some years. The new unit gave more time to carry out a comprehensive upgrading of Unit No. 1, and more flexibility for the future. The following profits are obtained:

(a) Improvement of efficiency
(b) Improvement of durability and safety
(d) Easy maintenance with less labour

(B)-(b) Environmental deterioration

- The risk of uncontrolled diversion of water over the inlet and into the river is minimized or at least reduced by having a duplicated power station. The river bed downstream the diversion dam in the river Glomma is normally semi-dry during winter. Cold winters cause the river to be covered with ice. A sudden shut-down (for instance caused by turbine collapse) in the diversion, causing sudden flooding of the river, may start ice avalanches with risk of damages on public roads and private property. One serious shutdown which caused breaking-up of the ice and ice drift downstream in Glomma downstream the intake has occurred. This resulted in serious damages.

Rendalen I power plant was constructed with a bypass valve in order to enable a smooth transition of water to the river bed in Glomma in case of a shut-down of the plant. This valve has proved unsuccessful and has only been in action for some days all together.

To a minor degree, the new solution can therefore be said to cause an improvement of river environment. However, it can also be said that this is a more or less unintentionally gain, which was scarcely regarded in the early planning stage.

(D)-(a) Needs for safety improvement
- This point is listed, but there are some uncertainty as to relevance. All safety, regulatory and operational compliance requirements were in principle met to satisfaction also before upgrading. As mentioned above, there is an improvement as to safety regarding shut-down and risk for ice avalanches downstream the intake at Høyegga.

Another result is the increased flexibility for production and maintenance, which results in more reliable production. However, this can rather be characterized as reliability than safety.

(ii) Opportunities to Increase Value

(C)-(a) Needs for higher performance
- This is a consequence of the Trigger Cause above. Higher performance was considered technical and economic feasible, and would give additional power output to acceptable costs. Higher performance is here the combination of an additional unit and flexibility for proper maintenance. The installation of Unit No. 2 gave higher flexibility for Rendalen HPP, then leading to reduced flow losses and hence increased production and income.

(iii)Market Requirements

(None)

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Before September 2009:	Planning, Evaluation and Feasibility Study
September 2009:	Board decision to realize the project
September 2009:	Start up of site works
January 2013:	Start testing
April 2013:	The new unit in commercial operation

2.3 Description of Work Undertaken (detail)

Categories and Key Points

The project can also be referred to in Key Points, and in particular to Category 1 Key Points:

Main:

1-d) Asset Management, Strategic Asset Management and Life-Cycle Cost Analysis

The project is a refurbishment project and is a part of a long-term strategy of optimal development of the owner's hydro power portfolio within profitable limits.

Two aggregates in Run off River Hydropower Plants are important for maintenance flexibility. With only one aggregate there is no time for maintenance without production losses. Maintenance normally requires stop of the unit, and may result in lower maintenance activities than required for. This will lead to higher probability for damages of the equipment.

For Rendalen HPP the extra power production is due to reduced maintenance time only, since the maximal capacity is not increased. In other cases, for example Kongsvinger HPP, the increased production is due to both higher capacity and more flexible time for maintenance.

Sub:

1-a) Energy policies of Countries & States

The extension is an important environmental effort, and in accordance with the Parliament's and the Government's stated superior goal to increase the production of renewable energy through a better utilization of the potential in existing power plants. Such measures have often lesser environmental impacts than constructing power plants in unexploited areas.

Category 2 Key Points are not evident or dominant regarding this project, and are therefore not particularly mentioned. Technical innovation & deployment of electro-mechanical (E/M) equipment are, to some degree, in question during upgrading of Unit No. 1 as well as installation of Unit No. 2. However, this is probably not beyond existing know how on turbine and generator design. The absolute conspicuous moments for Unit No. 2 are the planning, total solution and the implementation.

Ownership and background

Opplandskraft DA owns Rendalen HPP and 5 other large power plants in Hedmark and Oppland counties. Rendalen HPP is operated by Eidsiva Vannkraft AS.

Opplandskraft DA is a power company in close association with the power company Eidsiva Energi. Opplandskraft DA is owned by Akershus Energi AS, E-CO Energi AS, Eidsiva Vannkraft AS and Oppland Energi AS.

Eidsiva Energi with the sister company Eidsiva Vannkraft, operates 44 hydro power plants, and is also the owner of some of them. The ownership is public; 26 local municipalities and 2 county municipalities. Eidsiva Vannkraft's share of the total mean annual hydropower production of some 7 TWh is 3.5 TWh.

It is a pronounced policy in Eidsiva Energi, Eidsiva Vannkraft and associated power companies to increase the hydro power production (renewable energy). Some of the power plants have reached an age when renewal and upgrading is relevant. It is a continuous process to consider this, and eventually to follow up during planning, application and implementation.

Planning

The aggregate (Unit No. 1) was in bad condition after near to 40 years in more or less continuous operation. Necessary works were revision of main components in the waterway, corrosion prevention of steel components and replacement or rehabilitation of electrical equipment. The generator was the most critical component, and would be deciding for date and duration of rehabilitation. It was foreseen that a rather long period was necessary for a rehabilitation to satisfaction, and hence a considerable loss of production and income.

There had been one major incident caused by mechanical damages on the turbine, followed by 8 weeks of shut-down. The frequency and scope of future maintenance were expected to increase.

Two alternatives for improvement were considered. Alternative A was a comprehensive rehabilitation of the existing aggregate, which would result in a production stop for months. Alternative B was installation of an additional unit (duplicate unit), with so to say same size as the first one. The operation can then be alternating between the two units.

It was then proposed to select Alternative B. This was a better solution than an upgrading of Unit 1 only. In addition, and may be even more important, future maintenance works would be more flexible as to time schedules for implementation. Increased mean annual production was calculated to some 50 GWh.

The common Norwegian-Swedish electricity certificate market, which is a support system for renewable electricity production, started up January 1 in 2012. However, planning and decision for the new unit took place before the certificate market was decided to be realized, and hence this market was not a direct incentive for the new unit. So far we do not know if it will be applied for the right to take part in the electricity market.

Implementation

Construction works included excavation of new waterways, power station and access tunnel. Due to difficult geological conditions, it was inadvisable to extend power station 1 for the new aggregate. Hence it was required to excavate a new cavern, which was located some 200 m from the first one. A separate waterway was provided for as a branch from the existing.

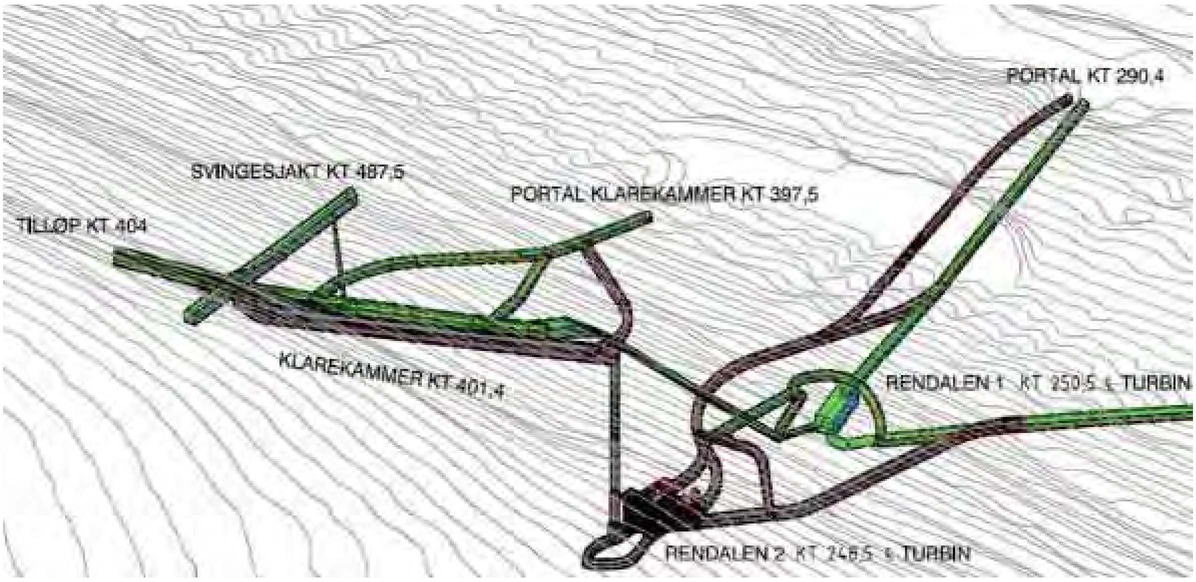


Figure 2 Outline of sedimentation chamber, surge shaft and power station

Explanations:
Tilløp: Headrace tunnel
Svingesjakt: Surge shaft
Klarekammer: Sedimentation chamber

A total of 85,000 m^3 of rock has been excavated. In addition the project includes casting of 9,200 m^3 of concrete and 500 tons of reinforcement. Safety measures were important during underground works. Cost of permanent safety measures in tunnels and caverns accounts for 65% of total excavation costs.

The diversion tunnel from Glomma is separated from the sedimentation chamber by a 3.5 m diameter throttle valve. This enables the new chamber to be excavated without emptying the tunnels. Nevertheless cleaning the chamber caused stop of operation. The new Rendalen Power Plant (1 and 2) has valve and sedimentation chamber duplicated. Future emptying of the sedimentation chamber can therefore be carried out without loss of production.

Sediment transport in the tunnel is not a severe problem. Most of the sediments are transported through the plant without causing abbreviation. Simple measures in the inlet reservoir were considered in order to minimize the bottom transport of sand during flood periods. This has not been implemented so far.

Deliveries

Technical equipment is produced in 13 countries. Producing locations were mainly in Europe, but there are also deliveries from Brazil and China. An important Norwegian delivery was civil engineering, but included also mechanical equipment in the waterways.

Main contractors, supporters and engineering services in the project were:

Main contractor civil works:	Veidekke Entreprenør AS
Consultant civil works:	Multiconsult AS
Supplier aggregate turbine:	Rainpower Norway AS
Supplier mechanical equipment waterway:	Rainpower Services AS
Supplier generator:	VG Power AG
Supplier transformer:	Siemens AG
Supplier 300 kV switchgear:	Siemens AS
Supplier control equipment:	Voith Norway AS
Supplier 300 kV cable:	Sűdkabel GmbH
Supplier machine hall crane:	Cone Cranes AB
Supplier cooling and draining installation:	Bismo Industrier AS

Waterways

The old 29 km long diversion tunnel from Glomma was built through difficult geological areas. The tunnel was excavated using conventional blast and excavation and was a pioneer project regarding use of shotcrete as safety measures. Inspection has revealed minor damages, but access to the tunnel is limited by gates of 2.7 x 2.7 m. Measures to avoid further rockslides or to excavate rockslides have been postponed. The diversion tunnel from the intake to the sedimentation chamber was not affected by the works for the new unit.

The two power plants have mainly a common waterway, but have separate branches to the respective turbines. The excavation for the separate waterway system for Unit No. 2 started in October 2009.

The waterway for the new power station branches from the existing headrace (diversion) tunnel just upstream the throttle valve in front of the existing sedimentation chamber. A new chamber and a new pressure shaft are located near the old ones. The water from the new unit is connected to the existing tailrace tunnel.

As predicted and experienced from 1971, rock quality has been a major concern throughout the project. Especially excavating the 4.5 m diameter and 150 m high vertical pressure shaft turned out to be difficult. The vertical shaft was excavated from the top using a 1.6 m diameter raise bored shaft as pilot. Accuracy in pilot for the raise driller turned out to be excellent in spite of bad rock conditions. The shaft was lined with cast in steel tubes. Seepage of water and bad rock conditions occurred and created challenges for the site crew.

The excavation and lining of the pressure shaft was carried out from June 2010 to June 2011.

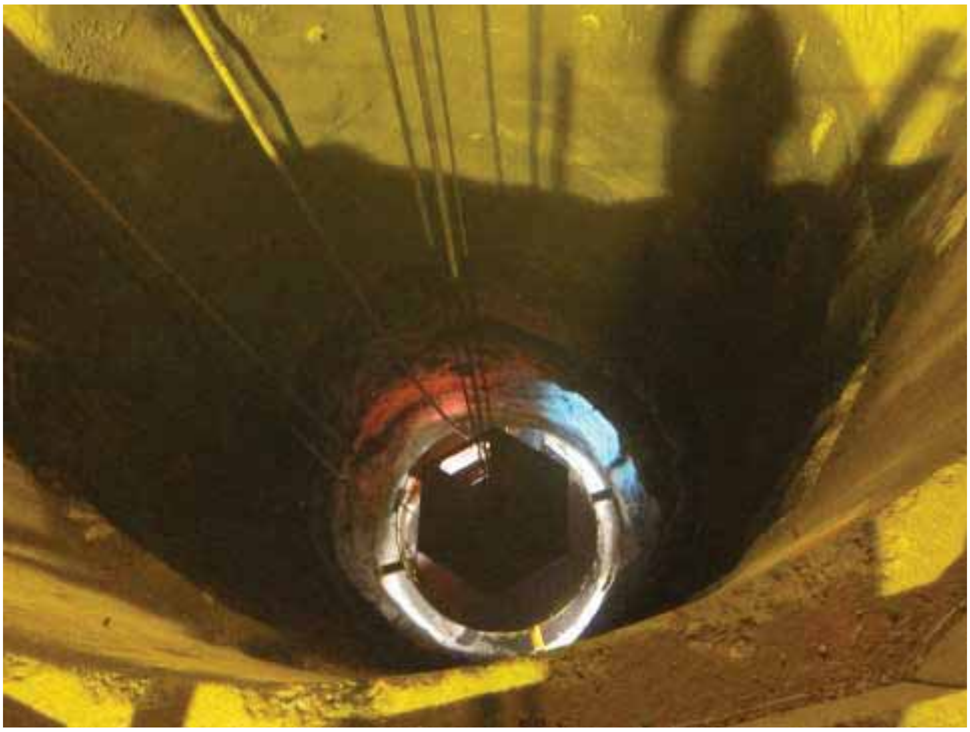


Figure 3 Pressure shaft under construction

Power station

The new power station is built in parallel with the old one. The sizes of turbine, generator and transformer are similar to those of the old ones.

The new underground power station is excavated with a separate chamber for the transformer. This is in accordance with gained experience from last decades, in order to avoid major hazard risk. Station 1 from 1971, with generator and transformer in the same cavern, was built in another respect.

Figure 4 Power station in the construction period

Mechanical installations started in January 2010, while electrical installations started in February 2012.

The old aggregate is used when the new aggregate is stopped for maintenance or other reasons. The aggregates can be run simultaneously under start and stop periods, within the maximum design discharge of 55 m^3/s in all.

The access tunnel for the new power station starts at the entrance to Rendalen 1. By connecting the two powerhouses by an extra access tunnel both Rendalen 1 and Rendalen 2 have separate emergency exits according to new regulations.

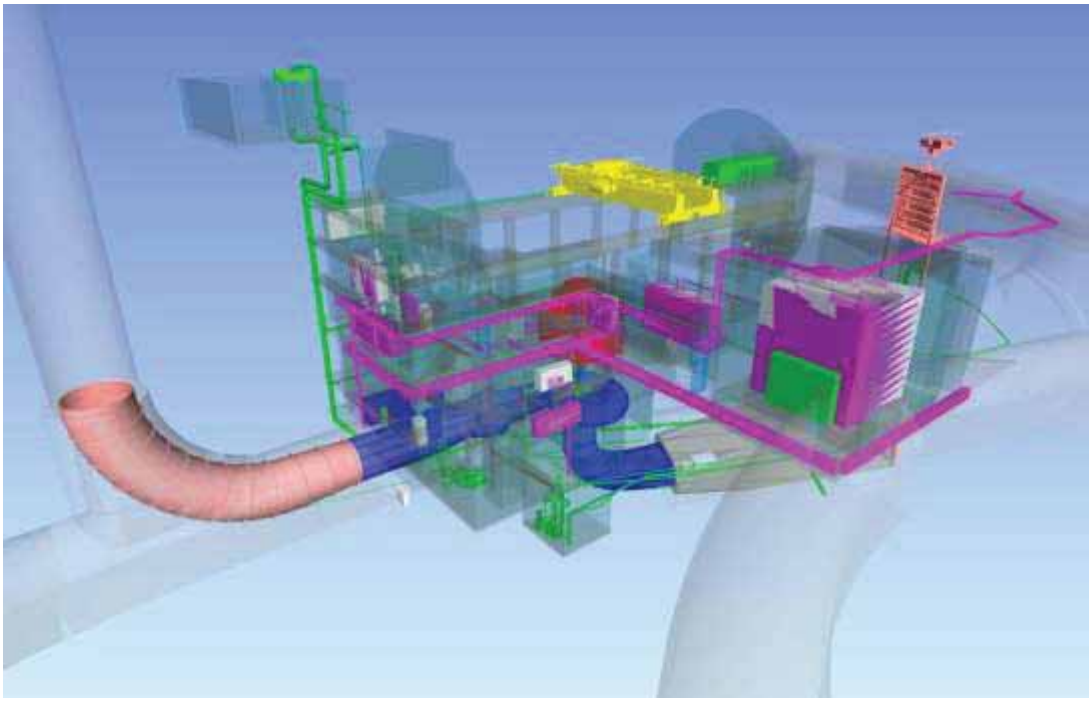


Figure 5 The new power station

Connection to the grid

Rendalen 2 is connected to the main 300 kV grid via a 650 m 300 kV cable in an idle switch bay in the existing open-air switchyard. New or reinforced transmission lines were not required.

Environment

The new power plant is mainly a duplicate of Rendalen 1 concerning utilization of the water. With exception of the access areas and the deposit of rock masses no environmental footprints will be left.

A total of 85,000 m^3 of rock has been excavated, and it was necessary to find an acceptable location and shape for a permanent deposit. A survey showed that the nearby topography was suitable for a required design of a deposit. This was followed up during construction. Some masses can also be used for other purposes. Planning of permanent deposit areas and considering possible use of rock masses have been performed in cooperation with NVE. NVE is also the approval authority for such performance.

New data

Current data for Rendalen HPP after installation of Unit No. 2 are shown in the table below.

Category	Specifications Unit 1	Specifications Unit 2	Summary
Gross head	210 m	210 m	
Installed capacity	92 MW	94 MW	92-94 MW
Turbine type	Francis turbine	Francis turbine	
Rpm		333.33 rpm	
Design discharge	55 m^3/s	55 m^3/s	55 m^3/s
Generator capacity	110 MVS	114 MVA	110-114 MVA
Annual production			725 GWh
Commissioning	1971	2013	

Table 2 New data

The production for Unit No. 1 is before installation of Unit No. 2. Unit No. 2 has higher efficiency than Unit No. 1, and will therefore be preferred for operation. Unit No. 1 will be used during maintenance on Unit No. 2.

The new unit was put in operation on April 15th in 2013, on contractual date. The total cost was NOK 356.5 mill. NOK (approximately USD 60 mill.). This was 3.8 % below budget.

3. Feature of the Project

3.1 Best Practice Components

- Planning and implementation were carried out properly
- Civil construction works and installation of a new unit (turbine, generator) while operating the existing unit for full production
- Similar to any project, implementation on time and budget is important and an obvious indicator for success

3.2 Reasons for Success

- Comprehensive evaluation of status for Rendalen I, thorough planning and a thought-through decision-making process
- Successful coordination of a number of contractors and suppliers
- Positive and effective cooperation with central and local authorities

4. Points of Application for Future Project

References are made to clauses 3.1 and 3.2 above.

5. Others (monitoring, ex-post evaluation, etc.)

None

6. Further Information

6.1 Reference

None

6.2 Inquiries

Company name: Opplandskraft DA
URL: www.eidsivaenergi.no

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

Sub: 2-a) Technological Innovation & Deployment Expansion of Electro-Mechanical (E/M) Equipment

Project Name:

Upgrading of Pirttikoski hydropower plant

Name of Country (including State/Prefecture):

Rovaniemi, Finland

Implementing Agency/Organization:

Kemijoki Oy

Implementing Period:

2009 - 2010.

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction

(C) Needs for higher performance

Keywords:

Profitability, upgrading, refurbishment, ancillary services

Abstract:

Pirttikoski HPP was built in 1956 - 1959. Both the turbines and the generators were approximately 50 years old. Through experience from previous upgrading projects, it was known, that by changing new turbine runners, the power output of Pirttikoski HPP could be upgraded from 110 MW to 152 MW. New turbines would also improve the efficiency and new generators losses are lower than the old ones. Because of oil-free runner hubs, new turbines will be environmentally friendly.

In Pirttikoski case new main transformers together with 400 kV switchyard were part of the project as well as renewal of automation, protection and hydraulic control systems.

1. Outline of the Project (before Renewal/Upgrading)

The power plants along the main channel of the Kemijoki River form a permanent production entirety, which is subject to intense peaking by the combined optimisation system. The retention time between consecutive power plants fluctuates greatly, and the flow rate increases significantly and progressively downstream. The head ponds of these power plants have limited capacity. The efficient integrated use of a chain of power plants therefore requires precise reciprocal compatibility of the maximum utilisable flow of the power plants. [1]

The upgrading projects on the main channel of the Kemijoki River were initiated in 1996. To date, twenty units have been upgraded. Every upgrade has been performed in connection with refurbishment. The extent of the upgrading measures and the implementation of other parts of the project has been specified based on overall cost-effectiveness. The order of implementation for the projects was specified by their feasibility, in addition to the condition and refurbishment requirements of the units. [1]

Pirttikoski HPP is located in Northern part of Finland. Kemijoki Oy owns 16 HPP in Lapland and Pirttikoski is one of them.

Fig. 1 Location of Pirttikoski HPP

Power plant was built in 1956 - 1959. Machine hall is excavated inside the bedrock to the depth of about 60 m and the tailrace channel is 3 000 meters long.

Originally power was 110 MW and annual electricity production was 551 GWh. After upgrading Pirttikoski key figures are 152 MW and 581 GWh/a.

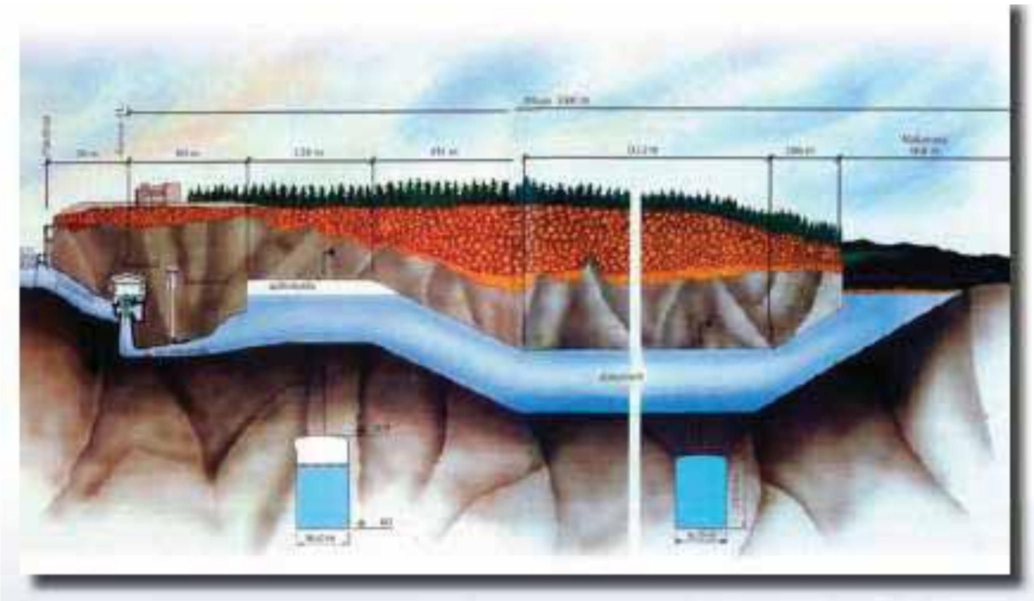


Fig. 2 Pirttikoski HPP tunnel

Sphere of influence of increased discharge will go 6,3 kilometers downstream the power plant. Kemijoki Oy has agreed on compensations with all the land owners. Part of the compensation are new boat harbours. More than 2 kilometers of riverside is covered with rock material to protect it from erosion caused by fluctuation of water level.

Fig. 3 View of Pirttikoski area

Fig. 4 Map of Pirttikoski sphere of influence (dark blue color)

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A) - (a) Degradation due to ageing and recurrence of malfunction - Improvement of efficiency and power

Increasing power and electricity production by renewal of turbine runners and increasing rated discharge through turbines.

(ii) Opportunities to Increase Value

(C) - (b) Needs for higher performance - Needs for higher performance and role change of hydropower generation (ancillary services)

Optimising frequency controlled normal operation reserves and frequency controlled disturbance reserves.

Laitos	Rakennus-virtaaman lisäys m³/s	Putous korkeus m	Lisä-teho MW	Lisä-energia GWh/a	-96	-97	-98	-99	-00	-01	-02	-03	-04	-05	-06	-07	-08	-09	-10	-11
PETÄJÄSKOSKI I	+50	20,5	8,0	12	■															
SEITAKORVA II	+40	24,0	8,0	7		■														
TAIVALKOSKI I	+50	14,5	6,0	5			■													
TAIVALKOSKI II	+50	14,5	6,0	5				■												
TAIVALKOSKI III	+50	14,5	6,0	5					■											
VALAJASKOSKI I	+100	11,5	10,3	10						■										
VALAJASKOSKI II	+100	11,5	10,3	10							■									
VALAJASKOSKI III	+100	11,5	10,3	10								■								
SEITAKORVA I	+100	24,0	22,0	14									■							
PERMANTOKOSKI		24,0	2,0	4										■						
PETÄJÄSKOSKI II	+100	20,5	18,5	21										■						
PETÄJÄSKOSKI III	+100	20,5	18,5	21											■					
OSSAUSKOSKI II	+110	15,0	10,3	16												■				
OSSAUSKOSKI I	+110	15,0	10,3	16													■			
OSSAUSKOSKI III	+110	15,0	10,3	16													■			
PIRTTIKOSKI II	+100	26,0	21,0	15														■		
PIRTTIKOSKI I	+100	26,0	21,0	15															■	
VANTTAUSKOSKI I	+75	17,0	6,0	12															■	
VANTTAUSKOSKI II	+75	17,0	6,0	12																■
PETÄJÄSKOSKI I	+75	17,0	10,0	7																■
YHTEENSÄ			221	233																

Fig. 5 Kemijoki Oy upgradings 1996 - 2011

(iii) Market Requirements

(None)

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Year 2006	General planning
Year 2006	Risk analysis and profitability calculations
Year 2007	Real estate negotiations and agreements
December 2007	License application
August 2008	First project meeting
December 2008	License approved
13.7. - 18.12.2009	First unit shutdown
12.7. - 26.11.2010	Second unit shutdown

2.3 Description of Work Undertaken

1-d) Asset Management, Strategic Asset Management and Life-cycle Cost Analysis

Asset management had strong influence on upgrading projects. Power plants were built between years 1957 and 1976. There was need for substantial refurbishment. [2]

Because of upgrading potential it was profitable to combine refurbishment and upgrading in same project. Refurbishment extends the power plant lifetime, reduces maintenance costs and improves safety issues. Upgradings increase power output and yearly production and furthermore gives you more technical reserves to support the electrical grid. Power regulation is very important especially in the coming years when the amount of wind-power and other unpredictable production increases. [2]

2-a) Technological Innovation and Deployment Expansion of Electro-Mechanical (E/M) Equipment

Power from hydropower plant depends on the amount of water running through turbines and of head. The more discharge and head you have the more power you get.

Turbine design has seen great improvement over the past decade. The best upgrades have attained a power increase in excess of 40 %. It is significant that no alterations were required to be made to the water channels and concrete structures in general. [2]

The majority of power increases were due to the increase in the discharge of the units. Credit should also be given to improving the efficiency typically from 0,5 – 2 % and the loss savings achieved at various points. [1]

Before shut down period starts, overhead cranes were completely overhauled and inspected. To minimize risks of big lifts of stator and rotor, it is necessary to make sure that cranes work reliably. During these lifts, the other unit was stopped for safety reasons. Project timetable is tight and in case of crane failure, it would have had influence on whole project.

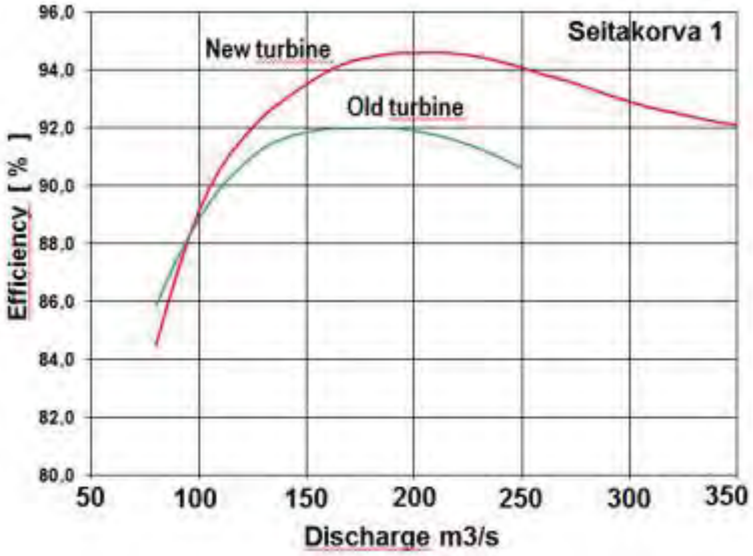


Fig. 6 Turbine efficiency improvement

Turbine hub can be made smaller when using high pressure hydraulic pressure system. With higher pressure, mechanism inside hub can be smaller. When the diameter of hub is smaller, it allows more discharge through turbine.

Traditionally there has been oil inside hub. In Pirttikoski oil has been replaced with oxygen-free water. It made turbines environmentally friendly as there are no oil leaks into river in case of blade sealing failure.


Fig. 7 Old and new turbine runner

Blade bearings are dimensioned considering the use of the units in continuous operation with frequency regulation. Blades more or less move all the time when unit is in operation. Also starts/stops have increased during last years and on the average there are 150-250 starts/stops per unit during one year.

Old generators could not manage the power after upgrading. Therefore generators had to be renewed. Works with new generator stator were executed before unit shut down started. The new stator frame was hauled in, in three parts and assembled together. After stator frame was checked to be round, plates were stacked into their places and stator winding was finished.

Because of lack of space in Pirttikoski machine hall, works after shut down had started, had to be executed in certain order. First the old stator was first lifted out, dismantled and hauled away. Then the new stator was lifted into its place. Next the old rotor was lifted out and old rotor poles were dismantled and taken away. After cleaning and inspection of rotor frame, new rotor poles were installed.

Fig. 8 New generator stator and rotor

Busbars from generators to main transformers had to be strengthened due to increased current. The problem was solved, when new copper flat bars were bolted to the old busbars.

Often when you start a large project in a power plant, it is profitable to do also other works during same shut down period. In Pirttikoski automation and generator and main transformer protection relays were renewed.

Fig. 9 New generator thrust bearing segment

Summary of works done in Pirttikoski upgrading projects:

Turbines:

- new turbine runner
- rated discharge from 250 m^3/s to 350 m^3/s
- power up from 55 MW to 76 MW
- efficiency improvement up to 2 %
- new hydraulic system, high-pressure
- oil-free hub
- increased frequency reserves

Generators:

- new stator and rotor poles
- power up from 70 MVA to 85 MVA
- efficiency improvement approx. 0,5 %
- new protection relays
- strengthening of busbars from generators to main transformers because of increased current
- new thrust bearings, PTFE

New automation and control systems

- better possibilities to carry out frequency reserves

Main transformers:

- original one-phase units were replaced by three phase transformers
- 2 x 85 MVA, 13,8 / 410 kV

New 400 kV disconnector switchyard

3. Feature of the Project

3.1 Best Practice Components

- Relatively high improvement in HPP upgrading, power up to 40 %
- Short shut down time, 23 and 20 weeks

3.2 Reasons for Success

Pirttikoski upgrading projects were numbers 16 and 18 in series of upgradings done by Kemijoki Oy. Personnel planning, supervising and carrying out the projects were very experienced. All projects are different, but they also have a lot in common.

