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Kawerau Steamfield Design

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ABSTRACT

The steamfield production piping size for the Kawerau geothermal power plant was determined by using predicted well performance and decline rates.

The final steamfield configuration used six production wells. The design optimization was based on the test data from four wells, which was extrapolated to include both "normal" and "big bore" wells.

A method of using the predicted well performance to determine the influence on steamfield piping size is reviewed. The method takes into account capital cost and make-up well drilling, and how this impacts net present value.

1. INTRODUCTION

Kawerau geothermal file has a long history of development. The original development has been mainly focused on supplying steam for direct use in the near-by pulp, paper, & timber mills. A recent large-scale development has been focused on electricity generation. This paper is concerned with the associated steamfield above ground gathering system, (also known as the resource production facility).

A steamfield's primary function is to transport geothermal fluid from the production wells to the power plant. It also transports waste fluid from the plant to the injection wells. This paper is only concerned with the production component.

The production wells are all located within, or close to, the pulp and paper mills. This significantly limited the possible pipe routes available to the designer. The impact of this was mainly in detailed engineering and construction difficulties.

A steamfield conceptual design should include the following considerations:

1. Well performance
2. Initial loss or "first flush" well decline
3. Reservoir decline
4. Economic pipeline pressure losses
5. Flow Regime
6. Design Life
7. Well flow control
8. Control methodology
9. Risk
10. The cost of construction

2. CONCEPT DESIGN

The majority of the production steamfield is located within or close to operational industrial facilities. (Refer to figure 1 – layout).

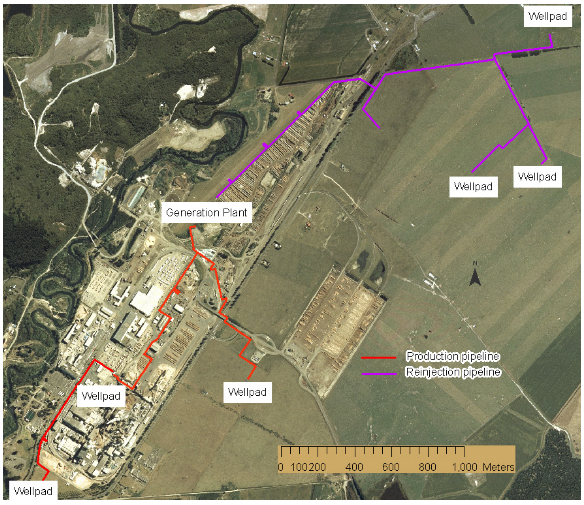

Figure 1: Kawerau Steamfield Layout

Venting of two phase fluid within the industrial facility was not acceptable (other than the small quantities required for pipeline warm up or shut down). Pipeline pressure protection was therefore located at the separation plant. Because pressure protection must be located upstream of isolation valves, this meant that branch line isolation valves were not practical.

Four production wells are located within the industrial plant confines. Two wells are located outside the industrial plant in nearby farm land.

Nominally, each of the wellpads is designed for one third of the generation plant's maximum design flow. The concept design goal was to be able to have sufficient flexibility to operate the plant on two wellpads only. Pipelines were to be designed so that slugging did not occur when operating at minimum design flow.

3. ECONOMIC EVALUATION

Well operating flow rate is proportional to the wellhead pressure. Wellhead pressure is governed by the plant inlet pressure and the pipeline pressure drop between the wellhead and the station. For the Kawerau development, the plant inlet pressure had been selected (based on estimated well performance curves and a performance based power plant tender process) and had been fixed by the time the steamfield optimization process had commenced.

Increasing pipe diameter decreases pressure drop (and consequently minimum operating wellhead pressure) but increases capital cost. Well decline rate (after the initial loss) and the minimum operating wellhead pressure affect the make-up well drilling rate. Pipe diameter selection is therefore a tradeoff between the number of wells initially drilled, the capital cost of the piping, and the make-up well drilling rate.

As there is a long production history of geothermal development at Kawerau, estimates of decline rate and well performance could be made with reasonable certainty. The wells drilled for the Kawerau project tended to have performance curves that were not heavily dependant on well head pressure (i.e. better performance than anticipated). This allowed the use of smaller diameter pipes than what was originally planned. In terms of pipe size the optimum diameter chosen would be the smallest for the worst case decline rate. From a pure risk vs. reward perspective, this approach is conservative but much less than the original estimate.

A hallmark of successful geothermal development is the ability to deal with change. Capital cost should be spent to allow easy adaptation to reasonably foreseeable change. It may not be appropriate to invest significant amounts on low probability (or long term) changes – it is possible that something else alters leaving inappropriately sized or stranded assets.

4. TWO PHASE FLOW

Prior to the steamfield pipe size optimization, established two phase pressure drop calculation methods were reviewed. Pressure drops were calculated for various pipe sizes. These pressure drops were compared with those calculated by consultants.

