STATE ELECTRICITY AUTHORITY
ICELAND

SUPPLEMENTARY REPORT ON 10 MW NON-CONDENSING GEOTHERMAL POWER STATION AT HVERAGERDI

MERZ and McLELLAN,
32, Victoria Street,
London, S.W.1.

DECEMBER, 1961

MERZ AND McLELLAN

CONSULTING ENGINEERS

ALAN E. POWELL, M.I.C.E., M.I.MECH.E.
ARTHUR HOWELL, M.I.MECH.E., M.I.E.E.
CHARLES L. BLACKBURN, M.I.E.E.
E. LEWIS E. WHEATCROFT, M.I.MECH.E., M.I.E.E.
HAROLD J. BEARD, M.I.E.E.
WILLIAM H. DIXON, M.I.MECH.E., M.I.E.E.
WILSON W. CAMPBELL, M.I.MECH.E., M.I.E.E.
ARTHUR W. PEDDER, M.I.MECH.E., M.I.E.E.
THOMAS W. WILCOX, M.I.E.E., MEM.A.I.E.E.

CONSULTANTS

JAMES R. BEARD, C.B.E., M.I.C.E., HON.M.I.E.E., FEL.A.I.E.E.
T. GRAEME N. HALDANE, M.I.C.E., M.I.E.E., FEL.A.I.E.E.
FREDERICK C. WINFIELD, M.I.E.E., FEL.A.I.E.E.
SIR JOHN HACKING, M.I.E.E.
DR. ALBERT PARKER, C.B.E., F.R.I.C., M.I.CHEM.E., M.I.GAS.E.

ALSO
32, VICTORIA STREET, LONDON, S.W.1.
AND
CARLIOL HOUSE, NEWCASTLE UPON TYNE 1

TELEX: 53224 (ALL OFFICES)

MILBURN,
ESHER,
SURREY.

TELEGRAMS: AMBERKRAFT ESHER
TELEPHONE: ESHER 2345

YOUR REFERENCE

OUR REFERENCE BW

December, 1961

THE DIRECTOR GENERAL,
The State Electricity Authority,
Reykjavik,
ICELAND.

Dear Sir,

10 MW NON-CONDENSING GEOTHERMAL POWER PROJECT

We have pleasure in submitting herewith our Supplementary Report on the development of geothermal power at Hveragerdi, prepared in accordance with your letter dated 23rd June, 1961. The report was submitted in draft form in August.

The report attached hereto deals with a proposal for a 10 MW non-condensing power station comprising two 5 MW sets at Stage I of construction and indicates the estimated cost of extending it by the addition of condensing turbines, in series with the back-pressure turbines, for full utilization of the steam at Stage II. Our findings and conclusions are summarized as follows:-

1. The power potential of steam already proven at Hveragerdi is about 13 MW for non-condensing machines operating at a pressure

of 5 kg/cm^2 gauge at the turbine stop valve. The steam required for 10 MW is sufficient for generating 23 MW condensing or 30 MW when utilizing also flash steam from the hot water separated at the wellheads.

2. We estimate the cost of the first stage, comprising an installed capacity of 10 MW, to be £1,335,000, i.e. £133.5 per kilowatt. We have assumed a 20 year life for the plant and pipework and a 5 year life for the wells. On this basis we assess the energy cost as 0.736 pence per kilowatt hour generated (as against 0.675 pence of our original Report).

3. We have estimated the capital cost as about £95 per kilowatt installed for the completed 30 MW station which would include a Stage II condensing station having a nominal output of 20 MW.

We are, Sir,
Yours faithfully,

MERZ and McLELLAN

STATE ELECTRICITY AUTHORITY

ICELAND

SUPPLEMENTARY REPORT ON 10 MW NON-CONDENSING GEOTHERMAL POWER STATION AT HVERAGERDI

MERZ and McLELLAN,
32, Victoria Street,
London, S.W.1.

DECEMBER, 1961

CONTENTS

SECTION 1

OUTLINE

Advantages of non condensing scheme

The ostensible advantages of a 10 MW non-condensing station compared with the 17 MW condensing project covered by our report of March 1961 are as follows:-

1. Reduced initial capital expenditure by some £650,000 resulting from smaller simpler turbines exhausting to atmosphere and requiring buildings of smaller volume and lower basement height and no circulating water works.