Technical targets were achieved, projects were on schedule and projects were realized according to the budget. During projects no industrial accidents happened and altogether 17 dangerous situation notifications were made.

Most of the work in projects were carried out by Kemijoki Oy’s own staff.

4. Points of Application for Future Project

Experiences from Pirttikoski projects were and will be used in latter projects. Both technical issues and work of the project team, develops along with several projects.

5. Others (monitoring, ex-post evaluation, etc.)

Pirttikoski units have been running normally after upgradings. One of the starting points when project plan was made was, that after upgradings the units are expected to run for 40 years.

A little less than half of the benefits of upgrading are utilised during flood times, due to the extra energy obtained from the improved energy production of the units. Typically, around a quarter of the benefits are obtained from the improvement in efficiency, 20 % from increased peaking facilitated by the highly increased power (increase in energy value), 5 % from increase in the amount of ancillary services sold (frequency controlled operation reserve and frequency controlled disturbance reserve), and the remaining benefits are obtained from e.g. modernisation of a variety of devices and equipment causing losses. [1]

The more you produce reserves the more it means operation and maintenance costs. As the role of hydro power ancillary services has grown in Finland, investment in frequency controlled reserves has however proved to be profitable.

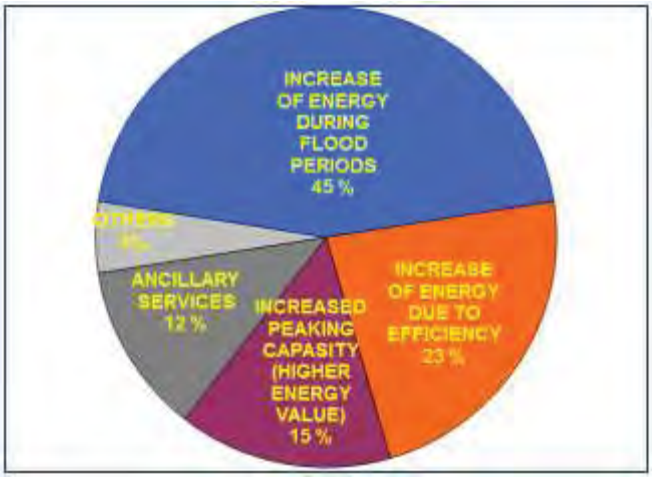


Fig. 10 Average distribution of benefits in upgradings [1]

6. Further Information

6.1 References

[1] Kari Lamminmäki, Janne Ala, Cost-effective new hydro capacity by upgrading existing hydro units on the Kemijoki River, Hydro 2012, Bilbao

[2] Janne Ala, IEA Annex XI – Reneval & upgrading of hydropower plants, Questionnaire

6.2 Inquiries

Company name: Kemijoki Oy, Finland.

URL: www.kemijoki.fi

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 - d) Asset management, strategic asset management and life-cycle cost analysis.

Sub: 1 - b) Investment incentives;
1 - f) Environmental Conservation and improvement;
2 - b) System and Reliability improvements in Protection & Control (P&C).

Project Name:

Poatina Modernisation Project

Name of Country (including State/Prefecture):

Australia, Tasmania

Implementing Agency/Organization:

Hydro Tasmania

Implementing Period:

2006-2010.

Trigger Causes for Renewal and Upgrade:

Main (A)Degradation due to ageing and recurrence of malfunction.
Secondary (B)Environmental deterioration;
(C)Needs for higher performance;
(D)Needs for safety improvement; and
(E)Needs due to third party factors.

Keywords:

Upgrade Turbine, Degradation over 40 years, Poor Reliability and Mitigate Key Risks, Pelton.

Abstract:

Between 2007 and 2011 Hydro Tasmania invested $69m AUD to upgrade three hydro machines at the Poatina Power Station to improve their efficiency and significantly improve plant performance to achieve a start reliability of 98% and availability of 95%. The capital investment also included work to mitigate key risks on all six machines associated with machine protection, main machine inlet valves and transformer oil containment. A key aspect in the engineering was to provide the safest upgrade to prevent recurrence of serious penstock pressure pulsations due to Main Inlet Valve malfunction which had the potential to catastrophically destroy the penstock and flood the station.

The project also aimed to significantly reduce maintenance costs by designing out existing problems caused by original poor design and original poor manufacturing quality in the 1960's.

1. Outline of the Project (before Renewal/Upgrading)

Hydro Tasmania is Australia's largest renewable energy producer located in the island state of Tasmania (for location, refer Figure 1). Hydro Tasmania owns 30 Hydro Power Stations with installed capacity totalling 2,280 MW, which produced approximately 12,000 GWh in 2014.

Poatina Power Station is the second most critical power station in Hydro Tasmania's power station portfolio having a major lake storage and high revenue capability providing critical operational flexibility.

Poatina Power Station has six high-head pelton turbines producing a maximum output of 360 MW's and started operation in 1965.

Hydro Tasmania's location in Australia

Figure 1 – Shows world location of Tasmania

Power Station is located in Central Northern Tasmania utilising water from the Great Lake. The underground station houses 6 generating units operating at a maximum net head of 820m (See figure 2).

Figure 2 – Shows topographical Arrangement of Poatina Power Scheme.

Table1 - Specification of the Poatina Power Plant

Category		Specification
Power Plant	Name of the power plant	Poatina Power Station
	Maximum output	360 MWs from 6 units
	Machine speed	600 rpm
	Total station discharge	50 m^3/sec
	Effective head	820m
	Location	150m underground
	Original machines commissioned	1965
	Main Turbine Inlet Valve	36 inch Rotary Valve Type with stainless steel sliding seal
	Machine Turbine	19 bucket pelton turbine with 4 injectors – Boving and Co 1965
	Machine Alternator	60 MVA Siemens Schuckertwerke A.G. 1965
	Turbine Guide Bearing	Split journal bearing, self pumping supplied by Boving 1965
	Governor	Type Electro-mechanical Model E10 KMW 1965 Low pressure hydraulic power unit 20 Bar
Water Delivery	Tunnel	5.6 km
	Penstock (steel)	1.8 km
Reservoir Great Lake	Effective Storage	3063 x 10^6 cubic metres
	Area of lake	114 square km
	Elevation	1030 m above sea level

Figure 3 below shows a cross section of the layout of a Poatina Machine

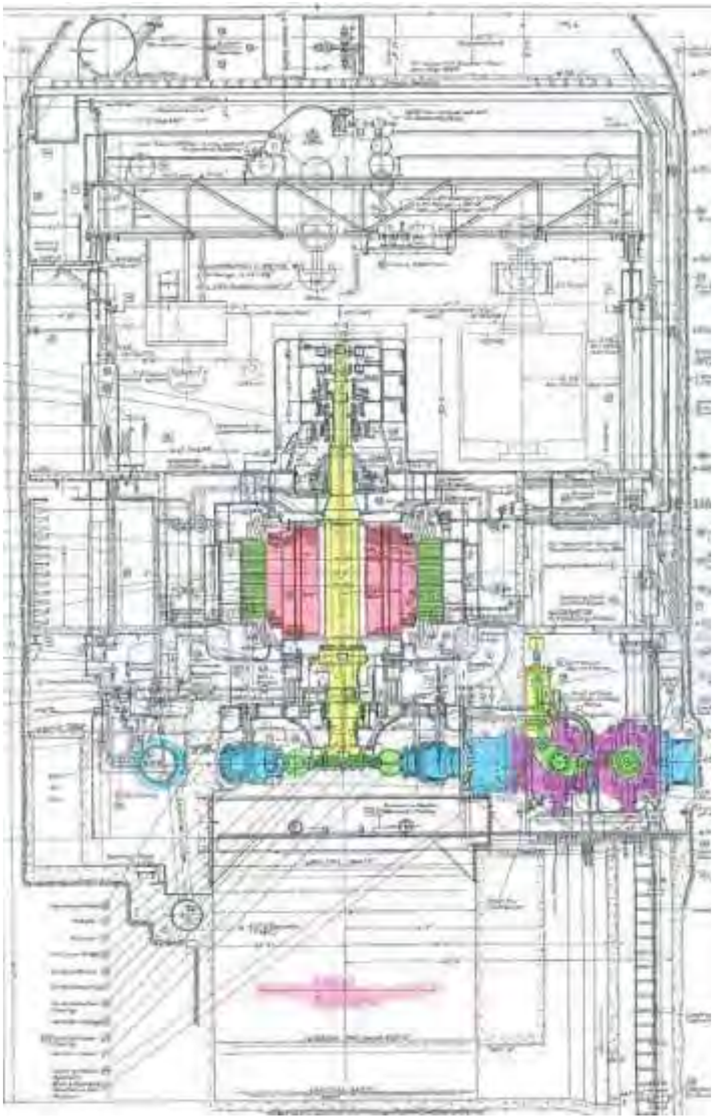


Figure 3 Showing Key Machine Components in Cross Section

Legend

- Blue – Penstock off take and spiral casing connecting to 4 off Injectors
- Purple – Isolating Valve followed downstream by the Main Inlet Valve
- Green – Turbine Runner
- Yellow – Machine Shaft System
- Pink – Generator Rotor
- Dark Green – Generator Stator

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A) – (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency

New Turbine runners and injectors provide 4.8% efficiency gain.

(A) – (b) Degradation due to ageing and recurrence of malfunction - improvement of durability and safety

New turbine runners are forged and more durable and injectors more reliable.

(A) – (c) Degradation due to ageing and recurrence of malfunction - cost reduction

New Turbine runners able to run 6,500 hrs without inspection and cavitation.

(A) – (d) Degradation due to ageing and recurrence of malfunction - easy maintenance with less labour

New Turbine guide bearings designed with adjustable pads to allow easy maintenance.

(B) – (c) Environmental deterioration - Others

New design of Turbine guide bearings prevents oil los during load rejection. Also installed a Transformer oil containment system.

(E) – (a) Needs due to third party factor - sustainable operation (sometimes accompanied by power reduction)

Regulation pond at tailrace to ensure downstream flows are regulated sufficiently for drinking water supply and agricultural irrigation.

(ii) Opportunities to Increase Value

(C) – (a) Needs for higher performance - addition of units, Expansion of power & energy

Extra machine capacity approx. 4 MW per machine.

(D) – (a) Needs for Safety improvement - improvement of safety

Improved Main Inlet Valve Controls and Protection system reduces the risk of serious penstock pressure pulsations.

(iii) Market Requirements

Design of new turbine injectors provided for extended Frequency Control Ancillary Services (FCAS) provision.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

2003/4	Feasibility study
2004	Feasibility study Business Development & Approval
2005	Machine controls & integration concept and detail design
2005	Original Equipment Manufacturer (OEM) Turbine runners & injectors Contract Award
2006	Business Development & Approval
2006	Original Equipment Manufacturer (OEM) Governor & Turbine Bearing Contract Award
2007	Poatina Unit 4 Modernisation
2008	Poatina Unit 1 Modernisation & Poatina Unit 2 sustain works
2009	Poatina Unit 2 Modernisation & Poatina Unit 3 sustain works
2010	Poatina Unit 6 sustain works.

2.3 Description of Work Undertaken (detail)

1-d) Asset management, strategic asset management and life-cycle cost analysis.

Strategic asset management is applied across Hydro Tasmania's portfolio of power stations to determine the extent of Capital Expenditure. Poatina Power station is considered one of Hydro Tasmania's top six most critical stations due to its significant contribution to production and system stability. Together with Tungatinah and Tarraleah, Poatina is one of three of these 'Six Most Critical' that are assessed as contributing a significant risk exposure to portfolio revenue.

In view of their major revenue contribution and strategic role, the Hydro Tasmania Strategy dictates that the Most Critical Stations are to receive priority when considering asset management and capital investment. This Strategy is centred around:

- improving asset condition to an acceptable risk rating within the next 5 years;
- sustaining performance of all machines to meet and maintain required productive capability within the next 5 years; and
- investing in capital works over the next 5 years to refurbish the Jewel stations.

The scope of work is decided by considering asset condition, asset performance, duty of care requirements and risk exposure. The engineering decisions made to determine the best for business option is decided by using Lowest Life Cycle Costing over a 30 year period.

An example Figure 4 demonstrates that Net Present Costing over 30 years shows that option of a Pivot Pad Design for the Turbine Guide Bearing is the most cost effective over the longer term – after 12 years the Pivot Pad Design has the lowest Net Present Cost and was therefore was selected as the best long term option.

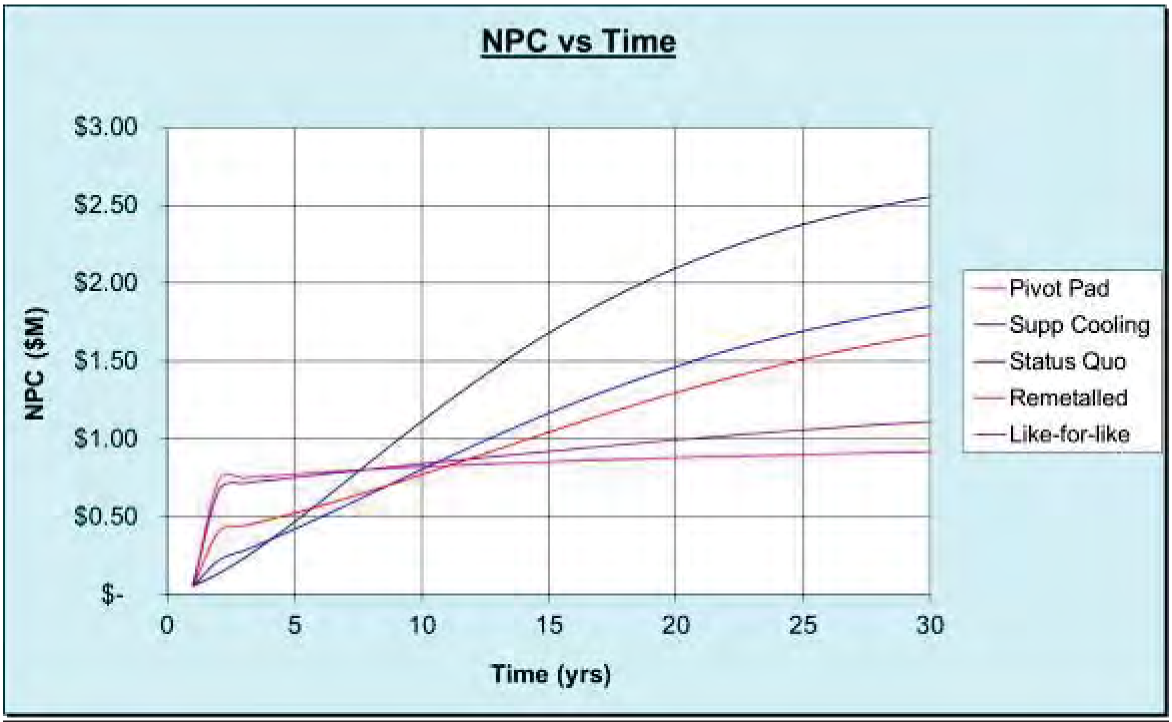


Figure 4 – Example of Life Cycle Costing

1-b) Investment incentives

One investment incentive for the Project included Renewable Energy Certificates provided by the Australian Government for the development on new or increased renewable energy production. The certificates are issued for additional renewable energy production above previous baselines and is payable once the REC's are sold. This provides incentive for Australian industry to develop additional renewable energy which may otherwise be uneconomical.

Another key benefit of the Project was to provide greater operational flexibility for Trading into the Australian National Electricity Market in order to provide Frequency Control Ancillary Services. The new machines incorporate ancillary services such as Fast Raise Capability, Spinning Reserve and improved Synchronous Condenser mode required to ensure system electrical frequency is maintained with in strict limits and load can be shed or replaced quickly if the undersea Basslink cable to mainland Australia is tripped.

1-f) Environmental Conservation and improvement

The following environmental improvements were made during the project:

- Turbine Guide Bearing – Oil Loss problem eliminated – The new turbine bearings have zero oil loss during all transient operating conditions – the original bearings lost 20 to 30 litres of oil to the tail race every time a machine trip occurred.
- Transformer Oil Containment – upgraded bunding and oil containment tank was installed to meet Environmental Standards – this mitigates the risk of an unacceptable environmental incident and reduces the risk of fire spreading if a transformer fire occurs.

2-b) System and Reliability improvements in Protection & Control (P&C).

The most significant new technology utilised in the Project was installation of PLC Based Electronic Governors and Protection & Controls. This replaced the old electro-mechanical governors and relay based controls and protection system respectively.

The PLC Based governor and controls replaced 40 year old systems which were unreliable and obsolete (spare parts for the old systems were mostly unavailable).

The new PLC based controls system was integrated seamlessly with the new PLC based governor to provide the best technical outcome. This ensures improved reliability and` functionality and also incorporates condition monitoring to align with current industry practiceand internal Hydro Tasmania policy to allow real capture and trending of critical operational parameters to enable information to be gathered for compliance and fault diagnosis.

3. Feature of the Project

3.1 Best Practice Components

- Hydro Tasmania's Strategic Asset Risk Assessment & Management. This process involves an integrated asset portfolio approach to identifying the extent and timing of upgrade intervention and agreed Business outcomes for in order to best manage the Business risk position and maximise production opportunities, consistent with the Asset Management Strategy.
- Knowledge Management. Integration design and design of ancillary upgrades was largely completed by Entura (Hydro Tasmania's Consulting Design arm) which developed the capability of their resources and provided opportunities for collaboration with the operational client and site work execution. Over the programme (full modernisation of three machines and selective work on three others), Hydro tasmania resources developed to assume key roles in the management and supervision of the work.

  Contract Risk Management. Entered into Implementation Alliance to develop a pool of own people and increase capability without being exposed to the full risk and burden of taking on the head contractor role:
- Local Economy. Use of local (Tasmania) service providers when practical to improve the state economy and support development of local skills for major works projects.

3.2 Reasons for Success

- Cross-functional teams reviewing designs at an early stage with key personnel available to contribute and influence works planning and follow through to implementation.
- Key resource continuity (eg. Project & Site Managers, some engineering personnel) ensured effective knowledge transfer between tranches of work.
- Meaningful post implementation review after each unit upgrade to identify the lessons learnt and application of those lessons into any necessary design changes, works planning and implementation for the following units.
- Over time, greater integration of local operational resources into the team resulting in greater ownership of outcomes.

4. Points of Application for Future Project

- Project resourcing plans should be fully developed at an early stage so that key personnel are available to contribute and influence works planning and follow through to implementation. Ideally "back-up" personnel should be identified in case of personnel changing roles or leaving the business.
- Project resourcing should allow for overlap of resources when there are changes required to ensure good hand-over of lessons learnt.
- Project scope should ideally cover holistic asset performance. Examples where this could have been improved include the replacement of the circuit Breakers and Machine transformers shortly after the end of the project.

5. Others (monitoring, ex-post evaluation, etc.)

The Modernised Machines have met or exceeded the targets for reliability & availability

	TARGET	PO4	PO1	PO5
Availability	95%	95.6%	95%	97.5%
Start reliability	98%	96%	100%	96.5%
Run reliability	95%	99.8%	99.7%	99.2%

Approximately 20MW of fast lower "frequency Control Ancillary service" capability per machine has been provided.

6. Further Information

6.1 Reference

1) "Key Learning's from the upgrade and modernization of a high head pelton machine at Poatina Power Station" Australasian Hydropower Engineering Exchange Conference, Author Fabian Kaica, September 2008
2) "World Class Hydro Machine Operation" Paper/submission to Institution of Engineers Australia 2009 – Winner of an Australian Engineering Excellence Award 2009, Authors Enes Zulovic and Fabian Kaica June 2009

6.2 Inquiries

Company name: Hydro Tasmania
URL: http://www.hydro.com.au/

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 - d) Asset management, strategic asset management and life-cycle cost analysis.

Sub: 1 - a) Energy policies of Countries & States;

1 - c) Integrated management of water resources and river systems;

1 - e) Project justified by the non-monetary valuation of stabilizing unstable power systems in the up-coming low-carbon society;

1 - f) Environmental conservation and improvement;

2 - a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment;

2 - b) System and Reliability improvements in Protection & Control (P&C); and

2 - c) Technological innovation, deployment expansion and new materials noise for civil and building works.

Project Name:

Tungatinah Modernisation project

Name of Country (including State/Prefecture):

Australia, Tasmania

Implementing Agency/Organization:

Hydro Tasmania

Implementing Period:

2010-2013

Trigger Causes for Renewal and Upgrade:

Main (A)Degradation due to ageing and recurrence of malfunction.

Secondary (B)Environmental deterioration;

(C)Needs for higher performance;

(D)Needs for safety improvement; and

(E)Needs due to third party factors.

Keywords:

Modernisation, Francis Turbine Upgrade, Degradation over 60 years, Poor Reliability and Mitigate Key Risks

Abstract:

Between 2010 and 2013 Hydro Tasmania has invested \$58M AUD to upgrade 3 hydro machines at the Tungatinah Power Station to deliver security of revenue by addressing the continued and un acceptable deterioration in station performance. The Modernisation of the 3 hydro machines will enhance station annual revenue by circa \$2M AUD by increasing efficiently by circa 3%, capacity by circa 5 MW per machine and improved Frequency Control Ancillary Services (FCAS) capability. The capital investment also included work to mitigate key risks associated with oil mist generation and related OH&S, maintenance and housekeeping issues, potential penstock and spiral casing failure, machine component deterioration including governor and control system, and waterway contamination from the oil lubricated turbine bearing. The Modernisation works also provided for National Electrically Rules (NER) compliance of the excitation system.

1. Outline of the Project (before Renewal/Upgrading)

Hydro Tasmania is Australia’s largest renewable energy producer located in the island state of Tasmania (for location, refer Figure 1). Hydro Tasmania owns 30 Hydro Power Stations with installed capacity totalling 2,280 MW, which produced approximately 12,000 GWh in 2014.

Figure 1 – Location of Tungatinah Power Station in Tasmania, Australia

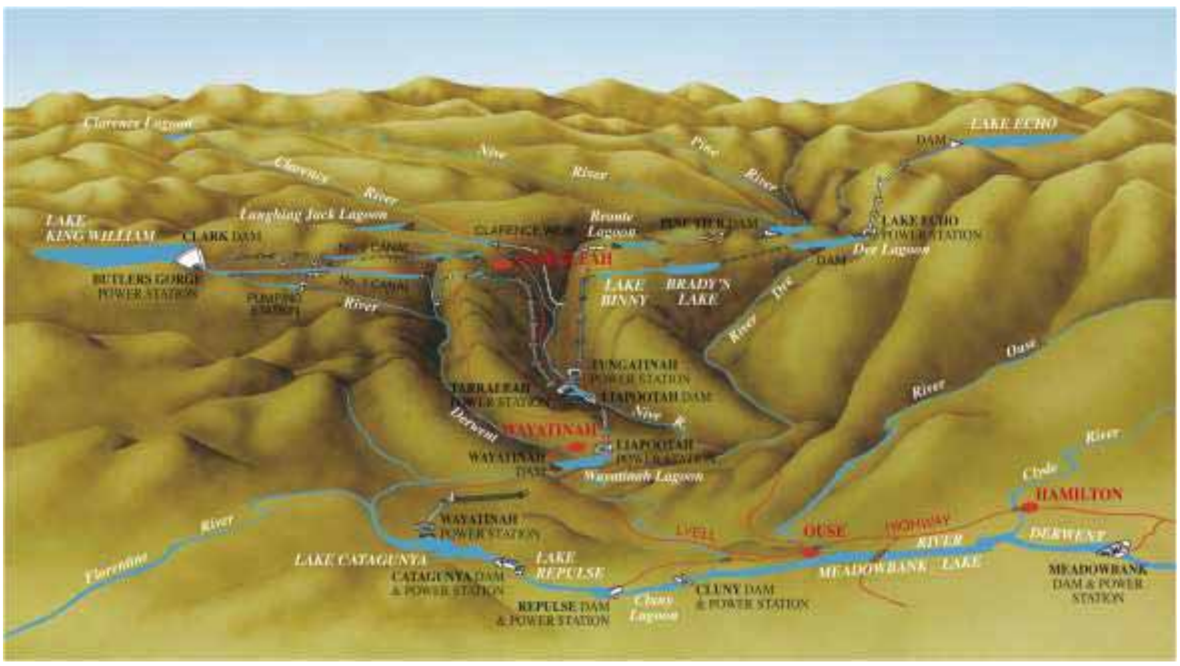


Figure 2 – Location of Tungatinah Power Station on Upper Derwent Scheme

Tungatinah Power Station was commissioned during period 1953-1955. It is located on the Nive River, part of the Upper Derwent River Scheme. The station has five 26 MW Francis Turbines, and is ranked 6th out of Hydro Tasmania's power station portfolio for revenue contribution. The water which passes through the power station is also used downstream at six other power stations. Therefore it is critical to Hydro Tasmania for water resource management. For station and machine specifications, refer Table 1.

As key assets are now approaching their 'end of life' a project is nearing completion to modernise three of the five machines at Tungatinah Power Station (the switchyard electrical and electrical protection were replaced as part of an earlier project). The project will return the machines to the required level of performance and condition, address key risks, and enhance revenue through increases in efficiency, capacity, and Frequency Control Ancillary Services (FCAS). The final two machines will undergo refurbishment works only which is yet to be fully defined.

Table 1 – Tungatinah Power Station Machine Specifications

Category		**Specification**
Power Plant	Name of the power plant	Tungatinah Power Station
	Maximum output	125 MWs from 5 units
	Machine speed	600 rpm
	Total station discharge	55 m^3/sec
	Rated head	290m
	Location	Nive River
	Original machines commissioned	1953-1956
	Main Turbine Inlet Valve	Rotary Valve Type
	Machine Turbine	Old: Francis – Boving New: Francis – ALSTOM Hydro
	Machine Alternator	GEC, 35 MVA
	Thrust Bearing	Old: White metal New: PTFE
	Turbine Guide Bearing	Old: Oil, hydrodynamic New: Water, hydrostatic
	Governor	Old: Boving F10 New: ALSTOM TSLG
	Control System	Old: Relay based New: PLC (Andritz) based
	Excitation	Old: GEC PMG New: Static, ABB Unitrol 6000
Water Delivery	Tunnel	Common, 4.5m (diameter) x 825m (length)
	Penstock (steel)	Individual, 2.1m (diameter) x 950m (length)
Reservoir Tungatinah Lagoon Chain	Effective Storage	Multiple small and 1 x medium
	Area of lake	NA
	Elevation	651m

Refer to Figure 3 for a machine cross section and summary of the major scope items of the Tungatinah Modernisation Project. In addition to the items in Figure 3 the following are also part of the project scope:

- Hill top valve refurbishment;
- Main Inlet Valve refurbishment;
- Turbine Relief Valve refurbishment – including modification for new actuation;
- Replace old electro-mechanical governor with new solid state based speed governor;
- Replace the existing self-excitation with static excitation system;
- New PLC based mechanical protection and control system;
- Clean and maintain rotor; and
- Re-wedge, clean and maintain stator.

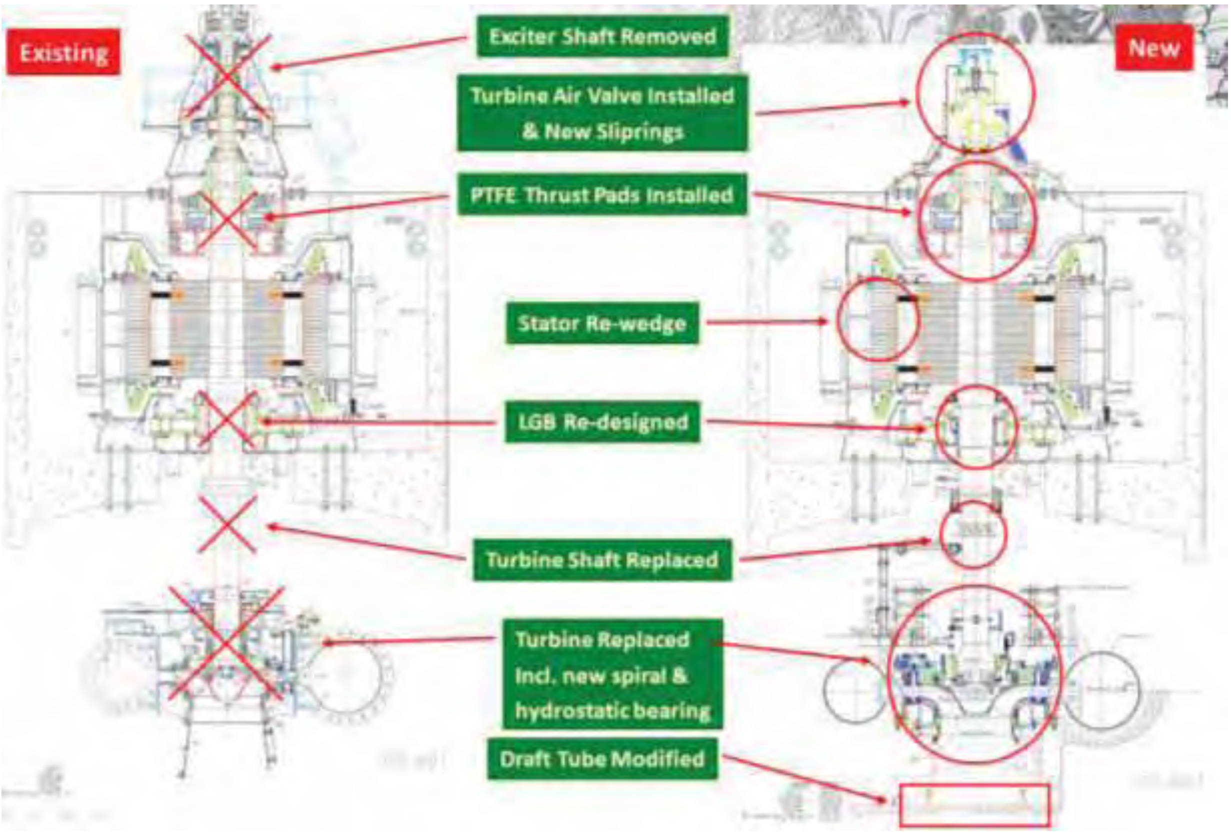


Figure 3 – Machine cross section before and after Modernisation

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A) – (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency Increase in efficiency of circa 3%.

(A) – (b) Degradation due to ageing and recurrence of malfunction - improvement of durability and safety

Addressing key risk associated with potential penstock and spiral casing failure, governor, control system, wear rings and guide vanes.

(A) – (c) Degradation due to ageing and recurrence of malfunction - cost reduction Less intrusive brush gear maintenance required.

(A) – (d) Degradation due to ageing and recurrence of malfunction - easy maintenance with less labour. Improved maintenance access, no jacking required, less lubrication required.

(B) – (c) Environmental deterioration - Others
Addressing key risks of waterway contamination from oil lubricated turbine bearing. New oil/ water heat exchanger reduces the risk of tube failure intrusive brush gear maintenance required

(ii) Opportunities to Increase Value

(C) – (a) Needs for higher performance - addition of units, Expansion of power & energy Increase in capacity of 5MW per machine.

(D) – (a) Needs for Safety improvement - improvement of safety
Risk reduction related to oil mist generation and the associated OH&S maintenance and housekeeping issues.

(iii) Market Requirements

Frequency Control Ancillary Services of 8MW per machine. Faster start times.