In general, pressure drop calculation results were consistent. However, some consultants had significant concerns about the flow regime as the Mandhane chart (and variants thereof) predicted that the pipeline would be subjected to slugging. As the diameter of the piping was large; avoidance of a slugging flow regime was required. Wellhead separation was recommended by some. Wellhead separation would have incurred significant increase in capital cost and an increase in parasitic load and operating cost due to high pressure brine pumps being required.

It is important to note that the terrain at Kawerau is flat. Review of the liquid phase distribution and velocity showed that it was improbable that a slug could form. The anticipated flow regime was either stratified or wavy. There was some concern slugging could be induced at abrupt changes in grade such as road crossings.

The pipeline specification required mechanical design for slug loading. A slug load was defined as two pipe diameter long slug traveling at superficial steam velocity (applied at every direction change).

5. PIPE SIZE SELECTION

The initial estimate for pipe sizes was based on preliminary well performance curves. These pipe sizes we used to develop the first budgetary estimate. Subsequent drilling and testing of wells indicated that their performance was greater than expected. Pipe sizes were then revised to take advantage of the well’s performance and therefore lower the steamfield capital (and net present value) cost. Pipe size selection was limited to commonly available sizes.

Figure 2 shows the impact of a particular decline rate on a series of typical well performance curves. These curves were tailored for each well, and later updated with the results of well performance tests.

Figures 3 to 6 give an indication of the evaluation results for the worst and expected well decline scenarios. These are based on well performance curves similar to those shown in figure 1.

6. PROOF OF CONCEPT

During the commissioning of the plant attempts were made to induce slugging in the two phase piping. The test procedure was to establish the minimum design flow at low pressure and then increase pressure until the operating pressure was achieved (or excessive slugging occurred). The flow rate was then decreased in stages. At no stage was slugging detected by the observing operators. During the steam separation system commissioning, the level in the water vessel was observed to cycle. Modification to tuning was required to reduce water level control valve hunting. The surging water level suggests that a wave type flow is occurring, as was expected.

Monitoring over a number of years will be required before decline rates can be confirmed. The test data to date confirms the design assumptions.

7. CONCLUSIONS

Initial operation has indicated that the use of predicted decline rates to establish optimal pipe size has been successful when applied to the Kawerau Geothermal power development. Smaller pipe sizes were used than were originally estimated. As well as reducing the steamfield capital cost and net present value, smaller sizes have helped reduce the likelihood of slugging, if it were to occur at all. This gave confidence to use a single separation plant rather than wellhead separation.

The Kawerau geothermal field has a long history of extraction. A high level of confidence can be given to predicted well performance and decline rates. The method for pipeline optimization described in this paper may not be appropriate for a development where less historical data is known.

This method of steamfield evaluation was used because the plant inlet pressure had been chosen by the time the steamfield was optimized. Determining the optimum plant inlet pressure using similar methods has the potential for a sufficiently greater impact than just optimization of the steamfield alone.

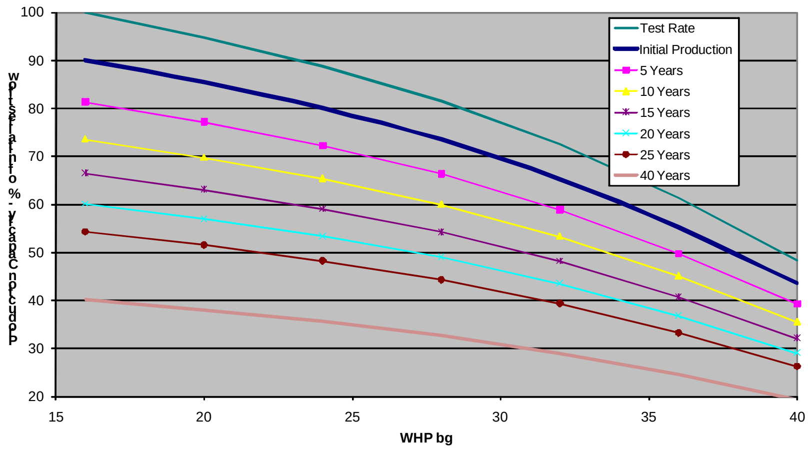

Figure 2: Typical predicted well decline rates

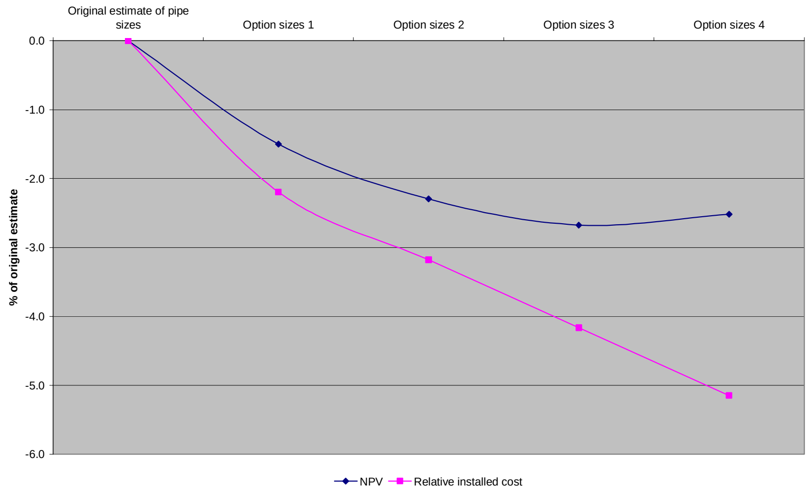

Figure 3: Net Present Value and Relative installed cost for worst case prediction of decline rates