2. The site can be chosen without regard to cooling water requirements and may accordingly be nearer the centre of gravity of the bores. This advantage applies to a pure non-condensing station and is lost if the station is ultimately to be converted to a condensing station by the addition of low pressure turbines in series.

3. A somewhat higher steam pressure at turbine inlet, viz 5 kg/cm^2, can be selected as the choice is free of turbine exhaust wetness limitations. This is particularly advantageous at the initial stage and retains significant merit if condensing plant is added.

4. Allows greater freedom to accommodate for changes brought about by accumulated information regarding the behaviour of the steam wells and the location of the steamfield.

Against these advantages there are some drawbacks, namely:-

1. Certain constant items of capital expenditure which would be common to both condensing and non-condensing projects assume a higher cost per kilowatt at the reduced output of the non-condensing station.

2. The steam rate of the non-condensing station is about double that of the condensing station so the cost of extra wells and steam collecting pipework partly offsets other savings. The same quantity of steam as is required for 10 MW non-condensing is capable of generating some 23 MW condensing (or 30 MW if flash steam is used).

Factors affecting choice of site

There appear to be three possibilities in selecting the site having regard to the probable future extension to run condensing:-

(a) To place the non-condensing station as near as practicable to the present centre of gravity of successful bores and to assume that any future condensing station will be immediately adjacent. A possible location for the station is indicated as B on Plate 1.

(b) To place the non-condensing station as in (a) but to pipe its exhaust steam at about atmospheric pressure ultimately to a condensing station on the site chosen for the original condensing project (shown as A on Plate 1).

(c) To retain the site of the original condensing station and to construct the non-condensing plant on that site so as to form a part of a future condensing station.

The advantage of (a) is that the pipework is reduced to a minimum, being largely collecting steam pipework rather than transmission pipework. A transmission distance of approximately 1000 metres can be saved by this means as compared with (c). The distance of 1000 metres applies to Well No. 8 which has a particularly good steam yield and is in the area where we presume further production drilling will be carried out. Alternative (b) retains this advantage, as regards the high pressure pipework, but suffers an even higher cost and inconvenience at the later stage when the whole of the steam would have to be transmitted over some 1000 metres at about atmospheric pressure, involving the use of very large diameter pipes.

Alternative (c) has the advantage of making use of the natural features of the terrain in that the Varma River at the point selected would offer sufficient natural cooling for something like 20 per cent of occasions for a 30 MW condensing station and can readily be dammed to form a low cost spray pond capable of providing supplementary cooling to cover the remainder of occasions. The location of the station on the edge of the steep bluff adjacent to the river some 7 metres above river level is advantageous as saving basement height if the orthodox location of the condensers immediately under the turbine is adopted and has some advantage even with outdoor condensers.

Chosen site

Our findings are that alternative (a) involving locating both initial and ultimate stages of the station close to the wells results in a cheaper non-condensing station but a somewhat more expensive condensing station, the overall cost of alternatives (a) and (c) at the ultimate stage being little different. Alternative (b) has nothing to recommend it and is not considered further. We have selected alternative (a) because it shows the lowest cost at the initial stage and seems to be at no significant disadvantage on the overall scheme.

We have not made any close investigation on the ground of sites further north than the one originally selected. Consequently we have to rely on map indications. It appears from maps and aerial photographs that a flat area exists on the south side of the Varma River between Wells No.6 and 7 in the position indicated by B on Plate 1. A non-condensing station located there would be well placed in relation to the bores, the greatest separation being about 650 metres from Well No.3. Well No.8 would be about 500 metres north-west of the station.

The saving on steam pipework we estimate to be of the order of £100,000 as compared with site A for the number of wells required for 10 MW back-pressure plant.

Considering the ultimate extension with condensing turbines, the river at site B being of negligible account, we have to make provision for artificial cooling for all the circulating water on all occasions. If a pond of some 25,000 m^2 in area could be formed by bulldozing off about 1 metre of loose material and lava and the rock used to make an embankment, then a spray pond at this site would be the best solution assuming that it will cost less than £100,000 which we estimate to be the cost of natural draught cooling towers for the 30 MW plant. If the exposed lava forming the pond bottom is not sufficiently watertight it might be covered with a layer of geothermal clay which is available nearby.

The station could be completely independent of the river as the condensate would provide more than sufficient water to cover evaporation and other minor losses. However it is likely that the pond would be constructed to embrace the river, and the additional cooling so obtained would outweigh possible drawbacks in the river bringing down sand and stones and being liable to flood.