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

2003	Pre feasibility study
2004/5	Feasibility study
2008	Business Development & Approval
2008	Original Equipment Manufacturer (OEM) Contract Award
2010/11	Tungatinah Unit 5 Modernisation
2012	Tungatinah Unit 1 Modernisation
2013	Tungatinah Unit 2 Modernisation (ongoing)

2.3 Description of Work Undertaken (detail)

1-d) Asset management, strategic asset management and life-cycle cost analysis.

Strategic asset management is applied across Hydro Tasmania's portfolio of power stations to determine the extent and timing of maintenance intervention. Tungatinah Power Station is considered one of Hydro Tasmania's top six most critical stations due to its contribution to revenue and water management. Tungatinah Power Station has been assessed as contributing a significant risk exposure to portfolio revenue due to its current condition.

In view of their major revenue contribution and strategic role, the Hydro Tasmania Strategy dictates that the six Most Critical Stations are to receive priority (after safety and duty of care obligations) when considering asset management and capital investment. This Strategy is centered around:

- Improving asset condition to an acceptable risk rating within the next five years;
- Sustaining performance of all machines to meet and maintain required productive capability within the next five years; and
- Investing in capital works over the next ten years to refurbish the critical stations.

The scope of work is decided by considering asset condition, asset performance, duty of care requirements and risk exposure. The engineering decisions made to determine the best for business option is decided by using Lowest Life Cycle Costing techniques.

1-a) Energy policies of Countries & States

Business benefits from the Project included Renewable Energy Certificates (REC) provided by the Australian Government for the development on new or increased renewable energy production. The certificates are issued for additional renewable energy production above previous baselines and is payable once the REC's are sold. This provides incentive for Australian industry to develop additional renewable energy which may otherwise be uneconomical.

Another key benefit of the Project was to provide greater operational flexibility in the Australian National Electricity Market in the form of Frequency Control Ancillary Services. The modernised machines incorporate improved FCAS R6 Capability.

1-c) Integrated management of water resources and river systems

The increase in reliability and improvement in efficiency for Tungatinah station provides for more effective water balance between upper level pond storages and lower power systems.

1-e) Project justified by the non-monetary valuation of stabilizing unstable power systems in the up-coming low-carbon society

Same justification as increasing Frequency Control Ancillary Services (FCAS), the need which is required due to the development of wind-farms in Tasmania.

1-f) Environmental conservation and improvement

A number of environmental improvements were made during the project. The Turbine Guide Bearing Oil Loss problem was eliminated. The new turbine is of a water lubricated hydro static design and hence no oil loss is possible.

A new oil/water heat exchanger has been installed to replace the original units. This will reduce the risk of tube failure and subsequent oil/water contamination.

Gaskets containing asbestos, lead-based painting systems and instrumentation containing mercury have been replaced (and appropriately disposed of) thereby reducing the possible risk of future health, safety and environmental impacts.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

- A water lubricated hydrostatic turbine bearing has been utilized. This is a technological development made by ALSTOM Hydro;
- Tenmat guide vane bushes (greaseless) have been utilised;
- The spiral casing was fully welded in the workshop and installed as a single piece, reducing distortion risk on-site;
- Maintenance access has been incorporated into the design with the provision of platforms, lifting assistance in the form of small jib cranes at the turbine, specialised access platforms/lifting mechanisms for the lower guide bearing and runner;

- Laser scanning was used to develop a station layout and piping isometrics as well as fly-throughs to assist with stakeholder engagement; and
- Laser surveying was used to accurately determine levels and centerline locations in a 3D space.

2-b) System and Reliability improvements in Protection & Control (P&C).

- Use of SIL rated components has been made to reduce the need for duplication; and
- A standardised PLC approach has been taken so that future upgrades over numbers of stations will have similar design, interface, commissioning and operating requirements. This will make the design, installation, commissioning and training requirements more efficient and allow increased operator mobility between stations.

2-c) Technological innovation, deployment expansion and new materials noise for civil and building works

Adoption of fire rated walls in between each machine to minimize noise from the station during construction and provide fire spread mitigation. This approach has reduced the risk to workers on site and provides for a building to a more modern standard.

3. Feature of the Project

3.1 Best Practice Components

- <u>Hydro Tasmania's Strategic Asset Risk Assessment & Management</u>. This process involves an integrated asset portfolio approach to identifying the extent and timing of upgrade intervention and agreed Business outcomes for in order to best manage the Business risk position and maximise production opportunities, consistent with the Asset Management Strategy.
- <u>Knowledge Management.</u> Major refurbishment projects provide for a unique and unrivalled opportunity to retain and grow hydro-centric skills in project management, site management, engineering and general trade skills that will provide for an upskilled workforce. Hydro Tasmania has taken steps to ensure that its own people are working in key roles within the Tungatinah Modernisation Project team to foster learning opportunities.
- <u>Contract Risk Management.</u> It is important to select the right procurement strategy for all major works packages based on a project risk assessment such that Hydro Tasmania can determine which risks that it wants to retain and which of those to be subcontracted out. This culminated in the right level of procurement oversight to deliver the required outcome while demonstrating value for money for the procured service.
- <u>Environmental Oil Loss.</u> Elimination of the environmental exposure due to Turbine guide bearing oil loss through the development and replacement of a water lubricated hydro static design for the new bearing.
- <u>Local Economy.</u> Use of local (Tasmania) service providers when practical to improve the state economy and support development of local skills for major works projects.

3.2 Reasons for Success

- Project adequately resourced at an early stage so that key personnel available to contribute and influence works planning providing continuity to end of implementation.
- Key resource continuity (eg. Project Manager, some engineering personnel) ensured effective knowledge transfer when transitioning between each unit Modernisation.

- Thorough post implementation review after each unit upgrade to identify the lessons learnt and application of those lessons into works planning and implementation for the following unit.
- With increasing knowledge gain, continuous improvement of works planning and implementation documentation and procedures.

4. Points of Application for Future Project

Continue to ensure that front end engineering and planning is sufficiently robust to influence the project in a positive way. Populate the project team with as many Hydro Tasmania employees as possible for the purposes of hydro-skills knowledge management.

5. Others (monitoring, ex-post evaluation, etc.)

Financial evaluation for first Modernization at Unit 5 resulted in a slightly higher Internal Rate of Return (IRR) of 13.1% achieved against 12.8% predicted. Similar financial analysis to be completed for Unit 1 & Unit 2 with expectation of a similar performance outcome.

6. Further Information

6.1 Reference

1. Tungatinah Modernisation, Patrick Reynolds, Hydropower & Dams Journal, December 2010;
2. Time for Tungatinah, Patrick Reynolds, International Water Power and Dam Construction, January 2012; and
3. Local television news story, ABC Television, Reporter Emily Bryant, February 2012.

6.2 Inquiries

Company name: Hydro Tasmania
URL: http://www.hydro.com.au/

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset management, strategic asset management and life-cycle cost analysis.

Sub: 1-b) Investment incentives (Feed-in-Tariff (FIT), Renewable Portfolio Standard (RPS), subsidies, financial assistance, tax deductions, etc.)

1-c) Integrated management of water resources and river systems

1-f) Environmental conservation and improvement

2-a) Technological innovation & development expansion of electro/mechanical (E/M) equipment

Project Name:

Benmore Refurbishment Project

Name of Country (including State/Prefecture):

North Otago, New Zealand

Implementing Agency/Organization:

Meridian Energy

Implementing Period:

2007 – 2012

Trigger Causes for Renewal and Upgrade:

(A)Degradation due to ageing and recurrence of malfunction

(C) Needs for higher performance

(D) Needs for safety improvement

(E) Needs due to third party factors

Keywords:

Powerplant equipment replacement and upgrade,

Improvements to grid injection point configuration

Abstract:

Benmore Power Station is a valued asset within the Waitaki Chain of hydropower stations, providing around 17% of the energy delivered from Meridian’s portfolio. Moreover, the station ensures hydrologic flexibility for Aviemore and the other Waitaki power stations and provides essential support services for the operation of the HVDC link between the South and North Island. Reduction in the station performance would not only decrease energy output, but also the ability to transfer energy to the North Island.

Benmore PS was commissioned in 1965 and several of the essential operating systems were nearing the end of their design/operating life. Significant risks and opportunities were identified during an engineering risk review of the station in 2003. Technical studies were completed to derive the optimum scope of work to address the risks at minimum costs, taking into account cost benefit and Meridian's long term objectives. The scope of work included:

- Replacement of the turbine runners
- Part replacement of the excitation system and automatic voltage regulators to eliminate the possibility of extended forced outages and enhance system performance;
- Reconfiguration of the grid input injection to eliminate transmission constraints, reduce transmission charges and provide a medium term solution for essential spares.

1. Outline of the Project (before Renewal/Upgrading)

The Benmore Power Station, shown in the photo below is located on the Waitaki River. The station comprises six 90MW generating units and was built to provide power to the North Island via the HVDC line. It is New Zealand's second largest 100% renewable electricity generation facility.

The Waitaki River hydropower development scheme is made up of eight hydro stations on the Waitaki River, as noted in Figure 1 and Table 1:

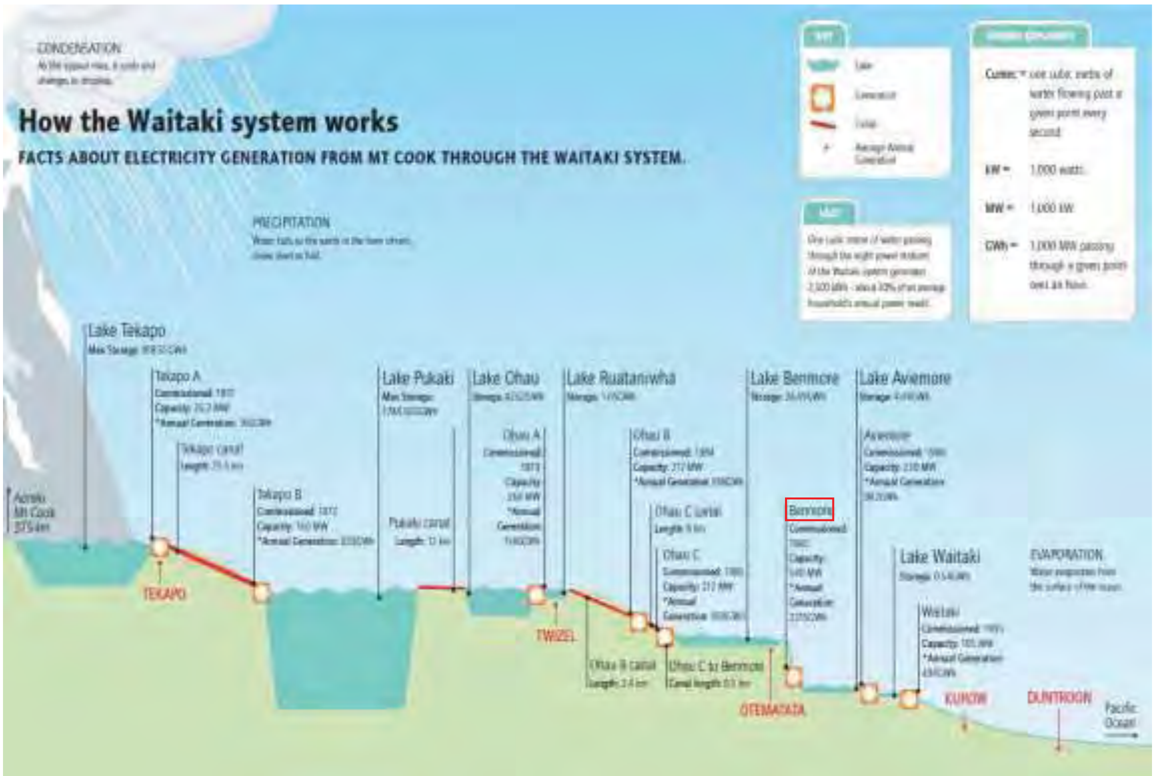


Fig. 1 Waitaki River Hydropower Development

The Benmore Hydro Plant provides hydrologic flexibility to the downstream Aviemore and Waitaki plants and essential support services for the operation of the HVDC link, in addition to its significant contribution to energy output,. Following an engineering study, Meridian Energy's Asset Management process identified a program of required refurbishment, comprising the following scope of work:

- Modernization of the local services equipment to improve safety and reliability
- The addition of three new 225MVA interconnection transformers and subsequent changes to the network or grid injection point configuration
- Installation of new turbine runners, new excitation systems and a full mechanical overhaul of each of the six generating units.

Hydropower Generating Asset	**Generating Capacity**	**Owner**
Waitaki	90[1] MW	Meridian Energy
Aviemore	220 MW	Meridian Energy
Benmore	540 MW	Meridian Energy
Ohau C	212 MW	Meridian Energy
Ohau B	212 MW	Meridian Energy
Ohau A	264 MW	Meridian Energy
Tekapo B	160 MW	Genesis
Tekapo A	25 MW	Genesis
Total Waitaki Chain	**1723 MW**	

Table 1 Hydropower Assets in Waitaki River System

2. Description of the Renewal and Upgrading Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

There are a number of Main and Secondary trigger causes that drove the renewal and upgrading of Benmore Power Station. Three examples are provided.

(i) Conditions, Performance and Risk Exposure and Others

(A)-(a) Degradation due to ageing and recurrence of malfunction – Improvement of efficiency

Existing runners suffered cavitation and overtime successive runner repairs led to degradation of runner efficiency

(ii) Opportunities to Increase Value

(C)-(a) Needs for higher performance-Addition of units, Expansion of power & energy

New runners, excitation systems and mechanical overhaul

Runner Upgrade

Efficiency test results indicated that efficiencies of the original turbine runners had dropped 3% since commissioning, mainly due to profile changes from repeated cavitation repairs (Figure 2).

[1] Waitaki reduced from 105 MW installed capacity to 90 MW available capacity after wicket gate bush seizure on Unit 3 in 1998

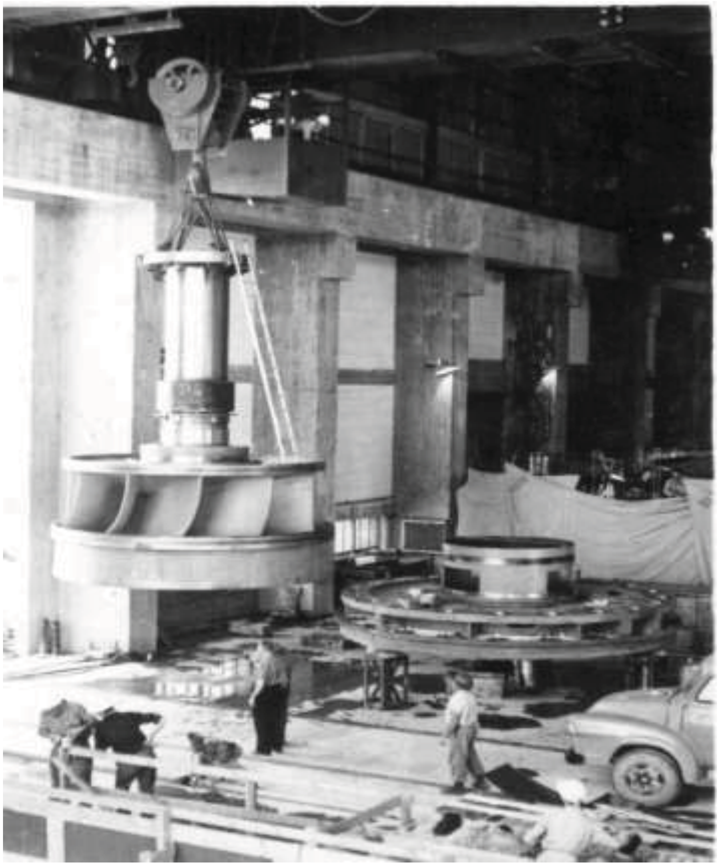


Fig. 2 Installation of G1 Turbine in 1963

The opportunity to regain this lost efficiency and gain an incremental increase through the replacement of the runners and other equipment was confirmed following CFD analysis and model testing An additional benefit was the long term reduction of maintenance effort, outage time to repair and cost in cavitation repairs. The work included the installation of new turbine runners (Figure 3), new wicket gates, new generator excitation & AVR systems and a full mechanical overhaul of each of the six generating units.

Fig. 3 New Runner for Benmore PS

(E)-(a) Needs due to third party factors-Sustainable operation (sometimes accompanied by power reduction)

Grid Injection Point Configuration Improvements

The existing 16kV air blast Circuit Breakers provided critical protection but were reaching end of life, resulting in reduced reliability. This affected plant availability and also posed significant risks to the grid operator's Transpower's transformers and associated equipment. Changes to Transpower's plans to replace a HVDC Pole would constrain station output without modification to the grid input configuration. Renewal included the addition of three new 225MVA interconnection transformers and subsequent changes to the grid injection point configuration

(D)-(a) Needs for safety improvement-Meet all safety, regulatory and operational compliance requirements

Safety Improvements

The lack of diversity and segregation of essential local supply presented a significant risk of local outages. As equipment needed to be maintained in a live state, this posed a major health and safety risk. The remedial work included a complete modernization of the local services equipment to improve safety and reliability.

The refurbishment also mitigated the risk of catastrophic equipment failure which has the potential to cause substantial secondary damage to associated plant and pose a risk to operations and maintenance staff

(iii) Market Requirements

(None)

2.2 Process to Identify and Define Renewal and Upgrade Work Measures

An engineering risk review of the station identified that several of the essential operating systems at the Benmore PS were nearing the end of their design/operating life and significant risks and opportunities were identified. The ensuing investigations and remnant life assessments identified components of the generation plant that:

- Pose a significant health and safety risk.
- Have failed, in respect to no longer operating within the original design performance parameters.
- Have reached the end of their supportable economic life, or are due to within the next few years.
- Have the potential to cause a substantial impact on revenue through reduction in plant and HVDC availability.

Technical and commercial analysis of the various refurbishment options were completed to derive the optimum scope and timing of work to maximize the benefit from the investment and ensure an appropriate fit with Meridian's long term corporate goals and strategies. The deteriorated state of the runners and 16kV circuit breakers, obsolescence and ongoing maintenance of compliance of the excitation system and the health and safety issues surrounding the local service electrical supply system drove the need for a major plant refurbishment. The scope also included the reconfiguration of the stations grid injection point to avoid limiting the output of the station from 540MW to 360MW as a result of the planned replacement of the HVDC pole #1.

The business case was approved by the Board in December 2005 and following a 21-month period of planning, design, contract negotiations and procurement activities, physical works started on site in September 2007 and was completed in 2010.

2.3 Description of Work Undertaken (detail)

The work undertaken for the implementation of the Benmore PS refurbishment project addressed critical risks and economic opportunities:

Turbine Runners – Efficiency test results had demonstrated that turbine hydraulic efficiency has fallen significantly since commissioning due to runner profile changes as a result of repeated cavitation repairs. An opportunity was also identified to further improve station efficiency over and above the original design. This gain was confirmed following CFD analysis and model testing. Replacing the runners also eliminated the maintenance burden from ongoing cavitation repair.

16 kV Circuit Breakers (CB) & Grid Injection – The 16 kV CBs were nearing the end of their life. Forced outages became both more frequent and more severe and presented a significant risk to plant, personnel and station availability. The deteriorating condition and reliability of the CBs also posed a significant risk to the Transpower owned interconnection and converter transformers and associated equipment. Furthermore, Transpower’s plans to replace Pole 1 of the HVDC by 2010 would have constrained station output to four units if the existing grid input configuration had not been modified.

Excitation & Automatic Voltage Regulation – The excitation system suffered from age related faults and required increasing maintenance efforts. The equipment was based on 1950’s technology, which is no longer supported, and future failures were expected to cause protracted unit outages due to the reduced availability of spare parts and maintenance expertise. The increasing number of stop/starts, based on new market requirements, was also expected to escalate the rate of deterioration. Maintaining power quality and compliance with Electricity Governance Rules (EGR’s) had become increasingly difficult and opportunities existed to improve voltage support performance and reduce synchronizing time with modern equipment;

Mechanical Refurbishment – In the late 1990s, Units 2, 3 & 6 underwent a mechanical refurbishment to address the deteriorated state of critical plant. The remaining three units were refurbished to maintain target levels of station availability and minimize lifecycle O&M costs

3.3kV and 415V Local Service Supplies – The lack of diversity and segregation of the essential supplies presented a significant risk of multiple-unit or even whole-of-station forced outage, particularly as the component parts were reaching their end of life.

1-b) Investment incentives (Feed-in-Tariff (FIT), Renewable Portfolio Standard (RPS), subsidies, financial assistance, tax deductions, etc.)

There are no specific investment incentives for renewable energy in New Zealand. However, there is consideration of an emerging renewable energy market. Work undertaken for the refurbishment of the Benmore PS will provide an important future role in that market included:

- Strengthening the HVDC link to the North Island
- Improving the performance & flexibility of systems, including a larger stable operating range with the new runners, and improved voltage stability and start times with new excitation
- Increase energy generated achieved through turbine efficiency improvements

1-c) Integrated management of water resources and river systems

Benmore PS is situated in the middle of the chain of hydroplants on the Waitaki River. Storage in Lake Benmore and generation flows through the Benmore PS provides hydrologic flexibility for the downstream Aviemore and Waitaki power stations.

1-d) Asset management, strategic asset management and life-cycle cost analysis

The project was identified as an outcome of Meridian Energy’s strategic asset management planning process. A risk management framework was used to prepare a ranked list of risks that required mitigation, including opportunities to enhance the portfolio. Specific asset management objectives included:

- Changes that ensured plant performance targets can be maintained or enhanced through the replacement of aging assets and/or reconfiguration to provide segregation and diversification of critical systems
- Changes to ensure future compatibility with Transpower’s proposed HVDC upgrades
- Support to extend the operational life of Benmore PS for a further 40 years
- Ensuring that life cycle costs are minimized by avoiding escalating maintenance requirements and costs and minimizing the revenue earning impact due to reduced reliability of ageing assets

Specific risk management objectives included:

- Mitigating catastrophic equipment failure risk and the potential for substantial collateral damage to associated plant and the ensuing risk to operations and maintenance staff
- Avoiding any long-term plant unavailability while parts are being procured or where repairs to obsolete equipment are required.
- Ensuring plant remains compliant with legislative and regulatory requirements
- Avoiding stranding the assets and constraining generation due to a failure of either pole 1 or the interconnecting converter transformers
- Avoiding constraining the HVDC as a result of multiple unit outages due to plant and local service failures

1-f) Environmental conservation and improvement

Support for Local Business.

Supporting local businesses is an important component of Meridian's sustainability strategy and Meridian in turn is equally dependent on the viability, capability and innovations that are brought to bear by local businesses. Meridian's close relationship with a range of partners was integral to their ability to design and execute this major capital project efficiently and safely. Nearly 40% of the project budget was allocated to major equipment sourced from overseas, including new turbine runners and transformers, with the balance spread across approximately 60 separate contracts principally with New Zealand contractors and design consultants.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Innovation was encouraged over the course of the project, and supported by strong contractor relationships. A particular highlight was the construction of a purpose-built mobile site-installed distributor machining tool, substantially reducing time, cost and potential risk.

3. Feature of the Project

3.1 Best Practice Components

Asset Management and Risk Management. The project was identified as an outcome of Meridian Energy's strategic asset management planning process. A risk management framework was used to prepare a ranked list of risks that required mitigation and opportunities to enhance the value of the assets

Utility Partnerships. This project was an opportunity for Meridian and Transpower, the grid owner & operator, to work very closely together, particularly following the decision to decommission one HVDC pole. This required Meridian to review its planned scope of work in regard to the grid injection point upgrade as part of the Benmore Refurbishment Project and bring forward a new and additional capital project, the Benmore Final [Electrical] Configuration Project.

Contract Risk Management. Meridian leveraged the strong working relationships fostered through previous refurbishment projects, engaging key contractors early to ensure schedules of work based on pre-outage inspections had been accurately scoped and priced. While this required a longer than normal planning and negotiating timeframe, it delivered substantial benefits during the execution of the work, with no impacts on cost, scope or the work program. This was a major achievement given the high level of uncertainty inherent in work of this kind.

3.2 Reason for Success

The primary reasons for the success of the Benmore PS Refurbishment Project are based on adopting the best practices mentioned above. This resulted in a project considered to be a huge success, delivered on-time and more than10% below budget, despite significant commodity price increases. In terms of safety, over 180,000 man-hours were worked with no lost-time injuries. Importantly the new turbine runners delivered an increase in efficiency which equates to approximately 70 GWh per year of additional energy, while using no additional water. (Figure 4)

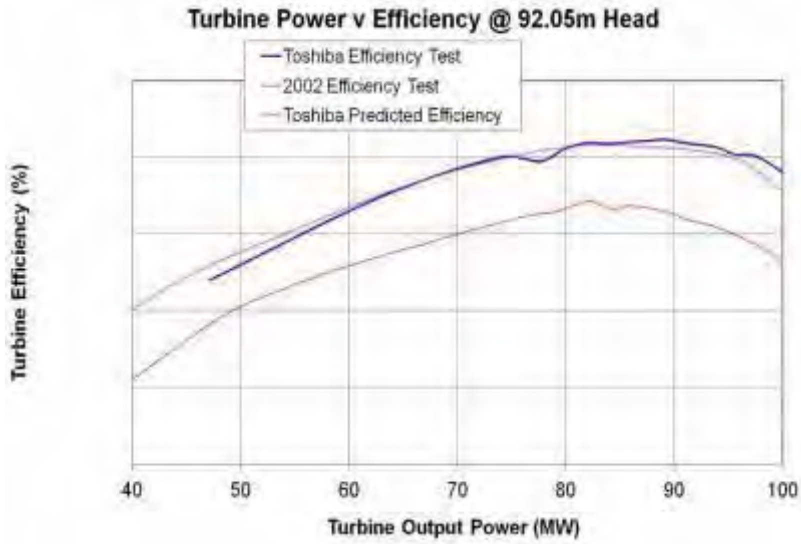


Figure 4: Turbine Efficiency Relationships

4. Points of Application for Future Project

It is Meridians policy to use lessons learned from previous projects as an important step in assessing and implementing future projects. This covers all aspects of the project including technical, environmental and social, project and contract management. With the overall success of the Benmore PS refurbishment project, many points of application will be adopted for future projects. Among the most important of these will be:

- Ensure a rigorous asset and risk management process is used to identify and define the scope of the refurbishment project
- Optimize the timing of all refurbishment initiatives to avoid duplication of costs and impact on station availability
- Schedule works within an optimized time frame that balances expenditure with costs of reduced plant performance
- Align the specific requirements of asset refurbishment with the overall asset portfolio strategy
- Continue to build the capability of Meridian staff in all matters of refurbishment

5. Others (monitoring, ex-post evaluation, etc.)

All project parameters, including condition, risk and plant performance are monitored, stored and analyzed regularly as part of the asset management process. This information is used as the basis of ongoing maintenance activities and future refurbishment work.

6. Further Information

6.1 Reference

1) Hydro Power Engineering Exchange (HPEE) Conference, August 2014, Hobart, Tasmania
2) Electrical Engineers Association (EEA) Conference, June 2014, Auckland, New Zealand

6.2 Inquiries

Company name: Meridian Energy Ltd
URL: https://www.meridianenergy.co.nz/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset management, strategic asset management and life-cycle cost analysis.

Sub: 1-c) Integrated management of water resources and river systems

1-f) Environmental conservation and improvement

2-b) System and Reliability improvements in Protection & Control (P&C)

2-c) Technology innovation, deployment expansion and new materials used for civil and building works

Project Name:

Waitaki Hydro Power Station Refurbishment

Name of Country (including State/Prefecture):

North Otago, New Zealand

Implementing Agency/Organization:

Meridian Energy Ltd

Implementing Period:

2013 – 2017

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction

(D) Needs for safety improvement

(E) Needs due to third party factors

Keywords:

Ageing dam,
Powerhouse and power plant equipment,
Seismic upgrade,
Reliable operation to meet flow consents

Abstract:

The Waitaki hydropower station on the Waitaki River is over 80years old with a large proportion of its turbine & generator plant original and exhibiting key indicators of end-of-life. This spurred a whole-of-asset review commencing in 2008 of all generation plant and assets. This review at Waitaki included a full asset condition, performance and risk assessment leading to scope definition and funding approval for a comprehensive refurbishment project. The scope of work included:

- Dam & powerhouse upgrades
- Sluice pier civil repairs
- South riverbank civil repairs

- Sluice gate rails & wheels
- Generator electrical protection upgrade
- Generator fire suppression upgrade
- Crane(s) upgrade & refurbishment
- Intake screen replacement
- Recommissioning Unit 3

1. Outline of the Project (before Renewal/Upgrading)

Waitaki power station (circa 1934) is the original and downstream hydropower project on the Waitaki River, South Island, New Zealand. It comprises eight hydropower stations, of which Meridian owns and operates six, and Genesis two (see Figure 1 and Table 1).

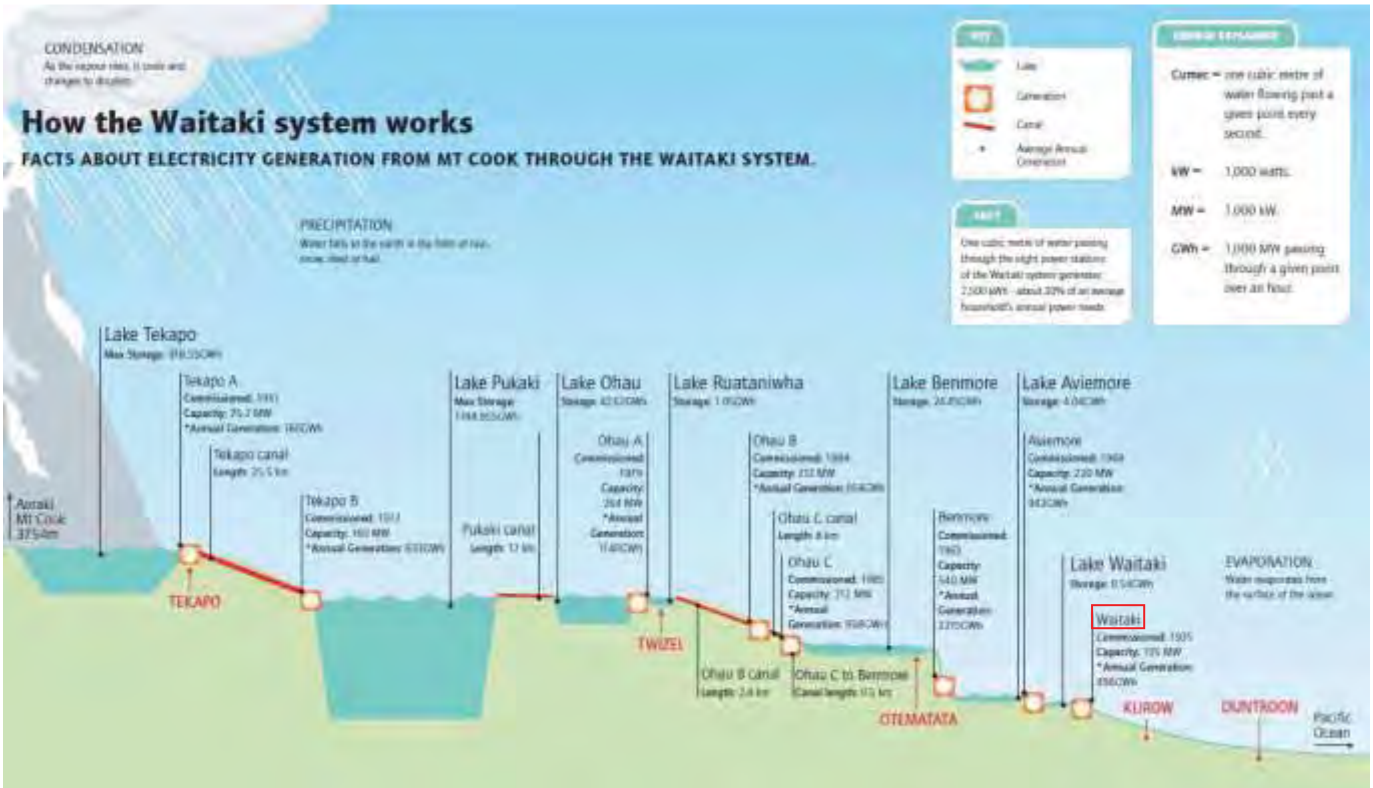


Fig. 1 Waitaki River Hydropower Development

Hydropower Generating Asset	**Generating Capacity**	**Owner**
Waitaki	90[1] MW	*Meridian Energy*
Aviemore	220 MW	Meridian Energy
Benmore	540 MW	Meridian Energy
Ohau C	212 MW	Meridian Energy
Ohau B	212 MW	Meridian Energy
Ohau A	264 MW	Meridian Energy
Tekapo B	160 MW	Genesis
Tekapo A	25 MW	Genesis
Total Waitaki Chain	**1723 MW**	

Table 1 Hydropower Assets in the Waitaki System

[1] Waitaki reduced from 105 MW installed capacity to 90 MW available capacity after wicket gate bush seizure on Unit 3 in 1998

Waitaki was constructed by manual labour as a “make work” project during the 1930’s Depression, with the first unit commissioned in 1934. It was the last major construction activity in New Zealand using manual pick & shovel methods without modern earthmoving and construction equipment. The project comprises a concrete arch, overspill weir gravity dam and power station. Waitaki generates approximately 490 GWh annually from its present complement of six hydro generating units.