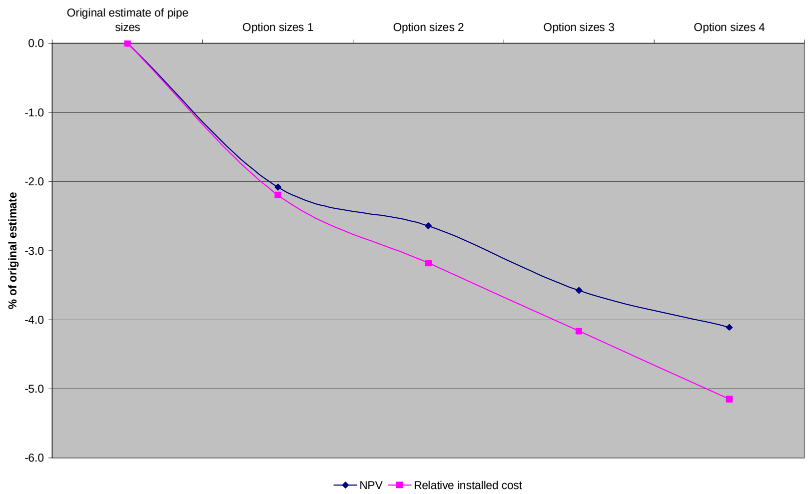

Figure 4: Net Present Value and Relative installed cost for expected decline rates

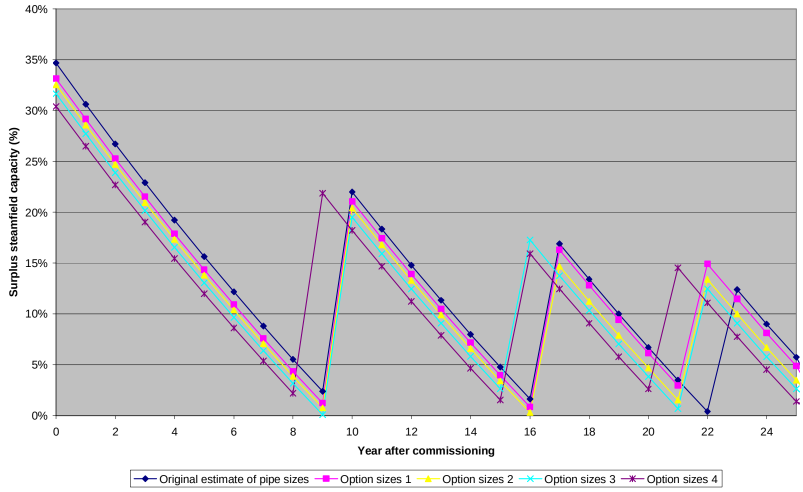

Figure 5: Surplus steamfield production capacity for predicted worst case decline rates

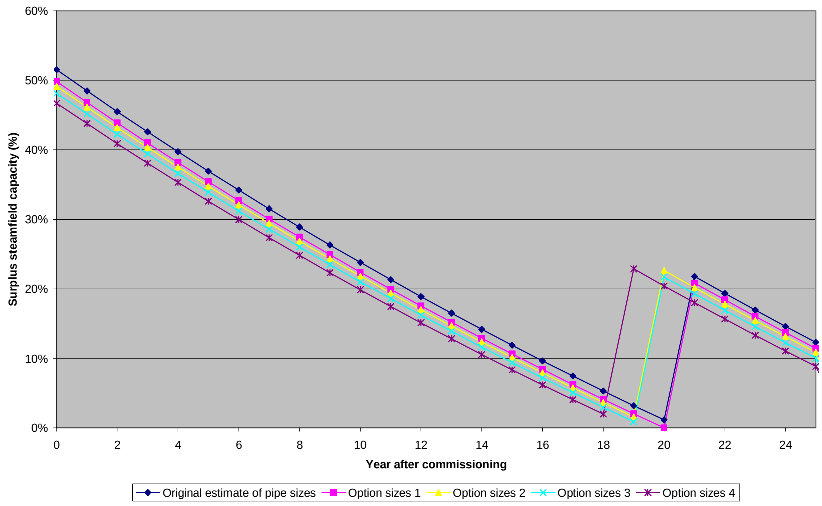

Figure 6: Surplus steamfield production capacity for expected decline rates