There is difficulty in making a precise comparison of costs for site B with those of site A in that the foundation conditions and contours at the former have not been fully investigated. Moreover there is a variety of ways in which the ultimate condensing plant might be designed, the choice of which will depend on details of the site and also on the state of knowledge at the time including the experience gained in the meantime.

Thus at the one extreme we could assume the use of natural draught cooling towers and an orthodox condenser arrangement, with the condenser immediately beneath the turbine. On a flat site such an arrangement would involve tall buildings. In this case the extra cost of the ultimate station on site B might include about £40,000 for the high buildings and £60,000 to £70,000 extra for cooling towers over the cost of a spray pond. This makes a total of £100,000 or £110,000 in extras which just about negatives the saving on steam pipework of £100,000. At the other extreme there could be a spray pond at site B and outdoor condensers on both sites. In this case the extra cost of the pond at site B might be, say, £20,000 and the extra cost of outdoor condensers on site B might be £10,000, making £30,000. The saving of £100,000 on steam pipes will then give site B an advantage of some £70,000. More accurate estimates than this cannot readily be made at present.

SECTION 2

DESIGN OF POWER STATION

Turbine inlet pressure

Within fairly wide limits the choice of inlet pressure for the non-condensing machines is not of primary importance, but we consider that there is sufficient reason to specify a pressure higher than that of 3 to 3.5 kg/cm^2 gauge which we selected as appropriate for a straight condensing machine. Two special factors arise. First, considerations of excessive exhaust wetness which limited the choice of the maximum inlet pressure for a condensing machine to about 3.5 kg/cm^2 gauge are no longer relevant in the case of a back-pressure machine exhausting at atmospheric pressure. If the station is later extended by the addition of condensing machines in series, separators will be installed in the cross-over pipework connecting the back-pressure and condensing turbines to limit the final exhaust wetness. Secondly the change in power output which results from working at higher wellhead pressures, with lower steam yields from the wells, is of small account with back-pressure generation.

The change in power potential with the well characteristics as so far proven, resulting from the choice of 5 rather than 3.5 kg/cm^2 gauge as turbine inlet pressure, is seen from Table 1 to be about 4 to 5 per cent increase when back-pressure generation alone is considered, compared with some 8 per cent reduction when considering condensing

TABLE 1

POWER OUTPUTS AT TURBINE INLET PRESSURES OF 3.5 AND 5 kg/cm^2 GAUGE

Turbine inlet pressure (kg/cm^2 gauge)	3.5	5
Nominal wellhead pressure (kg/cm^2 gauge)	5	6
Steam output of Wells 2,3, 6,7 and 8 (kg/sec)	70	60
Power output of back-pressure turbines (atmospheric exhaust) utilizing whole of steam output (MW)	12½	13
Power output of condensing turbines utilizing exhaust of back-pressure turbines (MW)	20	17
	32½	30
Approximate additional condensing output by utilizing flash steam (MW)	8	9

Note: The condensing outputs are calculated for a back-pressure of 1½ in Hg.

generation without flash steam, or 3 to 4 per cent reduction with flash steam.

It will be seen in Table 1 that the pressure drop between the wellhead and the station has been reduced from 1.5 kg/cm^2 at 3.5 kg/cm^2 inlet pressure to 1 kg/cm^2 at the higher turbine inlet pressure. The explanation is that in our opinion 5 kg/cm^2 gauge at the wellhead is about the minimum desirable working pressure for the wells due to the extremely high velocities which are developed as the pressure is reduced. Hence the pressure drop of 1.5 kg/cm^2 between the wellhead and the station was fixed arbitrarily by the allowable working pressures at the wellheads and the turbines. Advantage can now be taken of the closer proximity of site B to the bores compared with site A by designing for a smaller pressure drop and this entails increasing the turbine inlet pressure, but we have also increased the wellhead pressure in the light of the greater yields of later wells.

The fairly small loss of output of the ultimate back-pressure and condensing development is we think outweighed by certain practical advantages to be gained by adopting the higher pressure. The steam transmission pipe sizes (and the tonnage of steel employed) are reduced because of the lower mass flow and lower specific volume of the steam. Velocities in the well casings are somewhat reduced. The amount of flashing occurring in the wells is also slightly reduced so that the rate of scaling in the bores may be expected to be less, and the interval between drilling out deposits possibly extended. One other small advantage to be gained from adopting higher pressure is that the performance of steam jet ejectors, which might be used for gas extraction in Stage II, would be improved.