Figure 2 provides key information along with the powerhouse construction history and generating capacity increases since original construction.

Figure 2. Key Features of the Waitaki Power Station

Prior to the construction of the other hydropower, dam and other water control facilities upstream of Waitaki power station, generation output was paramount at Waitaki; which is why generating capacity increased at Waitaki since original construction up until the late 1950’s.

The present operation of the Waitaki project is to smooth flow variations in the lower Waitaki River by maintaining flow downstream of the dam at levels above the resource consented minimum. It also controls the rate of change of flow discharges from Waitaki within consented limits.

Two Waitaki generating units are required to be in service at all times to meet the normal minimum consented flow. The average flow through Waitaki power station is approximately 360m3/s, equivalent to discharge through four generating units. With the current six unit capacity, the 5th and 6th units are used infrequently and typically at times of high inflows or high electricity demand. During an average year, four generating units are in service approximately 70 – 85% of the time.

The history of the main turbine and generator equipment is given in Table 2.

Waitaki Generator Unit	Turbine Type & Details	Generator Details
1,2	Commissioned 1934. Francis design, 21.3m design net head, slightly larger runner throat diameter than Units 5, 6 & 7. Nominal flow 95 m3/sec at design output. Turbine manufacturer Boving.	15 MW nominal maximum output. Guide bearing above & below rotor. Air cooled generator. Generator manufacturer: English Electric.
3,4	Commissioned 1940 & 1947 respectively. Mixed flow propeller design (Francis blades, no traditional runner "band"), 21.3m design net head, 95 m3/sec nominal flow at design output. Turbine manufacturer: English Electric	15 MW nominal maximum output. Traditional umbrella design with a guide bearing below rotor. Air / water cooled generator. Generator manufacturer: English Electric.
5,6,7	Commissioned 1940 & 1947 respectively. Francis design, 21.3m design net head, slightly smaller runner throat diameter than Units 1 & 2. Nominal flow 95 m3/sec at design output. Turbine manufacturer Boving.	Identical to Units 3,4

Table 2. Key Turbine & Generator Parameters of the Waitaki Plant

2. Description of the Renewal and Upgrading Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

Waitaki Dam and Power Station has a number of areas that provide examples of ageing infrastructure and equipment. Single examples will be provided for each trigger cause.

(i) Conditions, Performance and Risk Exposure and Others

Main Trigger Cause

(A)-(b) Degradation due to ageing and recurrence of malfunction – Improvement of durability and safety

Refurbishment of generation assets

Generator stator condition was evaluated as very poor across all generators, which were considered at end of life. Work was carried out in 1991 to extend the remaining life of Units 3-7 generator stators by injecting resin into the stator winding insulation. This did a remarkable job, well exceeding the estimated 10 years life extension. Unit 1 & 2 stator windings were replaced in the late 1970's and early 1980's, and are also in a relatively poor condition.

If damage occurs to Units 3-7 stator windings; repairs are unlikely to be practical as the resin injection process has encased the stator windings and stator core into one hard resin encapsulated block. Based on engineering assessments, stator winding insulation failure is the key failure mode for the turbines & generators and any future stator failure on one unit could well mean that the remaining stators are likely to fail in close succession.

(ii) Opportunities to Increase Value

Secondary Trigger Cause(1)

(D)-(a) Needs for safety improvement – Improvement of safety

Dam and powerhouse structural safety enhancement

An assessment made of the Waitaki powerhouse seismic structural risks indicated that the powerhouse downstream columns, powerhouse roof trusses and props between the powerhouse and intake dam would be prone to failure as a result of a significant earthquake. Figure 3 shows a typical cross section through Waitaki power station. Three dimensional dynamic structural seismic modelling has been undertaken to establish the extent of seismic strengthening and it has been shown that relatively minimal work will be required to ensure the power station will not collapse as a result of an event having an annual exceedance probability of 1 in 2500.

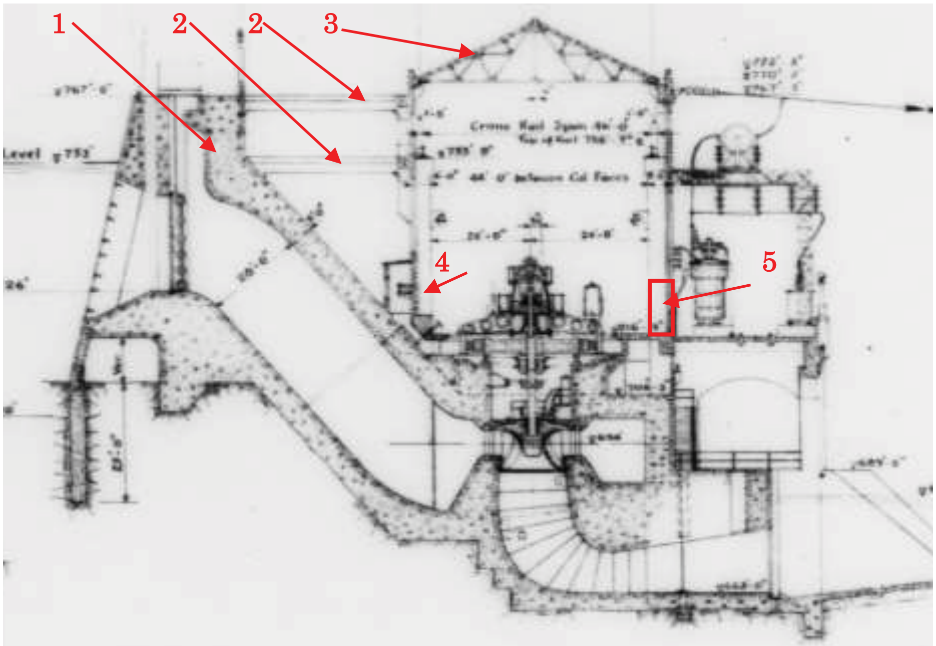


Figure 3. Typical Cross-Section through Waitaki Power Station

Key:

1. Intake dam – seismically acceptable
2. Reinforced concrete props between powerhouse columns and intake dam – the connections between the dam and powerhouse are seismically deficient
3. Powerhouse steel roof trusses – seismically deficient
4. Powerhouse reinforced concrete columns, upstream side – seismically acceptable
5. Powerhouse reinforced concrete columns, downstream side – the bottom 2-3m of the columns as indicated by the red box are seismically deficient

At the time of writing (March 2014), further seismic modeling is underway to confirm the adequacy of the identified deficient areas and required remedial works.

A detailed structural safety evaluation of the dam confirmed good performance of the dam in seismic events. Opportunities were identified to maintain access to the dam galleries following a significant event, which would allow for improved long-term management of uplift drains

Secondary Trigger Cause (2)

(E)-(a) Needs due to third party factors-Sustainable operation

Unit operation to meet required consents for riparian flows and ramping rates

Waitaki power station smoothes flow variations in the lower Waitaki River to meet resource consents. These include "environmentally permitted" requirements for minimum flow and ramping rates, and are achieved by operating the reservoir and the unit outflows to buffer inflow variations from upstream power plants. Reliable performance at Waitaki allows the upstream power plants to be operated flexibly to meet market requirements, manage storage and maximize revenues from generation. To achieve the required level of reliability, at least two Waitaki generating units must be in service at all times.

(iii) Market Requirements

(None)

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

As part of the Waitaki Refurbishment project studies, all assets, including engineering disciplines, operational & environmental impacts and potential impacts to third parties were assessed. A prefeasibility study and subsequent feasibility study were carried out to develop a robust business case and obtain funding approval to proceed with the remedial works.

To provide scope & cost certainty for some of the more complex and unique remedial works, a form of Early Contractor Involvement (ECI) with expert & practical contractors was used to develop practical solutions and provide realistic cost estimates.

During the prefeasibility and feasibility process, frequent communication was undertaken around the business & with management to ensure "no surprises" and the project objectives were appropriate. Also during the prefeasibility and feasibility process, opportunities were also assessed that would offer benefits to Meridian. The prefeasibility and feasibility process took approximately three years to complete. The process to determine project scope was based on prioritizing "must-do" work activities, such as:

- Dam & powerhouse upgrades
- Sluice pier civil repairs
- South riverbank civil repairs
- Sluice gate rails & wheels
- Generator electrical protection upgrade
- Generator fire suppression upgrade
- Crane(s) upgrade & refurbishment
- Intake screen replacement
- Road intersection upgrade

Turbine & generator upgrades were identified as a means to address end-of-life issues and also offer additional generated energy benefits, but they come at high costs. Based on the situation at Waitaki where "spare" generation capacity is normally available (typically four units are in service 70-85% of time compared to the six unit capability), alternatives were considered. Following technical and economic assessment, it was decided to further increase available generating capacity by returning Unit 3 to service. This would bring Waitaki back to its full complement of 105 MW from seven generating units. It was reasoned that recommissioning Unit 3 will:

- Provide sufficient generation capacity to cater for generator stator or other unit related failure and provide an acceptable risk to Meridian
- Defer the high cost of turbine & generator upgrades

As part of this approach, all Waitaki generating units will be maintained as per usual, but will be operated on a run-to failure basis. However, it is clearly noted that this approach is only considered viable at Waitaki due to its additional available generating capacity, and that Meridian does not operate the remainder of its hydro portfolio or wind portfolio in this manner. Note also that additional risk mitigation works would be undertaken to minimize the consequential impact of a generator stator failure, this being the likely event that will initiate the replacement of the generating units. These works include fire protection and electrical protection upgrades.

Funding approval was obtained in December 2012. The detailed design, procurement and physical remedial works is anticipated to take approximately four years to complete, starting in early 2013 with a number of work packages already underway. Scheduled completion is 2017.

2.3 Description of Work Undertaken (detail)

Key Considerations Made During Planning

Prefeasibility and feasibility studies identified and defined issues and risks, the scope of work and costs of mitigation, and prepared an economic analysis of various options. This covered all the assets at Waitaki, and risks associated with technical, operational & environmental issues, including those that could affect external parties. Sufficient scope & cost certainty of the more complex and unique risks was provided to enable a robust business case to be developed for funding approval. For some work packages, this included Early Contractor Involvement (ECI) with experienced contractors to develop practical solutions and provide realistic cost estimates.

During the process, frequent communication was undertaken around the business and with management to ensure "no surprises" and the project objectives were appropriate. Also opportunities were assessed that would offer benefits to Meridian. The three year process involved considerable input from internal Meridian engineering, asset management & operational staff, in addition to external consultants and contractors. Detailed seismic modeling was also undertaken for the dam and power house structure.

The project scope was developed on the basis of managing the key risks and issues that could affect Waitaki's ability to provide ongoing reliable hydropower generation and provide safe and reliable control of the downstream river (as Waitaki power station is the most downstream hydropower & water control facility on the Waitaki River). These include:

- **Dam seismic withstand capability.** A recent safety evaluation confirmed that the dam and appurtenant structures could withstand a maximum credible earthquake (MCE) without fail. However there were identified improvements that could be made to limit the impact and effects of the MCE.

- **Sluice gate rails & wheels.** The sluice gates are required for post-earthquake conditions to dewater the lake for emergency reasons, and the existing sluice gate rails and wheels are likely to be damaged by a significant earthquake

- **Powerhouse seismic withstand.** The powerhouse was assessed as seismically deficient in a 1 in 2500 annual exceedance probablility (AEP) event

- **South riverbank erosion.** The riverbank is presently eroded and poses risks to the switchyard in the event of major spillway discharges and flood events

- **Sluice pier damage.** The area downstream of the sluice gates is eroded and has undermined the concrete pier. This limits sluice gate operation.

- **Power station ancillary equipment.** Much ancillary equipment is either end-of-life or non-compliant, including health and safety hazards that must be addressed

- **Generating units.** All units are in poor condition and at or near end-of-life with uncertainly concerning ability to continue to operate reliably. The key failure mode(s) has been identified as stator insulation failure on the non-resin injected Units 1 and 2 and on Units 3 to 7 failure of the resin injected stator insulation.

Turbine & generator upgrades to mitigate identified risks also offered additional generated energy benefits, but came at high costs. Whilst Waitaki has "spare" generation capacity (typically four units produce more than 80% of the annual revenue), it is planned to further increase available generating capacity by returning the failed Unit 3 to service. This will bring Waitaki back to its full complement of 105 MW from seven generating units.

The justification for re-commissioning Unit 3 is to create additional generation capacity that caters for the potential of a generator stator or other unit related failure on the six currently in-service units. This will effectively enable Meridian to defer the high cost turbine & generator upgrades planned to mitigate risks on the original turbine & generator plant. However, to ensure that any potential unit failure is contained to one unit, and has minimal resultant damage to and inside the powerhouse; generator electrical protection upgrades and generator fire suppression upgrades are planned along with cleaning the stators of air cooled Units 1,2 which have a significant amount of oily accumulated debris on the stator core & windings, acting as a fire fuel source . As stated above, the key identified generating unit failure risk is generator stator insulation failure, and any single generator stator insulation failure are likely to be followed in close succession by other similar failures on other units.

Analysis indicates that the ability to defer the anticipated generator & turbine upgrades by at least four to five years will provide significant economic benefits. However, it is noted that any generating unit failure that is time consuming or expensive to repair will trigger turbine & generator upgrades, subject to an economic assessment and business case.

When generating unit upgrades are implemented; all seven generating units are unlikely to be upgraded as on average four units are operating 70-85% of the time. Hence four units at this stage would be proposed to be upgraded. If there are no significant generating unit failures within four to five years, the economics and business case for generator & turbine upgrades will be revisited.

1-c) Integrated management of water resources and river systems

Waitaki power station smoothes flow variations in the lower Waitaki River to meet resource consents. These include “environmentally permitted” requirements for minimum flow and ramping rates, and are achieved by operating the reservoir and the unit outflows to buffer inflow variations from upstream power plants. Reliable performance at Waitaki allows the upstream power plants to be operated flexibly to meet market requirements, manage storage and maximize revenues from generation. To achieve the required level of reliability, at least two Waitaki generating units must be in service at all times. (The description above is somewhat different from the point in the corresponding key point.)

1-d) Asset management, strategic asset management and life-cycle cost analysis

The project is a major, whole-of-asset refurbishment at the 80 year old Waitaki hydroelectric power station. Much of the turbine & generator plant at Waitaki is original and is exhibiting key indicators of end-of-life. A strategic asset review determined issues & risks to continued electricity generation from and conversely what opportunities are available, what work is required to mitigate these issues and risks and their associated costs. A life-cycle cost analysis provided input to the business case covering risk management, economics, and operational aspects to proceed with remedial works.

1-f) Environmental conservation and improvement

The Waitaki project is integral for the downstream management of the river (minimum flows and ramping rates) as noted under 1-c above

2-b) System and Reliability Improvements in Protection & Control (P&C)

The existing generator electrical protection relays were installed early 1990s and comprise electronic devices, which are currently operating satisfactorily and comply with Code. However industry guidelines suggest they would benefit from being replaced with modern duplicate digital electronic protection systems which would also offer the benefit of very quickly clearing fault conditions from generators, thus minimizing damage that may occur to the already delicate stator windings.

2-c) Technology innovation, deployment expansion and new materials used for civil and building works

The existing generator CO2 gas flood fire suppression system will operate, but may not prevent significant damage. Meridian has been upgrading all hydropower generators by replacing these with Inergen gas flood suppression & enhanced smoke detection systems, and these will be installed on all Waitaki units.

3. Feature of the Project

3.1 Best Practice Components

Asset Management and Risk Management. The project was identified as an outcome of Meridian Energy's strategic asset management planning process. The project scope was developed on the basis of managing the key risks and issues that could affect Waitaki's ability to provide ongoing reliable hydropower generation and provide safe and reliable control of the downstream river (as Waitaki power station is the most downstream hydropower & water control facility on the Waitaki River).

Structural Safety Review. Meridian has undertaken a rigorous structural safety review process for Waitaki dam that has been peer reviewed by international experts. The outcome of the assessment has concluded that the dam will competently withstand a Maximum Credible Earthquake for the site, or a Probable Maximum Flood event, without failure or uncontrolled release of the reservoir. These are the same load conditions and safety criteria that would apply to a new dam constructed on the same site.

Seismic modeling was also undertaken for the dam and power house structure and necessary remedial work is included in the refurbishment plan.

Alternative to Costly Unit Upgrades. Turbine & generator upgrades were identified as a means to address end-of-life issues and also offer additional generated energy benefits, but they come at high costs. Based on the situation at Waitaki where "spare" generation capacity is normally available, it was decided to further increase available generating capacity by returning Unit 3 to service. This would provide sufficient generation capacity to cater for generator stator or other unit related failure and provide an acceptable risk to Meridian and defer the high cost of turbine & generator upgrades

3.2 Reason for Success

The project is a major, whole-of-asset refurbishment at the 80 year old Waitaki hydroelectric power station. Much of the turbine & generator plant at Waitaki is original and is exhibiting key indicators of end-of-life. A strategic asset review determined issues & risks to continued electricity generation from and conversely what opportunities are available, what work is required to mitigate these issues and risks and their associated costs. A life-cycle cost analysis provided input to the business case covering risk management, economics, and operational aspects to proceed with remedial works.

4. Points of Application for Future Project

It is Meridians policy to use lessons learned from previous projects as an important step in assessing and implementing future projects. This covers all aspects of the project including technical, environmental and social, project and contract management. With the overall success of the Waitaki PS refurbishment project, many points of application will be adopted for future projects. Among the most important of these will be:

- Ensure a rigorous asset and risk management process is used to identify and define the scope of the refurbishment project

- Optimize the timing of all refurbishment initiatives to avoid duplication of costs and impact on station availability
- Schedule works within an optimized time frame that balances expenditure with costs of reduced plant performance
- Align the specific requirements of asset refurbishment with the overall asset portfolio strategy
- Continue to build the capability of Meridian staff in all matters of refurbishment

5. Others (monitoring, ex-post evaluation, etc.)

All project parameters, including condition, risk and plant performance are monitored, stored and analyzed regularly as part of the asset management process. This information is used as the basis of ongoing maintenance activities and future refurbishment work.

6. Further Information

6.1 Reference

1) Hydro Power Engineering Exchange (HPEE) Conference, August 2014, Hobart, Tasmania
2) Electrical Engineers Association (EEA) Conference, June 2014, Auckland, New Zealand

6.2 Inquiries

Company name: Meridian Energy Ltd.
URL : https://www.meridianenergy.co.nz/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – b) Investment incentives

Sub: 2 – a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Recovery Act: Installation of a Low Flow Unit at the Abiquiu Hydroelectric Facility

Name of Country (including State/Prefecture):

New Mexico, United States of America

Implementing Agency/Organization:

County of Los Alamos

Implementing Period:

November 2009 through March 2012

Trigger Causes for Renewal and Upgrade:

(C) Needs for higher performance(a)

Keywords:

low flow turbine, operational flexibility, powerhouse addition

Abstract:

This case study presents the results of a partially-DOE-funded hydropower modernization project to increase the power generation and efficiency of the Abiquiu hydroelectric facility in New Mexico, United States of America. Due to operational limitations at low flow conditions, power could not be generated reliably or efficiently during the winter months. The construction of a new powerhouse and installation of a new low flow turbine unit allowed the plant to significantly increase its generation through winter and provide additional flexibility year-round. The project was completed in March 2012 and increased the total capacity of the facility from 13.8 MW to 16.9 MW.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a powerhouse and low flow turbine-generator addition project funded in part by the Recovery Act (American Recovery and Reinvestment Act) through the DOE (Department of Energy) EERE (Office of Energy, Efficiency, and Renewable Energy) WWPP (Wind and Water Power Program).

The Abiquiu hydroelectric facility is located on the Rio Chama New Mexico, United States of America (36°14’17”N, 106°25’34”W), as shown in Fig. 1. The existing hydroelectric power plant (FERC No. 7396) began commercial operation in 1990 and is currently owned and managed by the County of Los Alamos, New Mexico. Prior to this project, the hydropower facility had two identical 6.9 MW Francis turbine-generators, with a total plant power generation capacity of 13.8 MW. The operating flow range prior to the project was between 250 and 1,300 cfs.

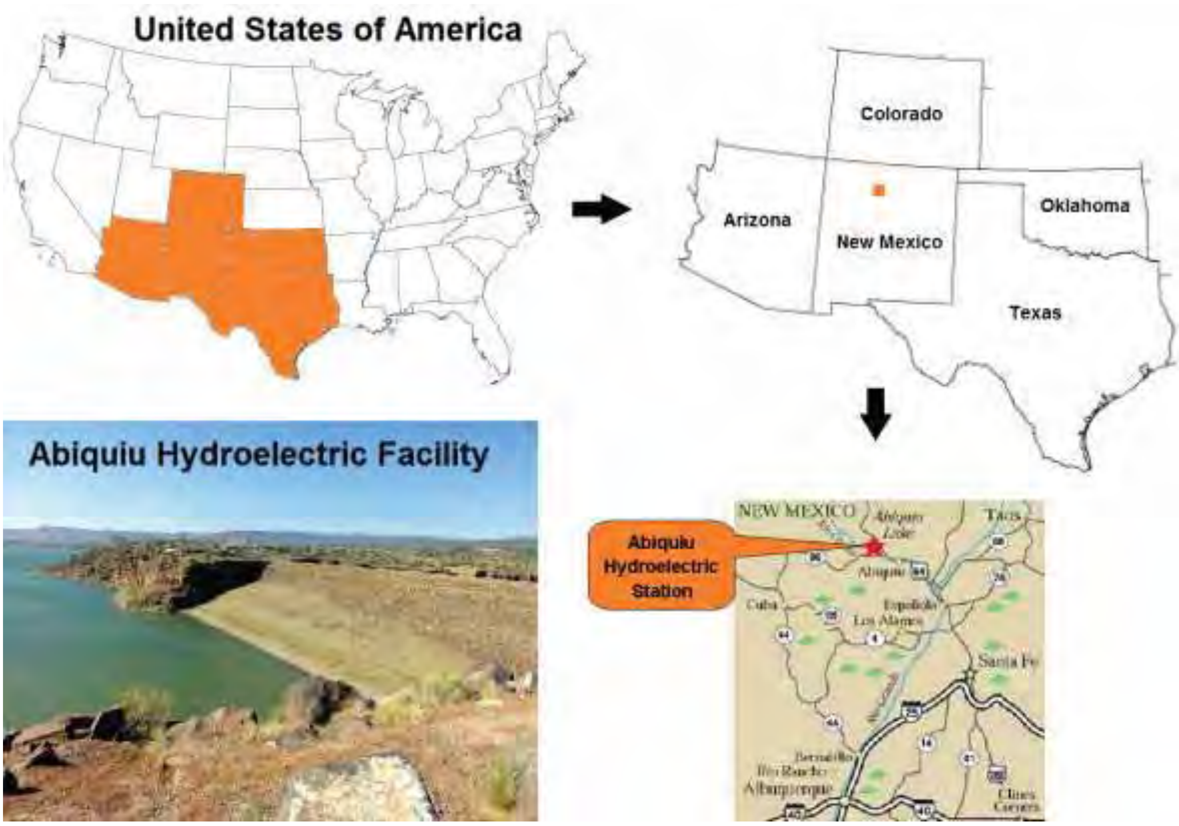


Fig. 1 Location of Abiquiu Hydroelectric Facility

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

During winter months and other times of low available flow, the plant’s old turbines were unable to operate efficiently, so a designated low flow turbine was desired. The DOE Funding Opportunity Announcement stated a goal of a 5% increase in plant energy generation.

(ii) Opportunities to Increase Value

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility's value through increased generation. Improved environmental performance was also a factor which could increase the project's value.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

The project was partially funded by the American Recovery and Reinvestment Act of 2009. The project period was November 1, 2009 through March 31, 2012. An Opening Ceremony was held on April 21, 2011 to celebrate the start up of the new low flow unit and the substantial completion of the project.

2.3 Description of Work Undertaken (detail)

1-b) Investment incentives

The project received a $4,558,344 Recovery Act grant from the Department of Energy's Wind and Water Power Program, representing a 49.4% cost share. This was leveraged with an equal amount from the private sector to fully fund the project. In addition to the substantial financial benefit, the project also received a secured interest rate of 3.0% which was considerably less than market rates at the time. The funding program, under DOE Funding Opportunity Announcement DE-FOA-0000120, aims to support the deployment of turbines and control technologies to increase and maximize system generation at existing non-Federal hydroelectric facilities without significant modifications to dams and with minimum regulatory delay. Improved environmental performance, efficiency, and quantity and quality of energy production were mentioned as key qualities of successful candidate projects.

Additionally, per the Energy Policy Act of 2005, all power generated from the installation of the low flow turbine-generator qualifies for Renewable Energy Credits (quantified as 1 MW-hour of power generated), which are further exploited as 80% of the power generated from the new unit qualifies for double Renewable Energy Credits since the power is generated on federal property and consumed on federal property by Los Alamos National Laboratory.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Due to the plant's seasonal flow variability, flow during winter months is often reduced. Prior to the new turbine installation, the two existing turbines provided a combined operating flow range of 250 to 1,300 cfs. The new low flow turbine was installed with an effective flow range between 75 and 250 cfs, allowing for an extended plant operating flow range of 75 to 1,550 cfs. The new 3.1 MW low flow, horizontal Francis turbine increased the plant's total installed capacity from 13.8 MW to 16.9 MW, an increase of 22%.

The installation of a new low flow turbine unit required the construction of a new powerhouse structure and cofferdam. In order to complete the in-the-river work during the low flow periods in winter, the design-build team revised its original plan so as to incorporate the permanent cofferdam into the powerhouse structure itself, thereby allowing for a single year low flow installation period instead of two and reducing environmental impacts. Fig. 2 includes a photograph of the low flow unit during installation.

Fig. 1 New low flow turbine, during installation and leveling

3. Feature of the Project

3.1 Best Practice Components

- Federal financial assistance for promising hydroelectric upgrade projects
- Installation of a low flow turbine to increase efficiency and operational flexibility

3.2 Reasons for Success

The success of the Abiquiu Dam upgrade project can largely be attributed to: 1) effective collaboration between the project operators and all funding and regulatory agency staff and 2) innovative design decisions to reduce environmental and energy production impacts and expedite project completion.

4. Points of Application for Future Project

The success of the ARRA-funded hydropower upgrade project demonstrates the benefits of federal financial assistance in identifying and funding promising renewable energy projects. This collaboration to achieve reliable, renewable energy resources demonstrates a successful model which may be mirrored at various levels of government.

5. Others (monitoring, ex-post evaluation, etc.)

Compared to the pre-existing turbines, the low flow turbine-generator allows for 35% better efficiency at flows below 250 cfs. Prior to the completion of the upgrade project, power generation during the previous low flow period of November through February was 355 MW-hours. During that same low flow period in the first year after project completion, power generation was 6,274 MW-hours, an increase of 1,700% in power generation. During the first 12 months of operation, the low flow turbine-generator achieved 19,792 MW-hours of power generation, far exceeding the previous estimate of 6,468 MW-hours.

6. Further Information

6.1 Reference

1) Incorporated County of Los Alamos New Mexico. Final Technical Report - Recovery Act: Installation of a Low Flow Unit at the Abiquiu Hydroelectric Facility, 2012.
2) DOE (Department of Energy), "Los Alamos County completes Abiquiu hydropower project, bringing new clean energy resources to New Mexico," viewed 24 February 2014. <http://apps1.eere.energy.gov/news/progress_alerts.cfm/news_id=19949 >
3) DOE (Department of Energy), Recovery Act: Hydroelectric Facility Modernization, Funding Opportunity Announcement Number: DE-FOA-0000120, 2009.
4) DOE (Department of Energy), "Recovery Act: Hydroelectric Facility modernization Project," presented at Water Power Peer Review, February 2014.

6.2 Inquiries

Company name : Oak Ridge National Laboratory

URL: https://www.ornl.gov/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – b) Investment incentives

Sub: 2 – a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Modernization of the Boulder Canyon Hydroelectric Project

Name of Country (including State/Prefecture):

Colorado, United States of America

Implementing Agency/Organization:

City of Boulder, Colorado (project owner)

Implementing Period:

January 2010 through December 2012

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction

(C) Needs for higher performance

Keywords:

turbine replacement, ageing equipment, historic preservation

Abstract:

This case study presents the results of a partially-DOE-funded hydropower modernization project to replace an oversized, aged turbine/generator unit with a smaller, more efficient unit at the Boulder Canyon hydroelectric project in Colorado, United States of America. Due to decreases in available flow since the start of operation in 1910, the only generating turbine unit still in operation was oversized and operating at low efficiency. The unit was replaced with a more efficient 5 MW Pelton turbine capable of meeting the expected flow variations at the site. Many associated upgrades were also performed to increase safety and environmental protection while creating a modernized facility. The project was completed in December 2012 with partial funding from DOE as a part of the American Recovery & Reinvestment Act and enabled continued operation of a historic hydroelectric facility.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a modernization project funded in part by the Recovery Act (American Recovery and Reinvestment Act) through the DOE (Department of Energy) EERE (Office of Energy, Efficiency, and Renewable Energy) WWPP (Wind and Water Power Program).

The Boulder Canyon hydroelectric project is located on Boulder Creek in Colorado, United States of America (40°0'15"N, 105°19'59"W), as shown in Fig. 1. The existing hydroelectric project (FERC No. 1005) was originally constructed in 1910 and was purchased by the City of Boulder, CO in 2001. By 2009, the two turbine generators (10 MW each, upgraded in the 1930s and 1940s) were near the end of their useful lives, with one generator inoperable and beyond repair since 2000, and the other expected to fail at any time. The pre-existing turbine/generator was a single nozzle Pelton turbine with a maximum turbine/generator efficiency of 82% and minimum flow of 4-5 cfs.

