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ENGINEERING ASPECTS OF THE DOWNHOLE GAS SEPARATOR

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ABSTRACT

Placement of a full size downhole gas separator (DHS) in a geothermal well is not considered a too highly complicated engineering exercise. The majority of problems and inconvenience occur later when the system is running and when well maintenance is required.

The preferred system is when the separator is fixed in the casing and the tubing carrying the extracted gas is allowed to expand through a gland at the wellhead.

All considered options of placing the separator precluded the use of downhole measurement instruments and more importantly monitoring of deposition build-up in the production zone.

At the time of writing no clear evidence was available to determine the exact level of deposition in any one well nor what affect the separator itself had on the level of deposition.

The estimate for placing the DHS in 1984 was $182200 the cost of removal $80000 and the cost of replacement $140000. An annual workover to remove calcite above and below the DHS, which would include replacement, was expected to cost $297000 without the cost of a new DHS.

INTRODUCTION

When the DHS was being considered as a full size downhole device MWD were asked for comments on possible installation and maintenance. Points to be considered were:

(a) The separator had to be located in the production casing after the hole was drilled and the slotted liner run (if required).

(b) It would need to be retrievable to enable maintenance work to be done below the separator.

(c) If possible the separator had to be manufactured in material that was drillable in **case** it got locked in position through deposition or corrosion.

(d) Free expansion of the tubing carrying the extracted gas had to be allowed for. If the separator was hung from the tubing then the separator had to be free to move **up** and down the casing. If the separator was firmly fixed to the casing then the tubing had to be allowed to either expand in a sliding joint in the tubing (difficult to inspect and maintain) or expand through a gland at the wellhead (or both).

(e) If fixed to the casing the system of locating the separator had to be adequate to support the tubinu weight.

All these points were considered along with specific comments on the cost of placement, removal and replacement were considered a5 well as the 'mass flow/steam **loss** due to placement of a restricting tube in the production casing.

DESIGN & CHOICE OF EQUIPMENT

It became apparent during a preliminary study that if the separator was hung from tubing then deposition or junk could wedge the separator, which must be free to move, in the casing resulting in the possible failure of the tubing. It was decided to consider a seating liner fixed to the inside of the production casing and with **a** top connection (tie back) to allow fixing to the **DHS** device.

The preferred system was a casing packer/stage cementer made of drillable materials with a tie back connection above the stage cementer. The packer/cementer would be set by a liner run back to the surface **with** the packer set by an opening plug which also opens the cement ports, and a cementing plug run to place a small amount of grout between the cementer and production casing. Fig 1.

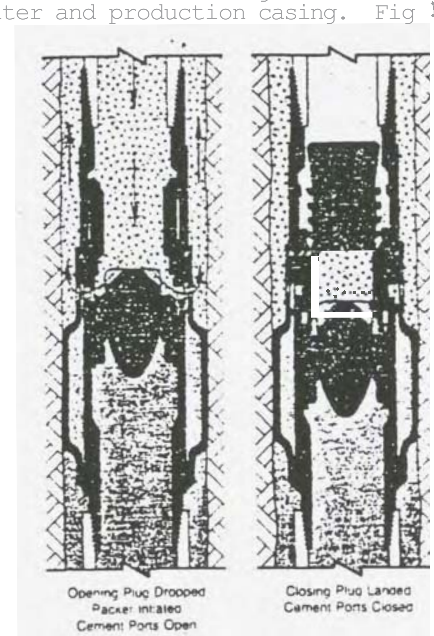

Fig 1.

The liner could then be removed from the tie back. An alternative system of running the packer/cementer on drillpipe would be more difficult when pressurising the packer to set with the cementing plugs held above the stage cementer.

The packer/cementer is drilled through to

Even if the slotted liner was not run in the well the production area would require full gauge reaming and scraping. As mentioned above the seating liner must therefore be made of a drillable material.

The DHS must then support the gas carrying tubing if seated and "tied back" into the cemented liner seat. A strengthened support would probably enclose the DHS and have an "easy release" connection for the tubing. This is to enable the tubing to be retrieved for workovers if the DHS adhered to the well bore (production casing) during its operation. The DHS would therefore also need to be manufactured in drillable materials.

The casing I.D. for the majority of Ngawha wells, for example, is 7.825". By allowing for the tubing support shell the maximum size for the DHS would be approximately 6". By using wells with 9-5/8" casing a larger diameter DHS is permitted. The placement of the DHS in 8-5/8" production casing is shown in Fig 2.