We are satisfied that any further substantial increase of turbine inlet pressure above the somewhat arbitrarily chosen level of 5 kg/cm^2 gauge, based on the characteristics of the present wells, would not be justified, the loss of power output becoming of increasing importance.

Steam requirements for 10 MW non-condensing station

The steam rate of a back-pressure turbine supplied at 5 kg/cm^2 gauge and exhausting to atmosphere will be about 17 kg/kWh, and the nominal requirements of a 10 MW station are accordingly 48 kg/sec. This is some 14 per cent more than the steam requirement of the 17 MW condensing station considered in our March Report.

The present combined output of Wells Nos. 2,3,6,7 and 8 is about 60 kg/sec at a wellhead pressure of 6 kg/cm^2 gauge. Thus there is very little spare productive well capacity, and additional bores will have to be drilled to give security of supply. Provision has to be made for Well No. 8 being out of service for drilling out deposits. This well yields about 24 kg/sec at 6 kg/cm^2 gauge which is twice the average yield. Accordingly we estimate that two new wells are required in any case and three will be needed to give 100 per cent standby on steam requirements.

Design pressure for pipes and equipment

Although a higher pressure of 5 kg/cm^2 is proposed for the turbine inlet the design pressure for the pipework and separators can still be specified for 150 lb/in^2 which we had adopted for the lower turbine inlet pressure of 3.5 kg/cm^2. For Stage II, the steam pipework inter-connecting the back-pressure and condensing stations would be specified for a nominal working pressure of 16 lb/in^2 absolute. However, the wall thickness will far exceed the calculated thickness, based on stress arising from operating pressure, being dictated by strength requirements for handling and welding in the field and the corrosion allowance.

Layout and plant arrangement

In order to indicate the order of the space requirements which would be valid on any site, we have shown on Plate 2 a preliminary layout of the back-pressure station and the space allocated for the Stage II extension. This is drawn for the same site as was chosen for the straight condensing station. A similar plant arrange-ment would be adopted for the alternative site B but the building levels would of course be altered to suit the ground formation as discussed in a previous section. The arrangement of the Stage II extension, including the spray pond and circulating water pumphouse, is appropriate to only site A although many features would be valid for the alternative site.

Steam from the wells is collected in a manifold on the east side of the station and is fed to two 5 MW machines via steam/water separators. The exhaust from the turbines is piped to a chimney outside the turbine room on the east side. The chimney will have to be of sufficient height or at sufficient distance from the station to disperse the steam and corrosive gases, otherwise troublesome icing up of buildings and switchyard equipment might occur and corrosive gases might concentrate in the station vicinity. Alternatively, the steam could be discharged slightly upward at ground level, possibly over the river, but well clear of the station. For the future condensing extension, provision would be made to extend the exhaust manifold along the east side. The valving arrangement in the exhaust ducts would enable the back-pressure machines to operate independently of the condensing machines.

In addition to the exhaust from the back-pressure sets, steam flashed from high pressure hot water separated at the wells would be supplied to the condensing machines of Stage II at about atmospheric pressure, the combined steam flow passing through separators before entering the turbines. The exhaust from the back-pressure turbines would have a wetness of approximately 7 per cent, and a small water content of the order of 1 per cent could also be carried over from the flash vessels.

Cooling water system

The back-pressure station requires small quantities of cooling water for the turbo-alternator oil coolers and air coolers. Either a small evaporative type cooler or alternatively air cooled radiators would be suitable for these duties, or by making a small dam sufficient water could be extracted from the river. All methods present some risk of freezing, the last being least vulnerable as there is sufficient hot water discharged to keep the river free of ice if reasonable precautions are taken. In a self-contained air cooled circuit anti-freeze could be used.

For Stage II the arrangement of the condensers and circulating water system is similar to that proposed in our first report. Each condenser is of the jet type using a barometric tube to discharge the condensate to a sump, adjacent to the pumphouse, which serves as the booster pump suction bay. The water is then pumped to the spray pond for cooling. For site A we had hitherto visualized the use of a cooling tower for the second stage of the straight condensing station. However, the cooling duty has been reduced because of the reduction in steam rate resulting from the higher turbine inlet pressure. Also, we see no objection to using the area of the pond further to the north to supplement the spray capacity and if necessary the pond could be extended beyond its present contour limits by bulldozing. The cooling water to the two condensing machines will be supplied by two pumps each delivering 18,000 Imperial gal/min (1,370 litres/sec) against a net head of some 55 feet (17 metres) and the motor rating will be about 320 kW. The three booster pumps for the sprays would have a rating $\frac{2}{3}$ that of a circulating water pump.