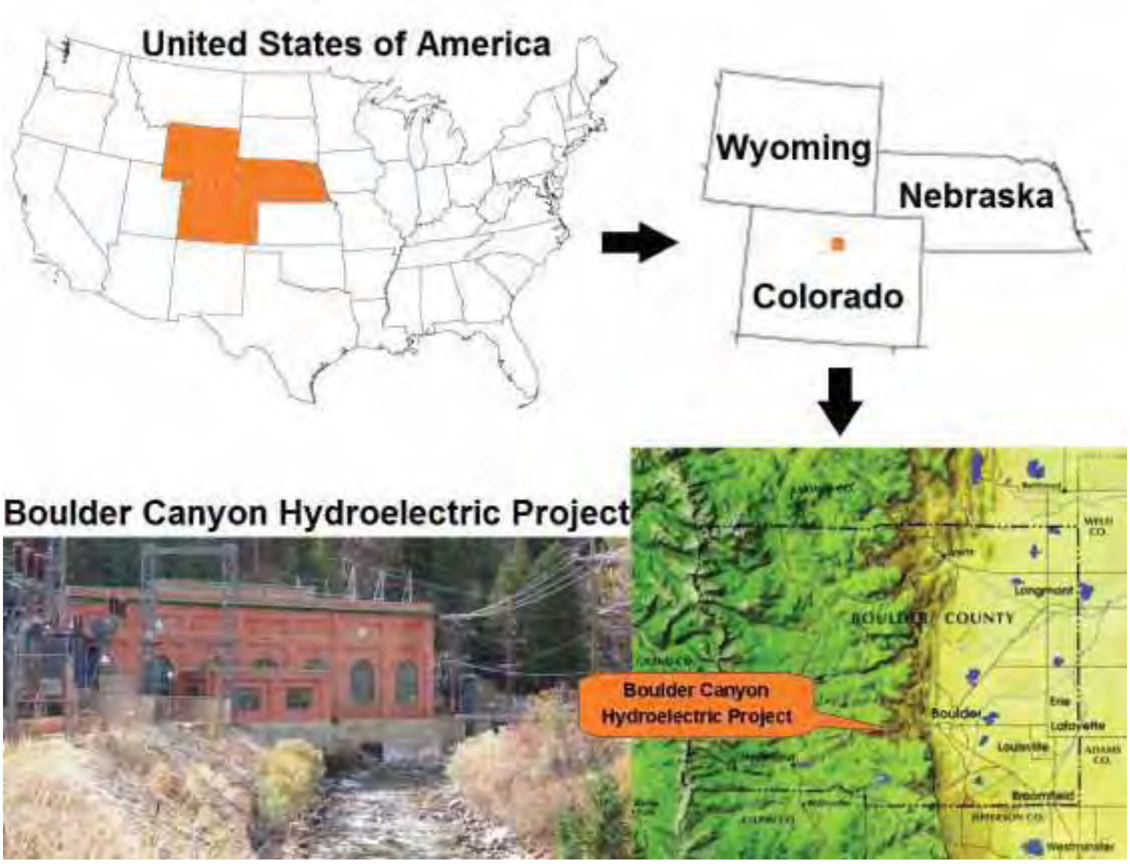


Fig. 1 Location of Boulder Canyon Hydroelectric Project

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure

(A) – (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency

The existing turbine/generators were in failing condition prior to the modernization project. With one unit out of service, the remaining operational 10 MW unit was dated 1936 and expected to fail within the next 5 years. The operating unit featured a single nozzle Pelton turbine with a maximum efficiency of 82% and lacked modern control equipment. Additionally, much of the historic water flow to the plant has been redirected since construction, resulting in an oversized application and reduced efficiency.

(A) – (b) Degradation due to ageing and recurrence of malfunction – improvement of durability and safety

The plant personnel were exposed to several safety hazards as a result of deteriorating conditions, including deteriorated wiring and asbestos. Additionally, decommissioning of aging transformers, installing lightning protection, and removing old hydraulic oil storage tanks near the site were identified as environmental safety hazards to address.

(ii) Opportunities to Increase Value

(C) **-** (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility's value through increased generation. Improved environmental performance was also a factor which could increase the project's value.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

January 1, 2010	DOE award of $1.18 million for modernization of BCH
March 30, 2010	DOE released hold on funding at completion of NEPA compliance
September 2010	Bid package issued for turbine/generator procurement
October 7, 2010	Bid due date for turbine/generator
January 3, 2011	Notice to Proceed with equipment manufacturing issued to Canyon Industries
March 7, 2011	Project kick-off meeting with Canyon Industries and DOE
March 28, 2011	Approval of Canyon Industries' first stage submittals
April 13, 2011	Final shop drawings from Canyon Industries
May 13, 2011	Receipt of first turbine runner casting by Canyon Industries
June 8, 2011	Receipt of second turbine runner casting by Canyon Industries
October, 2011	Construction contract awarded to Gracon Corporation
November 17, 2011	Gracon began mobilization
December 2011	Gracon worked to complete mechanical equipment demolition.
January 2012	Gracon removed concrete and some rock to prepare for new equipment. The concrete was extremely hard. On January 31, 2012 Gracon began to un-bolt the Betasso piping which began the water supply shutdown for the city.
January 24, 2012	Completion of equipment shop assembly by Canyon Industries
February 17, 2012	Equipment delivered to Boulder
February 2012	Continued demo of concrete, rock, and removal of the Unit B turbine isolation valve. Demo was completed by end of month and forming began for concrete.

March 2012	Concrete forming and placement continued throughout the month. Setting of sole plates for new TIV and Betasso Bypass valve was completed. New TIV valve was installed. The Betasso bypass piping was delivered and installation began immediately. Transformer A was removed at the end of the month.
April 2012	Concrete work was completed for equipment pads and turbine pit. Gracon began to set turbine casing and layout for generator. New transformer from Virginia Transformer was installed.
May 2012	Gracon completed installation of walkways, accumulator tanks, turbine casing, TIV, nozzles, piping, and began generator installation. The circuit switchers were delivered and installed.
June 2012	Gracon completed installation of generator, HPU, LPU, and stainless steel tubing for HPU and LPU.
July 2012	Gracon completed final clean-up and punch list items. Electrical (MWI) and Programming (EPE) subcontractors worked with AECOM and Exponential to commission equipment.
August 2012	Final electrical install and testing were completed including SCADA work. Canyon Industries and city worked through startup of unit.
September 14,2012	Completed final walk-through with Gracon. This is the date of Substantial Completion.
October 4 2012	Project completion ceremony
December 31, 2012	End of DOE project
March 31, 2013	Completion of final reporting to DOE
September 14,2014	End of 2-year Warranty Period.

2.3 Description of Work Undertaken (detail)

1-b) Investment incentives

The project received a $1,180,000 Recovery Act grant from the Department of Energy's Wind and Water Power Program, representing a 20.1% cost share. The city proposed funding the remaining anticipated project costs by borrowing money from the Lakewood Pipeline Remediation Reserve, with repayment coming from future power sale revenues with a 3% interest rate and received approval in January 2010. In addition to the substantial financial benefit, the project also received a secured interest rate of 3.0% which was considerably less than market rates at the time. The funding program, under DOE Funding Opportunity Announcement DE-FOA-0000120, aims to support the deployment of turbines and control technologies to increase and maximize system generation at existing non-Federal hydroelectric facilities without significant modifications to dams and with minimum regulatory delay. Improved environmental performance, efficiency, and quantity and quality of energy production were mentioned as key qualities of successful candidate projects.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Although the project received funding in January 2010, mobilization activities did not begin until November 2011 after the lengthy bidding, design, and equipment procurement processes were complete. Prior to installing the new equipment, mechanical equipment and some concrete and hard rock were removed from the facility to make way for the new valves and piping. New concrete work for the equipment pads and turbine pit and installation of the new transformer were completed in April 2012. The walkways, accumulator tanks, turbine casing, turbine isolation valve, nozzles, piping, and generator and circuit switchers were all installed in May 2012. The generator, HPU, LPU, and associated stainless steel tubing were installed in June, followed by final clean-up and equipment commissioning. The final walk-through was performed on September 14, 2012, with a project completion ceremony on October 4, 2012. Fig. 2 includes a photograph of the replacement turbine runner being installed.

Fig. 1 Installation of new turbine runner

Key decisions made during the project include the reduction of the turbine/generator unit from 6 MW to 5 MW and the replacement of Unit A instead of Unit B. Although the potential for 6 MW of generation from increased future flow conditions was discussed, the timing of peak flow conditions coincided with peak water demand, meaning that the flow available for generation would likely not exceed 5 MW during that time. The replacement of Unit B instead of Unit A allowed for multiple benefits, including less concrete removal, simplified bypass piping and electrical installation, decreased out-of-service time, and easier coordination and operations.

As a result of the project,1) generation and efficiency increased through the newly installed turbine unit, 2) personnel and equipment safety increased from new live wiring installation and asbestos elimination, 3) environmental protection increased through the replacement of two oil-cooled, generating transformer units from the 1940s with a smaller transformer and circuit switcher, 4) control equipment was upgraded to all for remote operation of the turbine isolation valve to protect against equipment and piping damage, 5) historical engineering information was preserved through state and local archiving, and 6) economic recovery was aided through the creation and preservation of jobs.

3. Feature of the Project

3.1 Best Practice Components

- Federal financial assistance for promising hydroelectric upgrade projects
- Replacement of ageing (approximately 100 year-old) equipment with new technology

3.2 Reasons for Success

The success of the Boulder Canyon upgrade project can largely be attributed to: 1) identification of a hydropower project in dire need of upgrades and 2) deciding to install a smaller turbine/generator unit to maximize efficiency and reduce capital costs.

4. Points of Application for Future Project

The success of the ARRA-funded hydropower upgrade project demonstrates the benefits of federal financial assistance in identifying and funding promising renewable energy projects. This collaboration to achieve reliable, renewable energy resources demonstrates a successful model which may be mirrored at various levels of government.

5. Others (monitoring, ex-post evaluation, etc.)

Although the newly installed 5 MW turbine/generator unit was smaller than the pre-existing 10 MW unit, changes in the available flow meant that the old unit was oversized and inefficient. A comparison of past performance to anticipated future project performance indicates a 37% increase in annual power generation as a result of the upgrade, with a total lifetime generation over 1200% higher due to the near-failing condition of the old turbine, which was expected to remain in service for less than 5 more years.

6. Further Information

6.1 Reference

1) City of Boulder, Colorado. Final Technical Report – Modernization of the Boulder Canyon Hydroelectric Project, 2013
2) DOE (Department of Energy), "Recovery Act: Hydroelectric Facility modernization Project," presented at Water Power Peer Review, February 2014.

6.2 Inquiries

Company name : Oak Ridge National Laboratory
URL: https://www.ornl.gov/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – b) Investment incentives

Sub: 2 – a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Tapoco Project: Cheoah Upgrade

Name of Country (including State/Prefecture):

North Carolina, United States of America

Implementing Agency/Organization:

Alcoa, Inc. (project owner)

Implementing Period:

January 2010 through October 2012

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction

(C) Needs for higher performance

Keywords:

turbine replacement, ageing equipment upgrade

Abstract:

This case study presents the results of a partially-DOE-funded hydropower modernization project to replace multiple aged turbine/generator units at the Cheoah Hydroelectric Facility in North Carolina, United States of America. Four of the five existing units, dating to the 1920s, were upgraded to increased generating capacity and avoid catastrophic failure. Unit 2, which failed in 2007, and Unit 1, which remained in operation, have currently been upgraded, with upgrades to the remaining units in the process of being completed. Modernization of the facility required proper planning and coordination to produce minimal modifications at an ageing facility in a remote location. The project increased the facility's total generating capacity while increasing environmental protection and providing employment and economic support to the area.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a modernization project funded in part by the Recovery Act (American Recovery and Reinvestment Act) through the DOE (Department of Energy) EERE (Office of Energy, Efficiency, and Renewable Energy) WWPP (Wind and Water Power Program).

The Cheoah hydroelectric facility is located on the Cheoah River in western North Carolina, United States of America (35°26’53”N, 83°56’16”W), as shown in Fig.1. The existing hydroelectric project (FERC No. 2169) was originally constructed in 1919 and provides power generation to Alcoa, Inc., the project owner, and the surrounding area as a part of the larger Tapoco Project hydroelectric system, which consists of four developments – Santeetlah, Cheoah, Calderwood, and Chilhowee. Prior to the upgrade, the Cheoah facility consisted of a dam and powerhouse containing five vertical Francis turbines. Four of the units were original equipment, with the fifth added in 1949. The licensed capacity of the five units was 144.7 MW, with a total hydraulic capacity of 9,436 cfs.

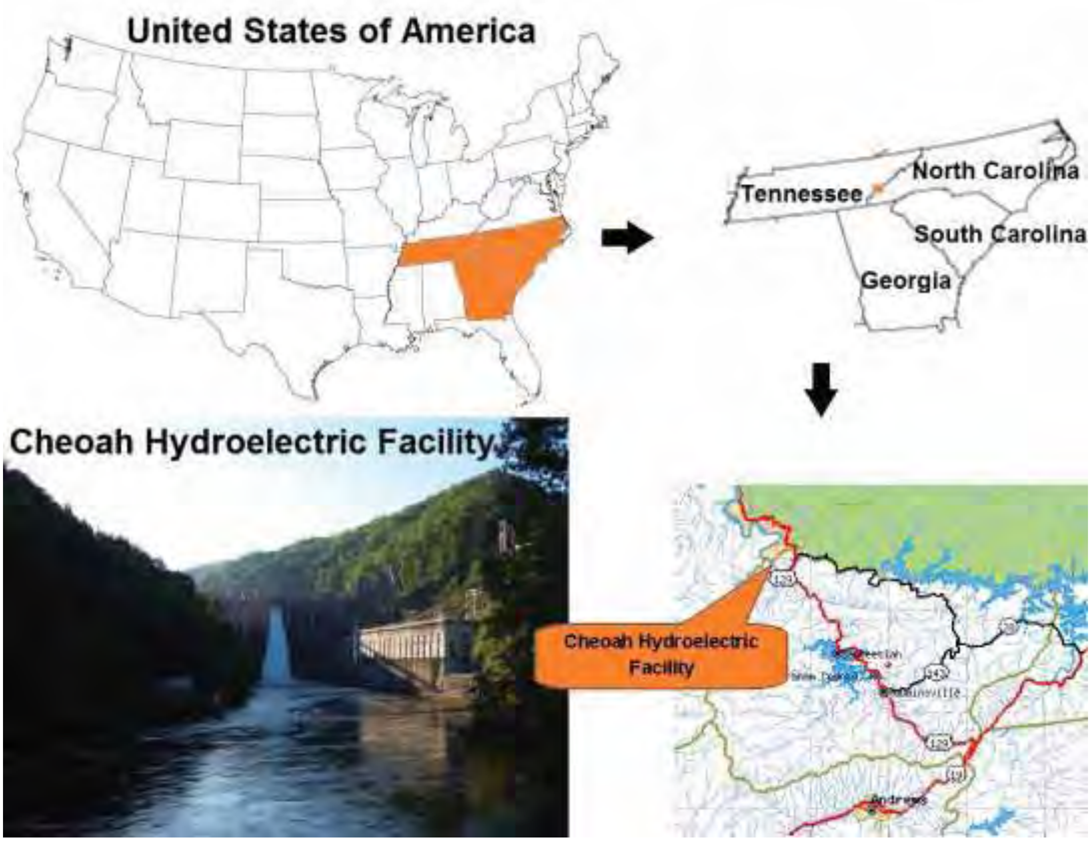


Fig. 1 Location of Cheoah Hydroelectric Facility

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A) – (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency

TVA (Tennessee Valley Authority) assessed the Tapoco system and designated the Cheoah facility as the highest priority for modification. The average age of the Cheoah project equipment prior to the project exceeded 90 years, well beyond the typical unit life and increasing the risk for imminent failure (as occurred in February 2007 with Unit 2). The potential for failure at Cheoah would have affected both upstream and downstream operations and greatly disrupted local power generation.

(ii) Opportunities to Increase Value

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility's value through increased generation. Improved environmental performance was also a factor which could increase the project's value.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

The risk for project failure led to the decision to upgrade four of the five units at Cheoah in 2006. In February 2008, funding was approved to support site-wide upgrades including four new generators and turbines and the upgrade of the power sub-station, main transformers, and high voltage switches. As a result of the global financial crisis, the project was placed on hold in March 2009 until the market made a recovery. The project period was from January 1, 2010 through October 31, 2012.

2.3 Description of Work Undertaken (detail)

1-b) Investment incentives

The project received an approximate $12,174,956 Recovery Act grant from the Department of Energy's Wind and Water Power Program, representing a 17.6% cost share, with the remaining funding coming from non-Federal sources. The funding program, under DOE Funding Opportunity Announcement DE-FOA-0000120, aims to support the deployment of turbines and control technologies to increase and maximize system generation at existing non-Federal hydroelectric facilities without significant modifications to dams and with minimum regulatory delay. Improved environmental performance, efficiency, and quantity and quality of energy production were mentioned as key qualities of successful candidate projects.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Detailed engineering began in March 2008 but was slowed significantly when all other project activity stalled in 2009 due to the global economic crisis. After the initial ARRA grant award, engineering restarted in 2010 and project mobilization began. During the project mobilization phase, generator and turbine manufacturing occurred, which allowed for installation in later tasks. Prior to a full plant outage, construction activities were conducted to prepare the site for the arrival of heavy equipment and material, enable removal and installation of equipment, and demolish the failed Unit 2 components. Following this pre-outage construction, Units 1-4 were shut down to allow for the removal of old equipment and installation of new equipment and material. Unit 2 was released for commercial operation on September 6, 2012, followed by Unit 1 on September 7, 2012. The modernization of the remaining units is currently ongoing and is being performed through non-Federal financing. Replacement of the wicket gates and turbine shafts, which were 86 years old, and the runners, which were 58 years old, increased facility efficiency by 40%. Units 1 and 2 gained 50% additional capacity, increasing from 22 MW to 33 MW each. Fig. 2 includes photographs of an original and upgraded unit.

Fig. 2 Original unit (left) and upgraded unit (right)

3. Feature of the Project

3.1 Best Practice Components

- Federal financial assistance for promising hydroelectric upgrade projects
- Minimal civil and structural modifications during replacement of ageing (nearly 100 year-old) equipment with new technology

3.2 Reasons for Success

The success of the Cheoah upgrade project can largely be attributed to: 1) identification of a hydropower project in dire need of upgrades and 2) effective coordination between multiple specialty contractors in meeting the project schedule and objectives.

4. Points of Application for Future Project

The success of the ARRA-funded hydropower upgrade project demonstrates the benefits of federal financial assistance in identifying and funding promising renewable energy projects. This collaboration to achieve reliable, renewable energy resources demonstrates a successful model which may be mirrored at various levels of government. The technical plans, along with the program plans and procedures provided an efficient and effective roadmap for implementing future hydropower modernization programs. Several lessons learned include:

- Meeting current code requirement when upgrading an older facility presents challenges.
- Limited space for storage and inventory can be problematic, and the upgrading of multiple units makes inventory tracking extremely important. A logistics plan should be implemented early in the project's lifecycle.
- Older equipment used for construction tasks demands extra intention to maintain operability.
- The remoteness of a project's location can present challenges for allocating skilled labor and may require multiple specialty contractors, in turn requiring additional oversight and effective management to meet schedule.
- Scheduling should be arranged to reduce revenue loss during outage periods.
- Compliant systems that are mandated for government programs should be implemented at the onset of a project.

- Equipment size and delivery logistics should be evaluated during the project development phase, especially when the project is in a remote location.
- For old facilities, challenges due to confined space and access should be evaluated during the development phase.
- Implementation of a daily ‘plan of the day’ meeting may be highly effective in coordinating interaction between multiple specialty contractors.
- Continuous safety training and focus is required to achieve safety goals.

5. Others (monitoring, ex-post evaluation, etc.)

The new generating units are state-of-the-art and have been guaranteed by Voith Hydro to deliver at least 25% higher generating capacity per unit. The new equipment increased the facility efficiency by approximately 40%, eliminated over 60% of the oil that was on site, provided secondary containment for transformers, eliminated water cooling of transformers and their discharge stream, eliminated greased bushings near the water passage, addressed lead paint and asbestos on the four units, and reduced the noise level on the generator flood of the powerhouse. Index test results indicate that the turbine produced a maximum output power of 33.519 MW, 10.9% higher than the guaranteed maximum output power of 30.235 MW. Additionally, the generator efficiency for the upgraded units was estimated as 98.3%. This upgrade project enables the facility to provide an additional 40-50 years of clean renewable energy.

6. Further Information

6.1 Reference

1) Alcoa, Inc. Recovery Act: Tapoco Project: Cheoah Upgrade – Final Technical Report, 2013
2) DOE (Department of Energy), “Recovery Act: Hydroelectric Facility modernization Project,” presented at Water Power Peer Review, February 2014.

6.2 Inquiries

Company name : Oak Ridge National Laboratory
URL: https://www.ornl.gov/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – b) Investment incentives

Sub: 1 – f) Environmental conservation and improvement

2 – a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

North Fork Skokomish Powerhouse at Cushman No. 2 Dam

Name of Country (including State/Prefecture):

Washington, United States of America

Implementing Agency/Organization:

City of Tacoma, Washington (project owner)

Implementing Period:

October 2009 through September 2013

Trigger Causes for Renewal and Upgrade:

(B) Environmental deterioration

(C) Needs for higher performance

Keywords:

powerhouse addition, fish passage, environmental protection

Abstract:

This case study presents the results of a partially-DOE-funded hydropower upgrade project to construct a new powerhouse and install environmental protection features at the Cushman No. 2 Dam hydropower facility in Washington, United States of America. As the result of the facility's relicensing, appeals were made concerning alleged damages related to the project. As part of the settlement agreement, the facility began the process of enhancing environmental protection and constructing a new powerhouse to capture previously unrealized energy generation. The project was completed in September 2013 with partial funding from the American Recovery & Reinvestment Act.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a modernization project funded in part by the Recovery Act (American Recovery and Reinvestment Act) through the DOE (Department of Energy) EERE (Office of Energy, Efficiency, and Renewable Energy) WWPP (Wind and Water Power Program).

The Cushman hydroelectric project (FERC No. 460) consists of two dams and two reservoirs in Washington, United States of America. The Cushman No. 1 development was completed in 1926 and is located approximately two miles upstream of the Cushman No. 2 development. Cushman No. 2 (47°23’52”N, 123°12’05”W) impounds Lake Kokanee and contains 3 turbine/generator units with a total installed capacity of 81 MW. Water from Lake Kokanee travels to a powerhouse well below the bottom of the dam and discharges into the Hood Canal, as illustrated in Fig. 1. The original 50-year license expired in 1974 and was followed by 24 years of annually-issued permits, numerous studies, and much contention from various parties. In 2003, FERC issued its final license, which many parties challenged due to alleged damages resulting from the Cushman project. After two years of negotiations, a landmark comprehensive settlement agreement was reached in January 2009 to issue a new FERC license and close the claim. The settlement, among other things, provided for numerous environmental features to protect fish and enhance wildlife and recreation and included an application for installing a new North Fork powerhouse at the base of Cushman No. 2 Dam.

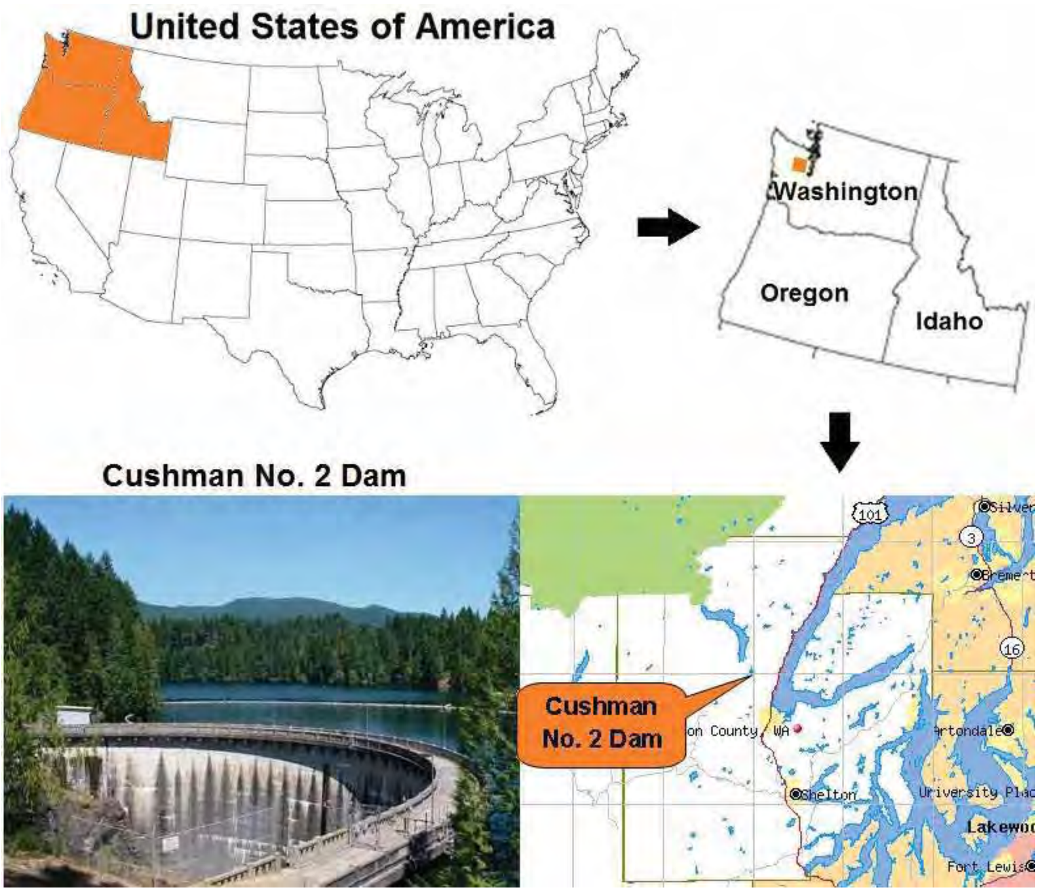


Fig. 1 Location of Cushman No. 2 Dam Hydroelectric Project

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure

(B) - (b) Environmental deterioration – improvement of river environment

In 1998, a continued dam operation license was issued for the Cushman No. 2 Dam project. As a result, multiple parties appealed the decision on several different grounds. During the appeals process, several fish populations in Washington became listed species under the Endangered Species Act, prompting the Federal District Court to issue a request for impact reevaluation. Additional appeals were issued until a decision was made in 2009 to close the appeals process and, among other things, provide for a new, more fish friendly instream flow regime, upstream and downstream fish passage, hatchery construction, wildlife mitigation, and recreation improvements.

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

As a part of the 2009 settlement agreement, an application was made for a non-capacity amendment for installing the new North Fork powerhouse at the base of Cushman No. 2 Dam. Prior to the project, water was released into the North Fork Skokomish River through a valve at the base of the dam without recovery of the energy. The construction of a new powerhouse and installation of associated equipment to capture this available flow and energy could provide an opportunity to generate 13% more energy at the site.

(ii) Opportunities to Increase Value

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility's value through increased generation. Improved environmental performance was also a factor which could increase the project's value.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Table 1 Project Schedule & Milestones

Title/Task Description	Task Completion Date		
	Original Planned	Revised Planned	Actual
Turbine/Generator Procurement & Delivery	Mar-12	Jul-12	Sep-12
Powerhouse General Construction Contract	Sep-12	Nov-12	Mar-13
Transmission Design and Construction	Sep-12	May-12	Jun-12
Fish Facility Design and Construction	Sep-12	Oct-12	Jun-13
Project Management and Reporting	Dec-12	Dec-12	Sep-13
Commence start-up testing	Jul-12	Nov-12	Jan-13
Begin commercial operation	Sep-12	Dec-12	Feb-13

2.3 Description of Work Undertaken (detail)

1-b) Investment incentives

The project received a $4,671,304 Recovery Act grant from the Department of Energy's Wind and Water Power Program. The City of Tacoma funded the remaining amount, with the DOE grant representing 17.5% of the total costs. Prior to the decision to accept the grant, a cost benefit analysis was performed with three different business cases. The first case, which assumed no ARRA funding, resulted in a benefit-to-cost ratio of 0.94 and a levelized benefit of -$2.67/MWh, indicating that it would be uneconomic. A second analysis assuming that ARRA funding was available and that the funding was assigned entirely to the powerhouse portion of the project; this scenario resulted in a benefit-to-cost ratio of 1.16 and a levelized benefit of $5.86/MWh. The third scenario closely reflects the true outcome of the project and resulted in a benefit-to-cost of 1.65, payback period of 8 years and levelized benefit of $19.81/MWh The funding program, under DOE Funding Opportunity Announcement DE-FOA-0000120, aims to support the deployment of turbines and control technologies to increase and maximize system generation at existing non-Federal hydroelectric facilities without significant modifications to dams and with minimum regulatory delay. Improved environmental performance, efficiency, and quantity and quality of energy production were mentioned as key qualities of successful candidate projects.

1-f) Environmental conservation and improvement

An innovative upstream fish passage system was constructed as a part of this upgrade project. A portion of the water discharge from the new turbines is routed from the new powerhouse through a screened floor of a concrete fish trap. Fish are attracted into the trap through a slotted fish entrance which then lifts the fish to the top of the dam on a tram via a transport hopper. A jib crane then lifts the hopper out of the tram and into a receiving tank where a new fish handling system is used to separate, count, and mark (as necessary) the fish. The fish are then transported in tanks to their final destination, upstream of the two Cushman dams or to one of two hatcheries. A 1/5th scale model was created and tested at Northwest Hydraulic Consultants office and demonstrated that the configuration could achieve the desired flows and resulted in a satisfactory tailrace diffuser strategy. Figs. 2 and 3 illustrate the fish collection facility.

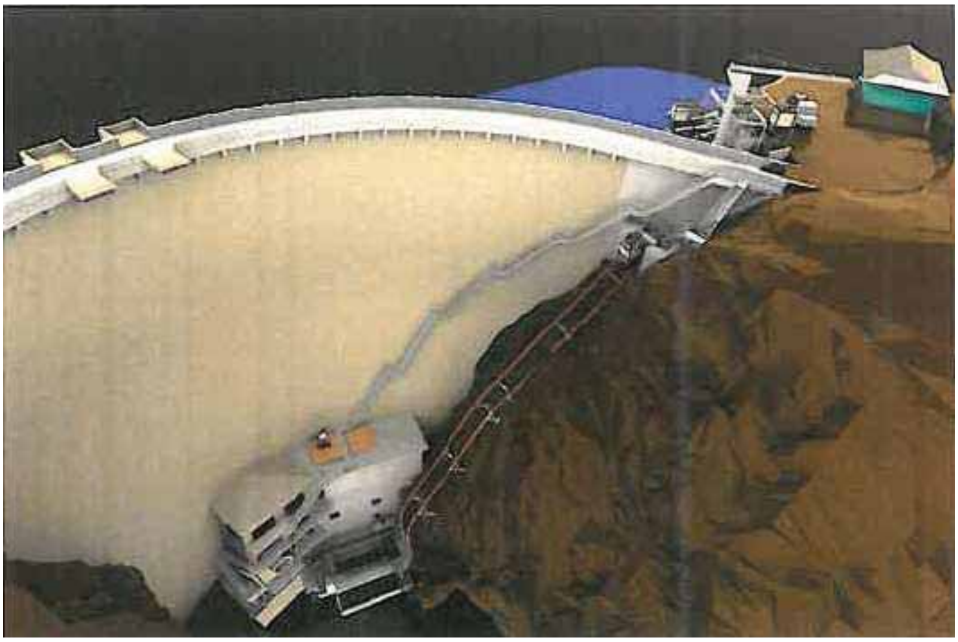


Fig. 2 Fish Collection Facility Illustration

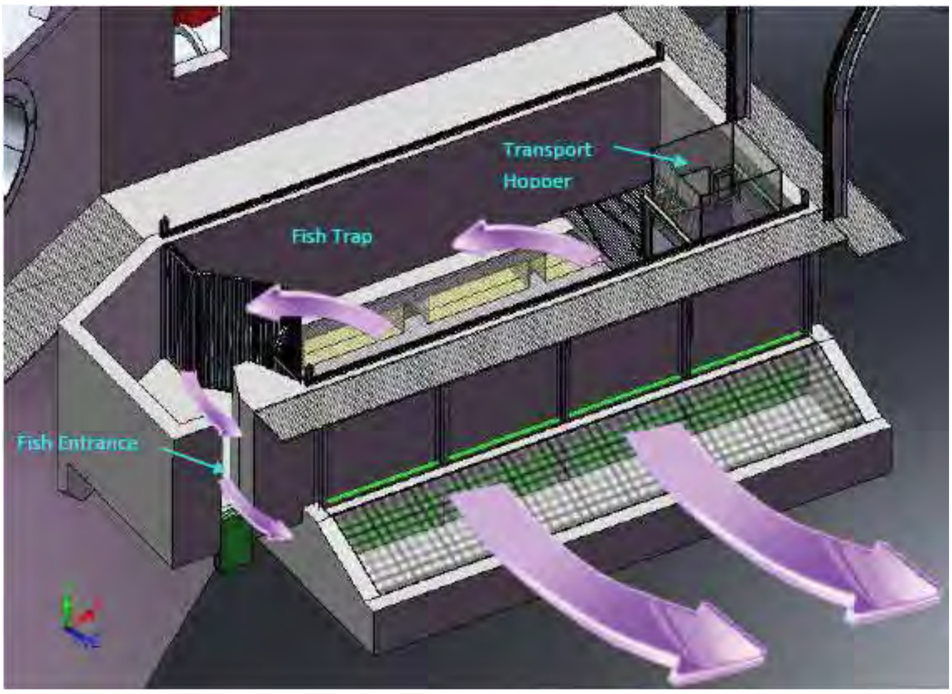


Fig. 3 Diagram of fish collection facility features at the base of Cushman No. 2 Dam

2–a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

The design process for the new North Fork powerhouse was difficult due to many limiting features at the site. The project began by erecting a tower crane, constructing a sediment pond and isolating the powerhouse site behind a sediment containment dam. During construction of the containment dam, the flow from the river outlet valve was stopped and rerouted to the spillway to maintain flow. Although not a suitable long term release method, the spillway was used for only three days while the containment dam was constructed, and the river outlet valve was reopened with the flow shooting over the containment dam. A pump was used to provide water to the settling pond whenever the water turned turbid or the pH was raised.