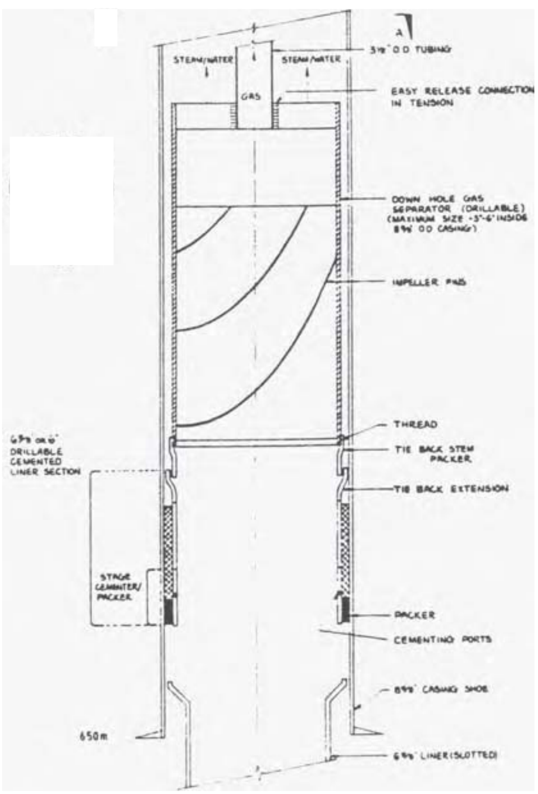

FIG. 2.

On present experience a minimum of four casing strings is required at Ngawha. There would be large cost increases in extra casing handling equipment for drilling if the maximum size to 650m was increased from 9-5/8" to 13-3/8". This cost may not be offset by the DHS separator usage savings alone. However, a nett gain in energy output from a larger bore may warrant the installation of a 13-3/8" production casing.

An alternative to the DHS supporting the tubing weight (approx 5,000 kg for 3½" dia pipe) would be a sliding joint with a the DHS thus allowing a larger diameter device to be installed. However there is the risk of the sliding joint becoming stuck due to deposition or debris and in any case a glanded wellhead which allows for the full expansion of the tubing should be allowed for. This wellhead would be similar to the NG9 dual completion. Fig 3.

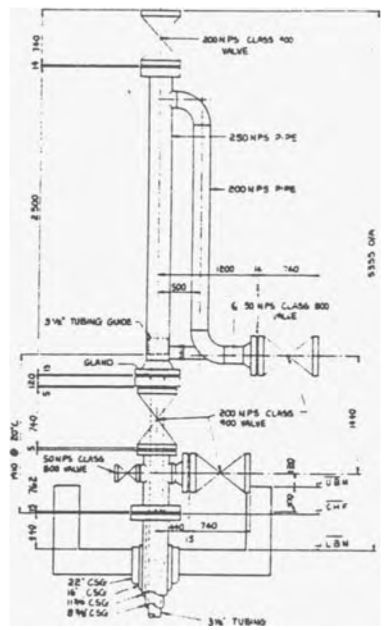

FIG. 3

The height of the wellhead is dependent on the expansion and contraction of the tubing and is calculated by:

$$\Delta L = \alpha L (\delta T)$$

where α = coefficient of expansion for the tubing ($11.7 \times 10^{-6}/°C$.)

L = depth to DHS or length of tubing (650m)

δT = temperature difference (°C)

(a) <u>Heating</u> (δT = 250°C)

Expansion after placement = $11.7 \times 10^{-6} \times 650 \times 250$m

= <u>1.9m</u>

(b) <u>Cooling</u> (δT = 40°C)

Contraction when quenching = $11.7 \times 10^{-6} \times 650 \times 250$m

= <u>0.3m</u>

MASS FLOW/STEAM LOSS

The question of mass/steam loss by placing a 3½" O.D. tube in an 8-5/8" dia Ngawha well between 400m - 650m was raised during the approval stage of developing the DHS and the following comments are appropriate.

The best practical guide for calculation was the NG9 dual completion results.

(a) The annular flow was outside the scope of the formulae used previously and preliminary calculations using an equivalent hydraulic radius for the annulus did not give very accurate results when compared to NG9 data.

In NG9 the 5½" cemented liner inside the 8-5/8" casing reduced the flow by 50%. For 3½" tubing a reduction by 30% could be assumed.

(b) The removal of gas reduces the buoyancy of the two phase mixture, hence reduction in flow and wellhead pressure.

(c) The DHS would provide throttling of the well bore. However, pressure drops may only be in the order of 1 to 2 bars (Grant-Taylor pers comm).

MONITORING OF DEPOSITION AND WELL PERFORMANCE

Quite simply, while installed, the DHS precludes the use of downhole measuring devices and more importantly monitoring of deposition buildup in the production zone.

ESTIMATES OF COST (1984)

(a) Cost of placement

Manhours	2,000
Labour	$ 23,500
Plant	$ 43,700
Materials	$ 33,000
Others (o/heads etc)	$ 77,500
Salaries	$ 4,500
Total	$182,200

NB does not include cost of DHS or its development.

(b) Cost of Removal of the DHS

To remove the wellhead and the DHS and drill out cemented liner (or DHS if stuck).

= $80,000

(c) Cost of drilling out calcite in the slotted liner, removal and replacement of same.

= $77,000

(d) Cost of replacement of the DHS

The cost of replacement is $182,000 less the cost of tubing and the wellhead.

= $140,000

Annual cost of workovers at Ngawha assuming calcite removal required every 12 months without the cost of the DHS is:

ACKNOWLEDGEMENTS

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