Electrical features

The electrical installation for the back-pressure station is simplified in that a supply for auxiliaries will not be required for starting the 5 MW machines. The two generators feed a single 10.5/138 kV transformer rated at

12 MVA. A 2 MVA, 10.5/11 kV transformer connected to the main switchboard supplies local load to the existing Sog system at 11 kV as indicated in our March Report. An auxiliary switchboard rated at 400 V, 25 MVA supplies power for the crane, workshop, lighting, etc.

The generation voltage of 10.5 kV has been retained and a rupturing duty of 350 MVA is recommended for the main switchboard. The Stage II condensing station would preferably be connected to a separate busbar via another step-up transformer of approximately 23 MVA rating to the single 138 kV breaker, keeping the two sections of main switchgear normally uncoupled.

SECTION 3

ESTIMATE OF COSTS

Capital expenditure - Stage I

Table 2 gives an estimate of capital cost for a station, located on site B, comprising two 5 MW back-pressure turbo-alternators, the net output of which will be almost 10 MW as auxiliary power requirements are negligible.

Generally our estimate is based on the same information as was used in the preparation of the estimate for the 17 MW condensing station submitted in our Report of March 1961.

We have assumed that certain of the capital cost items are unaffected by the substitution of a 10 MW back-pressure station for the 17 MW condensing station. These items are:-

1. Drilling rig and accessories.
2. Extensions to Ellidaar switching station.
3. Acquisition of property.
4. Houses for station operators.

We have further assumed that the same security on the supply of steam for the station is required, hence we have allowed for drilling wells to yield 96 kg/sec, at at wellhead pressure of 6 kg/cm^2 gauge, which is twice the nominal steam quantity needed for a station output of 10 MW. The total number of wells to produce this steam is assumed to be eight, based on an average yield of 12 kg/sec from each well. The cost of drilling and testing wells was taken at £500 per ton/h in our Report of March 1961, the figure being based on the measured yields at a wellhead pressure of 5 kg/cm^2 gauge. We now put the cost of drilling and testing at £580 per ton/h to compensate for the reduced yield at the higher wellhead operating pressure of 6 kg/cm^2 gauge.

TABLE 2

ESTIMATE OF CAPITAL COST FOR 10 MW NON-CONDENSING STATION

	£'s	
	Fob	Total cost in Iceland
Turbo-alternators, transmission pipework and wellhead equipment	225,000	383,000
Power station building, foundations, other civil works and crane	31,000	118,000
Wells: drilling and testing		197,000
Drilling rig and accessories		85,000
Electrical equipment including 138 kV transmission line spur	81,000	133,000
Extensions to Ellidaar switching station		90,000
Acquisition of property and disposal of hot water		68,000
Houses for station operators		30,000
		1,104,000
Contingencies and engineering		110,000
		1,214,000
Interest during construction 1.43 years at 7%		121,000
		1,335,000
Cost per kilowatt installed		£133.5

Cost of energy production

Using the capital estimate in Table 2 we calculate the cost of energy production as follows:

	Charges per annum, £'s
Interest on total capital 7% on £1,335,000	93,000
Sinking fund contribution: Basis 20 year life 2.5% on £1,098,000	27,000
Annual cost of well drilling: Basis 5 year life 17.4% on £237,000	41,000
plus cleaning out and maintenance on 8 wells at £5,500 per well	44,000
Operating salaries and wages	15,000
Administration and general expenses	10,000
	230,000

On energy generated
7500 hours use of maximum demand at 10 MW = 75 GWh

Generated cost: **0.736 pence/kWh**

Extension to Stage II

The extension of the station to a nominal 30 MW by a second stage utilizing the exhaust steam of the back-pressure sets and flash steam is estimated to cost £77 per kilowatt. The completed station would then cost about £95 per kilowatt.