Next, excavation was performed, including trimming rock from the hillside, leveling the construction site, and performing subsurface bedrock excavation. Approximately one-third of the powerhouse and fish pool footprint is on bedrock with the remainder sitting on loose rubble up to 60 feet deep near the center of the river. The fish pool was then constructed above tailwater and lowered into the water to correct grade and grout pumped under the floor. A fish collection structure was constructed on the deck, followed by a second level of frame over the structure. Draft tubes were then inserted into their receiving frames, and corrugated metal pipe was installed at each micropile location. Micropile installation followed, while substation construction started in parallel. Evaluation of the soil at the substation location indicated inadequate grounding characteristics, leading to the installation of additional ground rods and the employment of a special perimeter grounding system. Powerhouse construction followed with no major issues, though the limited space and overhead worked caused delays in the schedule. As the project continued, the contractor became far behind schedule, leading to a settlement agreement that assured that the powerhouse would either begin startup testing on January 1, 2013 or the contractor would pay liquidated damages. On January 8, 2013 startup began, though lighting and bathroom framing were incomplete, the fish facility equipment was not commissioned, and some items were not installed. Substantial completion was agreed to occur on July 1, 2013, with some equipment not yet accepted. The new powerhouse contains two Francis turbine/generator units, each with a 1.8 MW capacity. Additionally, a new integrated control system was installed that will serve as a model for upgrades at other Tacoma projects. The system integrates turbine, generator, river outlet valve, and fish facility control all on one platform to allow for increased operational efficiency.

3. Feature of the Project

3.1 Best Practice Components

- Federal financial assistance for promising hydroelectric upgrade projects
- Innovative fish passage system
- Expansion of an existing hydropower facility through the capture of previously unutilized discharge energy

3.2 Reasons for Success

The success of the Cushman upgrade project can largely be attributed to: 1) identification of a hydropower project in dire need of upgrades and 2) installation of new environmental protection features while constructing a new powerhouse to satisfy local parties and while expanding renewable energy generation.

4. Points of Application for Future Project

Although a physical hydraulic model was used to check the performance of the fish attraction and capture system, it did not accurately demonstrate the turbulence of flow resulting from turbine discharge flow used in driving the upwelling pool. This complication has resulted in difficulty in achieving flow necessary for uniform upwelling, and future projects could consider a more elaborate porosity control under the pool upwell, such as baffle blocks to reduce surging or more baffling in the draft tube exit to straighten flows. Another consideration for future projects is the introduction of air to the turbine stream to smooth cavitation rough zones. Such a system was installed at Cushman based on early examination, and although serious bubbles in the fish collection pool occur, measurements indicate that they do not result in any appreciable increase in the Total Dissolved Gas value. Fish may, however, reject the pool due to the bubbles, and the issue is being reviewed by the City of Tacoma. Operation of the two generating units unequally may avoid the most significant rough zones and form a pool without bubbles but could lead to higher cavitation wear. As stated in the Final Technical Report, the newly installed control system will serve as a model for upgrades at other Tacoma projects. A presentation of the project given in 2013 focused on lessons learned, including consideration of planning space, engineering vs contractor design, design simplicity, maintenance, and operator location and simplicity.

5. Others (monitoring, ex-post evaluation, etc.)

The new powerhouse is expected to increase annual power generation by approximately 13%. Due to the unique design of the facility, for every one MWh of energy saved at the North Fork Powerhouse, three MWh of energy are produced at the Cushman No. 2 powerhouse. Thus, the new powerhouse plans to continue operation so as to discharge at the agreed minimum flow, allowing for additional generation at the Cushman No. 2 powerhouse.

6. Further Information

6.1 Reference

1) City of Tacoma, Washington. Final Technical Report – North Fork Skokomish Powerhouse at Cushman No. 2 Dam, 2013
2) DOE (Department of Energy), “Recovery Act: Hydroelectric Facility modernization Project,” presented at Water Power Peer Review, February 2014.

6.2 Inquiries

Company name : Oak Ridge National Laboratory
URL: https://www.ornl.gov/

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – b) Investment incentives

Sub: 2 – a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Recovery Act: Fond du Lac Hydroelectric Project

Name of Country (including State/Prefecture):

Minnesota, United States of America

Implementing Agency/Organization:

Minnesota Power (project owner)

Implementing Period:

September 2010 through August 2013

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction

(C) Needs for higher performance

Keywords:

turbine replacement, ageing equipment

Abstract:

This case study presents the results of a partially-DOE-funded hydropower rehabilitation project to replace aged equipment and improve plant efficiency. During the project, a few complications arose, including the unexpected poor condition of the penstock and the occurrence of a 500 year flood. Despite the obstacles, the upgrades were implemented with no lost time accidents and enabled the continued operation and increased generation at a renewable energy project. The project was completed in August 2013 with partial funding from DOE as a part of the American Recovery & Reinvestment Act and enabled continued operation of a historic hydroelectric facility.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a modernization project funded in part by the Recovery Act (American Recovery and Reinvestment Act) through the DOE (Department of Energy) EERE (Office of Energy, Efficiency, and Renewable Energy) WWPP (Wind and Water Power Program).

The Fond du Lac hydroelectric project is located on the St. Louis River in Minnesota, United States of America (46°39’58”N, 92°17’44”W), as shown in Fig. 1. The existing hydroelectric project (FERC No. 2360) was originally constructed in 1924 and is owned and operated by Minnesota Power. Prior to project upgrade, the facility contained one 12 MW Francis turbine.

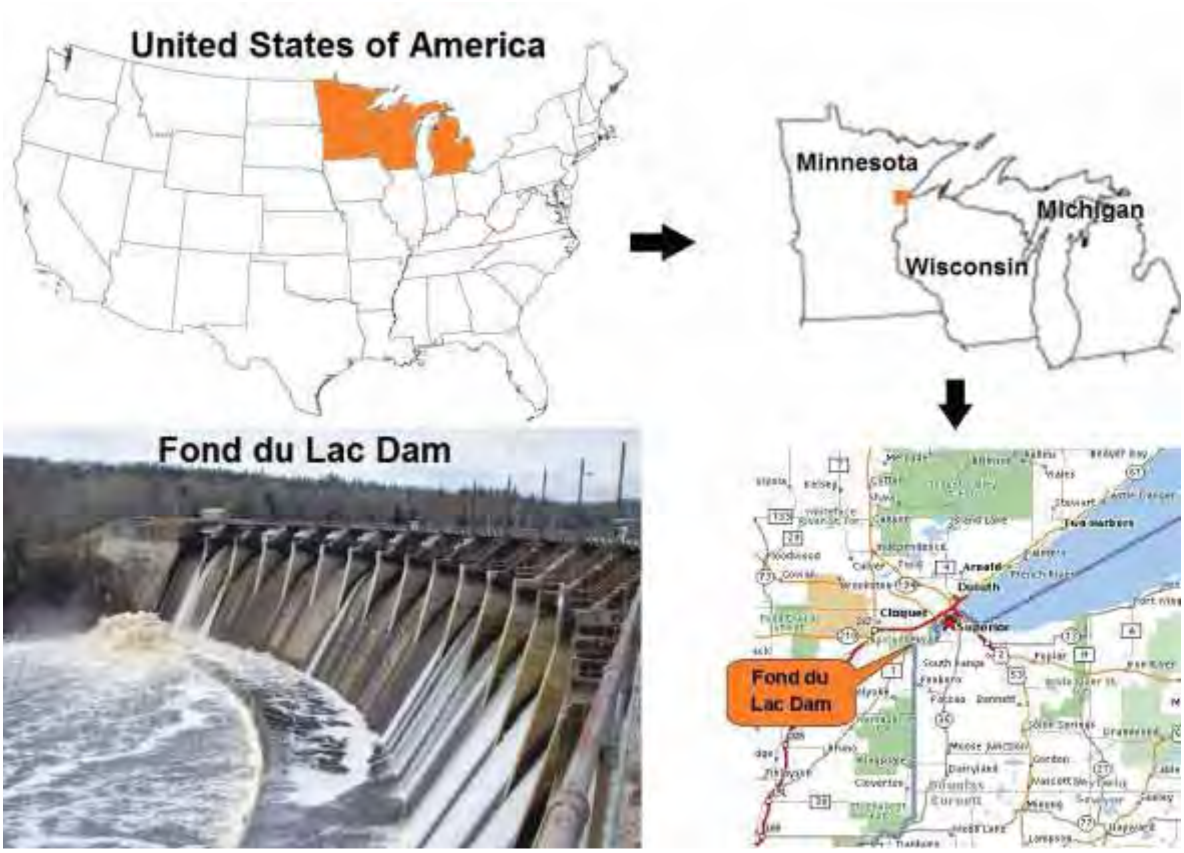


Fig. 1 Location of Fond du Lac Hydroelectric Project

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A) – (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency

Due to ageing equipment and material, the Fond du Lac hydroelectric project was found in need of upgrade. The 12 MW turbine performance had degraded over time and required replacement of bushings, bearings, and seals. Also, a crack in the head cover limited the gate opening to 78%. The existing stator and rotor were originally installed in 1924 and were nearing the end of their useful life. Additionally, the excitation system, water way head gate, and runners needed replacing. During an outage, inspection of the unit’s water ways indicated a poor penstock condition, which required major repairs.

(ii) Opportunities to Increase Value

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility's value through increased generation.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

The project was partially funded by the American Recovery and Reinvestment Act of 2009. The project period was September 2010 through August 2013.

2.3 Description of Work Undertaken (detail)

1-b) Investment incentives

The project received a $815,995 Recovery Act grant from the Department of Energy's Wind and Water Power Program, representing a 14.7% cost share. The funding program, under DOE Funding Opportunity Announcement DE-FOA-0000120, aims to support the deployment of turbines and control technologies to increase and maximize system generation at existing non-Federal hydroelectric facilities without significant modifications to dams and with minimum regulatory delay. Improved environmental performance, efficiency, and quantity and quality of energy production were mentioned as key qualities of successful candidate projects.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

The Fond du Lac station was removed from service in July 2011 to allow for upgrades. Originally planned to last until October 2011, the outage was prolonged until June 2013 due to the discovery of a poorly-conditioned penstock in need of major repairs. Prior to beginning penstock repairs, the site experienced a 500 year flood, which caused the forebay to breach at the upstream Thomson Station, further complicating the repair and reassembly process. Project accomplishments include replacing the turbine/runner with a state of the art more efficient stainless steel runner, rewinding the stator and rotor, improving the turbine bearing cooling system to provide better cooling and reduce oil spill risk, upgrading the generator excitation to a static excitation system, replacing the head gate, and automating the overhead crane. The project rehabilitated the aged facility to achieve the 12 MW original nameplate capacity.

3. Feature of the Project

3.1 Best Practice Components

- Federal financial assistance for promising hydroelectric upgrade projects
- Replacement of ageing (nearly 100 year-old) equipment with new technology

3.2 Reasons for Success

The success of the Fond du Lac rehabilitation project can largely be attributed to: 1) identification of a hydropower project in dire need of upgrades and 2) using state of the art technology to extend the equipment's usable life.

4. Points of Application for Future Project

The success of the ARRA-funded hydropower upgrade project demonstrates the benefits of federal financial assistance in identifying and funding promising renewable energy projects. This collaboration to achieve reliable, renewable energy resources demonstrates a successful model which may be mirrored at various levels of government.

5. Others (monitoring, ex-post evaluation, etc.)

Although the equipment was returned to service in June 2013, the pond level was reduced by 5 feet until repairs are completed at Thomson. Even under the low flow and low pond conditions, the plant has been able to achieve 12 MW generating capacity, though this has not been sustainable due to reduced flow. With the new equipment, the station is estimated to produce an additional 6,000 MWh annually due to the more efficient turbine.

6. Further Information

6.1 Reference

1) Minnesota Power. Final Technical Report – Recover Act: Fond du Lac Hydroelectric Project, 2013.
2) DOE (Department of Energy), “Recovery Act: Hydroelectric Facility modernization Project,” presented at Water Power Peer Review, February 2014.

6.2 Inquiries

Company name : Oak Ridge National Laboratory
URL: https://www.ornl.gov/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset Management, Strategic Asset Management, and Life-cycle Cost Analysis

Sub: 2-c) Technological innovation, deployment expansion and new materials used for civil and building works

Project Name:

Flaming Gorge Hydropower Facility: Final Assessment Report

Name of Country (including State/Prefecture):

Utah, United States of America

Implementing Agency/Organization:

United States Bureau of Reclamation (project owner)
Mesa Associates, HPPi, and ORNL (assessment team)

Implementing Period:

This project represents a condition, performance, and opportunity assessment with no completed or scheduled upgrade activities that have been identified from assessment.

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction
(C) Needs for higher performance

Keywords:

condition assessment, performance assessment, HAP (Hydropower Advancement Project)

Abstract:

This case study presents the results a condition and performance assessment of Flaming Gorge hydropower facility that was performed by a team of hydropower experts and engineers from Mesa Associates, HPPi, and ORNL following a site visit on February 22, 2012. Pre-assessment data were collected to enhance the visit’s productivity. On-site evaluation of plant components and plant personnel interviews enabled further data collection and verification to complete a full HAP assessment using the developed standard methodology. Overall, the Flaming Gorge plant was found to be in good condition with a high level of confidence in the assessment results. Despite the overall good condition, several upgrade opportunities were identified and recommended.

Based on the original HAP plan, additional U.S. hydropower facilities will be assessed using the HAP assessment methodology, and eventually the assessment results will be aggregated from all assessed facilities to characterize and trend the asset conditions across different facilities, owner fleets, regions, and overall U.S. hydropower fleet, and also to correlate the performance to the condition ratings.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a condition and performance assessment which identifies the improvement opportunities that should be examined through subsequent activities and evaluations at the Flaming Gorge hydropower facility and includes an order of magnitude cost estimate that may support determinations by the United States Department of Energy and hydropower facility owners as to which upgrades warrant further studies.

The Flaming Gorge hydropower facility is located on the Green River in northeastern Utah, United States of America (40°54’52”N, 109°25’17”W), as shown in Fig. 1. The Flaming Gorge Dam forms the Flaming Gorge Reservoir (capacity 3,788,700 acre-ft), and construction began in 1958, with operation starting in 1964. The hydropower facility has three Francis turbine units with a nominal rating of 50.7 MW and design net head of 440 ft each (152 MW total plant capacity). Various refurbishment, rehabilitation, and upgrading events have enhanced the project since its construction.

Fig. 1 Location of Flaming Gorge Dam

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

Because this case study represents an assessment for potential upgrades rather than a completed project, the following trigger causes and drivers for renewal and upgrading are based on recommendations from the Hydropower Advancement Project (HAP) standard assessment methodology.

(i) Conditions, Performance and Risk Exposure

(A) - (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency

Trash accumulation at the trash racks was found to be minor, but the lack of routine cleanings and trash removal prompted a recommendation for a trash monitoring system. In order to ensure long term viability, the dated automation system was also recommended for an update. The condition monitoring system was found to be limited, with data collection occurring infrequently. Due to the ageing mechanical governors, with potentially high replacement costs and lacking software programmability, conversion to digital technology was recommended. Carbon monoxide generation rates in the transformer oil were found to be elevated, indicating a need for monitoring to reduce accelerated ageing. In order to monitor the deterioration of electrical connections, incorporation of stator, rotor, PPT (power potential transformer), and GSU (generator step-up) transformer winding resistance tests were recommended as a part of the electrical test program.

(A) - (b) Degradation due to ageing and recurrence of malfunction – improvement of durability and safety

While found to be in satisfactory condition, penstock interiors are coated with coal tar enamel lining from the original construction. Should maintenance and repairs become excessive, consideration should be made to the use of silicone or epoxy based liners to improve hydraulic performance and reliability while increasing durability.

(ii) Opportunities to Increase Value

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility's value through increased generation. Improved environmental performance is also a factor which could increase the project's value.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

This case study presents the results a HAP assessment that was performed on February 22, 2012 by a team of hydropower experts and engineers from Mesa Associates, HPPi (Hydro Performance Processes Inc.), and ORNL (Oak Ridge National Laboratory). During the site visit, Units 2 and 3 were in operation, but Unit 1 was out of service, allowing for direct inspection of several components which are normally inaccessible during operation. The HAP assessment was performed to identify potential asset and operation improvements at the Flaming Gorge hydropower facility, and the on-site visit allowed for verification of pre-assessment information and acquisition of missing information needed the final HAP assessment.

Condition assessments were performed on all major components in mechanical, electrical, civil, and I&C (instruments and controls). The mechanical portion of the assessment was limited to turbines, governors, and the raw water and lubrication systems. Electrical components which were evaluated include the generator stator and rotor, exciter, and GSU transformers. Civil/structural components which were assessed include trash racks and intakes, penstocks, leakage and releases, and draft tube gates. The I&C portion of the assessment consisted of the automation system and instruments used for unit performance measurement. The condition assessments involved individual CI (Condition Indicator) and DI (Data Quality Indicator) ratings for all components and each unit. The CI and DI ratings were based on a 0-10 scale, with higher values indicating better conditions and higher assessment confidence, respectively. Performance assessments were conducted using hydrology-based and optimization-based operational and dispatch analyses.

2.3 Description of Work Undertaken (detail)

1-d) Asset Management, Strategic Asset Management, and Life-cycle Cost Analysis

The Flaming Gorge hydropower facility site visit was conducted as a part of a the HAP assessment, and the results of this assessment will eventually be aggregated with other facility assessments to characterize and trend the asset conditions across different facilities, owner fleets, regions, and overall U.S. hydropower fleet, and also to correlate the performance to the condition ratings. Cost estimates are also included to support determinations by DOE (U.S. Department of Energy) and hydropower facility owners as to which facility upgrades are worthy of further studies. According to the HAP assessment, total capital costs for the recommended improvements at the Flaming Gorge facility is around $1.0 million.

2-c) Technological innovation, deployment expansion and new materials used for civil and building works

Mechanical components at the Flaming Gorge facility were found to be in very good to excellent condition, with high confidence in the condition assessment results. Electrical components were found to be in good to very good condition, with high confidence in the condition assessment results. Civil/structural components were found to be in good overall condition, with high confidence in the condition assessment results for most components. Since access to trash racks and draft tube gates was restricted during the site visit, lower confidence is associated with the condition assessments for those components. I&C components were found to be in fair condition, with high confidence in the condition assessment results.

Recommendations based on the condition assessments results are listed in Section 4 of this report. Potential plant generation improvements due to direct optimization and plant efficiency improvements, while producing the same power at the same time, were small for Flaming Gorge, averaging about 0.2% for 2008-2011. The potential generation improvements from using available water at peak plant efficiencies range from 1.4% to 2.3% over the same study period. Correlation analyses indicated that the actual unit performance is approximately 1% lower than expected, and periodic efficiency losses for Units 1 and 2 indicate potential trash rack fouling.

3. Feature of the Project

3.1 Best Practice Components

- Collaboration between hydropower experts/engineers with facility owners to fully document component conditions and plant performance
- Standard methodology for conducting condition and performance assessments to identify recommended improvements

3.2 Reasons for Success

The success of the Flaming Gorge HAP assessment can largely be attributed to: 1) proper preparation by the hydropower experts/engineers prior to the site visit, 2) suitable accessibility to facility components, detailed archiving of maintenance activities, and effective communication between parties during the site visit, and 3) use of the developed standard assessment methodology using data and ratings following the site visit.

4. Points of Application for Future Project

As the HAP assessment represents an evaluation of potential upgrading opportunities rather than a completed project, the assessment's recommendations represent points of application for a future project. Details regarding the recommendations are listed below:

- Upgrade the current mechanical governors to digital technology
- Monitor the exposed un-insulated cooling water piping
- Include stator and electrical tests and PPT bridge resistance reading into the electrical test program
- Monitor the stator insulation condition on-line through partial discharge monitoring
- Monitor and trend carbon monoxide generation rates in the transformer oil
- Investigate and correct elevated dissolved oxygen levels in the transformer oil
- Perform ASTM D-1816 dielectric testing of transformer oil quality in lieu of ASTM D877
- Perform transformer winding resistance testing
- Install a trash rack monitoring system
- Replace the current coal tar enamel lining in the penstock with silicone or epoxy based liners
- Inspect the intake interiors regularly
- Complete all necessary repairs of the spillway tunnel and outlet works
- Add flow meters at the outlet works
- Continue monitoring of seepage at rock abutments
- Upgrade the dated automation system
- Implement a user-friendly historical archiving system
- Install an improved condition monitoring system

5. Others (monitoring, ex-post evaluation, etc.)

None

6. Further Information

6.1 Reference

ORNL, Mesa Associates, and HPPi. Flaming Gorge Hydropower Facility: Final Assessment Report, Hydropower Advancement Project, 2012.

6.2 Inquiries

Company name : Oak Ridge National Laboratory

URL: https://www.ornl.gov/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – d) Asset Management, Strategic Asset Management, and Life-cycle Cost Analysis

Sub: 2 – a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Rhodhiss Hydropower Facility: Final Assessment Report

Name of Country (including State/Prefecture):

North Carolina, United States of America

Implementing Agency/Organization:

Duke Energy Corporation (project owner)
Mesa Associates, HPPi, and ORNL (assessment team)

Implementing Period:

This project represents a condition, performance, and opportunity assessment with no completed or scheduled upgrade activities that have been identified from the assessment.

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction
(C) Needs for higher performance

Keywords:

condition assessment, performance assessment, HAP (Hydropower Advancement Project)

Abstract:

This case study presents the results a condition and performance assessment of Rhodhiss hydropower facility that was performed by a team of hydropower experts and engineers from Mesa Associates, HPPi, and ORNL following a site visit on August 1, 2011. Pre-assessment data were collected to enhance the visit's productivity. On-site condition evaluation of plant components and plant personnel interviews enabled further data collection and verification to complete a full HAP assessment using the developed standard methodology. Overall, the Rhodhiss plant was found to be in fair condition with a fair level of confidence in the assessment results. Despite the overall fair condition, several upgrade opportunities were identified to address ageing equipment and generating facilities, and recommendations were made.

Based on the original HAP plan, additional U.S. hydropower facilities will be assessed using the HAP assessment methodology, and eventually the assessment results will be aggregated from all assessed facilities to characterize and trend the asset conditions across different facilities, owner fleets, regions, and overall U.S. hydropower fleet, and also to correlate the performance to the condition ratings.

1. Outline of the Project (before Renewal/Upgrading)

The case study presented herein represents the results of a condition and performance assessment which identifies the improvement opportunities that should be examined through subsequent activities and evaluations at the Rhodhiss hydropower facility and includes an order of magnitude cost estimate that may support determinations by the United States Department of Energy and hydropower facility owners as to which upgrades warrant further studies.

The Rhodhiss hydropower facility, as shown in Fig. 1, is located on the Catawba River in North Carolina, United States of America (35°46’27”N, 81°26’16”W). The facility, with reservoir and all appurtenances, was constructed and commissioned in 1925 and is currently owned and managed by Duke Energy Corporation. The hydropower facility has three Francis turbine units with design net head of 59 ft each. The original nameplate capacity of each unit was 8.5 MW per unit (26 MW in total), but Unit 2 has since been uprated to 10.7 MW. Thus, the current plant power capacity is 28.2 MW. Various refurbishment, rehabilitation, and upgrading events have enhanced the project since its construction.

Fig. 1 Location of Rhodhiss Hydropower Facility

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

Because this case study represents an assessment for potential upgrades rather than a completed project, the following trigger causes and drivers for renewal and upgrading are based on recommendations from the Hydropower Advancement Project (HAP) standard assessment methodology.

(i) Conditions, Performance and Risk Exposure and Others

(A) - (a) Degradation due to ageing and recurrence of malfunction – improvement of efficiency

Trash buildup on the trash racks was a significant problem prior to replacement in 1998-1999, and the facility currently has no trash rack monitoring system. Turbine runners for Units 1 and 3 are the original equipment and are manufactured from cast iron, while the Unit 2 runner was replaced with a new composite runner in 2000. To address D.O. (dissolved oxygen) levels downstream of the dam, Rhodhiss discharges air from the turbine through augmented vacuum breaker systems in Units 1 and 2, leading to a drop in unit efficiency due to air intake into the turbine. The plant’s stay vanes and spiral cases, as well as the Unit 3 wicket gates are original equipment and could achieve higher efficiency through upgrades. The transformers were found to be in substandard condition after 86 years of service. The plant has no automatic supervisory control to optimize generation, though the units are small at Rhodhiss.

(ii) Opportunities to Increase Value

(C) - (a) Needs for higher performance – efficiency improvements, addition of power & energy, loss reduction

By addressing the potential for efficiency improvements, the upgrade can also increase the facility’s value through increased generation. Improved environmental performance is also a factor which could increase the project’s value.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

This case study presents the results a HAP assessment that was performed on August 1, 2011 by a team of hydropower experts and engineers from Mesa Associates and ORNL (Oak Ridge National Laboratory). During the site visit, only Unit 1 was in operation. The HAP assessment was performed to identify potential asset and operation improvements at the Rhodhiss hydropower facility, and the on-site visit allowed for verification of pre-assessment information and acquisition of missing information needed the final HAP assessment.

Condition assessments were performed on all major components in civil, mechanical, electrical, and I&C (instruments and controls). Civil/structural components which were assessed include trash racks, intakes, penstocks, and leakage and releases. The mechanical portion of the assessment was limited to turbine runners, wicket gates, stay vanes, spiral cases, draft tubes, vacuum breakers, generator stators and rotors, and governors. Electrical components which were evaluated include the generators, exciters, and transformers. The I&C portion of the assessment consisted of visual inspection of the control room and plant instrumentation. The condition assessments involved individual CI (Condition Indicator) and DI (Data Quality Indicator) ratings for all components and each unit. The CI and DI ratings were based on a 0-10 scale, with higher values indicating better conditions and higher assessment confidence, respectively. Performance assessments were conducted using hydrology-based and optimization-based operational and dispatch analyses.

2.3 Description of Work Undertaken (detail)

1-d) Asset Management, Strategic Asset Management, and Life-cycle Cost Analysis

The Rhodhiss hydropower facility site visit was conducted as a part of a the HAP assessment, and the results of this assessment will eventually be aggregated with other facility assessments to characterize and trend the asset conditions across different facilities, owner fleets, regions, and overall U.S. hydropower fleet, and also to correlate the performance to the condition ratings. Cost estimates are also included to support determinations by DOE (U.S. Department of Energy) and hydropower facility owners as to which facility upgrades are worthy of further studies. According to the HAP assessment, total capital costs for the recommended improvements at the Rhodhiss facility is around $3.6 million.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Civil/structural components were found to be in overall fair condition, with low confidence in the condition assessment results. The turbines and turbine governors were found to be in fair to good condition, with relatively high confidence in the mechanical condition assessment results. The generators were found to be in fair condition, and the exciters were found to be in good condition for Units 1 and 2 and fair condition for Unit 3, with fairly low confidence in the condition assessment results. Instruments and automation system components were found to be in fair to good condition, with high confidence in the assessment results. The overall low confidence in the condition assessment results is largely due to a lack of archived O&M records, physical limitations during the site visit, and an unclear scope of the HAP assessment at the time of the site visit. With future improvement to the HAP assessment methodology, higher confidence will be achieved.

Recommendations based on the condition assessments results are listed in Section 4 of this report. Potential plant generation improvements due to plant efficiency improvements and optimized plant dispatch, while producing the same power at the same time, averaged about 2.3% for 2007-2011. The potential generation improvements from using the available water at the peak plant efficiencies averaged about 4.7% over the same study period. The potential generation improvements from the combination of optimized plant dispatch, improved scheduling, and state of the art turbines and generators averaged about 9.8%.

3. Feature of the Project

3.1 Best Practice Components

- Collaboration between hydropower experts/engineers with facility owners to fully document component conditions and plant performance
- Standard methodology for conducting condition and performance assessments to identify recommended improvements

3.2 Reasons for Success

The success of the Rhodhiss HAP assessment can largely be attributed to: 1) proper preparation by the hydropower experts/engineers prior to the site visit, 2) suitable accessibility to facility components, detailed archiving of maintenance activities, and effective communication between parties during the site visit, and 3) use of the developed standard assessment methodology using data and ratings following the site visit.

4. Points of Application for Future Project

As the HAP assessment represents an evaluation of potential upgrading opportunities rather than a completed project, the assessment's recommendations represent points of application for a future project. Details regarding the recommendations are listed below:

- Install a trash rack monitoring system
- Develop a more modern hydraulic turbine runner design and improved aeration delivery method
- Replace the cast iron runners for Units 1 and 3
- Rehabilitate the Unit 3 gates through new coatings and shape re-profiling
- Rehabilitate the stay vanes through new coatings and shape re-profiling
- Evaluate the need for draft tube modification
- Monitor transformer oil oxygen and carbon monoxide levels
- Dry out the transformers and reclaim transformer oil
- Conduct winding power factor tests
- Evaluate the transformer 2 bushing power factor
- Replace the transformers
- Protect the collector rings on Unit 3
- Replace the Unit 3 exciter
- Update the generator efficiency curves
- Upgrade the control system
- Upgrade the Unit 3 control system to match Units 1 and 2
- Connect the SOE date to the iFIX system

5. Others (monitoring, ex-post evaluation, etc.)

None

6. Further Information

6.1 Reference

ORNL, Mesa Associates, and HPPi. Rhodhiss Hydropower Facility: Final Assessment Report, Hydropower Advancement Project, 2012.