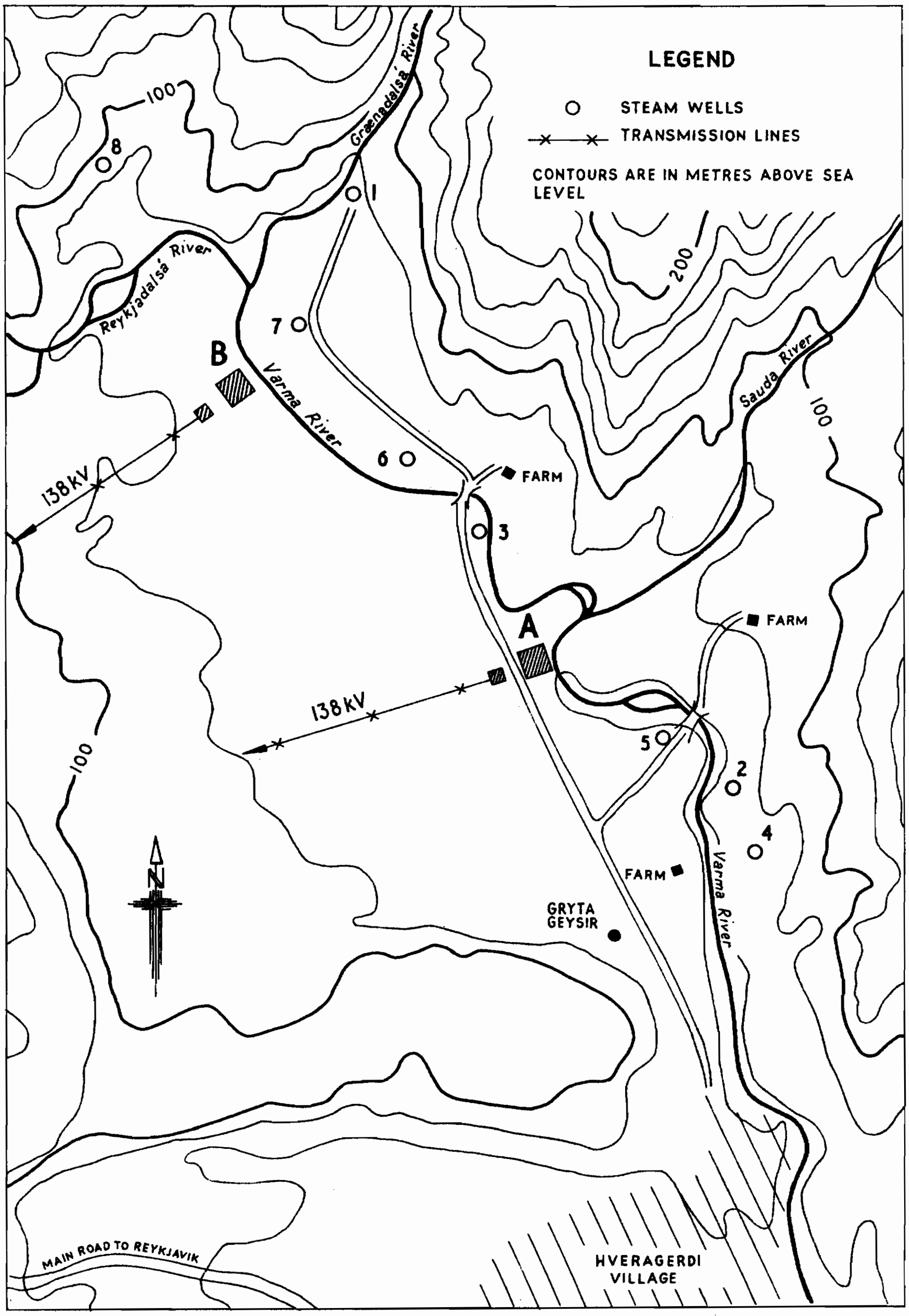
Stage II will not require a greater number of wells to commission the station hence there are no additional transmission pipe costs to be met. Wells will of course have to be replaced on the basis of the assumed 5 year life. The circulating water system and the flash steam plant are the principal additional features to be provided for the extension. No allocation has been made for any additional transmission line or for electrical extension at the receiving end since this will depend on the timing of the Stage II programme in relation to general system development.

Staffing

We do not visualize that the staffing arrangements for the back-pressure station will be different from that for the condensing station discussed in our previous report and we would assume a total of 16 men would be needed. A drilling crew of five men will still be engaged on the redrilling of wells and doing maintenance work on the wellhead and other equipment when not engaged on drilling.

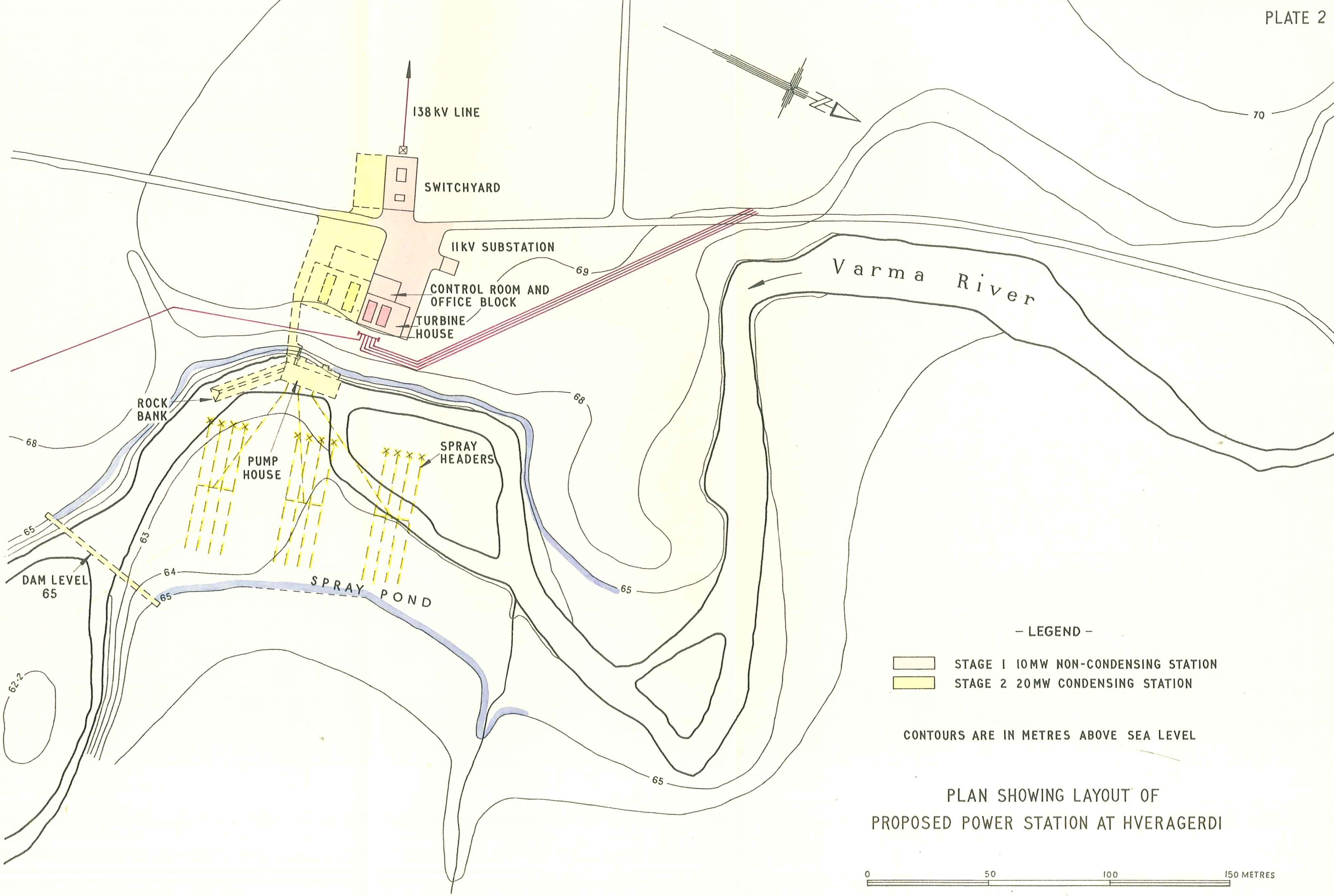
Time of construction

The manufacturing period allowed for the turbo-alternators is thirty months plus six months for delivery and erection and this is the controlling factor for the construction time. Hence construction time would be three years from the date of placing an order for the turbines as all other contracts could we consider be fitted into the same period.



HVERAGERDI STEAMFIELD

0 100 200 300 400 500 m



PLAN SHOWING LAYOUT OF
PROPOSED POWER STATION AT HVERAGERDI