6.2 Inquiries

Company name : Oak Ridge National Laboratory

URL: https://www.ornl.gov/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-d) Asset management, strategic asset management and life-cycle cost analysis

Sub: 2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

1-e) Projects justified by the non-monetary valuation of stabilizing unstable power systems in the up-coming low-carbon society

Project Name:

Refurbishment of Luiz Carlos Barreto de Carvalho (Estreito) Powerplant – Project of synchronous condenser

Name of Country (including State/Prefecture):

Brazil – São Paulo – Pedregulho

Implementing Agency/Organization:

ELETROBRAS FURNAS

Implementing Period:

January 2007 to August 2012

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction

Keywords:

Synchronous Condenser, Generator, Hydraulic Francis Turbine, Reactive Power

Abstract:

Next section reference

1. Outline of the Project (before Renewal/Upgrading)

This is one of the five FURNAS power plants with output greater than 1,000 MW. In 1962, FURNAS was in charge of finishing the viability studies for the Estreito Plant (as it was formerly called). Construction began in 1963, coinciding with the beginning of commercial operations at the FURNAS Plant, which is located upstream. Its first unit went online in March 1969, which was a significant milestone because of the amount of Brazilian manufacturers and construction companies involved and meant that the original schedule had been maintained.

The Luiz Carlos Barreto de Carvalho dam normally operates at an almost flat level, due to the water flow control done by the FURNAS Plant upstream. When it was concluded, the Estreito Power Plant had one of the lowest cost per kilowatt among power stations in the world, because of its run-of-river reservoir which led to low expropriation costs.

Established in 1969, the plant is located in the municipal area of Pedregulho, close to the city of Franca in São Paulo, and has six turbines with a total output of 1050 MW, sufficient to meet the energy needs of 20 medium cities.

Technical Data

Items			Descriptions
Dam and Reservoir	Dam	Type	Rock Filled Embankment Dam with a Clay Core
		Max. Height	92 m
		Crest Length	535 m
		Crest Width	15.8 m
		Crest Elevation	629 m
		Total Volume	4,290,000 m^3
	Reservoir	Max. Storage Level	622.50 m
		Max. Flood Level	626.64 m
		Min. Operating Level	618.50 m
		Flooded Area	46.7 km^2
		Total Volume	1,418 million m^3
		Operating Volume	178 million m^3
Power Station	Type		Covered
	Size		177 m x 24.2 m
	Generating Units	Quantity	6
		Revolutions	112.5 rpm
		Rated power	175 MW
	Turbines	Type	Francis Vertical Axis
		Rotor Diameter	5.8 m
		Manufacturer	Voith Consortium (Brazil & Germany)
		Max. Power Discharge	306.6 m^3/s
		Rated Head	65 m
	Generator	Frequency	60 Hz
		Terminal Voltage	13.8 kV
		Manufacturer	ASEA (Brazil & Sweden)
	Transformer	Quantity	20 (operational plus reserve)
		Type	Single Phase
		Total Operating Capacity	1199.88 MVA
		Transformation ratio	13.8/345 kV
		Manufacturers	Jeumont Schneider (France), ACEC (Belgium) & COEMSA (Brazil)

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A) Degradation due to ageing and recurrence of malfunction:

(ii) Opportunities to Increase Value

None

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

1962	Complete Feasibility Study
1963	Start Construction
1969 Mar.	Commissioning first unit
2007 Jan.	Start Refurbishment
2008 Feb.	Finish Unit 1
2008 Nov.	Finish Unit 2
2009 Sep.	Finish Unit 3
2010 Aug.	Finish Unit 5
2011 Jun.	Finish Unit 4
2012 May	Finish Unit 6
2012 Aug.	Finish Refurbishment

2.3 Description of Work Undertaken (detail)

FURNAS began the refurbishment of Estreito Power plant in 2006 and finished in 2012. The FURNAS’ decision to refurbish Estreito Power plant was due to recurrence of malfunction of the units and their auxiliary systems because of degradation and ageing.

FURNAS had studied new materials and processes to repair cavitation in Francis turbine blades and carried out the repair by the material "*Cavitalloy*". FURNAS also had developed a project to implement a pressurized air system so the units can operate as synchronous condensers.

Unit 1 went back online in February 2008, unit 2 in November, unit 3 in September 2009, unit 4 in June 2011, unit 5 in August 2010 and unit 6 in May 2012

1-d) Asset management, strategic asset management and life-cycle cost analysis

The cost of applying the material "*Cavitalloy*" is 30% greater than the costs of recovering the blades with the stainless steel traditionally used. However, the interval between repairs tend to increase by 50%. With this in mind, FURNAS expects to improve performance of the units by increasing the resistance of cavitation and therefore reducing maintenance costs.

The reason runner blades were so easily damaged by cavitation was that turbines always had been with operation in speed no load or upper load mode, in conditions always above or below of hillchart cavitation limits. This situation happened because the control system electric had been managed by ONS (Operador Nacional do Sistema Elétrico).

FURNAS always have been repaired their turbines with 34,000 hours operation, before the new method. FURNAS expects to change our maintenance inspection for 50,000 hours of operation with new method.

i) Alloys Used to fulfill (repair of cavitation erosion) and coating

The actual development of technology global have showed that the austenitic alloys associated with cobalt (Co), increase the resistance although intense cavitation.

Some hypotheses are suggested to explain the increase of this resistance, one is based on the mechanism of hardening, associated with the phase transformations (austenite to martensite $\gamma \rightarrow \alpha$) or (austenitic to ferritic $\gamma \rightarrow \varepsilon$) , caused by bubbles collapses deformations against the surface.

There is a reduction in the rate of material loss in the order of ten times, for the stainless steel 308 and 309, so there is a increase in the operation time of the equipment. The cobalt alloys were initially provided only for the coated electrode process, but they had a low productivity. The new alloys in the form of wire MIG / MAG, it only was possible to manufacture on compact form, due to the high hardness of the material.

The welding process MIG / MAG standard, the operational point of view, revealed problematic, resulting in poor surface, failure of fusion, and a lot of porosity. Thus, the excellent quality of the material, with respect to cavitation resistance, was seriously compromised because the faults arose in regions of cavitation.

In the presence of difficulty operational MIG/MAG wires cobalt, mainly by the unfavorable positions of welding, the Welding Laboratory of UFSC, developed a full technology (Patent: Privilege and Innovation. N. PI0004698-1 "MIG/MAG Thermal Pulsation". September 15, 2000), including the equipment that revolutionized the application of the wires cobalt, the MIG / MAG process for recovery turbines.

The basis of the technology have been joined the advantages the MIG/MAG with TIG, and was named MIG/MAG process pulsed thermal or double pulsed. The cycles of high-energy act to eliminate the lack of fusion, while the cycles of low energy are responsible for welding in position over-head. Welding Procedure Recommended Repairs Cavitation Erosion in Turbines.

The first step to recovery the blades is arise the damages regions and determine and register the profiles. The surface and internal discontinuities must be removed and have been confirmed by non-destructive testing techniques.

The usual procedure is to reconstruct the welding structure before applying coating compatible. (e.g. the carbon steel structure , use AWS E71T1, the martensitic stainless steel structure, E410 -NiMo use AWS). After the structure has been reconstructed, can be applied two layers with AWS 309L stainless steel. The coating on the cobalt alloy is then applied in two layers by welding MIG / MAG pulsed.

It is essential to perform a perfect cleaning and inspection non- destructive "inter - passes". The pre-heating for welding cobalt alloy is not required, however the component should be free of humidity and hydrogen in the surface. The welding is usually fulfilled in layers to reduce the heat input.

The gas protection for welding is composed of 98% Ar (argon) + 2% (oxygen) .The parameters suggested for welding in position overhead are : the distance between the contact tip and the piece "stickout", not exceeding 10mm (5mm nozzle protruding over the edge of the contact tip), 150A and 22V . The polarity of the wire is always positive.

ii) Source Welding Alloys

The test carried out at the Research Center for Energy - CEPEL (RE No.693/94-R), compared the strength of 309 in relation of the cobalt alloy, and it is showed that the samples of conventional alloy 309AWS-Mo decreased a rate 5.5 mg/hr, 11 times less resistance than the cobalt alloy. However, in the hydraulics turbines where conditions differ from cavitation laboratory test, this relationship has been observed in the range of 2.5 to 5 times. (Source CEPEL)

iii) Coating Based on the Cobalt Alloys

- Fulfill with carbon steel following the steps mentioned above, up to 10 mm depth.
- Continue with the deposition of stainless steel, which should be made at least two welding passes.
- Make surface regularization of the stainless steel up to at least 6 mm depth.
- Make a liquid penetrant test to evaluate the result of welding to the presence of pores, cracks, etc.
- Fulfill with cored wire cobalt alloy until finishing layer up to 3 mm.
- The cobalt alloy cannot be welded upon the carbon steel.

1-e) Projects justified by the non-monetary valuation of stabilizing unstable power systems in the up-coming low-carbon society

Synchronous condenser operation of hydropower is conducted, in cooperation with other phase modifiers in the power grid system, such as power capacitor, shunt reactor etc , for controlling reactive power in the grid and ensuring that power flows from generation to load.

Estreito plant has been operated for many hours continuously as very significant role of synchronous condensers by request from the power system operator.

In other words, the Estreito may be considered to be a good practice for the project which has a role as stabilizing unstable power grid caused by solar/wind power generation and other variable renewables.

2-a) Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Another project change made was implementation of “***a pressurized air system***” to lower the draft tube level, so the units can operate as synchronous condensers. This circumstance allows the units to operate as a synchronous condenser and reduce cavitation in the turbine because it no longer operates in “speed no load” mode.

The supplier designed the draft tube water level depression system and furnished the following equipment:

- Air compressor plant with controls
- The pressure vessels storing was reused of the hydraulic governor
- Air injection valves
- Cooling water valves for the runner wearing rings
- Level, flow, pressure and temperature control instruments and circuits
- Piping and connections

The system supplies compressed air for operation of all 6 units to working as synchronous condensers with the water level in the draft tube depressed and the runner rotating in air. The maximum level of downstream to operation is 564,60 m. The system of compressed air is composed of 5 compressors with 13.8bar. The rated power of the each compressor is 200CV. The 6 pressure vessels storing compressed air are sufficient quantity to supply to one UG.

To controlling the air discharge in draft tube, valves are actuated hydraulically by governor system. The valve DN 10 "ACX-02 is for rapid discharge of air while the valve DN 3" ACX-03 is to replacement for discharge, this condition is to control the water level depressed in the draft tube.

To returning to generator, the air drain valve DN 10 "ACX-04 is provided and is installed in the branch pipe that drains the air from the draft tube to downstream.

The transferring of the unit to operate as a synchronous condenser will be controlled by the digital system of supervision and control of the Plant.

In the operation synchronous condenser mode, is actuated cooling water system to the upper wearing ring of the turbine and the valves and AFX-01 at the same time that total closure of the wicket gate. The water for cooling the lower wearing ring of the turbine is automatically actuated when the gates release all hole pipes connected in spiral case.

The switch levels had had many problems and have been replaced by the switch pressure which sends the signal to the digital system of supervision and control that controls the valves and ACX-03 e ACX-04.

3. Feature of the Project

3.1 Best Practice Components

(None)

3.2 Reasons for Success

(None)

4. Points of Application for Future Project

(None)

5. Others (monitoring, ex-post evaluation, etc.)

(None)

6. Further Information

6.1 Reference

- Project of pressurized air system and control system regarding the operation of the units as synchronous condensers – Andritz Brazil Company
- Project of application of new materials and process to repair cavitation on Francis turbine blades – FURNAS Company

6.2 Inquiries

ELETROBRAS FURNAS
URL: http://www.furnas.com.br/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1 – c) Integrated management of water resources and river systems

Sub: 2 – a) Technological innovation & deployment expansion of E/M equipment

Project Name:

Refurbishment of thrust bearings and Francis turbines at SISTERON Hydro Power Plant

Name of Country (including State/Prefecture):

France

Implementing Agency/Organization:

Electricité de France

Implementing Period:

2009-2014

Trigger Causes for Renewal and Upgrade:

(A) Degradation due to ageing and recurrence of malfunction:

(a) Improvement of efficiency, (b) Improvement of durability and safety

Keywords:

Refurbishment, Thrust Bearing, Francis turbine/runner, Performances

Abstract:

The SISTERON Hydro Power Plant (France) is composed of two identical units of 128 MW each at 110 m of nominal net head. The turbines of these units are the Francis type. After 35 years of operation, the hydro-mechanical equipment showed serious signs of wear linked to chronic disorders which make operation more and more restrictive and risky. A general refurbishment was planned in order to secure operation and upgrade the overall performances of the unit.

Thrust bearings and wet turbines mechanical parts have been replaced by new equipment. Each new thrust bearing has now been equipped with pads held up by the hydraulic self-compensation technology, and with an oil-injection system designed to make unit starting and stopping sequences more reliable. A new runner has been designed including a new blade profile which should increase efficiency from 2% to 5% according to model test. As unit operation at part load is expected, an axial air-supplying system has been installed from the top of the unit to the open center of the runner passing through the existing hollow shaft in order to reduce downstream pressure fluctuations. The distributor has been replaced except the bottom ring and the head cover which have been kept and refurbished: low leakage is now expected due to a new water-tightness sealing system; the cinematic of the distributor has been modernized with a torque transmission system by friction between each gate and its lever, and a braking system in case of jamming and gate de-synchronization. During erection, shaft line alignment has been carried out meticulously in order to reduce bearing displacements and vibration levels.

1. Outline of the Project (before Renewal/Upgrading)

SISTERON HPP is an underground Power Plant on the Durance river line (located in south-east of France), commissioned in 1975, consisting of 2 identical units (Francis turbines) supplied by a 32 km open channel, then 2 independent penstocks (140 m, ∅6 m), for a total installed capacity of 244 MW under 110 m of nominal net head.

After 35 years of operation, the hydro-mechanical equipment showed serious signs of wear linked to chronic disorders which make power generation more and more restrictive and risky. A general refurbishment was planned in order to secure operation and upgrade the overall performances of the units.

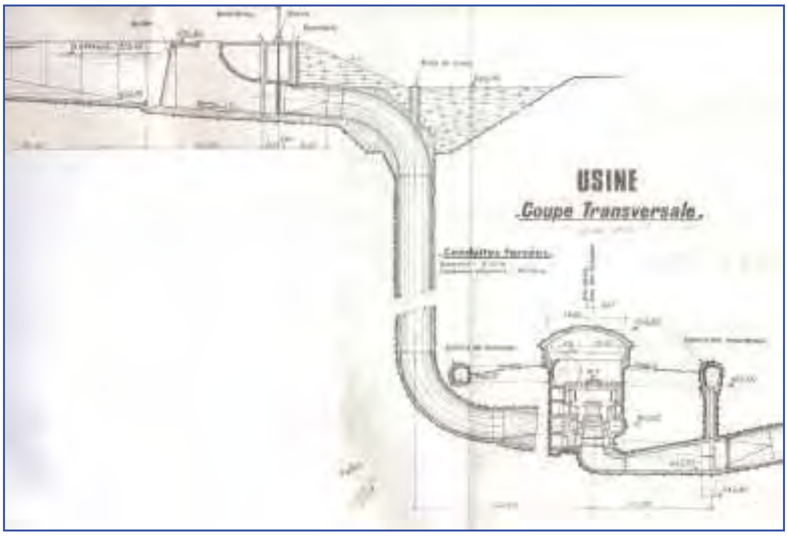


Figure – Hydro Power Plant cross section

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure and Others

(A)-(a) Degradation due to ageing and recurrence of malfunction - Improvement of the efficiency

Low level of hydraulic performance of the runners was confirmed by several series of measurements on site. New hydraulic components are designed to produce a marked improvement in performance: new runner (new hydraulic design); new guide vane profiles; replacing the tripod with an axial aeration of the runner through the tubed shaft line.

The considerable uncertainty of an in-situ performance measurement (±1.2% up to ±2%) puts the forecasts into perspective. However the potential gain remains positive even if the most unfavourable scenario is taken into account. The new runner should therefore lead to a minimum increase in overall hydraulic performance of 1.6%, which corresponds to an average gain of 11700 MWh/year for the 2 units.

Record of estimates and measurements	Optimum efficiency	Weighted average efficiency	Measurement uncertainty
Original in-situ measurements (1979)	Reference	Reference	±2.0%
Predictive performances for the new runner (2010)	Ref. + 3.9%	Ref. + 5.1%	
Model tests (2011)	Ref. + 3.7%	Ref. + 5.4%	±0.24%

Table – Estimates and measurements of hydraulic performances

(A)-(b) Degradation due to ageing and recurrence of malfunction - Improvement of durability and safety

The existing hydro-mechanical equipment showed serious signs of wear linked to chronic disorders which make power generation more and more restrictive and risky. A general refurbishment was planned in order to secure operation:

Disorders to resolve	Scope of rehabilitation
High thrust bearing temperatures (pads and oil) generating linear creep of the pads' white metal.	**New thrust bearing** ○ Hydraulic self-balancing technology (balancing the axial load between the pads); ○ Oil injection system on starting and stopping the units; ○ External cooling system.
Deformations of the distributor ○ Leaks through the distributor; ○ Impossible to operate in synchronous condenser mode; ○ Problem made worse by successive increases in the pre-stressing of the distributor; ○ Risks of seizure and permanent deformations.	**New watertight distributor** (except the existing head cover and bottom ring which are kept and rehabilitated).
Vibration state of the damaged shaft-line ○ Inclination of the shaft-line; ○ Guide bearing clearance values higher than usual; ○ Spiral case supporting surfaces out of horizontal; ○ Probable shaft coupling defect; ○ Overheating of the generator guide bearing.	**Upgrading the shaft-line** ○ Existing guide bearings kept and repaired; ○ Re-machining of the spiral case supporting surfaces; ○ Turbine shaft checked and repaired in the workshop; ○ Check and re-machining of generator shaft coupling flange and its holes on site; ○ New hydrostatic shaft seal; ○ New water cooling system of the generator guide bearing.

Table – Disorders and scope of rehabilitation

(ii) Opportunities to Increase Value

N/A

(iii) Market Requirements

N/A

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Before 2009: Feasibility study & Basic design study
2009: Bidding process
2010: Design studies
2011: Manufacturing stage
2011-2012: 1st on-site work (Unit n°2)
2013-2014: 2nd on-site work (Unit n°1)
2014: End of the Commissioning tests

2.3 Description of Work Undertaken (detail)

1–c) Integrated management of water resources and river systems

The SISTERON Hydro Power Plant is located at the end of a long run-of-river file implying other plants and leading to a major generating capacity. Moreover, SISTERON HPP is not equipped with relief valve or other specific relief device, meaning that all the flow coming to the plant must be generated. So, in case of total failure of the SISTERON HPP, the loss of generating power is huge and do not concern only this plant. The reliable operation of the electro-mechanical equipment of the SISTERON HPP must be secured.

Figure – Geographical situation

2–a) Technological innovation & deployment expansion of E/M equipment

The new weld-fabricated runner is made with martensitic stainless steel and consists of a runner crown, a set of 13 blades and a runner band. The rotating labyrinths are integrated. The existing tripod (installed inside the upper draft tube cone) is removed and replaced by a system of axial aeration of the hydraulic vortex under the runner: an automatic air-supplying valve (spring valve type) is installed at the top of the unit, designed to reduce pressure fluctuations in the draft tube; the hollow shaft line is tubed and sealed at the shaft coupling; lastly, the runner is open at the centre and a non-return ball valve in the runner cone prevents untimely overflowing. The air-supplying valve is said to be automatic because it opens as a result of the depressurization under the runner at partial loads.

The 10 pads of the existing thrust bearing, whose white metal is a lead-based alloy (80%), are mounted on spring of plate type plunged into a bath of oil cooled by a network of finned tubes submerged in the tank without a lifting system on starting up. The new design moves towards greater reliability of the component:

The number of pads is increased to 14 for better operating conditions (reduction of the specific pressure and a thicker film of oil). Since the thrust bearing’s conical support (an integral part of the head cover) has been kept, calculations have been made to ensure that its architecture (10 stiffeners coherent with the 10 existing pads) remains compatible with the sizing of the new thrust bearing (620 tons maximum load). The existing thrust rotating ring (in two parts) is kept, checked and machined after assembly on the shaft.

The new pads, covered with a tin-based coating (80%), are assembled on hydraulic compensators (maximal design pressure: 73 bars) made up of elastic metal bellows strapped between 2 flanges and linked to each other hydraulically for optimum distribution of the axial thrust. At the centre of the compensator, a spherical bearing compensates for any oil circuit outage.

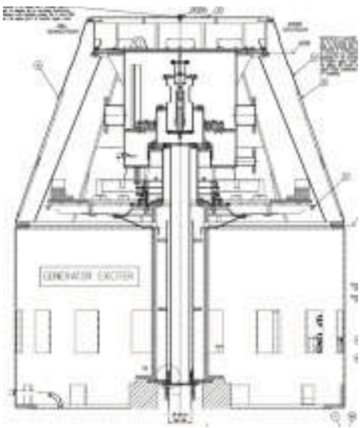
A high-pressure oil injection system (160 bars) at the pads' active surface creates a sufficient film of oil to carry out the frequent stop/start phases (3 per day) quite safely. The injection pumps are duplicated (normal/back-up).
The new refrigeration system is externalised to reduce the risk of water leaking into the oil, to allow ease of access and maintenance and to control the oil/water flows. A hydraulic network sends the oil out of the thrust bearing tank and the unit pit then brings it back in after cooling. A double exchanger with total cooling capacity of 400 kW allows operation on the normal/back-up principle which improves the whole system's reliability even more. The oil circulation pumps are also duplicated (normal/back-up).

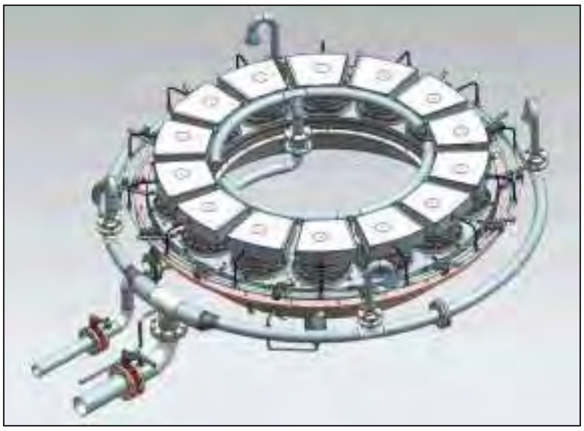
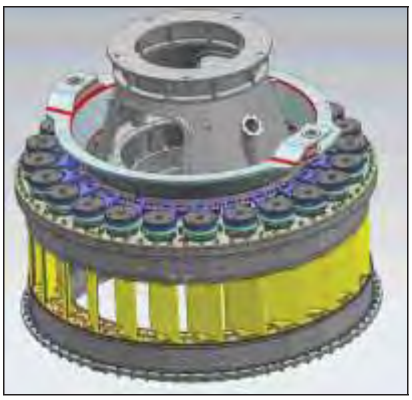
Apart from the covers (head cover and bottom ring) which were kept after being inspected and repaired in the workshop, the whole distributor was replaced, including the following elements: the fixed labyrinths, the guide vanes, the wearing plates, the guide vane stem housings, the guide vane bearings, the distributor mechanism (levers, lever-arms, links, stems and bushes, shear pins), the operating ring and the servomotors.

The new fixed labyrinths for the covers were machined and assembled in the workshop.

The new distributor is sealed with V-rings that can be dismantled, installed at 2 levels: between the guide vanes (when closed) and the wearing plates equipped with the joints; where two adjacent guide vanes meet along the profile.

The distributor mechanism drives a set of 24 guide vanes with a hydraulic tendency to close along most of the stroke. It has: a torque transmission system by friction between the guide vane and its lever; a braking system for each guide vane to slow it down in case of accidental de-synchronisation; a shear pin for each guide vane.




Figures - Air axial valve installed at the top of the unit - New thrust bearing - New distributor

3. Feature of the Project

3.1 Best Practice Components

- Runner aeration of axial type (through hollow shaft);
- Thrust bearing: increase in pads' number (reduction of the specific pressure, better operating conditions);
- Thrust bearing: externalization of the refrigeration system (less risk of leakage, easy maintenance, better flow control);
- Distributor: one shear pin for each guide vane with an alternative sizing of breaking torque (protection of each guide vane and less risk of cumulative breaks);
- Shaft-line alignment: on-site machining of the spiral case's supporting surfaces (horizontal flanges).

3.2 Reasons for Success

The main factor for the success of this project was to closely associate the improvement of the runner hydraulic performances and the need to up-grade the state of the mechanical equipment. During feasibility stage, some calculations (including CFD on existing runner) determined the predictive potential gain of energy generation in case of modern hydraulic runner design. It was demonstrated that the increase in performances could be enough to balance the cost of the refurbishment of the mechanical equipment, so that the project was considered profitable and not only fateful.

The profitability could be reached also because of short period of on-site works in order to minimize the loss of energy generation. So, the other reason for success was to manage the on-site refurbishment works within 6-7 months only for each unit.

4. Points of Application for Future Project

Refer to section 3.1

5. Others (monitoring, ex-post evaluation, etc.)

N/A

6. Further Information

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P. Laurier, B. Spennato, J.-Y. Segura, B. Boulet, SISTERON Hydro Power Plant (France), Refurbishment of Thrust Bearings and Francis Turbines, Design Stage and Preliminary Commissioning Tests, HYDRO 2013, Innsbruck, Austria, 2013.

6.2 Inquiries

Electricité de France

URL : https://www.edf.fr/

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-e) Projects Justified by the Non-monetary Valuation of Stabilizing Unstable Power Systems in the Up-coming Low-carbon Society

Sub: 1-a) Energy policies of Countries & States
1-f) Environmental conservation and improvement
2–a) Technological innovation & deployment expansion of E/M equipment
2-c) Technological innovation, deployment expansion and new materials used for civil and building works

Project Name:

FMHL+ extension project

Name of Country (including State/Prefecture):

Switzerland, Canton de Vaud

Implementing Agency/Organization:

Alpiq Suisse SA

Implementing Period:

2011 to 2016

Trigger Causes for Renewal and Upgrade:

(A)Degradation due to ageing and recurrence of malfunction:
(d) Easy maintenance with less labor
(C) Needs for higher performance
(a) Addition of units, Expansion of power & energy
(b) Role change of hydropower generation. Addition of new functions

Keywords:

Pumped storage, Extension project, Expanded capacity, Balancing energy

Abstract:

The FMHL+ project consists of an extension of the existing Veytaux powerplant in Switzerland, a 240MW pumped storage built in the early seventies, by providing an additional 240MW of pumped storage equipment, using 2 ternary pump-turbine units.

The new underground powerplant will be integrated in the existing waterways between the Hongrin upper storage lake, with a capacity of around 52millons of cubic meters at 1255m of altitude, and the lower lake Léman (Lake Geneva) at around 372m, principally by connecting into the existing penstock and tailrace.

1. Outline of the Project (before Renewal/Upgrading)

The existing Hongrin-Léman pumped-storage scheme, located in Western Switzerland, commissioned in 1971 and operated by FMHL, exploits a maximum head of 878 m between the upper Hongrin Reservoir (52 Mio m3 at 1255 m a.s.l.) and Lake Leman (89’000 Mio m3 at 372 m a.s.l.) at the Veytaux 1 underground powerhouse. The Hongrin reservoir is formed by a twin arch dam of 125 m and 90 m height respectively.

The existing powerhouse contains four horizontal axis pump-turbine units with a total installed power of 240 MW. During off-peak periods, the water from Lake Leman is pumped at a maximum rate of 24 m3/s to be turbined during periods of high demand with a discharge up to 32 m3/s. The connection between the existing powerhouse and Lake Leman is made by a 200 m long underground straight free surface channel.


Hongrin Reservoir with the twin arch dam and view of the existing 140 m long Veytaux 1 powerhouse

Layout and location of the existing dam, waterways and powerhouse

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance and Risk Exposure

(A)-(d) Degradation due to ageing and recurrence of malfunction - Easy maintenance with less labor

The existing powerhouse, consisting of 4 horizontal ternary units of 60MW each, features technology from the early seventies.

Even if close monitoring and maintenance of the units still ensure a good availability of the plant, the extension project will allow, after commissioning of the new powerhouse, to have a unit of the existing powerplant in Veytaux 1 used as reserve and therefore increase the overall availability of the newly formed powerplant.

(ii) Opportunities to Increase Value

(C) - (a),(b) Needs for higher performance - Addition of units, Expansion of power & energy, Role change of hydropower generation. Addition of new functions

The new units are implemented in a new cavern with almost no impact on the environment and with need of limited uprating of the existing waterways

The additional regulating power supplied by the two 120 MW units, including capacity of power regulating in pump mode (hydraulic short circuit), provide an additional value in form of ancillary services delivered to the network.

(iii) Market Requirements

(not applicable)

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

Main project dates are summarized below:

From 2007: Feasibility study

2009: Basic design study

2010: Bidding process

2011-2012: Contracts awards and design studies

2012-2015: on-site Civil works and electromechanical manufacturing stage

2015-2016: Main electromechanical works erection and Commissionning tests

Feasibility stage

First preliminary design studies were started in 2007, showing that an increase of around 180 MW of the existing 240 MW power capacity was considered as technically and economically feasible at the scheme.

Starting in July 2008, EDF and ALPIQ first worked on a preliminary study based on multi-criteria analysis. The purpose was to identify suitable power plant configurations involving all types of units technically available, and to make an economical analysis of the most adapted solutions based on the given project criteria.

The main constraints taken into account were the adaptation limitations of the existing waterways, the size of the machines and the setting needed with the new underground cavern construction, and the overall operational flexibility benefits of the plant. Following discussions with the Owner, additional criteria such as maintainability and service provided to the electrical grid were also defined in order to evaluate the various configurations with the most accurate method.

Basic design stage

Basic design studies were then carried out by the Engineer with the Owners representatives in 2009. This included key aspects of equipment selection with preliminary dimensioning, assessment of sub-configurations aspects, ancillary options, preferred bearing arrangements, shaft seal types, etc, and consideration of other principal design issues in order to optimize the final equipment specification. This stage was also structured in a way which included technical briefings and obtaining feedback from potential hydropower equipment suppliers, prior to the tendering stage. During year 2010, a detailed set of technical specifications was prepared for the 2 ternary units, including auxiliary power station equipment and inlet spherical valves.

This ternary unit layout is relatively unique in terms of size and unusual machine configuration compared to current worldwide experience of other pump storage machines.

Tender stage and Contract awarding

The tendering and evaluation stage was carried out at the end of 2010 with the final contract awarding of main hydro-mechanical equipment lots as well as civil works and penstocks held in early 2011.

2.3 Description of Work Undertaken (detail)

1-e) Projects Justified by the Non-monetary Valuation of Stabilizing Unstable Power Systems in the Up-coming Low-carbon Society

1-a) Energy policies of Countries & States

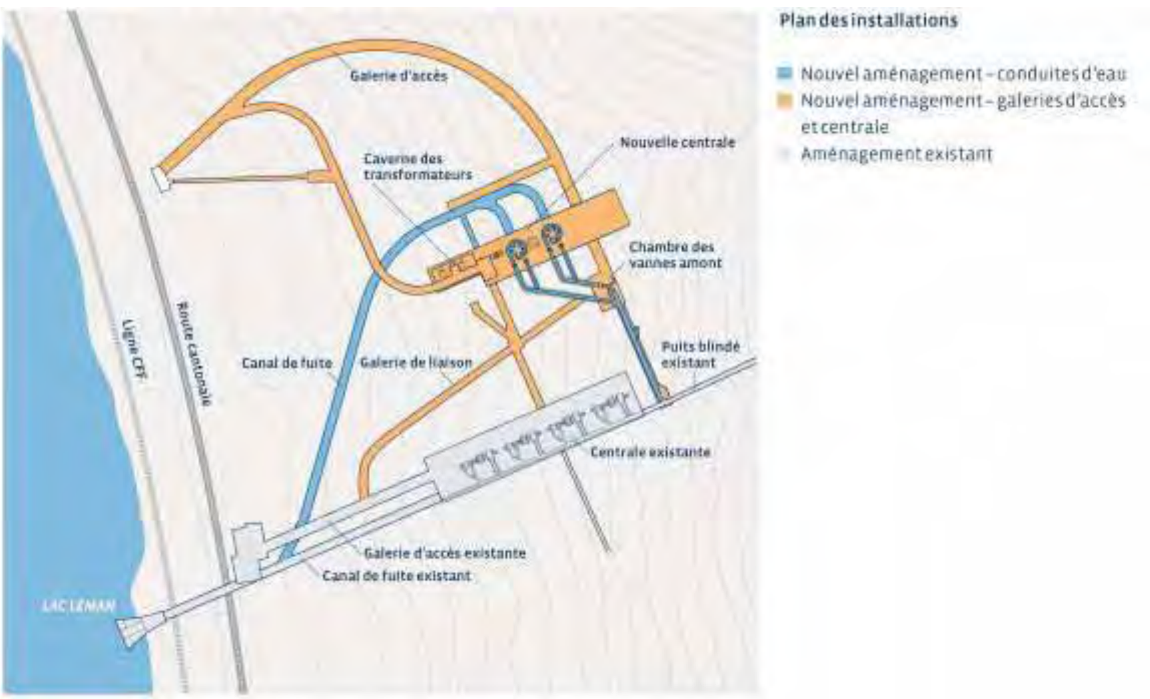
1-f) Environmental conservation and improvement

2-a) Technological innovation & deployment expansion of E/M equipment

2-c) Technological innovation, deployment expansion and new materials used for civil and building works

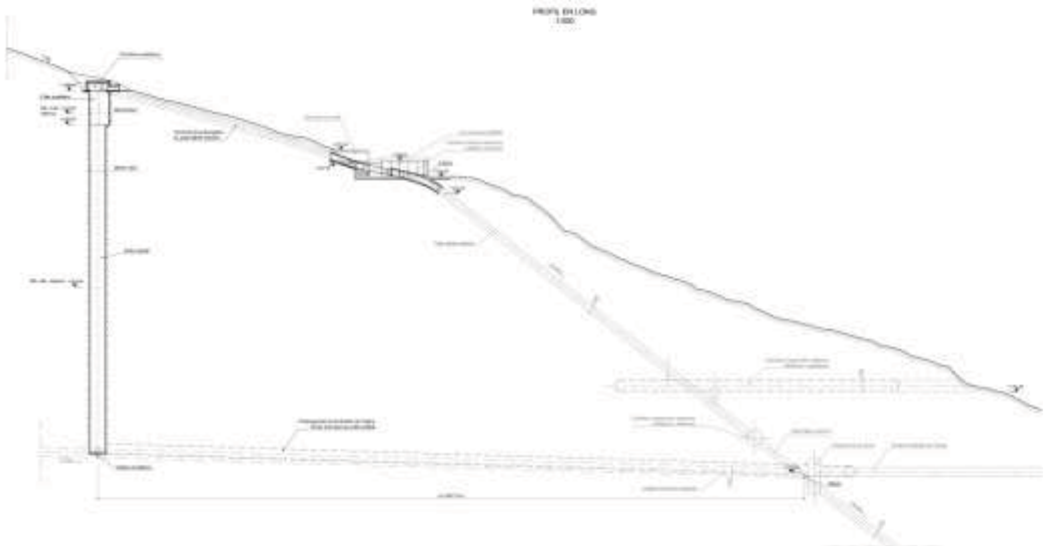
The objective of the FMHL+ enhancement project is to double today's plant capacity by constructing a new underground cavern adjacent to the existing one at Veytaux and to procure regulation energy both in turbine and pumping mode thanks to special function designed in hydraulic "short circuit" mode. Two additional vertical axis pump/turbine groups of 120 MW each will be installed.

The increased flexibility, generating peak electricity, will allow the plant to play an important role in supplying electricity to Western Switzerland and meeting the growing demand for balancing energy which is mainly due to the extension of new renewable energies in Europe and Switzerland.



General layout of both existing Veytaux I (grey) and future FMHL+ powerhouses (in blue new waterway and in orange new galleries and cavern)

The existing 8 km-long headrace tunnel and the 1.4 km-long pressure shaft have both enough capacity to transfer the new generation and pumping discharges of 57 m^3/s and 43 m^3/s, respectively. Nevertheless, the transient calculations of the upgraded scheme have shown that the volume of the exiting surge tank will be deficient regarding the water mass oscillation. Therefore, a new surge shaft of about 170 m length and 7.2 m of internal diameter will be constructed at the upstream end of the pressure shaft to the south-east of the existing one. It will be connected to the headrace tunnel by mean of 28.5 m-long tunnel with 2.2 m of internal diameter.



Cross sectional view of the new upstream waterway layout

3. Feature of the Project

3.1 Best Practice Components

Main specificity of the project is the fact that the new powerhouse is constructed next to the existing one remaining in operation, and that the waterways are modified to match with the future operation of both powerhouses.

Civil work close to the existing waterway in operation

Three years before the beginning of the sitework, some drill and blast tests were undertaken in a gallery near the existing powerstation, to determine the expected vibrations due to the projected sitework. A monitoring system in the existing power station during this test enabled the project engineer to fix some vibration limitation.

All the precautions and adapted methods enabled the excavation works of the new penstock gallery to be performed up to 6 m of the existing penstock under operation. The last 6 m were excavated during the shutdown of the production.

A day to day work and contact between the project Engineer, the geologist and the companies in charge of the work and the powerplant operator was necessary to fit in the requirement of this very particular excavation work.

Connection to the existing pressure shaft

The last 6 m were excavated and the existing 2.7 m diameter pressure shaft was cut and prepared for welding of the new T-junction. The T- Junction weighed 55 tons and was completed with a 15 tons elbow closed with a bulkhead.

T-Junction on existing pressure shaft

The main technical challenges were the handling of the T-Junction, the alignment and the adaptation of this junction on-site and the on-site welding.

Connection of the new surge tank

In the meantime the hydraulic connections were made for the new surge tank: connection of the new surge tank bottom to the existing water way, and the extension of the existing pressure shaft in the existing upper reservoir of the surge tank.

For this connection the existing waterway was steel-lined inside the existing steel-liner and a 2.2m steel pipe was installed in the gallery.

Connection on the waterway (left) and extension of the pressure shaft in the existing upper reservoir (right)

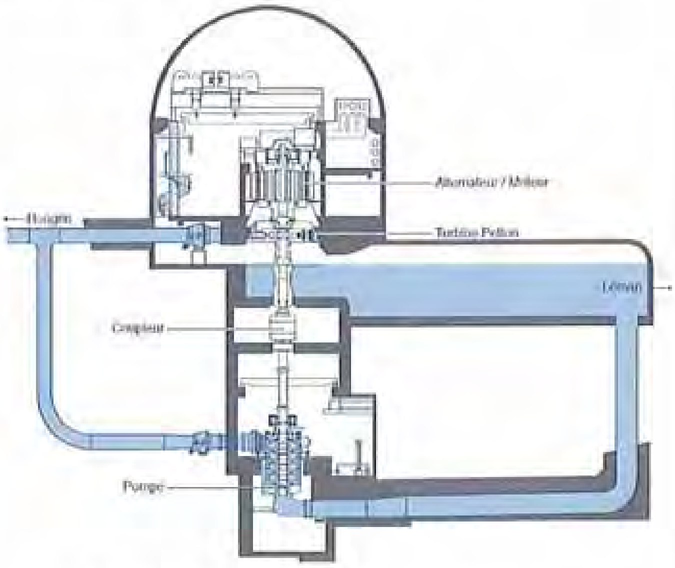
Deepening of the common downstream channel

A physical model test undertaken at EPFL (Ecole Polytechnique Fédérale de Lausanne) shows that a deepening of the common tailwater channel was necessary for the future operation of the new powerstation. The one meter deepening of the common tailwater channel was made during the same shutdown of the powerplant.

Deepening of the common tailwater channel

Hydro and electro mechanical equipment

The unit arrangement adopted is based on a classical ternary vertical unit layout, including from top-to-bottom, a generator-motor, a Pelton turbine, a mechanical coupler and a storage pump, as shown on the cross section view of the FMHL+ powerplant below.



Cross sectional view of the ternary unit

Design studies confirmed that the principle of a ternary arrangement could be used, and a number of feasible shaft connection and bearing arrangements were also considered. The total vertical shaftline length of each ternary unit is relatively long, at over 38.0 m. Each ternary unit is provided with two thrust bearings, one for the generator-motor/turbine section, and the other for the storage pump, along with a number of intermediary guide bearings.

The turbine is located below the generator-motor and above the mechanical coupler. The 118,8 MW Pelton turbine is a state of the art 5 jets unit with specific features related to the ternary unit configuration, such as a lower shaft and a lower bearing located in a watertight shaft sleeve going through the turbine pit and associated specific handling and dismantling tooling. The Pelton discharges directly into tailrace at atmospheric pressure.

Each multistage storage pump is of centrifugal-type, and is of modern “state of the art” design, vertically arranged, consisting of 5-stage impellers fitted onto a single pump rotor, housed within an outer array of integrally vaned return diffuser stages accordingly. The last (top) stage impeller discharges through a diffuser vane into the spiral volute casing, from where pump discharges back up the penstock via connected outlet pipe and discharge valve. The pump rotor is connected to mechanical coupler unit above by intermediary shaft, via top mounted pump thrust bearing.

The pumps are intended to be operated with high levels of efficiency with relatively wide range of operation. During normal pumping duty, the storage pump units always run at full load, either individually or 2 units together, fully independently, with or without other Veytaux 1 units operating. The pumps are also designed for hydraulic “short- circuit” operation, where a proportion of the pump discharge is diverted back though the Pelton turbine.

Thus a relatively complex set of hydraulic transient conditions are applicable to the entire scheme, arising from numerous different permutations of units operation with different unit types, plus possible transient scenarios. Maximum allowable waterhammer pressures were also limited on the Project, due to existing steel penstocks constraints.

The synchronous generator-motor is located on the top of the unit, with a rated apparent power of 130 MVA at a rated voltage of 15,5kV. It is connected through an air-isolated busbar to the main power transformer (135MVA, 15,5kV/400kV) with the unit circuit breaker on the medium voltage side.

The generator-motor supplier is responsible of the whole unit dynamic shaft line calculation, which is particularly challenging for this type of unit.

3.2 Reasons for Success

A close cooperation between the Owner and the Engineer from the very beginning of feasibility up to the current site works has ensured a high level of technical and contractual project management.

The suppliers have also been involved in the project from the early stage in order to ensure their understanding of the project constraints and this fact has allowed to develop the most adapted technical solution very early in the project.

The ongoing site activities also benefit from the close cooperation of all parties.

4. Points of Application for Future Project

State of the art ternary unit was the only adapted machine design to fit with the project constraints, and therefore specific care was taken to optimize arrangement and civil interface of such unusual electromechanical equipment layout. Some other project with similar constraints can benefit from the experience of FMHL+ design and implementation.

Specific constraints on civil works including existing powerhouse and waterways as well as location of the project in a very urban and touristic area, have also led to development of specific solution, which may benefit to other expansion projects involving similar specificities.

5. Others (monitoring, ex-post evaluation, etc.)

N/A

6. Further Information

Reference papers and contact person are summarized below.

6.1 Reference

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[4] **De Cesare.G, Candolfi.S, Wickenhäuser.M, Micoulet.G**, "Flow and waves in a common tailrace channel of two pumped-storage plants–physical and numerical simulations" *Simhydro 2012 Nice*, Session 12 : 3D flows in the near field of structure.

[5] **Lippold.F, Hellstern.N**, "Hongrin-Léman hydroelectric pumped storage plant, Veytaux II powerhouse – Developing a new generation of multistage pump", *Hydro 2012 Bilbao*, Session 9B, Pumped storage : case studies.

[6] **Laurier.P, Herbivo.S, Micoulet.G, Thackray.P** "Hydromechanical equipment of the FMHL+ extension project of the Hongrin-Léman powerplant, Switzerland", *Hydro 2013 Innsbruck, Session 20B*

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[8] **Nicolet Christophe, Taulan Jean-Pierre, Burnier Jean-Michel, Bourrilhon Monique, Micoulet Gaël, Jaccard Alain** – "*Transient Analysis of Hongrin-Léman Pumped-Storage Power Plant for New Surge Tank Design.*" *SHF Enhancing hydropower plant facilities*, Grenoble April 2014

6.2 Inquiries

Company name: Alpiq Suisse SA

URL: http://www.alpiq.ch/fr/index.jsp

Annex XI Renewal & Upgrading of Hydropower Plants

Format for the 2nd Round Data Collection (Definition of Case Histories)

Category and Key Points:

Main: 1-c) Integrated Management of Water Resources and River Systems

Sub: 2-a): Technological innovation & deployment expansion of electro-mechanical (E/M) equipment

Project Name:

Renewal, Upgrading and Capacity Expansion of 125MW Kaplan Turbine Generating Sets in Gezhouba Hydropower Station

Name of Country (including State/Prefecture):

Yichang City, Hubei Province, China

Implementing Agency/Organization:

ChinaYangtzePower Co., Ltd.

Implementing Period:

2005 - 2022

Trigger Causes for Renewal and Upgrade:

(A)Degradation due to ageing and recurrence of malfunction

(C) Needs for higher performance

Keywords:

Hydro-generating set, renewal & upgrade, capacity expansion

Abstract:

Since Gezhouba Hydropower Station was put into operation, the generating sets have been under long-term continuous operating state. The average annual operating hours are up to 6000 hours which are far higher than other similar hydropower stations in China. Until now, the generating sets have been operated for more than 30 years, and some parts of the generating sets have serious aging phenomenon and hidden safety hazards, which affect the safe and stable operation of the generating sets. Therefore, China Yangtze Power Co., Ltd. decided to renew and upgrade the 125MW hydro-generating sets along with the "Level-A Maintenance", and perform renewal and capacity expansion of the generating sets by modern technology and processing means.

By replacing the turbine runners, and generator stator cores, stators and rotor winding bars, this project is to renew and upgrade the old generating sets which have been running for more than 30 years and have hidden safety hazards into new generating sets with advanced level so as to re-establish the overall mechanical properties, eliminate hidden safety hazards caused by long-term operation and prolong the service life of the equipment. In addition to renewing and upgrading the equipment, the turbine power will be increased, the efficiency enhanced and the cavitation erosion resistance improved.

1. Outline of the Project (before Renewal/Upgrading)

Gezhouba Hydro-junction Project is the first large-scale water conservancy and hydropower project constructed on the stem stream of Yangtze River. The project is located at about 2.3km downstream of Nanjinguan (the outlet of Yangtze River Three Gorges), 38km away from the Three Gorges dam site, and about 6km away from the downtown area of Yichang city. It is the shipping cascade and re-regulation reservoir of Three Gorges project, used to channelize the 38km-long natural channels downstream the Three Gorges Dam, re-regulate the unsteady flow of Three Gorges Hydropower Station, and generate electric power by utilizing the water head between the two dams.

Gezhouba Hydro-junction Project is a Class-I Type (1) large project with the crest elevation of 70m, and the maximum dam height of 53.8m. The overall length of the project along the dam axis is 2606.5m. The main structures of the Gezhouba Hydro-junction Project (from left to right) include left bank earth rockfill dam, No.3 shiplock, Sanjiang flushing sluice, No.2shiplock, Huangcaoba concrete water retaining dam section, Erjiang Power Station, Erjiang release sluice, guide wall, Dajing Power Station, No.1shiplock, Dajiang flushing sluice, right bank concrete water retaining dam section.

Gezhouba Hydropower Station has the normal pool level of 66.0m and the lowest reservoir water level of 63.0m. It is a riverbed, run of river, low-head power station. The power house and dam are integrated. As one of the major power plants in Central China power grid, Gezhouba Hydropower Station is divided into Erjiang Power Station and Dajiang Power Station, totally equipped with 21 Kaplan turbine hydro-generating sets. Wherein, Erjiang Power Station is equipped with 7 generating sets, with single capacity of 170MW for 1F and 2F, and 125MW for the remaining 5 generating sets, and total installed capacity of 965 MW. Dajiang Power Station is equipped with 14 generating sets with single capacity of 125MW, and total installed capacity of 1750MW. The first generating set of Gezhouba Hydropower Station was synchronized to the grid in July 1981, and until December 1988, all the generating sets were put into operation to generate power.

Fig. 1 Overall Layout of Gezhouba Hydro-junction Project

Table 1 Technical Parameters of Gezhouba Hydropower Station

Category		Specification
Reservoir	Upstream water level	63-66.5m
	Gross storage capacity of the reservoir	711,000,000m^3
Dam	Name of the dam	Gezhouba Hydro-junction Project
	River name	The Yangtze River
	Type	Concrete gate dam
	Height	53.8m
	Crest length	2606m
Power Plant	Name of the power plant	Gezhouba Hydropower Station
	Rated installed capacity	2715 MW
	Effective head	18.6 m

2. Description of the Renewal and Upgrading of the Project

2.1 Trigger Causes and Drivers for Renewal and Upgrading

(i) Conditions, Performance, and Risk Exposure

(A)- (b)Degradation due to aging and recurrence of malfunction -Improvement of durability and safety

The generating sets in Gezhouba Hydropower Station are approaching the end of their service life so that the defects are increasing year by year, especially, the wear and cavitation on turbine blades are serious, which result in decrease of the turbine efficiency and stability. Therefore, it is necessary to upgrade the generating sets so as to improve the operation stability of the generating sets.

Annual actual utilization hours of the generating sets in Gezhouba Hydropower Station are approximately 6000 hours, which significantly exceeds the average level of hydropower generating sets in China. The maintenance duration is short and the workload is heavy, so great hidden safety hazards exist. Therefore, reducing the utilization hours of the generating sets by capacity expansion will be conducive to the safe operation of Gezhouba Hydropower Station.

(C)- (a) Needs for higher performance- Efficiency improvement,higher power & energy, loss reduction

Gezhouba Hydropower Station is the re-regulation hydro-junction of the Three Gorges Power Plant. When the Three Gorges Power Plant is at full output operation state or peak regulation operation state, the discharge flow will greatly exceed the full output flow of Gezhouba Hydropower Station to result in abandoned water of Gezhouba Hydropower Station, which will adversely affect the peak regulation capability of Three Gorges Power Plant and the overall efficiency of the Three Gorges - Gezhouba Hydropower Station joint operation.

(ii) Opportunities to Increase Value

The annual average generating capacity originally designed for Gezhouba Hydropower Station is 15,700,000,000 kW•h, and the corresponding water utilization ratio is about 76%. After renewal, upgrading and capacity expansion, the flow capacity of the generating sets will be improved to increase the generating capacity and improve the water utilization ratio to about 87%, and the annual average generating capacity can be increased by about 700,000,000 kW•h.

(iii) Market Requirements

None

2.2 Process to Identify and Define Renewal and Upgrade Work Measure

December 1988	Put all the generating sets into operation
1998	Start preliminary study on renewal, upgrading and capacity expansion of the generating sets
April 2005	Forthe two 125MW generating sets in Gezhouba Hydropower Station, properly repair the turbine blades and perform experimental upgrading and capacity expansion of generator, making the power of generating sets reach 146MW
2012	Decide to implement renewal, upgrading and capacity expansion of 125MW generating sets in batches.
2012-2013	Upgrade the generators of the generating set 12F and 15F in Gezhouba Hydropower Station to eliminate the excessive electromagnetic vibration of the generating sets
2013-2014	Upgrade the turbines of the generating set 03F and 06F in Erjiang Power Station and the generating set 08F, 10F, 15F and 20F in Dajiang Power Station
After Oct. 2014	Theupgrading and capacity expansion of the second batch turbines of the generating sets are in process
2022	It is planned to fully complete the renewal, upgrading and capacity expansion of the 19 hydro-generating sets

2.3 Description of Work Undertaken (detail)

1-c) Integrated Management of Water Resources and River Systems

1. Make full use of the incoming water to increase the efficiency of power generation

Gezhouba Hydropower Station is the re-regulation hydro-junction of the Three Gorges Power Plant. When the Three Gorges Power Plant is at full output operation state or peak regulation operation state, the discharge flow will greatly exceed the full output flow of Gezhouba Hydropower Station to result in abandoned water of Gezhouba Hydropower Station, which will adversely affect the peak regulation capability of Three Gorges Power Plant and the overall efficiency of the Three Gorges - Gezhouba Hydropower Station joint operation.

Before renewal& upgrading, the flow for power generation of the generating sets in Gezhouba Hydropower Station is about 18,600 m^3/s, and the flow for power generation of the 32 generating sets in the Three Gorges Power Plant is about 31,000m^3/s. After renewal, upgrading and capacity expansion, the rated flow of each generating set in Gezhouba Hydropower Station will be increased by 70-90m^3/s, and for the whole power station; the flow for power generation of the generating sets can be increased by about 1500 m^3/s; the annual average spillage time will be reduced to 67.7 days from 81.4 days; the water utilization rate can be increased to about 87% from 76%; and the annual average generating capacity can be increased by about 700,000,000 kW•h.

2. Electric power market demand

Gezhouba Hydropower Station is to supply power to the eastern fourprovinces in Central China. According to the electric power demand and power supply planning of the said four provinces, by 2020, after considering the electric power transmission capacity from outer regions, there is still a gap in power grid of the said four provinces. Hydropower is a clean energy, and after the renewal, upgrading and capacity expansion of the generating sets in Gezhouba Hydropower Station, the power grid within the power supply scope of Gezhouba Hydropower Station still has a large electric power market space.

In order to ensure the long-term safe and stable running of the equipment and improve water-energy utilization rate in the flood season, China Yangtze Power Co., Ltd. decided to implement the renewal, upgrading and capacity expansion of the 125MW hydro-generating sets successively since 2012 on the basis of the previous studies and tests.

The renewal, upgrading and capacity expansion of the generating sets in Gezhouba Hydropower Station will be implemented by utilizing the hub projects which have been built, without newly increasing construction land, no reservoir inundation or resettlement, or other problems. The renewal, upgrading and capacity expansion will be performed only inside the original hydropower station, so that the influence scope is very limited. The project is feasible in technology and mature in process, and not restricted by environmental influence factors. It is necessary to implement renewal, upgrading and capacity expansion to eliminate the hidden safety hazards in electric power production, enhance the safety of power grid, and improve the utilization rate of water resources.

2-a) Technological Innovation & Deployment Expansion of Electro-Mechanical (E/M) Equipment

1. Hidden operation safety hazards after long-term operation of the generating sets

The generating sets in Gezhouba Hydropower Station have been running for more than 30 years, and some parts of the generating sets are damaged seriously, which will affect the safe and stable operation of the generating sets. The main problems and hidden safety hazards existing in the generating sets are as follows:

(1) The wear and cavitation at turbine blade clearance, blade surfaces and blade skirts are serious, which result in decline of turbine efficiency, and adversely affect the economic operation of the generating sets.

(2) On some generating sets, the insulation boxes of the winding bar joints have cracks, phase-to-phase corona corrosion of the insulation boxes is serious, or relative replacement exists between insulation box and epoxy filler, etc.

(3) In accordance with the provisions of the relevant norms, the generating sets are approaching the end of their service life after long-term operation, so that there are hidden safety hazards in the aspects of their mechanical and electrical properties.

Therefore, even if no renewal, upgrading and capacity expansion will be conducted on the generating sets, local upgrading and replacement shall be performed for some parts of the generating sets. However, local upgrading can only partially improve the performance of the hydro-generating sets, but the hidden safety hazards existing on the generating sets are not completely eliminated, so that safety risks still exist.

2. Technical progress of electro-mechanical (E/M) equipment

In recent years, China has made gratifying achievements in hydropower construction, especially the successful experience accumulated through the construction of Three Gorges Power Plant and other giant power stations has made China basically become in line with the world advanced level in aspects of design and manufacturing level of hydro-generating sets. Many times of turbine model tests have shown that, compared with the original generating sets, the energy characteristics, cavitation performance, stability and other indexes of the new runners especially designed for Gezhouba Hydropower Station by Harbin Electric Machinery Co., Ltd., and Dongfang Electric Machinery Co., Ltd. of Dongfang Electric Corporation are improved greatly. Through the renewal, upgrading and capacity expansion, the safety performance and single capacity of the generating sets can be improved, so that the old generating sets which have been running for over 30 years can be transformed into the new generating sets with the advanced level.

3. Development of material and technology level of Electro-Mechanical (E/M) Equipment

The hydro-generating sets in Gezhouba Hydropower Station were produced in the late 1970s and early 1980s. The material, technology level and performance indexes at that time are significantly different from nowadays. In accordance with the provisions of relevant norms and operating state of hydro-generating sets, Gezhouba Hydropower Station has entered the renewal and upgrading stage. By using the mature process and new technology, it can effectively improve the operation performance of the generating sets, enhance the power generation efficiency, and re-establish the overall mechanical performance so as to eliminate hidden safety hazards caused by long-term operation, increase the service life of the equipment, increase the single capacity of the generating sets with less input, and improve the utilization rate of water resources, which is also in line with the national energy development strategy.

In summary, according to the actual situation that the generating sets in Gezhouba Hydropower Station have been running for more than 30 years and some parts of the generating sets have serious aging phenomenon and hidden operation safety hazards, it is very necessary and feasible to renew and upgrade the generating sets, eliminate the hidden hazards of equipment and properly increase the single capacity and total installed capacity of the generating sets under the condition that the operation conditions of existing civil works and reservoirs of Gezhouba Hydropower Station are not affected, by using the current new technology and new process in the aspects of equipment manufacturing and installation.

Implementation of the project was formally started in 2012.In the premise of assuring personal and equipment safety, the upgrading and capacity expansion of the generators of 2 generating sets and the turbines of 6 generating sets were completed on time with high quality. The generating sets successfully started in one time, and in the inspection after 72h test run, no abnormalities have been found. After the upgrading and capacity expansion of the generating sets, the main performance parameters of the generating sets are excellent, satisfy the desired objectives, and meet the requirements for long-term safe and stable operation of the generating sets.

Table 2 Major Technical Parameters of Turbine of HEC Generating Set before and after Upgrading and Capacity Expansion

Parameters	Before Upgrading and Capacity Expansion	After Upgrading and Capacity Expansion
Type	Kaplan turbine	Kaplan turbine
Model	ZZ500-LH-1020	ZZA1101-LH-1020
Rated head (m)	18.6	18.6
Max. head (m)	27	27
Min. head (m)	8.3	9.1
Rated power (MW)	129	153
Rated flow (m^3/s)	825	950.95
Rated speed (r/min)	62.5	62.5

Table 3 Major Technical Parameters of Turbine of DEC Generating Set before and after Upgrading and Capacity Expansion

Parameters	Before Upgrading and Capacity Expansion	After Upgrading and Capacity Expansion
Type	Kaplan turbine	Kaplan turbine
Model	ZZ500-LH-1020	ZZD673-LH-1020
Rated head (m)	18.6	18.6
Max. head (m)	27	27
Min. head (m)	8.3	9.1
Rated power (MW)	129	153
Rated flow (m^3/s)	825	923.39
Rated speed (r/min)	62.5	62.5

3. Feature of the Project

3.1 Best Practice Components

- The renewal, upgrading and capacity expansion of Gezhouba Hydropower Station is to use the built dam hub project and reservoirs to renew and upgrade the old equipment along with the maintenance of generating setsso as to achieve the capacity expansion purpose and improve the power generation efficiency.

- Use the new technology, new material and new process to improve the operating performance of the generating sets, enhance the flow capacity, capacity and efficiency of the generating sets, and effectively use water resources, which is conducive to improving the overall efficiency of the Three Gorges - Gezhouba Hydropower Station joint operation.

3.2 Reason for Success

As of 2014, the renewal, upgrading and capacity expansion of the generators of 2 generating sets and the turbines of 6 generating sets were completed. The generating sets after upgrading successfully started in one time, and maintain safe operation, without any unplanned outage events. After the renewal, upgrading and capacity expansion of the generating sets, the main operation performance parameters of the generating sets are excellent, satisfy the desired objectives, and meet the requirements for long-term safe and stable operation of the generating sets, which indicate that the renewal, upgrading and capacity expansion work of generating sets in Gezhouba Hydropower Station has preliminarily achieved progressive achievement.

In the flood season of 2014, the incoming water of Yangtze River was perfect. After renewal &upgrading, the generating sets in Gezhouba Hydropower Station are running under low head and large flow condition. By increasing the flow for power generating, the single output can be improved by about 10MW so that the flood resources can be fully utilized, which has laid a solid foundation for annual generating capacity 17,795,000,000 kwh of Gezhouba Hydropower Station and achieved remarkable economic benefits.

The project can achieve the progressive achievements mainly because of the following reasons:

Firstly, scientifically determine the goals of the upgrading project. According to the actual situation that after many years of operation, some parts of the generating sets in Gezhouba Hydropower Station have serious aging phenomenon and hidden safety hazards, it is to renew and upgrade the generating sets, eliminate the hidden hazards of the equipment, and improve equipment operation reliability under the condition that the operation conditions of the existing civil works and reservoirs of Gezhouba Hydropower Station are not affected.

Secondly, fully study and demonstrate and deeply develop the model tests to ensure the performance indexes of the upgraded equipment are excellent. China Yangtze Power Co., Ltd. started to study the upgrading of generating sets in 1998. In 2003-2010, the study and comparison for many upgrading solutions of generating sets were performed, including turbine blade repair, turbine runner diameter expansion, runner model optimization (without changing the runner diameter), and studies on the renewal, upgrading and capacity expansion schemes of the generating sets were conducted. Through many times of turbine model tests, and a number of tests on the real units, ultimately the upgrading solution of "achieving the renewal, upgrading and capacity expansion of the generating sets by improving the turbine efficiency and flow capacity, without changing the runner diameter, channels and characteristic head" was determined. Through prototype test for the generating sets after upgrading, it is proved that, compared with the original turbines, the energy characteristics, cavitation performance, stability and other indexes have been greatly improved.

Thirdly, make full use of the electro-mechanical technology upgrade, new materials and new processes. In recent years, the design and manufacturing level of hydro-generating sets in China have been improved constantly. By using the mature process and new technology, it can effectively improve the operation performance of the generating sets, enhance the power generation efficiency, and re-establish the overall mechanical performance so as to eliminate hidden safety hazards caused by long-term operation, increase the service life of the equipment, increase the single capacity of the generating sets with less input, and improve the utilization rate of water resources.

4. Points of Application for Future Projects

[Expected effect of the project]

- Scientifically determine the expected effect of the upgrading project, reduce the impact on the operating conditions of existing civil works and reservoirs of the hydropower station, and decrease the difficulty of the project implementation.

[Project implementation]

- Fully study and demonstrate and deeply develop the model tests and prototype tests to ensure the performance indexes of the upgraded equipment are excellent.

- For the annual regulation hydropower station, implement the upgrading in the dry season as far as possible, and reasonably arrange the project schedule to avoid the loss of power generation efficiency in the upgrading implementation process.

5. Others (monitoring, ex-post evaluation, etc.)

- In the process of renewal, upgrading and capacity expansion of the first batch of generating sets in Gezhouba Hydropower Station, by strengthening the close cooperation with the design and manufacturing parties, the project implementation party timely made evaluation and improvement in the aspects of project technical requirements, manufacturing and installation processes, project implementation and control, etc. and obtained the precious upgrading experience. Subsequently, evaluation and improvement will be performed according to the rolling implementation of the project.

6. Further Information

6.1 Reference

1) Fundamental Technical Requirements for Hydraulic Turbines(GB/T 15468-2006)

2) Hydraulic Turbines, Storage Pumps and Pump-Turbines - Rehabilitation and Performance Improvement (IEC 62256 2008-01)

3) Hydraulic Turbines, Storage Pumps and Pump-Turbines - Guideline for Rehabilitation and Performance Improvement (GB/T28545-2012)

4) The Yangtze River Survey Planning Design and Research Institute Co. Ltd.- Feasibility Study Report for Renewal, Upgrading and Capacity Expansion of Generating Sets in Yangtze River Gezhouba Hydropower Station (approved version), September 2013

6.2 Inquiries

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URL : http://www.cypc.com.cn/CH/index.html